## ATTACHMENT A

To avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, the following restrictions are imposed:

1. The diesel fuel used in drilling and completion equipment engines will be limited to Ultra Low Sulfur Fuel (ULSF) with a maximum sulfur content of 15 ppm.

2. There will not be any simultaneous operations of the drilling and completion equipment engines at the single well pad.

3. The maximum number of wells to be drilled and completed annually or during any consecutive 12--month period at a single pad will be limited to four.

4. The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, then the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control devise to limit the benzene emissions to 1 Tpy.

5. Condensate tanks used at the well pad shall be equipped with vapor recovery systems to minimize fugitive VOC emissions.

6. During the flowback phase, the venting of gas from each well pad will be limited to a maximum of 5 MMscf during any consecutive 12--month period. If "sour" gas is encountered with detected $H_2S$ emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m).

7. During the flowback phase, flaring of gas at each well pad will be limited to a maximum of 120 MMscf during any consecutive 12--month period.

8. Wellhead compressor will be equipped with NSCR controls.

9. No uncertified (i.e., EPA Tier 0) drilling or completion equipment engines will be used for any activity at the well sites.

10. The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both

particulate traps (CRDPF) and SCR controls. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence.

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

## ATTACHMENT B

PASSBY FLOW IMPLEMENTATION AND ENFORCEMENT

1. Monitoring and Reporting**.** Passby flows must be maintained instantaneously. Determinations of allowable removal rates will be made based on comparisons with instantaneous flow data.

2. Description of Gage Types

***Tier I***- Gage data in this category is collected by the permitee immediately downstream of the water withdrawal location using streamflow gage equipment capable of accurately measuring instantaneous flow rates as approved at the discretion of the Department.

***Tier II***- Gage data in this category is obtained from acceptable USGS gages that must be located at a point in the same watershed where the drainage area at the gage is from 0.5x to 2.0x the size of the drainage area as measured at the withdrawal point. The catchment area must not have altered flows unless the instantaneous flow measurements can take into account the alterations.

***Tier III***- Gage data in this category is obtained from USGS gages that are either outside the acceptable distance within the same watershed or are in adjacent watersheds that possess similar basin characteristics. The use of these "surrogate" watersheds are the most inaccurate account of stream flow and should be used only as approved at the discretion of the Department.

3. All streamflow records used in determining the instantaneous passby flow rates should be measured to the nearest 0.1 cfs at 15-minute increments. Water withdrawal rates must be reported as instantaneous measurements to the nearest 0.1 cfs at 5-minute increments. Reporting is required annually to Department in Microsoft Excel or similar electronic spreadsheet/database formats.

4. Violations and Suspension of Operations. Water withdrawal operations will be suspended immediately upon determination that the required passby flow has not been maintained. The Department has the right to modify passby flow requirements if water quality standards are not being met within a watercourse as the result of a water withdrawal. Failure to submit annual reports, filing of inaccurate reports on water withdrawals, and continuing to withdraw water after a determination that the required passby flow has not been maintained, are all considered separate violations of this permit and the Environmental Conservation Law Article 71-1305(2).

## ATTACHMENT C

## FOREST AND GRASSLAND FOCUS AREAS

Operators developing well sites in Forest and Grassland Focus Areas that involve disturbance in a contiguous forest patch of 150 acres or more in size or in a contiguous grassland patch of 30 acres or more in size must:

1) Implement mitigation measures identified as part of the Department-approved ecological assessment;

2) Monitor the effects of disturbance as active development proceeds and for a minimum of two years following well completion; and

3) Practice adaptive management as previously unknown effects are documented.

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New York State

DEC

# Appendix 11

## Analysis of Subsurface Mobility of Fracturing Fluids

Excerpted from ICF International, Task 1, 2009

Revised Draft
Supplemental Generic Environmental Impact Statement

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### *1.2.4 Principles governing fracturing fluid flow*

The mobility of hydraulic fracturing fluid depends on the same physical and chemical principles that dictate all fluid transport phenomena. Frac fluid will flow through the well, the fractures, and the porous media based on pressure differentials and hydraulic conductivities. In addition to the overall flow of the frac fluids, additives may experience greater or lesser movement due to diffusion and adsorption. The concentrations of the fluids and additives may change due to dilution in formation waters and possibly by biological or chemical degradation.

#### 1.2.4.1 Limiting conditions

The analyses below present flow calculations for a range of parameters, with the intent to define reasonable bounds for the conditions likely to be encountered in New York State. Although one or more conditions at some future well sites may lie outside of the ranges analyzed, it is considered unlikely that the combination of conditions at any site would produce environmental impacts that are significantly more adverse than the worst case scenarios analyzed. The equations used in the analyses are presented below to facilitate the assessment of additional scenarios.

The analyses consider potentially useful aquifers with lower limits at depths up to 1,000 feet, somewhat deeper than the maximum aquifer depth reported in Table 3 for the Marcellus Shale. Similarly, the minimum depth to the top of the shale is taken as 2,000 ft, well above the minimum depth reported in Table 3 for the Marcellus Shale. The 2,000 ft. depth has been postulated as the probable upper limit for economic development of the New York shales.

The analyses include an additional conservative assumption. Even for deep aquifers, the analyses consider the pore pressure at the bottom of the aquifer to be zero as if a deep well or well field was operating at maximum drawdown. This assumption maximizes the potential for upward flow of fracturing fluid or its components from the fracture zone to the aquifer.

[134] U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

### 1.2.4.2 Gradient

For a fracturing fluid or its additives to have a negative impact on a groundwater aquifer, some deleterious component of the fracturing fluid would need to travel from the target fracture zone to the aquifer. In order for fluid to flow from the fracture zone to an aquifer, the *total head*[135] must be greater in the fracture zone than at the well. We can estimate the *gradient*[136] that might exist between a fracture zone in the shale and a potable water aquifer as follows:

$$i = \frac{h_{t1} - h_{t2}}{L} \tag{1}$$

where $i$ = gradient
$h_{tn}$ = total head at Point n
$L$ = length of flow path from Point 1 to Point 2

Since the total head is the sum of the elevation head and the pressure head,

$$h_t = h_e + h_p \tag{2}$$

The gradient can be restated as

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} \tag{3}$$

where $h_{en}$ = elevation head at Point n
$h_{pn}$ = pressure head at Point n

If the ground surface is taken as the elevation datum, we can express the elevation head in terms of depth.

$$d_n = -h_{en} \tag{4}$$

Restating the gradient yields

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} = \frac{(-d_1 + h_{p1}) - (-d_2 + h_{p2})}{L} = \frac{(d_2 - d_1) + (h_{p1} - h_{p2})}{L} \tag{5}$$

where $d_n$ = depth at Point n

We can estimate the maximum likely gradient by considering the combination of parameters which would be most favorable to flow from the hydraulically fractured zone to a potential groundwater aquifer. These include assuming the minimum possible pressure head in the aquifer and the shortest possible flow path, i.e. setting $h_{p2}$ to zero to simulate a well pumped to the maximum aquifer drawdown and setting $L$ to the vertical distance between the fracture zone and the aquifer, $d_1 - d_2$.

[135] Total head at a point is the sum of the elevation at the point plus the pore pressure expressed as the height of a vertical column of water.
[136] The groundwater gradient is the difference in total head between two points divided by the distance between the points.

The gradient now becomes

$$i = \frac{(d_2 - d_1) + h_{p1}}{|d_1 - d_2|} \tag{6}$$

The total vertical stress in the fracture zone equals

$$\sigma_v = d_1 \times \gamma_R \tag{7}$$

where $\sigma_v$ = total vertical stress
$d_1$ = depth at Point 1, in the fracture zone
$\gamma_R$ = average total unit weight of the overlying rock

The effective vertical stress, or the stress transmitted through the mineral matrix, equals the total unit weight minus the pore pressure. For the purposes of this analysis, the pore pressure is taken to be equivalent to that of a vertical water column from the fracture zone to the surface. The effective vertical stress is given by

$$\sigma'_v = \sigma_v - (d_1 \times \gamma_W) \tag{8}$$

where $\sigma'_v$ = effective vertical stress
$\gamma_W$ = unit weight of water

The effective horizontal stress and the total horizontal stress therefore equal

$$\sigma'_h = K \times \sigma'_v \tag{9}$$

$$\sigma_h = \sigma'_h + (d_1 \times \gamma_W) \tag{10}$$

where $\sigma'_h$ = effective horizontal stress
$K$ = ratio of horizontal to vertical stress
$\sigma_h$ = total horizontal stress

The hydraulic fracturing pressure needs to exceed the minimum total horizontal stress. Allowing for some loss of pressure from the wellbore to the fracture tip, the pressure head in the fracture zone equals

$$h_{p1} = c \times \sigma_h = \frac{c \times d_1 \times [K(\gamma_R - \gamma_W) + \gamma_W]}{\gamma_W} \tag{11}$$

where $h_{p1}$ = pressure head at Point 1, in the fracture zone
$c$ = coefficient to allow for some loss of pressure from the wellbore to the fracture tip

Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of

the geologic materials (estimated at 150 pcf average), times the depth.[137] To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress, yielding

$$h_{p1} = \frac{110\% \times d_1 \times \left[0.75\left(150\,pcf - 62.4\,pcf\right) + 62.4\,pcf\right]}{62.4\,pcf} = 2.26 d_1 \tag{12}$$

Equation (6) thus becomes

$$i = \frac{\left(d_2 - d_1\right) + 2.26 d_1}{\left|d_1 - d_2\right|} = \frac{d_2 + 1.26 d_1}{\left|d_1 - d_2\right|} \tag{13}$$

Figure 1 shows the variation in the average hydraulic gradient between the fracture zone and an overlying aquifer during hydraulic fracturing for a variety of aquifer and shale depths. The gradient has a maximum of about 3.5, and is less than 2.0 for most depth combinations.

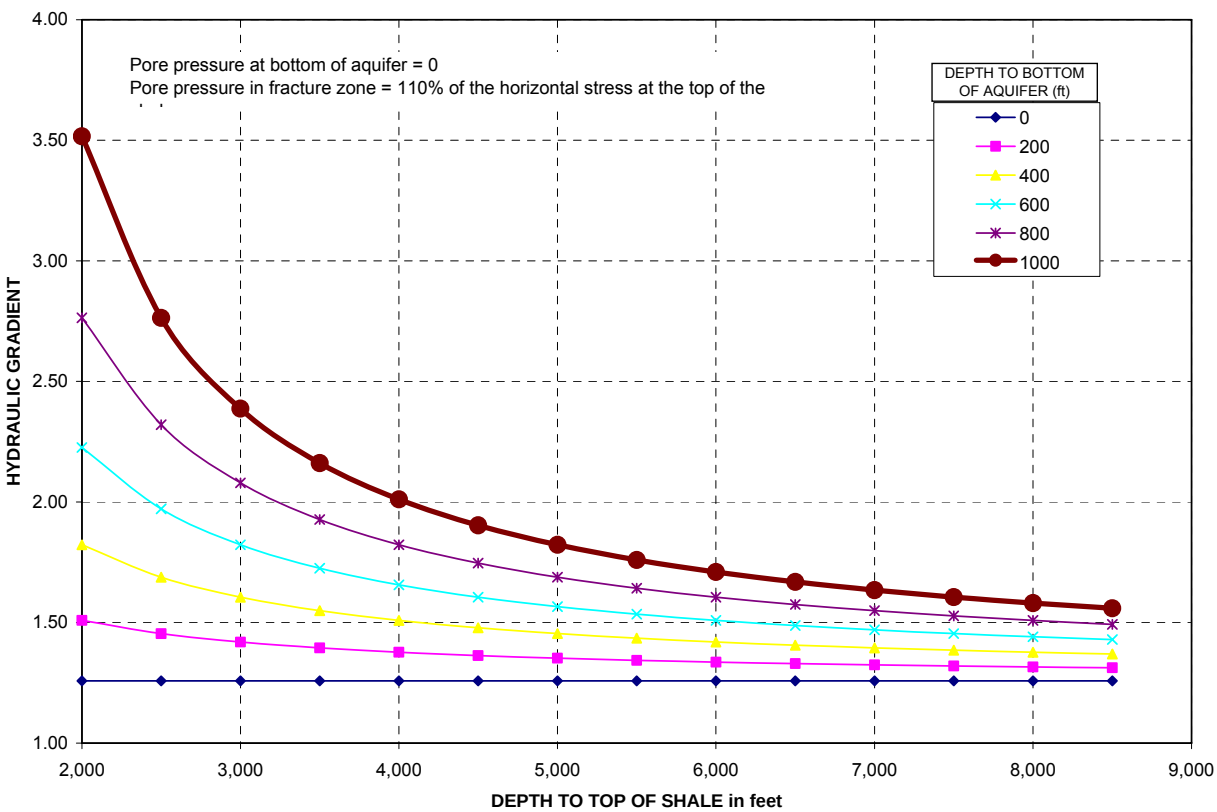


**Figure 1: Average hydraulic gradient during fracturing**

In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer

[137] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

to the fracture zone and lower than the average closer to the aquifer. It is important to note that these gradients only apply while fracturing pressures are being applied.

Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer. Evidence suggests that the permeabilities of the Devonian shales are too low for any meaningful hydrological connection with the post-Devonian formations. The high dissolved solid content near 300,000 ppm in pre-Late Devonian formations supports the concept that these formations are hydrologically discontinuous, i.e. not well-connected to other formations.[138] During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow.

#### 1.2.4.3 Seepage velocity

The second aspect to consider with regards to flow is the time required for a particle of fluid to flow from the fracture zone to the well. Using Darcy's law, the seepage velocity would equal

$$v = \frac{ki}{n} \tag{10}$$

where $v$ = seepage velocity
$k$ = hydraulic conductivity
$n$ = porosity

The average hydraulic conductivity between a fracture zone and an aquifer would depend on the hydraulic conductivity of each intervening stratum, which in turn would depend on the type of material and whether it was intact or fractured. The rock types overlying the Marcellus Shale are primarily sandstones and other shales.[139] Table 4 lists the range of hydraulic conductivities for sandstone and shale rock masses. The hydraulic conductivity of rock masses tends to decrease with depth as higher stress levels close or prevent fractures. Vertical flow across a horizontally layered system of geologic strata is controlled primarily by the less permeable strata, so the average vertical hydraulic conductivity of all the strata lying above the target shale would be expected to be no greater than 1E-5 cm/sec and could be substantially lower.

**Table 4: Hydraulic conductivity of rock masses[140]**

| Material | Minimum k | Maximum k |
|---|---|---|
| Intact Sandstone | 1E-8 cm/sec | 1E-5 cm/sec |
| Sandstone rock mass | 1E-9 cm/sec | 1E-1 cm/sec |
| Intact Shale | 1E-11 cm/sec | 1E-9 cm/sec |
| Shale rock mass | 1E-9 cm/sec | 1E-4 cm/sec |

Figure 2 shows the seepage velocity from the fracture zone to an overlying aquifer based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the seepage velocity would

[138] Russell, William L., 1972, "Pressure-Depth Relations in Appalachian Region", *AAPG Bulletin*, March 1972, v. 56, No. 3, p. 528-536.
[139] Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.
[140] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

be lower. For all of the analyses presented in this report, the porosity is taken as 10%, the reported total porosity for the Marcellus Shale.[141] Total porosity equals the contribution from both micro-pores within the intact rock and void space due to fractures. For the overlying strata, the analyses also use the same value for total porosity of 10% which is in the lower range of the typical values for sandstones and shales. This may result in a slight overestimation of the calculated seepage velocity, and an underestimation of the required travel time and available pore storage volume.

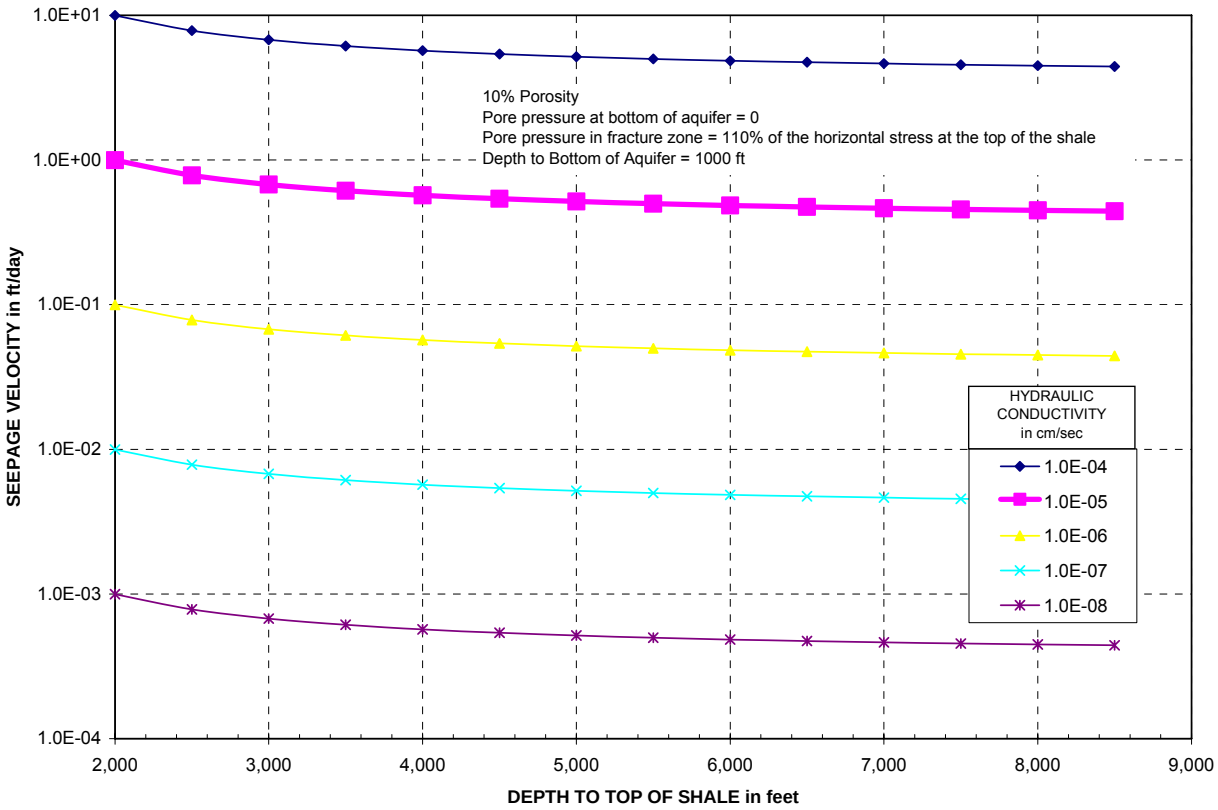


**Figure 2: Seepage velocity as a function of hydraulic conductivity**

Figure 2 shows that the seepage of hydraulic fracturing fluid would be limited to no more than 10 feet per day, and would be substantially less under most conditions. Since the cumulative amount of time that the fracturing pressure would be applied for all steps of a typical fracture stage is less than one day, the corresponding seepage distance would be similarly limited.

It is important to note that the seepage velocities shown in Figure 2 are based on average gradients between the fracture zone and the overlying aquifer. The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata.

[141] DOE, Office of Fossil Energy, 2009. *State Oil and National Gas Regulations Designed to Protect Water Resources*, May 2009.

#### 1.2.4.4 Required travel time

The time that the fracturing pressure would need to be maintained for the fracturing fluid to flow from the fracture zone to an overlying aquifer is given by

$$t = \frac{|d_2 - d_1|}{v} \tag{11}$$

where $t$ = required travel time

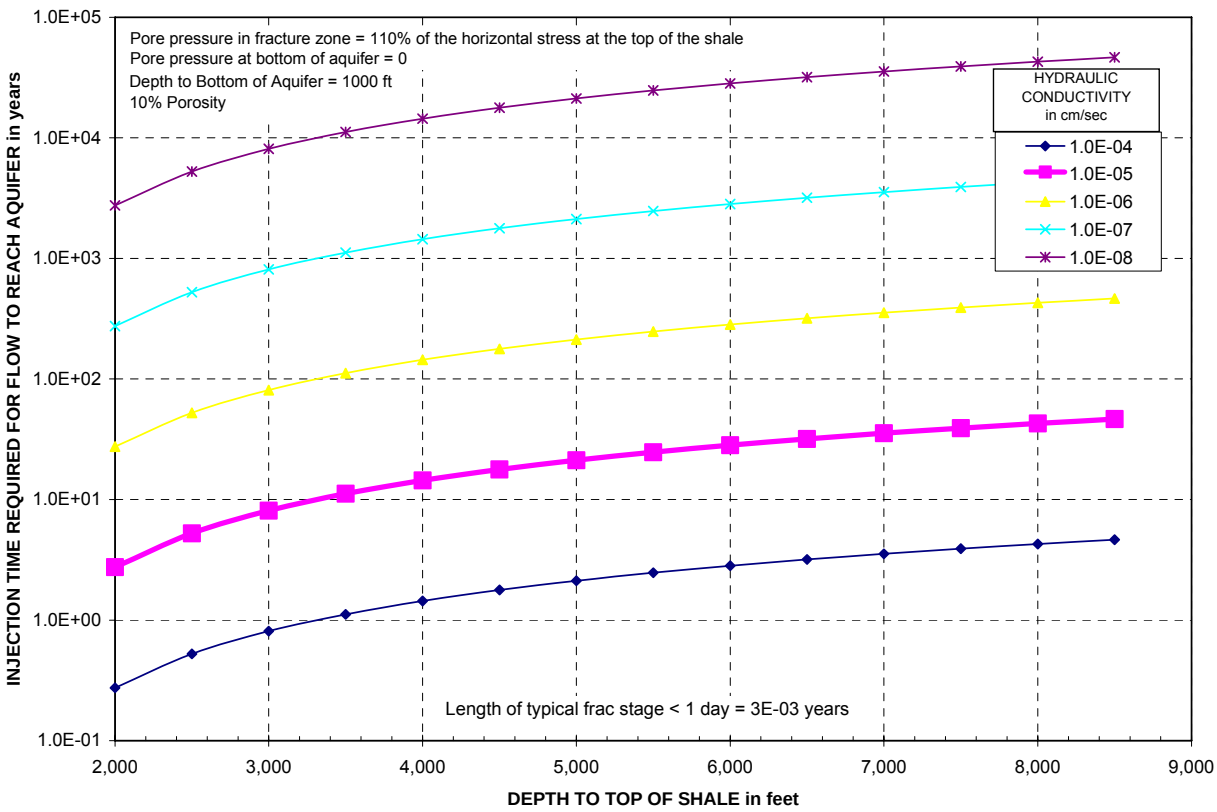


**Figure 3: Injection time required for fracture fluid to reach aquifer as a function of hydraulic conductivity**

Figure 3 shows the required travel time based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the required flow time would be longer. The required flow times under the fracturing pressure is several orders of magnitude greater than the duration over which the fracturing pressure would be applied.

Figure 4 presents the results of a similar analysis, but with the hydraulic conductivity held at 1E-5 cm/sec and considering various depths to the bottom of the aquifer. Compared to a 1000 ft. deep aquifer, 10 to 20 more years of sustained fracturing pressure would be required for the fracturing fluid to reach an aquifer that was only 200 ft. deep.

The required travel times shown relate to the movement of the groundwater. Dissolved chemicals would move at a slower rate due to retardation. The retardation factor, which is the

ratio of the chemical movement rate compared to the water movement rate, is always between 0.0 and 1.0, so the required travel times for any dissolved chemical would be greater than those shown in Figures 3 and 4.

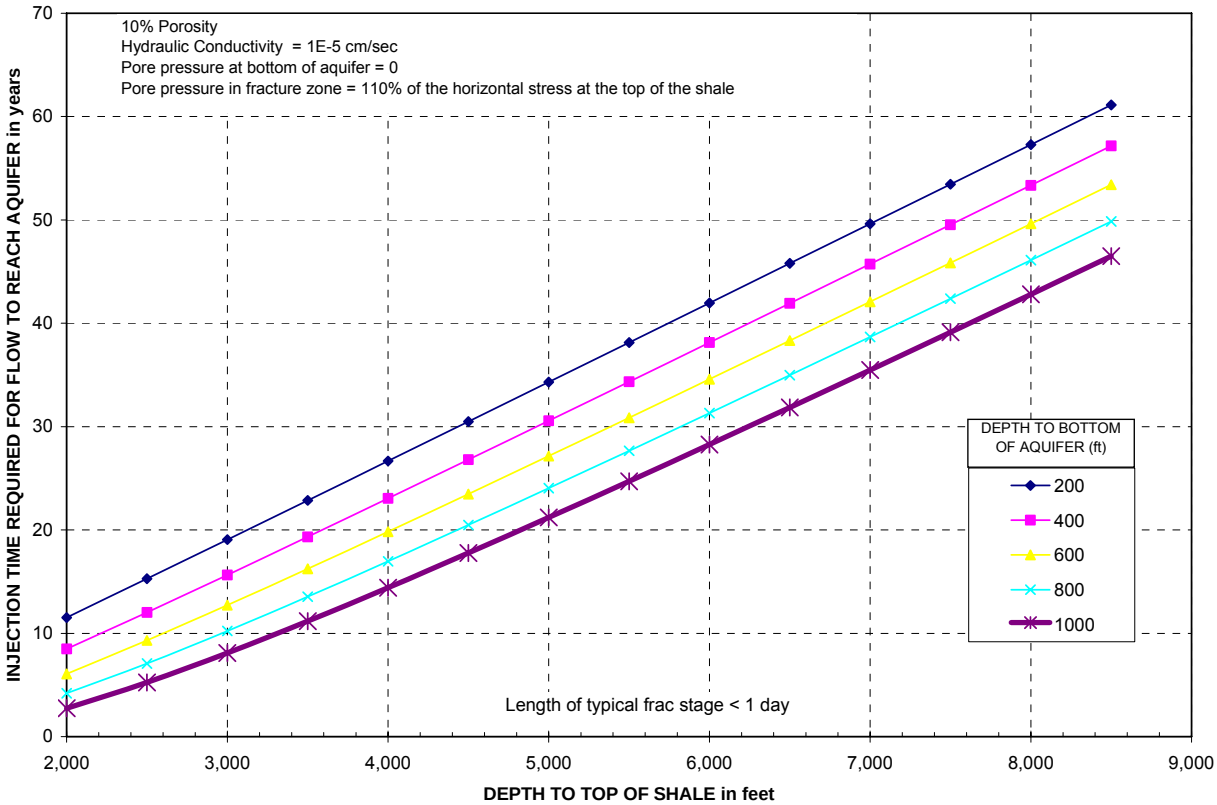


**Figure 4: Injection time required for flow to reach aquifer as a function of aquifer depth**

### 1.2.4.5 Pore storage volume

The fourth aspect to consider in evaluating the potential for adverse impacts to overlying aquifers is the volume of fluid injected compared to the volume of the void spaces and fractures that the fluid would need to fill in order to flow from the fracture zone to the aquifer. Figure 5 shows the void volume based on 10% total porosity for the geologic materials for various combinations of depths for the bottom of an aquifer and for the top of the shale, calculated as follows:

$$V = |d_1 - d_2| \times n \times \frac{43{,}560\, ft^2}{acre} \times \frac{7.48 gal}{ft^3} \qquad (12)$$

where $V$ = volume of void spaces and fractures

A typical slickwater fracturing treatment in a horizontal well would use less than 4 million gallons of fracturing fluid, and some portion of this fluid would be recovered as flowback. The void volume, based on 10% total porosity, for the geologic materials between the bottom of an aquifer at 1,000 ft. depth and the top of the shale at a 2,000 ft. depth is greater than 32 million gallons per acre. Since the expected area of a well spacing unit is no less than the equivalent of

40 acres per well,[142,143,144,145] the fracturing fluid could only fill about 0.3% of the overall void space. Alternatively, if the fracturing fluid were to uniformly fill the overall void space, it would be diluted by a factor of over 300. As shown in Figure 5, for shallower aquifers and deeper shales, the void volume per acre is significantly greater.

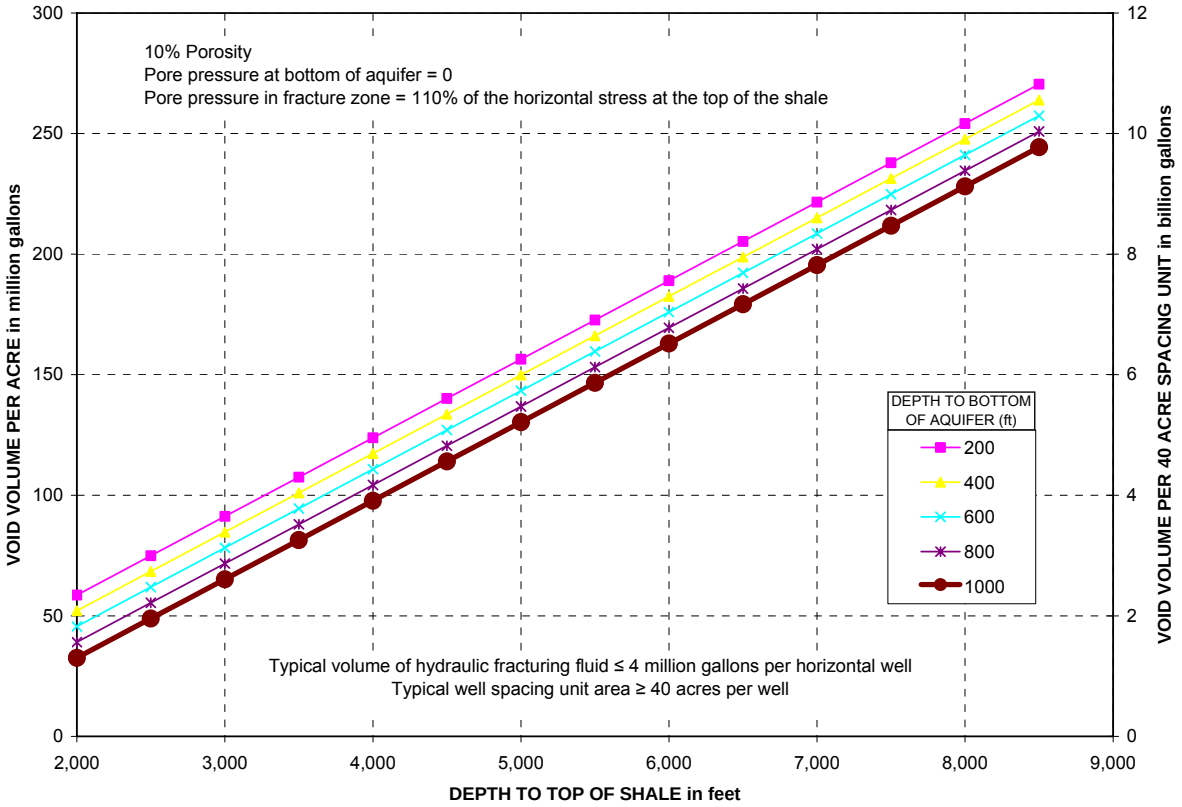


**Figure 5: Comparison of void volume to frac fluid volume**

### *1.2.5 Flow through fractures, faults, or unplugged borings*

It is theoretically possible but extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer. The open flow path would have a much smaller area of flow leading to the aquifer and the resistance to flow would be lower. In such an improbable case, the flow velocity would be greater, the time required for the fracturing fluid to reach the aquifer would be shorter, and the storage volume between the fracture zone and the aquifer would be less than in the scenarios described above. The probability of such a combination of unlikely conditions occurring simultaneously (deep aquifer, shallow fracture

[142] Infill wells could result in local increases in well density.
[143] New York regulations (Part 553.1 Statewide spacing) require a minimum spacing of 1320 ft. from other oil and gas wells in the same pool. This spacing equals 40 acres per well for wells in a rectangular grid.
[144] New York Codes, Rules, and Regulations, Title 6 Department of Environmental Conservation, Chapter V Resource Management Services, Subchapter B Mineral Resources, 6 NYCRR Part 553.1 Statewide spacing, (as of 5 April 2009).
[145] NYSDEC, 2009, "Final Scope for Draft Supplemental Generic Environmental Impact Statement (dSGEIS) on the Oil, Gas And Solution Mining Regulatory Program, Well Permit Issuance For Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-permeability Gas Reservoirs", February 2009.

zone, and open flow path) is very small. The fracturing contractor would notice an anomaly if these conditions led to the inability to develop or maintain the predicted fracturing pressure.

During flowback, the same conditions would result in a high rate of recapture of the frac fluid from the open flow path, decreasing the potential for any significant adverse environmental impacts. Moreover, during production the gradients along the open flow path would be toward the production zone, flushing any stranded fracturing fluid in the fracture or unplugged wellbore back toward the production well.

### *1.2.6 Geochemistry*

The ability of the chemical constituents of the additives in fracturing fluids to migrate from the fracture zone are influenced not just by the forces governing the flow of groundwater, but also by the properties of the chemicals and their interaction with the subterranean environment. In addition to direct flow to an aquifer, the constituents of fracturing fluid would be affected by limitations on solubility, adsorption and diffusion.

#### 1.2.6.1 Solubility

The solubility of a substance indicates the propensity of the substance to dissolve in a solvent, in this case, groundwater. The substance can continue to dissolve up to its saturation concentration, i.e. its solubility. Substances with high solubilities in water have a higher likelihood of moving with the groundwater flow at high concentrations, whereas substances with low solubilities may act as longer term sources at low level concentrations. The solubilities of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases such as the IUPAC-NIST Solubility Database.[146]

The solubility of a chemical determines the maximum concentration of the chemical that is likely to exist in groundwater. Solubility is temperature dependent, generally increasing with temperature. Since the temperature at the depths of the gas shales is higher than the temperature closer to the surface where a usable aquifer may lie, the solubility in the aquifer will be lower than in the shale formation.

Given the depth of the New York gas shales and the distance between the shales and any overlying aquifer, chemicals with high solubilities would be more likely to reach an aquifer at higher concentrations than chemicals of low solubility. Based on the previously presented fluid flow calculations, the concentrations would be significantly lower than the initial solubilities due to dilution.

#### 1.2.6.2 Adsorption

Adsorption occurs when molecules of a substance bind to the surface of another material. As chemicals pass through porous media or narrow fractures, some of the chemical molecules may adsorb onto the mineral surface. The adsorption will retard the flow of the chemical constituents relative to the rate of fluid flow. The retardation factor, expressed as the ratio of the fluid flow velocity to the chemical movement velocity, generally is higher in fine grained materials and in materials with high organic content. The Marcellus shale is both fine grained and of high organic content, so the expected retardation factors are high. The gray shales overlying the Marcellus

[146] IUPAC-NIST Solubility Database, Version 1.0, NIST Standard Reference Database 106, URL: http://srdata.nist.gov/solubility/index.aspx.

shale would also be expected to substantially retard any upward movement of fracturing chemicals.

The octanol-water partition coefficient, commonly expressed as $K_{ow}$, is often used in environmental engineering to estimate the adsorption of chemicals to geologic materials, especially those containing organic materials. Chemicals with high partition coefficients are more likely to adsorb onto organic solids and become locked in the shale, and less likely to remain in the dissolve phase than are chemicals with low partition coefficients.

The partition coefficients of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases. The partition coefficient is inversely proportional to solubility, and can be estimated from the following equation[147]

$$\log K_{ow} = -0.862 \log S_w + 0.710 \tag{13}$$

where $K_{ow}$ = octanol-water partition coefficient
$S_w$ = solubility in water at 20ºC in mol/liter

Adsorption in the target black shales or the overlying gray shales would effectively remove some percentage of the chemical mass from the groundwater for long periods of time, although as the concentration in the water decreased some of the adsorbed chemicals could repartition back into the water. The effect of adsorption could be to lower the concentration of dissolved chemicals in any groundwater migrating from the shale formation.

#### 1.2.6.3 Diffusion

Through diffusion, chemicals in fracturing fluids would move from locations with higher concentrations to locations with lower concentrations. Diffusion may cause the transport of chemicals even in the absence of or in a direction opposed to the gradient driving fluid flow. Diffusion is a slow process, but may continue for a very long time. As diffusion occurs, the concentration necessarily decreases. If all diffusion were to occur in an upward direction (an unlikely, worst-case scenario) from the fracture zone to an overlying freshwater aquifer, the diffused chemical would be dispersed within the intervening void volume and be diluted by at least an average factor of 160 based on the calculated pore volumes in Section 1.2.4.5. Since a concentration gradient would exist from the fracture zone to the aquifer, the concentration at the aquifer would be significantly lower than the calculated average. Increased vertical distance between the aquifer and the fracture zone due to shallower aquifers and deeper shales would further increase the dilution and reduce the concentration reaching the aquifer.

#### 1.2.6.4 Chemical interactions

Mixtures of chemicals in a geologic formation will behave differently than pure chemicals analyzed in a laboratory environment, so any estimates based on the solubility, adsorption, or diffusion properties of individual chemicals or chemical compounds should only be used as a guide to how they might behave when injected with other additives into the shale. Co-solubilities can change the migration properties of the chemicals and chemical reactions can create new compounds.

[147] Chiou, Cary T., *Partition and adsorption of organic contaminants in environmental systems*, John Wiley & Sons, New York, 2002, p.57.

### *1.2.7 Conclusions*

Analyses of flow conditions during hydraulic fracturing of New York shales help explain why hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers. Specific conditions or analytical results supporting this conclusion include:

- The developable shale formations are separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low permeability.
- The fracturing pressures which could potentially drive fluid from the target shale formation toward the aquifer are applied for short periods of time, typically less than one day per stage, while the required travel time for fluid to flow from the shale to the aquifer under those pressures is measured in years.
- The volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer.
- Some of the chemicals in the additives used in hydraulic fracturing fluids would be adsorbed by and bound to the organic-rich shales.
- Diffusion of the chemicals throughout the pore volume between the shale and an aquifer would dilute the concentrations of the chemicals by several orders of magnitude.
- Any flow of frac fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow toward the production zone as pressures decline in the reservoir during production.

The historical experience of hydraulic fracturing in tens of thousands of wells is consistent with the analytical conclusion. There are no known incidents of groundwater contamination due to hydraulic fracturing.

New York State

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# Appendix 12

## Beneficial Use Determination (BUD) Notification Regarding Road Spreading

Revised Draft
Supplemental Generic Environmental Impact Statement

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**New York State Department of Environmental Conservation**
**Division of Solid and Hazardous Materials**
**Bureau of Solid Waste, Reduction and Recycling, 9th Floor**
625 Broadway, Albany, New York 12233-7253
**Phone:** (518) 402-8704 • **FAX:** (518) 402-9024
**Website:** www.dec.ny.gov

Alexander B. Grannis
Commissioner

January 2009

# NOTICE TO GAS AND OIL WELL & LPG STORAGE FLUID HAULERS

All gas or oil well drilling and production fluids including but not limited to brine and fracturing fluids, and brine from liquefied petroleum gas (LPG) well storage operations, transported for disposal, road spreading, reuse in another gas or oil well, or recycling must be specifically identified in Part C and D of the New York State Waste Transporter Permit Application Form. Transporters must identify the type of fluid proposed to be transported in Section C in the Non-Hazardous Industrial/Commercial box and the Disposal or Destination Facility (or Use) in Part D.

Fracture fluids obtained during flowback operations may not be spread on roads and must be disposed at facilities authorized by the Department. Such disposal facilities must be identified in Part D of the permit application. If fluids are to be transported for use or reuse at another gas or oil well, that location must be identified in Part D of the permit application.

With respect to fluids transported under a Waste Transporter Permit, only production brines or brine from LPG storage operations may be used for road spreading. Drilling, fracing, and plugging fluids are not acceptable for road spreading.

Any person, including any government entity, applying for a Part 364 permit or permit modification to use production brine from oil or gas wells or brine from LPG well storage operations for road spreading purposes (i.e. road de-icing, dust suppression, or road stabilization) must submit a petition for a beneficial use determination (BUD). If a contract hauler is applying for a Part 364 permit or permit modification to deliver brine to a government agency for road spreading purposes, that government agency must submit the BUD petition. The BUD must be granted and the Part 364 permit/modification must be issued before brine can be removed from the well or LPG storage site for road spreading purposes or storage at an offsite facility.

The BUD petition must include:

1. An original letter signed and dated by the government agency representative or other property owner authorizing the use of brine on the locations identified in below item 3.

2. The name, address and telephone number of the person, company or government official seeking the approval.

3. An identification (or map) of the specific roads or other areas that are to receive the brine and any brine storage locations, excluding the well site storage locations.

4. The physical address of the brine storage locations from which the brine is hauled.

5. For each well field or LPG storage facility, a chemical analysis of a representative sample of the brine performed by a NYSDOH approved laboratory for the following parameters: calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil & grease, benzene, ethylbenzene, toluene, and xylene. Depending upon the analytical results, the Department may require additional analyses. (This analysis is not required for brine from a LPG well operation with a valid New York State SPDES permit.)

6. A road spreading plan that includes a description of the procedures to prevent the brine from flowing or running off into streams, creeks, lakes and other bodies of water. The plan should include:

- a description of how the brine will be applied, including the equipment to be used and the method for controlling the rate of application. In general this should indicate that the brine is applied by use of a spreader bar or similar spray device with shut-off controls in the cab of the truck; and with vehicular equipment that is dedicated to this use or cleaned of previously transported waste materials prior to this use;
- the proposed rate and frequency of application;
- a description of application restrictions. For dust control and road stabilization use this description should indicate that the brine is not applied: after daylight hours; within 50 feet of a stream, creek, lake or other body of water; on sections of road having a grade exceeding 10 percent; or on wet roads, during rain, or when rain is imminent. For road deicing use, this description should indicate that the brine is applied in accordance NYSDOT Guidelines for Anit-Icing with Liquids and include any other restrictions.

7. Where applicable, a brine storage plan that includes:

- a description of the type, material, size, and number of storage tanks and the maximum anticipated storage;
- procedures for run off and run-on control;
- provisions for secondary containment; and
- a contingency plan.

If you have any questions concerning your permit, please feel free to call this office at (518) 402-8707. You may also visit our public website at the address above for information and forms to download or print.

Waste Transporter Permit Program

New York State

DEC

# Appendix 13

## Radiological Data - Production Brine from NYS Marcellus Wells

Revised Draft
Supplemental Generic Environmental Impact Statement

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## NYS Marcellus Radiological Data from Production Brine

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| Maxwell 1C | 31-101-22963-03-01 | 10/7/2008 | Caton (Steuben) | Gross Alpha | 17,940 +/- 8,634 pCi/L |
| | | | | Gross Beta | 4,765 +/- 3,829 pCi/L |
| | | | | Cesium-137 | -2.26 +/- 5.09 pCi/L |
| | | | | Cobalt-60 | -0.748 +/- 4.46 pCi/L |
| | | | | Ruthenium-106 | 9.27 +/- 46.8 pCi/L |
| | | | | Zirconium-95 | 37.8 +/- 21.4 pCi/L |
| | | | | Radium-226 | 2,472 +/- 484 pCi/L |
| | | | | Radium-228 | 874 +/- 174 pCi/L |
| | | | | Thorium-228 | 53.778 +/- 8.084 pCi/L |
| | | | | Thorium-230 | 0.359 +/- 0.221 pCi/L |
| | | | | Thorium-232 | 0.065 +/- 0.103 pCi/L |
| | | | | Uranium-234 | 0.383 +/- 0.349 pCi/L |
| | | | | Uranium-235 | 0.077 +/- 0.168 pCi/L |
| | | | | Uranium-238 | 0.077 +/- 0.151 pCi/L |
| Frost 2 | 31-097-23856-00-00 | 10/8/2008 | Orange (Schuyler) | Gross Alpha | 14,530 +/-3,792 pCi/L |
| | | | | Gross Beta | 4,561 +/- 1,634 pCi/L |
| | | | | Cesium-137 | 2.54 +/- 4.64 pCi/L |
| | | | | Cobalt-60 | -1.36 +/- 3.59 pCi/L |
| | | | | Ruthenium-106 | -9.03 +/- 36.3 pCi/L |
| | | | | Zirconium-95 | 31.6 +/- 14.6 pCi/L |
| | | | | Radium-226 | 2,647 +/- 494 pCi/L |
| | | | | Radium-228 | 782 +/- 157 pCi/L |
| | | | | Thorium-228 | 47.855 +/- 9.140 pCi/L |
| | | | | Thorium-230 | 0.859 +/- 0.587 pCi/L |
| | | | | Thorium-232 | 0.286 +/- 0.328 pCi/L |
| | | | | Uranium-234 | 0.770 +/- 0.600 pCi/L |
| | | | | Uranium-235 | 0.113 +/- 0.222 pCi/L |
| | | | | Uranium-238 | 0.431 +/- 0.449 pCi/L |
| Webster T1 | 31-097-23831-00-00 | 10/8/2008 | Orange (Schuyler) | Gross Alpha | 123,000 +/- 23,480 pCi/L |
| | | | | Gross Beta | 12,000 +/- 2,903 pCi/L |
| | | | | Cesium-137 | 1.32 +/- 5.76 pCi/L |
| | | | | Cobalt-60 | -2.42 +/- 4.76 pCi/L |
| | | | | Ruthenium-106 | -18.3 +/- 44.6 pCi/L |
| | | | | Zirconium-95 | 34.5 +/- 15.6 pCi/L |
| | | | | Radium-226 | 16,030 +/- 2,995 pCi/L |
| | | | | Radium-228 | 912 +/- 177 pCi/L |
| | | | | Thorium-228 | 63.603 +/- 9.415 pCi/L |
| | | | | Thorium-230 | 0.783 +/- 0.286 pCi/L |
| | | | | Thorium-232 | 0.444 +/- 0.213 pCi/L |
| | | | | Uranium-234 | 0.232 +/- 0.301 pCi/L |
| | | | | Uranium-235 | 0.160 +/- 0.245 pCi/L |
| | | | | Uranium-238 | -0.016 +/- 0.015 pCi/L |

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| Calabro T1 | 31-097-23836-00-00 | 3/26/2009 | Orange (Schuyler) | Gross Alpha | 18,330 +/- 3,694 pCi/L |
| | | | | Gross Beta | -324.533 +/- 654 pCi/L |
| | | | | Cesium-137 | 3.14 +/- 7.19 pCi/L |
| | | | | Cobalt-60 | 0.016 +/- 5.87 pCi/L |
| | | | | Ruthenium-106 | 17.0 +/- 51.9 pCi/L |
| | | | | Zirconium-95 | 24.2 +/- 13.6 pCi/L |
| | | | | Radium-226 | 13,510 +/- 2,655 pCi/L |
| | | | | Radium-228 | 929 +/- 179 pCi/L |
| | | | | Thorium-228 | 45.0 +/- 8.41 pCi/L |
| | | | | Thorium-230 | 2.80 +/- 1.44 pCi/L |
| | | | | Thorium-232 | -0.147 +/- 0.645 pCi/L |
| | | | | Uranium-234 | 1.91 +/- 1.82 pCi/L |
| | | | | Uranium-235 | 0.337 +/- 0.962 pCi/L |
| | | | | Uranium-238 | 0.765 +/- 1.07 pCi/L |
| Maxwell 1C | 31-101-22963-03-01 | 4/1/2009 | Caton (Steuben) | Gross Alpha | 3,968 +/- 1,102 pCi/L |
| | | | | Gross Beta | 618 +/- 599 pCi/L |
| | | | | Cesium-137 | -0.443 +/- 3.61 pCi/L |
| | | | | Cobalt-60 | -1.840 +/- 2.81 pCi/L |
| | | | | Ruthenium-106 | 17.1 +/- 29.4 pCi/L |
| | | | | Zirconium-95 | 26.4 +/- 8.38 pCi/L |
| | | | | Radium-226 | 7,885 +/- 1,568 pCi/L |
| | | | | Radium-228 | 234 +/- 50.5 pCi/L |
| | | | | Thorium-228 | 147 +/- 23.2 pCi/L |
| | | | | Thorium-230 | 1.37 +/- 0.918 pCi/L |
| | | | | Thorium-232 | 0.305 +/- 0.425 pCi/L |
| | | | | Uranium-234 | 1.40 +/- 1.25 pCi/L |
| | | | | Uranium-235 | 0.254 +/- 0.499 pCi/L |
| | | | | Uranium-238 | 0.508 +/- 0.708 pCi/L |
| Haines 1 | 31-101-14872-00-00 | 4/1/2009 | Avoca (Steuben) | Gross Alpha | 54.6 +/- 37.4 pCi/L |
| | | | | Gross Beta | 59.3 +/- 58.4 pCi/L |
| | | | | Cesium-137 | 0.476 +/- 2.19 pCi/L |
| | | | | Cobalt-60 | -0.166 +/- 2.28 pCi/L |
| | | | | Ruthenium-106 | 7.15 +/- 19.8 pCi/L |
| | | | | Zirconium-95 | 0.982 +/- 4.32 pCi/L |
| | | | | Radium-226 | 0.195 +/- 0.162 pCi/L |
| | | | | Radium-228 | 0.428 +/- 0.335 pCi/L |
| | | | | Thorium-228 | 0.051 +/- 0.036 pCi/L |
| | | | | Thorium-230 | 0.028 +/- 0.019 pCi/L |
| | | | | Thorium-232 | 0.000 +/- 0.007 pCi/L |
| | | | | Uranium-234 | 0.000 +/- 0.014 pCi/L |
| | | | | Uranium-235 | 0.000 +/- 0.005 pCi/L |
| | | | | Uranium-238 | -0.007 +/- 0.006 pCi/L |

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| Haines 2 | 31-101-16167-00-00 | 4/1/2009 | Avoca (Steuben) | Gross Alpha | 70.0 +/- 47.8 pCi/L |
| | | | | Gross Beta | 6.79 +/- 54.4 pCi/L |
| | | | | Cesium-137 | 2.21 +/- 1.64 pCi/L |
| | | | | Cobalt-60 | 1.42 +/- 2.83 pCi/L |
| | | | | Ruthenium-106 | 5.77 +/- 15.2 pCi/L |
| | | | | Zirconium-95 | 2.43 +/- 3.25 pCi/L |
| | | | | Radium-226 | 0.163 +/- 0.198 pCi/L |
| | | | | Radium-228 | 0.0286 +/- 0.220 pCi/L |
| | | | | Thorium-228 | 0.048 +/- 0.038 pCi/L |
| | | | | Thorium-230 | 0.040 +/- 0.022 pCi/L |
| | | | | Thorium-232 | -0.006 +/- 0.011 pCi/L |
| | | | | Uranium-234 | 0.006 +/- 0.019 pCi/L |
| | | | | Uranium-235 | 0.006 +/- 0.013 pCi/L |
| | | | | Uranium-238 | -0.013 +/- 0.009 pCi/L |
| Carpenter 1 | 31-101-26014-00-00 | 4/1/2009 | Troupsburg (Steuben) | Gross Alpha | 7,974 +/- 1,800 pCi/L |
| | | | | Gross Beta | 1,627 +/- 736 pCi/L |
| | | | | Cesium-137 | 2.26 +/- 4.97 pCi/L |
| | | | | Cobalt-60 | -0.500 +/- 3.84 pCi/L |
| | | | | Ruthenium-106 | 49.3 +/- 38.1 pCi/L |
| | | | | Zirconium-95 | 30.4 +/- 11.0 pCi/L |
| | | | | Radium-226 | 5,352 +/- 1,051 pCi/L |
| | | | | Radium-228 | 138 +/- 37.3 pCi/L |
| | | | | Thorium-228 | 94.1 +/- 14.9 pCi/L |
| | | | | Thorium-230 | 1.80 +/- 0.946 pCi/L |
| | | | | Thorium-232 | 0.240 +/- 0.472 pCi/L |
| | | | | Uranium-234 | 0.000 +/- 0.005 pCi/L |
| | | | | Uranium-235 | 0.000 +/- 0.005 pCi/L |
| | | | | Uranium-238 | -0.184 +/- 0.257 pCi/L |
| Zinck 1 | 31-101-26015-00-00 | 4/1/2009 | Woodhull (Steuben) | Gross Alpha | 9,426 +/- 2,065 pCi/L |
| | | | | Gross Beta | 2,780 +/- 879 pCi/L |
| | | | | Cesium-137 | 5.47 +/- 5.66 pCi/L |
| | | | | Cobalt-60 | 0.547 +/- 4.40 pCi/L |
| | | | | Ruthenium-106 | -16.600 +/- 42.8 pCi/L |
| | | | | Zirconium-95 | 48.0 +/- 15.1 pCi/L |
| | | | | Radium-226 | 4,049 +/- 807 pCi/L |
| | | | | Radium-228 | 826 +/- 160 pCi/L |
| | | | | Thorium-228 | 89.1 +/- 14.7 pCi/L |
| | | | | Thorium-230 | 0.880 +/- 1.23 pCi/L |
| | | | | Thorium-232 | 0.000 +/- 0.705 pCi/L |
| | | | | Uranium-234 | -0.813 +/- 0.881 pCi/L |
| | | | | Uranium-235 | -0.325 +/- 0.323 pCi/L |
| | | | | Uranium-238 | -0.488 +/- 0.816 pCi/L |

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| Schiavone 2 | 31-097-23226-00-01 | 4/6/2009 | Reading (Schuyler) | Gross Alpha | 16,550 +/- 3,355 pCi/L |
| | | | | Gross Beta | 1,323 +/- 711 pCi/L |
| | | | | Cesium-137 | 1.46 +/- 5.67 pCi/L |
| | | | | Cobalt-60 | -2.550 +/- 5.11 pCi/L |
| | | | | Ruthenium-106 | 20.6 +/- 42.7 pCi/L |
| | | | | Zirconium-95 | 30.6 +/- 12.1 pCi/L |
| | | | | Radium-226 | 15,140 +/- 2,989 pCi/L |
| | | | | Radium-228 | 957 +/- 181 pCi/L |
| | | | | Thorium-228 | 38.7 +/- 7.45 pCi/L |
| | | | | Thorium-230 | 1.68 +/- 1.19 pCi/L |
| | | | | Thorium-232 | 0.153 +/- 0.301 pCi/L |
| | | | | Uranium-234 | 3.82 +/- 2.48 pCi/L |
| | | | | Uranium-235 | 0.354 +/- 0.779 pCi/L |
| | | | | Uranium-238 | 0.354 +/- 0.923 pCi/L |
| Parker 1 | 31-017-26117-00-00 | 4/2/2009 | Oxford (Chenango) | Gross Alpha | 3,914 +/- 813 pCi/L |
| | | | | Gross Beta | 715 +/- 202 pCi/L |
| | | | | Cesium-137 | 4.12 +/- 3.29 pCi/L |
| | | | | Cobalt-60 | -1.320 +/- 2.80 pCi/L |
| | | | | Ruthenium-106 | -9.520 +/- 24.5 pCi/L |
| | | | | Zirconium-95 | 1.39 +/- 6.35 pCi/L |
| | | | | Radium-226 | 1,779 +/- 343 pCi/L |
| | | | | Radium-228 | 201 +/- 38.9 pCi/L |
| | | | | Thorium-228 | 15.4 +/- 3.75 pCi/L |
| | | | | Thorium-230 | 1.25 +/- 0.835 pCi/L |
| | | | | Thorium-232 | 0.000 +/- 0.385 pCi/L |
| | | | | Uranium-234 | 1.82 +/- 1.58 pCi/L |
| | | | | Uranium-235 | 0.304 +/- 0.732 pCi/L |
| | | | | Uranium-238 | 0.304 +/- 0.732 pCi/L |
| WGI 10 | 31-097-23930-00-00 | 4/6/2009 | Dix (Schuyler) | Gross Alpha | 10,970 +/- 2,363 pCi/L |
| | | | | Gross Beta | 1,170 +/- 701 pCi/L |
| | | | | Cesium-137 | 1.27 +/- 5.17 pCi/L |
| | | | | Cobalt-60 | 0.960 +/- 4.49 pCi/L |
| | | | | Ruthenium-106 | 14.5 +/- 37.5 pCi/L |
| | | | | Zirconium-95 | 15.2 +/- 8.66 pCi/L |
| | | | | Radium-226 | 6,125 +/- 1,225 pCi/L |
| | | | | Radium-228 | 516 +/- 99.1 pCi/L |
| | | | | Thorium-228 | 130 +/- 20.4 pCi/L |
| | | | | Thorium-230 | 2.63 +/- 1.39 pCi/L |
| | | | | Thorium-232 | 0.444 +/- 0.213 pCi/L |
| | | | | Uranium-234 | 0.000 +/- 0.702 pCi/L |
| | | | | Uranium-235 | 1.17 +/- 1.39 pCi/L |
| | | | | Uranium-238 | 0.389 +/- 1.01 pCi/L |

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| WGI 11 | 31-097-23949-00-00 | 4/6/2009 | Dix (Schuyler) | Gross Alpha | 20,750 +/- 4,117 pCi/L |
| | | | | Gross Beta | 2,389 +/- 861 pCi/L |
| | | | | Cesium-137 | 4.78 +/- 6.95 pCi/L |
| | | | | Cobalt-60 | -0.919 +/- 5.79 pCi/L |
| | | | | Ruthenium-106 | -19.700 +/- 49.8 pCi/L |
| | | | | Zirconium-95 | 9.53 +/- 11.8 pCi/L |
| | | | | Radium-226 | 10,160 +/- 2,026 pCi/L |
| | | | | Radium-228 | 1,252 +/- 237 pCi/L |
| | | | | Thorium-228 | 47.5 +/- 8.64 pCi/L |
| | | | | Thorium-230 | 1.55 +/- 1.16 pCi/L |
| | | | | Thorium-232 | -0.141 +/- 0.278 pCi/L |
| | | | | Uranium-234 | 0.493 +/- 0.874 pCi/L |
| | | | | Uranium-235 | 0.000 +/- 0.540 pCi/L |
| | | | | Uranium-238 | -0.123 +/- 0.172 pCi/L |

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New York State

DEC

# Appendix 14

## Department of Public Service Environmental Management & Construction Standards and Practices – Pipelines

Revised Draft
Supplemental Generic Environmental Impact Statement

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**ENVIRONMENTAL MANAGEMENT AND CONSTRUCTION**

**STANDARDS AND PRACTICES**

**CHECK-OFF LIST: PART III**

**PIPELINE**


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New York State

DEC

# Appendix 15

## Hydraulic Fracturing – 15 Statements from Regulatory Officials

Revised Draft
Supplemental Generic Environmental Impact Statement

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# Part A

# GWPC's Congressional Testimony

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STATEMENT OF
SCOTT KELL
ON BEHALF OF THE
GROUND WATER PROTECTION COUNCIL

HOUSE COMMITTEE ON NATURAL RESOURCES
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES
WASHINGTON, D.C.
JUNE 4, 2009

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Mr. Chairman, thank you for the opportunity to testify today. My name is Scott Kell. I am President of the Ground Water Protection Council (GWPC) and appear here today on its behalf. I am also Deputy Chief of the Ohio Department of Natural Resources Division of Mineral Resources Management. With me today are Mike Paque, Executive Director of the GWPC, Dave Bolin, Assistant Director of the Alabama Oil and Gas Board, and Lori Wrotenbery, Director of the Oklahoma Corporation Commission's Oil and Gas Conservation Division. Within our respective States, we are responsible for implementing the state regulations governing the exploration and development of oil and natural gas resources. First and foremost, we are resource protection professionals committed to stewardship of water resources in the exercise of our authority.

The GWPC is a non-profit association of state agencies responsible for environmental safeguards related to ground water. The members of the association consist of state ground water and underground injection control regulators. The GWPC provides a forum through which its state members work with federal scientists and regulators, environmental groups, industry, and other stakeholders to advance protection of ground water resources through development of policy and regulation that is based on sound science. I have included a list of the GWPC Board of Directors in our written submission.

The GWPC understands that our nation's water and energy needs are intertwined, and that demand for both resources is increasing. Smart energy policy will consider and minimize impacts to water resources.

With respect to the protection of water resources, the GWPC recently published two reports of note. The first of these reports is called *Modern Shale Gas Development in the United States: A Primer (http://www.gwpc.org/e-library/documents/general/Shale%20Gas%20Primer%202009.pdf)*. The primer discusses the regulatory framework, policy issues, and technical aspects of developing unconventional shale gas resources. As you know, there are numerous deep shale gas basins in the United States, which contain trillions of cubic feet of natural gas. The environmentally responsible development of these resources is of critical importance to the energy security of the U.S. Recently, however, there has been concern raised about the methods used to tap these valuable resources. Technologies such as

hydraulic fracturing have been characterized as being environmentally risky and inadequately regulated. The primer is designed to provide accurate technical information to assist policy makers in their understanding of these issues.

In recent months, the states have become aware of press reports and websites alleging that six states have documented over one thousand incidents of ground water contamination resulting from the practice of hydraulic fracturing. Such reports are not accurate. Attached to my testimony are signed statements from state officials representing Ohio, Pennsylvania, New Mexico, Alabama, and Texas, responding to these allegations.

From the standpoint of the GWPC, the most critical issue is protection of water resources. As such, our goal is to ensure that oil and gas development is managed in a way that does not create unnecessary and unwarranted risks to water. As a state regulatory official, I can assure you that our regulations are focused on this task. This leads me to the second report the GWPC has recently published.

This report, entitled *State Oil and Gas Regulations Designed to Protect Water Resources,* (http://www.gwpc.org/e-library/documents/general/Oil%20and%20Gas%20Regulation%20Report%20Final%20with%20Cover%205-27-2009.pdf) evaluates regulations implemented by state oil and gas regulatory agencies as they relate to the protection of water. To prepare this report, the GWPC reviewed the regulations of the twenty-seven states that, when combined, account for more than 99.8% of all the oil and natural gas extracted in the U.S. annually. To prepare this report, each state's regulatory requirements were studied with respect to their water protection capacity. The study evaluated regulated processes such as well drilling, construction, and plugging, above-ground storage tanks, pits and a number of other topics. The report also contains a statistical analysis of state regulations. As a result of our regulatory review and analysis, the GWPC concluded that state oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, hydraulic fracturing, waste handling, and well plugging requirements. While State regulations are generally adequate, the GWPC report makes the following recommendations.

First, a study of effective hydraulic fracturing practices should be considered for the purpose of developing Best Management Practices (BMPs) that can be adjusted to fit the specific conditions of individual states. A one-size-fits-all federal program is not the most effective way to regulate in this area. BMPs related to hydraulic fracturing would assist states and operators in ensuring the safety of the practice. Of special concern are zones in close proximity to underground sources of drinking water, as determined by the state regulatory authority.

Second, the state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time. This process should be expanded, where appropriate, to include state oil and gas programmatic

elements not covered by the current state review guidelines. STRONGER is currently convening a stakeholder workgroup to consider drafting guidelines for state regulation of hydraulic fracturing.

Finally, the GWPC concludes that implementation and advancement of electronic data management systems has enhanced state regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental, or water related data. States should continue to develop comprehensive electronic data management systems and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

In conclusion, Mr. Chairman and Committee Members, we believe that state regulations are designed to provide the level of water protection needed to assure water resources remain both viable and available. The states are continuously striving to improve both the regulatory language and the programmatic tools used to implement that language. In this regard, the GWPC will continue to assist states with their regulatory needs for the purpose of protecting water, our most vital natural resource.

Thank you.

**DISCLOSURE REQUIREMENT**
**Required by House Rule XI, clause 2(g)**
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9. Any federal grants or contracts (including subgrants or subcontracts) from the Department of the Interior (and /or other agencies invited) which **you** have received in the last three years, including the source and the amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

10. Any federal grants or contracts (including subgrants or subcontracts) the Department of the Interior (and /or other agencies invited) which were received in the last three years by the **organization(s) which you represent** at this hearing, including the source and amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

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*Attachment 1 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009*

# State Oil and Natural Gas Regulations Designed to Protect Water Resources

## EXECUTIVE SUMMARY

Over the past several years the GWPC has been asked, "Do state oil and gas regulations protect water?" How do their rules apply? Are they adequate? The first step in answering these questions is to evaluate the regulatory frameworks within which programs operate. That is the purpose of this report.

State regulation of oil and natural gas exploration and production activities are approved under state laws that typically include a prohibition against causing harm to the environment. This premise is at the heart of the regulatory process. The regulation of oil and gas field activities is managed best at the state level where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Hence, the experience, knowledge and information necessary to regulate effectively most commonly rests with state regulatory agencies. Many state agencies use programmatic tools and documents to apply state laws including regulations, formal and informal guidance, field rules, and Best Management Practices (BMPs). They are also equipped to conduct field inspections, enforcement/oversight, and witnessing of specific operations like well construction, testing and plugging.

Regulations alone cannot convey the full measure of a regulatory program. To gain a more complete understanding of how regulatory programs actually function, one has to evaluate the use of state guides, manuals, environmental policy processes, environmental impact statements, requirements established by permit and many other practices. However, that is not the purpose of this study. This study evaluates the language of state oil and gas regulations as they relate to the direct protection of water resources. It is not an evaluation of state programs.

To conduct the study, state oil and gas regulations were reviewed in the following areas: 1) permitting, 2) well construction, 3) hydraulic fracturing, 4) temporary abandonment, 5) well plugging, 6) tanks, 7) pits, and 8) waste handling and spills. Within each area specific sub-areas were included to broaden the scope of this review. For example, in the area of pits, a review was conducted of sub-areas such as pit liners, siting, construction, use, duration and closure. The selection of the twenty-seven states for this study was based upon the last full-year list (2007) of producing states compiled by the U.S. Energy Information Administration.

In the area of well construction, state regulations were evaluated to determine whether the setting of surface casing below ground water zones was required, whether cement circulation on surface casing was also required, and whether the state utilized recognized cement standards. Attachment 3 is a listing of the programmatic areas and sub-areas reviewed.

After evaluation, each state was given the opportunity to review and comment on the findings and to provide updated information concerning their regulations. Thirteen states responded. These responses were incorporated into the study.

One of the most important accomplishments of the study was the development of a regulations reference document (Addendum). This document contains excerpted language from each state's oil and gas regulations related to the programmatic areas included in the study. Hyperlinks to web versions of each

state's oil and gas regulations are included as well as some of the forms used by state agencies to implement those regulations. A web enabled version of the study (to be completed by September, 2009) will also contain numerous hyperlinked text segments designed to provide the reader with an easy and effective way to review references and regulations.

**Key Messages and Suggested Actions:**

Key Message 1: State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.

Suggested Action 1: States should review current regulations in several programmatic areas to determine whether or not they meet an appropriate level of specificity (e.g. use of standard cements, plugging materials, pit liners, siting criteria, and tank construction standards etc…)

Key Message 2: Experience suggests that state oil and gas regulations related to well construction are designed to be protective of ground water resources relative to the potential effects of hydraulic fracturing. However, development of Best Management Practices (BMPs) related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice; especially as it relates to hydraulic fracturing of zones in close proximity to ground water, as determined by the regulatory authority.

Suggested Action 2: A study of effective hydraulic fracturing practices should be considered for the purpose of developing (BMPs); which can be adjusted to fit the specific conditions of individual states.

Key Message 3: Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.

Suggested Action 3: States with split jurisdiction of programs should insure that formal memorandums of agreement (MOAs) between agencies exist and that these MOAs are maintained to provide more effective and efficient implementation of regulations.

Key Message 4: The state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.

Suggested Action 4: The state review process should be continued and, where appropriate, expanded to include state oil and gas programmatic elements not covered by the current state review guidelines.

Key Message 5: The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental data.

Suggested Action 5: States should continue to develop and install comprehensive electronic data management systems, convert paper records to electronic formats and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

*Attachment 2 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009*

# Modern Shale Gas Development in the United States: A Primer

## EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the

known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-sizefits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas

development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces

future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include $NO_x$, volatile organic compounds, particulate matter, $SO_2$, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

# Ohio Department of Natural Resources

TED STRICKLAND, GOVERNOR | SEAN D. LOGAN, DIRECTOR

***John F. Husted, Chief***
*Division of Mineral Resources Management*
*2045 Morse Road, Building H-3*
*Columbus, OH 43229-6693*
*Phone: (614) 265-6633 Fax: (614) 265-7999*

May 27, 2009

Mike Paque
Executive Director
Ground Water Protection Council
13309 North MacArthur Boulevard
Oklahoma City, Oklahoma 73142

Dear Mike:

In recent months, the Ohio Department of Natural Resources, Division of Mineral Resources Management (DMRM) has become aware of website and media releases reporting that the State of Ohio has documented cases of ground water contamination caused by the standard industry practice of hydraulic fracturing. Such reports are not accurate. For example, some articles inaccurately portrayed hydraulic fracturing as the cause of a natural gas incident in Bainbridge Township of Geauga County that resulted in an in-home explosion in December 2007. This portrayal is not consistent with the findings or conclusions of the DMRM.

DMRM completed a thorough investigation into the cause of a natural gas invasion into fresh water aquifers in Bainbridge Township. The DMRM investigation found that this incident was caused by a defective primary cement job on the production casing, which was further complicated by operator error. As a consequence of this finding, the operator corrected the construction problem by completing remedial cementing operations. The findings and conclusions of this investigation are available on the web at http://www.dnr.state.oh.us/bainbridge/tabid/20484/default.aspx.

While an explosion significantly damaged one house, the investigation did not find any evidence to support the claim "that pressure caused by hydraulic fracturing pushed the gas...through a system of cracks into the ground water aquifer" as reported by some media accounts. In actuality, the team of geologists who completed the evaluation of the gas invasion incident in Bainbridge Township concluded that the problem would have occurred even if the well had never been stimulated by hydraulic fracturing.

After 25 years of investigating citizen complaints of contamination, DMRM geologists have not documented a single incident involving contamination of ground water attributed to hydraulic fracturing. Over this time, the Ohio DMRM has consistently taken decisive action to address oil and gas exploration and production practices that have caused documented incidents of ground water contamination. The DMRM has initiated amendments to statutes and rules, designed permit conditions, refined standards

operating procedures, and developed best management practices to improve protection of ground water resources. These actions resulted in substantive changes including:

1. elimination of tens of thousands of earthen pits for produced water storage;
2. development of a model Class II brine injection well program;
3. development of technical standards for synthetic liners used in pits during drilling operations;
4. tighter standards for construction and mechanical integrity testing for annular disposal wells;
5. detailed plugging regulations; and,
6. establishment of an orphaned well plugging program funded by a severance tax on oil and gas production.

The Ohio DMRM will continue to assign the highest priority to improving protection of water resources and public health and safety.

In conclusion, the Ohio DMRM has not identified hydraulic fracturing as a significant threat to ground water resources.

Sincerely,

Scott R. Kell, Deputy Chief

SRK/csc

Enclosure

cc: Cathryn Loucas, Deputy Director, ODNR
Mike Shelton, Chief, Legislative Services, ODNR
John Husted, Chief, DMRM

Pennsylvania Department of Environmental Protection

**Rachel Carson State Office Building**
**P.O. Box 8555**
**Harrisburg, PA 17105-8555**
June 1, 2009

**Bureau of Watershed Management** 717-772-4048

Michael Paque, Executive Director
Ground Water Protection Council
13308 North MacArthur Boulevard
Oklahoma City, OK 73142

Dear Mr. Paque:

I am the program manager for Pennsylvania's Ground Water Protection Program in the Pennsylvania Department of Environmental Protection (DEP). I have been concerned about press reports stating extensive groundwater pollution and contamination of underground sources of drinking water in Pennsylvania, as a result of hydraulic fracturing to stimulate gas production from deep, gas bearing rock formations. DEP has not concluded that the activity of hydraulic fracturing of these formations has caused wide-spread groundwater contamination.

After review of DEP's complaint database and interviews with regional staff that investigate groundwater contamination related to oil and gas activities, no groundwater pollution or disruption of underground sources of drinking water has been attributed to hydraulic fracturing of deep gas formations. All investigated cases that have found pollution, which are less then 80 in over 15 years of records, have been primarily related to physical drilling through the aquifers, improper design or setting of upper and middle well casings, or operator negligence.

If you have any questions or concerns, you may contact me by e-mail at josless@state.pa.us or by telephone at 717-772-4048.

Sincerely,

Joseph J. Lee, Jr., P.G., chief
Source Protection Section
Division of Water Use Planning

New Mexico Energy, Minerals and Natural Resources Department

Mark Fesmire
Division Director
Oil Conservation Division

May 29, 2009

Mr. Michael Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mike:

As per your request, I have reviewed the New Mexico Oil Conservation Division Data concerning water contamination caused by Hydraulic Fracturing in New Mexico.

While we do currently list approximately 421 ground water contamination cases caused by pits and approximately an equal number caused by other contamination mechanisms, we have found no example of contamination of usable water where the cause was claimed to be hydraulic fracturing.

Sincerely,

Mark E. Fesmire, PE
Director, New Mexico Oil Conservation Division

Oil Conservation Division
1220 South St. Francis Drive • Santa Fe, New Mexico 87505
Phone (505) 476-3440 • Fax (505) 476-3462 • www.emnrd.state.nm.us/OCD

# *STATE OIL AND GAS BOARD OF ALABAMA*

***OIL AND GAS BOARD***
*James H. Griggs, Chairman*
*Charles E. (Ward) Pearson, Vice Chairman*
*Rebecca Wright Pritchett, Member*
*Berry H. (Nick) Tew, Jr., Secretary*
*S. Marvin Rogers, Counsel*

*420 Hackberry Lane*
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*Tuscaloosa, Alabama 35486-6999*
*Phone (205)349-2852*
*Fax (205)349-2861*
*www.ogb.state.al.us*

***Berry H. (Nick) Tew, Jr.***
*Oil and Gas Supervisor*

May 27, 2009

Mr. Michel Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mr. Paque:

This letter is in response to your recent inquiry regarding any cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in Alabama. I can state with authority that there have been no documented cases of drinking water contamination caused by such hydraulic fracturing operations in our State.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that being to protect underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, to include the regulation and approval of hydraulic fracturing operations, have been actively implemented continually since the Board was established in 1945, pursuant to its legislative mandates.

The point to be made here is that the State of Alabama has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect those sources from all oil and gas operations. The fact that there has been no documented case of contamination from these operations, to include hydraulic fracturing, is a testament to the proactive regulation of the industry by the Board. Additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

If we can be of further assistance in this matter, please let me know.

Sincerely,

David E. Bolin

David E. Bolin
Deputy Director

# RAILROAD COMMISSION OF TEXAS

**CHAIRMAN VICTOR G. CARRILLO**

May 29, 2009

Mike Paque, Executive Director
Ground Water Protection Agency
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Re: Hydraulic Fracturing of Gas Wells in Texas

Dear Mr. Paque:

I am pleased that representatives of the Ground Water Protection Council will be appearing before the U.S. House Committee on Natural Resources next week on the issue of hydraulic fracturing. I was asked to participate but had a longstanding commitment to tour energy projects in Canada that prevented me from personally participating.

I sincerely hope that you will clear up the misconception that there are "thousands" of contamination cases in Texas and other states resulting from hydraulic fracturing. The Railroad Commission of Texas is the chief regulatory agency over oil and gas activities in this state. Though hydraulic fracturing has been used for over 50 years in Texas, our records do not indicate a single documented contamination case associated with hydraulic fracturing.

The Texas Groundwater Protection Committee (TGPC) tracks groundwater pollution in Texas. All Texas water protection agencies, including the Railroad Commission, are members. Each year, the TGPC publishes a Joint Groundwater Monitoring and Contamination Report, which can be found at http://www.tceq.state.tx.us/comm_exec/forms_pubs/pubs/sfr/056_07_index.html. The 2007 report cites a total of 354 active groundwater cases attributed to oil and gas activity – this in a state with over 255,000 active oil and gas wells. The majority of these cases are associated with previous practices that are no longer allowed, or result from activity now prohibited by our existing regulations. A few cases were due to blowouts that primarily occur during drilling activity. *Not one of these cases was caused by hydraulic fracturing activity.*

Hydraulic fracturing plays a key role in the development of virtually all unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed (and hydraulically fractured) in the Barnett Shale reservoir, one of the nation's most active and largest natural gas fields. Since 2000, over five trillion cubic feet of gas has been produced from this one reservoir and the Barnett Shale production currently contributes over 20% of Texas' total natural gas production. While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 trillion cubic feet, recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing groundwater contamination in the Barnett Shale play.

P.O. Box 12967 ★ Austin, Texas 78711-2967 ★ Phone (512) 463-7131 ★ Fax (512) 463-7161

Regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states. Most oil and gas producing state have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – harming domestic energy security. I urge the U.S. Congress to leave the regulatory authority over hydraulic fraturing and other oil and gas activities where it belongs – at the state level.

Sincerely,

Victor G. Carrillo, Chairman
Railroad Commission of Texas

cc: Commissioner Michael Williams
Commissioner Elizabeth Ames Jones
John J. Tintera, Executive Director

# Part B

# IOGCC's Statements from Oil & Gas Regulators from 12 Member States

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# REGULATORY STATEMENTS ON HYDRAULIC FRACTURING
# SUBMITTED BY THE STATES
# JUNE 2009

The following statements were issued by state regulators for the record related to hydraulic fracturing in their states. Statements have been compiled for this document.

## ALABAMA:

**Nick Tew, Ph.D., P.G.**
**Alabama State Geologist & Oil and Gas Supervisor**
**President, Association of American State Geologists**

There have been no documented cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in the State of Alabama.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board of Alabama's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that is, the protection of underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, which include the regulation and approval of hydraulic fracturing operations, have been continuously and actively implemented since the Board was established in 1945, pursuant to its mission and legislative mandates.

The State of Alabama, acting through the Board, has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect these sources from all oil and gas operations, including hydraulic fracturing. The fact that there has been no documented case of contamination from these operations, including hydraulic fracturing, is strong evidence of effective regulation of the industry by the Board. In our view, additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

## ALASKA:

**Cathy Foerster**
**Commissioner**
**Alaska Oil and Gas Conservation Commission**

There have been no verified cases of harm to ground water in the State of Alaska as a result of hydraulic fracturing.

State regulations already exist in Alaska to protect fresh water sources. Current well construction standards used in Alaska (as required by Alaska Oil and Gas Conservation Commission statutes

and regulations) properly protect fresh drinking waters. Surface casing is always set well below fresh waters and cemented to surface. This includes both injectors and producers as the casing/cementing programs are essentially the same in both types of wells. There are additional casings installed in wells as well as tubing which ultimately connects the reservoir to the surface. The AOGCC requires rigorous testing to demonstrate the effectiveness of these barriers protecting fresh water sources.

By passing this legislation [FRAC Act] it is probable that every oil and gas well within the State of Alaska will come under EPA jurisdiction. EPA will then likely set redundant construction guidelines and testing standards that will merely create duplicate reporting and testing requirements with no benefit to the environment. Additional government employees will be required to monitor the programs, causing further waste of taxpayer dollars.

Material safety data sheets for all materials used in oil and gas operations are required to be maintained on location by Hazard Communication Standards of OSHA. Therefore, requiring such data in the FRAC bill is, again, merely duplicate effort with and accomplishes nothing new.

## COLORADO:

**David Neslin**
**Director**
**Colorado Oil and Gas Conservation Commission**

To the knowledge of the Colorado Oil and Gas Conservation Commission staff, there has been no verified instance of harm to groundwater caused by hydraulic fracturing in Colorado.

## INDIANA:

**Herschel McDivitt**
**Director**
**Indiana Department of Natural Resources**

There have been no instances where the Division of Oil and Gas has verified that harm to groundwater has ever been found to be the result of hydraulic fracturing in Indiana. In fact, we are unaware of any allegations that hydraulic fracturing may be the cause of or may have been a contributing factor to an adverse impact to groundwater in Indiana.

The Division of Oil and Gas is the sole agency responsible for overseeing all aspects of oil and gas production operations as directed under Indiana's Oil and Gas Act. Additionally, the Division of Oil and Gas has been granted primacy by the U.S. Environmental Protection Agency, to implement the Underground Injection Control (UIC) Program for Class II wells in Indiana under the Safe Drinking Water Act.

## KENTUCKY:

**Kim Collings, EEC**
**Director**
**Kentucky Division of Oil and Gas**

In Kentucky, there have been alleged contaminations from citizen complaints but nothing that can be substantiated, in every case the well had surface casing cemented to surface and production casing cemented.

## LOUISIANA:

**James Welsh**
**Commissioner of Conservation**
**Louisiana Department of Natural Resources**

The Louisiana Office of Conservation is unaware of any instance of harm to groundwater in the State of Louisiana caused by the practice of hydraulic fracturing. My office is statutorily responsible for regulation of the oil and gas industry in Louisiana, including completion technology such as hydraulic fracturing, underground injection and disposal of oilfield waste operations, and management of the major aquifers in the State of Louisiana.

## MICHIGAN:

**Harold Fitch**
**Director, Office of Geological Survey**
**Department of Environmental Quality**

My agency, the Office of Geological Survey (OGS) of the Department of Environmental Quality, regulates oil and gas exploration and production in Michigan. The OGS issues permits for oil and gas wells and monitors all aspects of well drilling, completion, production, and plugging operations, including hydraulic fracturing.

Hydraulic fracturing has been utilized extensively for many years in Michigan, in both deep formations and in the relatively shallow Antrim Shale formation. There are about 9,900 Antrim wells in Michigan producing natural gas at depths of 500 to 2000 feet. Hydraulic fracturing has been used in virtually every Antrim well.

There is no indication that hydraulic fracturing has ever caused damage to ground water or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way.

## OKLAHOMA:

**Lori Wrotenbery**
**Director, Oil and Gas Conservation Division**
**Oklahoma Corporation Commission**

You asked whether there has been a verified instance of harm to groundwater in our state from the practice of hydraulic fracturing. The answer in no. We have no documentation of such an instance. Furthermore, I have consulted the senior staffs of our Pollution Abatement Department, Field Operations Department, and Technical Services Department, and they have no recollection of having ever received a report, complaint, or allegation of such an instance. We also contacted the senior staffs of the Oklahoma Department of Environmental Quality, who likewise, have no such knowledge or information.

While there have been incidents of groundwater contamination associated with oil and gas drilling and production operations in the State of Oklahoma, none of the documented incidents have been associated with hydraulic fracturing. Our agency has been regulating oil and gas drilling and production operations in the state for over 90 years. Tens of thousands of hydraulic fracturing operations have been conducted in the state in the last 60 years. Had hydraulic fracturing caused harm to groundwater in our state in anything other than a rare and isolated instance, we are confident that we would have identified that harm in the course of our surveillance of drilling and production practices and our investigation of groundwater contamination incidents.

## TENNESSEE:

**Paul Schmierbach**
**Manager**
**Tennessee Department of Environmental Conservation**

We have had no reports of well damage due to fracking.

## TEXAS:

**Victor G. Carrillo**
**Chairman**
**Railroad Commission of Texas**

The practice of reservoir stimulation by hydraulic fracturing has been used safely in Texas for over six decades in tens of thousands of wells across the state.

Recently in his introductory Statement for the Record (June 9, 2009) of the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, Senator Robert Casey stated:

> "Now, the oil and gas industry would have you believe that there is no threat to drinking water from hydraulic fracturing. But the fact is we are already seeing cases in Pennsylvania, Colorado, Virginia, West Virginia, Alabama, Wyoming, Ohio, Arkansas, Utah, Texas, and New Mexico where residents have become ill or groundwater has become contaminated after hydraulic fracturing operations began in the area."

This statement perpetuates the misconception that there are many surface or groundwater contamination cases in Texas and other states due to hydraulic fracturing. This is not true and here are the facts: Though hydraulic fracturing has been used for over 60 years in Texas, our Railroad Commission records ***do not reflect a single documented surface or groundwater contamination case associated with hydraulic fracturing***.

Hydraulic fracturing plays a key role in the development of unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed - and hydraulically fractured - in the Newark East (Barnett Shale) Field, one of the nation's largest and most active natural gas fields. Since 2000, over 5 Tcf (trillion cubic feet) of gas has been produced from this one reservoir and Barnett Shale production currently contributes over 20% of total Texas natural gas production (over 7 Tcf in 2008 – more than a third of total U.S. marketed production). While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 Tcf, conventional recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing surface or groundwater contamination in the Barnett Shale play.

Regulating oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states, which have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – substantially harming domestic energy security. Congress should maintain the status quo and let the states continue to responsibly regulate oil and gas activities, including hydraulic fracturing.

In summary, I am aware of no verified instance of harm to groundwater in Texas from the decades long practice of hydraulic fracturing.

## SOUTH DAKOTA:

**Fred Steece**
**Oil and Gas Supervisor**
**Department of Environment and Natural Resource**

Oil and gas wells have been hydraulically fractured, "fracked," in South Dakota since oil was discovered in 1954 and since gas was discovered in 1970. South Dakota has had rules in place, dating back to the 1940's, that require sufficient surface casing and cement to be installed in

wells to protect ground water supplies in the state's oil fields. Producing wells are required to have production casing and cement, and tubing with packers installed. The casing, tubing, and cement are all designed to protect drinking waters of the state as well as to prevent commingling of water and oil and gas in the subsurface. In the 41 years that I have supervised oil and gas exploration, production and development in South Dakota, no documented case of water well or aquifer damage by the fracking of oil or gas wells, has been brought to my attention. Nor am I aware of any such cases before my time.

**WYOMING:**

**Rick Marvel**
**Engineering Manager**
**Wyoming Oil and Gas Conservation Commission**

**Tom Doll**
**Oil and Gas Commission Supervisor**
**Wyoming Oil and Gas Conservation Commission**

- No documented cases of groundwater contamination from fracture stimulations in Wyoming.

- No documented cases of groundwater contamination from UIC regulated wells in Wyoming.

- Wyoming took primacy over UIC Class II wells in 1982, currently 4,920 Class II wells permitted.

Wyoming's 2008 activity:

- Powder River Basin Coalbed Wells – 1,699 new wells, no fracture stimulation.
- Rawlins Area (deeper) Coalbed Wells – 109 new wells, 100% fracture stimulated.
- Statewide Conventional Gas Wells – 1,316 new wells, 100% fracture stimulated – many wells with multi-zone fracture stimulations in each well bore, some staged and some individual fracture stimulations.
- Statewide Oil Wells – 237 new wells, 75% fracture stimulated.

The Wyoming Oil and Gas Commission Rules and Regulations are specific in requiring the operator receive approval prior to performing hydraulic fracturing treatments. The Rules require the operator to provide detailed information regarding the hydraulic fracturing process, to include the source of water and/or trade name fluids, type of proponents, as well as estimated pump pressures. After the treatment is complete the operator is required to provide actual fracturing data in detail and resulting production results.

Under Chapter 3, Section 8 (c) The Application for Permit to Drill or Deepen (Form 1) states…"information shall also be given relative to the drilling plan, together with any other information which may be required by the Supervisor. Where multiple Applications for Permit

to Drill will be sought for several wells proposed to be drilled to the same zone within an area of geologic similarity, approval may be sought from the Supervisor to file a comprehensive drilling plan containing the information required above which will then be referenced on each Application for Permit to Drill." Operators have been informed by Commission staff to include detailed information regarding the hydraulic fraction stimulation process on the Form 1 Application for Permit to Drill.

The Rules also state, in Chapter 3, Section 1 (a) "A written notice of intention to do work or to change plans previously approved on the original APD and/or drilling and completion plan (Chapter 3, Section 8 (c)) must be filed with the Supervisor on the Sundry Notice (Form 4), unless otherwise directed, and must reach the Supervisor and receive his approval before the work is begun. Approval must be sought to acidize, cleanout, flush, fracture, or stimulate a well. The Sundry Notice must include depth to perforations or the openhole interval, the source of water and/or trade name fluids, type proponents, as well as estimated pump pressures. Routine activities that do not affect the integrity of the wellbore or the reservoir, such as pump replacements, do not require a Sundry Notice. The Supervisor may require additional information." Most operators will submit the Sundry Notice Form 4 to provide the specific detail for the hydraulic fracturing treatment even though the general information might have been provided under the Form 1 Application for Permit to Drill.

After the hydraulic fracture treatment is complete, results must be reported to the Supervisor. Chapter 3, Section 12 Well Completion or Recompletion Report and Log (Form 3) state "upon completion or recompletion of a well, stratigraphic test or core hole, or the completion of any remedial work such as plugging back or drilling deeper, acidizing, shooting, formation fracturing, squeezing operations, setting a liner, gun perforating, or other similar operations not specifically covered herein, a report on the operation shall be filed with the Supervisor. Such report shall present a detailed account of the work done and the manner in which such work was performed; the daily production of the oil, gas, and water both prior to and after the operation; the size and depth of perforations; the quantity of sand, crude, chemical, or other materials employed in the operation and any other pertinent information of operations which affect the original status of the well and are not specifically covered herein."

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New York State

DEC

# Appendix 16

## Applicability of $NO_x$ RACT Requirements for Natural Gas Production Facilities

Revised Draft
Supplemental Generic Environmental Impact Statement

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**Applicability of $NO_x$ RACT Requirements for Natural Gas Production Facilities**

New York State's air regulation 6 NYCRR Part 227-2, Reasonably Available Control Technology (RACT) for Oxides of Nitrogen ($NO_x$), applies to boilers (furnaces) and internal combustion engines at major sources.

The requirements of Part 227-2 include emission limits, stack testing, and annual tune-ups, among others. Many facilities whose potential to emit (PTE) air pollutants would make them susceptible to $NO_x$ RACT requirements can limit, or "cap", their emissions using the limits within the New York State Department of Environmental Conservation's (DEC) Air Emissions Permits applicability thresholds to avoid this regulation.

New York State has two different major source thresholds for $NO_x$ RACT and permitting. Downstate (in New York City and Nassau, Suffolk, Westchester, Rockland, and Lower Orange Counties) the major source permitting and $NO_x$ RACT requirements apply to facilities with a PTE of 25 tons/yr or more of $NO_x$. For the rest of the state (where the majority of natural gas production facilities are anticipated to be located), the threshold is a PTE of 100 tons/yr or more of $NO_x$.

If the stationary engines at a natural gas production facility exceed the applicability levels or if the PTE at the facility would classify it as a Major $NO_x$ source, the following compliance options are available:

1. Develop a $NO_x$ RACT compliance plan and apply for a Title V permit.

2. Limit the facility's emissions to remain under the $NO_x$ RACT applicability levels by applying for one of two New York State Air Emissions permits, depending on how low emissions can be limited.

The permitting options for facilities that wish to limit, or "cap", their emissions by establishing appropriate permit conditions are described below.

New York State's air regulation 6 NYCRR Part 201, Permits and Registrations, includes a provision that allows a facility to register if its actual emissions are less than 50% of the applicability thresholds
(less than 12.5 tons/yr downstate and less than 50 tons/yr upstate). This permit option is known as "cap by rule" registration.

Part 201 also includes a provision that allows a facility to limit its emissions by obtaining a State Facility Permit, if its actual emissions are above the 50% level but below the applicability level (between 12.5 and 25 tons/yr downstate and between 50 and 100 tons/yr upstate).

If the facility $NO_x$ emissions cannot be capped below the applicability levels, then the facility should immediately develop a $NO_x$ RACT compliance plan. This plan should contain the necessary steps (purchase of equipment and controls, installation of equipment, source testing, submittal of permit application, etc.) and projected completion dates required to bring the facility into compliance. This plan is to be submitted to the appropriate DEC Regional Office as soon as possible. In this case the facility would also be subject to Title V, and a Title V air permit application must be prepared and submitted.

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New York State

DEC

# Appendix 17

## Applicability of 40 CFR Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities – Final Rule

Updated July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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**Applicability of 40 CFR Part 63 Subpart ZZZZ (Engine MACT)**
**for Natural Gas Production Facilities – Final Rule**

EPA published a final rule on August 20, 2010 revising 40 CFR Part 63, Subpart ZZZZ, in order to address hazardous air pollutant (HAP) emissions from existing stationary reciprocating internal combustion engines (RICE) located at area sources. A major source of HAP emissions is a stationary source that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year. An area source of HAP emissions is a source that is not a major source.

Available emissions data show that several HAP, which are formed during the combustion process or which are contained within the fuel burned, are emitted from stationary engines. The HAP which have been measured in emission tests conducted on natural gas fired and diesel fired RICE include: 1,1,2,2-tetrachloroethane, 1,3-butadiene, 2,2,4-trimethylpentane, acetaldehyde, acrolein, benzene, chlorobenzene, chloroethane, ethylbenzene, formaldehyde, methanol, methylene chloride, n-hexane, naphthalene, polycyclic aromatic hydrocarbons, polycyclic organic matter, styrene, tetrachloroethane, toluene, and xylene. Metallic HAP from diesel fired stationary RICE that have been measured are: cadmium, chromium, lead, manganese, mercury, nickel, and selenium. Although numerous HAP may be emitted from RICE, only a few account for essentially all of the mass of HAP emissions from stationary RICE. These HAP are: formaldehyde, acrolein, methanol, and acetaldehyde. EPA is proposing to limit emissions of HAP through emissions standards for formaldehyde for non-emergency four stroke-cycle rich burn (4SRB) engines and through emission standards for carbon monoxide (CO) for all other engines.

The applicable emission standards (at 15% oxygen) or management practices for existing RICE located at area sources are provided in the table below.

In addition to emission standards and management practices, certain stationary CI RICE located at existing area sources are subject to fuel requirements. Stationary non-emergency diesel-fueled CI engines greater than 300 HP with a displacement of less than 30 liters per cylinder located at existing area sources must only use diesel fuel meeting the requirements of 40 CFR 80.510(b),

which requires that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

| Subcategory | Emission standards at 15 percent O2, as applicable, or management practice | |
|---|---|---|
| | **Except during periods of startup** | **During periods of startup** |
| **Non-Emergency 4SLB* >500HP** | 47 ppmvd CO or 93% CO reduction | Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. |
| **Non-Emergency 4SLB ≤500HP** | Change oil and filter every 1440 hours; inspect spark plugs every 1440 hours; and inspect all hoses and belts every 1440 hours and re-place as necessary. | Same as above |
| **Non-Emergency 4SRB** >500HP** | 2.7 ppmvd formaldehyde or 76% formaldehyde reduction. | Same as above |
| **Non-Emergency CI >500HP** | 23 ppmvd CO or 70% CO reduction | Same as above |
| **Non-Emergency CI*** 300-500HP** | 49 ppmvd CO or 70% CO reduction | Same as above |
| **Non-Emergency CI ≤300HP** | Change oil and filter every 1000 hours; inspect air cleaner every 1000 hours; and inspect all hoses and belts every 500 hours and re-place as necessary. | Same as above |

*4SLB - four stroke-cycle lean burn
**4SRB – four stroke-cycle rich burn
***CI – compression ignition

New York State

DEC

# Appendix 18

# Definition of Stationary Source or Facility for the Determination of Air Permit Requirements

Revised July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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**Definition of Stationary Source or Facility**
**for the Determination of Air Permit Requirements**

Summary

NYSDEC must determine the applicability of air permitting regulations and requirements to natural gas drilling activities in the Marcellus Shale formation. Specifically, NYSDEC must determine applicable regulations and permit requirements for:

• sources subject to stationary source permitting under 6 NYCRR Part 201.
major stationary source - one that emits or has the potential to emit any of the following:
100 tons per year (TPY) or more of any regulated air pollutant ($NO_X$, $SO_2$, CO,, PM2.5, $PM_{10}$); 50 TPY of VOC.
10 TPY or more of any individual Hazardous Air Pollutant (HAP); or
25 TPY or more of any combination of HAPs.

• sources subject to New Source Performance Standards (**NSPS**)

• sources subject to National Emission Standards for Hazardous Air Pollutants (**NESHAP**), and

• 6 NYCRR Part 231 for major new or major modifications to existing sources subject to preconstruction review requirements under Prevention of Significant Deterioration (**PSD**) and/or Non-Attainment New Source Review (**NSR**)

In addition to threshold criteria detailed in regulation and guidance, NYSDEC must evaluate a variety of technical and factual information to assess applicability of these rules to specific sources through the permit application process. These evaluations, as they pertain to natural gas drilling activities in the Marcellus Shale formation, are discussed herein, including 1) whether emissions from two or more pollutant-emitting activities should be aggregated into a single major stationary source for purposes of NSR and Title V programs; and 2) how to assess NESHAP applicability given the unique regulatory definition of "facility" for the oil and gas industry.

Major Stationary Source Determinations for Criteria Pollutants

PSD, NSR and Title V operating permit program (Title V) regulations apply to certain sources with the potential to emit pollutants in excess of the major source thresholds. To assess applicability, DEC must evaluate whether emissions from two or more pollutant-emitting activities should be aggregated into a single major stationary source. The evaluation begins with the federal definition of "stationary source" at 40 CFR 52.21(b)(5) and a similar definition for major source under 6 NYCRR 201-2.1(b)(21). The federal definition reads "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant." "Building, structure, facility, or installation" is further defined in 40 CFR 52.21(b)(6):

> *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the *Standard Industrial Classification Manual, 1972*, as amended by the 1977 Supplement (U. S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

To identify pollutant-emitting activity that belongs to the same building, structure, facility, or installation, permitting authorities rely on the following three criteria: 1) whether the activities belong to the same industrial grouping; 2) whether the activities are located on one or more contiguous or adjacent properties; and 3) whether the activities are under the control of the same person (or person under common control).[1] These criteria are applied case-by-case to make the major stationary source determination.

Since the original SGEIS, DEC reviewed numerous source determinations from EPA permitting actions, guidance provided by EPA to inform permitting actions by other permitting authorities, and source determination protocol developed by other states. These documents have been informative. However, EPA has clearly stated that "no single determination can serve as an adequate justification for how to treat any other source determination for pollutant-emitting activities with different fact-specific circumstances." [2] "Therefore, while the prior agency statements and determinations related to oil and gas activities and other similar sources may be instructive, they are not determinative in resolving the source determination issue…, particularly where a state with independent permitting authority is making the determination and the prior agency statements had… substantially different fact-specific circumstances."[3]As such, DEC will formulate case-specific source determinations based on the foregoing, federal and state regulation, industry data and the specific facts of each air permit application. These determinations will be made during the review of permit applications for compressor stations which are associated with Marcellus Shale activities.

The three source determination criteria are discussed in more detail below.

1) **Do the pollutant-emitting activities belong to the same industrial grouping or "Major Group"?** In formulating the definition of "source," EPA uses a Standard Industrial Classification(SIC) code for distinguishing between sets of activities on the basis of their functional interrelationships.[4] Each source is to be classified according to its primary activity,

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[1] Memorandum from Gina McCarthy, EPA Assistant Administrator, to Regional Administrators, Sept. 22, 2009, available at http://www.epa.gov/region7/air/nsr/nsrmemos/oilgaswithdrawal.pdf
[2] Id.
[3] In The Matter Of Anadarko Petroleum Corporation, Frederick Compressor Station, Order Responding To Petitioners' Request That The Administrator Object To Issuance Of A State Operating Permit, February 2, 2011, Petition Number: VIII-2010-4.
[4] 45 FR 52695, at 31.

which is determined by its principal product or group of products produced or distributed, or services rendered.[5]

The Standard Industrial Classification Manual lists activities associated with oil and gas extraction in Major Group 13 and activities associated with natural gas transmission in Major Group 49. Establishments primarily engaged in operating oil and gas field properties, including wells, are grouped into Major Group 13. The Standard Industrial Classification Manual does not expressly list all equipment, such as midstream compressor stations, in Major Group 13, nor Major Group 49. Therefore, DEC may look to other information, such as federal and state regulations, industry data, and gas gathering agreements, to help make the source determination. For instance, under NESHAP, EPA regulates compressor stations that transport natural gas to a natural gas processing plant[6] in accordance with natural gas production facilities, Major Group 13.[7] In the absence of a natural gas processing plant, EPA regulates a compressor station in accordance with natural gas production facilities where the compressor station is prior to the point of custody transfer.[8] If the compressor station is after the point of custody transfer, EPA regulates the compressor station in accordance with natural gas transmission and storage facilities, Major Group 49. In relevant part, custody transfer means the transfer of natural gas to pipelines *after processing or treatment*.[9]

Where the pollutant-emitting activities do not belong to the same industrial grouping or "Major Group," DEC will ascertain whether one activity serves exclusively as a support facility for the other. In the Preamble to its 1980 PSD regulations, EPA "clarifies that "support facilities" that "convey, store, or otherwise assist in the production of the principal product*"* should be considered under one source classification, even when the support facility has a different two-digit SIC code.[10]

2**) Are the pollutant-emitting activities contiguous or adjacent?** EPA has routinely relied on the plain meaning of the word "contiguous," that is - being in actual contact; touching along a boundary or at a point. However, "the more difficult assessment is determining whether … a non-contiguous [pollutant-emitting activity] might be considered "adjacent."[11] First, EPA has not established a specific distance between activities in assessing whether such activities are adjacent.[12] Second, "the concept of "interdependency," which many individual EPA determinations consider, is not discussed in the 1980 Preamble or mentioned in the federal PSD or Title V regulations defining "source.*"*[13] "[I]nterdependency is a factor that has evolved over time in various case-by-case determinations. While interdependency is a consideration, it is not an express element of the actual three-part test set forth in regulation, and in the context of oil

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[5] 45 FR 52695, at 32.
[6] 40 CFR §63.761, *Natural gas processing plant.*
[7] 40 CFR §63.761, *Facility.*
[8] 40 CFR §63.760(a)(3)
[9] 40 CFR §63.761, *Custody transfer.*
[10] 45 Fed. Reg. 52676 (August 9, 1980)
[11] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 15, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf
[12] Id.
[13] Id. at 14

and gas infrastructure, it may have reduced relevance to an agency determination"[14] Nevertheless, to be thorough, DEC staff will evaluate the nature of the relationship between the facilities and the degree of interdependence between them to determine whether the non-contiguous emissions points should be aggregated.[15]

A "high level of connectedness and interdependence between two activities" is needed to deem them adjacent, and "interdependence requires that the two activities rely on each other – not just that one activity relies on the other activity.[16] Furthermore, "a determination of interdependence requires that the two activities rely upon each other *exclusively*; i.e., one activity cannot operate or occur without the other. The case-by-case determinations indicate that if activities operate independently and one activity does not act solely as a support operation for the other, the activities should not be deemed contiguous or adjacent."[17] In guidance provided by EPA to the Utah Division of Air Quality[18], EPA recommended using the following indicators as determinative of adjacency for two Utility Trailer Manufacturing Company facilities: 1) whether the location of the new facility was chosen because of its proximity to the existing facility; 2) whether materials would routinely be transferred back and forth between the two facilities; 3) whether managers and other workers would be shared between the two facilities; and 4) whether the production process itself would be split between the two facilities.[19] While DEC will use these and other questions to inform its source determination, some questions may have reduced relevance in the oil and gas industry. For instance, the location of oil and gas activity, proximate or otherwise, may "be controlled by land agreements, access issues, geologic formations, terrain, and, in other situations, by federal or state land management agencies, such as the Bureau of Land Management for oil and gas production on federal lands,"[20] and thus not necessarily indicative of a particular source category.

3) **Are the activities under common control?** To assess common control, EPA has historically relied on the Securities and Exchange Commission's definition of control as follows: The term control (including the terms controlling, controlled by and under common control with) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person (or organization or association), whether through the ownership of voting shares, by contract or otherwise. The following questions have been used previously and in more recent actions by EPA to determine "common control" [21]: 1) Whether control has been

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[14] Id. at 36

[15] Letter from Cheryl Newton, U.S. EPA, to Scott Huber, Summit Petroleum Corporation, October 18, 2010, at 4, http://www.epa.gov/region07/air/title5/t5memos/singler5.pdf

[16] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 21, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

[17] Id. at 36 – 37.

[18] Letter from Richard Long of EPA Region VIII to Lynn Menlove of Utah Division of Air Quslity, dated May 21, 1998. http://www.epa.gov/region07/air/title5/t5memos/util-trl.pdf

[19] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 20, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

[20] Id. at 40

[21] Letter from Kathleen Henry of EPA Region III to John Slade of Pennsylvania DEP, dated 1/15/99. Also, Letter from Richard Long of EPA Region VIII to Margie Perkins, Air Pollution Control Division, Colorado Department of Public Health Environment, dated October 1, 1999, http://www.epa.gov/region07/air/nsr/nsrmemos/frontran.pdf

established through ownership of two entities by the same parent corporation or a subsidiary of the parent corporation; 2) Whether control has been established by a contractual arrangement giving one entity decision making authority over the operations of the second entity; 3) Whether there is a contract for service relationship between the two entities in which one sells all of its product to the other under a single purchase or contract; 4) Whether there is a support or dependency relationship between the two entities such that one would not exist "but for" the other?

Thus, DEC will use answers to the following questions to help guide the case-specific source determinations for natural gas drilling activities in the Marcellus Shale formation that may be subject to NSR and Title V for criteria pollutants.

1. Do the pollutant-emitting activities belong to the same industrial grouping or “Major Group” as described in the Standard Industrial Classification Manual?
    a. What is the primary activity engaged in by the facility?
    b. If the pollutant-emitting activities do not belong to the same industrial grouping or Major Group, does one activity serve exclusively as a support facility for the other?
2. Are the pollutant-emitting activities contiguous or adjacent?
    a. Are the pollutant-emitting activities contiguous? Do they share a boundary or touch each other physically?
    b. If the pollutant-emitting facilities are non-contiguous, are they proximate or interdependent?
    c. Was the location of the new facility chosen because of its proximity to the existing facility?
    d. Will materials routinely be transferred back and forth between the two facilities?
    e. Will managers and other workers be shared between the two facilities?
    f. Will the production process be split between the two facilities?
3. Are the activities under common control?
    a. Has control been established through ownership of two entities by the same parent corporation or a subsidiary of the parent corporation?
    b. Has control been established by a contractual arrangement giving one entity decision making authority over the operations of the second entity?
    c. Is there a contract for service relationship between the two entities in which one sells all of its product to the other under a single purchase or contract?
    d. Is there an exclusive support or dependency relationship between the two entities such that one would not exist "but for" the other?

NESHAPS Applicability for Hazardous Air Pollutants

"[I]n the hazardous air pollutant ("HAP") arena, EPA has expressly determined, consistent with Congress' statutory mandate in the [Clean Air Act] CAA, 42 U.S.C. § 7412(n)(4)(A), oil and gas production field facilities are typically not industrial facilities that should be aggregated."[22] The CAA, 42 U.S.C. § 7412, defines "major source" as any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants; and "area source" as any stationary source of hazardous air pollutants that is not a major source. Notwithstanding this definition, Section 7412(n)(4)(A) exempts oil and gas wells and pipeline facilities from the requirement to aggregate with contiguous sources under common control when deciding if the source is a major source for NESHAPS applicability.

In the context of hazardous air pollutants, EPA declared that "[s]uch facilities generally are not in close proximity to or co-located with one another (contiguous) and located within an area boundary, the entirety of which (other than roads, railroads, etc.), is under the physical control of the same owner."[23,24] In light of this, EPA developed a unique definition of facility for the oil and gas industry NESHAP regulations (40 CFR 63 Subparts HH and HHH). For HAP major source determinations, the EPA-promulgated definition of "facility" states that "pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts . . . or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility."[25,26] EPA defines a "surface site" at 40 CFR 63.761 of Subpart HH as " Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed".

Accordingly, to determine applicability of the NESHAPs rules governing Oil and Gas Production and Natural Gas Transmission industry sectors, the regulatory definition of facility authorized by CAA, 42 U.S.C. § 7412(n)(4)(A) and found at 40 CFR 63 Subparts HH and HHH, must be used. DEC will follow this definition in determining the regulatory applicability of NESHAPS requirements for HAPS. This opens up the possibility that a "facility" definition for a certain permit application may result in a determination of "major source" for purposes of NSR or Title V permitting, but which will consist of several area source surface sites for the purposes

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[22] Id. at 23
[23] 63 Fed. Reg. 6288, 6303 (Feb. 6, 1998)
[24] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 23, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf
[25] 64 Fed. Reg. 32610, 32630 (June 17, 1999)
[26] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 23, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

of NESHAP applicability. Guided by EPA's three source determination criteria and the underlying recommendation to use case specific facts, DEC will consider all pertinent information on a case-by-case basis in arriving at its conclusions during source permitting review.

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New York State

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# Appendix 18A

## Evaluation of Particulate Matter and Nitrogen Oxides Emissions Factors and Potential Aftertreatment Controls for Nonroad Engines for Marcellus Shale Drilling and Hydraulic Fracturing

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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# Evaluation of Particulate Matter and Nitrogen Oxides Emissions Factors and Potential Aftertreatment Controls for Nonroad Engines for Marcellus Shale Drilling and Hydraulic Fracturing Operations

## Nonroad Emissions Standards

Tables 1 and 2 describe the EPA emissions standards for nonroad diesel engines relevant to natural gas well drilling and hydraulic fracturing. These standards are contained in 40 CFR Parts 89 and 1039. These standards may be considered worst case emission levels. Table 1 covers engines rated from 600-750 horsepower. Table 2 covers engines rated at more than 750 horsepower that are not installed in a generator set. Engines are held to these standards for a useful life of the lesser of 8000 hours or 10 years. Actual operating lifetimes are likely much longer.

Table 1 Nonroad Engine Standards for Engines Rated Between 600 and 750 Horsepower

| Standard | Initial Year | PM (g/bhp*hr) | NOx (g/bhp/hr) | HC (g/bhp*hr) | Notes |
|---|---|---|---|---|---|
| Tier 1 | 1996 | 0.4 | 6.9 | 1.0 | |
| Tier 2 | 2002 | 0.15 | 4.32 | 0.48 | 4.8 g/bhp*hr NOx + HC standard |
| Tier 3 | 2006 | 0.15 | 2.7 | 0.3 | 3.0 g/bhp*hr NOx + HC standard |
| Tier 4 interim | 2011 | 0.01 | 1.35 | 0.14 | NOx standard half-way between Tier 3 and Tier 4 |
| Tier 4 | 2014 | 0.01 | 0.3 | 0.14 | |

Tier 2 and Tier 3 $NO_x$ and hydrocarbon standards are an additive $NO_x$ plus hydrocarbon (HC) standard. For Tier 2 the limit is 4.8 g/bhp*hr. For Tier 3 the limit is reduced to 3.0 g/bhp*hr. In order to use the standards as conservative emissions limits, it is necessary to apportion the emission limit between the two pollutants. The Tables apportions 90% of the emissions to $NO_x$ and the remaining 10% to hydrocarbons. EPA and European Union (EU) emissions tiers that have separate $NO_x$ and hydrocarbon standards, not requiring exhaust aftertreatment, generally have the $NO_x$ standard equaling 86-88% of the sum of the two standards. It should be noted that data supplied on behalf of industry (1) assumed that 100% of these emissions are $NO_x$, which is deemed conservative.

There is no official "Tier 4 interim" standard for engines in the Table 1 horsepower class. Beginning in 2011, 50% of the engines in the class are supposed to meet the Tier 4 $NO_x$ standards. This would increase to 100% in 2014. When faced with the exact same phase-in schedule from 2007-2010 for highway diesel engines, manufacturers universally chose to initially certify all engines to a Family Emissions Level half way between the old standard and the new standard, and postpone the $NO_x$ aftertreatment requirements for three years. Thus, the $NO_x$ emissions level of 1.35 g/bhp*hr in the Table is the average of the Tier 3 and Tier 4 standards.

Table 2 Nonroad Engine Standards for Engines Rated Above 750 Horsepower

| Standard | Initial Year | PM (g/bhp*hr) | NOx (g/bhp/hr) | HC (g/bhp*hr) | Notes |
|---|---|---|---|---|---|
| Tier 1 | 2000 | 0.4 | 6.9 | 1.0 | |
| Tier 2 | 2006 | 0.15 | 4.32 | 0.48 | 4.8 g/bhp*hr NOx + HC standard |
| Tier 4 interim | 2011 | 0.075 | 2.6 | 0.3 | |
| Tier 4 final | 2015 | 0.03 | 2.6 | 0.14 | |

Tier 1 and Tier 2 standards for engines rated above 750 horsepower are the same as the corresponding standards for engines rated between 600 and 750 horsepower. Again, the Tier 2 $NO_x$ plus hydrocarbon standard is apportioned 90% $NO_x$ and 10% hydrocarbon. There are no Tier 3 standards for these engines. The Tier 4 interim standards are promulgated standards. Also, the Tier 4 standards for engines rated above 750 horsepower not installed in generator sets do not force the use of $NO_x$ aftertreatment.

## Retrofit of Exhaust Aftertreatment

Prior to Tier 4, none of the new engine standards were stringent enough to require exhaust aftertreatment. Current highway engine standards require aftertreatment to meet both the PM and $NO_x$ standards. Furthermore, there is now substantial experience with retrofitting exhaust aftertreatment to highway engines and stationary engines. Technologies include: Diesel Oxidation Catalysts which oxidize hydrocarbons and carbon based particulate matter, Continuously Regenerating Diesel Particulate Filters or "Traps" (CRDPF) where particulate matter is collected and oxidized, and Selective Catalytic Reduction (SCR) which uses ammonia (usually supplied as urea) or "$NO_x$ absorbers" to reduce $NO_x$ emissions. Although in the past EPA had identified the $NO_x$ absorbers as a promising technology, more recently it has not been proven to be so. Its use has been limited to certain light duty trucks and cars, but it has not been applied to the size class of the fracking engines. In addition, the "lean $NO_x$ Catalyst" system noted by EPA to have a certain $NO_x$ reduction would be insufficient to meet the ultimate engine standards. Thus, for $NO_x$ control, the SCR system is recommended.

Table 3 lists the aftertreatment effectiveness claimed by one manufacturer, Johnson Matthey[1], as an example for retrofit installations on stationary engines (2).

[1] Listing of this manufacturer does not imply any form of endorsement. Other manufacturers could provide similar aftertreatment information.

Table 3 Exhaust Aftertreatment Retrofit Effectiveness

| Technology | Abbreviation | PM Emissions Reduction (%) | NOx Emissions Reduction (%) | HC Emissions Reduction (%) |
|---|---|---|---|---|
| Diesel Oxidation Catalyst | DOC | 30% | 0 | 90% |
| Particulate Trap | CRDPF | 85% | 0 | 90% |
| Particulate Trap and SCR | SCR-DPF (SCRT) | 85% | 90% | 90% |

Johnson Matthey has EPA certification of its SCR-DPF system (referred to as SCRT) as a verified retrofit for some classes of highway diesel engines. That verification is for a 70% $NO_x$ emissions reduction (3). The development of Johnson Matthey's retrofit system is described by Conway and coworkers (4). This certification does not negate the 90% reduction expected for these nonroad engines due to factors discussed below.

The SCR and CRDPF technologies are the dominant technologies used to meet the current highway emissions standards, and are expected to dominate the market for large nonroad diesel engine exhaust aftertreatment. There are other $NO_x$ control technologies; however their applicability appears to be limited to smaller engines, such as those in light duty vehicles. Although the engines used in drilling and hydraulic fracturing are defined in regulation as nonroad mobile engines, they are physically static during drilling or hydraulic fracturing. They also have a relatively steady duty cycle, without the frequent transient operation seen in motor vehicles. Thus, the engineering and operational challenges associated with exhaust aftertreatment retrofits should be reduced in comparison to highway vehicles. It should also be easier to achieve higher $NO_x$ reduction levels with SCR.

The exhaust temperatures reported on behalf of industry (800-900 °F) (1) are high enough to support aftertreatment retrofits which require minimum temperatures of roughly 250 °C (<500 °F) (3) (4).

## Emissions of Nitrogen Dioxide

Nitrogen Dioxide ($NO_2$) is not explicitly regulated via EPA engine emissions standards. It is a component of the regulated pollutant $NO_x$. However, primary $NO_2$ emissions are a concern in our Marcellus Shale evaluation due to the new 1 hour $NO_2$ standard and specific emission factor estimates are necessary to assure that modeling results account for the $NO_2$ portion of the emissions.

Conventional information has been that roughly 5% of $NO_x$ emissions from internal combustion engines are $NO_2$; the balance are NO. However, European researchers have noted that ambient $NO_2$ concentrations have not been declining despite declining $NO_x$ emissions from engines and vehicles. This has led to some investigation of the $NO_2$ fraction of primary NOx emissions from highway vehicles. The most comprehensive summary is by Grice, et al (5), who needed the data

for model inputs. These researchers found that the conventional use of 5% $NO_2$ holds for gasoline engines. The $NO_2$ fraction for diesel engines varies for different emissions control technologies, but is always greater than 5%. The data are summarized based on European emissions standards which must be translated into aftertreatment technology level.

$NO_2$ fractions for diesels range between 10% and 55% (5). EURO II engines, which have no exhaust aftertreatment, have a $NO_2$ fraction of 11%. This $NO_2$ fraction is used for Tier 1, Tier 2, and Tier3 engines with no retrofitted aftertreatment. For particulate trap equipped EURO III engines the $NO_2$ fraction is 35%. This $NO_2$ fraction is used for cases with either a DOC or a CRDPF either standard or retrofitted. The oxidation reactions in DOCs oxidize some NO to $NO_2$ along with the desired oxidation of hydrocarbons and particulate carbon. Indeed, oxidation catalysts are placed ahead of CRDPFs to produce $NO_2$ for use in oxidizing particulate matter to regenerate the PM trap. $NO_2$ oxidizes carbon at a lower temperature than $O_2$.

Finally, Grice and coworkers chose to use a $NO_2$ fraction of 10% for engines equipped with SCR (EURO IV and later). However, the data for the SCR equipped engines was particularly sparse. This uncertainty is discussed further below.

For light duty vehicles equipped with $NO_x$ aftertreatment a $NO_2$ fraction of 55% was reported. Light duty vehicle $NO_x$ control generally avoids SCR, with its requirement that the operator maintain the urea supply. These alternative $NO_x$ aftertreatment technologies have not proven viable for heavy duty truck engines, never mind the even larger engines to be used in Marcellus Shale drilling and hydraulic fracturing. Thus the 55% $NO_2$ fraction does not have any applicability here.

Table 4 below summarizes the recommended $NO_2$ fractions.

Table 4 $NO_2$ Emissions as Fraction of $NO_x$ Emissions

| Technology | Fraction $NO_2$ (in %) |
|---|---|
| No Exhaust Aftertreatment | 11 |
| Diesel Oxidation Catalyst or Particulate Trap | 35 |
| SCR (with or without DOC or CRDPF) | 10 (see text) |

Specifying a single $NO_2$ fraction for an engine technology is clearly a simplification. Researchers have documented variation in the $NO_2$ fraction depending on engine load (6) and exhaust temperature (7). The $NO_2$ fractions in Table 4 for engines without SCR could be low for engines operated at low loads and low exhaust temperatures. They appear to better reflect the emissions at higher loads more in line with the operations expected during drilling and hydraulic fracturing.

Given the particularly high level of uncertainty regarding the $NO_2$ fraction when SCR is used, a review of the chemistry involved might help. SCR generally converts $NO_x$ to $N_2$. There are several different reactions involved (8), (9), (10). One of these reactions, the “fast” SCR reaction is much faster (and has lower minimum temperature requirements) than the others.

$$2NH_3 + NO + NO_2 \rightarrow 2N_2 + 3H_2O$$

The fast SCR reaction generally goes to completion before any of the other reactions become significant. This leads to a desire to have a $NO_2$ fraction near 50% at the SCR reactor inlet. However, given variations on the $NO_2$ consumption by a CRT and variations in engine load and engine out exhaust gas composition, consistently providing the SCR reactor with a 50:50 $NO_2$ to NO ratio would be quite difficult.

As long as the exhaust gases remain in the SCR reactor after the fast SCR reaction has exhausted one of the $NO_x$ species, other chemical reactions will continue to reduce $NO_x$. The reaction for NO produces nitrogen and water. Several competing reactions are possible for $NO_2$. Some of these produce ammonium nitrate or nitrous oxide in addition to nitrogen.

Another concern with SCR is "ammonia slip," the emission of ammonia injected into the exhaust stream but not consumed. Oxidation catalysts are employed after SCR reactors to oxidize ammonia to nitrogen. This catalyst could also oxidize NO to $NO_2$. Thus, it cannot be completely ruled out that $NO_x$ emissions from SCR equipped engines may consist of more than 10% $NO_2$ , possibly with an upper bound of 0.35%. However, further review of the literature regarding the chemistry of ammonia slip catalysts leads to the conclusion that oxidation of NO to $NO_2$ is not a major concern. The desired reaction in the ammonia slip catalyst is the oxidation of ammonia to nitrogen and water. Competing reactions form NO and $N_2O$, but not $NO_2$ (2). The fate of NO in an ammonia slip catalyst is to react with ammonia and form $N_2O$. $NO_2$ production would likely only begin if the ammonia was exhausted. The chemical reaction mechanism of ammonia oxidation is well known, it is an intermediate step in the industrial production of nitric acid (3). Given that there is no apparent path to $NO_2$ formation as long as $NH_3$ is present, greater confidence can be placed in a $NO_2$ emission estimate of 10% of $NO_x$ for SCR equipped engines.

Thus, actual data summarized by Grice and coworkers, although sparse, currently suggests that we consider the DOC/CRDPF $NO_2$ fraction of 10% as the appropriate factor. Regardless of the actual $NO_2$ fraction of the NOx emissions from a SCR equipped engine (retrofitted or standard), SCR will provide the lowest $NO_2$ and $NO_x$ emissions achievable with diesel engines.

**Emission Rates for Various Emissions Standards Tiers & Exhaust Aftertreatment Retrofit Options**

Considering the different Tiers of engine standards, the variety of possible exhaust aftertreatment retrofits, and the uncertainty in the $NO_2$ fraction of $NO_x$ emissions from SCR equipped engines, there are in excess of 20 different emissions cases possible. Calculations were performed by Barnes, (11) (12), but only the pertinent part of these results are presented in Tables 5 and 6.

These emissions rates are estimated from the relevant U.S. EPA standards presented in Tables One and Two. In cases where a NOx + HC standard was promulgated, the standard is apportioned 90% $NO_x$, 10% HC. Effectiveness of exhaust aftertreatment retrofits are based on Table Three. Where the claimed retrofit effectiveness reduces an emission rate below a subsequent standard expected to require the same exhaust aftertreatment technology the subsequent standard (the higher number) is used as the emissions rate. $NO_2$ emission rates are

calculated from $NO_x$ emission rates using factors presented in Table Four. For SCR equipped engines the $NO_2$ fraction of 10 of the NOx emissions is presented.

Table 5 Emissions Factors for Engines between 600 and 750 Horsepower

Air Drilling Engines

| Standard | Effective Year | Retrofit | PM (g/bhp*hr) | NOx (g/bhp*hr) | HC (g/bhp*hr) | $NO_2$ (g/bhp*hr) |
|---|---|---|---|---|---|---|
| Tier 1 | 1996 | None | 0.4 | 6.9 | 1.0 | 0.759 |
| | | DOC | 0.28 | 6.9 | 0.14 | 2.415 |
| | | CRDPF | 0.06 | 6.9 | 0.14 | 2.415 |
| | | SCR-DPF | 0.06 | 0.69 | 0.14 | 0.069 |
| Tier 2 | 2002 | None | 0.15 | 4.32 | 0.48 | 0.475 |
| | | DOC | 0.105 | 4.32 | 0.14 | 1.512 |
| | | CRDPF | 0.03 | 4.32 | 0.14 | 1.512 |
| | | SCR-DPF | 0.03 | 0.432 | 0.14 | 0.043 |
| Tier 3 | 2006 | None | 0.15 | 2.7 | 0.3 | 0.297 |
| | | DOC | 0.105 | 2.7 | 0.14 | 0.945 |
| | | CRDPF | 0.03 | 2.7 | 0.14 | 0.945 |
| | | SCR-DPF | 0.03 | 0.3 | 0.14 | 0.03 |
| Tier 4 | 2011 | None | 0.01 | 1.35 | 0.14 | 0.473 |
| | | SCR | 0.01 | 0.3 | 0.14 | 0.03 |
| Tier 4 | 2014 | None | 0.01 | 0.3 | 0.14 | 0.03 |

Table 6 Emissions Factors for Engines Greater than 750 Horsepower

Drilling Rig and Hydraulic Fracturing Engines

| Standard | Effective Year | Retrofit | PM (g/bhp*hr) | NOx (g/bhp*hr) | HC (g/bhp*hr) | $NO_2$ (g/bhp*hr) |
|---|---|---|---|---|---|---|
| Tier 1 | 2000 | None | 0.4 | 6.9 | 1.0 | 0.759 |
| | | DOC | 0.28 | 6.9 | 0.14 | 2.415 |
| | | CRDPF | 0.06 | 6.9 | 0.14 | 2.415 |
| | | SCR-DPF | 0.06 | 0.69 | 0.14 | 0.069 |
| Tier 2 | 2006 | None | 0.15 | 4.32 | 0.48 | 0.475 |
| | | DOC | 0.105 | 4.32 | 0.14 | 1.512 |
| | | CRDPF | 0.03 | 4.32 | 0.14 | 1.512 |
| | | SCR-DPF | 0.03 | 0.432 | 0.14 | 0.043 |
| Tier 4 interim | 2011 | None | 0.075 | 2.6 | 0.3 | 0.91 |
| | | CRDPF | 0.03 | 2.6 | 0.14 | 0.91 |
| | | SCR-DPF | 0.03 | 0.3 | 0.14 | 0.03 |
| Tier 4 | 2015 | None | 0.03 | 2.6 | 0.14 | 0.91 |
| | | SCR-DPF | 0.03 | 0.3 | 0.14 | 0.03 |

**Summary**

Between 2000 and 2015 nonroad engines will have gone through four or five (depending on engine power) different sets of emissions standards. PM mass reduction over this timeframe will be 93% for the largest engines and 98% for engines rated between 600 and 750 horsepower. NOx emissions will be reduced 96% for the 600 to 750 horsepower engines, but only 62% for the larger engines. Much of these emissions reductions can be achieved without premature replacement of older engines by retrofitting exhaust aftertreatment to these engines. A key consideration with these retrofits is that PM aftertreatment in the absence of SCR will increase $NO_2$ emissions. This concern also applies to current and future Tier 4 engines which may have PM aftertreatment but not NOx aftertreatment.

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New York State

DEC

# Appendix 18B

## Cost Analysis of Mitigation of $NO_2$ Emissions and Air Impacts by Selected Catalytic Reduction (SRC) Treatment

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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**Cost Analysis of Mitigation of $NO_2$ Emissions and Air Impacts by Selected Catalytic Reduction (SRC) Treatment**

## 1. Introduction

In order to mitigate modeled exceedences of the National Ambient Air Quality Standards (NAAQS) for nitrogen dioxide ($NO_2$) the SGEIS has recommended that the hydraulic fracturing engines (and tier 1 drilling engines) used in the development of gas production wells in the Marcellus formation in New York State must be equipped with post-combustion controls. Selective catalytic reduction (SCR) is the recommended technology for addressing $NO_2$ concerns (see Appendix 18A). SCR is a proven technology for reducing oxides of nitrogen ($NO_x$) emissions from combustion sources. This technology involves the use of a urea solution (32.5 percent urea) which converts $NO_x$ to nitrogen gas on a catalyst.

To determine the viability of the SCR control use for the hydraulic fracturing engines in terms of the associated costs, an approximate estimate of mitigation cost is presented in this appendix. It should be noted that these estimates are not necessarily representative of the actual costs which industry will experience. The purpose of these estimates is to determine the cost per ton of NOx removal for a relative comparison to cost thresholds used by the Department for NOx RACT purposes at stationary sources.[1] In addition, it should be noted that any reference to specific manufacturers (in footnotes) does not constitute an endorsement, but merely presents the specific information source.

First, an estimate is developed regarding how many jobs and how many hours a hydraulic fracturing engine could be used each year. In the third section, the costs of installing and operating an SCR system on a typical 2250 hp hydraulic fracturing engine are presented. In the fourth section the cost per ton of $NO_x$ removed from the exhaust stream is compared with the $NO_x$ RACT cost threshold used for stationary sources. A summary of the findings of this investigation are presented in the final section.

## 2. Operation of Hydraulic Fracturing Engines

According to ALL Consulting, hydraulic fracturing engines will be used at any given well pad for no more than 14 days. Mobilization and de-mobilization activities are expected to take a total of four days. Hydraulic fracturing activities are expected to take ten days per well pad (five days per well).[2] At most, a hydraulic fracturing engine could be used for 26 jobs per year. Allowing for additional travel time, maintenance and vacations, the Department is assuming an engine will be used for approximately 20 jobs per year in the Marcellus play. Further, it was assumed that these engines will be used for a maximum of five hydraulic fracturing events per day and will operate two hours per event at their maximum loading and emissions.[3] Therefore, a hydraulic fracturing engine could be used up to 2,000 hours per year at their maximum load:

$$(20\ \text{jobs/year})(10\ \text{days/job})(5\ \text{fracs/day})(2\ \text{hours/frac}) = 2{,}000\ \text{hours/year}$$

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[1] Hydraulic fracturing engines are considered nonroad sources.
[2] "NY DEC SGEIS Information Requests", ALL Consulting, September 16, 2010, page 39.
[3] "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, page 9.

3. Reduction of Oxides of Nitrogen and Costs

Selective catalytic reduction (SCR) is a proven technology for reducing $NO_x$ emissions and the Department is assuming that this technology will be preferentially used to reduce $NO_x$ emissions from hydraulic fracturing engines. The Department considered capital, periodic and annual costs in the cost estimates discussed in this section.

*Capital Costs*

The capital cost for a SCR system was assumed to be $16 per hp.[4] It was assumed that the scale-up factor was one. Installation costs were assumed to be 60 percent of the system cost.[5] Taxes were assumed to be eight (8) percent of the system cost. The estimated capital cost for a typical 2250 hp hydraulic fracturing engine is $60,480 as detailed below:

| | |
|---|---|
| System Cost: | $36,000 |
| Installation: | $21,600 |
| Taxes: | $ 2,880 |
| Total: | $60,480 |

As noted previously, these costs are used in order to estimate the "cost effectiveness" value for the purpose of comparisons to "thresholds" used by the Department.

*Periodic Costs*

The periodic costs considered by the Department were for replacing SCR catalysts every five years.[6] It was assumed that the replacement costs were seven (7) percent of the system costs[7] and installation 60 percent of the replacement cost. The periodic costs (at year 5) were estimated to be $4,032 as detailed below:

| | |
|---|---|
| Catalyst Replacement: | $2,520 |
| Installation: | $1,512 |
| Total: | $4,032 |

*Annual Costs*

Reagent (urea) costs are the primary costs in this category. The quantity of reagent used depends upon the amount of $NO_x$ coming from the engine. The control efficiency for SCRs was assumed

[4] The cost for a Volvo SCR is reported to be $9600 ("2010-Compliant Diesel Truck Price Increases Out – The Changing Paradigm", Jay Thompson, www.glgroup.com/NewsWatchPrefs/Print.aspx?pid=42461, August 14, 2009). Further, it was assumed the power rating for a typical truck is 600 hp.

[5] Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, pages 168-169.

[6] E-mail from Wilson Chu (Johnson Matthey) to John Barnes (NYSDEC) dated January 24, 2008.

[7] E-mail from Chad Whiteman (Institute of Clean Air Companies) to John Barnes dated November 27, 2007 and e-mail from Wilson Chu (Johnson-Matthey) to John Barnes dated January 24, 2008..

to be 90 percent for engines. The emission rates factored into this analysis are presented in Table 1 (see Appendix 18B). Further, it was assumed that hydraulic fracturing engines will be operated at 50 percent of capacity.[8] The urea requirement for each pound of $NO_x$ treated in an SCR is 0.2088 gallons.[9]

Table 1: $NO_x$ Emission Rates for Tier 2, Interim 4 (I4) and 4 Hydraulic Fracturing Engines

| Tier # | $NO_x$ (without control)[10] (g/bhp-h) | $NO_x$ (with control) g/bhp-h |
|---|---|---|
| 2 | 4.32 | 0.43 |
| Interim 4 (I4) | 2.60 | 0.26 |
| 4 | 2.60 | 0.26 |

The urea requirements range from 1.21 gallons per hour (gal/h) for a Tier 4 engine to 2.01 gal/h for a Tier 2 engine. The estimated cost of urea is $3.67 per gallon.[11]

In addition to the reagent requirements, annual insurance costs were estimated to be one (1) percent of the system cost[12] and maintenance costs were assumed to be six (6) percent of the system cost.[13] A summary of the annual costs is presented below:

| | Tier 2 | Tier I4 | Tier 4 |
|---|---|---|---|
| Reagent: | $14,800 | $9,200 | $8,900 |
| Insurance: | $ 600 | $ 600 | $ 600 |
| Maintenance: | $ 3,600 | $3,600 | $3,600 |
| Total: | $19,000 | $13,400 | $13,100 |

*Annualized Cost*

A discount rate of seven (7) percent was used to convert the above costs into an equivalent annual cost for a 10-year horizon. The estimated annualized costs are presented in the next section.

4. Cost Effectiveness Analysis

The cost effectiveness of applying SCR controls on Tier 2, I4 and 4 hydraulic fracturing engines is presented in Table 2. By comparison, the current cost threshold for the $NO_x$ standards used by the Department to judge the cost effectiveness of control limits as set forth in Subpart 227-2 Reasonably Available Control Technology (RACT) for Oxides of Nitrogen ($NO_x$) is $5,500 per

[8] "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, p. 10.
[9] E-mail from Michael Baran (Johnson Matthey) to John Barnes, April 17, 2008.
[10] See Appendix 18A
[11] E-mail from Wilson Chu (Johnson Matthey) to John Barnes (NYSDEC) dated January 24, 2008. Also factored was Consumer Price Index data: www.bls.gov/cpi/cpid0801.pdf and www.bls.gov/cpi/cpid0211.pdf.
[12] Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, page 202.
[13] IBID, page 200.

ton of $NO_x$ removed from the exhaust gas. This value is used in determining whether a "waiver" should be granted to a major stationary source which demonstrates that the cost of such controls is unreasonable. As an analogy, the Subpart 227-2 $NO_x$ standard that would apply to hydraulic fracturing engines if they were considered stationary sources is 2.3 g/bhp-h. Hydraulic fracturing engines equipped with SCRs will have emission rates ranging from 0.26 g/bhp-h (Tier I4) to 0.43 g/bhp-h (Tier 2).

Table 2: Cost Effectiveness of SCR Control on Hydraulic Fracturing Engines

| Engine Tier | Annualized Cost | $NO_x$ Removed (tons) | Cost Effectiveness ($ton^{-1}$) |
|---|---|---|---|
| 2 | $28,000 | 9.64 | $2,907 |
| I4 | $22,500 | 6.03 | $3,732 |
| 4 | $22,000 | 5.80 | $3,816 |

## Summary and Recommendations

The costs for mitigating the modeled $NO_2$ NAAQS exceedences are considered reasonable. The costs of control presented in Table 2 are less than the cost threshold for the Department's Reasonably Available Control Technology (RACT) for $NO_x$ which is $5,500 per ton. The $NO_x$ emission limits for these engines will range from 0.26 g/bhp-h (Tier 4) to 0.43 g/bhp-h (Tier 2). Therefore, it is concluded that the large (2250 hp) hydraulic fracturing engines can be, cost-effectively, equipped with SCR control systems as recommended in the SGEIS.

New York State

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# Appendix 18C

## Regional On-Road Mobile Source Emission Estimates from EPA's MOVES Model and Single Pad PM2.5 Estimates from MOBILE 6 Model

New July 2011

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2007 Annual Mobile Source Emissions

MOVES 2010a Based Inventory Runs

Includes all MOVES Emission Processes Except Evap. Permeation, Evap. Vapor Venting & Evap. Fuel Leaks

| | | Base Emissions | | | | | | Emissions resulting from additonal VMT from proposed drilling activity | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FIPS | County | NOX | VOC | $SO_2$ | $PM_{10}$ Total | $PM_{25}$ Total | CO | NOX | VOC | $SO_2$ | $PM_{10}$ Total | $PM_{25}$ Total | CO |
| | | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) |
| 36001 | ALBANY | 8423.0 | 3323.7 | 64.2 | 356.3 | 339.0 | 51044.0 | 8447.2 | 3326.2 | 64.3 | 357.6 | 340.2 | 51067.1 |
| 36003 | ALLEGANY | 1436.5 | 495.0 | 8.5 | 63.8 | 60.9 | 7205.9 | 1458.5 | 497.1 | 8.6 | 64.8 | 61.9 | 7227.5 |
| 36007 | BROOME | 4807.1 | 1998.9 | 36.2 | 209.0 | 198.5 | 30424.5 | 4830.2 | 2001.2 | 36.3 | 210.2 | 199.6 | 30447.8 |
| 36009 | CATTARUAGUS | 2446.6 | 839.0 | 15.0 | 107.9 | 103.0 | 12115.4 | 2468.7 | 841.2 | 15.0 | 108.9 | 104.0 | 12137.9 |
| 36011 | CAYUGA | 2020.5 | 774.2 | 13.6 | 84.0 | 80.2 | 11210.1 | 2043.2 | 776.5 | 13.7 | 85.2 | 81.3 | 11231.9 |
| 36013 | CHAUTAQUA | 4178.1 | 1410.3 | 26.5 | 184.6 | 176.3 | 20379.8 | 4200.5 | 1412.5 | 26.6 | 185.7 | 177.3 | 20402.2 |
| 36015 | CHEMING | 2113.2 | 861.3 | 15.1 | 89.3 | 85.2 | 12366.7 | 2137.1 | 863.8 | 15.1 | 90.5 | 86.4 | 12390.9 |
| 36017 | CHENANGO | 1066.9 | 510.5 | 7.9 | 43.8 | 41.5 | 7513.7 | 1089.4 | 512.8 | 7.9 | 44.9 | 42.6 | 7535.9 |
| 36023 | CORTLAND | 1653.3 | 543.1 | 11.1 | 71.8 | 68.5 | 8158.8 | 1675.5 | 545.3 | 11.1 | 72.9 | 69.6 | 8180.9 |
| 36025 | DELAWARE | 1224.2 | 539.2 | 9.0 | 50.1 | 47.5 | 8013.5 | 1246.3 | 541.3 | 9.1 | 51.1 | 48.6 | 8034.7 |
| 36029 | ERIE | 19260.0 | 7997.4 | 138.2 | 798.8 | 760.4 | 117094.0 | 19282.6 | 7999.7 | 138.3 | 799.9 | 761.5 | 117116.0 |
| 36037 | GENESEE | 3035.1 | 855.2 | 20.5 | 127.1 | 121.5 | 13116.7 | 3057.1 | 857.4 | 20.6 | 128.2 | 122.6 | 13138.1 |
| 36039 | GREENE | 1997.6 | 672.1 | 14.1 | 83.1 | 79.3 | 10151.8 | 2020.1 | 674.4 | 14.2 | 84.2 | 80.4 | 10174.1 |
| 36051 | LIVINGSTON | 1911.9 | 683.9 | 12.3 | 83.5 | 79.6 | 10006.3 | 1934.2 | 686.1 | 12.4 | 84.6 | 80.7 | 10028.8 |
| 36053 | MADISON | 1797.8 | 729.6 | 13.1 | 73.4 | 69.9 | 10881.9 | 1820.3 | 731.8 | 13.2 | 74.6 | 71.0 | 10903.7 |
| 36065 | ONEIDA | 4997.0 | 2222.6 | 38.1 | 211.2 | 200.7 | 32376.2 | 5020.6 | 2225.1 | 38.1 | 212.4 | 201.8 | 32399.3 |
| 36067 | ONONDAGA | 11468.5 | 4535.9 | 82.3 | 501.2 | 477.7 | 66575.9 | 11492.9 | 4538.4 | 82.4 | 502.4 | 479.0 | 66600.0 |
| 36069 | ONTARIO | 3628.0 | 1241.3 | 25.5 | 150.8 | 144.0 | 18507.6 | 3650.8 | 1243.7 | 25.6 | 152.0 | 145.1 | 18529.9 |
| 36071 | ORANGE | 7527.5 | 3123.6 | 49.7 | 302.3 | 286.3 | 53982.4 | 7551.6 | 3126.0 | 49.8 | 303.6 | 287.5 | 54005.2 |
| 36077 | OTSEGO | 1620.0 | 640.5 | 11.4 | 70.1 | 66.6 | 9659.1 | 1641.8 | 642.6 | 11.5 | 71.1 | 67.6 | 9681.4 |
| 36095 | SCHOHARIE | 1505.6 | 496.2 | 11.6 | 62.0 | 59.0 | 7964.9 | 1527.7 | 498.4 | 11.7 | 63.1 | 60.1 | 7987.0 |
| 36097 | SCHUYLER | 558.3 | 215.0 | 3.8 | 22.8 | 21.7 | 3102.1 | 580.9 | 217.4 | 3.9 | 23.9 | 22.9 | 3122.9 |
| 36099 | SENECA | 1234.1 | 401.9 | 8.3 | 52.1 | 49.8 | 5979.4 | 1256.6 | 404.2 | 8.4 | 53.2 | 50.8 | 6002.1 |
| 36101 | STEUBEN | 3969.5 | 1197.4 | 24.2 | 173.8 | 166.3 | 17845.0 | 3991.3 | 1199.5 | 24.3 | 174.9 | 167.3 | 17867.0 |
| 36105 | SULLIVAN | 1481.6 | 752.4 | 11.8 | 58.4 | 55.3 | 11050.7 | 1504.9 | 754.7 | 11.9 | 59.6 | 56.5 | 11070.8 |
| 36107 | TIOGA | 1398.8 | 599.9 | 10.5 | 57.6 | 54.9 | 8538.5 | 1423.3 | 602.6 | 10.6 | 58.9 | 56.2 | 8561.8 |
| 36109 | TOMPKINS | 1727.3 | 790.5 | 12.8 | 72.3 | 68.8 | 11227.7 | 1751.6 | 793.1 | 12.9 | 73.5 | 70.1 | 11250.9 |
| 36111 | ULSTER | 4114.3 | 1895.8 | 36.0 | 156.2 | 148.2 | 29231.2 | 4138.3 | 1898.4 | 36.1 | 157.5 | 149.4 | 29254.8 |
| 36121 | WYOMING | 999.9 | 414.6 | 6.5 | 42.3 | 40.4 | 5827.2 | 1022.8 | 416.9 | 6.6 | 43.5 | 41.5 | 5847.9 |
| 36123 | YATES | 477.8 | 222.1 | 3.2 | 19.3 | 18.4 | 3152.6 | 500.8 | 224.5 | 3.3 | 20.5 | 19.6 | 3173.5 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total For Counties in Marcellus Shale Area | | 104,080 | 40,983 | 741 | 4,379 | 4,170 | 614,703 | | 104,767 | 41,053 | 743 | 4,413 | 4,203 | 615,372 |
| | | Estimated additional mobile source emissions resulting from additional VMT associated with proposed gas drilling * | | | | | | | | Percentage increase in emissions assuming all wells operating | | | | | |
| | | | | | | | | | | NOX | VOC | $SO_2$ | $PM_{10}$ Total | $PM_{25}$ Total | CO |
| | | NOX | VOC | $SO_2$ | $PM_{10}$ Total | $PM_{25}$ Total | CO | | | 0.66% | 0.17% | 0.33% | 0.79% | 0.80% | 0.11% |
| | | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | (Tons/Yr) | | | | | | | | |
| | | 686.7 | 70.0 | 2.5 | 34.4 | 33.3 | 668.6 | | | | | | | | |
| | | Well pad emissions assuming total emissions split equally across all | | | | | | | | | | | | | |
| | | 0.28 | 0.03 | 0.00 | 0.01 | 0.01 | 0.27 | | | | | | | | |

* Does NOT include Evaporative emissions processes

**Marcellus Single Pad MOBILE Model Emissions of PM2.5 for CP-33 Comparison**

## Vehicle Trip Emissions

| Vehicle Type | Range of Trucks | Max Number of Trucks | Feet travelled per site* | Distance travelled per truck (miles) | PM 2.5 EF (lbs/mile) | Emissions (tons) |
|---|---|---|---|---|---|---|
| Drill Pad and Road Construction Equipment | 10-45 | 45 | 1700 | 14.49 | 0.0003 | 2.18799E-06 |
| Drilling Rig | 30 | 30 | 1700 | 9.66 | 0.0003 | 1.45866E-06 |
| Drilling Fluid and Materials | 25-50 | 50 | 1700 | 16.10 | 0.0003 | 2.4311E-06 |
| Drilling Equipment (casing, drill pipe, etc.) | 25-50 | 50 | 1700 | 16.10 | 0.0003 | 2.4311E-06 |
| Completion Rig | 15 | 15 | 1700 | 4.83 | 0.0003 | 7.2933E-07 |
| Completion Fluid and Materials | 10-20 | 20 | 1700 | 6.44 | 0.0003 | 9.72439E-07 |
| Completion Equipment – (pipe, wellhead) | 5 | 5 | 1700 | 1.61 | 0.0003 | 2.4311E-07 |
| Hydraulic Fracture Equipment (pump trucks, tanks) | 150-200 | 200 | 1700 | 64.39 | 0.0003 | 9.72439E-06 |
| Hydraulic Fracture Water | 400-600 | 600 | 1700 | 193.18 | 0.0003 | 2.91732E-05 |
| Hydraulic Fracture Sand | 20-25 | 25 | 1700 | 8.05 | 0.0003 | 1.21555E-06 |
| Flow Back Water Removal | 200-300 | 300 | 1700 | 96.59 | 0.0003 | 1.45866E-05 |
| **Total** | | **1340** | | **431.44** | | **6.51534E-05** |

*(1 - 750 foot trip onto site, 1 - 100 foot trip to station, 1- 100 foot trip back from the station and 1-750 foot trip off the site)

## Vehicle Idle Emissions

| Vehicle Type | Range of Trucks | Max Number of Trucks | Idle Time per truck (hrs)** | Hours idling per truck type (hrs) | PM 2.5 EF (lbs/hr) | Emissions (tons) |
|---|---|---|---|---|---|---|
| Drill Pad and Road Construction Equipment | 10-45 | 45 | 2 | 90.00 | 0.0013 | 5.74901E-05 |
| Drilling Rig | 30 | 30 | 2 | 60.00 | 0.0013 | 3.83267E-05 |
| Drilling Fluid and Materials | 25-50 | 50 | 2 | 100.00 | 0.0013 | 6.38779E-05 |
| Drilling Equipment (casing, drill pipe, etc.) | 25-50 | 50 | 2 | 100.00 | 0.0013 | 6.38779E-05 |
| Completion Rig | 15 | 15 | 2 | 30.00 | 0.0013 | 1.91634E-05 |
| Completion Fluid and Materials | 10-20 | 20 | 2 | 40.00 | 0.0013 | 2.55511E-05 |
| Completion Equipment – (pipe, wellhead) | 5 | 5 | 2 | 10.00 | 0.0013 | 6.38779E-06 |
| Hydraulic Fracture Equipment (pump trucks, tanks) | 150-200 | 200 | 2 | 400.00 | 0.0013 | 0.000255511 |
| Hydraulic Fracture Water | 400-600 | 600 | 2 | 1200.00 | 0.0013 | 0.000766534 |
| Hydraulic Fracture Sand | 20-25 | 25 | 2 | 50.00 | 0.0013 | 3.19389E-05 |
| Flow Back Water Removal | 200-300 | 300 | 2 | 600.00 | 0.0013 | 0.000383267 |
| **Total** | | **1340** | | **2680.00** | | **0.001711927** |

** Assume each truck idles at least 2 hours over the duration of the project

## Road Dust Emissions

| Vehicle Type | Range of Trucks | Max Number of Trucks | Feet travelled per site* | Distance travelled per truck (miles) | PM 2.5 EF (lbs/mile) | Emissions (tons) |
|---|---|---|---|---|---|---|
| Drill Pad and Road Construction Equipment | 10-45 | 45 | 1700 | 14.49 | 0.0863 | 0.000625511 |
| Drilling Rig | 30 | 30 | 1700 | 9.66 | 0.0863 | 0.000417007 |
| Drilling Fluid and Materials | 25-50 | 50 | 1700 | 16.10 | 0.0863 | 0.000695012 |
| Drilling Equipment (casing, drill pipe, etc.) | 25-50 | 50 | 1700 | 16.10 | 0.0863 | 0.000695012 |
| Completion Rig | 15 | 15 | 1700 | 4.83 | 0.0863 | 0.000208504 |
| Completion Fluid and Materials | 10-20 | 20 | 1700 | 6.44 | 0.0863 | 0.000278005 |
| Completion Equipment – (pipe, wellhead) | 5 | 5 | 1700 | 1.61 | 0.0863 | 6.95012E-05 |
| Hydraulic Fracture Equipment (pump trucks, tanks) | 150-200 | 200 | 1700 | 64.39 | 0.0863 | 0.002780047 |
| Hydraulic Fracture Water | 400-600 | 600 | 1700 | 193.18 | 0.0863 | 0.008340142 |
| Hydraulic Fracture Sand | 20-25 | 25 | 1700 | 8.05 | 0.0863 | 0.000347506 |
| Flow Back Water Removal | 200-300 | 300 | 1700 | 96.59 | 0.0863 | 0.004170071 |
| **Total** | | **1340** | | **431.44** | | **0.018626317** |

| Total PM 2.5 Emissions | Emissions (tons) | Emissions (lbs) |
|---|---|---|
| Vehicle Trip Emissions | 6.51534E-05 | 0.13 |
| Vehicle Idle Emissions | 0.001711927 | 3.42 |
| Road Dust Emissions | 1.86E-02 | 37.25 |
| **Total** | **0.02** | **40.81** |

New York State

DEC

# Appendix 19

## Greenhouse Gas (GHG) Emissions

Updated July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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# Part A

# GHG Tables

Updated July 2011

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GHG Tables (Revised July 2011, following replaces tables released in September 2009)

Table GHG-1 – Emission Rates for Well Pad[1]

| Emission Source/ Equipment Type | $CH_4$ EF | $CO_2$ EF | Units | EF Reference[2] |
|---|---|---|---|---|
| Fugitive Emissions | | | | |
| ***Gas Wells*** | | | | |
| Gas Wells | 0.014 | 0.00015 | lbs/hr per well | Vol 8, page no. 34, table 4-5 |
| ***Field Separation Equipment*** | | | | |
| Heaters | 0.027 | 0.001 | lbs/hr per heater | Vol 8, page no. 34, table 4-5 |
| Separators | 0.002 | 0.00006 | lbs/hr per separator | Vol 8, page no. 34, table 4-5 |
| Dehydrators | 0.042 | 0.001 | lbs/hr per dehydrator | Vol 8, page no. 34, table 4-5 |
| Meters/Piping | 0.017 | 0.001 | lbs/hr per meter | Vol 8, page no. 34, table 4-5 |
| ***Gathering Compressors*** | | | | |
| Large Reciprocating Compressor | 29.252 | 1.037 | lbs/hr per compressor | GRI - 96 - Methane Emissions from the Natural Gas Industry, Final Report |
| ***Vented and Combusted Emissions*** | | | | |
| ***Normal Operations*** | | | | |
| 1,775 hp Reciprocating Compressor | not determined | 1,404.716 | lbs/hr per compressor | 6,760 Btu/hp-hr, 2004 API, page no. 4-8 |
| Pneumatic Device Vents | 0.664 | 0.024 | lbs/hr per device | Vol 12, page no. 48, table 4-6 |
| Dehydrator Vents | 12.725 | 0.451 | lbs/MMscf throughput | Vol 14, page no. 27 |
| Dehydrator Pumps | 45.804 | 1.623 | lbs/MMscf throughput | GRI June Final Report |
| ***Blowdowns*** | | | | |
| Vessel BD | 0.00041 | 0.00001 | lbs/hr per vessel | Vol 6, page no. 18, table 4-2 |
| Compressor BD | 0.020 | 0.00071 | lbs/hr per compressor | Vol 6, page no. 18, table 4-2 |
| Compressor Starts | 0.045 | 0.00158 | lbs/hr per compressor | Vol 6, page no. 18, table 4-2 |
| ***Upsets*** | | | | |
| Pressure Relief Valves | 0.00018 | 0.00001 | lbs/hr per valve | Vol 6, page no. 18, table 4-2 |

[1] Adapted from Exhibit 2.6.1, ICF Incorporated, LLC. *Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs*, Agreement No. 9679, August 2009., pp 34-35.

[2] Unless otherwise noted, all emission factors are from the Gas Research Institute, *Methane Emissions from the Natural Gas Industry*, 1996. Available at: epa.gov/gasstar/tools/related.html.

Table GHG-2 – Drilling Rig Mobilization, Site Preparation and Demobilization – GHG Emissions

| | **Single Vertical, Single Horizontal or Four-Well Pad**[3] | | | | |
|---|---|---|---|---|---|
| **Emissions Source** | **Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)** | **Total Operating Hours** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions Light Truck & Heavy Truck Combined Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Transportation [4] | 432 | NA | NA | 4 | NA |
| Drill Pad and Road Construction [5] | NA | 48 hours | NA | 11 | NA |
| **Total Emissions** | 432 | NA | NA | 15 | NA |

Table GHG-3 – Completion Rig Mobilization and Demobilization – GHG Emissions

| | **Single Vertical, Single Horizontal or Four-Well Pad** | | | | |
|---|---|---|---|---|---|
| **Emissions Source** | **Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)** | **Total Operating Hours** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions Light Truck & Heavy Truck Combined Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Completion Rig[6] | 432 | NA | NA | 4 | NA |
| **Total Emissions** | 432 | NA | NA | 4 | NA |

[3] Site preparation for a single vertical well would be less due to a smaller pad size but for simplification site preparation is assumed the same for all well scenarios considered.
[4] ALL Consulting, 2011, Exhibit19B.
[5] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[6] ALL Consulting, 2011, Exhibit19B. Completion rig mobilization likely less than that for drilling rig but for simplification assumed the same.

Table GHG-4 – Well Drilling – Single Vertical Well GHG Emissions

| | Single Vertical Well | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)** | **Total Operating Hours** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Transportation[7] | 788 | NA | NA | NA | 9 | NA |
| Power Engines[8] | NA | 132 hours | 1 | NA | 74 | NA |
| Circulating System[9] | NA | 132 hours | 1 | negligible | NA | negligible |
| Well Control System[10] | NA | As needed | 1 | negligible | negligible | negligible |
| **Total Emissions** | NA | NA | NA | negligible | 83 | negligible |

[7] ALL Consulting, 2011, Exhibit 20B.
[8] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[9] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[10] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-5 – Well Drilling – Single Horizontal Well GHG Emissions

| | Single Horizontal Well | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)** | **Total Operating Hours** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Transportation[11] | 2,298 | NA | NA | NA | 26 | NA |
| Power Engines[12] | NA | 300 hours | 1 | NA | 168 | NA |
| Circulating System[13] | NA | 300 hours | 1 | negligible | NA | negligible |
| Well Control System[14] | NA | As needed | 1 | negligible | negligible | negligible |
| **Total Emissions** | NA | NA | NA | negligible | 194 | negligible |

[11] ALL Consulting, 2011, Exhibit19B.
[12] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[13] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[14] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-6 – Well Drilling – Four-Well Pad GHG Emissions

| | Four-Well Pad | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)** | **Total Operating Hours** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Transportation[15] | 9,192 | NA | NA | NA | 104 | NA |
| Power Engines[16] | NA | 1,200 hours | 1 | NA | 672 | NA |
| Circulating System[17] | NA | 1,200 hours | 1 | negligible | NA | negligible |
| Well Control System[18] | NA | As needed | 1 | negligible | negligible | negligible |
| **Total Emissions** | NA | NA | NA | negligible | 776 | negligible |

[15] ALL Consulting, 2011, Exhibit19B.
[16] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[17] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[18] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-7 – Well Completion – Single Vertical Well GHG Emissions

| | Single Vertical Well | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)** | **Total Operating Hours or Fuel Use** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Transportation[19] | 818 | NA | 1 | NA | 9 | NA |
| Hydraulic Fracturing Pump Engines | NA | 4,833 gallons[20] | 1 | NA | 54 | NA |
| Line Heater | NA | 72 hours | 1 | NA | negligible | NA |
| Flowback Pits/Tanks | NA | 72 hours | 1 | NA | NA | negligible |
| Flare Stack[21] | NA | 72 hours | 1 | 12[22] | 1,728[23] | NA |
| Rig Engines[24] | NA | 12 hours | 1 | NA | 4 | NA |
| Site Reclamation[25] | NA | 24 hours | NA | NA | 6 | NA |
| Transportation for Site Reclamation[26] | 280 | NA | NA | NA | 3 | NA |
| **Total Emissions** | NA | NA | NA | 12 | 1,804 | negligible |

[19] ALL Consulting, 2011, Exhibit 20B.
[20] ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10. Assumed vertical job is one-sixth of high-volume job.
[21] Assumed no use of reduced emission completion ("REC").
[22] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28. . Vertical well not likely to produce at assumed rate due to reduced completion interval.
[23] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28. Vertical well not likely to produce at assumed rate due to reduced completion interval.
[24] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[25] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[26] ALL Consulting, 2011, Exhibit 20B.

Table GHG-8 – Well Completion – Single Horizontal Well GHG Emissions

| | Single Horizontal Well | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)** | **Total Operating Hours or Fuel Use** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Transportation[27] | 2,462 | NA | 1 | NA | 28 | NA |
| Hydraulic Fracturing Pump Engines | NA | 29,000 gallons[28] | 1 | NA | 325 | NA |
| Line Heater | NA | 72 hours | 1 | NA | negligible | NA |
| Flowback Pits/Tanks | NA | 72 hours | 1 | NA | NA | negligible |
| Flare Stack[29] | NA | 72 hours | 1 | 12[30] | 1,728[31] | NA |
| Rig Engines[32] | NA | 24 hours | 1 | NA | 7 | NA |
| Site Reclamation[33] | NA | 24 hours | NA | NA | 6 | NA |
| Transportation for Site Reclamation[34] | 280 | NA | NA | NA | 3 | NA |
| **Total Emissions** | NA | NA | NA | 12 | 2,097 | negligible |

[27] ALL Consulting, 2011, Exhibit 19B.
[28] ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10.
[29] Assumed no use of reduced emission completion ("REC").
[30] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28.
[31] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28.
[32] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[33] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[34] ALL Consulting, 2011, Exhibit 19B.

Table GHG-9 – Well Completion – Four-Well Pad GHG Emissions

| | Four-Well Pad | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)** | **Total Operating Hours or Fuel Use** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Transportation[35] | 9,848 | NA | NA | NA | 112 | NA |
| Hydraulic Fracturing Pump Engines | NA | 116,000 gallons | NA | NA | 1,300 | NA |
| Line Heater | NA | 288 hours | 1 | NA | negligible | NA |
| Flowback Pits/Tanks | NA | 288 hours | 1 | NA | NA | negligible |
| Flare Stack[36] | NA | 288 hours | 1 | 48 | 6,912 | NA |
| Rig Engines[37] | NA | 96 hours | 1 | NA | 28 | NA |
| Site Reclamation[38] | NA | 24 hours | NA | NA | 6 | NA |
| Transportation for Site Reclamation | 280 | NA | NA | NA | 3 | NA |
| **Total Emissions** | NA | NA | NA | 48 | 8,361 | negligible |

[35] ALL Consulting, 2011, Exhibit 19B.
[36] Assumed no use of reduced emission completion ("REC").
[37] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.
[38] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to $CO_2$.

Table GHG-10 – First-Year Well Production – Single Vertical Well GHG Emissions[39]

| | Single Vertical Well | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Vehicle Miles Traveled (VMT)** | **Total Operating Hours** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Production Equipment 10 Truckloads[40] | 400 | NA | NA | NA | 1 | NA |
| Wellhead | NA | 8,376 hours[41] | 1 | NA | NA | negligible |
| Compressor | NA | 8,376 hours | 1 | not determined | 5,883[42] (&4[43]) | 123[44] |
| Line Heater | NA | 8,376 hours | 1 | negligible | negligible | negligible |
| Separator | NA | 8,376 hours | | NA | negligible | negligible |
| Glycol Dehydrator | NA | 8,376 hours | 1 | negligible | negligible | negligible |
| Dehydrator Vents | NA | 8,376 hours | 1 | 22[45] | 3[46] | negligible |
| Dehydrator Pumps | NA | 8,376 hours | 1 | 80[47] | NA | negligible |
| Pneumatic Device Vents | NA | 8,376 hours | 3 | 9[48] | NA | negligible |
| Meters/Piping | NA | 8,376 hours | 1 | NA | NA | negligible |
| Vessel BD | NA | 4 hours | 4 | negligible | NA | negligible |
| Compressor BD | NA | 4 hours | 4 | negligible | NA | negligible |
| Compressor Starts | NA | 4 hours | 4 | negligible | NA | negligible |
| Pressure Relief Valves | NA | 4 hours | 5 | negligible | NA | negligible |
| Production Brine Tanks | NA | 8,376 hours | 1 | negligible | NA | negligible |
| Production Brine Removal 44Truckloads[49] | 1,760 | NA | NA | NA | 3 | NA |
| **Total Emissions** | NA | NA | NA | 111 | 5,894 | 123 |

[39] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well. However, vertical well not likely to produce at assumed rate due to reduced completion interval.
[40] Assumed roundtrip of 40 miles.
[41] Calculated by subtracting total time required to drill and complete one vertical well (16 days) from 365 days.
[42] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[43] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[44] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[45] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[46] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[47] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[48] Emissions Factor (EF) of 0.664 lbs per hour.
[49] Assumed roundtrip of 40 miles.

Table GHG-11 – First-Year Well Production – Single Horizontal Well GHG Emissions[50]

| | Single Horizontal Well | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Vehicle Miles Traveled (VMT)** | **Total Operating Hours** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Production Equipment 10 Truckloads[51] | 400 | NA | NA | NA | 1 | NA |
| Wellhead | NA | 7,944 hours[52] | 1 | NA | NA | negligible |
| Compressor | NA | 7,944 hours | 1 | not determined | 5,580[53] (&4[54]) | 122[55] |
| Line Heater | NA | 7,944 hours | 1 | negligible | negligible | negligible |
| Separator | NA | 7,944 hours | | NA | negligible | negligible |
| Glycol Dehydrator | NA | 7,944 hours | 1 | negligible | negligible | negligible |
| Dehydrator Vents | NA | 7,944 hours | 1 | 21[56] | 3[57] | negligible |
| Dehydrator Pumps | NA | 7,944 hours | 1 | 76[58] | NA | negligible |
| Pneumatic Device Vents | NA | 7,944 hours | 3 | 9[59] | NA | negligible |
| Meters/Piping | NA | 7,944 hours | 1 | NA | NA | negligible |
| Vessel BD | NA | 4 hours | 4 | negligible | NA | negligible |
| Compressor BD | NA | 4 hours | 4 | negligible | NA | negligible |
| Compressor Starts | NA | 4 hours | 4 | negligible | NA | negligible |
| Pressure Relief Valves | NA | 4 hours | 5 | negligible | NA | negligible |
| Production Brine Tanks | NA | 7,944 hours | 1 | negligible | NA | negligible |
| Production Brine Removal 44Truckloads[60] | 1,760 | NA | NA | NA | 3 | NA |
| **Total Emissions** | NA | NA | NA | 106 | 5,591 | 122 |

[50] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well.
[51] Assumed roundtrip of 40 miles.
[52] Calculated by subtracting total time required to drill and complete one horizontal well (34 days) from 365 days.
[53] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[54] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[55] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[56] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[57] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[58] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[59] Emissions Factor (EF) of 0.664 lbs per hour.
[60] Assumed roundtrip of 40 miles.

Table GHG-12 – First-Year Well Production – Four-Well Pad GHG Emissions[61]

| | Four-Well Pad | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Vehicle Miles Traveled (VMT)** | **Total Operating Hours** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Production Equipment 10 Truckloads[62] | 1,600 | NA | NA | NA | 3 | NA |
| Wellhead | NA | 5,496 hours[63] | 1 | NA | NA | negligible |
| Compressor | NA | 5,496 hours | 1 | not determined | 3,860[64] (&3[65]) | 80[66] |
| Line Heater | NA | 5,496 hours | 1 | negligible | negligible | negligible |
| Separator | NA | 5,496 hours | | NA | negligible | negligible |
| Glycol Dehydrator | NA | 5,496 hours | 1 | negligible | negligible | negligible |
| Dehydrator Vents | NA | 5,496 hours | 1 | 58[67] | 8[68] | negligible |
| Dehydrator Pumps | NA | 5,496 hours | 1 | 210[69] | NA | negligible |
| Pneumatic Device Vents | NA | 5,496 hours | 3 | 6[70] | NA | negligible |
| Meters/Piping | NA | 5,496 hours | 4 | NA | NA | negligible |
| Vessel BD | NA | 16 hours | 8 | negligible | NA | negligible |
| Compressor BD | NA | 16 hours | 8 | negligible | NA | negligible |
| Compressor Starts | NA | 16 hours | 8 | negligible | NA | negligible |
| Pressure Relief Valves | NA | 16 hours | 10 | negligible | NA | negligible |
| Production Brine Tanks | NA | 5,496 hours | 2 | negligible | NA | negligible |
| Production Brine Removal 176 Truckloads[71] | 7,040 | NA | NA | NA | 11 | NA |
| **Total Emissions** | NA | NA | NA | 274 | 3,885 | 80 |

[61] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well.
[62] Assumed roundtrip of 40 miles.
[63] Calculated by subtracting total time required to drill and complete four horizontal wells (136 days) from 365 days.
[64] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[65] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[66] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[67] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[68] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[69] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[70] Emissions Factor (EF) of 0.664 lbs per hour.
[71] Assumed roundtrip of 40 miles.

Table GHG-13 – Post-First Year Annual Well Production – Single Vertical or Single Horizontal Well GHG Emissions[72]

| | Single Vertical Well or Single Horizontal Well | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Vehicle Miles Traveled (VMT)** | **Total Operating Hours** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Wellhead | NA | 8,760 hours[73] | 1 | NA | NA | negligible |
| Compressor | NA | 8,760 hours | 1 | not determined | 6,153[74] (&5[75]) | 128[76] |
| Line Heater | NA | 8,760 hours | 1 | negligible | negligible | negligible |
| Separator | NA | 8,760 hours | | NA | negligible | negligible |
| Glycol Dehydrator | NA | 8,760 hours | 1 | negligible | negligible | negligible |
| Dehydrator Vents | NA | 8,760 hours | 1 | 23[77] | 3[78] | negligible |
| Dehydrator Pumps | NA | 8,760 hours | 1 | 84[79] | NA | negligible |
| Pneumatic Device Vents | NA | 8,760 hours | 3 | 9[80] | NA | negligible |
| Meters/Piping | NA | 8,760 hours | 1 | NA | NA | negligible |
| Vessel BD | NA | 4 hours | 4 | negligible | NA | negligible |
| Compressor BD | NA | 4 hours | 4 | negligible | NA | negligible |
| Compressor Starts | NA | 4 hours | 4 | negligible | NA | negligible |
| Pressure Relief Valves | NA | 4 hours | 5 | negligible | NA | negligible |
| Production Brine Tanks | NA | 8,760 hours | 1 | negligible | NA | negligible |
| Production Brine Removal 50Truckloads[81] | 2,000 | NA | NA | NA | 3 | NA |
| **Total Emissions** | NA | NA | NA | 116 | 6,164 | 128 |

[72] Assumed production 10 mmcfd per well.
[73] Hours in 365 days.
[74] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[75] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[76] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[77] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[78] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[79] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[80] Emissions Factor (EF) of 0.664 lbs per hour.
[81] Assumed roundtrip of 40 miles.

Table GHG-14 – Post-First Year Annual Well Production – Four-Well Pad GHG Emissions[82]

| | Four-Well Pad | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Source** | **Vehicle Miles Traveled (VMT)** | **Total Operating Hours** | **Activity Factor** | **Vented Emissions (tons $CH_4$)** | **Combustion Emissions (tons $CO_2$)** | **Fugitive Emissions (tons $CH_4$)** |
| Wellhead | NA | 8,760 hours[83] | 1 | NA | NA | negligible |
| Compressor | NA | 8,760 hours | 1 | not determined | 6,153[84] (&5[85]) | 128[86] |
| Line Heater | NA | 8,760 hours | 1 | negligible | negligible | negligible |
| Separator | NA | 8,760 hours | | NA | negligible | negligible |
| Glycol Dehydrator | NA | 8,760 hours | 1 | negligible | negligible | negligible |
| Dehydrator Vents | NA | 8,760 hours | 1 | 93[87] | 12[88] | negligible |
| Dehydrator Pumps | NA | 8,760 hours | 1 | 335[89] | NA | negligible |
| Pneumatic Device Vents | NA | 8,760 hours | 3 | 9[90] | NA | negligible |
| Meters/Piping | NA | 8,760 hours | 4 | NA | NA | negligible |
| Vessel BD | NA | 16 hours | 8 | negligible | NA | negligible |
| Compressor BD | NA | 16 hours | 8 | negligible | NA | negligible |
| Compressor Starts | NA | 16 hours | 8 | negligible | NA | negligible |
| Pressure Relief Valves | NA | 16 hours | 10 | negligible | NA | negligible |
| Production Brine Tanks | NA | 8,760 hours | 2 | negligible | NA | negligible |
| Production Brine Removal 200Truckloads[91] | 8,000 | NA | NA | NA | 13 | NA |
| **Total Emissions** | NA | NA | NA | 437 | 6,183 | 128 |

[82] Assumed production 10 mmcfd per well.
[83] Hours in 365 days.
[84] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[85] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[86] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[87] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[88] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[89] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[90] Emissions Factor (EF) of 0.664 lbs per hour.
[91] Assumed roundtrip of 40 miles.

Table GHG-15 – Estimated First-Year Green House Gas Emissions from Single Vertical Well

| | **Single Vertical Well** | | | |
|---|---|---|---|---|
| | **$CO_2$ (tons)** | **$CH_4$ (tons)** | **$CH_4$ Expressed as $CO_2e$ (tons)**[92] | **Total Emissions from Proposed Activity $CO_2e$ (tons)** |
| Drilling Rig Mobilization, Site Preparation and Demobilization | 447 | NA | NA | 447 |
| Completion Rig Mobilization and Demobilization | 432 | NA | NA | 432 |
| Well Drilling | 83 | negligible | negligible | 83 |
| Well Completion including Hydraulic Fracturing and Flowback | 1,804 | 12 | 300 | 2,104 |
| Well Production | 5,894 | 234 | 5,850 | 11,744 |
| **Total** | 8,660 | 246 | 6,150 | 14,810 |

Table GHG-16 – Estimated First-Year Green House Gas Emissions from Single Horizontal Well

| | **Single Horizontal Well** | | | |
|---|---|---|---|---|
| | **$CO_2$ (tons)** | **$CH_4$ (tons)** | **$CH_4$ Expressed as $CO_2e$ (tons)**[93] | **Total Emissions from Proposed Activity $CO_2e$ (tons)** |
| Drilling Rig Mobilization, Site Preparation and Demobilization | 447 | NA | NA | 447 |
| Completion Rig Mobilization and Demobilization | 432 | NA | NA | 432 |
| Well Drilling | 194 | negligible | negligible | 194 |
| Well Completion including Hydraulic Fracturing and Flowback | 2,097 | 12 | 300 | 2,397 |
| Well Production | 5,591 | 228 | 5,700 | 11,291 |
| **Total** | 8,761 | 240 | 6,000 | 14,761 |

Table GHG-17 – Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical Well or Single Horizontal Well

| | **Single Vertical Well or Single Horizontal Well**[94] | | | |
|---|---|---|---|---|
| | **$CO_2$ (tons)** | **$CH_4$ (tons)** | **$CH_4$ Expressed as $CO_2e$ (tons)**[95] | **Total Emissions from Proposed Activity $CO_2e$ (tons)** |
| Well Production | 6,164 | 244 | 6,100 | 12,264 |

[92] Equals $CH_4$ (tons) multiplied by 25 (100-Year GWP).
[93] Equals $CH_4$ (tons) multiplied by 25 (100-Year GWP).
[94] Assumed production 10 mmcfd per well. However, vertical well not likely to produce at assumed rate due to reduced completion interval, and therefore emission estimates are conservative for vertical well production.
[95] Equals $CH_4$ (tons) multiplied by 25 (100-Year GWP).

Table GHG-18 – Estimated First-Year Green House Gas Emissions from Four-Well Pad

| | **Four-Well Pad** | | | |
|---|---|---|---|---|
| | **$CO_2$ (tons)** | **$CH_4$ (tons)** | **$CH_4$ Expressed as $CO_2e$ (tons)[96]** | **Total Emissions from Proposed Activity $CO_2e$ (tons)** |
| Drilling Rig Mobilization, Site Preparation and Demobilization | 447 | NA | NA | 447 |
| Completion Rig Mobilization and Demobilization | 432 | NA | NA | 432 |
| Well Drilling | 776 | negligible | negligible | 776 |
| Well Completion including Hydraulic Fracturing and Flowback | 8,361 | 48 | 1,200 | 9,561 |
| Well Production | 3,885 | 354 | 8,850 | 12,735 |
| **Total** | 13,901 | 402 | 10,050 | 23,951 |

Table GHG-19 – Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Pad

| | **Four-Well Pad** | | | |
|---|---|---|---|---|
| | **$CO_2$ (tons)** | **$CH_4$ (tons)** | **$CH_4$ Expressed as $CO_2e$ (tons)[97]** | **Total Emissions from Proposed Activity $CO_2e$ (tons)** |
| Well Production | 6,183 | 565 | 14,125 | 20,300 |

[96] Equals $CH_4$ (tons) multiplied by 25 (100-Year GWP).
[97] Equals $CH_4$ (tons) multiplied by 25 (100-Year GWP).

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# Part B

## Sample Calculations for Combustion Emissions from Mobile Sources

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## Sample Calculation for Combustion Emissions ($CO_2$) from Mobile Sources[1]

INPUT DATA: A fleet of heavy-duty (HD) diesel trucks travels 70,000 miles during the year. The trucks are equipped with advance control systems.

CALCULATION METHODOLOGY:

The fuel usage of the fleet is unknown, so the first step in the calculation is to convert from miles traveled to a volume of diesel fuel consumed basis. This calculation is performed using the default fuel economy factor of 7 miles/gallon for diesel heavy trucks provided API's Table 4-10.

$$70{,}000\,\frac{miles}{project} \times \frac{gallon\ diesel}{7\ miles} = 10{,}000\ \frac{gallons\ diesel\ consumed}{project\ move}$$

Carbon dioxide emissions are estimated using a fuel-based factor provided in API's Table 4-1. This factor is provided on a heat basis, so the fuel consumption must be converted to an energy input basis. This conversion is carried out using a recommended diesel heating value of $5.75 \times 10^6$ Btu/bbl (HHV), given in Table 3-5 of this document. Thus, the fuel heat rate is:

$$10{,}000\,\frac{gallons}{project\ move} \times \frac{bbl}{42\ gallons} \times \frac{5.75\ x\ 10^6\ Btu}{bbl} = 1{,}369{,}047{,}619\,\frac{Btu}{project\ move}(HHV)$$

According to API's Table 4-1, the fuel basis $CO_2$ emission factor for diesel fuel (diesel oil) is 0.0742 tonne $CO_2/10^6$ Btu (HHV basis).

Therefore, $CO_2$ emissions are calculated as follows, assuming 100% oxidation of fuel carbon to $CO_2$:

$$1{,}369{,}047{,}619\,\frac{Btu}{project\ move} \times 0.0742\ \frac{tonne\ CO2}{10^6}Btu = 101.78\ \frac{tonnes\ CO2}{project\ move}$$

To convert tonnes to US short tons:

$$101.78\ tonnes \times 2204.62\,\frac{lbs}{tonne} \div 2000\,\frac{lbs}{short\ ton} = 112.19\ tons\,\frac{CO2}{project\ move}$$

[1] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005. pp. 4-39, 4-40.

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# Appendix 20

# PROPOSED
# Pre-Frac Checklist and Certification

Updated July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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# PRE-FRAC CHECKLIST AND CERTIFICATION

**Well Name and Number:**
*(as shown on the Department-issued well permit)*

**API Number:**

**Well Owner:**

**Planned Frac Commencement Date:**

| Yes | No | |
|---|---|---|
| ☐ | ☐ | Well drilled, cased and cemented in accordance with well permit, or in accordance with revisions approved by the Regional Mineral Resources Manager on the dates listed below and revised wellbore schematic filed in regional Mineral Resources office.<br><br>Approval Date & Brief Description of Approved Revision(s)<br>*(attach additional sheets if necessary)* |
| ☐ | ☐ | All depths where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations are recorded on the attached sheet. Additional sheets are attached which describe how any lost circulation zones were addressed. |
| ☐ | ☐ | Enclosed radial cement bond evaluation log and narrative analysis of such, or other Department-approved evaluation, and consideration of appropriate supporting data per Section 6.4 "Other Testing and Information" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009) verifies top of cement and effective cement bond at least 500 feet above the top of the formation to be fractured or at least 300 feet into the previous casing string. If intermediate casing was not installed, or if was not production casing was not cemented to surface, then provide the date of approval by the Department and a brief description of justification.<br><br>Approval Date & Brief Description of Justification<br>*(attach additional sheets if necessary)* |
| ☐ | ☐ | Per Section 7.1 "General" under the heading "Well Construction Guidelines" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009), a representative blend of the cement used for the production casing was bench tested in accordance with API 10A Specification for Cements and Materials for Well Cementing (Twenty-Fourth Edition, December 2010) and was found to be of sufficient strength to withstand the maximum anticipated treatment pressure during hydraulic fracturing operations. |
| ☐ | ☐ | If fracturing operations will be performed down casing, then the pre-fracturing pressure tests required by permit conditions will be conducted and fracturing operations will only commence if the tests are successful. Any unsuccessful test will be reported to the Department and remedial measures will be proposed by the operator and must be approved by the Department prior to further operations. |

☐ ☐ All other information collected while drilling, listed below, verifies that all observed gas zones are isolated by casing and cement and that the well is properly constructed and suitable for high-volume hydraulic fracturing.

Date and Brief Description of Information Collected
*(attach additional sheets if necessary)*

☐ ☐ Fracturing products used will be the same products identified in the well permit application materials or otherwise identified and approved by the Department.

I hereby affirm under penalty of perjury that information provided on this form is true to the best of my knowledge and belief. False statements made herein are punishable as a Class A misdemeanor pursuant to Section 210.45 of the Penal Law.

**Printed or Typed Name and Title of Authorized Representative**
**Signature, Date**

## INSTRUCTIONS FOR PRE-FRAC CHECKLIST AND CERTIFICATION

The completed and signed form, and treatment plan must be received by the appropriate Regional office at least 3 days prior to the commencement of hydraulic fracturing operations. The treatment plan must include a profile showing anticipated pressures and volume of fluid for pumping the first stage. It must also include a description of the planned treatment interval for the well (i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)). The operator may conduct hydraulic fracturing operations provided 1) all items on the checklist are affirmed by a response of "Yes," 2) the *Pre-Frac Checklist And Certification*, and treatment plan are received by the Department at least 3 days prior to hydraulic fracturing and 3) all other pre-frac notification requirements are met as specified elsewhere. **The well owner is prohibited from conducting hydraulic fracturing operations on the well without additional Department review and approval if a response of "No" is provided to any of the items in the pre-frac checklist.**

## SIGNATURE SECTION

**Signature Section -** The person signing the *Pre-Frac Checklist And Certification* must be authorized to do so on the Organizational Report on file with the Division of Mineral Resources.

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# Appendix 21

## Publically Owned Treatment Works (POTWs) With Approved Pretreatment Programs

Revised Draft
Supplemental Generic Environmental Impact Statement

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# Pretreatment Facilities and Associated WWTPs

| Region | Pretreatment Program | Facility | SPDES Number |
|---|---|---|---|
| 1 | Nassau County DPW - this facility is tracked under Cedar Creek in PCS. | Inwood STP<br>Bay Park STP<br>***Cedar Creek WPCP | NY0026441<br>NY0026450<br>NY0026859 |
| | Glen Cove (C) | Glen Cove STP | NY0026620 |
| | Suffolk DPW | Suffolk Co. SD #3 - Southwest | NY0104809 |
| 2 | New York City DEP | Wards Island WPCP<br>Owls Head WPCP<br>Newtown Creek WPCP<br>Jamaica WPCP<br>North River WPCP<br>26th Ward WPCP<br>Coney Island WPCP<br>Red Hook WPCP<br>Tallman Island WPCP<br>Bowery Bay WPCP<br>Rockaway WPCP<br>Oakwood Beach WPCP<br>Port Richmond WPCP<br>Hunts Point WPCP | NY0026131<br>NY0026166<br>NY0026204<br>NY0026115<br>NY0026247<br>NY0026212<br>NY0026182<br>NY0027073<br>NY0026239<br>NY0026158<br>NY0026221<br>NY0026174<br>NY0026107<br>NY0026191 |
| 3 | Suffern (V) | Suffern | NY0022748 |
| | Orangetown SD #2 | | NY0026051 |
| | Orange County SD #1 | Harriman STP | NY0027901 |
| | Newburgh (C) | Newburgh WPCF | NY0026310 |
| | Westchester County | Blind Brook<br>Mamaroneck<br>New Rochelle<br>Ossining<br>Port Chester<br>Peekskill<br>Yonkers Joint | NY0026719<br>NY0026701<br>NY0026697<br>NY0108324<br>NY0026786<br>NY0100803<br>NY0026689 |
| | Rockland County SD #1 | | NY0031895 |
| | Poughkeepsie (C) | Poughkeepsie STP | NY0026255 |
| | New Windsor (T) | New Windsor STP | NY0022446 |
| | Beacon (C) | Beacon STP | NY0025976 |
| | Haverstraw Joint Regional Sewer Board | Haverstraw Joint Regional Stp | NY0028533 |
| | Kingston (C) | Kingston (C) WWTF | NY0029351 |
| 4 | Amsterdam (C) | Amsterdam STP | NY0020290 |
| | Albany County | North WWTF<br>South WWTF | NY0026875<br>NY0026867 |
| | Schenectady (C) | Schenectady WPCP | NY0020516 |
| | Rennselaer County SD #1 | Rennselaer County SD #1 | NY0087971 |
| 5 | Plattsburgh (C) | City of Plattsburgh WPCP | NY0026018 |
| | Glens Falls (C) | Glens Fall (C) | NY0029050 |
| | Gloversville-Johnstown Joint Board | | NY0026042 |
| | Saratoga County SD #1 | | NY0028240 |

| Region | Pretreatment Program | Facility | SPDES Number |
|---|---|---|---|
| 6 | Little Falls (C) | Little Falls WWTP | NY0022403 |
| | Herkimer County | Herkimer County SD | NY0036528 |
| | Rome (C) | Rome WPCF | NY0030864 |
| | Ogdensburg (C) | City of Ogdensburg WWTP | NY0029831 |
| | Oneida County | | NY0025780 |
| | Watertown | | NY0025984 |
| 7 | Auburn (C) | Auburn STP | NY0021903 |
| | Fulton (C) | | NY0026301 |
| | Oswego (C) | Westside Wastewater Facility<br>Eastside Wastewater Facility | NY0029106<br>NY0029114 |
| | Cortland (C) | LeRoy R. Summerson WTF | NY0027561 |
| | Endicott (V) | Endicott WWTF | NY0027669 |
| | Ithaca (C) | | NY0026638 |
| | Binghamton-Johnson City | | NY0024414 |
| | Onondaga County | Metropolitan Syracuse<br>Baldwinsville/Seneca Knolls<br>Meadowbrook/Limestone<br>Oak Orchard<br>Wetzel Road | NY0027081<br>NY0030571<br>NY0027723<br>NY0030317<br>NY0027618 |
| 8 | Canandaigua (C) | Canandaigua STP | NY0025968 |
| | Webster (T) | Walter W. Bradley WPCP | NY0021610 |
| | Monroe County | Frank E VanLare STP<br>Northwest Quadrant STP | NY0028339<br>NY0028231 |
| | Batavia (C) | | NY0026514 |
| | Geneva (C) | Marsh Creek STP | NY0027049 |
| | Newark (V) | | NY0029475 |
| | Chemung County | Chemung County SD #1<br>Chemung County - Elmira<br>Chemung County - Baker Road | NY0036986<br>NY0035742<br>NY0246948 |
| 9 | Middleport (V) | Middleport (V) STP | NY0022331 |
| | North Tonawanda (C) | | NY0026280 |
| | Newfane STP (T) | | NY0027774 |
| | Erie County Southtowns | Erie County Southtowns<br>Erie County SD #2 - Big Sister | NY0095401<br>NY0022543 |
| | Niagara County | Niagara County SD #1 | NY0027979 |
| | Blasdell (V) | Blasdell | NY0020681 |
| | Buffalo Sewer Authority | Buffalo (C) | NY0028410 |
| | Amherst SD (T) | | NY0025950 |
| | Niagara Falls (C) | | NY0026336 |
| | Tonawanda (T) | Tonawanda (T) SD #2 WWTP | NY0026395 |
| | Lockport (C) | | NY0027057 |
| | Olean STP (C) | | NY0027162 |
| | Jamestown STP (C) | | NY0027570 |
| | Dunkirk STP (C) | | NY0027961 |

# Mini-Pretreatment Facilities

| Region | Facility | SPDES Number |
|---|---|---|
| 3 | Arlington WWTP | NY0026271 |
| 3 | Port Jervis STP | NY0026522 |
| 3 | Wallkill (T) STP | NY0024422 |
| 4 | Canajoharie (V) WWTP | NY0023485 |
| 4 | Colonie (T) Mohawk View WPCP | NY0027758 |
| 4 | East Greenbush (T) WWTP | NY0026034 |
| 4 | Hoosick Falls (V) WWTP | NY0024821 |
| 4 | Hudson (C) STP | NY0022039 |
| 4 | Montgomery co SD#1 STP | NY0107565 |
| 4 | Park Guilderland N.E. IND STP | NY0022217 |
| 4 | Rotterdam (T) SD2 STP | NY0020141 |
| 4 | Delhi (V) WWTP | NY0020265 |
| 4 | Hobart (V) WWTP | NY0029254 |
| 4 | Walton (V) WWTP | NY0027154 |
| 7 | Canastota (V) WPCP | NY0029807 |
| 7 | Cayuga Heights (V) WWTP | NY0020958 |
| 7 | Moravia (V) WWTP | NY0022756 |
| 7 | Norwich (C) WWTP | NY0021423 |
| 7 | Oak Orchard STP | NY0030317 |
| 7 | Oneida (C) STP | NY0026956 |
| 7 | Owego (T) SD#1 | NY0022730 |
| 7 | Owego WPCP #2 | NY0025798 |
| 7 | Sherburne (V) WWTP | NY0021466 |
| 7 | Waverly (V) WWTP | NY0031089 |
| 7 | Wetzel Road WWTP | NY0027618 |
| 8 | Avon (V) STP | NY0024449 |
| 8 | Bath (V) WWTP | NY0021431 |
| 8 | Bloomfield (V) WWTP | NY0024007 |
| 8 | Clifton Springs (V) WWTP | NY0020311 |
| 8 | Clyde (V) WWTP | NY0023965 |
| 8 | Corning (C) WWTP | NY0025721 |
| 8 | Dundee STP | NY0025445 |
| 8 | Erwin (T) WWTP | NY0023906 |
| 8 | Holley (V) WPCP | NY0023256 |
| 8 | Honeoye Falls (V) WWTP | NY0025259 |
| 8 | Hornell (C) WPCP | NY0023647 |
| 8 | Marion STP | NY0031569 |
| 8 | Ontario (T) STP | NY0027171 |
| 8 | Seneca Falls (V) WWTP | NY0033308 |
| 8 | Walworth SD #1 | NY0025704 |
| 9 | Akron (V) WWTP | NY0031003 |
| 9 | Arcade (V) WWTP | NY0026948 |
| 9 | Attica (V) WWTP | NY0021849 |
| 9 | East Aurora (V) STP | NY0028436 |
| 9 | Gowanda (V) | NY0032093 |

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# Appendix 22

## Publically Owned Treatment Works (POTWs) Procedures for Accepting Wastewater from High-Volume Hydraulic Fracturing

Revised July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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**POTW Procedures for Accepting High-Volume Hydraulic Fracturing Wastewater**

The following procedure shall be followed when a Publically Owned Treatment Works (POTW) proposes to accept high-volume hydraulic fracturing wastewater from a well driller or other development company. Page 5 of this appendix shows a simplified flowchart of this process. Please note that this disposal option is limited to the extent that municipal POTWs which utilize biological wastewater treatment are generally optimized for the removal of domestic wastewater and as such are not designed to treat several of the contaminants present in high-volume hydraulic fracturing wastewater. In addition to the above concerns, the additional monitoring and laboratory costs which will result from additional monitoring conditions in the permit must also be considered prior to deciding to accept this source of wastewater.

1. The POTW operator receives a request to accept flowback water from a well driller. Prior to submitting this request to the Department for approval, the POTW should review the request to assure that it includes, at a minimum:
    a. The volume of water to be sent to wastewater treatment plant in gallons per unit time (e.g. 25,000 gallons per day);
    b. Whether the discharge is a one-time disposal, or will be an ongoing source of wastewater to the POTW;
    c. A characterization of high-volume hydraulic fracturing wastewater quality including all high-volume hydraulic facturing parameters of concern and NORM analysis;
    d. A characterization of existing POTW wastewater quality including:
        i. Sample results for all high-volume hydraulic fracturing parameters of concern, and
        ii. the results of short term high intensity monitoring for both TDS (in mg/l) and Radium 226 (in piC/l), consisting of the results of ten (10) samples each of existing influent, sludge, and effluent from the POTW.
    e. The source of the wastewater (well name, well developer, Mineral Resources permit number, and location(s) of the wells); and

f. A list of all additives used in the hydraulic fracturing process at the source well(s).

2. The POTW shall forward the above request to the Bureau of Water Permits, 625 Broadway, Albany NY 12233-3505 along with the following supporting information:
   a. Documentation of existing EPA and Departmental approval of the facility's headworks analysis for the acceptance of high-volume hydraulic fracturing wastewater; or a completed headworks analysis for the high-volume hydraulic fracturing specific parameters of concern for Department and USEPA approval;
   b. Demonstration of available POTW capacity to accept the proposed volume of high-volume hydraulic fracturing wastewater; and
   c. Confirmation that the facility has an approved USEPA pretreatment or Department mini-pretreatment program as part of its SPDES permit.

3. The Division of Water will review the submitted information to determine whether the high-volume hydraulic fracturing wastewater source has been adequately characterized. If additional information is necessary, the Division of Water will request additional sampling and source information from the POTW.

4. The Division of Water will review the facility's SPDES permit to determine whether the permit needs to be modified to include high-volume hydraulic fracturing specific monitoring, limits, and reporting conditions.

5. Concurrently with 3. and 4. above, if a headworks analysis for the high-volume hydraulic fracturing specific parameters of concern was submitted for approval, the Division of Water will forward a copy of the headworks analysis to the USEPA Region 2 office for its review and approval. The Division of Water and USEPA Region 2 will review the facility's headworks analysis to assure that the POTW is capable of accepting the proposed volume and quantity of high-volume hydraulic fracturing wastewater

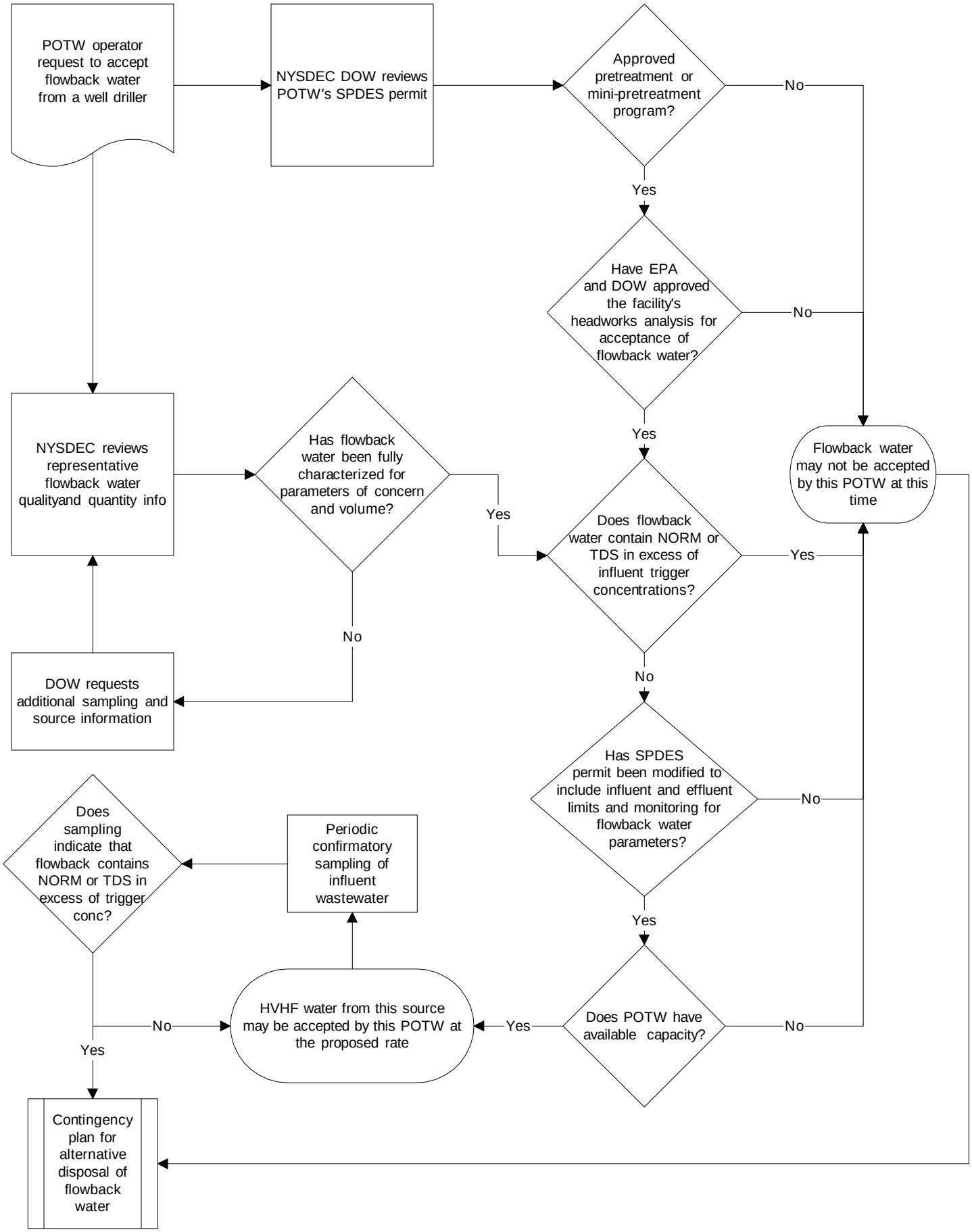
6. The Department will send a determination regarding the request to the permittee following the Division of Water and USEPA's analysis of the request. If the request is approved, the POTW may accept high-volume hydraulic fracturing wastewater from the requested source at the specified maximum concentrations and requested discharge rate following receipt of Departmental approval, which will include the following components:
    a. Approval of submitted headworks analysis by the Department and USEPA; and
    b. SPDES permit modification with high-volume hydraulic fracturing specific monitoring, limits, and reporting conditions, including;
        i. Specification of the source and maximum discharge rate of the high-volume hydraulic fracturing wastewater to be accepted;
        ii. Influent radium-226 and TDS limits;
        iii. Effluent limits and/or monitoring for NORM, TDS, and other high-volume hydraulic fracturing parameters of concern;
        iv. Periodic confirmatory sampling of influent wastewater for high-volume hydraulic fracturing parameters of concern to assure that the characteristics of the influent wastewater have not changed substantially from the characterization provided in the approval request;
        v. periodic sludge sampling to assure that the concentration of radionuclides in the sludge do not exceed 5 piC/g; and
        vi. Any other monitoring conditions necessary to assure that the discharge from the POTW does not cause or contribute to a violation of NYS water quality standards.

7. If the Department does not approve the acceptance of flowback water, a written denial will be sent to the permittee with the reason(s) for denial. These reasons could include, but not be limited to: inadequate receiving water assimilative capacity, NORM concentrations in excess of the applicable influent Radium-226 limit of 15- piC/l, influent concentrations of any other parameters in excess of the levels acceptable in the approved headworks analysis, or inadequate POTW capacity.

8. Following approval and permit modification, the POTW must notify the Department whenever:
    a. The facility wishes to increase the quantity of high-volume hydraulic fracturing wastewater accepted from this source;
    b. The facility wishes to accept any volume of high-volume hydraulic fracturing wastewater from a new or additional source;
    c. The high-volume hydraulic fracturing wastewater contains NORM or TDS in excess of the influent limits for these parameters; or
    d. The facility has decided to stop accepting high-volume hydraulic fracturing wastewater from one or more sources.

The notifications in a. – c. would be treated as a request for a new source of high-volume hydraulic fracturing wastewater, and would be processed in accordance with Items 1-7 above.

# Flowchart for acceptance of High Volume Hydraulic Fracturing (HVHF) wastewater by publicly owned treatment works (POTWs)



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# Appendix 23

## USEPA Natural Gas STAR Program

Revised Draft
Supplemental Generic Environmental Impact Statement

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TO: Peter Briggs, New York State Department of Environmental Conservation, Mineral Resources

FROM: Jerome Blackman, Natural Gas STAR International

DATE: September 1, 2009

RE: Natural Gas Star

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This memo lists methane emission mitigation options applicable in exploration and production; in reference to your inquiry. Natural Gas STAR Partners have reported a number of voluntary activities to reduce exploration and production methane emissions, and major project types are listed and summarized below and may help focus your research as you review the resources available on the Natural Gas STAR website.

In addition to these practices and technologies is an article that lists the same and several more cost effective options for producers to reduce methane emissions. Please refer to the link below.

*Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers*
www.epa.gov/gasstar/documents/CaseStudy.pdf

**Reduced Emission Completions**
Traditionally, "cleaning up" drilled wells, before connecting them to a production sales line, involves producing the well to open pits or tankage where sand, cuttings, and reservoir fluids are collected for disposal and the produced natural gas is vented to the atmosphere. Partners reported using a "green completion" method in which tanks, separators, dehydrators are brought on site to clean up the gas sufficiently for delivery to sales. The result is reducing completion emissions, creating an immediate revenue stream, and less solid waste.

Partner Recommended Opportunity from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/greencompletions.pdf

BP Experience Presentation with Reduced Emission Completions
www.epa.gov/gasstar/documents/workshops/2008-annual-conf/smith.pdf

Green Completion Presentation from a Tech-Transfer Workshop in 2005 at Houston, TX
www.epa.gov/gasstar/documents/workshops/houston-2005/green_c.pdf

**Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrator**
In dehydrators, as triethylene glycol (TEG) absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). When the TEG is regenerated through heating, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. Many wells produce gas below the initial design capacity yet

TEG circulation rates remain two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Optimizing circulation rates reduces methane emissions at negligible cost. Installing flash tank separators on glycol dehydrators further reduces methane, VOC, and HAP emissions and saves even more money. Flash tanks can recycle typically vented gas to the compressor suction and/or used as a fuel for the TEG reboiler and compressor engine.

Lessons Learned Document from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_flashtanks3.pdf

Dehydrator Presentation from a 2008 Tech-Transfer Workshop in Charleston, WV:
www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/charleston_dehydration.pdf

**Replacing Glycol Dehydrators with Desiccant Dehydrators**
Natural Gas STAR Partners have found that replacing glycol dehydrators with desiccant dehydrators reduces methane, VOC, and HAP emissions by 99 percent and also reduces operating and maintenance costs. In a desiccant dehydrator, wet gas passes through a drying bed of desiccant tablets. The tablets pull moisture from the gas and gradually dissolve in the process. Replacing a glycol dehydrator processing 1 million cubic feet per day (MMcfd) of gas with a desiccant dehydrator can save up to $9,232 per year in fuel gas, vented gas, operation and maintenance (O&M) costs, and reduce methane emissions by 444 thousand cubic feet (Mcf) per year.

Lessons Learned Document from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_desde.pdf

**Directed Inspection and Maintenance**
A directed inspection and maintenance (DI&M) program is a proven, cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions. A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair.

Lessons Learned Documents from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_dimgasproc.pdf
www.epa.gov/gasstar/documents/ll_dimcompstat.pdf

Partner Recommended Opportunity from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/conductdimatremotefacilities.pdf

DI&M Presentation from a Tech-Transfer Workshop in 2008 at Midland, TX
www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/midland4.ppt

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# Appendix 24

## Key Features of the USEPA Natural Gas STAR Program

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## Key Features of USEPA Natural Gas STAR Program[1]

Complete information on the Natural Gas STAR Program is given in USEPA's web site (http://epa.gov/gasstar/index.html)

- Participation in the program is voluntary.
- Program outreach is provided through the web site, annual national two-day implementation workshop, and sector– or activity – specific technology transfer workshops or webcasts, often with a regional focus (approximately six to nine per year).
- Companies agreeing to join ("Partners") commit to evaluating Best Management Practices (BMP) and implementing them when they are cost-effective for the company. In addition, " …partners are encouraged to identify, implement, and report on other technologies and practices to reduce methane emissions (referred to as Partner Reported Opportunities or PROs )."
- Best Management Practices are a limited set of reduction measures identified at the initiation of the program as widely applicable. PROs subsequently reported by partners have increased the number of reduction measures.
- The program provides calculation tools for estimating emissions reductions for BMPs and PROs, based on the relevant features of the equipment and application.
- Projected emissions reductions for some measures can be estimated accurately and simply; for example, reductions from replacing high-bleed pneumatic devices with low-bleed devices are a simple function of the known bleed rates of the respective devices, and the methane content of the gas. For others, such as those involving inspection and maintenance to detect and repair leaks, emissions reductions are difficult to anticipate because the number and magnitude of leaks is initially unknown or poorly estimated.
- Tools are also provided for estimating the economics of emission reduction measures, as a function of factors such as gas value, capital costs, and operation and maintenance costs.
- Technical feasibility is variable between measures and is often site- or application- specific. For example, in the Gas STAR Lessons Learned for replacing high-bleed with low-bleed pneumatic devices, it is estimated that "nearly all" high-bleed devices can feasibly be replaced with low-bleed devices. Some specific exceptions are listed, including very large valves requiring fast and/or precise response, commonly on large compressor discharge and bypass controllers.
- Partners report emissions reductions annually, but the individual partner reports are confidential. Publicly reported data are aggregated nationally, but include total reductions by sector and by emissions reduction measure.

[1] New Mexico Environment Department, *Oil and Gas Greenhouse Gas Emissions Reductions*. December 2007, pp. 19-20.

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# Appendix 25

## Reduced Emissions Completion (REC) Executive Summary

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## Reduced Emissions Completions – Executive Summary[1]

High prices and high demand for natural gas, have seen the natural gas production industry move into development of the more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involves hydraulic fracturing of the reservoir to increase well productivity. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and methane emissions to the atmosphere.

Conventional completion of wells (a process that cleans the well bore of stimulation fluids and solids so that the gas has a free path from the reservoir) results in gas being either vented or flared. Vented gas results in large amounts of methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) emissions to the atmosphere while flared gas results in carbon dioxide emissions.

Reduced emissions completion (REC) – also known as reduced flaring completion – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids so that the gas is suitable for injection into the sales pipeline. Reduced emissions completions help to mitigate methane, VOC, and HAP emissions during the well flowback phase and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of eight different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2005 emissions reductions from RECs have increased from 200 MMcf to over 7,000 MMcf. This represents additional revenue from natural gas sales of over $65 million in 2005 (assuming $7/Mcf gas prices).

| **Method for Reducing Gas Loss** | **Volume of Natural Gas Savings (Mcf/yr)[1]** | **Value of Natural Gas Savings ($/yr)[2]** | **Additional Savings ($/yr)[3]** | **Set-up Costs ($/yr)** | **Equipment Rental and Labor Costs ($)** | **Other Costs ($/yr)[4]** | **Payback (Months)[5]** |
|---|---|---|---|---|---|---|---|
| Reduced Emissions Completion | 270,000 | 1,890,000 | 197,500 | 15,000 | 212,500 | 129,500 | 3 |

1. Based on an annual REC program of 25 completions per year
2. Assuming $7/Mcf gas
3. Savings from recovering condensate and gas compressed to lift fluids
4. Cost of gas used to fuel compressor and lift fluids
5. Time required to recover the entire annual cost of the program

[1]Adapted from ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, *Task 2 – Technical Analysis of Potential Impacts to Air*, Agreement No. 9679, August 2009. Appendix 2.1.

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# Appendix 26

## Instructions for Using The On-Line Searchable Database to Locate Drilling Applications

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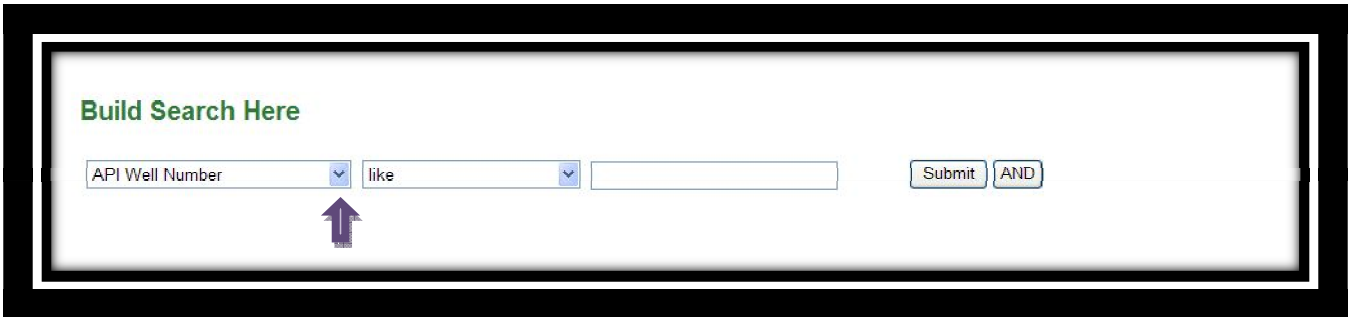
# How to Use the Online Searchable Database to Find Information about Recently Filed Permit Applications

The online searchable database can be found at http://www.dec.ny.gov/cfmx/extapps/GasOil/. It is a very user friendly program and can be used to conduct both simple and complex searches.

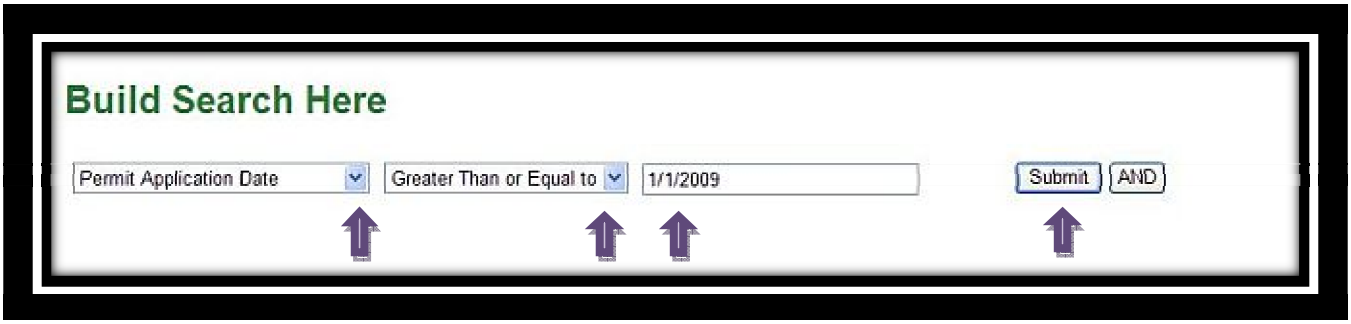
**How to Conduct a Simple Search**

1. Select Wells Data to begin your search.

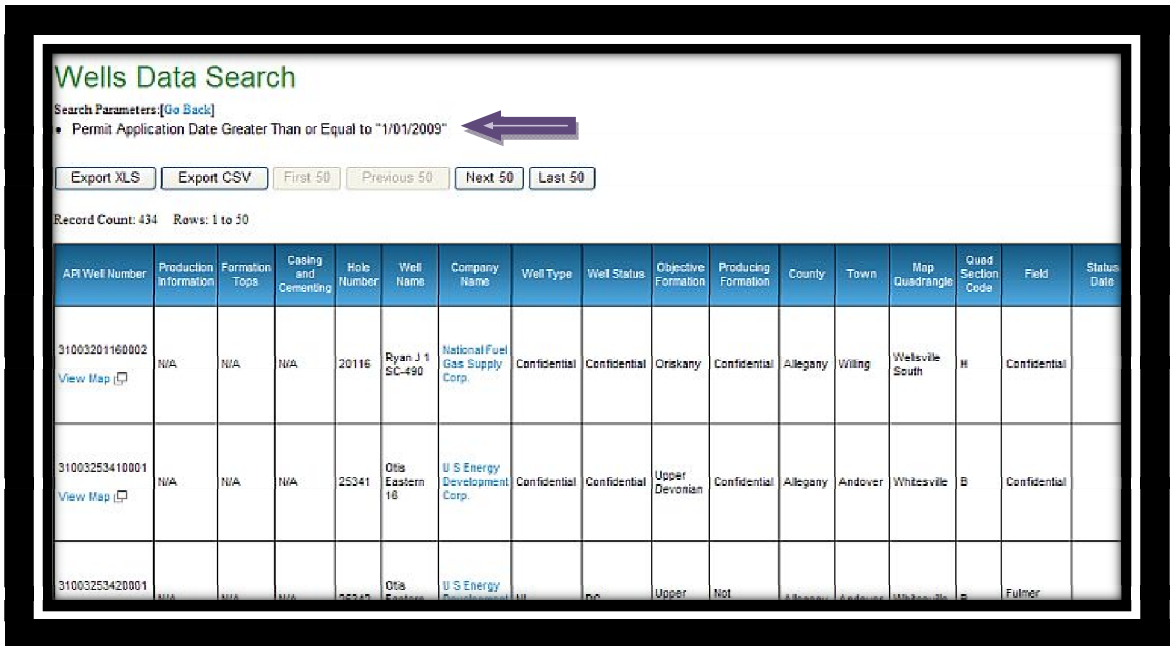
2. Select your search criteria. Use the drop down arrow next to API Number to select your search criteria.




3. To find a new permit application, enter Permit Application Date is Greater Than or Equal to, and the date that you would like to search from. Enter Permit Application Data is Greater Than or Equal to 1/1/year to find all permit applications filed during a specific year. Click the Submit button.



4. View results. By selecting the View Map hyperlink, a new window will open to Google Maps showing the well location along with latitude and longitude information. The results from your query can be saved to your computer as either an Excel spreadsheet (xls) or as a comma separated value file (csv) by clicking the appropriate Export button at the bottom the results screen. Clicking a hyperlink in the Company Name column will provide contact information for the company.



Wells Data Search

Search Parameters:[Go Back]

- Permit Application Date Greater Than or Equal to "1/01/2009"

Export XLS | Export CSV | First 50 | Previous 50 | Next 50 | Last 50

Record Count: 434 Rows: 1 to 50

| API Well Number | Production Information | Formation Tops | Casing and Cementing | Hole Number | Well Name | Company Name | Well Type | Well Status | Objective Formation | Producing Formation | County | Town | Map Quadrangle | Quad Section Code | Field | Status Date |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31003201160002 View Map | N/A | N/A | N/A | 20116 | Ryan J 1 SC-490 | National Fuel Gas Supply Corp. | Confidential | Confidential | Oriskany | Confidential | Allegany | Willing | Wellsville South | H | Confidential | |
| 31003253410001 View Map | N/A | N/A | N/A | 25341 | Otis Eastern 16 | U S Energy Development Corp. | Confidential | Confidential | Upper Devonian | Confidential | Allegany | Andover | Whitesville | B | Confidential | |
| 31003253420001 | N/A | N/A | N/A | 25342 | Otis Eastern | U S Energy Development | [illegible] | [illegible] | Upper | Not | [illegible] | [illegible] | [illegible] | [illegible] | Fulmer | |

**How to Narrow or Expand Your Search Utilizing the AND Button**

1. Select Wells Data to begin your search.

Search Database

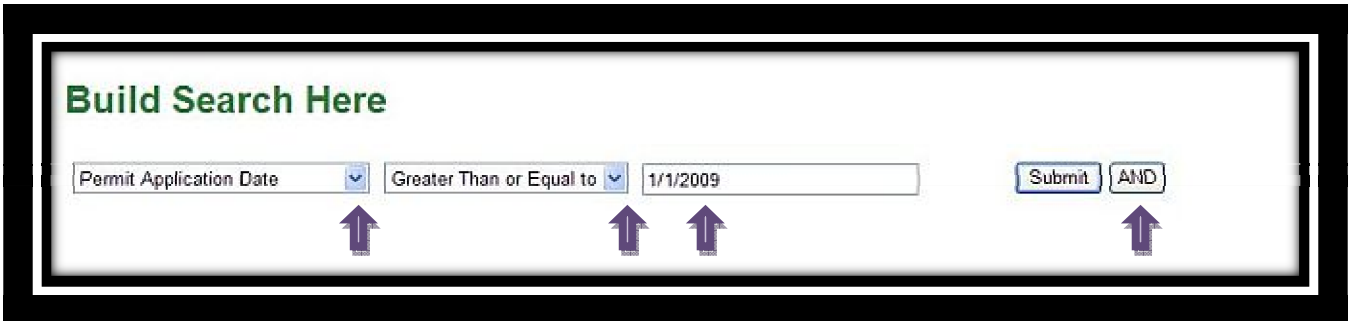
- General Search Tips/Help
- Set User Preferences
- Company Data
- Wells Data
- Annual Well Production
- Well Transfers
- Geologic Formation
- Geologic Fields

For more information:

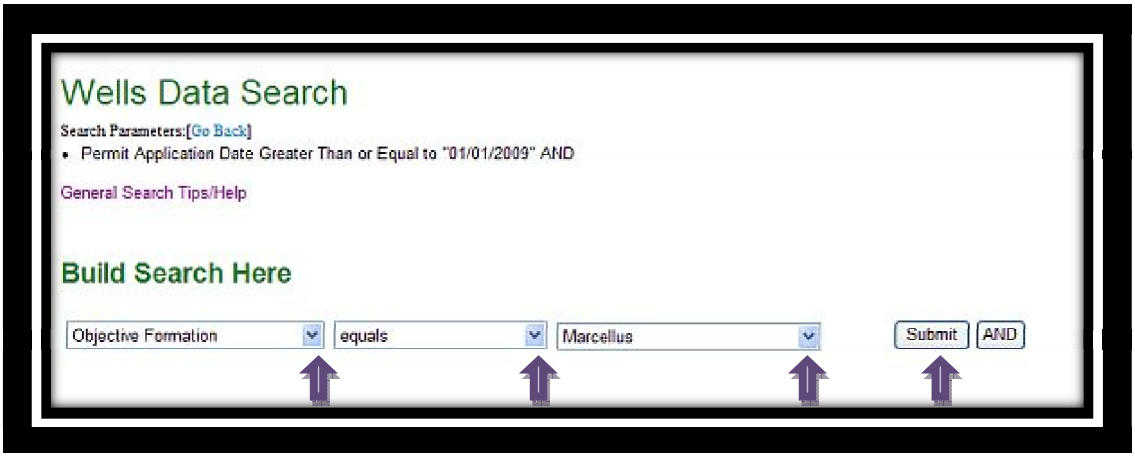
Division of Mineral Resources

Environmental Notice Bulletin for Minerals

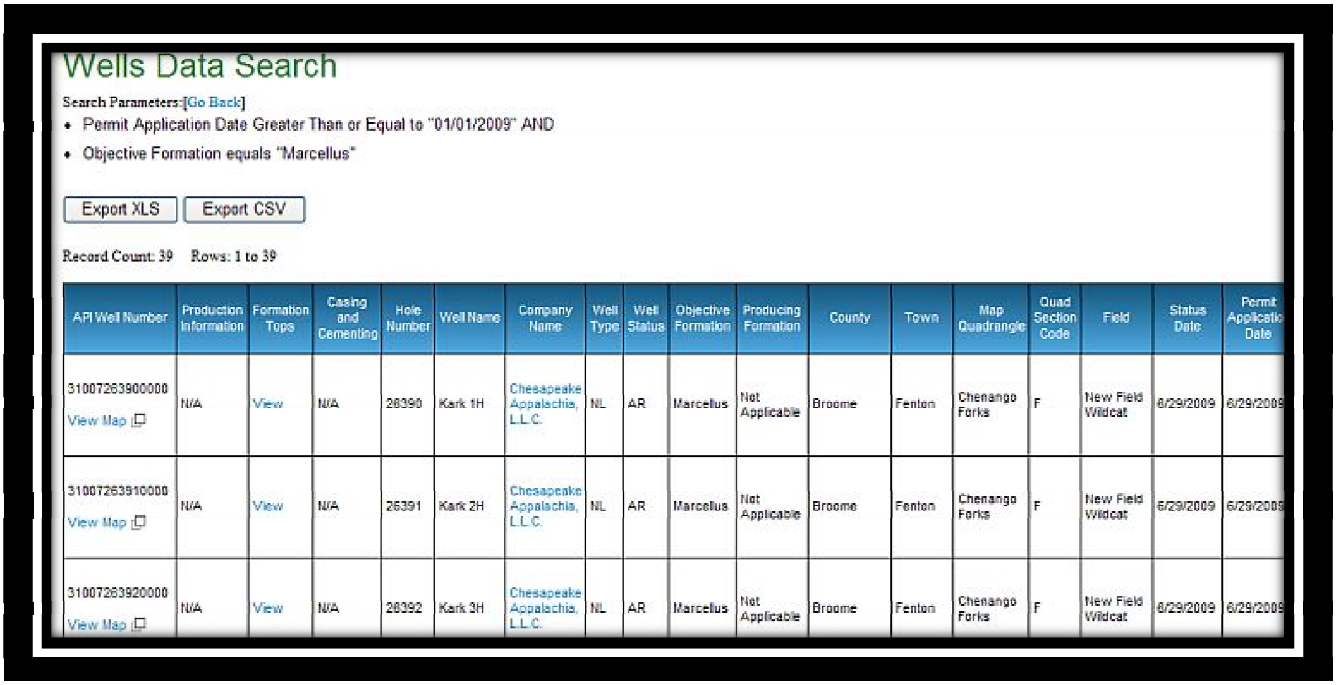
2. Select your search criteria. To find all permit applications filed in 2009 that target a specific geologic formation, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.




3. Select your next set of search criteria. To find all permit applications filed in 2009 for the Marcellus formation, select Objective Formation equals Marcellus. Click the Submit button.




4. View Results.

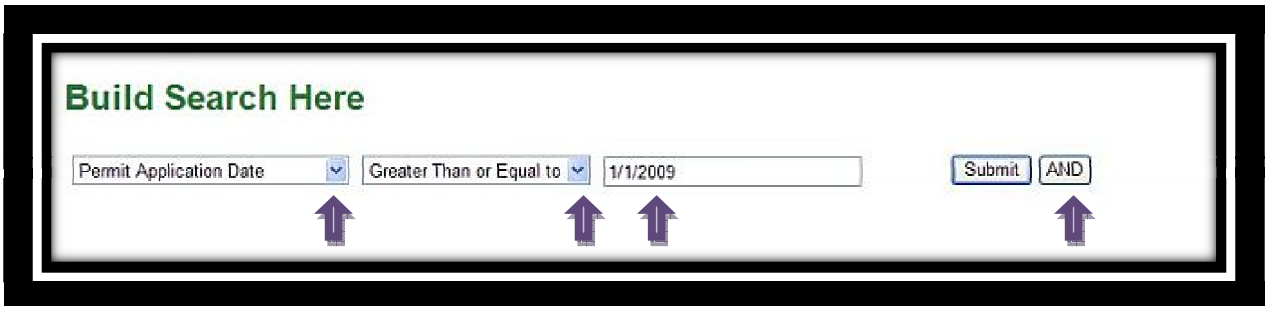



| API Well Number | Production Information | Formation Tops | Casing and Cementing | Hole Number | Well Name | Company Name | Well Type | Well Status | Objective Formation | Producing Formation | County | Town | Map Quadrangle | Quad Section Code | Field | Status Date | Permit Applicatio Date |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31007263900000 View Map | N/A | View | N/A | 26390 | Kark 1H | Chesapeake Appalachia, L.L.C. | NL | AR | Marcellus | Not Applicable | Broome | Fenton | Chenango Forks | F | New Field Wildcat | 6/29/2009 | 6/29/2009 |
| 31007263910000 View Map | N/A | View | N/A | 26391 | Kark 2H | Chesapeake Appalachia, L.L.C. | NL | AR | Marcellus | Not Applicable | Broome | Fenton | Chenango Forks | F | New Field Wildcat | 6/29/2009 | 6/29/2009 |
| 31007263920000 View Map | N/A | View | N/A | 26392 | Kark 3H | Chesapeake Appalachia, L.L.C. | NL | AR | Marcellus | Not Applicable | Broome | Fenton | Chenango Forks | F | New Field Wildcat | 6/29/2009 | 6/29/2009 |

**How to Narrow Your Search to Applications Submitted For a Specific County**

1. Select Wells Data to begin your search.

2. Select your search criteria. To find all permit applications filed in 2009 in a specific county, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.




3. Select your next set of search criteria. To find all permits applied for in 2009 in Allegany County, select County equals Allegany. Click the Submit button.

New York State

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# Appendix 27

## NYSDOH Radiation Survey Guidelines and Sample Radioactive Materials Handling License

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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# Radiological Survey Requirements

## I. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

## II. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

## III. Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

## IV. Survey Frequency

Radiological survey data must be conducted within 6 months following the start of gas production and at intervals not to exceed 12 months thereafter.

The permit tee must conduct surveys of all equipment used on the production train prior to disposal, recycling or transfer to any entity.

Equipment that exceeds 50microrem/hr is subject licensure by the New York State Department of Health.

## V. Survey data reports

Survey data must be submitted within 30 days following the survey, and must contain the information required by Section III.

NEW YORK STATE
DEPARTMENT OF HEALTH
BUREAU OF ENVIRONMENTAL RADIATION PROTECTION

# Radiation Guide 1.15

## GUIDE FOR APPLICATION TO POSSESS NATURALLY OCCURRING RADIOACTIVE MATERIAL (NORM) INCIDENT TO NATURAL GAS INDUSTRY

# I. INTRODUCTION

## PURPOSE OF GUIDE

The purpose of this regulatory guide is to provide assistance to applicants in preparing applications for new licenses for the possession of naturally occurring radioactive materials (NORM) incident to natural gas exploration and production. This regulatory guide is intended to provide you, the applicant, with information that will enable you to understand specific regulatory requirements and licensing policies as they apply to the license activities proposed.

After you are issued a license, you must conduct your program in accordance with (1) the statements, representations and procedures contained in your application; (2) the terms and conditions of the license; and (3) the Department of Health's regulations in 10 NYCRR 16 and 12 NYCRR 38. The information you provide in your application should be clear, specific and accurate.

# II. FILING AN APPLICATION

You, as the applicant for a materials license, must complete Items 1 through 4 and 18 on the attached application form. For other applicable Items, submit the information on supplementary pages. Each separate sheet or document submitted with the application should be identified and keyed to the item number on the application to which it refers. All typed pages, sketches, and, if possible, drawings should be on 8 ½ x 11 inch paper to facilitate handling and review. If larger drawings are necessary, they should be folded to 8 ½ x 11inches. You should complete all items in the application in sufficient detail for the Department to determine that your equipment, facilities, training and experience, and radiation safety program are adequate to protect health and to minimize danger to life and property.

You must submit two copies of your application with attachments. Retain one copy of the application for yourself, because the license will require that you possess and use licensed material in accordance with the statements and representations in your application and in any supplements to it.

Mail your completed application and the required non-refundable triennial fee ($3000) to:

New York State Department of Health
Bureau of Environmental Radiation Protection
Flanigan Square, 547 River Street
Troy, New York 12180

Please Note: Applications received without fees will not be processed .

## III. CONTENTS OF AN APPLICATION

Item 1. Name and address.

Enter the name and corporate address of the applicant and the telephone number of company management. The name of the firm must appear exactly as it appears on legal papers authorizing the conduct of business. Indicate if the name and address are different from those listed on the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill.

Item 2A. Addresses at which radioactive material will be used.

List all addresses and locations where radioactive material will be used or stored, i.e., the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill Nos., well name, and town name.

2.B. Not applicable

Item 3. Nature of business

Enter the nature of the business the applicant is engaged in and the name and telephone number (including area code) of the individual to be contacted in connection with this application.

Item 4. Previous radioactive materials license

Enter any previous or current radioactive materials license numbers and identify the issuing agency. Also indicate whether you possess any radioactive material under a general license.

Describe the circumstances of any denial, revocation or suspension of a radioactive materials license previously held.

Item 5. Department to Use Radioactive Material

Not Applicable

Item 6. Individual Users of Radioactive Materials

Not Applicable,

Item 7. Radiation Safety Officer

State the name, title and contact information (phone, fax, and e-mail) of the person designated by, and responsible to, management for the coordination of the radiation safety program. This person will be named on the license as the Radiation Safety Officer. He/she will be responsible to oversee and ensure that licensed radioactive material is possessed in accordance with regulations and the radioactive materials license.

Item 8. Radioactive Material

No response is required. The license will list Naturally Occurring Radioactive Material (NORM).

Item 9. Purpose for which Radioactive Material Will be Used

No response is required. (The type of use will be specified on the license as possession and maintenance of radiologically contaminated equipment, with specific limitations.)

Item 10. Training of individual users

Persons who perform radiological surveys that are required by regulation and radioactive materials license must receive initial and annual radiation protection training. The scope of training needs to be commensurate with their duties. Appendix A contains a model training program. Confirm that you will follow the model or submit your proposed training program for review.

Item 11. Experience with radioactive materials for individual users

No response is required. Implementation of a training program as required in Item 10 of the application addresses Item 11 for the scope of license tasks.

Item 12. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

A model procedure for conducting a radiological survey is provided in Appendix C.

Item 13. Calibration and operational checks of instrumentation

Instrument calibrations must be performed before first use of the instrument and at intervals not to exceed 12 months by an entity that is licensed by the US Nuclear Regulatory Commission or an Agreement State to perform radiological survey instrument calibrations. The instrument must be checked for proper operation (minimally a battery condition check must be performed, and a response to a radiation source is recommended) on each day of use. Records of instrument calibrations must be maintained for a period of 5 years for review by the Department. Confirm that calibrations and daily battery checks will be performed as indicated above and that instrument calibration records will be maintained.

Item 14. Personnel monitoring and bioassays

Not applicable.

Item 15. Facilities and Equipment

Submit simple sketches of any storage area(s), pipe yards, etc., for contaminated equipment.

Item 16. Radiation Protection Program

The applicant does not need to establish a comprehensive radiation safety program. However, the applicant needs to implement a radiation protection program that is commensurate with the type of radioactive material authorized by the license. Appendix B contains a model radiation protection program. Please confirm that you will implement the model program or submit your proposed program for review.

Item 17. Waste Disposal

The applicant must plan for proper disposal of radiologically contaminated equipment when their use has been discontinued. Confirm that you will dispose of radiologically contaminated items in accordance with all applicable state and federal requirements.

Item 18. Certification

Provide the signature of the chief executive officer of the corporation or legal entity applying for the license or of an individual authorized by management to sign official documents and to certify that all information in this application is accurate to the best of the signator's knowledge and belief.

## IV. AMENDMENTS TO LICENSES

Licensees are required to conduct their programs in accordance with statements, representations and procedures contained in the license application and supporting documents. The license must therefore be amended if the licensee plans to make any changes in the facilities, equipment, procedures, and authorized users or radiation safety officer, or the radioactive material to be used.

Applications for license amendments may be filed either on the application form or in letter form. The application should identify the license by number and should clearly describe the exact nature of the changes, additions, or deletions. References to previously submitted information and documents should be clear and specific and should identify the pertinent information by date, page and paragraph.

APPENDIX A  Training Program for Individuals Performing Radiological Survey Measurements.

The applicant/licensee may use the services of a health physicist, licensed medical physicist or an individual who is authorized by a radioactive materials license to conduct radiological surveys. In these situations, the applicant/licensee needs to obtain documentation that the individual is qualified. Examples of documentation include a radioactive materials license that names the person as an authorized user, or copy of a resume for the health physicist or licensed medical physicist. Records of training must be maintained for a period of 5 years.

However, if the applicant/licensee plans to use his/her staff to conduct surveys, such individuals must receive training.

Individuals must demonstrate competence in the following subjects that prior to being approved to perform required surveys. Training must be conducted by an individual who is knowledgeable in health physics principles and procedures.

I. Fundamentals of Radiation Safety

- A. Characteristics of radiation
- B. Units of radiation dose and quantity of radioactivity
- C. Levels of radiation from sources of radiation
- D. Methods of minimizing radiation dose:
  1. working time
  2. working distance
  3. shielding

II. Radiation Detection Instruments

- A. Use of radiation survey instruments
  1. operational
  2. calibration

- B. Survey techniques

III. Requirements of the regulations and License Conditions

IV. Records of training will be maintained for a period of 5 years. Records will include the date of training, name of persons trained, name of the trainer and his/her employer, a copy of the training agenda or topics covered, and the results of any test or determination of proficiency. Records will be maintained for review by the Department.

APPENDIX B Radiation Protection Program

I. Responsibility

A. The owner/licensee will delegate authority to the Radiation Safety Officer to implement the program and the responsibility to oversee the day to day oversight of the program

B. Ensure that individuals receive initial and annual radiation protection training.

C. Ensure that radiological surveys are performed in an effective manner and at the time intervals required by the License.

D. Ensure that notifications required by regulations and License Conditions are made.

E. Ensure that an inventory of radiologically contaminated equipment is maintained.

F. Ensure that contaminated equipment in storage is labeled as containing radioactive material and is not released for unrestricted use.

G. Ensure that radioactive waste is disposed in accordance with all applicable state and federal requirements.

H. Ensure that only entities that have a specific license to perform decontamination perform service of equipment that exceeds 50 microrem at any accessible surface.

II. Maintain Records of:

A. Radiation Protection Training Program

B. Results of radiological surveys including instrumentation calibrations and operational checks.

C. Inventories of contaminated equipment

D. Waste disposal records

E. Service of contaminated equipment that exceeds 50 microrem at any accessible surface, including documentation of the service provider's radioactive materials license.

F. Radiological survey data

G. Maintain a complete radioactive materials license

APPENDIX C

Radiological Survey Guidance

I. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

II Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

**NEW YORK STATE DEPARTMENT OF HEALTH**
**RADIOACTIVE MATERIALS LICENSE**

Pursuant to the Public Health Law and Part 16 of the New York State Sanitary Code, and in reliance on statements and representations heretofore made by the licensee designated below, a license is hereby issued authorizing radioactive material(s) for the purpose(s), and at the place(s) designated below. The license is subject to all applicable rules, regulations, and orders now or hereafter in effect of all appropriate regulatory agencies and to any conditions specified below.

---

1. Name

_____

2. Address

_____

_____

Attention:
Radiation Safety Officer

3. License Number

4. a. Effective Date

_____

b. Expiration Date

_____

5. Reference Number
DH No. _____

---

| 6. Radioactive Materials (element & mass no.) | 7. Chemical and/or Physical Form | 8. Maximum quantity licensee may possess at one time |
|---|---|---|
| A. Radium 226 | A. Any | A. As necessary |
| B. Naturally Occurring Radioactive Material (NORM) | B. Any | B. As necessary |

9. Authorized use. The authorized locations of use are those specified in New York State Department of Environmental Conservation Permit to Drill Nos. _____.

A. The licensee is authorized for possession only of NORM listed in License Condition No. 6 as contamination in equipment incidental to oil and gas exploration and production.

B. The licensee may perform maintenance, not inculding decontamination or removal of scale containing radioactive material on equipment that does not exceed 50 microrem per hour at any accessible point.Only a licensee authorized by the US Nuclear Regulatory Commission or an

Agreement State to perform decontamination and decommissioning services shall service equipment that exceeds 50 microrem per hour at any accessible point.

10. A. Radioactive material listed in Item 6 shall be used by, or under the supervision of the Radiation Safety Officer.

_____ B.

C. The licensee shall notify the Department by letter within 30 days if the Radiation Safety Officer permanently discontinues performance of duties under the license.

11. Except as specifically provided otherwise by this license, the licensee shall possess and use licensed material described in Items 6, 7 and 8 of this license, in accordance with statements, representations, and procedures contained in the documents (including any enclosures) listed below:

A. Application for New York State Department of Health Radioactive Materials License dated _____, signed by _____.

B. Letter dated _____, signed by _____.

The New York State Department of Health's regulations shall govern the licensee's statements in applications or letters unless the statements are more restrictive than the regulations.

12. A. Transportation of licensed radioactive material shall be subject to all regulations of the U.S. Department of Transportation and other agencies of the United States having jurisdiction insofar as such regulations relate to the packaging of radioactive material, marking and labeling of the packages, loading and storage of packages, monitoring requirements, accident reporting, and shipping papers.

B. Transportation of low level radioactive waste shall be in accordance with the regulations of the New York State Department of Environmental Conservation as contained in 6 NYCRR Part 381.

13. The licensee shall have available appropriate survey instruments which shall be maintained operational and shall be calibrated before initial use and at subsequent intervals not exceeding twelve months by a person specifically authorized by the U.S. Nuclear Regulatory Commission or an Agreement State to perform such services. Records of all calibrations shall be kept a minimum of five years.

14, The licensee shall conduct gamma exposure rate measurements of accessable areas of gas production equipment within 6 months of the effective date of the license and at subsequent

intervals not to exceed 12 months. The licensee shall maintain measurement records for review by the Department. The licensee shall notify the Department within 7 calendar days following identification of any exposure rate measurement that meet or exceed 2 millirem per hour. Notification may be made by phone or in writing.

15. Equipment in storage that exceeds 50 microrem per hour at any accessible point shall be labeled by means of paint or durable label or tag.

16. The licensee shall maintain an inventory of equipment, including but not limited to tubular goods, piping, vessels, wellheads, separators, etc., that exceeds 50 microrem per hour at any accessible point. The records of the inventories shall be maintained for inspection by the Department, and shall include the location and description of the items, and the date that items were entered on the inventory record.

17. A. Before treatment or disposal of any gas production water in a manner that could result in discharge or release to the environment, the licensee shall obtain from the New York State Department of Environmental Conservation either:

    i) A valid permit, or

    ii) A letter stating that no permit is required.

    B. The licensee shall maintain the letter or valid permit required in paragraph A of this condition on file for the duration of the license and make such letter or permit available for inspection by the Department upon request.

18. The licensee shall submit complete decontamination procedures to the Department for approval ninety (90) days prior to the termination of operations involving radioactive materials.

19. Plans of facilities which the licensee intends to dedicate to operations involving the use of radioactive material shall be submitted to the Department for review and approval prior to any such use.

20. The licensee shall maintain records of information important to safe and effective decommissioning at the location listed in License Condition No. 2 and at other locations as the licensee chooses. The records shall be maintained until this license is terminated by the Department and shall include:

    A. Records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site;

    B. As-built drawings and modifications of structures and equipment in restricted areas where radioactive materials are used and/or stored, and locations of possible inaccessible contamination, such as buried pipes, which may be subject to contamination;

C. Records of the cost estimate performed for the decommissioning funding plan or the amount certified for decommissioning, and records of the funding method used for assuring funds if either a funding plan or certification is used.

21. The licensee may transfer contaminated equipment that exceeds 50 microrem at any accessible point to a Department licensee if the equipment is to be used in the oil and gas industry. The licensee shall maintain records of each transfer of equipment authorized by this License Condition.

FOR THE NEW YORK STATE DEPARTMENT OF HEALTH

Date: By _____
CJB/ :

Charles J. Burns, Chief
Radioactive Materials Section
Bureau of Environmental Radiation Protection

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context of this SGEIS and in accordance with Subpart 200.6 requirement defined in Section 6.5.1 to assure all potential adverse impacts are identified and rectified. The additional assessments performed for these short term impacts are addressed separately to distinguish certain information for PM10/PM2.5 gathered from industry since the initial modeling analysis in the SGEIS.

**A)** PM 10 and PM2.5 24-hour Impact Modeling and Potential Mitigation Measures.

As part of the Industry's Responses (dated September 16, 2009) to Information Requests, IOGA referenced a modeling assessment performed by consultants for Chesapeake Energy which incorporated a number of revisions to and recommendations on the Department's modeling analysis[90]. The analysis was based on one year of Binghamton meteorological data which indicated compliance with the PM10 NAAQS and much lower PM2.5 impacts than the Department's results, but still exceedances of the PM2.5 NAAQS. Mitigation measures were listed for resolving the latter exceedances. The analysis incorporated a set of assumptions which are summarized below with the Department's position on each of these:

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

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

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

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

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

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

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

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

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

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

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

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

also indicate that the different sets of engines could be dealt with using different mitigation measures.

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

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

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

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

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

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

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

With respect to the Tier 0 and Tier 1 completion equipment engines, these emissions have not been analyzed or modeled, but for the same reasons as for the drilling engines, Tier 0 completion equipment engines should not be used in New York. In addition, based on the scaling of the maximum impact in Table 6.18 by the ratio of Tier 1 to Tier 2 emission factors (2.7), it is determined that Tier 1 engines have the potential to cause a modeled exceedance even if equipped with a particulate trap (maximum impact of 82 $\mu g/m^3$ with 85% control). Industry can suggest impact mitigation in addition to the use of PM traps in order to show compliance with

the NAAQS, but lacking such a demonstration, it is the Department's interim conclusion that Tier 1 completion equipment engines should not be used in New York. On the other hand, and as also suggested by industry and the public, newer Tier 4 engines, which would likely be equipped with traps in order to achieve the required emission factors for those engines, can be used as an alternative to the Tier 2 engines with a PM trap.

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

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

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

Simple scaling to demonstrate compliance was not possible for the $NO_2$ 1-hour impacts due to the very large concentrations projected using the same method. Instead, it was necessary to account for a number of refinements in the modeling based on EPA and Department guidelines. There are at least two main aspects to the $NO_2$ modeling which need to be addressed in such refinements. These issues have been raised by EPA, industry and regulatory agencies as needing

further guidance. Similar to the PM2.5 guidance, EPA released a memorandum[93] on June 29, 2010 which provides guidance on how to perform a first Tier assessment for the $NO_2$ NAAQS. More recently, EPA has provided further guidance [94]on particulars in the modeling approach for $NO_2$ 1-hour NAAQS compliance determinations.

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

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

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

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

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

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

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

First to consider, however, is that a confounding issue which this initial modeling did not include was the discovery that the $NO_2$ to $NO_x$ ratio is increased by the particulate trap from 0.11 to 0.35 due to the generation of $NO_2$ in order to oxidize and remove the particulates (see Appendix 18A). This would lead to even higher $NO_2$ impacts. These results clearly indicate that some form of after-treatment exhaust control method is necessary for the completion equipment

engines. The after-treatment methods to reduce $NO_x$ emissions are discussed in Appendix 18A which indicates that at present the recommended exhaust treatment method in practical use for on-road engines or engines in general is the SCR system. As noted in Appendix 18A, this preferred after-treatment method for $NO_x$ control would reduce the $NO_2$ to $NO_x$ ratio (with the CRDPF traps in place) down to essentially the same value as without the traps (i.e. 0.10). Of course, the SCR system would also substantially reduces the $NO_x$ emissions by 90%. Therefore, the last step in the modeling of the completion equipment engines was to use the 90% reduction in emissions and the $NO_2$/ $NO_x$ ratio of 0.10 with the OLM option. The analysis relied on the Tier 2 emissions provided by the Industry Information Report as the base emissions which were then reduced by 90% by the SCR controls. This level of modeling was deemed the most refinement allowed currently by Department and EPA guidance.

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

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

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

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

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

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

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

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

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

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

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

The supplemental modeling assessment has concluded that in order to meet the ambient standards for the 24-hr PM2.5 and the 1-hour $NO_2$ NAAQS, it is necessary that the completion equipment engines tiers allowed to be used in New York to be equipped with particulate filter

traps (CRDPF) and SCR control for $NO_x$. These are Tier 2 and newer completion equipment engines. Similarly, the Tier 1 rig engines and air compressors would be required to be equipped with both control devices if these are used in New York. The determination on the specific after-treatment controls was based on the review of available control methods used in practice (see Appendix 18A). Currently available alternative control measures considered were deemed inadequate for the purpose of achieving the level of PM2.5 and $NO_x$ emission reductions necessary to demonstrate NAAQS compliance and/or having a proven record of use in practice.

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

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

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

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

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

Details of an analysis of the "cost effectiveness" of the SCR controls for completion equipment engines and the comparable value currently used by the Department for stationary sources is provided in Appendix 18B. It is important to note that the "cost effectiveness" is based on acceptable "engine size scaling-up" method for the completion equipment engines with certain assumptions which might not be representative of the actual cost of installation of SCR after treatment. The calculations in Appendix 18B indicate that the cost of requiring SCR on the completion equipment engines is within the value used by the Department for stationary sources

and is deemed reasonable. The cost effectiveness for the smaller drilling engines should be lower. It is recognized that the applicability of 227.2 RACT requirements are meant for major individual stationary sources, but it is also to be noted that the potential annual $NO_x$ emissions from the sum total of engine use throughout the Marcellus Shale are rather large, as discussed in the next section. Based on the conversations with the engine manufacturers, the main concern with the installation of SCR as an after-treatment control relates again to the need for a "stand-alone" system on the completion equipment engines, with the added complexity that these systems would require "continuous" maintenance to achieve the level of reduction assumed in the Department's analysis. In addition, these discussions indicate that the cost associated with the installation of the PM traps and SCR are likely above those assumed by the Department. A calculation using the approach in Appendix 18C for PM after-treatment indicates that the "cost effectiveness" value is well above the value used for $NO_x$ RACT waiver determinations. Thus, it is recommended that industry undertake a detailed assessment of the PM traps and SCR controls in addressing the Department's recommendations of these controls as the required mitigation measures on certain Tier drilling and completion equipment engines in order to demonstrate compliance with the 24-hour PM2.5 and 1-hour $NO_2$ NAAQS.

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

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

*6.5.2.7 Conclusions from the Modeling Analysis*

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

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

The modeling analysis of all sources was carried out for the short-term and annual averages of the ambient air quality standards for criteria pollutants and for Department defined threshold levels for non-criteria pollutants. The initial modeling used limitations on simultaneous

operations of the various equipment at both onsite and offsite operations for a multi-well pad in the analysis for the short-term averages, while the annual impacts accounted for the potential use of equipment at the well pad over one year period for the purpose of drilling up to a maximum of ten wells. For the modeling of chemicals in the flowback water, two impoundments of expected worst case size were used based on information from industry: a smaller on-site and a larger off-site (or centralized) impoundment.

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

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

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

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

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

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

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

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

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

Table 6.15 - Maximum Background Concentration from Department Monitor Sites

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

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

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

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

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

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

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

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

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

*** See Supplemental Modeling Section for revised analysis

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

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

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

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

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

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

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

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

| Met Data Location | Met Data Year | PM10, 24-hr (µg/m$^3$) | | PM2.5, 24-hr (µg/m$^3$) | | $NO_2$, 1-hour impact (µg/m$^3$) (see NOTE) | | |
|---|---|---|---|---|---|---|---|---|
| | | Hydraulic Fracturing | Drilling | Hydraulic Fracturing | Drilling | Hydraulic Fracturing | Rig Engine | Compressor |
| Albany | 2007 | 313 | 76 | 152 | 36 | 198 | 256 | 216 |
| | 2008 | 268 | 84 | 129 | 40 | 198 | 259 | 230 |
| Syracuse | 2007 | 224 | 95 | 144 | 34 | 156 | 196 | 198 |
| | 2008 | 327 | 81 | 120 | 27 | 161 | 180 | 208 |
| Binghamton | 2007 | 281 | 87 | 154 | 34 | 194 | 239 | 208 |
| | 2008 | 327 | 89 | 121 | 35 | 213 | 231 | 220 |
| Jamestown | 2001 | 339 | 74 | 151 | 29 | 180 | 237 | 221 |
| | 2002 | 229 | 83 | 155 | 33 | 181 | 248 | 217 |
| Buffalo | 2006 | 338 | 106 | 202 | 55 | 147 | 269 | 231 |
| | 2007 | 318 | 102 | 189 | 59 | 148 | 272 | 231 |
| Montgomery | 2005 | 255 | 77 | 104 | 28 | 169 | 198 | 202 |
| | 2006 | 301 | 66 | 108 | 21 | 155 | 211 | 200 |
| Maximum (µg/m$^3$) | | 339 | 106 | 202 | 59 | 213 | 272 | 231 |
| Max @ 75m (µg/m$^3$) | | 92 | 75 | 44 | 30 | 100-140 | 140-170 | 120-150 |
| Max Dist to NAAQS - Background (m) | | 60 | 60 | 150 | 120 | <90 | <100 | <100 |

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

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

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

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

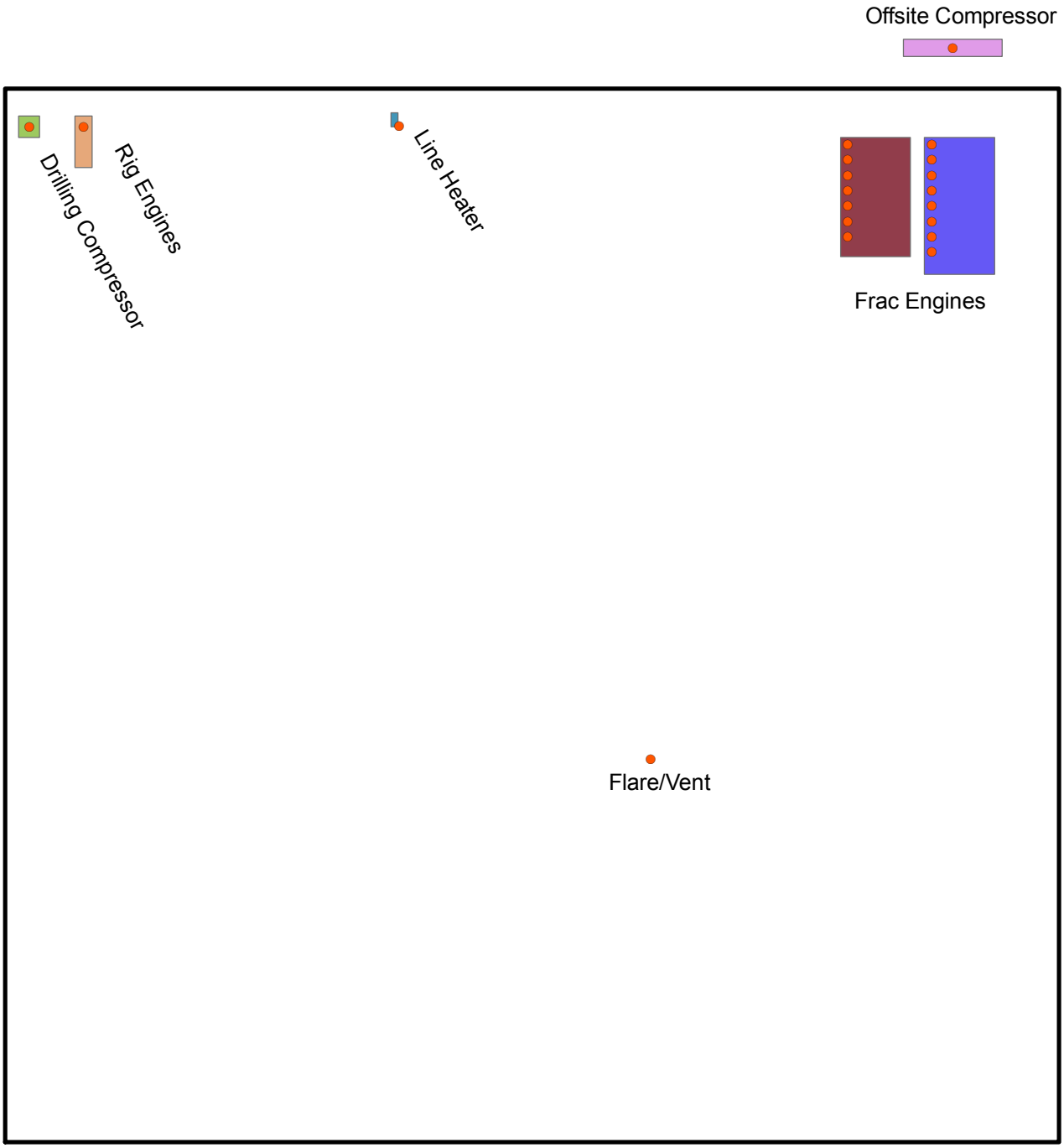



**Figure 6.10- Location of Well Pad Sources of Air Pollution Used in Modeling**

## Buildings

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

0 5 10 20 30 40 50 Meters

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

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

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

*Attainment Status and Current Air Quality*

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

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

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

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

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

*State Implementation Plans*

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

Projected Emissions and Current/Potential Control Measures

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

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

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

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

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

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

Small Spark-Ignition Engines

Federal On-board Vapor Recovery

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

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

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

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

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

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

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

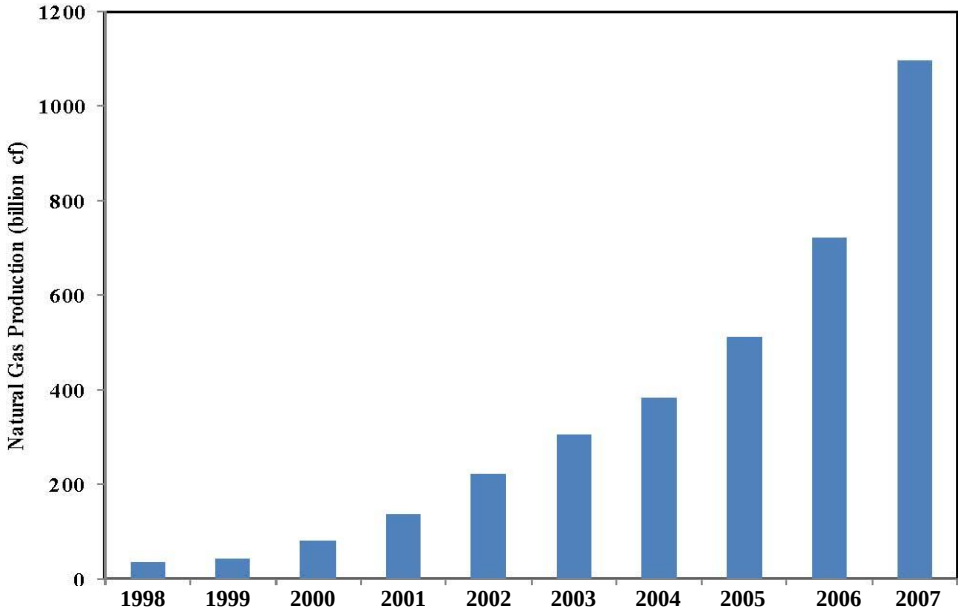
In order to assist the Department to develop a full understanding of the cumulative and regional emissions and impacts of developing the gas resources of the Marcellus Shale, available information from similar activities in other areas of the country has been reviewed. Notably, certain information from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

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

Thus, the cumulative impacts of gas well drilling within the Marcellus Shale would also vary depending on what point in time those impacts are measured as the development of the gas resource expands over time. As an example of how well development proceeded in the Barnett Shale, the Figure 6.11 indicates that gas production rose dramatically from 1998-2007. This chart is being used by the Department for illustration purposes only to indicate the timeframes

which might be involved in the Marcellus development and not as an actual indication of expected development. Preliminary information from Pennsylvania indicates a more rapid increase in gas well drilling and production.

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




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

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

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

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

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

Table 6.21 - Predicted Ozone Precursor Emissions (Tpy)

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

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

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

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

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

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

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

*Effects of Increased Truck Traffic on Emissions*

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

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

directly related to the drilling operations impacts the overall mobile emissions that normally would occur throughout the Marcellus Shale drilling area.

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

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

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

*Comparison to Barnett Shale Emission*

A referenced report[101] on the Barnett Shale oil and gas production prepared by Southern Methodist University (SMU) for the Environmental Defense Fund (EDF) has been noted as a source of emission calculation schemes and resultant regional emissions for that region of Texas. In terms of the projected emissions of $NO_x$ and VOCs, while caution should be exercised in

making comparisons between the two areas, a picture of emissions from the Barnett Shale may be a useful point of departure for understanding the magnitude and types of emissions to be expected with the development of the Marcellus Shale. The Department has not undertaken a review of the rationale or the methodologies used in the SMU report and is also aware of the Texas Commission on Environmental Quality (TCEQ)'s critique of the report.[102] Since the report, TCEQ has undertaken a detailed emission inventory development program to better characterize the sources and to quantify the corresponding emissions.

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

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

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

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

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

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

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

*Further Discussions and Conclusions*

There are stringent regulatory controls already in place for controlling emissions from stationary and mobile sources in New York. With additional required emission controls recommended in the revised SGEIS for the operations associated with drilling activities, coupled with potential deployment of further emission controls arising from upcoming $O_3$ SIP implementation actions, the Department is confident that the effect of cumulative impacts from the development of gas resources in the multi-county area underlain by the Marcellus Shale would be adequately mitigated. Thus, the Department would be able to continue to meet attainment goals that it has set forth in cooperation with EPA. In addition to eliminating the use of uncertified and certain older tier engines and requiring specific mitigation measures to substantially reduce PM and $NO_x$ emissions in order to meet NAAQS, the Department would review the need for certain additional

mitigation prior to finalizing the SGEIS. As part of the information, the Department is seeking from industry an implementation timeline to expedite the use of higher tier drilling and completion equipment engines in New York. Furthermore, as the Department readies for the soon to be announced revised $O_3$ NAAQS and potential revisions to the PM2.5 NAAQS, the need for imposing further controls on drilling engines not being currently required to be equipped with PM traps and SCR would be revisited. If it is determined that further mitigation is necessary, further controls would be required. The review would consider the relatively high contribution to regional emissions of $NO_x$ from the drilling engines and result from regional modeling of $O_3$ precursors which would be performed in preparation of the Ozone SIP.

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

### *6.5.4 Air Quality Monitoring Requirements for Marcellus Shale Activities*

In order to fully address potential for adverse air quality impacts beyond those analyzed in the SGEIS relate to associated activities which are either not fully known at this time or verifiable by

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

### *6.5.5 Permitting Approach to the Well Pad and Compressor Station Operations*

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

with all applicable standards. To further assure that these restrictions are adhered to for all well operations, a set of necessary conditions identified in Section 7.5.3 and Appendix 10 will be included in DMN well permits.

DMN Well Drilling Permit Process Requirements

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

## 6.6 Greenhouse Gas Emissions

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

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

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

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

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

### *6.6.1 Greenhouse Gases*

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

### *6.6.2 Emissions from Oil and Gas Operations*

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

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

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

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

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

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

*6.6.2.1 Vented Emissions*

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

*6.6.2.2 Combustion Emissions*

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

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

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

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

*6.6.2.3 Fugitive Emissions*

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

*6.6.3 Emissions Source Characterization*

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

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

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

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

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

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

Drilling Rig Mobilization, Site Preparation and Demobilization

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

Completion Rig Mobilization and Demobilization

Completion Rig

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

Well Completion

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

Well Production[119]

Production Equipment (5 – 10 Truckloads)

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

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

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

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

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

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

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

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

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

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

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

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

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

### *6.6.4 Emission Rates*

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

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

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

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

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

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

### *6.6.5 Drilling Rig Mobilization, Site Preparation and Demobilization*

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

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

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

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

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

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

### *6.6.6 Completion Rig Mobilization and Demobilization*

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

### *6.6.7 Well Drilling*

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

perform the work required to spud the well and reach its total depth. Table GHG-4 in Appendix 19, Part A includes estimates for $CO_2$ emissions generated by these stationary sources. As shown in the table, approximately 83 tons of $CO_2$ emissions per single vertical well would be generated as a result of drilling operations. Tables GHG-5 and GHG-6 show $CO_2$ emissions of 194 tons and 776 tons for the drilling of a single horizontal well and four-well pad, respectively.

### *6.6.8 Well Completion*

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

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

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

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

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

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

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

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

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

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

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

### *6.6.9 Well Production*

GHGs from the well production phase include emissions from transporting the production equipment to the site and then operating the equipment necessary to process and flow the natural gas from the well into the sales line. Carbon dioxide emissions are generated from the trucks needed to haul the production equipment to the wellsite. As previously stated, GHG emissions of $CO_2$ from transportation rely on estimated fuel usage where available or VMT, which ultimately requires a determination of fuel usage. Such emissions associated with well production activities, include those from transportation related to the removal of production brine, as discussed below. The estimated VMT for each case was then used to determine approximate fuel use and resultant $CO_2$ emissions. As shown in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A, transportation needed to haul production equipment to a wellsite for a one-well project and a four-well pad results in first-year $CO_2$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 $CO_2$ emissions. Transportation estimates were used to determine $CO_2$ emissions from each well development scenario, and emission estimates are presented in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A. Table GHG-10 presents $CO_2$ and $CH_4$ emissions for a one-well project for the period of production remaining in the first year after the single vertical well is drilled and completed. For the purpose of this analysis, the duration of production for a single vertical well in its first year was estimated at 349 days (i.e., 365 days minus 16 days to drill & complete) and for a single horizontal well in its first year 331 days (i.e., 365 days minus 34 days to drill & complete). Table GHG-13 shows estimated annual emissions for a single vertical well or single horizontal well commencing in year two, and producing for a full year. Table GHG-12 presents $CO_2$ and $CH_4$ emissions for a four-well pad for the period of production remaining in the first year after all ten wells are drilled and completed. For the purpose of this analysis, the duration of production for the ten-well pad in its first year was estimated at 229 days (i.e., 365 days minus 136 days to drill & complete). Instead of work phases occurring sequentially, actual operations may include concurrent well drilling and producing activities on the same well pad. Table GHG-14 shows estimated annual emissions for a four-well project commencing in year two, and producing for a full year.

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

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

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

*6.6.10 Summary of GHG Emissions*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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