



September 2, 2011

Mr. Joe Martens, Commissioner
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233

Subject: Preliminary Revised Draft Supplemental Generic Environmental Impact Statement
Economic Impediments to Shale Gas Development

Dear Commissioner Martens:

The Independent Oil and Gas Association of New York (IOGA of NY) respectfully submits the following concerns regarding the Preliminary Revised Draft Supplemental Generic Environmental Impact Statement (prdSGEIS), the associated rule-making, the parallel effort to expand the general permit program relative to stormwater discharges from natural gas drilling and completion activities, and the anticipated economic impacts to shale gas development in New York. We anticipate that this document will frame the issues for discussion at our meeting on Tuesday, September 6. IOGA of NY is submitting this document in part:

- (1) To assess the wisdom of proceeding with a broad rule-making in the face of the incremental and increasing economic costs associated with the requirements identified within the prdSGEIS, and
- (2) To assist the New York State Department of Environmental Conservation (DEC) in understanding the economic impacts to the oil and gas industry so that the decision-makers in New York State will have a better understanding of why a number of these proposals will delay or preclude drilling activities in New York for many years to come.

This document is not intended to be a comprehensive list of issues in prdSGEIS and the associated regulatory processes that are of concern to IOGA of NY. Rather, it is intended only to highlight critical issues that need to be addressed now. If not revised, the Supplemental Generic Environmental Impact Statement (SGEIS) and the associated regulatory processes will make shale gas development in New York non-competitive with other states. As a result, the capital that is necessary for drilling and production will continue to flow elsewhere. In turn, the lack of investment in New York will seriously impact landowners, local communities in the form of lost property taxes, and the state through lost income and sales taxes. Of course, the state will also forego the biggest prize of all: an indigenous supply of clean-burning natural gas.

IOGA of NY has had several discussions with its member companies, as well as other interested industry representatives, and has concluded that conducting broad rule-making concurrently with the adoption of the SEGIS is not in the best interests of the state, landowners or industry. Our comments in this document, therefore, are being submitted subject to a full reservation of rights regarding the propriety of and technical justification for the rule-making process. Although we recognize that the DEC has

requested specific cost information regarding all of the mitigation proposals that are intended to be incorporated in new rule-making, the IOGA of NY SGEIS Working Group has determined that it would be futile to provide detailed cost information regarding individual mitigation proposals unless the overall competitiveness of the entire regulatory process is evaluated now and significant changes are made to keep New York competitive with other states that are actually promoting the development of this resource. As demonstrated herein, IOGA of NY estimates that the overall cost of the regulatory proposals will increase the cost for each wellbore in New York State in excess of \$1 million above the cost to drill the same wellbore in other states, which will render New York non-competitive. In requesting significant changes, IOGA of NY is not asking the DEC to compromise on environmental protection. Rather, we are asking the DEC to recognize that many of the proposals go too far and must be adjusted before the costs associated with specific measures should be evaluated. Consistent with that goal, IOGA of NY has prepared this document to alert the DEC to a number of overriding concerns with the current draft of the SGEIS and the associated rule-making process that are critical to maintaining a modicum of economic competitiveness. Accordingly, IOGA of NY provides the following concerns, comments, and recommendations:

- If DEC decides to move forward with the rule-making process, it should limit that process to only the most essential regulatory requirements.
- The original Generic Environmental Impact Statement (GEIS) has served the state and operators extremely well since its adoption in 1992. Flexibility in both the conduct and practices of oil and gas operations and DEC's monitoring and enforcement is desirable and necessary to promote current and future efficiencies and technological advancements.
- Adopting conditions and standards in rule-making will blunt and delay implementation of new technologies that are advancing with exploration and development of natural gas (e.g., water recycling and disposal).
- No other industry operating within New York, even though possibly impacting the environment to a greater extent than the oil and gas industry, will be burdened by these unjustified, excessive and inequitable rules, regulations, requirements, mitigation measures, permit conditions and access restrictions.
- DEC should take a hard look at the incremental environmental benefits versus the oil and gas industry's significant costs incurred in order to implement the mandated mitigation. We believe that many of the requirements impose unnecessary costs with no tangible benefit to the environment.
- Many of the proposals are inconsistent with the DEC's statutory mandate to promote the development of the resource and protect correlative rights and go beyond the statutory authority of the DEC (e.g., the effort to regulate private land use).

In addition to these overriding concerns, IOGA of NY has identified a number of critical issues that will make New York non-competitive and preclude large portions of the state from development. These issues, which are similarly not meant to be exhaustive, include:

- the proposed prohibitions and setbacks, which make it virtually impossible to lay out spacing units and engage in any meaningful development of the resource;
- the draft stormwater general permit requirements, which go well beyond what is required of any other industry in New York State and include many requirements that will unnecessarily increase the cost of drilling and completion substantially, ultimately deterring any investment in New York State;

- the mitigation requirements currently being proposed to address air impacts, many of which are not feasible, most of which are not demonstrated to be beneficial, and all of which fail to recognize the need for equipment to move freely among states without state-specific requirements and may be preempted under the Clean Air Act;
- the codification of best management practices, which eliminates flexibility, stifles improvement and results in many unnecessary costs;
- the passby flow methodology being proposed by the DEC is unnecessarily conservative and conflicts with their statutory obligation to balance competing water resources; and
- a number of circumstances where the regulatory proposals conflict with New York law (e.g., the effort to impose a different passby flow standard in areas regulated by interstate compact commissions that conflicts with recently enacted water withdrawal legislation in New York State).

Finally, we have included an analysis of shale gas economics and the lost economic opportunities, which demonstrate how New York State is already at a competitive disadvantage given market conditions and the unproven geology and the reasons why, therefore, unnecessary regulatory burdens will make New York that much more non-competitive.

The following paragraphs provide more specific comments.

Setbacks and Prohibitions

Without a scientific basis or rationale, the DEC has proposed a series of prohibitions and setbacks never before contemplated, despite New York's long-standing history of natural gas exploration and development. Some of these prohibitions and setbacks preclude any development while others preclude the siting of well pads within prohibited areas. When these prohibitions and setbacks are mapped against leasehold interests, it often becomes impossible to lay out units or site well pads in a manner that makes development in New York State economically viable. As a consequence, operators will lose hundreds of millions of dollars already invested in minerals leases, landowners will lose millions of dollars in royalties, significant tax revenue will be lost, and very few operators, if any, will be willing to invest their drilling budgets in New York State. The result will be lost economic opportunity for New York totaling billions of dollars.

New York State's Environmental Conservation Law (ECL), as it pertains to oil and gas, has long since been recognized as a "conservation statute" that is designed to promote the recovery of the resource and protect the correlative rights of landowners. Consistent with that goal, ECL § 23-0301 declares that it is in the public interest to "regulate the development, production and utilization of natural resources of oil and gas in the state in such a manner as will prevent waste; *to authorize and provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas may be had, and that the correlative rights of all owners and the rights of all persons including landowners and the general public may be fully protected* [emphasis added]." These guiding principles serve as the basis for the oil and gas regulatory framework in New York State.

In furtherance of these goals and objectives, New York State has created detailed statutory schemes for spacing and compulsory integration to promote the greater recovery of the resource and protect correlative rights. The spacing and permitting provisions are generally found in ECL Article 23, Title 5. In accordance with the fundamental policy, ECL § 23-0503(2) authorizes the issuance of permits to drill wells if a proposed spacing unit "conforms to statewide spacing and is of approximately uniform shape with other spacing units within the same field or pool, and abuts other spacing units in the same pool, unless sufficient distance remained between units for another unit be developed." For the more

ubiquitous plays like the Marcellus and the Utica, this is likely to require relatively uniform rectangular-shaped abutting units in order to avoid gaps in the development of the resource.

Also paramount in the well permitting process is the need to site a well pad in a location that minimizes environmental impacts to the maximum extent practicable. This is frequently accomplished by looking for locations that avoid stream crossings, wetlands, steep slopes, endangered species, and known areas of historic significance, and by taking into account other siting considerations consistent with Best Management Practices (BMPs). The existing regulations found in 6 NYCRR Section 553.2 contain appropriate setbacks that have worked well for decades and have not led to any demonstrable problem with the 14,000 operating wells in New York State.

Against this backdrop, the DEC is proposing a series of setbacks and prohibitions. These include the following:

- Prohibitions:
 - the prohibition of well pads in the New York City and Syracuse watersheds and a buffer zone that is 4000 feet around those watersheds, and
 - certain State lands (State Forests, State Parks, etc.).
- Setbacks:
 - primary aquifers and within a 2,000-ft buffer;
 - within 2,000 feet of public water supply wells and reservoirs;
 - within 500 feet of private drinking water wells or domestic use springs, unless waived by the owner, and within 100-year floodplains.

The prdSGEIS also declares that a supplemental environmental analysis (i.e., a site-specific Environmental Impact Statement [EIS]) will be required in certain instances. These instances cover three categories: location, drilling depth and type of water-related issues. The location carve-outs require a site-specific EIS:

- within 1,000 feet of New York City's subsurface water supply infrastructure;
- principal aquifers or within 500 feet of the boundary of a principal aquifer;
- within 150 feet of a perennial or intermittent stream that is not a tributary to a public drinking water supply, storm drain, lake or pond; and
- within 500 feet of a tributary to a public drinking water supply.

Furthermore, private lands with tracts of grassland greater than 30 acres or forest greater than 150 acres may be off limits to surface occupancy and/or severely restricted insofar as their future development potential is concerned. IOGA of NY questions whether the DEC has the legislative authority to impose such restrictions on private lands. Moreover, the setbacks proposed by the DEC are to the "edge of location" (i.e., the well pad), not to the well itself. Therefore, all estimates of acreage excluded from development, particularly insofar as vertical wells are concerned, must add an additional 200 feet from the restricted area/edge of surface disturbance to the centrally located well, which increases the setbacks significantly.

As an initial matter, the proposed prohibitions directly conflict with the policy objectives of the statutory scheme in that they fail to promote the recovery of the resource or protect the correlative rights of the landowners in the prohibition areas. For this reason alone, the prohibitions should be eliminated.

Regarding the setbacks, although some reasonable setbacks are not objectionable (e.g., the existing regulations), when multiple setbacks are established without the authority of the DEC to grant waivers for good cause shown, it becomes extremely difficult, if not impossible, for an operator to lay out units in an orderly fashion. Further complicating this issue is the trend in the industry to drill longer horizontal wells, thereby reducing the number of well pads that are required. This trend further reduces the surface footprint of the industry and corresponding impacts to the environment. Because New York law limits the size of spacing units for shale wells up to 640 acres, it will be the practice of industry to layout back-to-back units with a common well pad for both units thereby draining areas up to 1280 acres (two square miles). As such, the location of the well pad becomes a critical factor in laying out spacing units based upon mineral lease rights and other environmental considerations.

By way of example, one operator has laid out spacing units based upon back-to-back 640 acre unit spacing, its mineral leases and traditional factors to avoid sensitive environmental areas. In the Owego area of Tioga County, this operator has sufficient mineral rights to develop twelve 640 acre spacing units with back-to-back spacing units and common well pads. Unfortunately, when land constraints are overlaid with the regulatory setbacks being proposed by the DEC, only two of the units are feasible. Because the spacing law allows spacing "up to" 640 acres, this operator may be able to develop other smaller units, but it will increase the number of well pads significantly, thus increasing the cost to the operator and increasing both the surface impacts and truck traffic from multiple locations. Even then, certain areas will be inaccessible, with the consequence that millions of dollars already invested in leases will not be practical to develop. Maps will be presented to the DEC during our upcoming meeting to demonstrate the significance of this issue.

Another operator has gone through a similar exercise in Chemung County, New York. The primary aquifer provision will eliminate significant developable acreage. This operator estimates that 50% to 60% of their current leasehold in Chemung County is located in primary aquifer areas. And, this prohibition is being proposed even though the same operator has developed four Trenton Black River wells through the very same primary aquifer without any environmental contamination. It is difficult to understand the rationale behind the prohibition for Marcellus-type wells while Trenton Black River wells are allowed to proceed. The primary aquifer prohibition and the many other setbacks proposed will require abandonment of attractive and logical drill sites and cause losses to the operator and the mineral owners of tens to hundreds of millions of dollars.

Given the foregoing, industry predicts that the acreage available to develop the shale resources in New York is far less than the 80% being predicted by the DEC and may approach numbers as low as 40% to 50%, if not lower. This situation will:

- (1) leave large tracts without development of the resource in direct contrast to the ECL's statutory directives,
- (2) subject operators to lost investments in many leases,
- (3) preclude landowners from reaping billions of dollars of economic benefits from the development of shale resources in New York State,
- (4) deny significant tax revenue to local municipalities as well as the State, and
- (5) deter most, if not all, operators from giving any serious consideration to New York State.

The overall result will be a large amount of stranded acreage that will not be drilled, leaving natural gas in the ground along with landowners who will be economically impacted and who will not understand why their land will not be drilled when neighboring properties have reaped the benefits.

As an alternative, the industry recommends that many of the setbacks be eliminated or reduced to the existing setbacks, or setbacks that are consistent with those in place in other neighboring states. Industry further recommends that broad waiver provisions be included in the regulations to allow setbacks to be waived by the DEC for good cause shown.

Stormwater General Permit for High-Volume Hydraulic Fracturing

Uncontaminated stormwater discharges associated with oil and gas extraction activities are exempt from the federal National Pollutant Discharge Elimination System (NPDES) program and therefore from the NY State Pollutant Discharge Elimination System (SPDES) program, as well as under § 402(l)(2) of the Clean Water Act as clarified in § 323 of the Energy Policy Act of 2005. Despite this, the DEC has proposed a new stormwater general permit (GP) for high volume hydraulic fracturing (HVHF) in complete disregard of this exemption. To compound this, the DEC's proposal unnecessarily creates requirements unique to the natural gas industry that are far too numerous, unnecessarily prescriptive and lacking the requisite flexibility.

- To acknowledge the exemption, the HVHF GP should reflect New York's current SPDES Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activities (GP-0-06-002) by requiring the HVHF GP only for "stormwater discharges associated with industrial activity from oil and gas extraction ... which have had a discharge of a reportable quantity (RQ) of oil or a hazardous substance for which notification is required under [federal regulations]."
- Similarly, statutory NPDES permit exemption applicable to stormwater discharges associated with construction activities remains in effect, even though a federal court overturned U.S. Environmental Protection Agency (EPA) regulations implementing it. The DEC should modify the HVHF GP to mirror Pennsylvania's streamlined Erosion and Sediment Control General Permit (ESCGP-1). The Pennsylvania permit requires robust planning for environmental protection along with expedited permit review and authorization.

IOGA of NY has the following technical concerns associated with the HVHF GP:

- Transition between construction and HVHF operations – The DEC should modify the final stabilization requirements to remove the requirement that all construction activities must be completed before drilling can begin to allow for the drilling of multiple wells on a single pad.
- HVHF fluid evaluation – The requirement that operators evaluate hydraulic fracturing fluid every time they conduct well stimulation should be removed. It is unique to New York, and it assumes falsely that hydraulic fracturing (HF) additives are constantly changing, equally effective, universally available, and not subject to trade secret protections.
- Site maps – The HVHF GP should incorporate the flexible site mapping requirements in the Multi-Sector GP at Part III.C.2. together with the provisions in Sector I for Oil and Gas Extraction and Refining.
- General Best Management Practices (BMP) requirements – The proposed HVHF GP should mirror the flexibility in structural and non-structural BMP selection available in the Multi-Sector GP Part IX.B.
- Specific BMP requirements – The BMP provisions in Part X are far too numerous and unnecessarily prescriptive. They should all be replaced with flexible narrative standards for BMP selection that could be modeled after Pennsylvania's NPDES General Permit for Discharges of Stormwater Associated with Industrial Activities (PAG-03).

- Benchmark monitoring – The benchmarking requirements in Part X are excessive, given the purpose of stormwater outfall monitoring as stipulated in section 3.e. The DEC should replace all of the proposed benchmark monitoring requirements with the current total suspended solids (TSS), chlorides and pH requirements in the Multi-Sector GP coupled with targeted supplemental sampling and analysis, if needed. These testing requirements go well beyond what is required of any other industry in New York State, are very expensive and will send a signal to the oil and gas industry that New York State is not open for business.
- Annual Inspections in lieu of Benchmark Monitoring – Pennsylvania’s PAG-03 allows oil and gas extraction industry to conduct an Annual Inspection in lieu of benchmark monitoring. The facilities are only required to inspect annually due to the medium risk associated with stormwater discharges that they pose. The DEC should incorporate a similar annual inspection option into the HVHF GP in addition to the streamlined benchmark monitoring recommended here.

Attachment A contains more detailed explanation and background information.

Air Emissions

With the prdSGEIS the DEC is seeking to establish statewide regulations and mitigation requirements that conflict with existing and/or proposed EPA air quality regulations pertaining to the same emission sources and may be preempted by the Clean Air Act. As recently as August 23, 2011, the EPA proposed new standards specific to the oil and gas sector (sector).¹ The rule proposes a cost-effective regulation based upon proven technologies that would reduce air pollution from the sector while enabling responsible growth in U.S. oil and natural gas production. For the upstream sector EPA’s proposed rule includes wells that are hydraulically fractured (both new wells and workover operations), emissions from storage tanks, pneumatic device fugitive emissions, and some glycol dehydrators.² In addition, over the last seven years the EPA has passed new regulations on every type of engine used in the oil and gas industry to include diesel-fired, new and reconstructed, and non-road engines. **Attachment B** contains a detailed explanation of these new and proposed federal rules and reasons why, in almost every case, they should be relied upon to control the air emissions addressed in the prdSGEIS as opposed to the DEC mandating different controls.

The DEC’s approach in establishing their air emissions controls was based upon a worst-case dispersion modeling scenario. While this may provide assurance that the air emissions are controlled in a worst-case scenario, those prescriptive controls should not be required at every location in the state, at every time of day or year, nor at every tank battery regardless of production. To do so would be unnecessary and would greatly over-control most sources. It would also mandate controls, some of which are technically infeasible, not cost-effective, and/or potentially unsafe for certain sources. EPA’s rules have provided the state with all the air emission control options necessary to regulate the development of shale gas. The DEC should remove the prescriptive source-specific emissions controls specified in the prdSGEIS and instead rely on the EPA’s air emissions control requirements for those same sources both in the current version of the prdSGEIS and when conducting their air emissions permit application reviews.

Water Withdrawals and Natural Flow Regime Considerations

The prdGEIS states that a primary emphasis of the DEC is protection of water resources and that water withdrawals affecting surface or groundwater have been identified as a potential impact resulting from use by the natural gas industry for HVHF. While IOGA of NY certainly agrees that protection of water resources is critical, the utilization of the natural flow regime (NFR) method to calculate passby flows, as

proposed by DEC, is misguided, unduly stringent, and contradicts the passby methods employed by the Susquehanna River Basin Commission (SRBC) and Delaware River Basin Commission (DRBC), both of which have regulatory authorities for water withdrawals in their specific jurisdictions. The SRBC and DRBC have been effectively regulating water withdrawals for decades in New York State and the DEC acts as the New York State representative on these commissions. The SRBC has the most experience with the natural gas industry and SRBC methods in particular are proven to be protective of existing aquatic communities, are designed to be conservative, and incorporate data collected specific to the location of the proposed withdrawal.

It is unreasonable that DEC would impose the NFR method for passby conditions solely for the natural gas industry, when all other withdrawals, such as golf courses, water bottling and industrial sources, would be regulated using the guidance implemented by the commissions. Withdrawals within the Susquehanna and Delaware River Basins should be regulated by the SRBC and DRBC, respectively, to avoid duplication and to ensure regulatory consistency and streamlined approvals. As a result of the water withdrawal legislation adopted into law in New York State this year, outside of the Susquehanna and Delaware basins, the DEC would have primacy regarding water withdrawals greater than 100,000 gallons per day. That legislation specifically exempts from the permitting requirements withdrawals that are permitted by the DRBC or the SRBC. This is current legislative and gubernatorial recognition of the need for the DEC to defer to the Interstate Compact Commissions regarding water withdrawals subject to their jurisdiction. The DEC, therefore, should consider using the SRBC passby flow guidance, which is environmentally protective and with which the industry is familiar.

Under the NFR methodology, all withdrawals, including those on large river systems, regardless of withdrawal quantity and rate, would require a passby. While many operators have developed storage capacity and all are utilizing recycled waters, uninterrupted withdrawals with predictable availability are important for year-round operations by the industry. Using the NFR methodology would greatly increase the number of days per year that a source point is unavailable, when compared with the SRBC passby guidance. Since source points would be unusable during much of the year under NFR, the industry will be forced to construct a greater number of sources (withdrawal points), potentially increasing the overall habitat impact, and likely reducing the opportunities to share sources among operators. Additionally, industry may need to purchase additional waters from older and larger public water supplies in New York State that may not have undergone the rigorous environmental review currently employed by SRBC. Purchasing water from public water supplies also will increase costs to the industry. The NFR methodology is overly complicated, will be difficult and costly to implement and appears to be administratively burdensome on both the industry and the regulatory agency. Metering and monitoring requirements themselves are projected to exceed an additional \$200,000 per withdrawal location, with no demonstrated environmental benefits over the passby flow guidance conditions implemented by SRBC.

Moreover, the NFR methodology being proposed by the DEC does not take into account its statutory obligation to balance competing water resources as required by Environmental Conservation Law Section 15-0105 and the cases interpreting the balancing obligations of the DEC regarding water consumption and use. The unnecessarily conservative NFR methodology conflicts with this statutory obligation.

All of the concerns expressed by DEC in the prdSGEIS regarding potential water withdrawal impacts, including reduced stream flow, impacts to aquatic habitats and ecosystems, impacts to wetlands, and aquifer depletion, are addressed by the river basin commissions through their extensive water withdrawal regulatory programs. In the prdSGEIS, the DEC itself recognizes that the amount of water withdrawn specifically for HVHF is projected to be low compared to overall water use in New York State, increasing fresh water demand by only 0.24%. In light of this small increase in projected water use and the existing authorities operating in New York State, this proposed duplicative effort is unwarranted. The programs

implemented by SRBC and DRBC are environmentally protective, robust, and should be utilized by DEC for regulating withdrawals by the natural gas industry.

Best Management Practices and Burdensome Costs

The prdSGEIS includes a broad spectrum of specific mitigation measures, some of which DEC refers to as BMPs, others which they simply specify as required mitigation. IOGA of NY believes that this is a misguided approach on the part of DEC. In federal regulations, as well as that of other states, a BMP is normally intended as a practical and effective approach for the mitigation of an environmental impact under a specific set of circumstances. Quite simply, a BMP is not intended to be a one-size-fits-all solution that is also static in time. As such, BMPs should be presented as options that can be selected from in order to meet a site-specific mitigation need. BMPs should not be mandated as the sole required solution, which is how DEC has often presented them; doing so makes them requirements, not options, and, therefore, not BMPs. For instance, in regard to air emissions, the prdSGEIS should not be stipulating “control measures”; instead it should establish “control thresholds” and then allow the air permitting process and proven control technologies to determine the actual control measures applicable to a given set of circumstances.

Additionally, by stipulating specific mitigation measures the prdSGEIS does not effectively provide for the future development of new technologies that may achieve similar, or even better, levels of mitigation. If the roll-out of a new technology requires a specific environmental impact statement and positive determination prior to its use there will be an additional burden on the industry in both expense and time. This review process could cost tens, or even hundreds, of thousands of dollars and take anywhere from six months to two years to work through, causing costly delays in development. Such a process is not conducive to the timely roll-out of new technologies that might improve the industry’s mitigation of environmental impacts. It is quite possible that this could actually serve to significantly hinder the deployment of new technologies in New York even while those same technologies are being successfully implemented in other states. As a result, New York would be behind the curve when it comes to the implementation of improved mitigation approaches for minimizing environmental impacts.

Furthermore, IOGA of NY believes that this could have even broader implications to the long-term useful life of the SGEIS (once it is completed). Early in the SGEIS process (2009), DEC expressed a desire that the resulting document would have a lifespan of decades, not a mere handful of years. The previous GEIS was finalized in 1992, giving it an effective useful life of approximately 20 years. And in many respects the 1992 GEIS continues to apply to the oil and gas industry in New York insofar as activities not involving horizontal drilling and high-volume hydraulic fracturing are concerned. Therefore, the GEIS in fact lives on as a useful document. Considering the rapid evolutionary improvements in industry practices happening in other states, the specific requirement of individual mitigation measures to address impacts associated with horizontal drilling and HVHF which are outlined in the prdSGEIS is likely to limit the valid life of the SGEIS to a number of years that could be counted on the fingers of even a single hand. The supplemental GEIS would itself then require a supplement.

The following provide a few examples but do not encompass all areas of concern:

- The prdSGEIS requires extensive management of invasive species. Each site (well pad and roadway) must first be surveyed for invasive species and a plan must be submitted to DEC for the management of any such plants found. The approach must include the removal and proper destruction/disposal of invasive species prior to initiating construction on the site. During work, all construction equipment, etc., must be inspected and, if necessary, decontaminated whenever the equipment enters or exits the site. The costs and other constraints associated with the invasive

species plan are difficult to predict; however, it would not be unreasonable to anticipate costs associated with plan development, equipment needs and implementation to exceed \$50,000 for every well pad or similar construction task (e.g., compressor stations). IOGA of NY is not aware of other states with such strict requirements.

IOGA of NY would suggest, as an alternative, the requirement to implement BMPs relative to the handling of invasive species common to the area of operations currently utilized by other construction industries active in the area. Absent such a requirement, IOGA of NY is prompted to pose the questions: Does New York place equivalent requirements on the logging and forest products industries that potentially disturb land and vegetation even more extensively than does the oil and gas industry? Also, does New York place equivalent requirements on the logging and forest products industries regarding the restoration and re-vegetation of disturbed land?

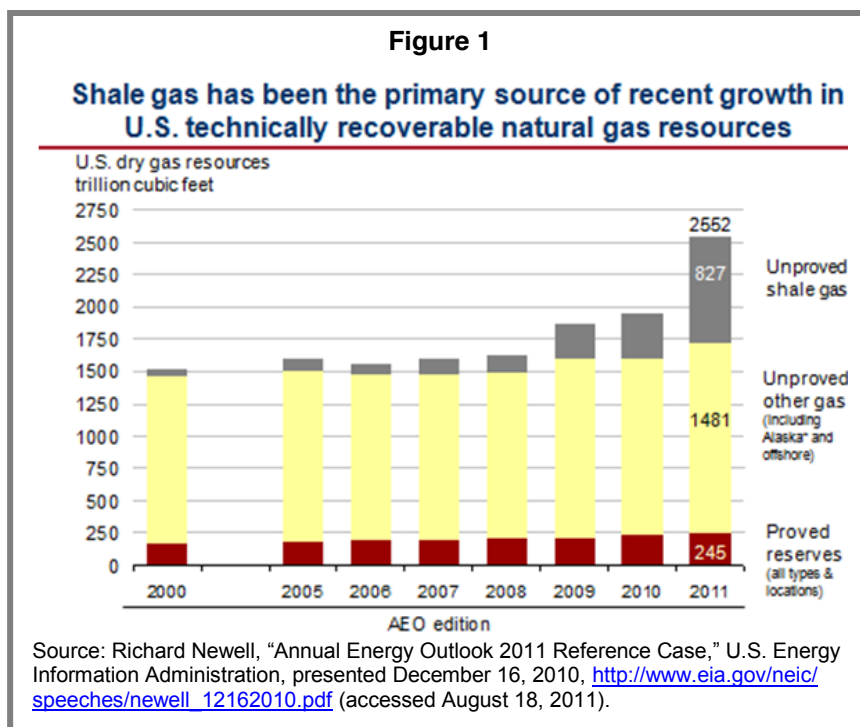
- The detailed invasive species plan is just one of many plans being required by the DEC that will choke the ability of industry to develop New York's indigenous natural gas resources in an economically viable manner. Another example is the requirement to conduct pre-disturbance biological studies and an evaluation of potential impacts on forest interior birds from a proposed project. Pre-disturbance studies by a qualified biologist would be required. These studies must include a compilation of historical information on forest interior birds and a minimum one-year field survey to determine the extent (if any) of such birds' use of the site. Similar pre-development surveys of plants and animals are required as is post-disturbance monitoring. Requiring a one-year pre-disturbance study will mean that many leases will expire without timely development. Industry simply cannot tolerate that kind of regulatory delay. In addition, these types of detailed surveys will add significant expense (\$100,000 or more) for each well pad. These types of studies, delays and expenses simply are not justified for the temporal activities associated with natural gas exploration and development. Again, this is just another example of a burdensome and costly requirement that is being selectively applied to the natural gas industry and will turn that industry away from New York State.
- Retrofitting every engine with Selective Catalytic Reduction (SCR) (not even considering particulate traps), which is difficult if not useless on variable load engines, has not been demonstrated to IOGA of NY's knowledge, and is expected to cost approximately \$140,000 in capital expenditures, plus every year another \$145,000 in operating costs in addition to manpower and reductant (chemical) costs.³ IOGA of NY would suggest guidelines to promote emissions controls such as the promotion of the use of state of the art equipment when available as well as emissions guidelines designed around the temporary nature of most of the equipment utilizing engines.
- In the development of a plan for handling hydrocarbon vapors that may be emitted from crude or condensate tanks, requiring a vapor recovery unit (VRU) for every tank battery is expected to cost upwards of \$80,000 in capital costs per tank battery (plus fuel, operations, and maintenance costs).⁴ Alternatively, a combustion device can be installed at roughly \$22,000 plus another \$1,000 each year in operating costs.⁵ The combustor typically achieves a destruction efficiency of 98% or greater, requires no electricity, is low maintenance, and is more appropriate for sites such as the dry gas development anticipated in New York where insufficient Volatile Organic Compound (VOC) emissions exist to operate the VRU.

Should operators decide to pursue development in New York their costs will no doubt be greater than in other states. One operator has estimated that the cost to drill and complete a generic Marcellus or Utica well will increase by at least \$1,000,000 per well, or more, as a result of the prdSGEIS. This is due to the requirements to obtain waivers from what is anticipated to be overly burdensome rulemaking (as DEC has indicated they are currently contemplating). Furthermore, it is not possible to quantify the additional costs

relating to the delays that must be anticipated due to permitting applications exceeding the capabilities of the DEC to process in a timely manner. In addition, these cost estimates do not take into account the lost investment in mineral leases due to the unworkable setbacks. Required use of add-ons, equipment and limiting best management practices that are not currently used or not readily available with no documented environmental improvement will cost New York billions of dollars to be invested in the state's resource development industry and put New York at a competitive disadvantage to neighboring states.

Shale Gas Economics

According to the Energy Information Administration (EIA), the majority of recent increases in natural gas production and potential are resulting from the emerging shale gas plays (see **Figures 1** and **2**).⁶

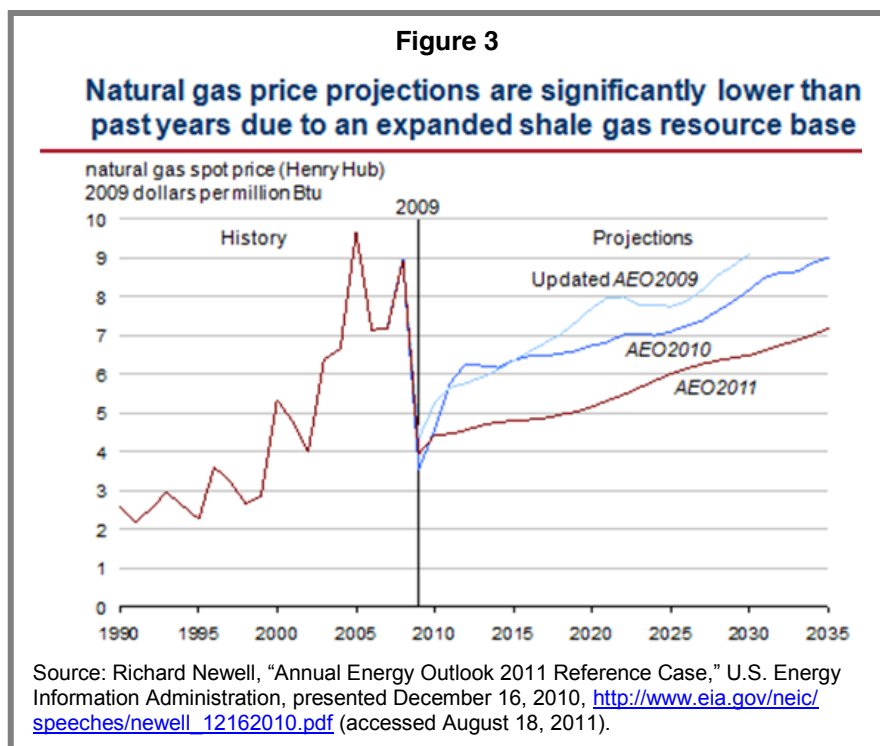
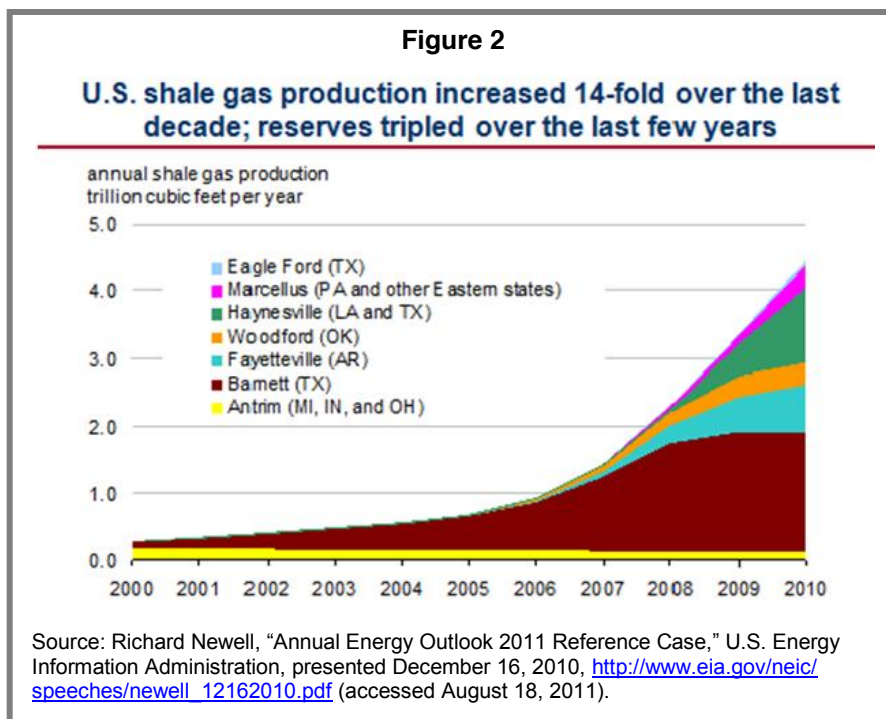


Currently (July 2011), the Henry Hub average spot price for natural gas is \$4.42 per million British thermal units (MMBtu). The average spot price in 2012 is expected to be roughly similar. For the last several years the market prices have been low and are continuing to track at low levels because of high rates of production.⁷ EIA's current outlook for natural gas prices does not rise above \$5.00/MMBtu until approximately 2020 (see AEO 2011 curve on **Figure 3**). Furthermore, for the past three years EIA's long-term projections have predicted lower and lower prices with each year's revisions (see AEO 2009, AEO 2010, and AEO 2011 curves on **Figure 3**).⁸

Based on the above trends indicating increasing natural gas production sourced primarily from shale gas and on the forecast low spot price looking to the future, it should be abundantly clear that the prospects for meaningfully higher gas prices are remote. In order for the profitability of shale gas plays to make a significant leap forward, commodity prices must increase. But there is no such increase predicted.

Figure 2 also demonstrates that there is significant unconventional gas drilling activity in a variety of plays under different state regulatory regimes. As noted above, there is likely to be a significantly higher

cost for operating in New York versus other shale gas states. Therefore, one must anticipate that New York's imposition of additional costs resulting from more demanding mitigation and compliance requirements can only serve to weigh heavily on the profitability of shale gas prospects.



There can be little doubt that, in an effort to maintain profitability in the face of a challenging economic environment, operators must take into consideration where (geographically) their exploration budgets are best allocated. An additional consideration must be that some shale plays such as the Bakken (oil) in Montana and North Dakota, the Eagle Ford Shale (condensate) in Texas, and the Utica Shale (oil) in Ohio, are rich in liquid hydrocarbons. Liquid hydrocarbons serve to significantly improve the drilling economics for these plays in comparison to a dry gas play, such as is expected for the Marcellus in New York. It is interesting to note that, in spite of the shale gas boom, for the first time in 18 years there are more drilling rigs drilling oil wells than there are drilling natural gas wells.⁹ And many of these wells are using the same technologies as shale gas wells: horizontal drilling and HVHF.

Compounding these economic realities is the fact that the productivity of the shale resources in New York remains unproven. There are many factors that can affect future development of the shale resources in New York, not the least of which are depth, thickness, organic content, and thermal maturity of the formation. In fact, many operators anticipate that the intersection of these critical geologic factors will be less favorable in New York than they are in neighboring Pennsylvania based upon core data and other geologic indicators.

As noted above, the cost to drill and complete a typical Marcellus or Utica well will increase by at least \$1,000,000 per wellbore as a result of the prdSGEIS. Therefore, one must anticipate that there is now, and will be for some time, very stiff competition among exploration plays for equipment, qualified personnel and drilling budgets.

Without the opportunity for economically viable development there is a plethora of lost opportunity:

- To operators:
 - Leases lost at great cost to operators because wells could not be drilled in time to satisfy lease requirements because of delays in finalizing the SGEIS.
 - Leases lost at great cost to operators because of setbacks and prohibitions on drilling.
 - Leases that may no longer be developed because not enough contiguous acreage can be assembled to provide the necessary reserves for economically viable prospects.
- To mineral rights owners:
 - With no production from their mineral rights, owners are denied their royalties.
- To business owners:
 - Hotels, restaurants, etc., are unable to participate in the economic gains of increased business. Some of the development areas are already economically challenged and in desperate need of these revenues.
 - Companies providing direct services to the gas industry are reluctant to establish offices in New York to support an industry with uncertain local future, particularly when one considers that such business opportunities are much more attractive in neighboring states where drilling and production are already occurring in more favorable economic climates.
- To the local and state governments:
 - New York has already lost major economic opportunities as operators and service companies have already established permanent offices/facilities in the Northern Tier of Pennsylvania.

- Lease bonus and royalty payments for mineral rights on lands that will not be developed as a result of prohibitions and the corresponding loss of income tax revenue to the state.
- Tax revenues that result from the robust *ad valorem* tax system applicable to oil and gas development in New York State that will be lost at a time when it is most needed.
- Tax revenues from all associated businesses that will not be realized without development.
- To the citizens of New York:
 - The benefits of tax revenues from development reinvested in state and community infrastructure and services.
 - The benefits of participating in the potential economic growth that would come with gas development.

These are but a few of the examples of opportunities that have been and/or will be lost without an opportunity for timely and economically viable development of shale gas resources.

Summary

In summary, industry recognizes that there are numerous challenges to crafting a well informed regulatory framework for hydrocarbon development with the proven technologies of horizontal drilling and hydraulic fracturing that is simultaneously protective of the environment and the rights of the citizens and still encourages the investment of capital and creation of jobs and wealth. The prdSGEIS and the parallel rule-making process will not facilitate industry investment in New York's hydrocarbon resources. The already long and drawn-out process of developing the SGEIS and the anticipated highly restrictive regulatory framework for New York exploration has already destroyed real economic value for mineral owners, towns, the state as well as the investors and operators who have thus far had the courage to invest in New York.

Also the economic uncertainty of commodity prices compounded by the costs of SGEIS-imposed mitigation requirements weighs heavily on sensitive drilling economics. These uncertainties are further complicated by the fact that there has as yet to be a single horizontal well drilled and stimulated using HVHF in New York; consequently, there is still no in-state local benchmark with which to better predict production.

The limitations imposed by the prdSGEIS and, we expect, the regulations likely to emerge from the rule making process will make the exploration and development of unconventional natural gas in New York non-economic and unattractive. IOGA of NY anticipates that there will be every incentive for industry to spend their exploration and production budgets in states with more pragmatic regulations. Furthermore, shale plays that are rich in liquid hydrocarbons, such as the nearby Utica Shale in Ohio, will sport more favorable economics. As noted herein, the prdSGEIS proposes to impose mitigation solutions with, in some cases, limited environmental benefit and little or no flexibility in how operators may implement them. New York's regulations and requirements, if finalized, will be viewed by industry as too challenging and restrictive to allow for cost-competitive development in the current and forecast natural gas market. Thus, New York is rapidly moving towards, and showing all signs of becoming, non-competitive with other states in its ability to attract industry's development dollars.

In the final analysis, the regulatory proposals being put forth by the DEC relative to shale gas development in New York State do not send the signal that New York State is "open for business." Not only does this conflict with statutory mandate of the DEC to promote the development of the resource and

protect the correlative rights of landowners, it is in direct conflict with recent efforts to promote that New York State is "open for business." Taken in total, these proposals do not provide necessary assurances to our members that they can be successful in exploration and development in New York. If the State fails with the biggest economic opportunity available to it through the development of its clean-burning, indigenous natural gas resources, New York policymakers must understand the message that this will send to all industries.

Sincerely,
Independent Oil and Gas Association of New York,



Brad Gill
Executive Director

xc: Andrew M. Cuomo, Governor
Marc Gerstman, Executive Deputy Commissioner
Eugene Leff, Deputy Commissioner, Remediation and Materials Management
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¹ EPA, 40 CFR Parts 60 and 63, EPA-HQ-OAR-2010-0505, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, <http://www.epa.gov/ttn/atw/oilgas/fr23au11.pdf> (accessed August 26, 2011).

² EPA, 40 CFR Parts 60 and 63, EPA-HQ-OAR-2010-0505, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, <http://www.epa.gov/ttn/atw/oilgas/fr23au11.pdf> (accessed August 26, 2011).

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⁵ Albert Hendler, Jim Nunn, Joe Lundeen, and Ray McKaskle, *VOC Emissions From Oil and Condensate Storage Tanks*, Final Report (October 31, 2006, revised April 2, 2009), Table 4-2, <http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf> (accessed August 19, 2011).

⁶ Richard Newell, "Annual Energy Outlook 2011 Reference Case," U.S. Energy Information Administration, presented December 16, 2010, http://www.eia.gov/neic/speeches/newell_12162010.pdf (accessed August 18, 2011).

⁷ Energy Information Administration (EIA), "Short-Term Energy Outlook" (August 9, 2011), <http://www.eia.gov/emeu/steo/pub/contents.html> (accessed August 18, 2011).

⁸ Richard Newell, "Annual Energy Outlook 2011 Reference Case," U.S. Energy Information Administration, presented December 16, 2010, http://www.eia.gov/neic/speeches/newell_12162010.pdf (accessed August 18, 2011).

⁹ Tom Fowler, "More Rigs Now Drill for Oil," *Houston Chronicle* (August 18, 2011), <http://www.chron.com/dispatch/story.mpl/business/energy/7702262.html> (accessed August 18, 2011).

Attachment A
Stormwater General Permit
Supporting Information

Federal Stormwater Permit Exemptions for the Oil & Gas Extraction Industry

Uncontaminated stormwater discharges associated with oil and gas extraction activities are exempt from the federal National Pollutant Discharge Elimination System (NPDES) program and therefore from the NY State Pollutant Discharge Elimination System (SPDES) program as well.

The 1987 Water Quality Act (WQA) added section 402(l)(2) to the Clean Water Act (CWA) specifying that the U.S. Environmental Protection Agency (EPA) and States shall not require NPDES permits for uncontaminated storm water discharges from oil and gas exploration, production, processing or treatment operations, or transmission facilities.

Section 323 of the Energy Policy Act of 2005 clarifies and strengthens the CWA NPDES exemption by defining the term "oil and gas exploration, production, processing, or treatment operations or transmission facilities" to mean "all field activities or operations associated with exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activity." See 33 U.S.C. §1362(24).

RQ Release as the Industrial Stormwater Permit Threshold for the Oil and Gas Extraction Sector

The current SPDES Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activities (GP-0-06-002) recognizes the federal exemption for uncontaminated stormwater discharges. The Multi-Sector GP states that the permit applies to "stormwater discharges associated with industrial activity from oil and gas extraction ... which have had a discharge of a reportable quantity (RQ) of oil or a hazardous substance for which notification is required under [federal regulations]." It also stipulates that operators must include information in the Stormwater Pollution Prevention Plan (SWPPP) that accompanies a Notice of Intent "about the RQ release which triggered the permit application requirements." The information in the SWPPP must include a thorough description of the nature and scope of the RQ release and its environmental impacts.

The proposed high volume hydraulic fracturing (HVHF) General Permit (GP) should mirror these provisions and provide relief from the permitting requirements until the operator reports a RQ release at the site.

SPDES General Permit for Construction Activity

Beginning in April 2010, the New York State Department of Environmental Conservation (DEC) started to require operators to obtain Construction Stormwater General Permit coverage for Article 23 drilling activities that are exempt from the Multi-Sector GP. The construction permit is now imposed whenever well activities requiring an Article 23 well drilling permit disturbs one or more acres of land. The proposed HVHF GP would continue and expand upon the current stormwater permitting requirements.

Until last April, the DEC acknowledged the federal exemption for construction activities by regulating well site development to avoid pollution via stormwater runoff through the Article 23 well permitting program. The DEC imposed the SPDES Construction Stormwater General Permit requirement after a federal court decision, in *Natural Resources Defense Council v. United States Environmental Protection Agency*, 526 F.3d 591 (9th Cir. 2008), which vacated EPA's 2006 oil and gas construction stormwater regulation.

The court decision vacating the EPA rule did not overturn the underlying federal law, however, so the NPDES permit exemption for uncontaminated stormwater discharges from oil and gas activities and facilities remains in place.

In Pennsylvania, the Department of Environmental Protection (DEP) responded to the 2005 Energy Policy Act clarification of the CWA exemption and the court action vacating the associated EPA rule by

acknowledging the continuing exemption but imposing a streamlined state-specific permit regime that accomplishes the same objectives of the federal program. The DEP's ESCGP-1 provides an expedited permit process for earth disturbance activities associated with oil and gas exploration, production, processing or treatment operations or transmission facilities that disturb five or more acres.

ESCGP-1 requires the submission of a robust Erosion and Sediment Control Plan that must contain best management practices (BMPs) designed to minimize point source discharges to surface waters, preserve the integrity of stream channels and protect the physical, biological and chemical qualities of the receiving water. The plan must also address Special Protection requirements when earth disturbance activities occur in a High Quality or Exceptional Value watershed or Exceptional Value wetlands. The permit also requires operators to ensure that proposed construction activity will not adversely impact threatened and endangered plant and animal species and their critical habitats by requiring proof that a Project Planning Environmental Review was conducted and any possible impacts were reviewed and mitigated through work with the various state and federal agencies with jurisdictional responsibility for the listed species.

DEP has also established an expedited permit review procedure for the ESCGP-1 that can be utilized for oil and gas activities other than transmission facilities. Applicants that follow the expedited review process and qualify for permit coverage will be provided with an acknowledgement of coverage under ESCGP-1 within 14 business days from the submission of a complete and acceptable Notice of Intent (NOI).

Under the terms of a recent settlement of litigation initiated by the Chesapeake Bay Foundation, the ESCGP-1 will no longer be available for projects potentially affecting Special Protection water bodies or for those located in a floodplain or on contaminated land. Instead, the DEC plans to develop a new ESCGP-2 that will expand the period for public review of a proposed earth disturbance and require a more detailed technical review of the application.

DEC's decision to impose the full SPDES stormwater permit program on oil and gas extraction activities that continue to be exempt from the federal program was unnecessary and need not be expanded through the HVHF GP. Instead, the DEC should consider adopting a General Permit program that incorporates the advantages provided to both the DEC and to operators by the Pennsylvania ESCGP-1. Expedited permit review does not translate into reduced environmental protection.

The following paragraphs provide additional information:

- Transition from the Construction Phase of Permit Coverage – Final stabilization requirements in Part VI.D.2. and Part VIII.A.3. stipulate that the operator must provide written certification of the completion of all construction activities to the DEC before HVHF operations can begin. The HVHF Phase cannot begin until the Construction Phase is complete. These provisions appear to create artificial barriers to drilling multiple wells on a single pad.
- HVHF Fluid Evaluation – New HVHF SWPPP content provisions in Part IX.A.A.1. require operators to evaluate HVHF Phase fluid additives for each well stimulation project and use HVHF additives that exhibit the least aquatic toxicity and pose the least risk to water resources and the environment. In the alternative, the provisions require the operator to provide documentation to the DEC's satisfaction that some of the available alternative products are not equally effective or feasible.

The requirements assume that hydraulic fracturing (HF) additives are constantly changing, equally effective, universally available, and not subject to trade secret protections. It includes no standards for demonstrating the validity of a HF additive selection decision to the DEC, and no criteria for assessing DEC satisfaction. This requirement exists in no other state program should be deleted.

- Site Map Requirements – Part IX (Contents of the HVHF SWPPP) requires mapping of a variety of resources, facilities and activities that extend well beyond the scope of site map requirements imposed on all other industrial sectors in the Multi-Sector GP.

Current requirements in the Multi-Sector GP at Part III.C.2., together with the provisions in Sector I for Oil and Gas Extraction and Refining, provide thorough site mapping instruction without being overly prescriptive. The current Multi-Sector GP provisions are adequate to address the needs of the SGEIS.

- Required non-structural BMPs – The current Multi-Sector GP provides substantial flexibility to the operator to select structural and non-structural BMPs for use at the regulated facility. The proposed HVHF GP should mirror that flexibility in Part IX.B. by eliminating unnecessary requirements related to:
 1. Good housekeeping,
 2. Minimizing exposure,
 3. Preventative maintenance,
 4. SPCC requirement,
 5. Routine site inspections,
 6. Records of inspection, and
 - 7.a. and c. Employee training.
- BMPs and Benchmark Monitoring – The BMP provisions in Part X of the HVHF GP are far too numerous and prescriptive. The proposed HVHF GP should track the current Multi-Sector GP by providing as much flexibility in BMP selection to the owner or operator as possible.

The benchmarking requirements in Part X are excessive, given the purpose of stormwater outfall monitoring as stipulated in section 3.e. (Benchmark/Compliance Monitoring and Analysis):

The benchmark monitoring cut-off concentrations are intended as a guideline for the owner or operator to determine the overall effectiveness of the HVHF SWPPP in controlling the discharge of pollutants to receiving waters. The benchmark concentrations do not constitute direct numeric effluent limitations and, therefore, an exceedance is not a general permit violation. However, the owner or operator must evaluate potential sources of stormwater contaminants at the HVHF operation. Any sources of contamination that are identified must be remedied.

Unlike the proposed HVHF GP, the Multi-Sector GP only requires benchmark monitoring for Total Suspended Solids (TSS), chlorides and pH in the oil and gas extraction sector. These three parameters serve as surrogates for any potential pollution that may enter receiving waters from the facilities' outfalls. They provide reliable indicators that further analysis may be warranted to determine whether other potential pollutants may be discharging through a stormwater outfall.

The following sections of Part X of the HVHF GP contain unnecessarily prescriptive BMPs, impose excessive benchmark monitoring requirements, and in some cases are more appropriately regulated in other programs:

- B. Well-Drilling and High Volume Hydraulic Fracturing
- C. Vehicle and equipment storage/maintenance areas
- D. Vehicle equipment and cleaning areas
- E. Fueling areas

- F. Materials and chemical storage areas
- G. Chemical mixing, material handling and loading/unloading areas
- H. Chemical/fluid storage areas
- I. Employee housing and sanitary facilities
- J. Piping/conveyances
- K. Lumber storage or processing areas
- L. Cement mixing
- M. Freshwater surface impoundments and reserve pits
- N. Well production phase

All should be replaced with flexible narrative standards for BMP selection. Pennsylvania's NPDES General Permit for Discharges of Stormwater Associated with Industrial Activities (PAG-03) provides an appropriate model. In Appendix J (additional facilities), PAG-03 specifies the following BMPs for the oil and gas extraction sector:

1. Perform periodic inspections and maintenance on all transfer areas, piping, pumps, valves, compressors and other equipment where failure/leaks could cause petroleum releases.
2. Ensure secondary containment and leak detection for all petroleum product tanks and produced water tanks at exploration sites.
3. Develop and implement a detailed spill response plan, including immediate clean-up of petroleum residues and contaminated soils potentially exposed to stormwater.
4. Reclaim produced water pits and other disturbed areas at extraction sites immediately upon well closure.
5. Provide for oil-water separators to treat runoff from all areas where there is potential exposure to petroleum products.

In addition, the Benchmark Monitoring requirements in all of the foregoing sections should be eliminated and replaced with provisions that reflect the current Multi-Sector GP requirements for the oil and gas sector with targeted supplemental sampling and analysis if needed. The specific monitoring parameters listed for each type of facility or activity that could be associated with a well site would more appropriately serve as supplemental investigative tools if benchmark monitoring at an outfall indicates potential stormwater contamination.

- Annual Inspections in lieu of Benchmark Monitoring – Pennsylvania's PAG-03 allows oil and gas extraction industry permittees to conduct an Annual Inspection in lieu of benchmark monitoring. The facilities are only required to monitor annually due to the medium risk associated with stormwater discharges that they pose.

The Annual Inspection reports provide information on the overall quality of the discharges, focus on industry specific pollutants of concern, and are useful to help determine the effectiveness of pollution prevention plan controls. The Annual Inspection must include visual inspection of all outfalls and a Comprehensive Site Compliance Evaluation that applies to every outfall on the site. The visual inspection must identify any substances present in the sediment. The Annual Inspection/Certification must identify all areas that may be contributing pollutants to stormwater discharges and evaluate whether measures to reduce pollutant loadings identified in the Preparedness, Prevention, and Contingency (PPC) Plan are adequate and properly implemented in accordance with terms of the General Permit or whether additional control measures are necessary.

The DEC should incorporate a similar annual inspection option into the HVHF GP in addition to the streamlined benchmark monitoring suggested above to replace the requirements included in current HVHF GP proposal.

Documents referenced

New York documents

New York State Department of Environmental Conservation. *SPDES Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity*. Permit No. GP-0-06-002. December 2006. http://www.dec.ny.gov/docs/water_pdf/gp0601.pdf (accessed September 1, 2011).

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Pennsylvania documents

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**Attachment B
Air Emissions
Supporting Information**

Selected Air Quality Issues in the Preliminary Revised Draft SGEIS (prdSGEIS) dated July 2011

With the Preliminary Revised Draft Supplemental Generic Environmental Impact Statement (prdSGEIS) the New York State Department of Environmental Conservation (DEC) is seeking to establish statewide regulations and mitigation requirements that conflict with existing and/or proposed U.S. Environmental Protection Agency (EPA) air quality regulations pertaining to the same emission sources. Furthermore, the EPA regulations allow for a more flexible approach to satisfying the goals of reduced emissions than do the prescriptive mitigation requirements of the prdSGEIS.

On August 23, 2011, the EPA proposed new standards for the oil and gas sector (sector).¹ The rule proposes a cost-effective regulation based upon proven technologies that would reduce air pollution from the sector while enabling responsible growth in U.S. oil and natural gas production. For the upstream sector the rule primarily targets wells that are hydraulically fractured (both new wells and workover operations), emissions from storage tanks, pneumatic device fugitive emissions, and some glycol dehydrators.² A good example of mandated controls in the prdSGEIS conflicting with the EPA's recently passed regulations is the New Source Performance Standard (NSPS) OOOO. The new NSPS contains work practice standards for all new well completions. The standard requires reduced emissions completions (REC) for all completions where a sales pipeline is available and flaring of the vented gas if a good reason for not conducting a REC is documented. Therefore, the prdSGEIS does not need to address completions venting since a national standard has been proposed. The proposed NSPS is now in its 60-day public comment period after which the EPA must take final action by February 28, 2012.³ EPA's proposed rule is expected to cut volatile organic compound (VOC) emissions from the sector by nearly one-fourth nationwide (540,000 tons), methane emissions by 65 million tons of carbon dioxide equivalent, and air toxics by 38,000 tons every year. EPA estimates that industry's combined annual costs for complying with the new rule will be \$754 million by 2015.⁴

In the past few years, EPA has also passed multiple new rules targeting engines including those used in the oil and gas sector.

- On August 20, 2010, the EPA finalized a rule for reciprocating internal combustion engines (40 CFR Part 63, Subpart ZZZZ).⁵ This rule complemented an earlier rule by pulling into regulation engines located at smaller sources and engines less than 500 horsepower (hp).⁶ EPA estimated this rule would reduce hazardous air pollutant (HAP) emissions by 6,000 tons per year (tpy), carbon monoxide by 109,000 tpy, VOCs by 31,000, and nitrogen dioxides by 96,000 tpy at a cost of \$253 million (in 2013 dollars).⁷
- In 2008 EPA passed several new rules targeting new and reconstructed engines (estimated to affect over 433,000 stationary engines nationwide). This rule was expected to reduce nitrogen dioxides by 84,000 tpy, carbon monoxide by 49,000 tpy, VOCs by 2,400 tpy, and HAP emissions by 900 tpy at a cost of \$44 million initially and another \$20 million annually.⁸
- Diesel engines that are not classified as stationary engines (i.e., including diesel drill rig and completion engines) were also targeted by the EPA. Since 2004, the EPA has been passing comprehensive rules to reduce emissions from these engines by integrating engine and fuel controls as a system and mandating the use of ultra low sulfur diesel fuel. EPA estimated that the new rules would reduce levels of sulfur in the fuel by more than 99% and both nitrogen dioxides and particulate emissions by 90% by 2030.⁹

All of the above new and proposed regulations have been enacted following EPA's rigorous review process that considers nationwide applicability, cost effectiveness, and proven control technologies and all have been passed within the last seven years. The extent and magnitude of these rules is seen in the emissions reductions, compliance costs, and lengthy federal notices that describe each rule. These rules

target the very same emission sources for which the DEC has proposed their own prescriptive mitigation controls based largely on a worst-case dispersion modeling scenario. Setting inflexible emissions controls based upon such a scenario is not justified for all areas of the state, at all times of the year, and for every operator. The DEC is requiring specific air emissions controls that include or apply to reduced emissions completions, benzene and other glycol dehydrator emissions, storage tanks, engine add-on controls, and venting emissions during well completions. These are all well regulated by the recent EPA enactments. New York is dealing with very similar air quality issues as many other locations around the country and the EPA rules were designed to allow for responsible development of new energy sources while greatly reducing the levels of air pollution nationwide. It is inappropriate for the DEC to mandate additional, inflexible emissions controls on these proposed sources that are not proven, not cost-effective, and that may even be unsafe in some cases.

Remove SCR control requirements for the completion equipment engines

Several concerns arise when considering these add on controls. First, the prdSGEIS needs to clarify that only the large (>2,000 horsepower [hp]) fracturing pump engines are at issue. Second, the technical requirements and costs to add Selective Catalytic Reduction (SCR) control to existed fracturing pump engines that must meet weight, height, length and width requirements for transport on tractor trailers are immense, if not technically infeasible. Indeed, we are not aware of any successful demonstration of SCR control on completion equipment engines. Moreover, no other state has such a requirement. Third, the basis for this SCR requirement is modeled exceedance of the new 1-hr nitrogen dioxide (NO₂) National Ambient Air Quality Standards (NAAQS). The NO₂ standard has been very difficult to meet causing the EPA to acknowledge the specific problem of modeling potential emissions from intermittent sources. In a March 11, 2011, guidance document from EPA's Air Quality Modeling Group, EPA acknowledges the specific problem of modeling potential emissions from intermittent sources, such as emergency engines that operate less than 500 hours per year.¹⁰ In regard to "Treatment of Intermittent Emissions," EPA states in part:

TREATMENT OF INTERMITTENT EMISSIONS

Modeling of intermittent emission units, such as emergency generators, and/or intermittent emission scenarios, such as startup/shutdown operations, has proven to be one of the main challenges for permit applicants undertaking a demonstration of compliance with the 1-hour NO₂ NAAQS. Prior to promulgation of the new 1-hour NO₂ standard, the only NAAQS applicable for NO₂ was the annual standard and these intermittent emissions typically did not factor significantly into the modeled design value for the annual standard. Sources often take a 500 hour/year permit limit on operation of emergency generators for purposes of determining the potential to emit (PTE), but may actually operate far fewer hours than the permitted limit in many cases and generally have not been required to assume continuous operation of these intermittent emissions for purposes of demonstrating compliance with the annual NAAQS. *Due in part to the relatively low release heights typically associated with emergency generators, an assumption of continuous operation for these intermittent emissions would in many cases result in them becoming the controlling emission scenario for determining compliance with the 1-hour standard [emphasis added].*

EPA's guidance in Table 8-2 of Appendix W involves a degree of conservatism in the modeling assumptions for demonstrating compliance with the NAAQS by recommending the use of maximum allowable emissions, which represents emission levels that the facility could, and might reasonably be expected to, achieve if a PSD permit is granted. However, *the intermittent nature of the actual emissions associated with emergency generators and startup/shutdown in many cases, when coupled with the probabilistic form of the standard, could result in modeled impacts being significantly higher than actual impacts would realistically be expected to be for these*

emission scenarios. The potential overestimation in these cases results from the implicit assumption that worst-case emissions will coincide with worst-case meteorological conditions based on the specific hours on specific days of each of the years associated with the modeled design value based on the form of the hourly standard [emphasis added]. In fact, the probabilistic form of the standard is explicitly intended to provide a more stable metric for characterizing ambient air quality levels by mitigating the impact that outliers in the distribution might have on the design value. The February 9, 2010, preamble to the rule promulgating the new 1-hour NO₂ standard stated that “it is desirable from a public health perspective to have a form that is reasonably stable and insulated from the impacts of extreme meteorological events.” 75 FR 6492. Also, the Clean Air Science Advisory Committee (CASAC) “recommended a 98th-percentile form averaged over 3 years for such a standard, given the potential for instability in the higher percentile concentrations around major roadways.” 75 FR 6493.

To illustrate the importance of this point, consider the following example. Under a deterministic 1-hour standard, where the modeled design value would be based on the highest of the second-highest hourly impacts (allowing one exceedance per year), a single emission episode lasting 2 hours for an emergency generator or other intermittent emission scenario could determine the modeled design value if that episode coincided with worst-case meteorological conditions. While the probability of a particular 2-hour emission episode actually coinciding with the worst-case meteorological conditions is relatively low, there is nonetheless a clear linkage between a specific emission episode and the modeled design value. By contrast, under the form of the 1-hour NO₂ NAAQS only one hour from that emission episode could contribute to the modeled design value, i.e., the daily maximum 1-hour value. However, *by assuming continuous operation of intermittent emissions the modeled design value for the 1-hour NO₂ NAAQS effectively assumes that the intermittent emission scenario occurs on the specific hours of the specific days for each of the specific years of meteorological data included in the analysis which factor into the multiyear average of the 98th-percentile of the annual distribution of daily maximum 1-hour values. The probability of the controlling emission episode occurring on this particular temporal schedule to determine the design value under the probabilistic standard is significantly smaller than the probability of occurrence under the deterministic standard; thereby increasing the likelihood that impact estimates based on assuming continuous emissions would significantly overestimate actual impacts for these sources [emphasis added].*

Given the implications of the probabilistic form of the 1-hour NO₂ NAAQS discussed above, we are concerned that assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself. As a result, we feel that it would be inappropriate to implement the 1-hour NO₂ standard in such a manner and recommend that compliance demonstrations for the 1-hour NO₂ NAAQS be based on emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. EPA believes that existing modeling guidelines provide sufficient discretion for reviewing authorities to exclude certain types of intermittent emissions from compliance demonstrations for the 1-hour NO₂ standard under these circumstances [emphasis added].

EPA’s *Guideline on Air Quality Models* provides recommendations regarding air quality modeling techniques that should be applied in preparation or review of PSD permit applications and serves as a “common measure of acceptable technical analysis when supported by sound scientific judgment.” 40 C.F.R. Part 51, Appendix W, section 1.0.a. While the guidance establishes principles that may be controlling in certain circumstances, the guideline is not “a strict modeling ‘cookbook’” so that, as the guideline notes, “case-by-case analysis and judgment are frequently required.” Section 1.0.c. In particular, with respect to emissions input data, section 8.0.a. of

Appendix W establishes the general principle that “the most appropriate data available should always be selected for use in modeling analyses,” and emphasizes the importance of “the exercise of professional judgement by the appropriate reviewing authority” in determining which nearby sources should be included in the model emission inventory. Section 8.2.3.b.

For the reasons discussed above, EPA believes the most appropriate data to use for compliance demonstrations for the 1-hour NO₂ NAAQS are those based on emissions scenarios that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations [emphasis added]. Section 8.1.1.b of the guideline also provides that “[t]he appropriate reviewing authority should be consulted to determine appropriate 10 source definitions and for guidance concerning the determination of emissions from and techniques for modeling various source types.” *When EPA is the reviewing authority for a permit, for the reasons described above, we will consider it acceptable to limit the emission scenarios included in the modeling compliance demonstration for the 1-hour NO₂ NAAQS to those emissions that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations [emphasis added].* Consistent with this rationale, the language in Section 8.2.3.d of Appendix W states that “[i]t is appropriate to model nearby sources only during those times when they, by their nature, operate at the same time as the primary source(s) being modeled” [emphasis in original]. While we recognize that these intermittent emission sources *could* [emphasis added] operate at the same time as the primary source(s), the discussion above highlights the additional level of conservatism in the modeled impacts inherent in an assumption that they do *in fact* [emphasis added] operate simultaneously and continuously with the primary source(s).

It is clear from this EPA memo that agencies should not require compliance with the 1-hour NO₂ NAAQS for intermittent stationary emissions. This would logically apply even more for temporary non-stationary intermittent sources such as completion engines. The fracturing pump engines only emit maximum emissions for a short time for each fracturing stage. Assuming 8 fracturing stages and 2 hours of maximum fracturing pump emissions, the maximum emissions would occur only 16 hours per well. For ten wells that is only 160 hours/year, much less than 500 hours for an emergency generator. Someone might argue that the average emissions from each fracturing job should be modeled to demonstrate compliance with the 1-hour NO₂ NAAQS. However, assuming 8 fracturing stages per well for 5 hours per fracturing stage, gives 40 hours per well. For ten wells that is only 400 hours per year.

Even if completion service companies could eventually overcome the technical mountain to retrofit existing fracturing pump engines with SCR, the cost would be very substantial. Retrofitting every engine with SCR (not even considering particulate traps) is expected to cost at least \$140,000 in capital expenditures, plus every year another \$145,000 in operating costs in addition to manpower and reductant costs.¹¹ Hydraulic fracturing a well is a massive operation and adding the additional operational burden of trying to maintain an SCR control system on fracturing pump engines that only run at maximum horsepower for a very limited time period would create additional safety hazards. An additional safety concern is the storage, transport, and handling of the reductant (e.g., ammonia or urea). Operating such a system involves precise exhaust temperature regulation, unplanned injection system cut-offs, and extensive operator attention. It is doubtful if operators could maintain the emissions reductions target given the large and sudden load swings these diesel engines experience. EPA’s rules aimed at controlling air emissions from nonroad diesel equipment call for new engines with advanced emission control technologies that integrate the engine with the appropriate fuel control that results in reductions of more than 90% of nitrogen oxides (NO_x) and Particulate Matter (PM) emissions.¹²

The only rationale given in the prdSGEIS for requiring SCR on the completion engines was to demonstrate compliance with the 1-hour NAAQS. Based on the above, compliance with the 1-hour NO₂ NAAQS is not necessary and neither is the SCR control requirement. Combining the mandated use of

Ultra Low Sulfur Diesel fuel along with the appropriate diesel Tier standard provides safe, available (or soon will be), and appropriate emissions controls for this equipment. It is both counterproductive environmentally and cost inefficient to require the use of additional add-on control technologies, such as adding SCR control to the completion engines, which may not be readily available, effective, or safe to operate.

Remove particulate filter traps (CRDPF) control requirements for the completion equipment engines if air modeling based on a more appropriate PM emissions rate demonstrates compliance with the PM₁₀ and PM_{2.5} NAAQS

The DEC has assumed that particulate traps are feasible add-on controls regardless of the engine's size, purpose, or hours of operation and, based upon that assumption, DEC is mandating the use of this control measure. This approach fails to consider the potential issues that can arise when multiple add-on controls are used. For instance, the added fuel use to operate particulate traps raises NO₂ emissions, followed by higher NO_x to NO₂ conversions when traps are used, and the possibility of particulate contamination of the catalyst, etc. This is one of the reasons the EPA chose advanced emission control technologies that integrate with the engine.

While the guidance on modeling intermittent emissions above was for the 1-hour NO₂ NAAQS, the same rationale applies to the 24-hour PM₁₀ and PM_{2.5} NAAQS. At the very least, the DEC should accept the industry's previous comments that the average PM emissions rate of 1.9 pound per hour (lb/hr) should be used for modeling instead of the maximum PM emissions rate of 6.6 lb/hr. In fact, EPA guidance for intermittent emissions when modeling for the 1-hour NO₂ NAAQS recommends using an average emissions rate based on 8,760 hours. From the same EPA memo on Treatment of Intermittent Emissions for air modeling of the 1-hour NO₂ NAAQS:¹³

Another approach that may be considered in cases where there is more uncertainty regarding the applicability of this guidance would be to model impacts from intermittent emissions based on an average hourly rate, rather than the maximum hourly emission. For example, if a proposed permit includes a limit of 500 hours/year or less for an emergency generator, a modeling analysis could be based on assuming continuous operation at the average hourly rate, i.e., the maximum hourly rate times 500/8760. This approach would account for potential worst-case meteorological conditions associated with emergency generator emissions by assuming continuous operation, while use of the average hourly emission represents a simple approach to account for the probability of the emergency generator actually operating for a given hour. Also note that the contribution of intermittent emissions to annual impacts should continue to be addressed as in the past to demonstrate compliance with the annual NO₂ standard.

Following the above approach, a PM emissions rate of 0.38 lb/hr would be appropriate for the 24-hour PM₁₀ and PM_{2.5} NAAQS. (6.6 lb/hr x 500/8760 = 0.38 lb/hr).

The only rationale given in the prdSGEIS for requiring particulate filter traps (CRDPF) on the completion engines was to demonstrate compliance with the 1-hour PM₁₀ and PM_{2.5} NAAQS. Additional air modeling using one of the methods above may demonstrate compliance with these standards. No other states require particulate filter traps on these engines, nor do they require compliance with the NAAQS for non-road engines.

Remove the requirement for use of a VRU for every condensate storage tank

Mandating the use of vapor recovery units (VRUs) on all condensate tanks is inappropriate. This requirement is not technically feasible in most well sites that produce little condensate. EPA acknowledges this in the new NSPS Subpart OOOO and allows the use of a combustion device or a

vapor recovery system for condensate storage tanks that would emit more than 6 tpy of VOC (presently based on a condensate throughput threshold of only 1 barrel of oil equivalent per day of condensate or 20 barrels of oil per day).

A VRU requires a pressurized system to handle pressure surges during separator dumps; therefore, safety becomes an issue of concern. It takes a minimum amount of vent gas to technically and safely operate a VRU (around 10,000 to 12,000 standard cubic feet/day [SCFD]). In the absence of sufficient emissions to operate a VRU, a combustion system is typically the most appropriate mitigation device. In a Texas study of 22 tank batteries in the Dallas-Fort Worth and Houston-Galveston-Brazoria regions, only 3 of those tank batteries produced sufficient flow rates (i.e., above 12,000 SCFD) to operate a VRU.¹⁴ Since the Marcellus Shale in New York is expected to produce dry gas, there will be little if any condensate or crude to potentially produce flashing emissions. Therefore, requiring their use in this area for every tank battery is expected to be unsafe and inappropriate. Implementing each VRU system can cost upwards of \$80,000 in capital costs per tank battery (plus fuel, operations, and maintenance costs),¹⁵ while a combustion device can be installed at roughly \$22,000 plus another \$1,000 each year in operating costs.¹⁶ The combustor typically achieves a destruction efficiency of 98% or greater, requires no electricity, is low maintenance, and is more appropriate for sites where insufficient VOC emissions exist to operate the VRU. The prdSGEIS does not need to address controls on condensate storage tanks since a national standard has been proposed

Remove the limit of 5 million standard cubic feet (MMSCF) of gas that may be vented from completions from one well pad in any 12-month period

The EPA's proposed new NSPS Subpart OOOO for the oil and gas industry contains work practice standards for all new well completions. The standard requires RECs for all completions where a sales pipeline is available and flaring of the vented gas if a good reason for not conducting a REC is documented. Therefore, the prdSGEIS does not need to address completions venting since a national standard has been proposed.

¹ EPA, 40 CFR Parts 60 and 63, EPA-HQ-OAR-2010-0505, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, <http://www.epa.gov/ttn/atw/oilgas/fr23au11.pdf> (accessed August 26, 2011).

² EPA, 40 CFR Parts 60 and 63, EPA-HQ-OAR-2010-0505, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, <http://www.epa.gov/ttn/atw/oilgas/fr23au11.pdf> (accessed August 26, 2011).

³ EPA, 40 CFR Parts 60 and 63, EPA-HQ-OAR-2010-0505, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, <http://www.epa.gov/ttn/atw/oilgas/fr23au11.pdf> (accessed August 26, 2011).

⁴ EPA, 40 CFR Parts 60 and 63, EPA-HQ-OAR-2010-0505, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, <http://www.epa.gov/ttn/atw/oilgas/fr23au11.pdf> (accessed August 26, 2011).

⁵ EPA, 40 CFR Part 63, EPA-HQ-OAR-2008-0708, National Emission Standards for Reciprocating Internal Combustion Engines, <http://www.epa.gov/ttn/atw/rice/fr20au10.pdf> (accessed August 26, 2011).

⁶ EPA, 40 CFR Part 63, EPA-HQ-OAR-2008-0708, National Emission Standards for Reciprocating Internal Combustion Engines, <http://www.epa.gov/ttn/atw/rice/fr20au10.pdf> (accessed August 26, 2011).

⁷ EPA, 40 CFR Part 63, EPA-HQ-OAR-2008-0708, National Emission Standards for Reciprocating Internal Combustion Engines, <http://www.epa.gov/ttn/atw/rice/fr20au10.pdf> (accessed August 26, 2011).

⁸ EPA, 40 CFR Parts 60, 63, 85, 90, 1048, 1065, and 1068, EPA-HQ-OAR-2005-0030, FRL-8512-4, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, <http://www.epa.gov/ttn/atw/area/fr18ja08.pdf> (accessed September 1, 2011).

⁹ EPA, "Nonroad Diesel Technical Amendments and Tier 3 Technical Relief Provision" (January 11, 2011), <http://www.epa.gov/nonroaddiesel/420f07055.htm> (accessed August 26, 2011).

¹⁰ Tyler Fox, EPA Memorandum to Regional Air Division Directors, Subject: Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO₂ National Ambient Air Quality Standard, March 1, 2011, http://www.epa.gov/ttn/scram/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf (accessed September 1, 2011).

¹¹ New Mexico Environment Department (NMED), *Four Corners Air Quality Task Force Report of Mitigation Options* (November 1, 2001), http://www.nmenv.state.nm.us/aqb/4C/Docs/4CAQTF_Report_FINAL_OilandGas.pdf (accessed August 19, 2011).

¹² EPA, "Clean Air Nonroad Diesel – Tier 4 Final Rule" (updated June 30, 2011), <http://www.epa.gov/nonroaddiesel/2004fr.htm> (accessed August 19, 2011).

¹³ Tyler Fox, EPA Memorandum to Regional Air Division Directors, Subject: Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO₂ National Ambient Air Quality Standard, March 1, 2011, http://www.epa.gov/ttn/scram/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf (accessed September 1, 2011).

¹⁴ Albert Hendler, Jim Nunn, Joe Lundeen, and Ray McKaskle, *VOC Emissions From Oil and Condensate Storage Tanks*, Final Report (October 31, 2006, revised April 2, 2009), Table 4-2, <http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf> (accessed August 19, 2011).

¹⁵ Newfield Exploration Company, Anadarko Petroleum Corporation, Utah Petroleum Association, Interstate Oil & Gas Compact Commission, and Independent Petroleum Association of Mountain States, "Reducing Methane Emission with Vapor Recovery on Storage Tanks: Lessons Learned from the Natural Gas STAR Program," Presentation for the Producers Technology Transfer Workshop, Vernal, UT, March 23, 2010, Slide 38, http://www.epa.gov/gasstar/documents/workshops/vernal-2010/06_vrus.pdf (accessed August 19, 2011).

¹⁶ Albert Hendler, Jim Nunn, Joe Lundeen, and Ray McKaskle, *VOC Emissions From Oil and Condensate Storage Tanks*, Final Report (October 31, 2006, revised April 2, 2009), Table 4-2, <http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf> (accessed August 19, 2011).