NRDC
THE EARTH'S BEST DEFENSE

NATURAL RESOURCES DEFENSE COUNCIL

December 31, 2009

New York State Department of Environmental Conservation
Attn: dSGEIS Comments
Bureau of Oil & Gas Regulation
Division of Mineral Resources
625 Broadway, Third Floor
Albany, NY 12233-6500

Re: *Comments on Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*

Dear Sir or Madam:

The Natural Resources Defense Council, Inc. ("NRDC") submits these comments to the New York State Department of Environmental Conservation ("NYSDEC") on the Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs, dated September 2009 ("DSGEIS").

NRDC is a national, non-profit legal and scientific organization that has been active on a wide range of environmental issues since the organization was founded in New York in 1970. Although we have grown to an international organization with six offices and almost 400 staff, we retain a team of lawyers, scientists and other specialists devoted exclusively to safeguarding New York's environment and to improving the quality of life for the State's residents, including our almost 100,000 members and activists who are New Yorkers. Over the past 40 years, NRDC has reviewed and commented on innumerable federal and state environmental impact statements.

NRDC's fundamental conclusion following its thorough and careful review of the DSGEIS is that it is so fatally flawed that it must be withdrawn and the environmental review process must be commenced anew. Simply put, the document fails to demonstrate that drilling in the Marcellus Shale can proceed without putting New York's natural resources and the health and safety of its residents at serious risk. Therefore, it would be not only grossly irresponsible but illegal if the New York State Department of Environmental Conservation ("NYSDEC")

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were to proceed with permitting drilling in the Marcellus Shale on the basis of the DSGEIS in its current form.

Detailed technical comments prepared on behalf of NRDC and its partner organizations (Earthjustice, Inc., Riverkeeper, Inc., and Catskill Mountainkeeper) by a team of leading national environmental review and scientific experts (AKRF, Inc., CEA Engineers, P.C., Harvey Consulting, LLC, Professor Glenn Miller, and Dr. Tom Myers) are being submitted under separate cover and are incorporated herein by reference. In addition, enclosed are comments directed particularly to the potential impacts of shale development on municipalities and localities prepared on behalf of NRDC by Sive, Paget & Riesel, P.C., a leading environmental law firm specializing in environmental review in New York, which are also incorporated herein by reference.

We submit these additional comments to underscore and provide greater detail on several items addressed by NRDC's consultants.

The DSGEIS Is Fatally Flawed and Must Be Withdrawn

As reflected in the discussion below as well as in NRDC's expert technical comments, the DSGEIS fails to comport with the requirements of the State Environmental Quality Review Act ("SEQRA") in numerous critical respects. As such, the DSGEIS is incompetent to serve as the basis for a permitting program for development of the Marcellus Shale or other low permeability formations in New York State. Nor can these deficiencies, given their number and character, be adequately addressed during the transition to a final document. *See Webster Assocs. v. Town of Webster*, 59 N.Y.2d 220, 228 (1983) ("[T]he omission of a required item from a draft EIS cannot be cured simply by including the item in the final EIS."). Rather, significant new and revised analyses must be performed. NYSDEC must therefore withdraw the DSGEIS and prepare a new draft document containing all legally required analyses.

The DSGEIS Fails to Evaluate Potential Cumulative Impacts

The first critical flaw of the DSGEIS is its failure to evaluate potential cumulative impacts as mandated by SEQRA and its implementing regulations. NYSDEC's SEQRA regulations require the preparation of a cumulative impact assessment when, even if no single project's impact is significant, the aggregated impacts from multiple actions may be significant. 6 N.Y.C.R.R. § 617.7(c)(2) ("agency must consider reasonably related long-term, short-term, direct, indirect and cumulative impacts"). This is precisely the scenario presented in the case of development of the Marcellus Shale. Even if it were the case that the development of any single well pad might not result in significant adverse environmental impacts (which, as reflected in the accompanying technical comments, is not the case), it is evident that widespread development on a local, regional, and/or statewide basis throughout the shale has the potential to result in such cumulative impacts. Thus, a

cumulative impact assessment is necessary to assess and disclose any potential significant adverse impacts from a full-build scenario, and to identify and propose mitigation to address such impacts. The DSGEIS fails utterly to do so.

Although the DSGEIS acknowledges that gas drilling in the Marcellus Shale will have cumulative impacts on the surrounding environment (DSGEIS at 6-145), the document fails to contain any meaningful assessment of cumulative impacts, relying on three legally and/or scientifically invalid bases: (1) the improper claim that it is "too difficult" to determine where and at what rate development will occur; (2) the improper dismissal of so-called "qualitative" cumulative impacts, e.g., community character and visual impacts, while also ignoring quantifiable (but not quantified in the DSGEIS) cumulative impacts; and (3) the improper reliance on the1992 GEIS' supposed consideration of cumulative impacts based on denser 40-acre spacing.

First, the DSGEIS claims that it is essentially impossible to evaluate cumulative impacts because "[t]he timing, rate and pattern of development, on either a statewide or local basis, are very difficult to accurately predict." (DSGEIS at 6-145.) This statement flies in the face of its own previous recitation of precisely the sorts of available and/or reasonably surmised data that would permit it to do so, e.g., the rate of development in other shale gas states, the numbers of available workers and equipment, and historical market trends. (*Id.* at 6-143 to 6-145.)

DEC's failure to attempt to estimate the rate of development or to assess impacts also is counter to its own regulations and guidance. SEQRA's implementing regulations state that a generic EIS can "present and analyze in general terms a few hypothetical scenarios that could and are likely to occur." 6 N.Y.C.R.R. § 617.10(a). NYSDEC's own SEQR Handbook suggests that these hypothetical scenarios be included. NYSDEC, *SEQR Handbook* at § H(9) (2009). As a matter of established law, and as discussed further in the accompanying technical comments from AKRF concerning well-established SEQRA practice, it is elemental that the DSGEIS must make, at the very least, a reasonable worst-case prediction of maximum development in the state and prepare an analysis of regional and/or statewide cumulative impacts on that basis. The failure of the DSGEIS to do so renders it fatally flawed.

Second, NYSDEC claims that a cumulative impact assessment is unnecessary to determine whether there should be mitigating limits on development essentially because it is impossible to establish thresholds for significance for impacts that are "qualitative" in nature, i.e., noise, visual and community character impacts. (DSGEIS at 6-145 to 6-146.) Initially, this contention ignores the fact that noise impacts – as well as others that collectively make up community character, such as traffic – are readily quantifiable. (*See* accompanying report of AKRF.) Moreover, it fails to recognize that even "qualitative" impacts are routinely evaluated for a determination of significance as a matter of law.

Perhaps more importantly, NYSDEC's own regulations explain exactly how an evaluation of phasing to mitigate cumulative impacts of a large-scale or long-term project (like development of a natural gas resource across the state) should be accomplished. *See* 6 N.Y.C.R.R. § 617.10(c); *see also id.* § 617.10(e) ("In connection with projects that are to be developed in phases or stages, agencies should address not only the site specific impacts of the individual project under consideration, but also, in more general or conceptual terms, the cumulative impacts on the environment and the existing natural resource base of subsequent phases of a larger project or series of projects that may be developed in the future. In these cases, this part of the generic EIS *must* discuss the important elements and constraints present in the natural and cultural environment that may bear on the conditions of an agency decision on the immediate project." (emphasis added)).

Third, NYSDEC claims that no regional cumulative assessment is necessary because the 1992 GEIS analyzed the cumulative impacts of development based on 40-acre spacing, which is denser than the 640-acre spacing required for Marcellus Shale development. (DSGEIS at 6-143 to 6-144.) This justification fails for at least three reasons. First, the 1992 GEIS contained virtually no cumulative impacts assessment and certainly not one that satisfies the mandates of SEQRA.

Second, while the higher density of 40-acre spacing might arguably result in fewer *surface* impacts, it has no bearing on the myriad increased impacts associated with the vastly greater amounts of water and fracking fluids utilized in or wastewater generated by high-volume hydraulic fracturing using multiple horizontal wells per well pad in the Marcellus Shale – the precise basis on which NYSDEC determined a supplemental GEIS was necessary. All of the increased impacts would, of course, be even more significant on a cumulative basis than on the single well pad basis, and thus the meager 1992 analysis cannot plausibly serve as the basis of estimation for the cumulative impacts of developing the Marcellus Shale.

And, lastly, this justification completely ignores the potential for in-filling with vertical wells within the Marcellus Shale to access gas not fully developed using horizontal wells. (DSGEIS at 5-19.)

For all of these reasons, NYSDEC has failed utterly to comply with the requirements of SEQRA and its own implementing regulations to prepare a meaningful cumulative impact assessment.

The DSGEIS Fails to Properly Consider Alternatives to the Proposed Action

A second fatal shortcoming of the DSGEIS is its failure to meaningfully evaluate possible alternatives to the proposed action that would result in fewer unmitigated significant adverse environmental impacts. The DSGEIS purports to consider three alternatives to the proposed action, i.e., development of the Marcellus Shale without limitation: (1) a "Prohibition Of Development" alternative, (2) a "Phased Permitting Approach" alternative, and (3) a "Green Or Non-Chemical

Fracturing Technologies And Additives" alternative. (DSGEIS, Chap. 9.) None of these analyses meets the requirements of SEQRA. ECL § 8-0109(2)(d); 6 N.Y.C.R.R. § 617.9(b)(5)(v). We address each of these three purported alternatives in turn.

Failure to Properly Evaluate an Alternative with Partial Prohibitions on Development

The DSGEIS contains what it describes as a "Prohibition Of Development" alternative, which is apparently intended to serve as the required "no action" alternative. (DSGEIS § 9.1.) Initially, a proper formulation of the no action alternative would not be a prohibition on all development in the Marcellus Shale. Rather, it would be based on an assumption that a permitting program for development of the Marcellus Shale would proceed under the existing regulatory program for oil and gas development. Because the Governor has imposed a temporary moratorium on development of the Marcellus pending completion of the SEQRA process, a decision to proceed at that point without creating a new regulatory approach for development of the Marcellus – i.e., the no action alternative – would equate to a return to permitting under the extant structure rather than imposition of a permanent prohibition of development of the Marcellus. The DSGEIS thus fails to comport with NYSDEC's own SEQRA regulations requiring consideration of a no action alternative. 6 N.Y.C.R.R. § 617.9(b)(5)(v).

The "Prohibition Of Development" analysis fails, moreover, to properly evaluate the impacts of this alternative, including whether imposition of one or more partial prohibitions could result in fewer unmitigated significant adverse environmental impacts than the proposed action, as is required by law. ECL § 8-0109(1). More specifically, the DSGEIS fails to properly consider whether placing particularly valuable and/or vulnerable resources – such as the Catskill/Delaware watershed that supplies 90% of New York City's drinking water, the Delaware River Basin, the Catskill Park, and/or other such areas – off-limits to drilling could reasonably mitigate potentially significant adverse impacts.

The DSGEIS claims that prohibiting development of the Marcellus Shale would "be contrary to New York State and national interests" and contravene ECL § 23-0301. (DSGEIS at 9-1 to 9-3.) To begin with, the referenced section of the ECL directs that the development, production, and utilization of natural gas resources in the state be conducted in such a manner that "the rights of all persons including landowners and *the general public* may be fully protected." ECL § 23-0301 (emphasis added). Plainly, if – following completion of the requisite analyses (which were not performed in this DSGEIS) – the adverse environmental impacts to the general public of developing the Marcellus Shale were determined to be so significant as to outweigh any benefits to the state, a prohibition on development could not be seen as running afoul of state law.

Even assuming, *arguendo*, that a full prohibition on development might be an inappropriate alternative, the DSGEIS contains no analysis as to whether partial

prohibitions that would still allow for development of remaining portions of the shale in New York State would be a reasonable alternative. This is a critical failure of the document to conform to the requirements of SEQRA.

Failure to Properly Evaluate a Phased or Capped Development Alternative

The DSGEIS also purports to evaluate a "Phased Permitting Approach" alternative (DSGEIS § 9.2), but dismisses it on the ground that "[p]hased permitting as a means to mitigate regional cumulative impacts is not practical *or necessary* given the inherent difficulties in predicting gas well development for a particular region or part of the State." (*Id.* at 9-3; emphasis added.) In this circumstance, the argument the DSGEIS advances is particularly problematic – if it is prohibitively difficult even to analyze the cumulative impacts of unlimited development on the Marcellus Shale at this stage, it is illogical to conclude that phased permitting might not be necessary to mitigate such impacts. At the very least the document should make provision for a future determination whether the cumulative impacts of development are significantly adverse that limiting or phasing permitting on a going-forward basis is required.

More importantly, however, the DSGEIS could in fact examine a phased alternative right now. As set out above, on the basis of a reasonable worst case scenario, the document can – and legally must – first properly evaluate the cumulative impacts of development of the Marcellus Shale on a local, regional, and statewide basis. Then, it must consider whether an approach that would phase in the number of permits issued – or even establish an upper cap on them – in all or certain parts of the state would adequately mitigate significant adverse impacts.

In other words, based on the same illegitimate rationale underlying the DSGEIS' failure to properly evaluate cumulative impacts discussed above, the document fails to evaluate a reasonable, sound alternative with the potential to result in fewer unmitigated significant adverse impacts than the proposed action. As such, the DSGEIS fails to meet SEQRA's requirements.

Failure to Properly Evaluate a Less Toxic Alternative

Lastly, the DSGEIS contains a discussion of what is termed a "Green Or Non-Chemical Fracturing Technologies And Additives" alternative. (DSGEIS § 9.3.) However, there is no meaningful assessment of the possibility of requiring the use of, for example, non-chemical or reduced-chemical fracturing fluids on the basis that it is, again, "too difficult" to do so because there is no recognized metric and many companies hold their formulae as proprietary. However, NYSDEC is already using its regulatory authority to compel the disclosure of alleged proprietary information regarding the ingredients of non-"green" fracturing fluid, and no explanation is provided as to why it could not do so for "green" alternatives. Nor is it acceptable to disclaim responsibility to assess the potential benefits of "green" alternatives because a new metric might need to be developed. New York State certainly has

sufficient expertise in both NYSDEC and its sister agency, the New York State Department of Health ("NYSDOH"), to at least attempt to develop a reasonable metric.

NYSDEC and NYSDOH also collectively have the ability to perform toxicological evaluations of the more than 240 specific chemicals proposed to be used in fracturing and drilling operations to determine whether the risks associated with the use of any such chemicals are significantly great as to justify prohibitions on their use. (*See* reports of Dr. Glenn Miller and Harvey Consulting, LLC.) Yet no attempt whatsoever was made in the DSGEIS to perform such an assessment. Accordingly, the DSGEIS again fails to meaningfully evaluate an alternative that might result in fewer unmitigated significant adverse impacts, in contravention of SEQRA's requirements.

The DSGEIS Fails to Propose a New Regulatory Program, Improperly Relying on a Patchwork of Discretionary Permit Conditions, Filings and Guidance

A third crucial failing of the DSGEIS is its reliance on permit conditions, filings and guidance rather than proposing a new regulatory process for oil and gas drilling, particularly in the Marcellus Shale. Throughout the DSGEIS, NYSDEC proposes a number of across-the-board so-called mitigation measures.[1] Without addressing the adequacy or appropriateness of these examples as mitigation for significant adverse environmental impacts (some of which are addressed in the accompanying technical comments), these measures appear to be intended as rules, which under New York State law are defined as "fixed, general principle[s] to be

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[1] These include, for example, a ban on "centralized flowback water surface impoundments within the boundaries of primary and principal aquifers, unfiltered water supplies, or mapped 100-year floodplains," DSGEIS at 7-96; a ban on the annular disposal of drill cuttings, *id.* at 7-61; a ban on above-ground flowback water piping and conveyances in 100-year floodplains, *id.* at 7-72; a ban on keeping fracking additives on site if it will be unattended, *id.* at 7-32; a requirement that flowback water handled at the well pad be directed to and contained in steel tanks, *id.* at 7-34; requirements about monitoring wells, *id.* at 7-38; requirements about intermediate and production casing cementing, *id.* at 7-47; requirements for the submission of forms detailing pre-fracking activities and flowback water handling, *id.* at 7-45, 7-50; requirements that a well operator implement greenhouse gas emissions mitigation, visual impacts mitigation, and noise impacts mitigation plans, *id.* at 7-95, 7-103 to 7-106, 7-109; requirements about secondary containment and tank filling and placement practices for drilling rig fuel tanks, *id.* at 7-27, 7-73; requirements about the construction and operation of, liners for, and size of water impoundment pits in general and within primary and principal aquifers and the New York City watershed, *id.* at 7-30, 7-34 to 7-35, 7-64; a requirement that well pads within floodplains use closed-loop tank systems instead of reserve pits to manage fluids and cuttings, *id.* at 7-72; and a requirement that a pressure relieve valve be installed if a well will produce annular gas, *id.* at 7-48.

applied by an administrative agency without regard to other facts and circumstances relevant to the regulatory scheme of the statute it administers." *E.g., Cubas v. Martinez*, 8 N.Y.3d 611, 621 (2007). Accordingly, they require formal promulgation as regulations pursuant to the State Administrative Procedure Act ("SAPA"), rather than reliance on imposition of discretionary permitting conditions and other *ad hoc* guidance documents as seemingly proposed by the DSGEIS. SAPA § 201.

Yet NYSDEC has made no indication that it will propose new regulations pursuant to SAPA to implement the measures that do not follow from existing statutes and regulations. Nor are SEQRA's procedures a substitute for SAPA's. *See, e.g.*, SAPA §§ 202(1), 202-a, 202-b (requiring submission of "a notice of proposed rule making to the secretary of state for publication in the state register" and issuance of "regulatory impact statement" and "regulatory flexibility analysis"). Thus, unless NYSDEC goes through a formal SAPA rulemaking, it will be in violation of state law if it seeks to apply the new mitigation measures identified in the DSGEIS as rules.

On the other hand, if NYSDEC does not intend these measures to be binding as rules on all applicants, it cannot claim that they will function as legally required mitigation for identified significant adverse environmental impacts from the proposed action. Should NYSDEC opt not to promulgate regulations under SAPA, its proposed mitigation measures will not be codified and will be subject to *ad hoc* implementation, change on a case-by-case basis, and modification without public review or debate. Only properly promulgated regulations (or law-making) can ensure that this will not happen. NYSDEC must finally follow through on what it said in 1992 it would do (*see* GEIS at 10): propose and duly implement regulations to govern gas drilling in New York State, and in particular horizontal drilling and high volume hydraulic fracturing in the Marcellus Shale.

The DSGEIS Fails to Comply with SEQRA with Respect to the Catskill/Delaware Watershed

The Catskill/Delaware watershed is a unique natural and hydrological resource of incalculable importance. This watershed area, which stretches over much of five counties in the Catskill Mountains, supplies drinking water to 9 million New Yorkers – roughly half of the State's population. It is the source for the largest municipal drinking water system in the nation and provides approximately 1.2 billion gallons a day to residents in New York City, Westchester Country and a number of smaller jurisdictions within the watershed boundaries. In addition, it is one of only five urban systems in America that because of its high quality source water has been granted waivers from the federal Safe Drinking Water Act filtration requirement.

Preserving the Catskill/Delaware watershed and protecting it from pollution have long been high public priorities for New York State. The Catskill/Delaware

watershed boundaries overlap to a significant degree with the State's Catskill Park and Catskill Forest Preserve, whose preservation have been state public policy for more than 100 years. More recently, over the past two decades – since the promulgation by the U.S. Environmental Protection Agency of its Surface Water Treatment Rule (implementing the Safe Drinking Water Act) – New York State has taken extraordinary steps to safeguard water quality in the Catskill/Delaware watershed.

For example, in the mid-1990's, Governor George Pataki brought city, state, federal and watershed town stakeholders together and brokered the precedent-setting 1997 Watershed Memorandum of Agreement. Since then, the signatories have all committed substantial financial resources to advance the goals of watershed protection, filtration avoidance and environmentally sound economic development that is consistent with preserving the hydrological resources of the Catskill/Delaware watershed. State, city, and federal officials have over this period repeatedly recognized that pollution prevention should be a guiding principle for this watershed in view of the enormous economic costs (over $10 billion in capital costs alone) if the Catskill/Delaware watershed system needs to be filtered. And even if filtration were not immediately required as a result of pollution within the watershed, state officials have long sought to avoid the adverse health risks that would be raised by (and the loss of public confidence that could result from) new pollution discharges into this unique water resource.

Unfortunately, the prospect proposed in the DSGEIS of widespread gas drilling using high-volume hydraulic fracturing and horizontal drilling presents the greatest threat in memory to water quality in the Catskill/Delaware watershed. According to consultants retained by the New York City Department of Environmental Protection, it is quite possible that approval of the DSGEIS gas drilling proposal would result in as many as 3,000 to 6,000 fracking wells within the Catskill/Delaware watershed over the several decades during which drilling would likely take place. Drilling would introduce hundreds of tons of per day of fracturing chemicals into the watershed over this time period. At full build-out, over several decades, the projection by the City's consultants is that between 500,000 and 1 million tons of chemicals would be used for drilling operations in the watershed. The drilling activities would pose a significant risk to water supply infrastructure and lead to an "industrialization of the watershed," with "high levels of site disturbance, truck traffic and intensive industrial activity on a relatively constant basis, over a period of decades," according to the consultants (*see generally*, Hazen and Sawyer "Final Impact Assessment Report: Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed," December 2009, and *see* New York City Department of Environmental Protection, "Briefing to the NYC Water Board on the Natural Gas Impact Assessment Project," December 23, 2009 at 7, 11, 15, and 18). All such drilling would occur in a watershed region that has had very little, if any, recent industrial activity, that has largely retained its rural character, and that has an economy based upon tourism, farming, forestry, education and healthcare, much more than on heavy industry.

The failure to recognize and take into account the unique characteristics of the Catskill/Delaware watershed, and the paramount importance of protecting this natural resource of statewide significance, is inconsistent in several ways with SEQRA and its implementing regulations. First, the DSGEIS treatment of the Catskill/Delaware watershed clashes with SEQRA on the question of alternatives. SEQRA requires, among other things, that an EIS include "a description and evaluation of the range of reasonable alternatives to the action that are feasible, considering the objectives and capabilities of the project sponsor." 6 N.Y.C.R.R § 617.9 (b) (5) (v). But the DSGEIS does not evaluate, as a reasonable alternative, a Marcellus Shale gas drilling proposal that would prohibit drilling in certain areas of exceptional ecological or hydrological significance, such as the Catskill/Delaware watershed. However, since the Catskill/Delaware watershed currently subject to gas drilling comprises approximately 6% of the Marcellus in New York State (and since other areas of special significance such as the Catskill Park make up similarly small portions of the total Marcellus Shale formation in New York State), DEC should have analyzed as an alternative a gas drilling proposal that might allow drilling to proceed in certain portions of the state, but that would prohibit drilling in other areas, such as the Catskill/Delaware watershed. (We believe the same legal obligation requires, for example, state analysis of an alternative that also would prohibit hydraulic fracturing in the historic New York State Catskill Park.) (And, as noted elsewhere in these comments, we do not believe that the currently proposed DSGEIS provides adequate protection for water resources anywhere in New York State.)

Second, the DSGEIS' consideration of the Catskill/Delaware watershed fails to provide legally sufficient mitigation. A cornerstone of SEQRA is that an EIS include "mitigation measures proposed to minimize the environmental impact" of the proposed action. ECL § 8 – 0109 (2) (f). But in its purported mitigation of potential adverse water quality impacts of gas drilling in the Catskill/Delaware watershed, the DSGEIS relies primarily on arbitrary or inapplicable set-back distances. (*See*, e.g., DSGEIS at 7-68). The DSGEIS argues, for example, that the set-back distances that it suggests could be inserted into drilling permits that are larger than other set-back distances set forth in New York City's Watershed Rules and Regulations. But this ignores the fact that the existing rules do not allow for other heavy industry, pollution-generating activities within the watershed. Moreover, the DSGEIS proposed set-back distances lack scientific support, ignore evidence on the migration of fracking chemicals and fail to mitigate other substantial risks associated with widespread gas drilling in the Catskill/Delaware watershed and documented in other public comments, including the NYCDEP Hazen and Sawyer consultants' report.

Third, the DSGEIS is flawed regarding the Catskill/Delaware watershed on the issue of cumulative impacts. As detailed above, the DSGEIS' discussion of cumulative impacts in general is woefully inadequate. The document states that cumulative impacts of industrial gas drilling are "very difficult to accurately predict."

(DSGEIS at 6-145.) Thus, the DSGEIS fails to forecast, let alone analyze, the impact that between 3,000 and 6,000 gas wells could have on water quality and industrialization of the landscape, among other things, in the Catskill/Delaware watershed. In short, the DSGEIS discussion of this issue, such as it is, fails to fulfill the SEQRA requirements that the agency analyze "not only the site specific impacts of the individual projects under consideration but also . . . the cumulative impacts on the environment." (6 N.Y.C.R.R. § 617.10 (e)). For all of these reasons, the DSGEIS' treatment of the Catskill/Delaware watershed is deficient as a matter of law.

Conclusion

Thank you for the opportunity to submit these comments on the DSGEIS. NRDC appreciates the good intentions of many NYSDEC staff who contributed to the preparation of the DSGEIS. Unfortunately, as currently drafted, the DSGEIS fails to establish that drilling in New York's Marcellus Shale can proceed in a manner that protects the health and safety of the state's residents or its precious natural resources. Accordingly, before NYSDEC proceeds with any permitting for drilling in the Marcellus Shale, it must recommence its consideration of the proposed activity and conduct all scientifically and legally required analyses in a new draft environmental impact statement.

Sincerely,

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December 30, 2009

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Re: **Comments on the Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Permitting Program**

Dear Sir or Madam:

This comment letter is submitted on behalf of the Natural Resources Defense Council ("NRDC") in connection with the Draft Supplemental Generic Environmental Impact Statement ("DSGEIS") on the Oil, Gas, and Solution Mining Permitting Program -- Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs (the "Permitting Program"). These comments identify multiple deficiencies in the DSGEIS specifically related to potential impacts of concern to units of local government, including the following:

(a) The DSGEIS fails to undertake any quantitative or meaningful qualitative analysis of potential significant adverse traffic, visual, noise, community character, and land use impacts from the Permitting Program and to require appropriate mitigation measures. The DSGEIS fails to establish reasonable worst case scenarios, analyze those scenarios, identify any significant adverse impacts, and require appropriate mitigation measures.

(b) The DSGEIS unlawfully segments the environmental review of traffic, visual, noise, community character and land use impacts by failing to undertake any quantitative or meaningful analysis of those potential significant impacts and by deferring such an analysis to the future environmental review of a particular well drilling application.

(c) The DSGEIS and the Permitting Program preclude the New York State Department of Environmental Conservation ("NYSDEC") (or another lead

agency) from issuing a positive declaration to require future preparation of a site specific supplemental environmental impact statement based on the potential of a particular well drilling application to generate significant adverse traffic, visual, noise, community character, and land use impacts. Rather, the DSGEIS and the Permitting Program delineate an artificially circumscribed set of seven criteria which are the exclusive factors for determining which well drilling applications will require a lead agency to make a site specific determination of significance. None of those seven criteria relate to traffic, visual, noise, community character, and land use impacts. Thus, the NYSDEC is precluded from considering potential traffic, visual, noise, community character, and land use impacts when determining whether a particular well drilling application requires a determination of significance. Unless one of the seven criteria is satisfied, there will be no determination of significance for a particular well drilling application even if that application would have the potential to generate significant adverse traffic, visual, noise, community character, or land use impacts and would require preparation of a supplemental environmental impact statement.

(d) The environmental assessment form ("EAF") and the required addendum for high-volume hydraulic fracturing ("EAF Addendum") fail to require submission of necessary information to enable NYSDEC (or another lead agency) to determine whether a well drilling application has the potential to generate significant adverse traffic, visual, noise, community character and land use impacts.

(e) The DSGEIS acknowledges that units of local government are preempted by Article 23 of the Environmental Conservation Law ("ECL") from regulating well drilling except as to matters relating to roads and collection of real property taxes. Yet the DSGEIS assumes that units of local government could require well drilling applicants to comply with local wetland laws and local floodplain development laws. There is no analysis anywhere in the DSGEIS to support the assumption that the Article 23 preemption does not apply to local wetland laws and local floodplain development laws. To the extent that the DSGEIS and the Permitting Program rely on units of local government to apply and enforce local wetland and local floodplain development laws to well drilling, the DSGEIS is defective for failing to analyze and conclude that such laws are not preempted.

(f) The DSGEIS and the Permitting Program require minimum setbacks from wetlands for certain, but not all, facilities associated with high-volume hydraulic fracturing well drilling operations. The "wetlands" referred to in the DSGEIS appear to be only freshwater wetlands protected by New York State under the ECL. The DSGEIS does not require a setback from wetlands protected by local laws and fails to analyze the potential significant adverse impacts from siting well drilling operations proximate to or in wetlands protected by local laws, assuming that such local wetland laws are preempted by the ECL when applied to well drilling operations.

(g) The DSGEIS and the Permitting Program fail to establish any meaningful role for units of local government, even in an advisory capacity, in the NYSDEC's process for issuance of well drilling permits and in the imposition of appropriate

conditions on permit approvals. Units of local government are not required to be notified of any application for high-volume hydraulic fracturing well drilling other than the very first application, thereby requiring the unit of local government to monitor the NYSDEC's website on a daily basis to determine if such an application has been filed. Even if a unit of local government becomes aware of an application, it is not entitled to a copy of application materials nor does it have any inherent opportunity to review or comment on the application. The DSGEIS should have considered an alternative in which: (a) units of local government are required to be informed by the applicant when an application is filed for high-volume hydraulic fracturing and well drilling within their boundaries; (b) such units of local government are provided all application materials; and (c) such units of local government are given a reasonable opportunity to submit comments to NYSDEC on the proposed application, including but not limited to an advisory recommendation in opposition to or in favor of the application, and, if the latter, any reasonable conditions which should be imposed by NYSDEC.

Overview of Relevant Elements of the NYSDEC Well Permitting Process

An applicant seeking a well drilling permit must submit: (1) an application, including various site plans showing the proposed well location, the boundaries of the lease or unit containing the well and information about other nearby wells; and (2) an EAF (set forth in DSGEIS Appendix 5) and the EAF Addendum (set forth in DSGEIS Appendix 6). Neither the EAF nor the EAF Addendum require the applicant to submit any information concerning:

(a) the number of truck trips, the weight and size of the trucks, the duration and frequency of truck trips, the hours during the day and days of the week of trucking operations, or any similar information;

(b) the location of visual impact receptors and the degree to which well drilling rigs, impoundments, and other facilities associated with the proposed well drilling permit would be seen from such receptors;

(c) the location of potential noise receptors and the projected noise levels from well drilling, blasting, trucking, and machinery operation at such noise receptors;

(d) temporary and permanent changes to the land which would have the potential to significantly alter community character; and

(e) uses of land proximate to well drilling and related activities and which are not compatible with such activities, including hospitals, schools, nursing homes, places of worship, etc.

The EAF Addendum requires that a topographic map be attached showing, inter alia, location of the access road, but none of the other information enumerated above. The EAF Addendum also requires certain affirmations by the applicant, including:

(a) that the applicant has consulted applicable FIRM, Flood Boundary and Floodway maps and that any proposed well pad and access road are not within a mapped 100-year flood plain;

(b) any existing comprehensive, open space and/or agricultural plan or similar policy document(s) identified and reviewed by the applicant;

(c) that the access road will be located as far as practical from occupied structures, places of assembly and unleased property, unless otherwise required by the lease;

(d) that the operator will prepare and adhere to the following site plans, which will be available to the NYSDEC on request and available on-site to the NYSDEC inspector while activities addressed in the plan are occurring:

(i) a visual impacts mitigation plan consistent with the SGEIS;

(ii) a noise impacts mitigation plan consistent with the SGEIS;

(iii) a greenhouse gas mitigation plan consistent with the SGEIS; and

(iv) an invasive species mitigation plan.

Note regarding the required EAF Addendum affirmations:

(a) There is no requirement that the applicant take any action to comply with any existing comprehensive, open space and/or agricultural plan or similar policy document(s) other than to affirm which ones, if any, the applicant has identified and reviewed. There is no requirement that the applicant actually identify any of the plans in existence that are applicable to the land on which the well drilling permit is sought, the surrounding areas, or the areas in which trucks will be traveling to and from the well pad or impoundment. Nor is there any requirement that the applicant actually review any or all such plans. Even if a municipality has a series of comprehensive, open space and agricultural plans and similar plans, the applicant would still be in compliance with the EAF Addendum if it represented that it never looked for and, therefore, failed to identify or review any such plans.

(b) There are no definitional or other criteria for determining what is "as far as practical" concerning location of the access road in relation to occupied structures, places of assembly and unleased property. Nor is there any required explanation by the applicant to support its affirmation or submission of a map showing such structures and uses in relation to the access road. Nor is there any required hierarchy in determining which uses of land require greatest distance from the access road in the event that movement of the access road away from one use would bring it closer to another. All that is required of the applicant is a bare affirmation that it has located the access road.

(c) The visual impacts and noise impacts mitigation plans do not have to be prepared prior to issuance of the well drilling permit and are not subject to prior approval by the NYSDEC. The only apparent requirement is that these plans be prepared by the applicant in conformity with the SGEIS and made available to the NYSDEC on request.

The principal purpose of the EAF and EAF Addendum is to provide facts to enable NYSDEC (or another lead agency) to determine whether any one of the following seven criteria has been "tripped," thereby requiring a site specific determination of significance by the lead agency:[1]

(a) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone is shallower than 2,000 feet along the entire proposed length of the wellbore;

(b) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along the entire proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply;

(c) Any proposed centralized flowback water surface impoundment. Emphasis of the initial review will be on proposed additive chemistry relative to potential emissions of Hazardous Air Pollutants. Additional review of site topography, geology and hydrogeology will be required for any proposed centralized flowback water surface impoundment at the following locations:

(i) within 1,000 feet of a reservoir;

(ii) within 500 feet of a perennial or intermittent stream, wetland, storm drain, lake or pond, or within 300 feet of a public or private water well or domestic supply spring;

(d) Any proposed well pad within 300 feet of a reservoir, reservoir stem or controlled lake;

(e) Any proposed well pad within 150 feet of a private water well, domestic-use spring, watercourse, perennial or intermittent stream, storm drain, lake or pond;

(f) A proposed surface water withdrawal that is found not to be consistent with the Department's preferred passby flow methodology as described in Chapter 7; and

(g) Any proposed well location determined by NYCDEP to be within 1,000 feet of subsurface water supply infrastructure.

If a well drilling application falls within one of the foregoing seven criteria, then the lead agency (presumably NYSDEC in most if not all instances) must determine whether the application may have the potential to generate any significant adverse environmental

[1] See DSGEIS at 3-12 to 3-13.

impacts. If so, a supplemental environmental impact statement would be required. Conversely, if a well drilling application does not fall within any of the foregoing seven criteria, there will be no determination of significance, the application will be treated as a Type II action under the New York State Environmental Quality Review Act ("SEQRA"), and there would be no identification of any potential significant adverse environmental impacts arising from the proposed well drilling, nor imposition of any mitigation measures.

None of the seven enumerated criteria relates in any way to potential significant adverse traffic, visual, noise, community character or land use impacts. Thus, the DSGEIS and the Permitting Program do not provide for submission of facts relevant to such potential significant adverse environmental impacts in the EAF or EAF Addendum and preclude a lead agency from issuing a positive declaration for a particular well drilling application based on the presence of such potential significant adverse environmental impacts. This violates one of the most fundamental requirements of SEQRA -- that the lead agency take a "hard look" at all of the potential significant adverse environmental impacts when making a determination of significance. By establishing, a priori, that only certain enumerated and circumscribed criteria could potentially trigger a determination of significance, the DSGEIS and the Permitting Program preclude the "hard look" mandated by SEQRA.

Regardless of whether a well drilling application requires an individualized determination of significance, the NYSDEC will notify a town only of the first application for high-volume hydraulic fracturing in any town. (DSGEIS at 8-3.) As stated at DSGEIS 8-4 to 8-5, the notification will include:

(a) a brief description of permitting process;

(b) an explanation that the letter is a notification for purposes of local coordination of jurisdictional issues (e.g., road use), not a SEQRA notice;

(c) pertinent website links, including SGEIS, mapping applications and various lookup tables; and

(d) instructions for using the website to track well status and future applications.

Once a town is notified of the first well drilling application for high-volume hydraulic fracturing, there is no requirement that the town ever be notified by the NYSDEC of any subsequent application by that applicant or any other applicant. The DSGEIS is silent as to whether the NYSDEC will notify units of local government other than towns (cities and villages) if an application for high-volume hydraulic fracturing is filed within their boundaries. After a well drilling permit has been issued, the permittee must notify any affected local government and surface owner prior to commencing operations. (DSGEIS 8-3.) There is no requirement that neighbors ever be notified of any application for high-volume hydraulic fracturing. Although the DSGEIS states that NYSDEC staff welcome

input from the surface owner and neighbors during the application review and may impose specific permit conditions to address environmental concerns, if appropriate, there is no such statement made regarding input from units of local government, nor is there any process by which NYSDEC solicits such input or is required to consider such input in any way if it is informally proffered.

Overview of Regulatory Authority

The NYSDEC has exclusive authority to regulate oil, gas, and solution mining industries. (See DSGEIS 1-2;) ECL § 23-0303(2). As set forth in the DSGEIS, "ECL §23-0303(2) provides that NYSDEC's Oil, Gas and Solution Mining Law supersedes all local laws relating to the regulation of oil and gas development except for local government jurisdiction over local roads and the right to collect real property taxes. Likewise, ECL §23-1901(2) provides for supercedure of all other laws enacted by local governments or agencies concerning the imposition of a fee on activities regulated by Article 23." (DSGEIS 1-2.)

The DSGEIS omits any discussion of NYSDEC's understanding and interpretation of the breadth and scope of the local government regulatory preemption contained in the ECL. Without explanation, the DSGEIS assumes that local governments have the power to require those seeking to engage in well drilling for high-volume hydraulic fracturing to comply with local wetland laws and local laws governing construction and other activities in floodplains. For example, the DSGEIS notes that "if the proposed action falls under the jurisdiction of more than one agency, based, for example, on the need for a local floodplain development permit, the lead agency must be determined by agreement among involved agencies." (DSGEIS 3-7.) See also Question 18 in the EAF in which the NYSDEC requires an applicant to state whether the proposed well drilling would require a local wetland permit or a local floodplain permit. Nowhere in the DSGEIS is there any explanation as to how units of local government would possess such regulatory authority given the preemptive language contained in ECL Article 23.

Nevertheless, the DSGEIS assumes that local governments could apply local wetland and floodplain development laws to well drilling applications. Presumably that is why the DSGEIS and the Permitting Program only require setbacks from those wetlands protected by the ECL. However, the mere assumption that local wetland laws are not preempted is insufficient to establish that such local regulatory authority does actually exist. Without such an analysis and supporting conclusion, the DSGEIS cannot rationally conclude that wetlands outside NYSDEC's jurisdiction will be protected by local wetland laws.

The DSGEIS Fails To Identify Or Analyze Potential Traffic Impacts

The DSGEIS fails to identify or analyze potential significant adverse traffic impacts that would arise from the construction and operation of hydraulic fracturing, horizontal wells, multiple well pads, and other related well drilling infrastructure and activities. The DSGEIS acknowledges that "the water requirement of high volume hydraulic fracturing could lead to significantly more truck traffic than was discussed in the GEIS." (DSGEIS

6-138.) And although the DSGEIS estimates that more than one thousand (1,000) truck loads would likely be required for each well per fracture job,[2] there is no attempt to analyze the potential adverse impacts of such a substantial increase in truck traffic, as required by SEQRA. (See id. 6-138 to 6-139.)

To the extent that the DGSEIS implicitly defers the analysis of potential adverse traffic impacts to the future environmental review of a particular application for a well drilling permit, such a wholesale deferral of environmental review of potential significant adverse traffic impacts violates SEQRA. A generic environmental impact statement cannot simply defer all environmental review of potential adverse traffic impacts to the filing of a site specific application.[3]

Moreover, even to the extent that analysis of site specific traffic impacts could be legitimately deferred, in part, to the review of a specific well drilling application, the process created by NYSDEC is defective. None of the seven criteria that would trigger a determination of significance has anything to do with truck traffic. Thus, even if a proposed well drilling application would contemplate massive truck traffic that would overwhelm local streets, those facts would not be germane to triggering a determination by NYSDEC (or any other lead agency) that a site specific determination of significance is required. Thus, the very process created by the NYSDEC to establish when a future well drilling application would require a determination of significance precludes potential traffic impacts from being considered. Even if the NYSDEC (or other lead agency) issues a positive declaration on the basis of one of the seven criteria cited above, there is still no guarantee that potential adverse traffic impacts would be analyzed. The EAF and EAF Addendum require no truck traffic data or trip generation information. Thus, it is difficult to imagine on what basis the NYSDEC (or another lead agency) would require preparation of a supplemental EIS to address potential adverse truck traffic impacts.

The foregoing confirms that potential significant adverse truck traffic impacts are neither analyzed in the DSGEIS nor is there any reasonable likelihood that such potential impacts would ever be analyzed in connection with any future well drilling application. Put simply, this violates SEQRA.

The DSGEIS also fails to comply with SEQRA's requirement to include mitigation measures to avoid or minimize adverse environmental impacts. The DSGEIS states that the "applicant should attempt to obtain a road use agreement with the municipality or document the reasons for not obtaining one. When there is no agreement, operators should develop a trucking plan that includes estimated amount of trucking, hours of operations, appropriate off road parking/staging areas, and routes for informational

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[2] The DSGEIS fails to analyze the potential traffic associated with multiple fracture jobs that would likely be completed at each well.

[3] A Generic EIS must establish thresholds and conditions that would trigger the need for supplemental determinations of significance or site specific EISs and must analyze the secondary, or indirect impacts of a project, including traffic. See NYSDEC, THE SEQR HANDBOOK at 79; cf. Horn v. Int'l Bus. Machines Corp., 110 A.D.2d 87, 96, 493 N.Y.S.2d 184, 191 (2d Dept. 1985) (GEIS "replete with lengthy studies, analyses and discussions of the potential impact of the proposed project . . . on the surrounding areas" reflect that agency took a "hard look" at the proposed project pursuant to SEQRA's requirements).

purposes." (DSGEIS 7-109.) Both the road use agreement and the trucking plan are "for informational purposes only." (Id. 7-110.) "The Department strongly encourages operators to attain road use agreements with governing local authorities . . . [but] does not have the authority to require, review or approve road use agreements or trucking plans." (Id. 8-4.) Merely requesting information does nothing to mitigate any adverse environmental impacts. Documents submitted pursuant to these information requests will not state what mitigation measures must be taken or who is responsible for mitigating the adverse traffic impacts. As such, they fall far short of what is required by SEQRA.

As an alternative, or in addition to, developing a reasonable worst case scenario upon which to perform a full traffic assessment in the DSGEIS,[4] NYSDEC should require that applicants include in their permit applications and EAF Addendum a site-specific traffic study identifying temporary traffic control measures that ensure safe operations. This study must include a full traffic analysis showing what potentially significant adverse traffic impacts would arise and how those impacts will be mitigated. Such study should be implemented at applicant's own expense.

As a condition of receiving a NYSDEC well permit, the applicant should also be required to obtain certification from the Chief Executive Officer of the local municipality in which the well will be located (e.g., the Supervisor of the Town) stating that all required local road use permits have been obtained and/or the applicant has entered into all applicable local road use agreements. The certification should certify that the applicant has posted all necessary road security bonds prior to any land disturbance.

The DSGEIS Fails to Identify or Analyze Potential Wetland Impacts

The DSGEIS states that "[a]ctions located within 100 feet of wetlands regulated by Article 24 of the ECL [freshwater wetlands] generally require a permit from DEC." (DSGEIS 7-6.) It appears that only NYSDEC-regulated freshwater wetlands within the ECL Article 24 definition are within the scope of the DSGEIS. See ECL §24-0107(1). This definition excludes wetlands under the jurisdictions of the U.S. Army Corps of Engineers ("ACOE") and local governments. Such a scope for the DSGEIS is far too narrow because it does not include wetlands that fall outside of the ECL Article 24 freshwater wetlands definition. Therefore, the Final SGEIS must include an analysis of potentially significant adverse impacts of drilling operations on wetlands within the jurisdiction of the ACOE and local governments. Particularly, with respect to the latter, the Final SGEIS must address potential impacts on wetlands under local government jurisdiction if local wetland laws are preempted.

In addition, if the Final SGEIS concludes that local wetland laws are not preempted, then the Final SGEIS should recommend that the Permitting Program require a certification by the municipality's Chief Executive Officer, similar to the traffic certification described above. The certification would confirm that the application complies with all local wetland laws, if any exist, and that the applicant has applied for and obtained the requisite wetland permit or variance to commence drilling in the proposed location.

[4] See accompanying report by AKRF, Inc.

The DSGEIS Fails to Identify or Analyze Potential Visual, Noise, Community Character and Land Use Impacts

The same defects noted above regarding potential traffic impacts apply equally to the handling of potential visual, noise, community character, and land use impacts. The EAF and EAF Addendum do not require submission of facts and data based upon which an evaluation of potential visual, noise, community character, or land use impacts could be undertaken by the NYSDEC (or other lead agency). The seven enumerated criteria cited above do not authorize the NYSDEC (or other lead agency) to require a determination of significance based on the potential significant adverse visual, noise, community character, or land use impacts. Even if one of the seven criteria is triggered and a positive declaration is made, there is no requirement that the scope of the resulting supplemental EIS would include analysis of potential visual, noise, community character, or land use impacts. Indeed, it is hard to imagine how such a supplemental EIS could include such analyses given that the EAF and EAF Addendum fail to require submission of facts that would be germane to identifying such potential significant adverse environmental impacts.

In addition, regarding potential community character and land use impacts, the EAF Addendum merely requires that the applicant attest to any existing comprehensive, open space and/or agricultural plan or similar policy document(s) it has reviewed. (DSGEIS, App. 6.) This attestation is meaningless. There are no consequences for not identifying or reviewing any of a municipality's plans and there is no requirement that an applicant take such plans into account when siting its facilities. Even if the failure to comply with such plans would have the potential to generate a significant adverse community character or land use impact, there is no requirement that such a potential impact be disclosed in the EAF or EAF Addendum, nor that such a potential significant adverse impact be mitigated.

In order to comply with SEQRA, NYSDEC must require that the applicant identify all land uses within 2,500 feet of a proposed well. These land uses should include, but not be limited to hospitals, senior citizen residences, schools, places of worship, and residential uses. If a specified land use is located within 2,500 feet of a proposed well, the applicant must include a mitigation plan detailing how it plans to mitigate potential adverse noise, traffic, visual, and light impacts to the maximum extent practicable. This plan should be subject to review and comment by local government officials of the municipality in which the proposed well will be located and must be approved prior to issuance of a well drilling permit by NYSDEC.

The DSGEIS Should Analyze an Alternative Enabling Units of Local Government to Provide Advisory Input to the NYSDEC as an Integral Part of the Well Permitting Process

The DSGEIS does not analyze, and the Permitting Program does not provide for, meaningful input by units of local government in the well permitting approval process.

Mere notification of the first application for a high-volume hydraulic fracturing well drilling operation is woefully inadequate. While the NYSDEC is correct that no statute or extant regulation requires additional notification or greater involvement by units of local government in the permitting process, it is also true that NYSDEC is not precluded from providing for additional local government involvement by regulation. It should analyze as an alternative a proposed regulation in which units of local government would be given notice of all applications for high-volume hydraulic fracturing well drilling and an opportunity to comment on such applications.

By definition, the DSGEIS does not and cannot address the specific impacts associated with an individual high-volume hydraulic fracturing well drilling application in any particular unit of local government. Given the far more intensive nature of such well drilling activities compared to traditional well drilling (especially concerning potential traffic, visual, noise, community character and land use impacts), NYSDEC is well within its rights and would be acting responsibly to protect the environment by providing a meaningful opportunity for units of local government to provide advisory input to NYSDEC as part of the permitting process. Obviously, the potential impacts of high-volume hydraulic fracturing well drilling projects will vary depending upon their specific locations. Local government involvement is essential to provide input to NYSDEC about local conditions and concerns -- especially given the very limited instances in which a determination of significance and supplemental EIS would be required in connection with future applications.

When an applicant submits an application and EAF and EAF Addendum for high-volume hydraulic fracturing well drilling, a copy of these materials should be provided to the affected unit of local government, even if the local government is not an involved agency. An applicant should be required to demonstrate that constructing and operating the proposed well will comply with the municipality's road use requirements and/or trucking plan and comply with local wetland permits and floodplain requirements.

Prior to issuing a well permit, NYSDEC should give the affected local government the opportunity to submit comments on the proposed application. In particular, the affected local government should be given the opportunity to recommend denial of the permit, or if approval is recommended, to identify conditions on which approval should be imposed by NYSDEC. In order to make such local government input meaningful, NYSDEC should adopt regulations which require it to make a reasoned elaboration in the record if it chooses to act contrary to a unit of local government's recommendation.

The foregoing is not contrary to the ECL preemption of local government regulation of well permitting, but does provide an opportunity for meaningful input by the local government within which the high-volume hydraulic fracturing well drilling will occur.

Conclusion

For the foregoing reasons, it is respectfully submitted that the DSGEIS is defective as presently written and violates the requirements of SEQRA.

Respectfully submitted,

Steven Barshov

Memorandum

To: Kate Sinding, Natural Resources Defense Council, Inc.

From: Philip C. Sears

Date: December 30, 2009

Re: **Comments on the Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program**

cc: Deborah Goldberg, Esq., Earthjustice; James Simpson, Esq., Riverkeeper; Ramsay Adams, Catskill Moutainkeeper

A. INTRODUCTION

We are pleased to have assembled the data from the team of experts[1] retained by NRDC and its partner organizations, Earthjustice, Inc., Riverkeeper, Inc., and Catskill Mountainkeeper, in order to prepare this comment memorandum on the Draft Supplemental Generic Environmental Impact Statement (DSGEIS) on the Oil, Gas, and Solution Mining Regulatory Program. These comments are intended to assist the New York State Department of Environmental Conservation (NYSDEC or Department) in identifying relevant areas of environmental and public health concern that require new or substantially revised research and analysis before the DSGEIS will (1) disclose and evaluate all of the potential environmental impacts of gas exploration, development, and production, including use of horizontal drilling and high-volume hydraulic fracturing to develop natural gas resources from the Marcellus Shale and other low-permeability gas reservoirs; (2) comprehensively evaluate existing rules and new regulations required to govern such development (the Regulatory Program) and the Department's enforcement capacity and practices so that they adequately protect the environment and public health and safety from this industrial activity; (3) thoroughly present best management practices and mitigation measures that will promote safe and environmentally benign development; (4) carefully analyze the cumulative impacts of full development; and (5) support selection of an alternative that will result in the fewest unmitigated significant adverse environmental impacts.

[1] CEA Engineers, P.C., Harvey Consulting, LLC., Dr. Glenn Miller, and Dr. Tom Myers

This memorandum summarizes the extensive analysis of the DSGEIS by the assembled team of experts in the fields of engineering, environmental impact analysis, hydrogeology, toxicology, hydrology, and biology. Appended are 8 attachments that contain the full analyses supporting the comments in this memorandum.

B. OVERARCHING COMMENTS

Overall, the DSGEIS does not meet the requirements of the State Environmental Quality Review Act (SEQRA). The DSGEIS does not analyze all low-permeability formations; fails to provide analyses of key areas of environmental concern and human health; and offers only incomplete analyses of other areas. The DSGEIS does not propose a complete regulatory program, relying instead on a proposed permitting process, which itself is not sufficient to protect human health and the environment. Significant mitigation measures proposed in the body of the DSGEIS are missing from the list of permit conditions in Appendix 10. The DSGEIS further fails to contain legally required regional and statewide cumulative impacts assessments; segments potential impacts of developing natural gas resources so as to exclude them from its analyses; and does not adequately consider alternatives. Proceeding with gas development in the Marcellus Shale and other low-permeability formations on the basis of the DSGEIS would accordingly be arbitrary and capricious, unsupported by substantial evidence, and contrary to law.

FAILURE TO ANALYZE ALL NEW YORK LOW-PERMEABILITY GAS RESERVOIRS

The subtitle of the DSGEIS indicates that the document will analyze impacts of developing "the Marcellus Shale *and Other Low-Permeability Gas Reservoirs*." (Emphasis added.) However, the DSGEIS attempts to analyze potential impacts from developing only the Marcellus Shale. The text briefly describes the Utica Shale, but without offering any environmental analysis of its development. The DSGEIS presents no evidence that the impacts of developing other shale formations will be the same as those caused by Marcellus Shale development. In fact, there is strong evidence that the impacts will be materially different. Therefore, the DSGEIS may be considered applicable only to the Marcellus Shale and not to other low-permeability natural gas reservoirs unless substantial scientific and technical analyses are added in a revised DSGEIS.

LACK OF A COMPREHENSIVE REGULATORY PROGRAM

The DSGEIS was intended to supplement the 1992 environmental review of the oil, gas, and solution mining "regulatory program" to address development of the Marcellus Shale. However, the DSGEIS falls short of recommending a supplemental, comprehensive regulatory program for the Marcellus Shale. It has been 37 years since New York State first adopted most of its oil, gas, and solution mining regulations. Thus, it is past time for an updated and revised regulatory program, and the SGEIS could, if properly prepared, serve as an appropriate tool, to identify regulations that must be adopted for safe, effective development of the Marcellus Shale.

Throughout the DSGEIS words like "should," "recommended," and "suggested" are used in conjunction with proposed mitigation measures, but there is no corresponding recommendation to codify these requirements in enforceable regulations. The DSGEIS assumes that its recommended or suggested measures would be implemented, but it does not propose new regulations or identify resources needed to enforce implementation of the suggestions. Instead, the DSGEIS proposes to implement mitigation measures exclusively through the applicant's completion of new forms and checklists, and through NYSDEC's imposition of permit conditions. The use of permit conditions, in place of codifying these requirements in regulations, is an unacceptable solution. Permit conditions can be changed and modified with each permit

application without any public environmental review. There is no assurance that NYSDEC has sufficient personnel or financial resources to implement this new patchwork of permit conditions. The public and the industry have no assurances that the limitations agreed upon in the SGEIS process will continue to be implemented and enforced in a consistent manner.

By promulgating regulations, NYSDEC would alert the oil and gas industry to what it has to do, the community is ensured that environmentally protective mandates will be imposed consistently, and the regulators have clear guidance in enforcing operational standards and mitigation requirements. The SGEIS process provides the Department with an excellent opportunity to develop and implement a state-of-the-art regulatory program for the oil and gas industry in New York State. Unfortunately, the DSGEIS and the proposed permit conditions do not even approach this goal. The DSGEIS does not encompass either the full range of processes that are necessary to successfully develop the natural gas resources (i.e., exploration, development, production, and closure) or the ancillary facilities needed for and induced by that development. Even the permit conditions (no regulations are proposed) for the development processes that are covered do not constitute best practices adopted in other federal and state regulatory programs for the oil and gas industry. Before the Final SGEIS can be prepared, NYSDEC must recommend and submit for public review a complete, improved regulatory program, and establish standards and best practices from exploration, through production, treatment, gathering, transmission of the natural gas into regulated pipelines, and closure of the wells.

FAILURE TO INCLUDE NECESSARY ANALYSES

The DSGEIS includes inadequate analysis in many areas of human health and environmental concern and it fails to provide any analysis in other areas. It therefore fails both to disclose all potential significant adverse impacts and to describe the mitigation measures necessary to avoid or minimize those impacts to the maximum extent practicable, as required by law. For example, there is no quantitative analysis to support NYSDEC's recommendation for noise mitigation, although models are readily available for such analysis. There is no analysis whatsoever of traffic impacts, even though the DSGEIS admits that as many as 1,350 truck trips will be needed for the fracturing of a single well, and that multiple wells are likely to be developed simultaneously at a single well pad. The analytical deficiencies combined with the lack of analysis in many of the critical technical areas makes the DSGEIS incomplete with any number of undisclosed significant adverse impacts.

CUMULATIVE IMPACTS

The DSGEIS does not analyze the potential for cumulative impacts on a regional or statewide basis on the grounds that "*the number of wells which will ultimately be drilled cannot be known in advance....*" (Section 9.2.1). Reasonable worst cases are regularly developed for SEQRA disclosure purposes. As an example, almost every large area rezoning includes a reasonable worst case analysis, even though a build out plan does not exist. A regional reasonable worst case of gas development of the Marcellus Shale including secondary impacts on a regional and statewide basis can, and **must be** developed in order to present a comprehensive analysis of potential impacts. The failure to disclose cumulative impacts deprives the decision makers of a rational basis for going forward. The experience in Pennsylvania where 99 Marcellus permits were issued in 2007 and nearly 1,600 were issued through October 31, 2009 provides one basis for making an estimate of likely future development in an area. In addition, one gas development company has supplied its internal estimates of the rate of development to the Department

(Section 6.13.2.1), which provides a second basis and a check on the Pennsylvania experience. In addition, shale gas development experiences in Pennsylvania, Texas, and Colorado provide data on the available number of workers, equipment, and market trends that have not been analyzed in the DSGEIS.

SCOPE OF REGULATORY PROGRAM

NYSDEC limits the analyses in this DSGEIS to drilling and fracturing of the Marcellus Shale, while ignoring all other parts of developing the gas resource. Drilling a well, and stimulating it, is only the start of the process of "Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs."

Gas resource development occurs in two distinct phases: (1) exploration and (2) production; commonly referred to as the upstream Exploration & Production (E & P) sector, to distinguish between downstream activities such as refining and marketing. Exploration activities are completed to locate the hydrocarbon resources, and collect sufficient data to determine whether the hydrocarbon resources can be safely and economically developed. Exploration processes typically include: drilling, completion, seismic data collection, geologic and geophysical assessment, and other studies. Due to the very limited amount of data known and available on the Marcellus Shale, it is evident that New York is still in the Marcellus Shale exploration phase.

Prior to conducting exploration, an EIS is typically completed to identify methods to mitigate exploration impacts. If data collected during exploration supports a production/development scenario, then larger scale production (multiple wells, on larger drill sites, and surface processing and distribution facilities) may be needed to develop the resource.

A full EIS examination of the production scenario is the next step after exploration activities are completed. Typically two different EIS analyses are performed; yet, in this case NYSDEC attempts to combine exploration and production drilling and fracture treatment all into one SGEIS. The DSGEIS fails to meet scientific and technical standards because there are insufficient data at this time to support an EIS beyond exploration.

NYSDEC attempts to include the production phase in this DSGEIS, but it encompasses only the drilling and completion portions of the production phase, ignoring the surface processing facilities, pipelines, compressor stations, service areas, and waste treatment facilities needed to develop the Marcellus Shale.

It is recommended that the DSGEIS be limited to the Marcellus Shale exploration phase, to match the data set available at this time. This does not preclude the DSGEIS from recommending regulatory improvements that clearly should be put in place for the future production scenario, but it allows a conservative, step-wise, rational process to take place to collect data during the exploration phase to support a future production scenario.

When sufficient data are available from the exploration phase, an EIS can be developed to evaluate the full suite of production impacts from all production activities (drilling, completion, surface processing facilities pipelines, compressor stations, service areas, and waste treatment facilities) not one limited just to a small segment of the production phase (i.e., drilling and completion), as in this DSGEIS. Examples of the data sets required to properly analyze the potential impacts from development, production, and closure are given in Attachment A.

SEGMENTATION

The DSGEIS contains several instances of segmentation. The document must take into account the readily predictable secondary development that will inevitably result from the proposed action, such as development of ancillary servicing and treatment facilities for the produced natural gas and its waste products. For example, the October 14, 2009 issue of NYSDEC's Environmental Notice Bulletin contained a negative declaration for the Schlumberger 65-acre natural gas servicing facility at Horseheads. Construction of this facility was directly induced by expected drilling for natural gas in the Marcellus Shale, and the potentially significant adverse impacts from this project and similar projects that will be built as a result of gas development activities should be analyzed in the DSGEIS. In addition, the DSGEIS in Section 5.16.8 claims that the potential impacts from the necessary new pipelines would be reviewed by the Public Service Commission (PSC). However, a large number of pipelines, including high pressure less than a certain length and low pressure, are specifically excluded from PSC jurisdiction, except for safety matters. Therefore, these pipelines would be built through the area of Marcellus Shale development without any type of environmental review. The same applies for servicing facilities. PSC was not the lead agency for the Schlumberger facility mentioned above. The need for servicing facilities and gathering pipelines comes directly from the issuing of permits to drill and produce natural gas; gathering pipelines and servicing facilities have no independent utility without the permits for drilling and producing natural gas. This type of induced growth, as well as construction of new waste treatment facilities needed for gas wastewater treatment, has been segmented from the permitting of individual wells.

ALTERNATIVES

SEQRA requires analysis of alternatives to the proposed action, but the DSGEIS does not present any meaningful analysis of alternatives. First, each EIS must contain a "no action" alternative.'

Characterizing the prohibition of developing natural gas from the Marcellus Shale as the "no action" alternative is not appropriate. The "no action" alternative would be continuation of the current program without alteration. A proper analysis of the "no action" alternative must be prepared.

The consideration of prohibitions on development—whether in parts or all of New York State—is appropriate in the context of evaluating alternatives that could result in fewer unmitigated significant adverse impacts than those associated with proposed action. The DSGEIS fails to consider partial prohibitions at all. Its discussion of a full prohibition ignores the fact that the policies and laws of New York State encourage development of oil and gas resources only after giving due consideration to the interest of the general public, e.g., significant environmental and public health risks. This alternative should be reevaluated in that context.

The Phased Permitting alternative is summarily dismissed as a possible alternative because of "…the inherent difficulties in predicting gas well development for a particular region or part of the State" (page 9-3). As addressed above in the context of NYSDEC's failure to properly evaluate the cumulative impacts of the proposed action, SEQRA does not allow a lead agency to avoid developing an analysis because it is "difficult." NYSDEC has not considered whether phasing in permitting in regions or all of the state is an appropriate alternative that would better mitigate cumulative significant adverse environmental impacts on a regional or statewide basis.

The Green or Non-Chemical Fracturing Technologies and Additives alternative addresses only one source of potential impacts from developing the Marcellus Shale, i.e., the use of non-chemical fracturing fluids. Even in this regard, NYSDEC has failed to use its regulatory authority to properly ascertain whether such fluids might in fact be viable alternatives; nor has it performed the requisite analyses to determine whether some or all proposed chemical constituents should be prohibited from use. Nor does the document consider whether less toxic alternatives are available to address other identified impacts not associated with the fracturing fluids. It is therefore not an adequately examined alternative.

The slim 10 pages of text on alternatives contain no analysis and improperly dismiss three legitimate alternatives (Partial prohibition on development, phased permitting, and the use of non-toxic technologies and additives) with potentially fewer unmitigated significant adverse environmental impacts in violation of SEQRA's requirements.

C. DETAILED TECHNICAL COMMENTS

Overall, the DSGEIS does not meet the requirements of SEQRA. The document does not include all of the technical areas of analysis promised in NYSDEC's Final Scope of Work. The 803-page document does not have an Executive Summary, which is a required element [6 NYCRR § 617.9(b)(4)]. The level of analysis in almost every technical area fails to satisfy the "hard look" standard of SEQRA. Whole areas of potential impacts are ignored. The *City Environmental Quality Review (CEQR) Technical Manual, 2001* has established methodologies and criteria for analyzing potential impacts in the wide range of technical areas required in the preparation of an Environmental Impact Statement. In areas where New York State does not have established methodologies and criteria, the use of the *CEQR Technical Manual* is suggested. Where some level of analysis is provided, no real conclusions regarding the analysis are made. When some conclusions are reached, they are often not translated into permit conditions, and no regulations are proposed. SEQRA regulations require analysis for potential catastrophic events, which is specifically called for in projects with natural gas facilities [*id*. § 617.9(b)(6)], but the DSGEIS contains no such analysis. Environmental justice is mentioned, but no analysis is provided, and NYSDEC imposes no requirement that environmental justice be analyzed as part of a site-specific assessment. The DSGEIS lists several mitigation "plans" as proposed permit conditions, but plans that are not subject to public reviews or NYSDEC approval are not sufficient mitigation measures. Specific comments on each technical area are presented below, and relevant backup studies are attached.

ADHERENCE TO FINAL SCOPE

The DSGEIS does not include all of the analyses that NYSDEC committed to prepare in the Final Scope of Work. Attachment B lists all of the analyses that were included in the Final Scope of Work and highlights the analyses that were not completed. Among the major areas for which the DSGEIS analysis does not match the Final Scope of Work are: water withdrawals, cumulative impacts, traffic, noise, and emergency response. The Final SGEIS must be expanded to include all of the analyses that the Department committed to in the Final Scope of Work. If the Final SGEIS is to be applied to other low-permeability formations, a new draft SGEIS will be needed to examine all technical areas listed in the Final Scope of Work for those formations, because the DSGEIS is silent on all other low-permeability gas reservoirs.

BEST MANAGEMENT PRACTICES

Scope of DSGEIS

The DSGEIS scope should be limited to analysis of the Marcellus Shale Gas Reservoir. The Marcellus Shale is a substantial accumulation, and warrants its own EIS analysis. Additional information and analysis is needed to examine the impacts of exploring and developing other low-permeability gas reservoirs.

There are insufficient data available on the Marcellus Shale Gas Reservoir to support a statewide exploration and production plan. The data set provided by NYSDEC in this first draft SGEIS is equivalent to that supporting only early exploration. There is insufficient information to support statewide production/development scenarios for the Marcellus Shale Gas Reservoir. NYSDEC should consider either:

- Narrowing the scope of this DSGEIS to exploration activities, and baseline study work, and completing a separate future EIS when additional exploration data is available to support a production/development case; or
- Clearly outline in this DSGEIS the data set that must be obtained, and analyses that must be performed during exploration, to obtain sufficient information to support a production/development case. The DSGEIS should then establish a process for conducting a site-specific environmental assessment for each production/development well site (or unit of well sites proposed by a single developer in the same area) based on that data collected during the exploration phase.

NYS Regulations Are Needed to Guide Marcellus Shale Exploration & Development

NYSDEC should update its regulations to include best technology and best management practices for oil and gas exploration and production in general, and more specifically for shale gas development. Oil and gas exploration and production should not be managed using out-of-date regulations, augmented by a patchwork of permit conditions and guidance memoranda. An updated regulatory framework provides: operators with clear, consistent rules to work from; NYSDEC staff with simplified instructions for implementation; a public process for input; and a more orderly and safe exploration and development process for New York State.

Even if NYSDEC persists, without adequate data, in addressing both exploration and production in this SGEIS, the proposed supplementary permit conditions are incomplete and inconsistent with both some of the DSGEIS findings and best technology/practices for gas shale development. The “Proposed Supplementary Permit Conditions” should be renamed to serve as a “List of Regulatory Proposed Improvements of and Revisions to New York State’s Regulations.” This list should reflect the numerous recommendations in this memorandum and its attachments and those substantive comments received by NYSDEC from others. The list should be used to revise New York State regulations, because the DSGEIS claims to be serving and should appropriately serve as the basis for examining and improving NYSDEC’s “regulatory program” for shale gas.

New York State’s regulations need to be revised to address Marcellus Shale gas development, provide a clear, complete list of prohibited activities, and describe maximum allowable levels of activities and expected mitigation. When codified in regulations, NYSDEC staff, the applicant, and the public will fully understand the “bottom-line” requirements.

Drilling Mud Composition and Drilling Waste Disposal

New York State regulations should be revised to acknowledge and mitigate drilling mud pollution impacts, minimize drilling waste generation, limit heavy metal and Normally Occurring Radioactive Material (NORM) content, and establish best practices for collection, treatment and disposal of drilling waste.

Disposal of Drilling & Production Waste & Equipment Containing NORM

NYSDEC should adopt regulations to establish best practices for collection, treatment, and disposal of drilling and production wastes, as well as equipment containing NORM. NYSDEC should adopt regulations prohibiting use of Marcellus Shale gas wastewater containing NORM for land or road spreading applications.

Casing and Cementing Requirements

New York State casing and cementing regulations should be developed specific to Marcellus Shale gas reservoir development. They should address high angle well construction, ensuring that casing and cementing are structurally sound and provide an effective drinking water barrier, particularly when high-volume fracture treatments are performed.

Flaring, Venting, and Fugitive Emissions

NYSDEC should develop regulations to restrict flaring, venting, and fugitive emissions to the lowest level technically feasible.

Hydrogen Sulfide

NYSDEC should adopt regulations to require gas production operators to follow hydrogen sulfide detection and protection procedures for employees and the public during drilling and production operations.

Seismic Data Collection

NYSDEC should establish regulatory requirements for seismic data collection that reduce impact to the environment and the public.

Corrosion & Erosion Control

New York State regulations should require equipment to be designed to prevent corrosion and erosion, and require monitoring, repair and replacement programs.

Spill Prevention

NYSDEC should adopt regulations to require more stringent oil spill prevention measures for temporary fuel tanks associated with drilling and well stimulation activities. NYSDEC should incorporate existing United States Environmental Protection Agency (EPA) oil spill prevention standards for oil and gas activities that require secondary containment for all fuel tanks 1,320 gallons and larger.

Spill Response

NYSDEC should adopt EPA Spill Prevention Control and Countermeasures (SPCC) requirements for drilling operations.

Fuel Selection

NYSDEC should require operators to use cleaner fuels than diesel (such as natural gas) or electric power whenever technically feasible.

Hydraulic Fracture— Design and Monitoring

NYSDEC should revise its regulations to specify best technology and best practices that must be used to collect data, model, design, implement, and monitor a fracture treatment. The regulations should specify that all data collected by industry must be reported to NYSDEC and made available to the public. Best technology and best practices should include:

- Collecting additional geophysical and reservoir data to support a reservoir simulation model;
- Developing a high-quality Marcellus Shale 3-dimensional reservoir model(s) to safely design fracture treatments;
- Hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone;
- Careful monitoring of the fracture treatment, including shutting the treatment down if data indicates casing leaks or out-of zone fractures;
- Collecting data, and carefully analyzing fracture treatment performance in the field on smaller fracture treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience (e.g. at least 4,000 feet deep and 150 feet thick);
- Using experience gained on fracture testing to design and implement larger treatment volumes over time (potentially allowing increasingly shallower and thinner intervals, only if technical data supports the safety of this technique);
- Documenting, reporting, and remediating fracture treatment failures to ensure drinking water protection; and
- Taking a conservative, step-wise approach to ensure there is technical data to support high-volume fracture treatments that protect the environment, before NYSDEC issues a blanket approval to fracture the Marcellus Shale at all depths and all thickness intervals.
- NYSDEC needs to technically justify the proposed minimum 1000-foot vertical offset with actual field data, 3-dimensional reservoir simulation modeling, and a peer-reviewed hydrological assessment to ensure drinking water sources are protected.

Hydraulic Fracture Treatment Additive Limitations

NYS regulations should identify the type, volume, and concentrations of fracture treatment additives that are protective of human health and the environment. NYSDEC regulations should develop a list of prohibited additives and require the use of non-toxic materials to the extent possible.

Hydraulic Fracture Fluid Flowback Impoundments

New York State regulations should require fracture fluid flowback be routed to onsite treatment systems for fracture fluid recycling and/or collected in tanks for transportation to offsite treatment systems. Surface impoundments should not be used for fracture fluid flowback.

The DSGEIS should disclose how many times a well may be fractured and treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario.

Chemical Tank Containment

NYSDEC should adopt regulations requiring secondary containment for chemicals stored on the well pad or, alternatively, the use of double-wall tanks.

Reserve Pit & Impoundment Liner Quality

NYSDEC should adopt regulations requiring closed-loop tank systems as a best practice instead of reserve pits and impoundments, unless the operator demonstrates that it is not technically feasible.

If reserve pits and impoundments are demonstrated to be environmentally preferable, NYSDEC should adopt regulations that require impermeable, chemical resistant liner material, and limit the type of chemicals stored to those compatible with the liner material, require wildlife protection design standards, and establish firm removal and restoration requirements.

Wellbore Plugging & Abandonment Requirements

NYS regulations should clearly state when future Marcellus Shale wells must be plugged and abandoned, and this should be retroactively applied to existing wells that are no longer operating and may pose a risk to the environment.

Well Control & Emergency Response Planning

NYS regulations should be updated to include best practices for well control and emergency response planning.

Hazardous Air Pollution Control

NYS regulations should include best technology and practices to reduce hazardous air pollution to the lowest possible level.

Compressor Stations, Pipelines, and Gas Processing Facilities

NYSDEC should include compressor stations, pipelines and gas processing facilities in the DSGEIS, and identify best technology and practices for this equipment.

NYSDEC Inspection and Enforcement Program

NYSDEC should demonstrate in the DSGEIS that it has the personnel, equipment, technical expertise, and funding to carry out the inspection and enforcement procedures listed in the DSGEIS.

Financial Assurance Amount

NYSDEC should require financial assurance adequate to fund long-term monitoring, publicly incurred response costs and the cost of properly remediating and abandoning operations.

Attachments C and D provide further analysis and explanation of these recommendations.

HYDROLOGY AND HYDROGEOLOGY

HYDRAULIC FRACTURING FLUID SETBACKS

Hydraulic fracturing operations require that a large volume of fracturing fluids (e.g., water, chemicals, and propping agents) be stored on a well pad in preparation for a fracturing treatment. These materials have the potential to be spilled. Some of the fracturing fluids injected into the shale for fracturing will return to the surface as flowback, which also could spill. The operator must provide a means of capturing, handling, and storing the high volume of flowback which

will flow at rates up to 130 gallons per minute (gpm). NYSDEC appropriately proposes to require tanks at the well site to handle flowback. However, because of the potential for leaks to occur in the connection between the well and tank, additional site-specific analysis should be required for every gas well located 2,000 feet or closer to surface water sources. In addition, a monitoring well system should be installed for every gas well 1,000 feet or closer to domestic drinking water wells.

Attachment D provides further analysis and explanation of this recommendation.

HYDRAULIC FRACTURING WATER SUPPLY

The large amounts of water withdrawn from streams or rivers for fracturing may harm downstream surface waters by depleting and lessening flows sufficiently to impair public water supplies, natural habitats, and water quality during low flows periods. The discussion of water withdrawals for fracturing downplays these potential impacts by considering the withdrawals only in the context of large river basins.

The DSGEIS considers different regulatory regimes from the different commissions that have regulatory authority, but none of the approaches considered are protective of habitat. The Natural Flow Regime Method, proposed for application in the area regulated by NYSDEC, would limit diversions during normal low flow periods and is to be preferred to the other methods discussed in the DSGEIS. However, diversions should be allowed only when aquatic habitat will be minimally affected. This standard would permit water withdrawals only when the flow rate achieves a water level at or above the point where the wetted perimeter/flow area ratio is a minimum. The DSGEIS proposes a minimum passby requirement equal to 30 percent of the average annual daily flow. This requirement is reasonable only as long as the minimum passby is greater than 30 percent of average monthly flow during the month in which the diversion will occur. This added restriction is necessary to protect wet season flows responsible for channel forming processes. These recommendations may prevent diversions during much of the latter half of the summer and early autumn when the aquatic ecosystems are most stressed. The gas industry could be allowed to make diversions in advance of its late summer needs and store the water in tanks, lined ponds, or other reservoirs if the timing is going to be an issue.

Industry may propose to withdraw groundwater instead of or to supplement its surface water withdrawals. Most of the proposed mitigation provisions merely require that well operators report their pumping rates if they exceed certain levels, which is insufficient to protect the aquifer resource and its discharges to surface water. NYSDEC should specify a limit to the amount of water that can be diverted from an aquifer based on the expected recharge to that aquifer. NYSDEC should also specify the conditions under which the withdrawal of sufficient water for fracturing would be a “depletion” of an aquifer or “potential” aquifer. For example, a 5,000,000 gallon diversion is more than would be removed in a year by 15 domestic wells and could significantly impact the water balance of a small aquifer.

The passby regulatory regimes in the areas controlled by the Delaware River Basin Commission, Susquehanna River Basin Commission, and Great Lakes Compact are all insufficient to adequately protect downstream waters. To ensure that drilling in these areas does not result in significant adverse impacts to such waters, NYSDEC should evaluate whether it is necessary to limit (or even prohibit) development of the Marcellus Shale in these areas.

Attachment D provides further analysis and explanation of this recommendation.

HYDROGEOLOGY AND GROUNDWATER

The DSGEIS provides too little information about the targeted shale and the overlying formations. There are little or no data concerning hydraulic conductivity, porosity, groundwater contours, or natural flow directions, either horizontal or vertical. Hydraulic fracturing changes the properties of the targeted shale so that gas will flow toward the well, but this process will also change the flow paths. Industry should provide well logs, appropriate geochemistry of the cuttings, and cores, whenever possible, from the wells they drill to determine and verify the intrinsic properties of the shale in New York prior to fracturing.

Fracturing by injecting fluids into the shale will cause conditions that make transport of contaminants from the shale to surface aquifers possible. Specifically, fracturing could allow contaminants to exit the shale and reach the overlying formations where, if there is a vertical groundwater gradient, contaminant transport to the surface could contaminate aquifers. The potential contaminants include both flowback of the fracturing fluid and produced water from the formation. According to the DSGEIS, fracturing operations average about 5.0 million gallons of fluid and about 65 percent of it does not return to the surface as flowback. A simple numerical analysis (see Attachment D, Appendix A) demonstrated one simple conceptual flow pathway that would allow contaminants to reach overlying media, but there are many other potential pathways.

No vertical offset alone would guarantee that contaminants will not flow from the shale to the aquifers over time. Only a detailed site-specific analysis can determine the risk. In areas with an upward groundwater gradient above the shale, the industry should complete adequate site-specific analysis for all well pads. NYSDEC should include in its revision of the DGEIS a map of vertical groundwater gradient. The operator should collect a core sample and water level measurements to determine the vertical gradient and media properties at each site within an area with a vertical gradient. The operator should then do standard transport calculations to estimate the potential for contaminants to reach the surface aquifers. If the calculations based on measured data yield a travel time estimate of less than 500 years, the operator should be required to design the fracturing operation to end 25 feet shy of the edge of the shale and complete appropriate tests to verify that fractures did not reach into the overlying media. NYSDEC should require that the industry apply for permits covering an entire well pad or a series of well pads located closely together at one time. NYSDEC should also require more site-specific data regarding the geology and additional analysis of vertical transport as outlined above in this section.

The potential for long-term contaminant transport to the near-surface aquifers is real, but determining the source years in the future or assigning responsibility will be very difficult. NYSDEC should implement a long-term monitoring plan based on regional geology and flow and transport modeling to provide a lead time to identify the movement of contaminants and plan to mitigate it.

MONITORING WELLS SYSTEM

The monitoring system should be vastly improved over that proposed in the DSGEIS which includes testing only of existing domestic drinking water wells. Once contamination reaches these wells, it will be too late to prevent the degradation. NYSDEC should instead require dedicated properly screened monitoring wells between the well pads and nearby domestic wells. Monitoring should continue substantially beyond the end of production because of the long-term potential for transport from well pads to domestic drinking water wells.

Attachment E contains the detailed analyses to support these recommendations.

TOXICOLOGY OF FRACTURING FLUID AND WATER FROM THE MARCELLUS SHALE

The DSGEIS falls short of an adequate assessment of the risk of using the fracturing additives for hydraulic fracturing of the Marcellus Shale in New York. It similarly falls short of assessing the risk of formation waters contaminated with high levels of Total Dissolved Solids (TDS), heavy metals, and radioactivity, which will be transported to the surface both as a component of the flowback and during production. Specifically the following summary points should be considered:

Hydraulic Fracturing Additives

- The additives used in the hydraulic fracturing process are not well defined and the DSGEIS essentially provides only a laundry list of approximately 258 chemicals that may be used in the process.
- There is effectively no indication of the toxicity of each chemical, and insufficient information is provided that would allow the public to understand the hazard associated with individual or groups of chemicals.
- There is no clear indication of how much of each chemical will be used, and this lack of information is particularly troubling, because it eliminates the ability of the public to understand the risk of using effectively all of these chemicals.
- Certain of these chemicals will react with others and produce secondary products that are particularly problematic. Again, the lack of information on which chemicals will be used eliminates the opportunity to conduct a reasonable risk assessment for use of these chemicals.

A more complete listing of the use rates of these chemicals is required, as well the quantities of chemicals that will be used.

In addition, NYSDEC appears to place no restrictions on use of any of the chemicals, even though certain of these chemicals (e.g., acrylamide and benzene) pose significant risks, including carcinogenicity. NYSDEC should re-evaluate use of these 258 chemicals and propose use restrictions on the most toxic of the group.

Gas Wastewater:

- The flowback water (containing both the shale fracturing water and the produced water) that will carry contaminants from the shale and the fracturing additives is likely to be highly contaminated with metals, salts, and radioactivity that, in some cases, are greater than 1,000 times the drinking water standards. This level of contamination is sufficiently high that any level of contamination of surface and groundwater is unacceptable.

NYSDEC needs to develop a much better data set on the expected concentrations of contaminants in the gas wastewater, and should require disclosure of both the identities of the chemicals being produced in the waste as well as the amounts of those chemicals.

Chemical Analysis and Monitoring Issues:

- Many, if not most, of the hydraulic fracturing additives are not included as analytes in standard chemical analyses of flowback water. If a chemical is being injected into the subsurface (and thus has the potential to contaminate surface or accessible groundwater), that

chemical should be measured in the flowback and in samples of groundwater withdrawn from strategically located monitoring wells.

The NYSDEC should require that the identity of the hydraulic fracturing additives be revealed at each specific well, and require the gas production entities to establish monitoring methods for those chemicals, as well as a protocol and plan for their monitoring.

Monitoring of wells for these contaminants should be conducted at least for a full year (monthly or at least quarterly sampling) before drilling begins to provide a baseline for seasonal changes in water quality.

Following plugging and abandonment of a gas well, monitoring should be required for a minimum of 5 years, with a special emphasis on testing for those contaminants that will move the most rapidly (e.g., chloride). Prior to installation of these gas recovery wells, site-specific plans for cleanup of contamination should be developed by the operator and approved by NYSDEC.

Attachment F has further analysis and explanation of these recommendations.

WASTEWATER, STORMWATER, AND SPILLS

NYSDEC fails to assess and provide mitigation measures for the cumulative potential environmental impacts associated with wastewater treatment; energy use; increased stormwater pollution from wastewater transport; unavoidable spills of wastewater, drilling fluids, and other chemicals associated with natural gas development; and disposal of solid waste generated by natural gas wastewater treatment processes. NYSDEC must assess all of the cumulative adverse environmental impacts of both wastewater and stormwater associated with natural gas development processes and ancillary treatment facilities.

The DSGEIS does not evaluate the cumulative volume and production rate of wastewater requiring treatment and fails to identify publicly-owned treatment works (POTW) or private wastewater treatment plants (WWTP) with adequate capacities and treatment technologies to accept, treat, and dispose of the generated wastewater from individual or multi-well pad sites. NYSDEC must require that applicants for well drilling permits produce a signed contract for the disposal of flowback water to be treated off-site at an authorized POTW or other permitted WWTPs. Additionally, NYSDEC must require an analysis of all potential contaminants in the flowback water and the impact of the contaminants, including barium and iron, on the ability of a OITW ir WWTP to treat the generated wastewaters.

The DSGEIS does not account for the cumulative impacts of multiple stormwater discharges to a stream or river that may result in increased flow, in-stream velocities, and increased total suspended solids (TSS) and turbidity. Additionally, as the cumulative effects of increased TSS and turbidity could potentially result in the need for New York City to construct a filtration system for the drinking water supply, NYSDEC must provide a regional cumulative analysis to determine the potential impacts of stormwater discharges within the watershed associated with individual and multi-well pad sites.

In addition to TSS and turbidity, NYSDEC fails to identify and evaluate the impact of stormwater runoff on the highly erodible soils found within the Marcellus Shale, and fails to evaluate the inability of typical stormwater management systems to effectively remove such soils. Flocculants are sometimes used to improve the settleabilty; however, NYSDEC has not evaluated the use or limitations on the use of these flocculants. NYSDEC must evaluate the cumulative potential impacts resulting from the use of flocculants or other additives that the

Department will allow operators to use to enhance soils that settle poorly and also evaluate potential limitations on the use of these flocculants, as they are toxic to aquatic fauna such as rainbow trout.

The DSGEIS fails to provide any changes to Section AD of the Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity (MSGP), and therefore, it is not possible to fully assess the impacts of industrial stormwater associated with gas well development. NYSDEC must provide an analysis of industrial stormwater environmental impacts and mitigation measures for each individual permit. If and when NYSDEC modifies the MSGP, another SGEIS must be prepared that analyzes industrial stormwater environmental impacts and defines mitigation methods.

Attachment G contains the detailed analyses to support these analyses and recommendations.

NATURAL RESOURCES

The DSGEIS does not fully address the cumulative impacts to various natural resources that would be affected by gas development processes. Stormwater discharges from multi-well pad sites would increase in-stream erosion resulting in an increase in TSS and turbidity in receiving waters. The NYSDEC fails to evaluate the cumulative impact of such increases of TSS and turbidity on the fauna that utilize the associated watercourses and waterbodies. Increases in turbidity have demonstrated detrimental effects on freshwater fish, including trout and bass, and have the potential to result in significant changes to population dynamics among fish populations and other aquatic species.

The DSGEIS does not fully address the potential cumulative impacts associated with spills of brine, spent fracturing fluids, chemical additives, and petroleum products. NYSDEC must provide adequate setback requirements for all watercourses and waterbodies, including wetlands, so as to afford equal protections of these resources in the event of a spill. Additionally, NYSDEC must prohibit the placement of well pads and all ancillary equipment within floodplains to eliminate the potential for flood-related spills of contaminants.

The DSGEIS does not provide a comprehensive analysis of the potential cumulative impacts to wildlife, such as the noise associated with multi-well pad development. NYSDEC also fails to analyze the effects of flowback water surface impoundments on vernal pools, waterfowl, and migratory bird species. An individual and cumulative impacts analysis on bats, including the state and federally endangered Indian bat (Myotis sodalis), must also be conducted by NYSDEC to fully address the potential for impacts to bat hibernacula. Finally, NYSDEC fails to address the potential cumulative impacts on rare, threatened, or endangered (RTE) species as a result of habitat destruction and fragmentation resulting from individual and multi-well pad development. NYSDEC must provide a comprehensive analysis of all potential cumulative impacts to wildlife associated with noise, flowback water surface impoundments, and habitat destruction and fragmentation resulting from gas well development processes.

NYSDEC must require a four-season natural resource inventory (NRI) for both individual and multi-pad well sites to provide a comprehensive analysis of flora and resident and migratory fauna. NYSDEC has the ability to provide detailed maps for public review that would assist in a comprehensive evaluation and understanding of the regional cumulative impacts to watercourses, waterbodies, wetlands, and RTE species within areas of potential gas well development.

Attachment G contains the detailed analyses to support these recommendations.

CENTRALIZED FLOWBACK IMPOUNDMENTS

The DSGEIS contemplates that centralized surface impoundments could be proposed to store flowback for substantial periods prior to treatment or for recycling. Steel tanks should be required for any centralized storage of flowback water because lined systems are subject to leakage and tears. If impoundments are permitted, contrary to these recommendations, all wells proposed to use such impoundments should be disclosed during the permitting process. NYSDEC proposed that centralized impoundments use a double-liner system (or tank) with leak detection, with requirements based on landfill regulations. If permitted to be used at all, NYSDEC should require that centralized impoundments be lined with a dual synthetic liner system and leak detection system. Synthetic liners should have permeability of 1×10^{-11} centimeters per second (cm/s) or less. A geosynthetic clay liner (GCL) must have the equivalent conductivity of two feet of clay compacted to 1×10^{-7} cm/s. The leak detection system should not be designed as a drain, and should be limited to 150 gallons per day (gpd) for the entire unit, which may be a pond of over 5 acres.

Attachment D contains the detailed analyses to support these recommendations.

AIR QUALITY

The air quality modeling and analysis is not conservative and may understate the significant adverse impacts that are predicted to occur. As an example, the air modeling assumed that one rig would be operating at a time, while the DSGEIS states that two rigs might be operating at the same time (Section 5.2.1) This non-conservative analysis found that the emissions from drilling on a well pad would exceed 24-hour ambient air quality standards for particulate matter finer than 2.5 microns ($PM_{2.5}$) by a factor of 10 and for particulate matter finer than 10 microns (PM_{10}) by more than a factor of 3 (Table 6.17). The air quality modeling did not include mobile sources, and large trucks are known to be large contributors of particulate matter. These exceedances are significant adverse impacts, even though the DSGEIS did not declare them to be significant adverse impacts. Because “no simple mitigation measures were indicated” (Page 7-88), the only mitigation suggested was “public access must be precluded from the pad area out to minimum distance of 500 m in all directions by erecting a fence or a comparable measure (e.g. posting of signs is not an acceptable measure).” Keeping the public away from the area does not address the impacts of exceeding Ambient Air Quality Standards. In addition, fencing off this large area of land is likely not an option open to a private gas developer.

The analysis of centralized impoundments found that they would cause short term exceedences of the guidelines for glutaraldehyde, methanol, and heavy naphtha. For the annual guidelines, acrylamide, glutaraldehyde, methanol, formaldehyde, and heavy naphtha were exceeded. The proposed mitigation is not practicable. For a 5 to 6 acre centralized impoundment, a fence line would be placed about 3,280 feet from the edge of the water surface. This requirement would require a fence to encompass about 330 acres or just over a half square mile. This approach likely would not be available to any natural gas developer. Fencing off an area does not address the impacts of short term exceedences of hazardous air pollutant guidelines.

The air quality analysis does not disclose the expected total region-wide criteria pollutant emissions, including ozone, for the various nonattainment areas. In Wyoming, natural gas development has worsened air quality and led to nonattainment for ozone. The DSGEIS represents a generic analysis of individual potential sites, but it is also required to examine the total cumulative impacts of all of these potential sites. An obvious potential cumulative impact is the combined regional criteria pollutant emissions from all potential sites in all relevant

nonattainment areas. The total potential emissions in each nonattainment area should be disclosed and discussed in the context of existing or future emission budgets.

A best estimate of the reasonable worst-case overall operations likely to occur per year is required under SEQRA to evaluate the region-wide implications and determine the need for mitigation. The difficulty in "accurately" predicting the unique nature of the New York play does not absolve NYSDEC of its obligation to present a best estimate. This requirement is not covered under the "regulatory analysis" provided in the DSGEIS.

NYSDEC's greenhouse gas analysis also includes a number of non-conservative assumptions. Therefore, the emissions of greenhouse gases are greatly underestimated. The potential impacts on air quality need to be re-analyzed, and detailed mitigation measures, such as diesel particulate filters and other emissions controls, proposed. A future greenhouse gas emission impacts mitigation plan that is not subject to public review and that does not require NYSDEC approval would not be an adequate mitigation measure. The greenhouse gas analysis also needs to be re-modeled, and effects on statewide programs, such as the State Implementation Plan and the Climate Action Plan disclosed.

Attachment H contains the detailed analyses to support these recommendations.

NOISE

The noise analysis is qualitative, whereas a fully quantified noise model is required to assess impacts and potential mitigation measures. The use of the *CEQR Technical Manual* for appropriate methodology is suggested. A generic well pad development can be modeled so that likely noise impacts can be identified. The mobile source noise from the truck and worker trips can be added to the stationary source noise from equipment. Then mitigation measures, including source control, path controls, and locational controls, can be developed, and regulations promulgated. The drilling and completion activities would take place 24 hours a day, 7 days a week, and for up to 3 years. Up to 21 engines and an undisclosed number of pieces of equipment and trucks would be operating simultaneously. Based on the number and size of the pieces of equipment and the length of the drilling operation, exceedances of the Department's noise impact criteria[2] will occur. A very basic noise screening model of a generic well pad development found that the noise levels would be about 62.1 dBA at 1,000 feet from the well pad (see Attachment I). The screening likely included fewer pieces of noise-generating equipment than would actually be used. Given the quiet background noise levels in rural areas, this level of noise will greatly exceed the Department's guidelines for impact. Therefore, the DSGEIS contains undisclosed significant adverse noise impacts. Without quantification, these impacts cannot be mitigated. A noise mitigation plan that is not subject to public review and that does not require NYSDEC approval would not be an adequate mitigation measure.

Attachment I contains the detailed analyses to support these recommendations.

TRAFFIC

There is virtually no analysis of traffic impacts. In a one-page section on "Road Use" (Section 6.11), the DSGEIS estimates that between 890 and 1,340 truck trips will be required for development of a well. The truck trip estimate in Chapter 6 is based on 1 to 3 millions gallons of hydraulic fracture water, while Chapter 5 states that between 2.4 to 7.8 million gallons will be

[2] "Assessing and Mitigating Noise Impacts" DEP-00-1

required. Moreover, this estimate assumes that each well will be fractured only once, whereas multiple fracturing treatments are likely. No estimates are made of worker vehicular trips or service trips. This large number of truck and vehicular trips on rural roads will cause significant adverse traffic impacts that are not disclosed and for which no mitigation is proposed. A generic well pad development must be modeled using methods and criteria specified in the *CEQR Technical Manual* so that likely type and cause of traffic impacts can be identified. Then generic mitigation measures can be developed, and regulations promulgated.

COMMUNITY CHARACTER AND SERVICES

The analysis of potential impacts on community character does not recognize the impacts of importing hundreds of workers into an area for years at a time. Many of the gas field workers will come from Texas and Oklahoma, as has been demonstrated in the Pennsylvania experience. These transient workers will be housed in the area and will need support services, including lodging, food, stores, and recreation. These workers will be located in rural areas that often lack these services or have the services but only at great distances. These needs will have to be filled, and service suppliers will come to the area. The influx of workers and service suppliers will have an effect on the rural areas. The supplemental report on community character never addresses the impacts of hundreds of transient workers with little or no investment in local New York communities and new service suppliers.

Another aspect that is not discussed or analyzed is the need for community services, such as police, medical, fire, and schools. Demands for these services will increase due to the larger number of workers and support staff. The need for these community services places heavy demands on local municipalities, and often the municipalities are unable to meet these demands. Placing a local government in situation where it can not meet its community service obligations is an unmitigated significant adverse impact. The use of the *CEQR Technical Manual* for appropriate methodology and criteria is suggested.

ENVIRONMENTAL JUSTICE

While environmental justice is difficult to adequately analyze generically, environmental justice must be analyzed as part of any site specific permit application. Environmental justice is an official policy of the Department, and the potential effects of drilling in the Marcellus Shale on communities of concern can not be ignored. Each application must have an environmental justice analysis of impacts on communities of concern, including low-income communities, in the area around the well pad. Further, DEC must compile all of the environmental justice analyses to determine if, on the whole, development of the Marcellus Shale is placing an undue burden on communities of concern statewide. If undue burdens are being placed on communities of concern by the development of Marcellus Shale, the Department must develop a plan of action to address any unacceptable situations found.

VISUAL RESOURCES

The DSGEIS requires that operators prepare a generic visual impacts mitigation plan and that the plan be available for NYSDEC's inspection. The DSGEIS refers generically to the NYSDEC guidance policy, but puts no real restrictions on the operator. The drilling and completion operations are 24 hours a day under bright lights. The DSGEIS suggests that the operator direct the lights downward and avoid glare on nearby roads. However, these are phrased as suggestions. Appendix 10 states that a visual impacts mitigation plan must be available upon request to NYSDEC prior to the start of drilling, but this procedure offers no opportunity for

public review or even notice to affected local residents A visual resources mitigation plan that is not subject to public review and that does not require NYSDEC approval would not be an adequate mitigation measure.. In addition, any proposed visual impacts mitigation must address the potential of a number of multi-well pads being visible from one location.

The DSGEIS contains no analysis of the effects of the 24-hour lighting on natural resources. Nocturnal birds and animals will be attracted to the lights. The literature documents birds and bats flying into the lights and equipment with a corresponding high death rate. The potential impacts of 24-hour lighting must be analyzed and enforceable mitigation measures developed.

EMERGENCY RESPONSE

Emergency response is a critical area that has been totally ignored in the DSGEIS. SEQRA regulations specifically call for an analysis of potentially catastrophic events. Catastrophic events, spills, fires, and industrial accidents will occur. Such accidents are documented everywhere gas is developed; they are inevitable with the large numbers of heavy equipment and workers. Moreover, local volunteer emergency response organizations often do not have the training, equipment, and personnel necessary to adequately respond to large industrial events. To ignore these facts is to ignore reality. In assuming that no accidents will happen, the DSGEIS fails to disclose significant adverse impacts on the local communities and emergency response organizations.

The only mitigation proposed to address emergency response to industrial accidents is a permit condition requiring notification to the county emergency management office prior to undertaking certain activities. Requiring notification is not the same as requiring that an emergency response plan be developed, submitted, approved, and implemented. The DSGEIS must assess the ability of the local emergency responders to handles accidents and spills. New regulations need to be proposed as part of the regulatory program, requiring the preparation of an emergency response plan, tailored to the specific locality. Construction Health and Safety Plans (CHASP), which are typically required by the Department’s Division of Solid and Hazardous Materials on all projects, are readily available for guidance.

Mitigation measures for gas exploration and production emergencies must be developed and presented in the Final SGEIS. The DSGEIS now has undisclosed significant adverse impacts on the local emergency response organizations.

SOCIOECONOMIC IMPACTS

The DSGEIS alludes to the economic benefits associated with development of natural gas from the Marcellus Shale, but no where does the document provide an estimate of the costs, including to local communities of the natural gas development. The use of the *CEQR Technical Manual* for appropriate methodology and criteria is suggested. As discussed above under Community Character and Emergency Response, the influx of transient workers will place demands on local institutions, and the likelihood of industrial accidents and spills will tax local emergency responders. A generic analysis of these costs must be prepared and mitigation for the costs to local communities developed. The local communities will likely be unable to bear these costs without assistance and mitigation. Moreover, the industrialization of rural areas may have adverse impacts on tourism and recreational businesses. Investment in fossil fuel development by an industry that does not fully internalize its costs is likely to impede development of carbon-free energy and “green” jobs.

ODORS

The DSGEIS totally ignores the problem of odors from the flowback and produced waters, although a recent report (Health Survey Results of Current and Former DISH/Clark Texas Residents at www.earthworksaction.org/pubs/DishTXHealthSurvey_FINAL_hi.pdf) indicates that residents surrounding shale gas wells are frequently subjected to seriously objectionable odors. The odors can include a variety of sulfides, amines and other chemicals that can substantially reduce the quality of life of nearby residents (and perhaps their health). Odors have especially severe effects on children. While very real in terms of impact on people in the surrounding area, odors are often transient, and difficult to quantify. The DSGEIS must analyze this serious problem, and describe in detail how the odors will be identified, regulated, and controlled.

D. CLOSING

We are please to have the opportunity to assemble and prepare these comments. We trust that they will be used by NRDC and it partner organizations to assist NYSDEC in ensuring that development of natural gas from the Marcellus Shale is done where appropriate and in such a manner to ensure protection of the environmental and public health. If you have any question or comments, please do not hesitate to contact me at (646) 388-9795. If needed, we are available to meet with you at your convenience to discuss these comments.

List of Attachments

Attachment A:	Required Data Sets and Analysis
Attachment B:	Table of Adherence of the DSGEIS to the Final Scope of Work
Attachment C:	Harvey Consulting, LLC. *Review of DSGEIS and Identification of Best Technology and Best Practice Recommendations*
Attachment D:	Harvey Consulting, LLC. *New York State Casing Regulation Recommendations*
Attachment E:	Tom Myers, Ph.D., *Technical Memorandum*
Attachment F:	Glenn Miller, Ph.D., *Toxicity and Exposure to Substances in Fracturing Fluids and in the Groundwater Associated with the Hydrocarbon-bearing Shale*
Attachment G:	CEA Engineers, P.C.
Attachment H:	Air Quality Memorandum to Marcellus Shale Files
Attachment I:	Noise Screen

DATA SETS NEEDED FOR ANALYSIS

The following data sets and analyses are examples of what is missing from the DSGEIS. These examples and others must be collected, described, analyzed, and subject to public comment before NYSDEC's review under SEQRA will adequately address the potentially significant adverse environmental impacts of shale gas exploration in New York State and legally required mitigation measures:

Utica Shale

- All data to support analysis of potentially significant environmental impacts resulting from development of the Utica Shale in NYS, with the exception of the geologic and geophysical data described in Section 4.3 of the DSGEIS

Other Low-Permeability Formations

- All data to support analysis of potentially significant environmental impacts resulting from development of "other" low-permeability gas reservoirs in NYS.

Marcellus Shale

Mapping of features of the Marcellus Shale region, including:

- Total area of potential well pad development within Marcellus Shale
- Critical Environmental Areas
- Navigable waters of the state, as defined as under 6 NYCRR § 608, including all DEC-regulated lakes, rivers, streams, and other bodies of water
- Watercourses, reservoirs, reservoir stems, intermittent streams, and perennial streams, as defined by New York City Watershed Rules and Regulations
- Primary and principal aquifers
- 8-digit United States Geological Survey (USGS) Hydrologic Unit Code (HUC) watershed outline and associated watercourse flowlines based on USGS National Hydrography Dataset (NHD)
- National Wetland Inventory (NWI) mapped wetlands and watercourses regulated under Section 404 of the Clean Water Act.
- Rare, Threatened, and Endangered species that are present or documented.
- Groundwater contours, including groundwater contours for the sandstone above the Marcellus Shale and for the near surface aquifers
- Vertical gradient based on the foregoing contour maps

Shale Formation and Overburden Properties

- Data documenting geologic, geophysical, geochemical, hydrologic, and hydrogeologic properties of shale formations in other states that the DSGEIS deems analogous to the Marcellus Shale, with references or sources
- Geologic, geophysical, geochemical, hydrologic, and hydrogeologic data offering a detailed understanding of the in-situ conditions present in the reservoir (e.g. shale thickness, reservoir pressure, rock fracture characteristics, special core analysis) to document Marcellus Shale reservoir heterogeneity across NYS (including variations in NORM content)

- Geologic, geophysical, geochemical, and hydrologic data documenting site-specific properties of the shale, from well cores obtained from exploratory wells, sufficient to permit development of sophisticated 3-dimensional reservoir models to more accurately design fracture treatments
- Geologic, geophysical, geochemical, and hydrologic data on the Marcellus Shale overburden (including data documenting permeability and presence of fractures) from well cores to the top of the Marcellus Shale, including all reservoirs separating the Marcellus Shale and drinking water aquifers
- Data used in reservoir simulation and fracture design models run prior to fracturing of the Marcellus Shale in NYS or other states
- Data from well cores documenting post-fracturing properties of the Marcellus Shale in NYS or other states, especially additional permeability, to verify the accuracy of any reservoir simulations or fracture models run prior to fracturing

Exploration

- Data documenting impacts of industrial seismic exploration

Drilling

- Data documenting the chemical content of drilling muds prior to use and when mixed with drill cuttings, including NORM and heavy metal content
- Toxicity data for the full range of drilling mud additives that will be permitted in NYS
- Data or references documenting impacts of long-term burial of drill cuttings coated with drilling muds containing heavy metals or NORM
- Data documenting capacity of authorized commercial treatment and disposal facilities in NYS to accept drilling muds and cuttings, including those containing heavy metals or NORM
- Data or references documenting when underground injection of drilling muds and cuttings is an environmentally preferable waste disposal alternative
- Data or references documenting amounts and rates of water diversions needed for fracturing fluid

Stimulation and Production

- Data documenting the projected total consumptive use of water for fracturing operations, including but not limited to the estimate of 25 mgd from the Susquehanna River basin.
- Toxicity data or references for each of the additives and chemicals that will be permitted for use in fracturing treatments
- Data documenting the concentrations of each chemical in flowback and produced water from Marcellus Shale wells
- Data documenting flowback rates and amounts from Marcellus Shale wells, correlated with properties of the well (*e.g.*, total vertical depth and horizontal extent)

- Data supporting estimated cumulative volume and production rate of gas wastewater requiring treatment
- Site specific modeling of hazardous air pollutant impact from flowback impoundments
- Data documenting the nature and extent of spills and leaks (including but not limited to spills of fracturing fluid during mixing and storage, flowback leaks, and leaks through or around well casings) that have occurred with gas development in New York and other states. Spills include.
- Data documenting capacity of POTWs or commercial treatment and disposal facilities authorized in NYS to accept gas wastewaters, including flowback or produced waters containing elevated TDS levels, BTEX compounds, heavy metals or NORM
- Actual field data, 3-dimensional reservoir simulation modeling and a peer-reviewed hydrological assessment supporting the proposed minimum 1,000-foot vertical offset with to ensure drinking water sources are protected.

Naturally Occurring Radioactive Materials

- Data documenting the identity of the radionuclides in Marcellus Shale gas wastes and a mass balance of contributors for the alpha emitters
- Data verifying the amount of NORM in Marcellus Shale formation water (produced water)
- Data documenting the radiological health risk of produced water containing NORM, especially the bottom sludges or residual salts of the surface impoundments
- Data supporting the claim that drinking water well contamination by oil and gas drilling activities will be eliminated by new casing and cementing practices and fresh water aquifer supplementary permit conditions

Other

- Data documenting comparative energy efficiency of collecting waste in the container that will be used to transport it offsite to a waste disposal facility, rather than use of intermediate storage pits
- Data documenting comparative energy efficiency of on-site and off-site wastewater treatment
- Data to verify the amounts benzene emissions estimated
- Data supporting estimated stormwater pollution from transportation of wastewater
- Data supporting estimated number of brine-hauling truck trips and associated impacts
- Data supporting noise analysis for impacts on wildlife
- Data supporting nighttime light analysis for impacts on wildlife
- Data supporting analysis of known and potential bat hibernacula associated with Karst formations and abandoned mines

- Data supporting estimates of total number of workers per multi-well pad with the number of shifts, schedule of shifts, and number of workers per shift
- Data supporting expected schedule of a typical multi-well pad development
- Data documenting whether proposed mitigation measures adopted by reference to regulations in other states have actually been successful in preventing adverse impacts, including but not limited to liner regulations for centralized impoundments

ATTACHMENT A

Examples of required Data Sets and Analyses

ATTACHMENT B

AKRF, INC.

Table of Adherence of the DSGEIS to the Final Scope of Work

ATTACHMENT C

HARVEY CONSULTING, LLC

Review of DSGEIS and Identification of Best Technology and Best Practices Recommendations

ATTACHMENT D

HARVEY CONSULTING, LLC.

New York State Casing Regulation Recommendations

ATTACHMENT E

TOM MYERS, Ph.D.

Technical Memorandum
Review and Analysis of Draft Supplemental Generic Environmental Impact Statement

ATTACHMENT F

GLENN MILLER, Ph.D.

Toxicity and Exposure to Substances in Fracturing Fluids and in the Groundwater Associated with Hydrocarbon-Bearing Shale

ATTACHMENT G

CEA ENGINEERS, P.C.

Comments on the Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

ATTACHMENT H

AKRF, INC.

Air Quality and Greenhouse Gas Memorandum

ATTACHMENT I

AKRF, INC.

Noise Screen

MARCELLUS SHALE
ADHERENCE OF dSGEIS TO FINAL SCOPE

Final Scope Statement	Addressed	Section	Title	Page	Comments
1.5 Pipeline Regulation					
The dSGEIS will describe pipelines and associated facilities likely to be associated with a multi-well shale gas production site	Yes	5.16.8	Gas Gathering	129-130	dSGEIS includes general summary, but does not describe details or specs of any equipment or facility.
The dSGEIS will describe the environmental review process for pipelines and identify potential measures to prevent or minimize adverse impacts.	Yes	5.16.8.1	Regulation of Gas Gathering and Pipeline Systems	131-132	References Public Service Law, Public Service Commission (PSC) and DEC application and review process.
2.1.1 Horizontal Drilling					
The dSGEIS will examine whether there are any potential environmental impacts associated with horizontal drilling itself that have not already been sufficiently reviewed and mitigated.	Yes	5.2 6.1.3	Horizontal Drilling Cumulative Impacts	21-31 141-146	Description of rigs, well pad development, drilling mud, cuttings volume and content associated with multi-well pads. Site specific and quantified impacts of multi-well pad.
The dSGEIS will review the potential impacts of multi-well site development, considering the requirement in ECL §23-0501(1)(b)(1)(vi) that all horizontal infill wells in a multi-well shale unit be drilled within three years of the date the first well in the unit commences drilling. In conjunction with the temporal noise, visual and air quality impacts referenced in Section 4 of this Final Scope, this review will also evaluate the need for a larger setback from private buildings or dwellings.	Yes	6.1.4 5.18.3.2 7.1.12	Groundwater Impacts Associated with Well Drilling and Construction Setbacks Setbacks	34-36 154 64-72	Turbidity, release of well drilling fluids, natural gas migration. Review of other states programs and details related to setbacks. Setback guidelines.
The dSGEIS will also address the management and disposal of the larger volume of cuttings at multi-well sites.	Yes	5.13.1 6.1.9 7.1.9	Cuttings from Mud Drilling Solids Disposal Solids Disposal	118 40-41 7-61	Requirements for non-freshwater fluids. Cuttings disposal
2.1.2 Hydraulic Fracturing					
Chemical composition of fracturing fluid additives proposed for fracturing shale formations in New York. This information will be shared with other appropriate Divisions within DEC, including the Division of Water (“DOW”), as well as with the NYS Department of	Yes	5.4 5.41 5.42	Fracturing Fluid Properties of Frac Fluids Classes of Additives	33-66	Includes CAS #s for individual compounds for each class of additive.

MARCELLUS SHALE
ADHERENCE OF dSGEIS TO FINAL SCOPE

Final Scope Statement	Addressed	Section	Title	Page	Comments
Health and will be reviewed to determine if applicable standards and regulations are sufficient to prevent or mitigate potential impacts of their use and management.		5.43	Composition of Frac Fluids		
The feasibility of requiring use of green or non-chemical fracturing technologies and additives.	Yes	9.3.1	Environmentally Friendly Chemical Alternatives	8-11	Indicates requirement might not be feasible, additional studies should be completed
Fluid handling at the surface and whether any additional controls are warranted.	Yes	5.6 5.11.2 7.1.3.3	On-site Storage and Handling of Hydraulic Fracturing Additives Flowback Water Handling at Well Site Hydraulic Fracturing Additives	69-72 98-99 32-34	Includes description of applicable NYSDEC regs. Containment Controls and spill response
Hydraulic fracturing design and modeling, with emphasis on containment of fractures and fracturing fluid in the target formation. The dSGEIS will review the available methodologies for ensuring containment, and evaluate the design parameters that should be included in well permit applications for staff review prior to permit issuance.	Yes	5.8	Hydraulic Fracturing Design	86-90	Subsections for fracture development and methods to limit fracture growth.
The effectiveness of the regulations of other oil and gas producing states with high volume hydraulic fracturing of shale and other low permeability reservoirs. This evaluation will consider the advisability of adopting additional protective measures based on those that have proven successful in other states for similar activities.	Yes	5.18	Other States Regulations	144-158	GWPC, ICF, Alpha reviews. Review of 27 states. Includes fracturing, permitting, well construction, abandonment, well plugging, pits, waste handling, and spills.
2.1.2.1 Fluid Handling at the Well Site					
Examination of whether pit liner specifications should be required for high-volume hydraulic fracturing flowback operations.	Yes	7.1.3.2 Appendix 10	Drilling Fluids Proposed Supplementary Permit Condition for High Volume Fracturing	28-31	Liner specifications Includes liner specifications.
Assessment of whether steel tanks should be required in some or all areas to contain flowback fluids from high-	Yes	5.18.3.2 a	Alpha Review – Best Management Practices	150	Recommends steel tanks for flowback water.

MARCELLUS SHALE
ADHERENCE OF dSGEIS TO FINAL SCOPE

Final Scope Statement	Addressed	Section	Title	Page	Comments
volume hydraulic fracturing operations.		7.1.3.4 Appendix 10	Flowback Water Proposed Supplementary Permit Condition for High Volume Fracturing	34-35	DEC proposal for steel tanks Step 35. Steel tanks must be used for flowback water
2.1.2.2 Fluid Removal from Well Site and Ultimate Disposition of Returned Fluids					
Review of information the Department is presently collecting from operators regarding volume and composition of the spent fracturing fluid.	Yes	5.11 5.11.3.2	Fluid Return Composition of Flowback Water	97-99 107-110	2.4 – 7.8 million gallons, Chemical categories and lab testing.
Examination of each of the above disposal options (other than road-spreading which has been prohibited), discussion of the limitations or regulatory controls that apply to each, and determination of whether any additional controls are warranted. This will include a review of the suitability and implications of fluid disposal at permitted municipal waste water treatment plants.	Yes	5.13.3	Flowback Water	119-123	Injection wells, sewage treatment facility, treatment plants, enhanced oil recovery etc.
Evaluation of the feasibility of requiring reuse/recycling of fracturing flowback fluids.	Yes	5.12	Flowback Water Treatment, Re-Use, and Recycle	110-117	Membrane, reverse osmosis, thermal distillation, ion exchange, ozone, ultraviolet, electro dialysis.
Examination of whether additional waste tracking and manifesting requirements are necessary.	Yes	7.1.6.1	Drilling and Production Waste Tracking Form	50	Required for all activities in SGEIS
Evaluation of potential well permitting procedures, such as verification of a disposal well permit or contract with a specific treatment plant, to ensure that available capacity exists for any proposed disposal destination.	Yes	7.1.8.1	Treatment Facilities	56-60	Verification review for POTW, private treatment facilities and disposal wells.
2.1.2.4 Re-Fracturing					
Because of the possibility, not addressed in the GEIS, for additional high-volume hydraulic fracturing subsequent to the initial well completion, the dSGEIS will address the potential impacts of re-fracturing wells and will evaluate the need for additional procedures to avoid or mitigate such impacts.	Yes	5.10 8.3.2	Refracturing High Volume Refracturing	96-97 9	Description High volume refracturing will require submittal of EAF addendum.
2.1.3 Well Testing					

MARCELLUS SHALE
ADHERENCE OF dSGEIS TO FINAL SCOPE

Final Scope Statement	Addressed	Section	Title	Page	Comments
The dSGEIS will consider whether any aspects of testing shale wells after high volume hydraulic fracturing warrant additional regulatory control.	No	5.14	Well Cleanup and Testing	123	Description of process, but did not find review to determine need for additional regulatory control.
2.1.4 Natural Gas Production					
The dSGEIS will examine the likelihood of larger production well pads to determine whether there are any associated environmental impacts not addressed by the GEIS.	Yes	5.1.2	Well Pad	9-10	Concludes production phase will use less area than fracturing phase.
2.1.6 Well Density					
The scenario of multiple horizontal wells drilled from common pads is not specifically reviewed in the GEIS. It will be addressed by the dSGEIS, with emphasis on whether size of the well pad and time needed to drill multiple horizontal wells at the same surface location may cause any potential environmental impact not addressed by the GEIS.	Partial	5.1.3	Well Pad Density	10-20	Description of density and area. Time needed to drill discussed in section 5.2. No specific discussion on potential impacts associated with well pad size or time needed to drill, but size/time parameters appear to be used for Section 6.
3.0 GEOLOGY					
Description of the Marcellus and other shale formations and summary of their history of development in New York, if any, along with recent reports on shale potential and reserve estimates. Stratigraphic columns for central and southeastern New York will be included.	Yes	4.1 to 4.5	Geology	1-356	
Analysis of NORM data and review of any required special precautions for cuttings or fluids handling and disposal.	Yes	4.6 5.1.3 5.16.7 5.1.7 5.2.4.2 6.1.9.1 6.8	NORM in Marcellus Shale Waste disposal – Cuttings NORM in Production Brine Well Plugging NORM in Marcellus Cuttings Solids Disposal – Norm Considerations – Cuttings Norm Materials in	36 118 129 143 30-31 40 129-131	

MARCELLUS SHALE
ADHERENCE OF dSGEIS TO FINAL SCOPE

Final Scope Statement	Addressed	Section	Title	Page	Comments
		7.1.6.1 7.8	Marcellus Shale Drilling and Production Waste Tracking Form Mitigating Norm Impacts	50 98-102	
4.1 Noise, Visual and Air Quality Impacts					
The dSGEIS will explore the drilling, hydraulic fracturing, flowback and testing phases for Marcellus shale wells with respect to temporal noise, visual and air quality impacts.					See Sections 4.1.1, 4.1.2, and 4.1.3 below
The dSGEIS will examine how the temporal noise, visual and air quality impacts will be experienced at multi-well drilling pads.					See Sections 4.1.1, 4.1.2, and 4.1.3 below
4.1.1 Noise Impacts					
The dSGEIS will discuss (1) sources of noise, including truck movement into and out of the site and fluid pumping, associated with the high-volume hydraulic fracturing, flowback and well testing stages for the Marcellus Shale and other low-permeability gas reservoirs that could be developed by horizontal drilling and high-volume hydraulic fracturing and (2) available mitigation measures that may be employed, with 21 reference, as applicable, to Department Program Policy DEP-00-1, Assessing and Mitigating Noise Impacts.	Yes	5.18.3 6.10 6.12 & 6.13.1 7.10	Summary of Alpha's Regulatory Survey Noise Community Character & Site Specific Cumulative Impacts Mitigating Noise Impacts	153 134-138 139 141 106-108	Study of other states that address noise issues. Pad sighting, access roads, multi-well pads.
The dSGEIS will discuss whether any additional production equipment or activities would be found at Marcellus Shale wells that would necessitate new or different mitigation measures.	Partial	6.10	Noise	134-138	Not specific, general statements about typical noise levels for additional construction vehicles. No quantitative review on noise related to additional traffic.
4.1.2 Visual Impacts					
The dSGEIS will review the factors summarized below in the context of anticipated Marcellus Shale operations, with reference, as applicable, to Department Program Policy DEP-00-2, Assessing and Mitigating Visual Impacts:	See below				Section 2.4.11 describes the visual resources for the area.
The possibility of larger well pads. The possibility of larger lined pits for temporary storage	Yes	6.9	Visual Impacts	131-133	

MARCELLUS SHALE
ADHERENCE OF dSGEIS TO FINAL SCOPE

Final Scope Statement	Addressed	Section	Title	Page	Comments
of fluids associated with high-volume hydraulic fracturing operations. Greater number of trucks and tanks associated with multi-stage, high-volume hydraulic fracturing operations. Longer duration of impacts if multiple wells are drilled from a single surface location.		7.9	Protecting Visual Resources	130-105	Sections 6 and 7 do not specifically mention greater number of trucks..
For informational purposes, the dSGEIS will include photographs of a variety of actual well sites in New York developed since the publication of the GEIS to illustrate their appearance during each stage of operations.	Yes	NA	Photos 6.2 – 6.13	156-163	
Aerial views of existing densely drilled areas in New York will be included to assess whether cumulative long-term visual impacts exist in areas that have been developed for natural gas production.	Yes	NA	Photos 5.8 – 5.11	15-18	
The dSGEIS will propose thresholds for site-specific reviews of potential visual impacts in close proximity to the Catskill Forest Preserve, the Upper Delaware Scenic Byway and the Upper Delaware Scenic and Recreational River.	Partial	2.3	Project Location	7	States drilling will not occur on State-owned land in Adirondack & Catskill Forest Preserve. Does not Mention Upper Delaware Scenic Byway in Document.
4.1.3 Air Quality Impacts					
The dSGEIS will examine the following topics with respect to potential air quality impacts at well sites where horizontal drilling and high-volume hydraulic fracturing will be employed:	(Sections addressing Air Quality)	6.5 6.6 7.5 7.6 App. 16 App. 17	Air Quality Greenhouse Gas Emissions Protecting Air Quality Mitigating Greenhouse Gas Emissions Applicability of NO_x RACT Requirements Applicability of Proposed	108 109-128 83 - 90 90 - 95	

MARCELLUS SHALE
ADHERENCE OF dSGEIS TO FINAL SCOPE

Final Scope Statement	Addressed	Section	Title	Page	Comments
		  App. 18 App 19	Revisions to 40 CFG Part 63 Subpart ZZZZ Clean Air Act Facility Definition Greenhouse Gas Emissions		
6 NYCRR Part 212[30] applicability and potential local impacts of air toxics and odors at well sites, based on a reasonable worst-case scenario for expected emissions of natural gas contaminants and hydraulic fracturing additives. Modeling will be in accordance with Department Policy DAR-1, Guidelines for the Control of Toxic Ambient Air Contaminants.	Partial	6.5 App. 16 App. 17 6.5.2	Air Emissions Applicability of NO_x RACT Requirements Applicability of Proposed Revisions to 40 CFR Part 63 Subpart ZZZZ Air Quality Assessment	48–108 57-108	No direct discussion on Part 212 applicability. Appendix 16&17 contain general info on applicability of NO_x RACT and proposed revisions to 40 CFR Part 63 Subpart ZZZZZ. Complete and detailed modeling using AERMOD
Applicability and possible impacts of 40 CFR 63 Subpart HH[32] with respect to ongoing well operations such as gas dehydration.	Yes	6.5.1.2	Natural Gas Production Facilities NESHAP 40 CFR 63 Subpart HH32	51-52	
Investigation of the potential applicability of major source status under 6 NYCRR Part 201[33] for diesel equipment that may be present at multi-well sites for more than 30 days.	No				Extensive discussion on diesel, but no mention of 6 NYCRR Part 201.
Investigation of possible impacts on ozone attainment.	No				No mention of ozone attainment
Investigation of the expected amount of sulfur dioxide emissions to determine if mitigation measures such as requiring low-sulfur fuel are advisable.	Yes	6.5.2 7.5 App. 17	Air Quality Assessment Protecting Air Quality 40CFR63Subpart ZZZZ	 86	In-depth review Proposed mandate of low sulfur.
4.2.1 Water Withdrawals					
The following concerns related to water withdrawals, including the potential cumulative impact of numerous withdrawals, will be addressed in the dSGEIS:.					(see below)
potential effects on volume of water available for other needs, including public water supply,	Yes	6.1.1.6 6.1.1.7	Aquifer Depletion Cumulative Water Withdrawal Impacts	6-7 7-9	
potential degradation of a stream's designated best use,	Partial	6.1.1.2	Degradation of a Stream's Best Use	4	Does not discuss impacts, simply states uses are dependent on sufficient water.
potential impacts to downstream wetlands and users,	Yes	6.1.1.5	Impacts to Downstream Wetlands	6	Basic overview

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potential impacts to fish and wildlife, and	Yes	6.1.1.3 6.1.1.4	Impacts to Aquatic Habitat Impacts to Aquatic Ecosystems	5 5	
potential aquifer depletion.	Yes	6.1.1.6	Aquifer Depletion	6-7	
The dSGEIS will also discuss potential mitigation measures to prevent transfer of invasive species from one surface waterbody to another as a result of water withdrawal and subsequent discharge of unused fresh water into another surface waterbody.	Yes	3.2.2.7 6.4 7.4 Table 7.3	Invasive Species Survey and Map Ecosystems and Wildlife Protecting Ecosystems and Wildlife Summary of Regs Pertaining to Invasive Species	11 43-47 73-79 80-82	Required part of EAF Addendum ID of plant and aquatic inv. species
The dSGEIS will evaluate the sufficiency of existing authorities (internal to DEC and external), protocols and regulations for addressing the potential impacts, including cumulative impacts, of water withdrawal associated with shale gas development by high-volume hydraulic fracturing.	Yes	6.1.1.7 7.1 7.1.1	Cumulative Water Withdrawal Impacts Protecting Water Resources Water Withdrawal Regulatory and Oversight Programs	7-14 2 3-21	Existing jurisdictions and regulatory programs, discussion of three methodologies for mitigation of SW withdrawal impacts, and NYSDEC chosen methodology.
The dSGEIS will propose parameters for well-specific review of the identified water source for high-volume hydraulic fracturing. Duplication of an existing authority's efforts will be avoided to the extent possible while still meeting the Department's resource protection objectives.	Yes	3.2.2 3.2.3 App. 6	EAF Addendum Site Specific SEQRA Determination Proposed EAF Addendum	8-11 12-13	
The dSGEIS will explore the opportunities and standards for alternate sources of water, such as waste water treatment plant effluent, cooling water, or saline aquifers.	No	5.7	Source Water for High Volume Hydraulic Fracturing	73	Indicates potential alternate water sources are discussed in Chapter 7. Did no find information related to alternate water sources in Chapter 7.
4.2.1.4 Assessment of Water Withdrawals for High-Volume Hydraulic Fracturing in the Marcellus Shale and Other Low Permeability Gas Reservoirs					
The dSGEIS's proposed parameters for well-specific review of water sources in the Susquehanna and Delaware River Basins will be based upon the Department's conclusions regarding the adequacy of the	Yes	7.1.1	Water Withdrawal Regulatory and Oversight Programs	3-21	

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reviews done, respectively, by SRBC and DRBC, including review of the methodologies used to protect a surface water body's designated best use during periods of low flow.					
For well permits which propose new water withdrawals outside the Susquehanna and Delaware River Basins for high-volume hydraulic fracturing of the Marcellus Shale and other low-permeability formations, and to the extent found necessary within the Basins, the dSGEIS will discuss potential review parameters and mitigation measures such as, but not limited to:	(see below)				
in-stream species evaluation,	No	7.1.1.1	Impact to Aquatic Ecosystems	5	Indicates 6NYCRR Part 608 (Use and Protection of Waters) contains Subparts to address fish and wildlife species, but does not elaborate.
assessment of combined impact of the proposed withdrawal and upstream/downstream intakes within a certain distance,	No				Did not find discussion on upstream/downstream combined impact.
evaluation of impacts to aquatic resources, competing users and the stream's designated best use during periods of low flow,	No	7.1.1.5	Cumulative Impacts	22	Mentions Natural Flow Regime Method could address adverse impacts IF each permitted user reported properly. No evaluation completed.
passby flow requirement,	Yes	2.4.8 7.1.1.4	Water Resources Replenishment Natural Flow Regime Method	32 18	
reduction or discontinuance of the withdrawal during periods of low flow,	Partial	2.4.8 7.1.1.4	Water Resources Replenishment Natural Flow Regime Method	32 18	Appears to be addressed by Natural Flow Regime Method, but no direct discussion.
limitation of withdrawal rates and locations as necessary to maintain compliance with the Department's narrative flow standard for fresh surface water and protect best uses of the water body even during low flow periods,	Partial	2.4.8 7.1.1.4	Water Resources Replenishment Natural Flow Regime Method	32 18	Appears to be addressed by Natural Flow Regime Method, but no direct discussion.
water intake design to minimize aquatic impacts from impingement and entrainment,	No				Mentioned in SRBC and DRBC sections, but not for areas outside of SRBC/DRBC.

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controls or treatment to prevent the spread of aquatic invasive or nuisance species,		3.2.2.7 6.4 7.4 Table 7.3	Invasive Species Survey and Map Ecosystems and Wildlife Protecting Ecosystems and Wildlife Summary of Regs Pertaining to Invasive Species	11 43-47 73-79 80-82	Part of EAF Addendum ID of plant and aquatic inv. species
evaluation of alternative water sources such as produced brine, flowback, or other available waste water streams, and	No				
requirement for mitigation through water storage or conservation releases.	No				
For well permits which propose new consumptive uses of potable water from public water supply systems, the dSGEIS will additionally address potential aquifer depletion from the incremental increase in withdrawals.	Partial	7.1.1.1	Aquifer Depletion	6	Only mentions NYSDEC Division of Water's Pump Test Procedures for Water Supply applications will be used in conjunction with SRBCs aquifer testing protocol.
4.2.2 Groundwater Quality					
The dSGEIS will evaluate whether anticipated horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale or other low-permeability formations in New York have the potential to create any groundwater pollution scenario that is not examined by the GEIS or is not addressed by existing requirements and practices. This will include examination of the potential need for setbacks from private water wells and springs used for domestic supply.	Yes	6.1.3 through 6.1.8	Water Resources	16-40	Surface spills, drilling, additives, flowback water, surface storage, transport, and disposal
The dSGEIS will evaluate potential requirements for private water well sampling, testing and monitoring by gas well operators.	Yes	7.1.4.1	Private Water Well Testing	38-39	Very limited parameter list compared to listed chemicals in hydrofrac solution.
4.2.3 Surface Water Quality					
The dSGEIS will evaluate whether anticipated water use or other activities associated with Marcellus Shale development in New York, including in proximity to the Upper Delaware Scenic and Recreational River, have the potential to create any surface water impact that is not	Yes	7.1.12.2	Setbacks from Surface Water Resources	69-72	

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examined by the GEIS or is not addressed by existing authorities, requirements and practices. This will include the examination of the potential need for increased surface water setbacks for sites where horizontal drilling and high-volume hydraulic fracturing are proposed.					
4.2.3.1 Surface Municipal Water Supplies					
the dSGEIS will examine whether any additional environmental reviews or special mitigating permit conditions are necessary to protect surface reservoirs in the New York City Watershed.	Yes	7.1.12.2	Setbacks from Surface Water Resources	69-72	
4.2.3.2 Stream Disturbance					
the dSGEIS will propose parameters for well-specific review of the identified source of water for high-volume hydraulic fracturing operations. The need for an Article 15 permit, if it has not already been obtained, would be identified during this review along with the potential impacts and required mitigation measures.	Yes	3.2.2 3.2.3 App. 6	EAF Addendum Site Specific SEQRA Determination Proposed EAF Addendum	8-11 12-13	
4.2.3.3 Erosion and Sedimentation Control					
The dSGEIS will review applicability of the Department's General Stormwater Permit and the best management practices available to well operators.	Yes	7.1.2	Stormwater	23-25	SWPPP
4.2.4 New York City Watershed					
The dSGEIS will evaluate the sufficiency of existing protocols and regulations for protecting New York City's subsurface water supply infrastructure from potential impacts related to gas well drilling and hydraulic fracturing.	Yes	7.1.10 7.1.11	Protecting NYC's Subsurface Water Supply Infrastructure Protecting the quality of NYCs Drinking Water Supply	61-62 62-64	
The dSGEIS will address the need for any exclusion zone, additional environmental review and additional special permit conditions. Protection of correlative rights with respect to offset drainage from wells on properties adjacent to any exclusion zone will also be considered.	Partial	7.1.12.2	Setbacks from Surface Water Resources	69-72	Could not find a mention of correlative rights with respect to offsite drainage.
As stated above for New York City water supply infrastructure, the dSGEIS will evaluate the sufficiency	Yes	7.1.11	Protecting the quality of NYCs Drinking Water	62-64	

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of existing protocols and regulations for protecting New York City's surface water reservoirs, with consideration of the fact that New York City controls a substantial amount of the acreage surrounding the reservoirs through fee ownership or conservation easements so that drilling would not occur on such acreage without the City's permission. Like any landowner, the City has the right to enter into leases for mineral rights or other use of its lands.		7.1.12.2	Supply Setbacks from Surface Water Resources	69-72	
4.4 Invasive Species					
The dSGEIS will review the options available to well operators for controlling invasive species at well sites, as determined through consultation between the Division of Mineral Resources and the Department's Office of Invasive Species.	Yes	6.4 7.4 Table 7.3	Ecosystems and Wildlife Protecting Ecosystems and Wildlife Summary of Regs Pertaining to Invasive Species	43-47 73-79 80-82	Part of EAF Addendum ID of plant and aquatic inv. species
As stated in Section 4.2.1.4 of this Final Scope, the dSGEIS will discuss potential mitigation measures for preventing the spread of aquatic invasive and nuisance species caused by water withdrawals or transfers.	Yes	7.4	Protecting Ecosystems and Wildlife	73-79	
4.5 Floodplains					
The dSGEIS will examine whether any additional protections or environmental reviews are needed for drilling sites in floodplains where horizontal drilling and high volume hydraulic fracturing are proposed.	Yes	7.2	Protecting Floodplains	72	Addressed with EAF and Supplemental Permit
4.6 Freshwater Wetlands					
The dSGEIS will propose parameters for well-specific review of the identified water source for high-volume hydraulic fracturing. The proposed parameters will address review of potential impacts to downstream wetlands.	Yes	7.3	Protecting Freshwater Wetlands	73	Addressed with EAF and Supplemental Permit
4.7 Road Use					
The dSGEIS will describe the types and number of vehicles and trips associated with each stage of typical development at multi-well sites where high-volume hydraulic fracturing will be employed.	Yes	6.11	Road Use	138-139	

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the dSGEIS will identify potential mitigation measures to ameliorate the impacts of short-term, high-volume truck traffic, such as:	Partial	7.11	Mitigating Road Use Impacts	109-110	Section just re-lists all items below. No additional discussion
route selection to maximize efficient driving and public safety,					(See above)
avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods,					
coordination with local emergency management agencies and highway departments,					
upgrades and improvements to roads that will be traveled frequently for water transport to and from many different well sites,					
advance public notice of any necessary detours or road/lane closures,					
adequate off-road parking and delivery areas at the site to avoid lane/road blockage, and					
use of rail or temporary pipelines where feasible to move water to and from well sites.					
4.8 Cumulative Impacts					
The dSGEIS will review and assess the information and methodologies that are available for estimating the potential rate of Marcellus Shale development, and will include a description of likely development based on the information and methodology deemed most applicable and appropriate.	Partial	6.13.2.1	Rate of Development and Thresholds	144-146	State that accurately estimating rate of development is inherently difficult due to the wide and variable range of the resource, rig, equipment and crew availability, permitting and oversight capacity, leasing, and most importantly, economic factors.
The dSGEIS will assess the levels of activity within a reasonable temporal and geographic framework that may result in adverse cumulative impacts with respect to noise, visual effects, air quality and water resources.	Partial	6.13 7.13	Cumulative Impacts Mitigating cumulative Impacts	141-146 111-112	Since DEC states it can't accurately prediction rate and amount of development, it can't determining threshold for which development will result in unacceptable cumulative impacts during development
The analysis of cumulative water resources impacts will acknowledge and evaluate the methodologies used by	Partial	6.1.1.7	Cumulative Water Withdrawal Impacts	7-16	Indicate Natural Flow Regime Method to be used to mitigate all surface water removals is option to

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SRBC and DRBC to address cumulative impacts related to water withdrawal. Duplication of an existing authority's efforts will be avoided to the extent possible while still meeting the Department's resource protection objectives. Evaluation of cumulative impacts of water withdrawals will consider the scale of other everyday withdrawals, the non-continuous nature of withdrawals for well development, and the likely time frame for taking into account the natural replenishment of water sources.		7.1.1.5	Cumulative Water Withdrawal Impacts	21-22	address cumulative impacts. Only mentions surface water withdrawals for areas outside SRBC and DRBC jurisdiction, does not mention what will be used to address groundwater withdrawals
In conjunction with the above analyses, the dSGEIS will describe the measures available to prevent or mitigate significant adverse cumulative impacts associated with individual well pads and within defined geographic areas.	Partial	7.10.3 7.11	Multi-Well Pads Mitigating Road Use Impacts	107-108 109-110	Noise impacts Includes description for multi well pad, but does not expand to a defined geographic location (see stated limited factors above).
4.9 Community Character					
Evaluation of whether any aspect of multi-well site development or high-volume hydraulic fracturing of shale wells could be expected to change the GEIS's conclusion that major long-term changes to land use patterns, traffic and the need for public services are not anticipated as the result of gas well development. This will include review of the compatibility of shale gas development with other land uses such as agriculture, tourism, and alternative energy development.	Partial	6.11 6.12 7.11 7.12	Road Use Community Character Impacts Mitigating Road Use Impacts Mitigating Community Character Impacts	138-139 139-141 109-110 110-111	Basic conclusion of reduced pad area=lower impacts, even with additional trucking for frac water No additional evaluation of agriculture, tourism, or alt. energy development. Suggests local gov't to be proactive in applying NYS traffic laws.
Evaluation of whether drilling and high-volume hydraulic fracturing of horizontal shale wells have any potential positive or negative community impact, including potential environmental justice impacts.	Partial	6.12.2	Environmental Justice	140-141	Simply states SGEIS/SEQRA process will provide opportunity for input and protection to communities, drilling locations are determined by location of gas, and land owners/surrounding community will benefit with revenue.
Evaluation of potential economic and energy supply impacts of developing the Marcellus Shale and other low-permeability reservoirs in New York.	No				
5.0 PERMIT PROCESS AND REGULATORY COORDINATION					
The dSGEIS will include, for public review and comment, a proposed EAF Addendum for shale well	Yes	3.2.2	EAF Addendum	8	

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applications in New York that include plans for high-volume hydraulic fracturing. Recommendations received during scoping regarding the information that should be required with well permit applications will be evaluated as part of the EAF development process.		App. 6	Proposed EAF Addendum		
The dSGEIS will examine the extent of necessary additional coordination with other agencies such as the Susquehanna and Delaware River Basin Commissions, the New York City Department of Environmental Protection, and the National Park Service which reviews projects in the Upper Delaware Scenic and Recreational River corridor on behalf of the Upper Delaware Council. It should be noted that DEC is already represented on both River Basin Commissions and on the Upper Delaware Council, and is actively engaged with NYCDEP regarding protection of the City's drinking water supply	Yes	8.1	Interagency Coordination	1-6	Includes statements on SRBC and DRBC.
The dSGEIS will provide an updated version of Table 15.1 in the GEIS which summarizes the interagency coordination involved in the regulation of oil, gas, solution mining, and brine disposal operations in New York State.	Yes	NA	Table 8.1	8-10	Updated table attached to Chapter 8
5.1 Public and Local Government Participation					
The dSGEIS will consider whether the Department should require the notification to include other information such as anticipated truck traffic or any planned shipments of spent fluids to municipal waste water treatment plants, which would provide the opportunity for local governments to interact directly with the permittee or the waste hauler regarding these issues, and to involve the public as the municipality may deem appropriate.	No				No explanation in Permit Process and Coordination – Local Governments. Also didn't see anything in Chapter 5, 6 or 7.
The dSGEIS will investigate appropriate measures and timing for sharing of information with localities to ensure awareness regarding the proposed action and its potential impacts.	Yes	8.1.1.3	Notification to Town Supervisors	3-4	DEC to provide notice to town upon initial receipt of first application.

MARCELLUS SHALE
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The final SGEIS will be followed by a Findings Statement which will determine the level of public involvement required for the actions evaluated. Proposed Findings will be included in the dSGEIS.	Yes	3.1 3.2	Use of a GEIS Statement Future SEQRA Compliance	1-3 3-4	
7.0 ALTERNATIVE ACTIONS					
Alternatives to be reviewed by the dSGEIS will include:					(see below)
the prohibition of development of Marcellus Shale and other low permeability reservoirs by horizontal drilling and high-volume hydraulic fracturing, and	Yes	9.1	Prohibition of Development	1-3	
use of a phased-permitting approach to developing the Marcellus Shale and other low permeability reservoirs, including consideration of limiting and/or restricting resource development in designated areas.	Yes	9.2	Phased Permitting Approach	3-8	
8.2 Mapping					
The dSGEIS will identify the resources used by staff and will also identify reference materials available to the public, including maps.	Partial		Bibliography		Each map contains a reference, and each reference is listed in the bibliography, but there is no written section describing availability to the public

2009 NYS DSGEIS

Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Review of DSGEIS and Identification of Best Technology and Best Practice Recommendations

Report to:

Natural Resources Defense Council (NRDC)

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Introduction

This analysis responds to the Natural Resources Defense Council's (NRDC) request for a review of the New York State (NYS) September 2009 *Draft Supplemental Generic Environmental Impact Statement* (DSGEIS) *on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs.*

NRDC requested a technical review of the DSGEIS to determine if best technology and practices protective of the environment were included. NRDC and its partners have commissioned additional experts to make recommendations on the protection of other resources. Therefore this list of recommendations is not exhaustive, and is complementary to the work assigned to other experts reviewing the DSGEIS. A complete list of best technology and practices recommended by the experts can be found in the summary cover letter submitted by AKRF, Inc. to the New York State Department of Environmental Conservation (NYSDEC) during the DSGEIS public comment period.

This report makes recommendations for improving the NYS DSGEIS analysis. This report also makes recommendations for how to more formally adopt and require best practices in NYS regulations.

Specific recommendations are highlighted in a blue text box.

1. Scope of DSGEIS

Recommendation No. 1: The DSGEIS scope should be limited to analysis of the Marcellus Shale Gas Reservoir. The Marcellus Shale is a substantial accumulation, and warrants its own EIS analysis. Additional information and analysis is needed to examine the impacts of exploring and developing other low-permeability gas reservoirs.

NYSDEC proposes that the DSGEIS cover all horizontal drilling and high-volume hydraulic fracturing in all low-permeability gas reservoirs in NYS; yet, only the Marcellus Shale Gas Reservoir is studied in detail. The DSGEIS is incomplete for all other low-permeability gas reservoirs.

The DSGEIS provides some information on the Utica Shale Gas Reservoir (mostly in the form of geologic assessment), but it does not examine in detail the impacts of drilling or high-volume hydraulic fracture treatments on the Utica Shale or other low-permeability gas reservoirs in the region.

Chapter 4 provides a geologic description of the Marcellus and Utica shale gas reservoirs; however, no other low-permeability gas reservoirs are examined.

Chapters 5 and 6 provide an analysis of drilling, fracturing, and development approaches in the Marcellus Shale Gas Reservoir. Yet, Chapters 5 and 6 are essentially silent on how the Utica Shale Gas Reservoir would be developed. No other low-permeability gas reservoirs are examined.

Technical reports, which were provided by NYSDEC's consultants as supporting documents for the DSGEIS, focus on Marcellus Shale development; they do not provide technical data about or support for development of other low-permeability gas reservoirs in the region.

The Utica Shale Gas Reservoir is almost twice as deep as the Marcellus Shale Gas Reservoir at its deepest point in southern NYS. The Utica Shale dips to 9,000' deep,[1] while the Marcellus Shale is approximately 5,000' deep.[2] Utica Shale wells will take longer to drill than Marcellus Shale wells, generating more air pollution and drilling waste. Utica Shale development will also require more resources and equipment. Therefore, the maximum impact assessment for a Marcellus Shale well is not sufficient to examine the maximum impact for a Utica Shale well.

Low-permeability gas reservoirs that are present at depths shallower than the Marcellus Shale were not studied in any detail, and there is insufficient information in this EIS to justify any development at this time.

Best technology and best practices, in many cases, are gas reservoir specific. Because the DSGEIS does not contain information on the depth, type, activity or equipment requirements for the general category in DSGEIS called "***other*** *low-permeability gas reservoirs*," it is not possible to determine if the maximum impact assessment for a Marcellus Shale well sufficiently covers the maximum impact from "***other*** *low-permeability gas reservoirs*." Nor is it possible to determine whether best technology and practices developed for the Marcellus Shale would apply.

Recommendation No. 2: There is insufficient data provided on the Marcellus Shale Gas Reservoir to support a statewide exploration and production plan. The dataset provided by NYSDEC, in this DSGEIS, is equivalent to early exploration. Additional information is needed to support site-specific production/development scenarios for the Marcellus Shale Gas Reservoir.

NYSDEC should consider either:

(1) Narrowing the scope of this DSGEIS to exploration activities, and baseline study work, and complete a separate future EIS when additional exploration data is available to support a production/development case; or

(2) Clearly outline in this DSGEIS the data set that must be obtained, and analyses that must be performed during exploration, to obtain sufficient information to support a production/development case. The DSGEIS should then establish a process for conducting a site-specific environmental assessment for each production/development well site based on that data collected during the exploration phase.

During the scoping analysis for this DSGEIS, the paucity of exploration data and baseline study work on the Marcellus Shale was not evident. NRDC, and its partners, supported alternatives to examine statewide production/development scenarios assuming exploratory work and baseline datasets were available to NYSDEC to support such an analysis. It was not until the DSGEIS was published in September 2009 that the paucity of data became patently obvious.

Not only is there insufficient exploration data and baseline study work to support a production/development case for the Marcellus Shale on a statewide basis, the DSGEIS also made it clear that there is insufficient infrastructure, support facilities, expertise and agency oversight systems in place to support large-scale, statewide development of the Marcellus Shale. While there may be small site-specific areas within NYS that have more tightly refined exploration data that could possibly support a small production/development case, this is certainly not true for all of NYS. The statewide dataset

[1] DSGEIS, p. 4-6.
[2] DSGEIS, p. 4-15.

provided by NYSDEC, in this first draft, is equivalent to early exploration; it does not support a statewide production/development plan.

NYS's attempt to complete a statewide EIS to cover all future Marcellus Shale gas development is an enormous task. The first draft of the DSGEIS clearly demonstrates that there is insufficient data to complete this analysis. Because there is insufficient data to support a high-quality, site-specific scientific and technical assessment of Marcellus Shale gas production/development scenarios on a statewide basis, NYSDEC should consider either limiting this DSGEIS to exploration activities or should establish a process whereby additional data can be collected during exploration to support future production/development proposals.

Gas resource development occurs in two distinct phases: (1) exploration and (2) production; commonly referred to as the upstream Exploration & Production (E&P) sector, to distinguish between downstream activities such as refining and marketing. Exploration activities are completed to locate the hydrocarbon resources and collect sufficient baseline data to determine whether the hydrocarbon resources can be safely, and economically, developed. Exploration typically includes single wells and numerous studies. Most commonly, an EIS is completed during the pre-exploration (leasing phase) to establish exploration limits, and to determine the baseline data that should be collected to guide future production/development opportunities. If data collected during exploration supports a production/development scenario, then larger scale production (multiple wells, on larger drill sites, and surface processing and distribution facilities) may be needed to develop the resource. Commonly, a full environmental assessment of the production/development scenario is the next step after exploration activities are completed. Site-specific production/development scenarios are typically prepared by the operator, in support of its proposed project, and are supported with high-quality, site-specific scientific and technical information to address the unique aspects of that project.

Because NYSDEC's DSGEIS attempts to combine both exploration and production approval into one EIS, substantially more information is required to support the EIS. And, in many cases, the data has not been collected because the exploratory work has not been completed. For this reason, the exploration and production EIS processes are very commonly separated throughout the United States. For example, the U.S. Minerals Management Service (MMS), which is responsible for developing all of the U.S. oil and gas resources in the Outer Continental Shelf, sets forth a two step process.[3]

- First, an environmental analysis is required to support the exploration phase. Based on that analysis and the sufficiency of the Exploration Plan prepared by the applicant, MMS issues an **Exploration Plan Approval** allowing operators to drill exploratory wells to delineate the oil and gas reservoir, and collect additional information that can support a Development and Production Plan and EIS.

- Second, an environmental analysis is required to support the production phase. Based on that analysis and the sufficiency of the Development and Production Plan, MMS issues a **Development and Production Plan Approval**.

Other oil and gas producing states, similarly, have regulations that provide for a step-wise approval process transitioning from leasing to exploration, and then to production and development. For example, Alaska follows a similar process as the MMS.[4] Alaska requires a Best Interest Finding document to be

[3] MMS Regulations for Oil and Gas and Sulphur Operations in the Outer Continental Shelf. 30 C.F.R. pt. 250, Exploration and development are defined in 30 C.F.R. § 250.105. See 43 U.C.S. § 1340 and 30 C.F.R. §§ 250.211 to .235; 250.280 to .285 for Exploration Plan requirements. See 43 U.S.C. § 1351 and 30 C.F.R. §§ 250.241 to .273; 250.280 to .285 for Development and Production Plan requirements.
[4] See 20 Alaska Admin. Code §§ 25.005, .990 (distinguishing exploration and development wells).

prepared before an area is even leased.[5] This is essentially a state EIS process conducted prior to exploration. Once the leases are sold by the state, an exploration permit can be obtained to just drill the exploration wells and conduct studies.[6] Drilling additional wells, and developing surface facilities requires a development plan and full environmental assessment (operators must put a complete package together from drilling and all the surface facilities right up to where they connect into a sales line).[7] This stepwise approach allows for responsible development to proceed in areas where there is sufficient data to support the project, and requiring additional study and exploration in areas that are not well understood.

While state regulations vary in procedural detail, this same basic approach is common, allowing exploratory operations to collect sufficient data to support a thorough, high-quality production and development assessment. If there is sufficient information available to support both exploration and production, it may be possible to permit both simultaneously, but this approach is uncommon.

NYSDEC's attempt to combine both exploration and production operations into one analysis has complicated the assessment and created an unmanageably large and complex analysis that is unsupported by the limited amount of currently available data.

While the lack of data on the Marcellus Shale may have been self evident to NYSDEC, it was not to the public, and NYSDEC should have disclosed this problem during scoping, allowing other alternatives to be considered. At this point, there a couple recommended options for proceeding:

- One alternative is to narrow the scope of this EIS to **exploration** of the Marcellus Shale. At some point in the future, when sufficient information is collected, an additional EIS to support the **production/development** phase of the Marcellus Shale development can be drafted.

- Alternatively, the DSGEIS can attempt to combine exploration and production phases, but clearly define the data that must be obtained, and analyses that must be performed during exploration, to obtain sufficient information to support a production/development case. The DSGEIS could establish a process for conducting a site-specific environmental assessment for each production/development well site based on that data collected during the exploration phase.

2. NYS Regulations are Needed to Guide Marcellus Shale Exploration & Development

Recommendation No. 3: NYSDEC should update its regulations to include best technology and best management practices for oil and gas exploration and production in general, and more specifically for shale gas development. Oil and gas exploration and production should not be managed using out-of-date regulations, augmented by a patchwork of permit conditions and guidance memoranda. An updated regulatory framework provides: operators with clear, consistent rules to work from; NYSDEC staff with simplified instructions for implementation; a public process for input; and a more orderly and safe exploration and development process for NYS.

[5] Alaska Statute § 38.05.180.
[6] Alaska Statutes § 38.05.131 to .134.
[7] 20 Alaska Administrative Code § 25.517.

This DSGEIS proposes to build on the existing 1992 Generic Environmental Impact Statement (GEIS) for oil and gas drilling in NYS by providing additional information on the Marcellus Shale reservoir and high-volume hydraulic fracturing. This approach does not address the fact that, since 1992, numerous best technology and best management practice improvements have been made to basic elements of the E&P industry. By relying on 1992-vintage decisions and technology as the foundation for Marcellus Shale development, NYS's DSGEIS starts with an unstable foundation. Therefore, the first and most logical step in this analysis is to examine the basic elements of the 1992 GEIS and determine what new best technology and best practice improvements have been made since 1992, and update the foundation of the analysis. Then, and only then, can NYS build a well-supported incremental analysis that examines the impact of new techniques such as horizontal drilling and high-volume fracture treatments.

The 1992 GEIS is based on oil and gas regulations, most of which were adopted in 1972. 1972 vintage regulations are clearly inadequate to guide shale gas development in 2010 and beyond.

Since 1992, NYSDEC has found other gaps in NYS's regulatory structure and has developed numerous guidance documents in an attempt to bridge the regulatory gap.

Now in 2009, 17 years later (and 37 years after adoption of most of the existing regulations), NYSDEC is faced with antiquated regulations that do not address the decades of oil and gas best technology and best practice improvements. This situation is compounded by a patchwork of permit stipulations and guidance documents that attempt to regulate the oil and gas industry in NYS.

NYSDEC's 2009 DSGEIS further compounds the problem by adding another list of permit conditions (Appendix 10) for shale gas development, without taking the time to step back and develop an updated, comprehensive set of regulations to guide future oil and gas development in NYS.

It is recommended that this DSGEIS conclude that it is time for NYS to revise its regulations to include best technology and best management practices for oil and gas exploration and production in general, and develop regulations specific to the shale gas.

An updated regulatory framework provides: operators with clear, consistent rules to work from; NYSDEC staff with simplified instructions to implement; a public process for input; and a more orderly and safe exploration and development process for NYS.

The current patchwork of permit conditions and guidance documents do not provide for adequate public input because permit conditions can be revised subsequent to completion of the EIS, and guidance documents do not go through public review. NYS law requires public input in the regulatory development process, and any subsequent amendment.

Recommendation No. 4: Even if NYSDEC persists, without adequate data, in addressing both exploration and production in this SGEIS, the proposed supplementary permit conditions are incomplete and inconsistent with both some of the DSGEIS findings and best technology/practices for gas shale development. The "Proposed Supplementary Permit Conditions" should be renamed to serve as a "List of Regulatory Improvements Required to NYS's Regulations." This list should reflect the numerous recommendations herein and those substantive comments received by NYSDEC from others. The list should be used to revise the NYS regulatory framework, because the DSGEIS should appropriately serve as the basis for examining and improving NYSDEC's regulatory program for shale gas.

There is a significant disconnect in the DSGEIS between the assumptions, analysis and mitigation measures discussion in Chapter 7 and the final *Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing* (Appendix 10). NYSDEC proposes to use this revised set of permit conditions to regulate industry; thus, it is critical that the conditions reflect the best technology and best practices (mitigation), making the end-product a useable tool for the regulator, the applicant and the public.

As explained above, it is recommended that NYSDEC revise its regulations to include best technology and best management practices for oil and gas exploration and production in general, and shale gas development in particular. This approach provides the best, most comprehensive method of creating exploration and production stipulations, and is a substantial improvement over generating a patchwork of "proposed supplementary permit conditions" to bridge a known regulatory gap. This report, along with other reports submitted by NRDC and its co-signatories, provides specific recommendations for improving NYS's oil and gas exploration and production regulations.

As stated in the title, the purpose of this DSGEIS was to examine the "oil and gas and solution mining regulatory program," with a goal of more specifically identifying regulatory improvements to NYSDEC's regulatory program for shale gas, not to merely generate a list of permit conditions.

Therefore, it is recommended that the "Proposed Supplementary Permit Conditions" be renamed to serve as a "List of Regulatory Improvements Required to NYS's Regulations." This list should be updated and complete, reflecting the numerous recommendations herein and those comments received by NYSDEC from others. The refined list should serve as a basis for revising the NYS regulatory framework, which is the next logical step.

Recommendation No. 5: NYS's regulations need to be revised to address Marcellus Shale gas development, provide a clear, complete list of prohibited activities, and describe maximum allowable levels of activities and expected mitigation. When codified in regulations, NYSDEC staff, the applicant, and the public will fully understand the "bottom-line" requirements.

NYS's regulations need to provide a clear, complete list of prohibited activities, and describe maximum allowable levels of activities. The regulations also need to include a clear description of expected mitigation. This approach facilitates implementation and enables NYSDEC staff, the applicant, and the public to fully understand the "bottom-line" requirements.

In some cases, the DSGEIS proposes mitigation that is not carried through to the proposed permit conditions. In many cases, the DSGEIS describes limitations (e.g. maximum volume, duration, depth) to explain why NYSDEC believes the impact will be limited. Yet, often these limits are not translated into enforceable permit conditions. Without regulatory constraints, impacts from exploration and development activities will exceed those considered in the DSGEIS, and there may be undisclosed and unmitigated significant adverse environmental impacts.

While not an exhaustive list, the short list provided below demonstrates the disconnect between the limits and assumptions found in the text of the DSGEIS and the requirements listed in the *Proposed Supplementary Permit Conditions*. Other examples are identified elsewhere in this report. None of these limits found in the text of the DSGEIS are set by permit condition:

- diesel-based fracture fluid is not allowed;[8]

[8] DSGEIS, p. 7-41.

- site-specific analysis is required for high-volume hydraulic fracture at depths less than 2,000' TVD,[9] or if the distance between the target fracture zone and a fresh water supply is less than 1,000' TVD;[10]
- maximum hydraulic fracture size;[11]
- maximum three (3) days of flaring;[12]and,
- maximum of 250 days of operation for drilling engines, maximum of 20 days for hydraulic fracturing engines, and maximum of 30 days of flaring in a given year.[13]

In other areas of the DSGEIS, the stated limits conflict. For example, Section 6.5.2.2 "Sources of Air Emissions and Operational Scenarios" states that the worst case scenario for emissions produced from a single well pad is a drilling rig in operation while an adjacent well is being completed, another well is being routed to flare, and an onsite line heater is in use. This maximum case air pollution scenario doesn't take into account the possibility of a simultaneous drilling rig operation at the same well pad, which is discussed in Section 5.2.2: "*One operator has stated that on a well pad where six or more wells are needed, it is possible that two triple-style rigs may operate concurrently*." Therefore, the maximum air pollution case would be the operation of two concurrent drilling rigs, not just one, unless simultaneous operation of two drilling rigs on a single pad is prohibited. Because there are no limits on the number of concurrently operating air pollution sources in the proposed permit conditions, significant potential adverse impacts have not been determined, and required mitigation has not been identified.

The DSGEIS recommends in Chapter 7 that additional, more stringent permit conditions be added in some cases; however, these more stringent mitigation measures are not included in the *Proposed Supplementary Permit Conditions* (Appendix 10). For example, Section 7.1.3.4, p. 7-35, lists more stringent requirements in primary aquifers and unfiltered water supply areas, including: removal of fluids within 7 days of drilling and stimulation operations for each well; immediate fluid removal if operations are suspended; immediate fluid removal if the site is left unattended at any time; and removal of fluids within 7 days of completing drilling and stimulation operations at the last well on a pad. These more stringent requirements are not summarized in the proposed permit conditions for NYSDEC staff to select as an alternative to the 45-day timeframe allowed by proposed Permit Condition No. 16.

3. Drilling Mud Composition and Drilling Waste Disposal

Recommendation No. 6: NYS regulations should be revised to acknowledge and mitigate drilling mud pollution impacts, minimize drilling waste generation, limit heavy metal and NORM content, NORM, and establish best practices for collection, treatment and disposal of drilling waste.

The 1992 GEIS allows drill cuttings to be buried onsite, and the DSGEIS is silent on the potential pollution impact from drilling muds. Current regulations incorrectly conclude that "drilling muds are not considered to be polluting fluids." 6 NYCRR § 554.1(c)(1). This error should be corrected.

Drilling muds are used to control the hydrostatic pressure in a wellbore. The most common weighting agent used is barite. U.S. Department of Energy studies show that barite contains mercury (1ppm-10ppm

[9] TVD= True Vertical Depth.
[10] DSGEIS, p. 7-49.
[11] DSGEIS, p. 6-56.
[12] DSGEIS, p. 6-63.
[13] DSGEIS, p. 6-72.

Hg, depending on its origin.)[14] Mercury concentrations can be reduced by using thermal methods, leaching with dilute acids, or selecting barite with naturally occurring lower concentration levels of mercury.[15]

The U.S. Department of Interior estimates that 0.8 metric tons of mercury is discharged into the Gulf of Mexico (GOM) annually (1839 lb Hg/yr) from mud disposed from drilling operations.[16] This equates to approximately 1.69 lbs of mercury per well, for wells drilled to a total depth of approximately 12,000'.

(1,091 wells/yr drilled in GOM)) (12,038 ft/well)*(140 lbs barite/ft)*(1x10^{-6} Hg/g barite)= 1,839 lb Hg/yr.*

(1,839 lb/Hg)/(1,091 wells) = 1.69 lbs of mercury per well.

Using an average wellbore length of 5,000' for a Marcellus Shale well, and a lower barite use rate of 100 lbs/ft to account for lower expected pressures, **the mercury content in the drilling mud is estimated at 0.5- 5.0 lbs of mercury per well,** depending on barite quality:

1ppm Hg in barite= (1 Marcellus well) (5,000 ft/well)*(100 lbs barite/ft)*(1x10^{-6} Hg/g barite) = 0.5 lb Hg/well*

10ppm Hg in barite= (1 Marcellus well) (5,000 ft/well)*(100 lbs barite/ft)*(10x10^{-6} Hg/g barite) = 5.0 lb Hg/well*

Drilling muds may also contain the heavy metal cadmium, leading the EPA to establish cadmium concentration limits in drilling muds for muds disposed offshore.[17]

The DSGEIS proposed permit conditions require a disposal plan pursuant to 6 NYCRR § 554.1(c)(1); however, the plan is not available for public review or input, so it is unclear what the plan will require.

The DSGEIS explains that NYS solid waste management regulations at 6 NYCRR Chapter IV, Subchapter B (Solid Waste) provide the authority by which the state (through the Division of Solid and Hazardous Materials) establishes standards and criteria for solid waste management operations, including landfills and land application. However, the DSGEIS is unclear on what NYSDEC has deemed to be the best management practice for handling drilling waste.

A recent U.S. Department of Energy review of NYS drilling waste disposal regulations concluded:

> *"The [NYS] **DEC has developed no regulations, policies, or guidelines** governing slurry injection, subsurface injection, or annular disposal of drilling wastes and reserve-pit wastes."*[18]

NYSDEC has not established regulations to minimize the generation of drilling waste (e.g. reuse, recycle), nor has NYSDEC established limits on the heavy metal content of drilling mud additives.

Proposed Permit Condition No. 23[19] requires the use of a "closed loop tank system" instead of a reserve pit to manage drilling fluids and cuttings within a floodplain, but the DSGEIS not explain why a "closed

[14] http://www.fossil.energy.gov, "Mercury Removal from Barite for the Oil Industry."
[15] http://www.fossil.energy.gov, "Mercury Removal from Barite for the Oil Industry."
[16] http://www.gomr.mms.gov/homepg/regulate/environ/Hg%20discharge%20estimate.pdf.
[17] U.S. Environmental Protection Agency, Development Document for Effluent Limitation Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-93-003, 1993.
[18] U.S. Department of Energy, Drilling Waste Management Information System, http://web.ead.anl.gov/dwm/regs/state/newyork/index.cfm.
[19] DSGEIS, Appendix 10.

loop tank system" cannot be employed for all areas. Unless drilling mud and cuttings will be disposed of onsite, it is more efficient to use a closed loop tank system to collect this waste and route it to a treatment and disposal location, avoiding the impact of constructing a reserve pit and the potential for leakage into the environment.

There are numerous potential drilling mud disposal methods, but the DSGEIS is not clear on what method is determined to be best practice for NYS. New Mexico requires all fluids to be removed from the reserve pit and recycled or disposed of in accordance with state regulations.[20] New Mexico also requires the drill cuttings and reserve pit liners be sent to a disposal facility in accordance with state regulations, and the soil under the reserve pit to be tested for benzene, total BTEX[21], TPH[22], the GRO[23] and DRO[24] combined fraction, and chlorides.[25] If contamination is found, it must be excavated and remediated. If the soil is clean it can be backfilled. The City of Fort Worth, Texas, prohibits onsite burial of drilling muds and cuttings.[26] The reserve pits are temporary and all muds and cuttings must be removed and handled at an approved waste management facility.

NYSDEC's consultant, Alpha, concludes that although New Mexico and Texas have more stringent drilling cutting and mud disposal standards, allowing onsite burial of drilling cuttings may be acceptable for NYS because Pennsylvania allows that approach. Yet there is no analysis of the environmental consequences of onsite burial. And, there is no explanation as to why best practices in other states would not be considered for NYS. Since drilling muds contain heavy metals and other pollutants, and drill cuttings contain NORM in NYS, careful consideration of treatment and disposal options is needed. While NYSDEC provides some data on drill cutting NORM content, concluding the NORM content is too low to pose a concern. NYSDEC dataset is insufficient to demonstrate that the NORM content will be safe statewide, because shales are known to be very heterogeneous and the composition could vary substantially.

Proposed Permit Condition No. 40 requires only that the operator remove and handle drilling fluids pursuant to 6 NYCRR § 554.1(c)(1), but drill cuttings containing NORM and coated with drilling mud containing heavy metals and other chemicals can remain in the reserve pit after drilling mud is removed. Although the requirements of long-term burial are unclear, it appears that NYSDEC is proposing to leave the drill cuttings in the reserve pit at the site, without removal or any further treatment.[27]

The DSGEIS's muds and cuttings disposal plan raises a number of concerns. Foremost, 6 NYCRR § 554.1(c)(1) states that "drilling muds are not considered to be polluting fluids." Therefore, any waste management plan developed to dispose of drilling fluids, and approved by NYSDEC, would be based on the assumption that the drilling mud waste was non-toxic. Yet, drilling muds contain heavy metals and other pollutants. NYS's regulations need to be updated to reflect the actual composition of drilling muds and the potential environmental risk. NYS's regulations should provide specific instruction for the proper treatment and disposal of drilling muds and cuttings that contain heavy metals and NORM.

Second, 6 § NYCRR 554.1(c)(1) requires only submission of a waste management plan, but sets no standards for disposal. There is no instruction on what to do with the drill cuttings, or whether long-term

[20] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.17.
[21] BTEX= benzene, toluene, ethylbenzene, and xylene.
[22] THP= total petroleum hydrocarbons.
[23] GRO= gasoline range organics.
[24] DRO= diesel range organics.
[25] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.17.
[26] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.18.
[27] Except in a flood plain (where reserve pits are prohibited by Permit Condition No. 24).

onsite burial in the reserve pit is best practice. Alpha confirms that NYS's oil and gas regulations do not include instruction for how to dispose of drill cuttings containing NORM:

> *"The State's Oil and Gas Regulations do not specifically refer to discharge or storage of radioactive materials. Low-level, naturally occurring radioactive material (NORM) is present in many of the geological formations throughout much of New York. The development of natural gas wells into the Marcellus Shale can bring low-level NORM to the surface through produced fluids or cuttings. Subpart 380-1.2(e) of 6 NYCRR indicates that Part 380 for the Prevention and Control of Environmental Pollution by Radioactive Materials "does not apply to NORM or materials containing NORM unless processed and concentrated"; consequently, the disposal of drill cuttings from the Marcellus or other gas shales in New York would not be subject to the 6 NYCRR Part 380 regulations.* ***The drill cuttings generated, therefore, would not fall under WRR Section 18-33, and return of the drill cuttings to the ground at a drill pad site within the Watershed, also would not be prohibited"*** *[emphasis added].* [28]

NYSDEC's consultant, Alpha, concludes that:

> *"Deep well injection and landfill disposal are options in PA, but are not readily available options in NY, unless PA has the capacity to handle the increased volume from both NY and PA"*[29]

Therefore, it is not clear what the waste management plan is for drilling fluids and cuttings. Where will drilling waste be taken for treatment and disposal? Does the treatment capacity exist to handle this incremental waste in NYS? If so, where are the treatment facilities located? What type of treatment will be completed? What is the ultimate disposal location for the treatment by-products? If drill cuttings are not removed from the reserve pit, how will the operator ensure that there is no contamination left below the reserve pit liner before the reserve pit is covered and permanently closed?

Clearly, there is need for regulatory improvement. The DSGEIS should determine which drilling mud composition and disposal practices are "best practice" for the various locations and scenarios under evaluation in this DSGEIS. Based on the location and scenario, there may be reason to select one method over another. It is critical that NYSDEC carefully think through known best technology methods and best management practices, and then explain in the DSGEIS why it has selected the appropriate technology for the location and scenario under study.

At a minimum, the DSGEIS should examine the following practices and make a recommendation for the lowest environmental impact:

1. Waste minimization (drilling mud recycle and reuse when possible);
2. Use of drilling mud additives with lower environmental impact;
3. Beneficial reuse of uncontaminated drilling wastes;
4. Use of closed loop tank systems to transport waste, versus use of reserve pits;
5. Burial (e.g. landfills, or reserve pits);
6. Commercial treatment and disposal facilities; and/or
7. Underground injection.

A combination of waste minimization, selection of low impact additives, collecting waste in a closed-loop system, pumping that waste to a cuttings reinjection (CRI) unit, and disposing of the waste by deep well injection into a well-designed, properly constructed disposal well is usually the best management practice

[28] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.96.
[29] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p. 20.

in most applications. These methods: reduce waste; reduce toxicity; eliminate air pollution; and eliminate the need for surface disturbance from reserve pits and the potential for leaks, contamination, and future remediation. However, there may be unique locations and situations where this combination of practices is not appropriate and that must be thoroughly analyzed by NYSDEC in the DSGEIS.

4. Disposal of Drilling & Production Waste & Equipment Containing NORM

Recommendation No. 7: NYSDEC should adopt regulations to establish best practices for collection, treatment, and disposal of drilling and production wastes, as well as equipment containing NORM.

The DSGEIS acknowledges that drilling and production waste and equipment may contain Naturally Occurring Radioactive Material (NORM). NYSDEC reports that the Marcellus Shale contains Uranium-238 and Radium-226, and that this NORM may be present in drill cuttings, produced water and stimulation treatment waste.[30] NYSDEC identified Radium-226 as the most significant NORM of concern, because it is water soluble and has a half-life of 1,600 years.[31] Radiation pathways can include external gamma radiation, injection, inhalation of particulates, and radon gas.[32]

Produced Water Waste: Produced water is rich in chloride, which enhances the solubility of other elements, including the radioactive element radium.[33] NYSDEC reports it has insufficient data on NORM in produced water, but acknowledges that NORM is present and is known to be found in elevated levels. NYSDEC identifies the need for additional research and testing.[34] The DSGEIS proposed Permit Condition No. 47 (Appendix 10) requires produced water to be tested for NORM; yet, no treatment or disposal requirements are set based on the NORM testing outcome. It is unclear how the NORM test data will be used to establish the best waste management practice to safely dispose of produced water. Buried in the DSGEIS at p.7-50 there is one statement that indicates that NYSDEC will use a radioactivity scan in the decision to issue a Beneficial Use Determination (BUD), if “potential public exposure concern” is indicated, but the threshold for concern is not quantified. Nor is this requirement carried into the proposed permit conditions (Appendix 10) or the BUD application (Appendix 12).

Proposed Permit Condition No. 48 requires only that produced water be “disposed, recycled or reused” and transported by a waste transporter with a 6 NYCRR Part 364 permit. No pollutant thresholds, disposal limits or treatment requirements are set.

Recommendation No. 8: NYSDEC should adopt regulations prohibiting use of Marcellus Shale gas wastewater containing NORM for land or road spreading applications and establishing best practices for collection, treatment and disposal of drilling and production wastes and equipment containing NORM.

Appendix 12 of the DSGEIS states that produced water may be spread on roads if a BUD is issued by the NYSDEC Division of Solid and Hazardous Materials, under the Part 364 Transporter Program, but no thresholds or standards are established for NORM limits in the material. Other oil and gas producing

[30] DSGEIS, p. 4-36.
[31] DSGEIS, p. 6-129.
[32] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[33] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[34] DSGEIS, p. 5-31.

states, such as Texas, specifically prohibit road spreading of waste containing NORM.[35] A study conducted by Argonne National Lab for the US Department of Interior (DOI) concluded that land spreading of diluted NORM waste presented the highest potential dose of exposure to the general public of all waste disposal methods studied.[36]

Since the Beneficial Use Determination does not require an operator to test for NORM,[37] it is unclear how the NORM testing at the well site will be integrated into the BUD process, and what level of NORM, if any will be allowed in fluids used for road spreading. The DSGEIS does not examine the cumulative impact of spreading small amounts of NORM, repeatedly over the same area. It is recommended that waste containing NORM be prohibited for use in land or road spreading.

The DSGEIS explores produced water disposal options (e.g. injection wells, treatment plants, and road spreading),[38] but does not land on a best practice method for produced water containing NORM.

Produced water containing NORM should **not** be used for road spreading. Produced water, containing NORM, should be returned to the subsurface formation from which it came, or should be handled at an approved waste treatment plant.

Furthermore, EPA identifies produced water pits (brine pits) as an outdated practice if produced water contains NORM. EPA reports that:

> *"Lined and/or earthen pits were previously used for storing produced water and other nonhazardous oil field wastes, hydrocarbon storage brine, or mining wastes. In this case, TENORM[39] in the water will concentrate in the bottom sludges or residual salts of the ponds.* ***Thus the pond sediments pose a potential radiological health risk****….produced waters are now generally reinjected into deep wells…No added radiological risks appear to be associated with this disposal method as long as the radioactive material carried by the produced water is returned in the same or lower concentration to the formations from which it was derived"[40][emphasis added].*

Hydraulic Fluid Waste: The DSGEIS proposed Permit Condition No. 47 (Appendix 10) requires hydraulic fracture (frac) fluid waste to be tested for NORM; yet, no treatment or disposal requirements are set based on the NORM testing outcome. It is unclear how the NORM test data will be used to establish the best waste management practice to safely dispose of frac fluid.

Proposed Permit Condition No. 23 requires waste fluids to be handled in accordance with 6 NYCRR § 554.1(c)(1), yet this regulation does not specify the best practice for handling hydraulic fluid waste. Instead, 6 NYCRR § 554.1(c)(1) merely provides a process for an applicant to submit a waste management plan. The regulation states:

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[35] Texas Railroad Commission (TXRRC), 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632. "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes.

[36] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[37] The example BUD application provided in Appendix 12 requires testing for calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil and grease, benzene, ethylbenzene, toluene and xylene, but not NORM.

[38] DSGEIS, p. 5-131.

[39] TENORM is Technologically Enhanced Natural Occurring Radioactive Material.

[40] http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.

*"Prior to the issuance of a well-drilling permit for any operation in which the probability exists that brine, salt water or other polluting fluids will be produced or obtained during drilling operations in **sufficient quantities** to be deleterious to the surrounding environment, the operator must submit and receive approval for a plan for the environmentally safe and proper ultimate disposal of such fluids. For purposes of this subdivision, drilling muds are not considered to be polluting fluids. Before requesting a plan for disposal of such fluids, the department will take into consideration the known geology of the area, the sensitivity of the surrounding environment to the polluting fluids and the history of any other drilling operations in the area. **Depending on the method of disposal chosen by the applicant**, a permit for discharge and/or disposal may be required by the department in addition to the well-drilling permit. An applicant may also be required to submit an acceptable contingency plan, the use of which shall be required if the primary plan is unsafe or impracticable at the time of disposal" [emphasis added].*

Terms such as "sufficient quantities" deleterious to the environment are not quantified. The waste disposal method is selected by the applicant, with no instruction on the best waste management practice.

While recycle and reuse of frac fluid is discussed in the DSGEIS, there is no requirement to use this best practice in the proposed permit conditions. There is insufficient information in the DSGEIS to determine if the capacity exists to handle the high volumes of frac fluid that may be produced, especially fluid containing NORM, through either underground injection or surface treatment and disposal at an authorized facility.

Equipment Scale and Sludge: Equipment (water lines, flow lines, injection wellheads, vapor recovery units, water storage tanks, heaters/treaters, and separators)[41] used to process natural gas and produced water containing NORM can become coated with radium scale and sludge deposits.[42] Scale precipitates from produced water when it is brought to the surface, cooled to lower temperatures, and subject to lower pressures.[43] The most common form of scale is barium sulfate, which readily incorporates radium in its structure.

While the DSGEIS acknowledges the likelihood that NORM will build up in equipment scale and sludge,[44] the proposed permit conditions are silent on how equipment contaminated with NORM should be cleaned, handled, and disposed.

Because E&P waste is exempt from the federal Resource Conservation and Recovery Act (RCRA),[45] it is critical that states establish clear best practice requirements for handling E&P waste, especially NORM found in equipment scale and sludge. The DSGEIS cites other oil and gas states, such as Texas and Louisiana, as adopting stringent NORM regulations, including: occupational dose control, surveys, testing and monitoring, record keeping, signs and labeling, and treatment and disposal methods.[46] Yet, the DSGEIS does not recommend adopting these more stringent approaches taken by other states and is silent on any recommendation in the proposed permit conditions (Appendix 10).

[41] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.
[42] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[43] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[44] DSGEIS, p. 6-30.
[45] Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, October 2002.
[46] DSGEIS, p. 7-101.

The DSGEIS (Section 7.8.2)[47] describes NYS's existing radioactive waste regulations, noting that equipment contaminated with NORM may be subject to the NYS Department of Health licensing requirements under State Sanitary Code, Chapter 1, Part 16 (10 NYCRR 16) and Industrial Code Rule 38 (12 NYCRR 38). Yet it makes no conclusion as to whether E&P equipment contaminated with NORM will actually be subject to regulation or how the waste will be collected, treated, and disposed.

While NYS has some current regulations relating to radioactive material exposure and disposal, these rules are not specific to gas production equipment or methods. NYSDEC should adopt regulations to establish best practices for collection, treatment, and disposal of drilling and production wastes and equipment containing NORM.

NYSDEC should evaluate the following list of practices and determine which are best for the specific locations and scenarios examined in the DSGEIS:

1. NORM testing of all material produced from the gas well, all material used in well stimulation and equipment scale and sludge;
2. NORM testing of equipment scrap metal, and cleaning prior to smelting. Pollution control devices (e.g. filters and bubblers) should be installed in smelter stacks to reduce airborne radiation;
3. Reinjection of produced water back into aquifer of the gas reservoir from which it came;
4. Treatment and disposal by a licensed NORM disposal facility; or
5. Collection and transportation of waste for disposal in a salt dome.

5. Casing and Cementing Requirements

Recommendation No. 9: NYS casing and cementing regulations should be developed specific to Marcellus Shale gas reservoir development. They should address high angle well construction, ensuring that casing and cementing are structurally sound and provide an effective drinking water barrier, particularly when high-volume fracture treatments are performed.

Section 2.4.6 concludes that drinking water well contamination by oil and gas drilling activities, such as incidents reported in the 1980s in Chautauqua County, is mitigated by NYS's new casing and cementing practices and fresh water aquifer supplementary permit conditions.

While NYS's new casing and cementing practices are an improvement, these requirements are found in guidance instead of regulation, and therefore are subject to change by appointed officials without public review. The DSGEIS should conclude that NYS's new casing and cementing practices and fresh water aquifer supplementary permit conditions are mandatory minimum requirements for all wells drilled and fractured in low-permeability gas reservoirs in the state. Additionally, NYSDEC should take steps to codify these requirements in regulation.

Attachment C to the Comments on this DSGEIS prepared by AKRF, Inc. provides a September 16, 2009 report to NRDC documenting several recommendations for improving NYS's best practices for casing and cementing.[48] The September 16, 2009 report compares NYS's best practices for casing and cementing to those of other large and experienced oil and gas producing states (Texas, California, Alaska and Pennsylvania). Specific recommendations are included for: high angle well casing and cementing; cement

[47] DSGEIS, p. 7-103.

[48] New York State (NYS) Casing Regulation Recommendations, report prepared by Harvey Consulting, LLC., for the Natural Resources Defense Council (NRDC), September 16, 2009.

and casing quality standards and testing; operator certification; and when to set intermediate casing to protect ground water (especially in wells that undergo fracture treatments).

6. Flaring, Venting, and Fugitive Emissions

Recommendation No. 10: NYSDEC should develop regulations to restrict flaring, venting, and fugitive emissions to the lowest level technically feasible.

Both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[49] Initially the motive was to conserve hydrocarbon resources to maximize federal and state revenue and gas supply. More recently, focus on greenhouse gas (GHG) emission reduction has prompted additional innovation to further reduce flaring and venting.

Reducing flaring and venting to the lowest level technically achievable is widely considered best practice. The proposed permit conditions do not include this best practice. Proposed Permit Condition No. 2 merely requires notification to the county emergency management office when flaring occurs. NYSDEC should develop regulations to restrict flaring, venting, and fugitive emissions to the lowest level technically feasible.

Drilling & Completions: Flares may be used during well drilling, completion and testing to safely combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. If gas processing equipment and pipeline systems are in place, gas flaring can be avoided in all cases except equipment malfunction.

During the drilling and completion phase of the first well on a well pad, a gas pipeline may not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply is found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to route it to. However, subsequent wells drilled on that same pad would be in a position to implement Reduced Emission Completion (REC), also called “green completion,” which involves routing gas to a pipeline. Green completions require equipment to be brought to the well site to process wet gas from the well (during well completion activities) to ensure the gas meets pipeline specifications. The DSGEIS states that green completions are not currently required in NYS.[50] The DSGEIS estimates that without a gathering line in place, initial cleanup or testing could require flaring to last for three to 30 days.[51]

Gas Production: High pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams[52] and gaseous by-product streams[53] that are uneconomical to conserve.[54] Venting or flaring may also occur during manual or

[49] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.
[50] DSGEIS, p. 6-52.
[51] DSGEIS, p. 5-125.
[52] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.
[53] For example: instrument vent gas; stabilizer overheads and process flash gas.
[54] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and removal of hydrates from pipelines.[55]

Best practices for flaring and venting during gas production should limit flaring and venting to the smallest amount needed for safety. Gas should be collected for sale, used as fuel, or reinjected for pressure maintenance, unless it is proven to be technically and economically unfeasible.

NYSDEC should adopt very clear regulations limiting flaring and venting during gas production operations. If gas collection, use, or sale is not possible, NYSDEC should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces hazardous air pollutants, volatile organic compound emissions, and GHG emissions.[56]

Several states (e.g. Alaska and California) require operators to keep accurate records of gas venting and flaring to ensure that the amount is limited to safety related needs. Some states and the federal government (in the Outer Continental Shelf) require operators to pay royalty and taxes on flared and vented gas not authorized for safety purposes. This encourages investment in gas collection and control devices to conserve natural gas. [57]

Best Practices for Flares: When flare use is necessary for safety, the following best practices should be instituted:

- Minimize the risk of flare pilot blowout by installing a reliable flare system;
- Ensure sufficient exit velocity or provide wind guards for low/intermittent velocity flare streams;
- Ensure use of a reliable ignition system;
- Minimize liquid carry over and entrainment in the gas flare stream by ensuring a suitable liquid separation system is in place; and
- Maximize combustion efficiency by proper control and optimization of flare fuel/air/steam flow rates.

Best Practices for Venting and Fugitive Emissions: Best Practices for controlling venting and fugitive emissions include:

- Leak Detection and Repair (LDAR) programs including acoustic detectors and infrared technology to detect odorless and colorless leaks;
- Use of low bleed pneumatic instruments,[58] instrument air, electric or solar powered control devices;
- Use of dry centrifugal compressor seals;
- Use of smart automation plunger lifts for liquid unloading;
- Early installation of pipelines; and
- REC methods for gas well completions.

In most cases these best practices improve safety and collect marketable gas for sale. For example, RECs, “green completions,” provide an immediate revenue stream by routing gas that would otherwise be vented

[55] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[56] Fugitive and Vented methane has 21 times the global warming potential as combusted methane gas. Methanetomarkets.org, epa.gov/gasstar.

[57] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

[58] Process controllers, chemical pumps, and glycol pumps often vent pressurized natural gas used for pneumatic actuation.

to a gas sale line. Industry has demonstrated that green completions are both best environmental practice and profitable. Green completion equipment has a short economic payout. A green completion requires the operator to bring in gas processing equipment to the well pad to clean up wet gas, improving it to gas pipeline quality. Typically, portable gas dehydration units, gas-liquid-sand separator traps, and additional tanks are required.[59] Most companies report a one-to-two-year payout for investment in their own green completion equipment, and substantial profit thereafter, depending on the gas flow rate.[60] It is also possible for smaller operators to rent green completion equipment. NYSDEC's consultant, ICF Incorporated LLC, found that equipment payouts may be as short as three months, and more than $65 million in profits was made on a national level in 2005 by companies conducting green completions.[61] Natural Gas STAR also provided technical advice to NYSDEC (Appendix 23) recommending green completions as a technically feasible economic method. Yet, the DSGEIS does not require green completions. The DSGEIS encourages participation in the Natural Gas STAR program,[62] but this program is voluntary and will not require operators to institute flaring and venting reductions. The best practice of green completions should be codified in NYS regulation.

7. Hydrogen Sulfide

> **Recommendation No. 11**: NYSDEC should adopt regulations to require gas production operators to follow hydrogen sulfide detection and protection procedures for employees and the public during drilling **and** production operations.

The DSGEIS proposed Permit Condition No. 21 requires operators to conform to the American Petroleum Institute Recommended Practice 49 (API RP49) for Drilling and Well Servicing Operations Involving Hydrogen Sulfide. Hydrogen sulfide (H_2S) is a deadly gas. API RP49 is widely accepted as a guidance document. However, API RP49 does not address H_2S at gas production and processing facilities. API RP 55 addresses Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, including procedures to protect employees and the public. Both API RP49 and API RP55 should be added to NYS's regulatory requirements.

8. Seismic Data Collection

> **Recommendation No. 12**: NYSDEC should establish regulatory requirements for seismic data collection that reduce impact to the environment and the public.

The DSGEIS addresses naturally occurring seismic events in Chapter 4, but is silent on the impacts of industrial seismic exploration used to locate subsurface gas reservoirs. Seismic waves created from a source on the surface travel through the earth and are reflected back to surface. Recording instruments called geophones collect data and transmit it to a seismic recording truck. The speed at which waves travel through the earth and are reflected allow geophysicists to map subsurface geology and identify potential gas reservoirs.

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[59] EPA, Green Completion, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, Fact Sheet No. 703, 2004.
[60] Reduced Emissions Completions, Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop, Casper Wyoming, August 30, 2005.
[61] DSGEIS, Appendix 25.
[62] DSGEIS, p. 7-92.

Historically seismic exploration was most commonly conducted using dynamite placed in surface drilled boreholes to create small surface explosions that produced the requisite seismic waves.[63] Due to environmental and public concerns, dynamite use has decreased, and has commonly been replaced by large, heavy wheeled or tracked vehicles with Vibroseis units that propagate energy signals into the earth, or "thumper" trucks that pound the ground surface to create seismic vibrations by dropping a heavy weight raised by a hoist.

Seismic exploration data can be obtained to create two and three dimensional subsurface maps. This data is collected by running seismic equipment along a tightly gridded surface path, often requiring trees and brush to be cut to allow passage of the heavy equipment and crews. This method leaves surface scarring.

Due to competition among operators to locate gas resources, seismic surveys are usually collected and held proprietary, requiring each operator to collect its own data. This leads to multiple seismic surveys over the same surface terrain.

Best practices for seismic exploration should include:

- Prohibiting explosive use and requiring less destructive methods such as Vibroseis;
- Acquiring data during winter months, when ground is frozen and surface impacts are minimized;
- Encouraging operators to jointly conduct seismic surveys whenever possible to avoid repeat impacts;
- Limiting equipment and crew sizes to the smallest units possible to minimize surface damage and reduce the amount of tree and vegetation removal required;
- Maximizing data acquisition along existing roadways and cleared utility easements and routes; and
- Requiring restoration (planting trees and vegetation).

These best practices should be codified in NYS regulation.

9. Corrosion & Erosion Control

Recommendation No. 13: NYS regulations should require equipment to be designed to prevent corrosion and erosion, and require monitoring, repair, and replacement programs.

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in oil and gas exploration and production are subject to internal corrosion by water, enhanced by the carbon dioxide (CO_2) and hydrogen sulfide (H_2S) present in the gas. High velocity gas contaminated with water and sediment can erode internal pipes, fittings and valves.

The DGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require the best practice to design facilities resist to corrosion (e.g. material selection and coatings), or to monitor corrosion and repair and replace corroded equipment.[64] The DSGEIS concluded that NYS regulations need to be revised to require erosion monitoring, repair, and replacement programs as best practice.

[63] Sheriff, Robert E. and Lloyd P. Geldart, Exploration Seismology, Cambridge University Press, Cambridge., 1995.
[64] Curran, E., Corrosion Control in Gas Pipelines, Coating Protection Provides a Lifetime of Prevention, Pipeline & Gas Journal, October 2007.

10. Spill Prevention

Recommendation No. 14: NYSDEC should adopt regulations to require more stringent oil spill prevention measures for temporary fuel tanks associated with drilling and well stimulation activities. NYSDEC should incorporate existing EPA oil spill prevention standards for oil and gas activities that require secondary containment for all fuel tanks 1,320 gallons and larger.

Section 5.2.1 and Appendix 7 include sample rig specifications showing 10,000-12,000-gallon fuel storage tanks used with the large rigs. Section 7.1.3.1 states the drilling rig fuel tanks are exempt from NYS's petroleum bulk storage regulations, and tank registration requirements at 6 NYCRR §§ 612-614, because they are temporary storage tanks (non-stationary).

It is not clear why temporary fuel tanks are exempt from NYS's spill prevention regulations, when all other tanks 1,100 gallons and larger must register in NYS, install secondary containment, and undergo inspections at 5 and 10 year intervals. A temporary 1,100 gallon fuel tank poses a greater environmental risk than a stationary 1,100 gallon fuel tank, because temporary fuel tanks are relocated many times during their operating lives, increasing the potential for tank damage during transit. Large temporary fuel tanks should be subject to the same secondary containment requirements as large stationary fuel tanks, particularly when they may be installed in one location for a significant period of time, or alternative methods such as use of double walled or vaulted tanks should be considered, as explained further below.

NYSDEC recommends two mitigation measures be added to prevent fuel spills:

(1) "*encouragement*" to operators to set the tank 500' back from water bodies; and
(2) requirement to install secondary containment for tanks 10,000 gallons and larger placed within 500' of a waterbody.

NYSDEC references a draft NYSDEC Program Policy DER-17 for construction standards and a September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on how the secondary containment might be constructed. Appendix 10 proposed Permit Condition No. 13 relies on the outdated SPOTS memo and establishes weak setback standards "to the extent practical."

The DSGEIS does not cite existing EPA spill prevention requirements at 40 CFR § 112 that apply to fuel tanks, including drilling tanks at 40 CFR § 112.7(c). EPA's regulations, which were revised in 2002, require sufficiently impervious secondary containment to prevent a discharge to the environment for tanks 1,320 gallons and larger. EPA allows an operator the opportunity to demonstrate under 40 CFR § 112.7(d) that it is impracticable to install secondary containment; however, EPA requires a formal written "impracticability determination." It also requires periodic integrity testing of the tank, leak testing of the valves and associated piping, a Part 109 contingency plan, and a written commitment of manpower, equipment, and materials to respond to a spill.

NYSDEC's recommended mitigation measures, and proposed Permit Condition No. 13, are insufficient to protect the environment from fuel spills.

- First, NYSDEC's proposed mitigation measure to "encourage" operators to set the tank 500' back from water bodies[65] is not enforceable.
- Second, NYSDEC's proposed mitigation measure to require secondary containment for tanks 10,000 gallons and larger placed within 500' of a waterbody provides less spill protection than EPA's standard.

[65] DGEIS, p. 7-27.

- Third, NYSDEC proposed mitigation measures reference an unenforceable draft NYSDEC Program Policy document (DER-17) for construction standards and an outdated September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on how a secondary containment could be constructed.

The DSGEIS estimates that as many as 16 vertical wells (9 horizontal) could be drilled from one central pad; each well would take approximately one month to drill; and approximately 10 wells could be completed and hooked up for production within a year.[66] Therefore large fuel tanks used for drilling could be located at a drill site for 1.5 years. This is sufficient time to install secondary containment for tanks.

When fuel tanks are used for shorter periods of time (e.g., a single well), double-walled or self-diking tanks could be used, avoiding the need to construct a large temporary containment are for only a short duration.

NYS regulations (either at 6 NYCRR §§ 612-614 or in 6 NYCRR §§ 550-559 pursuant to its authority under Environmental Conservation Law § 23-0305(8)(d)) should be amended to include drilling operations. Secondary containment standards, as well as inspection and integrity standards at 6 NYCRR §§ 613-614, should be applied to all fuel tanks of at least 1,100 gallons used to explore or develop the Marcellus Shale gas reservoir (and any other gas reservoir covered under the final EIS).

Other oil and gas producing states have allowed the use of vaulted, self-diked, or double-walled portable tanks to meet the secondary containment requirement in cases where the operator can demonstrate it is infeasible to install a containment area meeting EPA's 110% of the largest tank volume requirement. NYSDEC could consider allowing these alternative tanks where secondary containment is proven to be infeasible.

Vaulted, self-diked, and double-walled portable tanks are equipped with catchments that hold fuel overflow or divert it into an integral secondary containment area. Industry standards for construction of vaulted, self-diked, and double-walled portable tanks include:

- Underwriters Laboratories' Steel Aboveground Tanks for Flammable and Combustible Liquids (UL 142);
- Appendix J of the American Petroleum Institute's (API) Welded Steel Tanks for Oil Storage (API 650); and,
- API's Specification for Shop Welded Tanks for Storage of Production Liquids (API Spec 12F).

Due to higher potential for damage during relocation and use at multiple sites, it is recommended that inspections be routinely performed on vaulted, self–diked, and double-walled portable tanks to identify damage or corrosion using one of the following standards:

- Steel Tank Institute's (STI) Standard for the Inspection of Aboveground Storage Tanks, Third Edition (STI SP00l); or
- API's Tank Inspection, Repair, Alteration, and Reconstruction Standard (API 653).

Additionally, most oil-producing states also require that stationary and portable tanks be equipped with high–liquid-level alarms that sound and display in a manner immediately recognizable to personnel

[66] DSGEIS at pgs. 117, 120, and 311.

conducting a transfer; high–liquid-level automatic pump shutoff devices set to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of each tank.

11. Spill Response

Recommendation No. 15: NYSDEC should adopt EPA SPCC requirements for drilling operations.

The DSGEIS at p. 7-33 recommends a spill response team and employee training for spill prevention. EPA's regulations at 40 CFR § 112 require a Spill Prevention Control and Countermeasures (SPCC) Plan for fuel storage volumes of 1,320 gallons or greater. EPA's requirements are much more comprehensive and stringent than the proposed mitigation measures suggested by NYSDEC. The DSGEIS should clearly state EPA's SPCC requirements, so that all operators are aware of them and comply. NYSDEC may also want to adopt more stringent oil spill prevention and response requirements in its regulations that exceed the federal EPA standard (many states have taken this approach).

12. Fuel Selection

Recommendation No. 16: NYSDEC should require operators to use cleaner fuels than diesel (such as natural gas) or electric power whenever technically feasible.

Shale gas development provides a cleaner natural gas fuel source than liquid fuels. The DSGEIS is based on use of large quantities of diesel fuel to power onsite equipment, without consideration of alternative cleaner energy sources. While diesel engines are often used as the prime mover power supply for rotary well drilling, natural gas or dual fuel (diesel/gas) engines are available to take advantage of cleaner fuel supplies.[67] EnCana, a gas producer, reports natural gas fired rigs reduce air pollution by 90% compared to diesel fired rigs.[68]

Some rigs have been converted to accept electric power. Power can also be supplied to the drilling rig by a natural gas powered reciprocating turbine that can generate electricity on site. If high-line power is available nearby the well site, rig power can be obtained directly from power lines, substantially reducing local air pollution impacts. Natural gas fired and electric powered rigs are commonly used in Alaska to reduce air pollution.

Power generated by natural gas fired engines or turbines can be used for hoisting equipment, fluid circulating equipment, lighting, rotary equipment, and to meet gas compression requirements.

An initial well on a well pad needs to be drilled with diesel to obtain a natural gas supply; subsequent wells can be drilled using natural gas or electric power. Smaller temporary gas processing units are available to process wellhead gas to the quality required for equipment use.

[67] www.naturalgas.org.
[68] EnCana 2005 Annual Report.

13. Hydraulic Fracture Design and Monitoring

Recommendation No. 17: NYSDEC should revise its regulations to specify best technology and best practices that must be used to collect data, model, design, implement, and monitor a fracture treatment. The regulations should specify that all data collected by industry must be reported to NYSDEC and made available to the public. Best technology and best practices should include:

(a) Collecting additional geophysical and reservoir data to support a reservoir simulation model;

(b) Developing a high-quality Marcellus Shale 3D reservoir model(s) to safely design fracture treatments;

(c) Hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone;

(d) Careful monitoring of the fracture treatment, including shutting the treatment down if data indicates casing leaks or out-of zone fractures;

(e) Collecting data, and carefully analyzing fracture treatment performance in the field on smaller fracture treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience (e.g. at least 4,000' deep and 150' thick);

(f) Using experience gained on fracture testing in (e) to design and implement larger treatment volumes over time (potentially allowing increasingly shallower and thinner intervals, *only* if technical data supports the safety of this technique);

(g) Documenting, reporting, and remediating fracture treatment failures to ensure drinking water protection; and

(h) Taking a conservative, step-wise approach to ensure there is technical data to support high-volume fracture treatments that protect the environment, before NYSDEC establishes a blanket permitting program allowing fracturing of the Marcellus Shale at all depths and all thickness intervals.

Experts agree that Marcellus Shale gas production can be maximized by drilling long horizontal wells to increase the drainage area, and conducting hydraulic fracture treatments to improve permeability and access to trapped gas. However, successful, safe development requires hydraulic fracture treatments that are properly designed and sized to create fractured rock and improved permeability <u>within</u> the shale zone.

Fracture treatments that propagate fractures <u>outside</u> the shale zone (fracturing out-of-zone) reduce gas recovery and may risk pollutant transport beyond the Marcellus Shale formation. Pollutant transport and pollutant toxicity issues are addressed in Tom Myers' and Glenn Miller's reports to NRDC on the DSGEIS, and therefore are not addressed here. This recommendation centers on what type of data, analysis, tools, and methods a professional engineer/operator should have in place and use to ensure that a fracture treatment can be contained within the Marcellus Shale zone.

The DSGEIS does not demonstrate that NYSDEC and/or operators have sufficient data on the NYS Marcellus Shale. Nor does it demonstrate that engineering tools are in place to ensure high-volume fractures can be constrained to the Marcellus Shale.

Buffer Zones Needed: Vertical fractures that extend above and below the shale zone will decrease gas recovery rates by allowing vertical migration into the overlying strata, or by allowing water influx from

aquifers above or below the shale. NYS has a financial incentive to ensure fracture treatments are conducted correctly, because NYS will want to maximize its royalty share and tax revenue.

To avoid fracturing out-of-zone, engineers typically design fracture treatments with a buffer zone (an un-fractured zone at the top of the shale layer and at the base of the shale). Buffer zone size should increase with geologic and technical uncertainty. Buffer zone size may decrease as industry gains experience and data quality/quantity improves. The DSGEIS does not contain sufficient information to demonstrate that NYSDEC and/or operators proposing high-volume fracture treatments have developed engineering tools capable of computing a safe buffer zone.

Marcellus Experience Very Limited: Marcellus Shale gas development has a high level of uncertainty. Shales by nature are very heterogeneous.[69] Industry has limited experience exploiting the Marcellus Shale using horizontal wells and slickwater fracs. The first Appalachian Basin Marcellus Shale gas well stimulation using high-volume slickwater fracture treatments was only recently performed in Southwestern Pennsylvania in 2004.[70] Therefore, industry has less than five years of experience developing the Marcellus Shale using the techniques proposed in the DSGEIS.

Even NYSDEC's consultants acknowledge that industry literature on and experience with the Marcellus Shale is so limited that most of their analysis was based on development of other shale gas reservoirs, such as the Barnett and Fayetteville. NYSDEC's consultant, ICF, states that:

> "***Drilling operations, and especially multi-horizontal wells, are relatively new in Marcellus Shale***. *While drilling operations are underway in neighboring states as evidenced by over 450 wells in Pennsylvania for example,* ***technical studies have yet to be published*** *that quantify actual drilling operations in Marcellus Shale.* ***For the most part, we have had to make assumptions, where technically appropriate, that drilling operations in other shale formations are representative of expected Marcellus operations*** *[emphasis added].*[71]

Lack of Marcellus Shale experience increases the risk of fracturing out-of-zone, unless a conservative, step-wise approach is taken to better understand the Marcellus Shale before large scale development occurs in NYS.

NYS Marcellus Data Set Improvement Needed: Site-specific data, unique to the Marcellus Shale in NYS, must be collected to: better understand the reservoir heterogeneities; develop sophisticated three dimensional (3D) reservoir models to more accurately design fracture treatments; and examine actual fracture performance in the field. Reservoir simulation models are critical engineering design tools. The DSGEIS provides no indication that a model exists for the NYS Marcellus Shale.

Engineers use 3D models to predict fracture height, length, and orientation prior to actually performing the job at the well. The goal is to design a stimulation treatment that optimizes fracture networking and maximizes gas production, while confining fracture growth to within the gas shale target formation.[72]

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[69] Cipolla, C.L., Lolon, E.P., and Mayerhofer, M.J., Reservoir Modeling and Production Evaluation in Shale-Gas Reservoirs, International Petroleum Technology Conference, Paper 13185, December 2009.
[70] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.
[71] NYS DSGEIS, ICF Task 2 Report, p.1.
[72] ALL Consulting, Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale, Presented at The Ground Water Protection Council 2008 Annual Forum Cincinnati, Ohio, September 21-24, 2008.

Engineers examine various parameters (e.g., volume, pressure, treatment placement) to optimize a fracture treatment. Without a high-quality 3D reservoir simulation model to design a fracture treatment, operators cannot demonstrate to NYSDEC that the fracture is predicted to stay in zone.

Typically an operator would start by collecting core analysis, well logs, and other subsurface data in the area it is interested in developing, to populate a site-specific 3D reservoir model. To collect this data, additional exploration and appraisal wells must be drilled (see recommendation No. 2). The limited amount of special core analysis and core data on the Marcellus Shale, as well as overlying intervals, is described in Chapter 4 of the DSGEIS, showing a need for additional data.

Test in Deepest, Thickest Zones First: NYSDEC is proposing to allow high-volume fracture treatments, without requiring the standard of care a petroleum engineer would typically use to collect data, and model, design, and monitor fracture treatments. NYSDEC should require that additional data be collected to support a model, and initially it should only allow a few, small fracture treatments that are conducted with intensive monitoring to verify that they are designed and implemented to stay within the Marcellus Shale. This data gathering and testing should be conducted in the deepest portions of the Marcellus Shale (below 4,000') and in the thickest section of the shale (over 150') to ensure there are adequate buffer zones to protect the environment during the data gathering and testing process. Operators should start with smaller fracture treatment sizes, collecting field data to better understand fracture performance, and use field data to calibrate that performance in the 3D model.

Over time, with careful analysis and a conservative, step-wise approach, larger fracture treatments can be tested and carefully monitored. Over time it may be possible to safely use the treatments on thinner reservoirs and shallower reservoirs, but certainly not as a first step. High-volume fracture treatments should not be conducted until there is a sophisticated data set, model, and monitoring program to verify pre-fracture and post-fracture reservoir properties.

Regulations Needed: While NYSDEC's consultant, ICF[73], documents a number of the engineering methods that can be used to model, monitor, and improve fracture treatments, NYSDEC does not require any of these methods in its existing regulations. Absent a regulatory requirement, there is no assurance these methods will be used.

Best practice for hydraulic fracture planning includes a detailed understanding of the in-situ conditions present in the reservoir (e.g., shale thickness, reservoir pressure, rock fracture characteristics, and special core analysis). In highly heterogeneous reservoirs, reservoir simulation is often coupled with stochastic methods (e.g. Monte Carlo analysis and geostatistical techniques) to improve the quality of the 3D reservoir model.[74]

Data collected on previous fracture treatments in the Marcellus Shale and drilling data will be useful to refine the fracture modeling. Actual fracture treatments must be carefully monitored and implemented to ensure fractures stay within zone. Data collected during each fracture treatment should be used to calibrate the 3D reservoir model to improve future fracture treatment design.

Peer-reviewed articles and technical data on Marcellus Shale vertical fracture growth characteristics are sparse. While fracture growth models exist at an industry level, and have been tuned for fracture treatments in the Barnett Shales and other gas reservoirs, considerable technical work is still needed to develop fracture growth models for NYS Marcellus Shale development.

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[73] ICF International, Technical Assistance to NYS on DSGEIS, August 2009.
[74] Schepers, K.C., Gonzalez, R.J., Koperna, G.J., and Oudinot, A.Y., Reservoir Modeling in Support of Shale Gas Exploration, Society of Petroleum Engineers, June 2009.

A literature review was completed by the author in search of a Marcellus Shale 3D reservoir model for NYS; none was found in the petroleum engineering published literature. It is not clear if the lack of a Marcellus Shale reservoir model for NYS indicates that one does not exist, or whether industry is holding models proprietary. Yet in other shale gas developments (e.g., Barnett and Fayetteville) there is extensive industry literature on: available reservoir simulation model; completion and fracture design; and performance assessment to compare predicted fracture growth with that achieved in the field. Lack of industry literature is usually a strong indication that additional data gathering and technology development is needed.

The data void for NYS's Marcellus Shale technical literature reinforces the need for NYSDEC to use a conservative, step-wise approach, rather than launching into a massive drilling and fracturing campaign without the data or tools in place to do a safe and effective job.

NYSDEC should require additional information be collected by industry to better understand the geological and geophysical properties of the Marcellus Shale zone and the overlying strata between the Marcellus and drinking water aquifers.

NYSDEC should require 3D reservoir simulation models be developed to accurately predict hydraulic fracture treatment performance, and to ensure the jobs are well engineered and designed with adequate safety factors to avoid fracturing out-of-zone.

The DSGEIS must assure the public that fractures can be contained to the Marcellus Shale zone. The DSGEIS does not provide data sufficient to meet this standard. The DSGEIS does not document the existence of 3D reservoir simulation models for NYS's Marcellus Shale, nor does NYSDEC require engineers to design fracture treatments using 3D models.

While Marcellus Shale development in Pennsylvania precedes development in NYS, data collected from the Pennsylvania wells is not applicable to the NYS Marcellus Shale because the depth of burial, thickness, organic content, permeability, and other reservoir properties in NYS differ. Industry experts warn that site-specific data is critical:

> *"By their nature,* ***shales are extremely variable*** *and* ***regional differences in structure, mineralogy and other characteristics should always be considered in treatment design****…The wide geographic range [of the Marcellus Shale] has led to numerous different completion schemes being utilized as with the geographic variation comes geologic variability within the formation itself. A primary topic of [industry] discussion has been determining the optimal size and type of stimulation treatment for a given area"* [75] *[emphasis added].*

The Marcellus Shale thickness drops off substantially in western NYS to less than 75' for roughly one-third of the total development.[76] Fracturing thin shale zones increases the risk of fracturing out-of-zone, unless a very cautious approach is taken to design and implement the fracture treatment. Hydraulic fracture treatments in NYS must be carefully tailored to the geophysical properties of the Marcellus Shale in NYS, taking into account shale thickness, local stress conditions, compressibility, and rigidity.

NYSDEC's consultants point out that a gas operator has no incentive to fracture out of the Marcellus Shale zone because doing so could result in a loss of gas reserves or increase produced water volumes.

[75] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.
[76] DSGEIS, Figure 4.9.

Yet NYSDEC's consultant, ICF, also recognizes that fracture design is complicated and it could be possible to inadvertently fracture out of zone. As a result, ICF examined the potential for fracture fluids to propagate vertically and contaminate an overlying drinking water aquifer.

Proposed permit conditions (Appendix 10) require a Pre-Frac Checklist and Certification (Appendix 20). The conditions require and the checklists verify a number of important best practices for fracture treatments; however, additional NYS regulatory requirements should be considered to further refine the mitigation and codify these practices.

NYSDEC should require operators to complete hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone and to collect data to further refine a hydraulic fracture model for the Marcellus Shale. These requirements should be added to NYS's regulations.

NYSDEC could either develop a Marcellus Shale fracture model that could be used as a standard for all operators, or it could require operators to collaboratively fund the development of a model. In either case, model(s) should be developed by a fracture expert and be peer-reviewed prior to use. Model(s) should be maintained, calibrated using field data, and continuously improved to ensure fracture prediction matches field implementation as closely as possible.

Technology is available to assess actual fracture growth including: minifracs,[77] microseismic fracture mapping,[78] tilt surveys, well logging (e.g., tracer and temperature surveys[79]), etc.[80] These technologies can be used to provide more accurate assessments of the locations, geometry, and dimensions of a hydraulic fracture system.[81] This data can be obtained in the Marcellus Shale in a few different areas of NYS to further refine the hydraulic fracture model. Minifractures are particularly helpful in estimating fracture dimensions, fracture efficiency, closure pressure, and leakoff prior to implementing a high-volume, full-scale treatment. NYSDEC should require operators to conduct minifractures to better understand site-specific reservoir characteristics prior to conducting a high-volume fracture treatment.

The fracture treatment should be carefully monitored, and shut down if pressure data indicates casing leaks. The American Petroleum Institute recommends continuous and careful monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate, and immediate shutdown of the fracture treatment if abnormal pressures indicate a casing leak.[82]

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[77] Minifracs are small fracture treatments conducted in the well to better understand fracture conductivity and flow geometry prior to implementing a large fracture treatment. Minifracs are typically used to optimize the fracture design and calibrate the fracture model. These tests involve periods of intermittent injection followed by intervals of shut-in and/or flowback. Pressure and rate are measured throughout a minifrac and recorded for subsequent analyses.

[78] Microseismic monitoring is a method that measures the seismic wave generated during a fracture treatment to map the fracture extent, and it can be used to make "real-time" changes in the fracture design and implementation program.

[79] After the fracture treatment is completed, an operator can run a temperature log in the well to measure the variation in reservoir temperature resulting from the treatment. The reservoir temperature is hotter than the fracture fluid and proppant. Cooler temperatures will be measured where frac fluid and proppant are placed. Temperature logs will provide insight into fracture location and growth outside the casing.

[80] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

[81] Schlumberger, Microseismic Hydraulic Fracture Monitoring, http://www.slb.com/content/services/stimulation/stimmap.asp.

[82] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

Recommendation No. 18: NYSDEC needs to technically justify the proposed minimum 1,000' vertical offset with actual field data, 3D reservoir simulation modeling and a peer-reviewed hydrological assessment to ensure drinking water sources are protected.

Vertical Offsets Useful If Sized Correctly: The use of vertical offset limits to separate hydrocarbon recovery operations from drinking water aquifers is a good approach. However, the size of the vertical offset must be technically supported to ensure it is large enough to protect the drinking water aquifer.

ICF recommended additional well-specific technical analysis for high-volume hydraulic fracture treatments conducted at depths less than 2,000' TVD, or if the distance between the target fracture zone and a fresh water supply is less than 1,000' TVD.[83] ICF assumes that vertical fracture conducted in a horizontal section of a Marcellus Shale will not propagate more than 1,000' and intersect a drinking water aquifer above. Yet ICF does not provide NYS specific 3D reservoir simulation modeling or field evidence (e.g., pressure data, microseismic fracture mapping, tilt surveys, history matching simulation, or tracer testing) to support its recommendation. ICF does not substantiate how it can guarantee that an operator will not implement a fracture out-of-zone or propagate above the Marcellus. ICF argues that the 1,000' vertical buffer is a safe distance between the top of the Marcellus and a drinking water zone, but site-specific data is needed to support this hypothesis.

ICF argues that even if a fracture does propagate out-of-zone above the Marcellus, the fracture fluid will not migrate into the drinking water zone above, if at least 1,000' vertical offset is maintained. ICF also argues that absent a direct fracture connection from the Marcellus to the drinking water aquifer, it would not be possible for contaminants to flow from the Marcellus to the overlying aquifer. Yet Tom Myers' report for NRDC identifies a number of problems with ICF's hydrological analysis and assumptions. Myers, a professional hydrologist, shows that it is possible for fracture fluids to naturally migrate toward the drinking water aquifer over time. Myers recommends additional data collection and analysis on this point.

Moreover, while ICF recommends at least a 1,000' vertical standoff to protect drinking water sources, there is no equivalent regulatory limit requiring this vertical buffer in NYSDEC's proposed permit conditions (Appendix 10). If a vertical buffer is needed for drinking water protection, that limit should be clearly stated in NYS regulations. The 1,000' vertical buffer zone must be technically justified or a larger vertical offset should be adopted to ensure drinking water standards are protected.

Proper design and monitoring of hydraulic fractures is not only best practice from an environmental and health perspective, it is also good business because it optimizes gas production and reduces hydraulic fracture treatment cost. The most logical way forward is to limit development to the deepest Marcellus Shale intervals, maximizing the vertical separation from drinking water aquifers until an accurate, field-calibrated 3D reservoir simulation model is developed for designing fracture treatments in NYS.

Drilling into the deepest, thickest Marcellus Shale intervals (e.g., below 4,000') will maximize data collection on the Marcellus and all overlying intervals between the Marcellus and the drinking water aquifers. This will allow core samples, well logs, and pressure transient data to be obtained, verifying whether there are continuous permeability barriers hydraulically separating the Marcellus Shale and the overlying drinking water aquifers.

[83] DSGEIS, p. 7-49.

Smaller fracture treatments should be tested, initially, increasing in size over time only when data is collected to support the conclusion that large fracture treatments can remain in zone.

As data is collected, and 3D reservoir simulations models are developed and refined, it may be possible to safely develop the Marcellus at shallower depths and in thinner intervals. However, there is insufficient technical data in the DSGEIS to support development of shallow, thin sections of the Marcellus at this time. Neither NYSDEC nor its consultant team has demonstrated that high-volume hydraulic fracturing can be safely conducted in thin sections of the Marcellus Shale at depths as shallow as 2,000' deep.

14. Hydraulic Fracture Treatment Additive Limitations

Recommendation No. 19: NYS regulations should identify the type, volume, and concentrations of fracture treatment additives that are protective of human health and the environment. NYS regulations should develop a list of prohibited additives and require the use of non-toxic materials to the extent possible.

DGEIS Section 5.3[84] states that NYSDEC collected compositional information from chemical suppliers and service companies on many of the additives proposed for use in shale fracture treatments. NYSDEC reports it has some compositional data on 197 products and complete compositional data on 152 products. Tables 5.3-5.7 provide lists of chemicals proposed for use in fracture treatments, and Section 5.4.3.1 describes the potential health impacts of categories of chemicals. Yet the DSGEIS does not arrive at any recommendation or conclusion about which fracture treatment additives are acceptable for use in NYS and which are not.

While Section 5.4.3.1 lists a number of potential adverse human health and environmental impacts, the mitigation measures proposed in Chapter 7 do not set limits on chemical use (volume or concentration) that are protective of human health and the environment. Chemical use should be limited to non-toxic chemicals that do not pollute the air or water.

Section 9.3.1[85] briefly describes the possibility of using environmentally friendly chemicals, but rules this option out due to the lack of "green chemical" metrics in the US.

Appendix 10, Proposed Permit Condition No. 32, limits the use of fracturing products to those identified in the well permit application, but it does not specify what chemicals are actually acceptable to include in a well permit application. This proposed permit condition appears to allow any fracturing product proposed by industry in a well permit application.

This proposed permit condition also states that NYSDEC "may require a site-specific environmental assessment and SEQRA determination" prior to approving fracturing treatment chemicals that were not "previously reviewed." It is not clear what is meant by "previously reviewed." Does this mean fracture treatment chemicals "previously reviewed" in the DSGEIS? If this is the meaning, it raises serious concerns because, while the DSGEIS lists a number of fracturing products in Chapter 5, it does not make a toxicological decision about which chemicals are acceptable. In its current form, NYSDEC cannot rely on Chapter 5 to guide NYSDEC staff as to which fracturing treatment chemicals should be used. Chapter 5 is merely a "laundry list" of chemicals currently used without an adequate review of the potential impacts on health or the environment.

[84] DSGEIS, p. 5-34.
[85] DSGEIS, p. 9-10.

There are several models in place that NYSDEC could use to develop regulations and standards for fracture fluid composition. For example, many government entities have adopted the Olso-Paris Convention (OSPAR) PLONOR list of environmentally friendly chemicals (chemicals considered to Pose Little Or No Risk to the marine environment) for screening chemical use in drilling and stimulation treatments. Other government entities prohibit use of chemicals that have harmful characteristics, such as: low biodegradability; high bioaccumulation potential; high acute toxicity; and detrimental mutagenic or reproductive affects.

Best environmental practices can be implemented by developing a list of environmentally friendly chemicals that operators must comply with, as well as a list of chemicals that are prohibited.

15. Hydraulic Fracture Fluid Flowback Surface Impoundments

> **Recommendation No. 20**: NYS regulations should require fracture fluid flowback be routed to onsite treatment systems for fracture fluid recycling and/or collected in tanks for transportation to offsite treatment systems. Surface impoundments should not be used for fracture fluid flowback.

The DSGEIS does not present a consistent or clear recommendation on whether fracture fluid flowback impoundments are environmentally acceptable or allowed. The DSGEIS also leaves many other unanswered questions about what the expectations are for operators. Is the operator required to flow back fracture fluid to a tank? Are toxic chemicals allowed in impoundments? Is the operator required to stop using impoundments and flow to tanks? Is an operator required to complete site-specific modeling to better understand hazardous air pollutant impact from flowback impoundments? Or is an operator just required to build a larger fence to keep the public and wildlife away from the hazardous waste?

Best technology for fracture flowback treatment is to eliminate the use of surface impoundments altogether. The use of temporary surface impoundments results in surface disturbance. It also has the potential for leakage to occur through or around the liner, impacting ground water and creating substantial amounts of hazardous air pollution. The BLM recommends the use of closed loop tank systems whenever possible.[86] Fort Worth, Texas, prohibits frac fluid placement in an open pit.[87]

Fracture treatment flowback to metal tanks is an efficient collection method because fluid can be easily transferred to a treatment and disposal location, or taken to another well for reuse. Flowing fracture treatment fluid into a temporary reserve pit for later collection and disposal is inefficient, and creates the possibility of fracture fluids contaminating ground water (e.g. a leaking reserve pit liner).

Of serious concern is the amount of hazardous air pollution predicted for these surface impoundments. Section 6.5.1.8 of the DSGEIS, "Potential Emission of Fracturing Water Additives from Surface Impoundments," concludes that:

> *"Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission [estimate] of* ***32.5 tons*** *(i.e.,"****major" quantity of HAP****) is theoretically possible at a central impoundment"*[88] *[emphasis added].*

[86] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.
[87] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p. 9.
[88] DSGEIS, p. 6-56.

Section 6.5.2.2, "Sources of Air Emissions and Operational Scenarios," states: "The Department has performed an assessment of a set of representative chemicals in the additives." But, NYSDEC has not set any limits in the DSGEIS on the type of chemicals that can be used in fracture treatment; therefore, there is no assurance that NYSDEC's subsequent air impact analysis at 6.5.2.3 is a worst case scenario or even representative of the emissions that will actually occur in the field (see analysis at pp. 6-75 though 6-76).

While it is unclear if NYSDEC's estimate of 32.5 tons of Hazardous Air Pollutants (HAPs) is even a worst case assessment, this is an unacceptably large amount of HAPs. NYSDEC's HAPs finding, alone, should result in a mitigation measure that prohibits operators from using fracture fluid flowback impoundments, and requires operators to collect fracture fluid flowback into closed treatment systems and/or closed tanks for transport to a treatment system.

This mitigation measure should be codified in NYS regulations.

The DSGEIS acknowledges the human health and environmental exposure risks, and proposes several different solutions, but does not identify a solution that meets a best practices standard. In fact, its recommendations are inconsistent.

For example:

Section 7.5.3.2, "Centralized Flowback Water Surface Impoundments" states:

> *"The **EAF Addendum will require the operator to identify all proposed fracturing additives**. **Site specific review of potential HAP emissions will be based on these proposed additives** (i.e., components and concentrations) and assessing air quality impacts of these compounds might be necessary, **unless the same additive mix has been previously analyzed** for a similar centralized impoundment. The EAF Addendum will also require the operator to identify proposed control measures for preventing public exposure to HAPs in excess of guidance thresholds. **These could consist of eliminating specific compounds such as methanol, heavy naptha and benzene**; **limiting the duration and use of the impoundment; covering the impoundment or placing physical barriers**"[89] [emphasis added].*

Section 7.5.3, "Summary of Air Quality Impacts Mitigation" proposes different mitigation:

> ***"If flowback impoundments are to be used, it will be necessary to exclude "solvent" and certain surfactants (containing benzene and xylene) from the current list of additives proposed by industry for use in fracturing operations**. Furthermore, for the remaining chemicals, it is necessary to take steps to **preclude public exposure to certain pollutant impacts by either eliminating their use or fencing in the impoundments**. Specifically, for the smaller on-site impoundments, limiting public access to beyond approximately 150m from the impoundment would be one means of eliminating potential adverse impacts. On the other hand, for the larger centralized impoundment, **public exposure to potential adverse impacts can be eliminated by erecting a fence at a rather large distance of approximately 1000m**, or at a smaller distance if certain chemicals listed in Table 6.21, are eliminated. It is also determined that these larger off-site impoundments have the potential to qualify as a major source of Hazardous Air Pollutants (HAPs) due to certain chemicals. Thus, a case specific review might be required for these larger impoundments"[90] [emphasis added].*

[89] DSGEIS, p. 7-90.
[90] DSGEIS, p. 7-89.

On p. 7-90, the DSGEIS provides yet a different conclusion:

> *"However, as discussed elsewhere in this Supplement, **uncertainties relative to potential flowback water volume and composition have led the Department to propose that flowback water not be directed to an on-site reserve pit but instead be held on the well pad in tanks prior to shipment to a disposal, treatment or re-use location**"[91] [emphasis added].*

Section 7.1.7.4, "Use of Tanks Instead of Impoundments for Centralized Flowback Water Storage" then says:

> *"Above ground storage tanks have some advantages over surface impoundments. The Department's experience is that landfill owners prefer above ground storage tanks over surface impoundments for storage of landfill leachate. **Tanks, while initially are more expensive, experience fewer operational issues associated with liner system leakage**. **In addition, tanks can be easily covered to control odors and air emissions from the liquids being stored.** Precipitation loading in a surface impoundment with a large surface area can, over time, increase the volumes of liquid needing treatment. Lastly, above ground tanks also can be dismantled and reused. The provisions of Section 360-6.3 address the minimum regulatory requirements applicable to above ground storage tanks which would be equally **applicable for adequate flowback water containment as well**"[92] [emphasis added].*

Section 7.1.3.4[93] proposes fracture treatment flow back be routed to metal tanks, rather than reserve pits.

NYSDEC's consultant reports that the most common, current practice observed at Pennsylvania drilling sites is for the frac flowback to be contained in a closed system that captures the water in steel frac tanks.[94]

The DSGEIS is unclear on what an operator will be required to do in terms of fracture fluid flowback. NYSDEC's proposed application and mitigation system is cumbersome, time consuming, and labor intensive. It is not clear that NYSDEC has the staff needed to oversee permitting and enforce the new requirements proposed in this DSGEIS. A simplified, best practice approach of prohibiting, via regulations, surface impoundments for fracture fluid flowback is more cost effective and protective of human health and the environment. There could be a provision in the regulations for an operator to make a showing that it is technically infeasible to operate without fracture fluid flowback impoundments, and in these limited cases a more detailed assessment could be made at a site-specific level to determine if an impoundment is best technology for that situation.

Please note that this recommendation does not include freshwater surface impoundments where water may be collected prior to adding fracture treatment chemicals. Operators developing the Marcellus Shale gas reservoir in Pennsylvania have found that:

> *"The preferred method for delivery of water to the wellhead is to pump water directly from a withdrawal point on a surface water source through pipelines to an impoundment or tank battery near the well completion location. In order to pump efficiently, the surface water withdrawal point should be located within one mile of the storage. Direct pumping is the preferred method because it substantially reduces the risks and costs associated with bulk hauling by truck… Bulk*

[91] DSGEIS, p. 7-90.
[92] DSGEIS, p. 7-55.
[93] DSGEIS, p. 7-34 and 7-35.
[94] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.19.

hauling over public roadways is not the preferred method to supply source water for fracing as it can cause roadway damage, increased traffic congestion, air and noise pollution and increased safety risk."[95]

In areas where bulk hauling over public roadways is not a preferable environmental alternative, freshwater surface impoundments may be a reasonable option, because freshwater does not pose a risk of water or air pollution. However, NYSDEC should ensure there are adequate regulations for surface disturbance reclamation.

Recommendation No. 21: The DSGEIS should disclose how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario.

The DSGEIS appears to report water use and waste volumes based on a single initial fracture treatment; this approach does not consider the fact that most shale gas wells require multiple fractures treatments. The DSGEIS should disclose how many times a well may be fracture treated over its life, and provide a worst-case scenario for water use and waste disposal requirements based on this scenario. It may be possible that repeat fracture treatments would not only dramatically increase water needs and disposal volumes, but also result in long-term use of impoundments pits. NYSDEC is not proposing to design impoundments for long–term use.

16. Chemical Tank Containment

Recommendation No. 22: NYSDEC should adopt regulations requiring secondary containment for chemicals stored on the well pad or, alternatively, the use of double-wall tanks.

Chemicals, especially corrosive chemicals, can result in storage container leaks and spills to the environment. Best practice for permanent chemical storage is to install secondary containment under the storage container, and ensure the containers are not in contact with soil or standing water.[96] NYSDEC's consultant, Alpha, agrees on this point, yet Alpha's recommendation does not materialize into a permit condition. Alpha's report states:

"It is recommended that regardless of exemption or regulatory status, the temporary on site storage of hydrofracing additive chemicals (and petroleum) comply with accepted best management practices (BMPs) for handling and spill containment. These practices may include, as appropriate to the specific containers, monitoring and recording inventories; manual inspections; berms or dikes, secondary containment; monitored transfers, storm water runoff controls, mechanical shut-off devices, setbacks, physical barriers, and materials for rapid spill cleanup and recovery."[97]

Alpha specifically recommended that chemical tanks be placed in lined containment areas, sufficient to contain 110% of the single largest chemical container, and that the tanks be set back from a perennial or intermittent stream, private or public well, wetland, storm drain, lake, or pond. These important best

[95] Gaudlip, A.W., Paugh, L.O., and Hayes, T.D., Marcellus Shale Water Management Challenges in Pennsylvania, SPE Paper 119898, November 2008.
[96] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.
[97] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.36-37.

practice recommendations were not included, but should be, in the DSGEIS; they should also be codified in NYS regulations. Alternatively, double-wall tanks may provide another protective alternative.

17. Reserve Pit & Impoundment Liner Quality

Recommendation No. 23: NYSDEC should adopt regulations requiring closed-loop tank systems as a best practice instead of reserve pits and impoundments, unless the operator demonstrates that it is not technically feasible.

The BLM recommends the use of closed loop tank systems as a best practice instead of reserve pits and impoundments, whenever technically feasible.[98] Texas requires closed looped mud systems with steel tanks.[99] It is much more efficient (from an energy standpoint) to collect waste in the container that will be used to transport it offsite to a waste disposal facility than it is to create an intermediate storage pit. The use of temporary reserve pits and impoundments results in surface disturbance. It also has the potential for leakage to occur through the liner, impacting groundwater. NYS regulations should require use of closed-loop tank systems, unless an operator can demonstrate is not technically feasible to operate without a reserve pit or impoundment. NYSDEC reports that some operators use closed loop tank systems to capture muds, cuttings, and flow back fluids (Section 5.2.3).[100] This is a best practice that should be required for all operations.

Recommendation No. 24: If reserve pits and impoundments are demonstrated to be environmentally preferable, NYSDEC should adopt regulations that require impermeable, chemical resistant liner material, and limit the type of chemicals stored to those compatible with the liner material; require wildlife protection design standards; and establish firm removal and restoration requirements.

If there are cases where reserve pits and impoundments are necessary, liner quality should be specified. NYS regulations should specify under what circumstances closed-looped tank systems are not technically feasible, and specify that only under these limited circumstances, if any, should reserve pits and impoundments be used. In cases where reserve pits and impoundments are necessary, regulations should require the use of impermeable, chemical resistant liner material. Proposed Permit Condition No. 12 establishes liner thickness and seam specifications, but does not specify liner quality.

The DSGEIS notes that some drilling and stimulation chemicals can react with and damage reserve pit liner materials.[101] The DGEIS reiterates the importance of installing impermeable liner material and ensuring the liner is maintained, repaired, and replaced.[102] Yet, the proposed supplementary permit conditions do not include a requirement to install impermeable, chemical resistant liner material.

The DSGEIS does not limit the types of chemicals that can be introduced into the reserve pits or impoundments. For example, used oils, paints, pipe dope, as well as toxic, corrosive, or bioaccumulating chemicals, should be prohibited.

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[98] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.
[99] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.8 states Fort Worth, Texas, requires closed tanks.
[100] DSGEIS, p. 5-29
[101] DSGEIS, p.7-29
[102] DSGEIS, p.7-29 and p. 7-30

NYSDEC should list the type of chemical additives that are allowed to be temporarily stored in a reserve pit, and identify liner material specifications that will ensure the liner material is both impermeable and chemically resistant to those materials.

- Proposed Permit Condition No. 16 requires fluids to be removed from the reserve pit, and the pit to be reclaimed within 45 days of drilling or stimulations operations, but does not specify what materials may actually be left in the reserve pit for long-term burial and storage. For example, Section 7.1.9 indicates that cuttings drilled with oil based muds cannot be stored in reserve pits, but it does not explain which type of muds and cuttings would be allowed for long-term disposal (e.g,. are all water based and synthetic muds and additives allowed?).
- What type of testing will be required to ensure the material left in the reserve pit will not be harmful to the environment? For example, barite, a common ingredient in drilling muds, contains several heavy metals, including compounds of lead, cadmium, mercury, and arsenic.[103] Will drilling mud solids containing lead, cadmium, mercury, and arsenic be allowed to be stored in the reserve pit on a long-term basis?
- What type of testing will be conducted to demonstrate that the reserve pit liner was not damaged during use, and to ensure that the liner provides an impermeable barrier for long-term ground water protection?
- What maintenance, testing and repair requirements will be put in place to ensure liner integrity?

Unless there is an environmentally compelling reason to allow long-term disposal at onsite reserve pits, the preferred cleanup plan would be to remove all materials from temporary reserve pits, test waste material, and process it according to federal waste handling requirements at a licensed treatment and disposal site.

If a reserve pit is determined to be an environmentally preferable temporary storage solution, the reserve pit should be fenced and netted to prevent wildlife and livestock from accessing the reserve pit.

18. Wellbore Plugging & Abandonment Requirements

Recommendation No. 25: NYS regulations should clearly state when future Marcellus Shale wells must be plugged and abandoned, and this should be retroactively applied to existing wells that are no longer operating and may pose a risk to the environment.

Part 555 of 6 NYCRR requires gas wells to be permanently plugged and abandoned (P&A'd), but NYS's regulations do not provide specific criteria to determine when a well must be P&A'd. An operator may submit a "Notice of Intention to Plug and Abandon" a well, but it appears to be a voluntary, operator-initiated action. Alternatively, NYSDEC allows operators to shut-in wells or temporarily abandon wells without plugging, for what appears to be an indefinite time period. Historically, temporarily abandoned wells have been the source of environmental damage, because operators are not present to monitor wellbore integrity on a routine basis and wellbore infrastructure can corrode and erode, failing over time.[104]

[103] Rae, P. BJ Services Company, "Towards Environmentally-Friendly Additives for Well Completion and Stimulation Operations," Society of Petroleum Engineering Paper 68651, 2001.

[104] As a case in point, the 2009 catastrophic well leak in the Australian Timor Sea resulted from an improperly handled temporarily suspended well.

NYS regulations should clearly state the P&A requirements for a Marcellus Shale well. The regulations should define the best technology and practices for determining at what point in time a well must be P&A'd. The regulations should also specify the procedures required to properly abandon horizontal and multi-lateral wellbores. Most states limit temporary abandonment to a one-year period of time, with a wellbore integrity monitoring program requirement to ensure that the well is not leaking during temporary abandonment.

The revised regulations should retroactively apply to existing wells that are no longer in operation and may pose a risk to the environment. As a priority, NYSDEC should carefully examine and require wells to be plugged and abandoned in close proximity to drinking water sources, and in areas under consideration for new high-volume fracture treatments.

19. Well Control & Emergency Response Planning

Recommendation No. 26: NYS regulations should be updated to include best practices for well control and emergency response planning.

The DSGEIS does not require an emergency response plan, or well blowout control plan, in the event of a fire, explosion, or blowout. Best practices include developing and testing these types of plans prior to drilling. The capacity of local emergency response teams to take on potentially catastrophic fire and explosion hazards must be evaluated in the DSGEIS. NYSDEC must determine whether local emergency response capability exists, or if operators should be required to supplement emergency response with additional equipment, personnel, and training.

Joint industry and local emergency response planning and training is considered best practice. It ensures local emergency response personnel and equipment will be able to provide support in an actual emergency, and that industry and local team response can be effectively and efficiently integrated.[105] For example, well site roadways or access may be difficult for standard firefighting, rescue, and emergency medical services vehicles to access. Emergency response equipment may not have sufficient ground clearance to traverse the typically narrow dirt roads. Fire and rescue services should be aware of the areas and test drive the access roads to ensure that vehicles can gain access to sites.

NYS regulations at 6 NYCRR § 556.2(c) require all gas wells capable of production to be equipped with wellhead controls adequate to contain and control gas flow. This regulation does not require an operator to install a fail-safe automatic surface controlled subsurface safety valve (SSSV) system capable of preventing an uncontrolled gas release in the event wellhead surface safety valves fail, or the wellhead is damaged. Many states require the use of SSSVs to provide a redundant prevention system.

20. Hazardous Air Pollution Control

Recommendation No. 27: NYS regulations should include best technology and practices to reduce hazardous air pollution to the lowest possible level.

Dehydration Units: Dehydrator units are required to remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water, and in the process the TEG

[105] Penn State Extension, Marcellus Shale: What Local Government Officials Need to Know; www.naturalgas.psu.edu. 2009.

absorbs methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs); these gases are vented to atmosphere unless pollution controls are installed on the dehydration units. Best technology includes installation of flash-tank separators to recover the gas pollutants, or routing vapors to a vapor collection/destruction unit.

The DSGEIS does not require installation of flash-tank separators to control hazardous air pollutants, and provides conflicting information on the estimated dehydration unit throughput. It's also unclear as to whether or not pollution control will be required at a federal level. Section 6.5.1.2 of the DSGEIS concludes that dehydration units used for the gas development will be exempt from EPA's National Emission Standards for Hazardous Air Pollutants (NESHAP) since gas production is estimated to be below 3 MMscfd[106] and benzene emissions are estimated to be below 1 tpy. Yet, this conclusion conflicts with NYSDEC's consultant report (ICF International's August 2009, Subtask 2.5), that concludes: *"Information gathered by NYSERDA and NYS DEC field trips to Marcellus Shale well sites indicate a potential production rate of 7 to 10 MMscf per day."*

NYS regulations should require installation of flash-tank separators to control hazardous air pollutants. Alternatively, desiccant dehydrators can be used in place of TEG dehydrators; these units have shown to cost less, have lower operating and maintenance costs, and control 99% of HAPs.[107]

Impoundments: The DSGEIS estimates that a very large amount of hazardous air pollution (methanol) may be present at central impoundments (32.5 tons per year),[108] and gives inconsistent approaches to pollution mitigation.[109] EPA lists methanol as a hazardous air pollutant, but has not yet classified methanol with respect to carcinogenicity. The reproductive and developmental effect of methanol on humans is not understood.[110] Testing in rats yielded skeletal, cardiovascular, urinary system, and central nervous system malformations.[111] Chronic inhalation or oral exposure may result in headache, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, blurred vision, and blindness in humans. Neurological damage, specifically permanent motor dysfunction, may also result.[112]

The EPA lists a major source of hazardous air pollution if more than 10 tons of a listed HAP is released per year. The DSGEIS proposes to allow the Marcellus Shale impoundment to pollute the air at a level more than three times this major source HAP threshold. The best practice is to use a closed loop collection and tank system, rather than impoundments. Vapors should be routed to an air pollution control device to filter or destroy HAPS.

Benzene: The DSGEIS does not estimate significant amounts of benzene emissions; however, recent reports indicate the Texas Commission on Environmental Quality is finding surprisingly high levels of benzene emitted from Barnett Gas Shale activities in Texas.[113] Additional analysis is warranted to better

[106] MMscfd= millions of standard cubic feet of gas per day.
[107] Fernandez, R., Petrusak, R., Robinson, D., Zavadil, D., Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.
[108] DSGEIS, p. 6-57.
[109] DSGEIS at pgs. 7-55, 7-88, 7-89, and 7-90.
[110] http://www.epa.gov/ttn/atw/hlthef/methanol.html
[111] American Conference of Governmental Industrial Hygienists (ACGIH), TLVs and BEIs, Threshold Limit Values for Chemical Substances and Physical Agents, Biological Exposure Indices, Cincinnati, OH, 1999.
[112] The Merck Index. An Encyclopedia of Chemicals, Drugs, and Biologicals. 11th ed. Ed. S. Budavari. Merck and Co. Inc., Rahway, NJ. 1989.
[113] Dr. Michael Honeycutt, Head of TCEQ's Toxicology Division, quoted in WFAA-TV new report, November 20, 2009. Dr. Michael Honeycutt "was shocked to see air sampling revealed high levels of benzene, a cancer-causing toxin, near some natural gas facilities."

understand and quantify the potential benzene exposure because it is a known, EPA-listed human carcinogen. Best control technologies should be identified and codified in regulation.

21. Compressor Stations, Pipelines, and Gas Processing Facilities

Recommendation No. 28: NYSDEC should include compressor stations, gathering pipelines, and gas processing facilities in the DSGEIS, and identify best technology and practices for this equipment.

The DSGEIS states that compressor stations and pipelines are not within the scope of the DSGEIS. No best technologies or practices are evaluated. In its December 15, 2008 scoping comments to NYSDEC, the NRDC and co-signatories requested that gathering pipelines and gas treatment facilities be included and analyzed in the DSGEIS. NYSDEC should include compressor stations, gathering pipelines, and gas processing facilities in the DSGEIS, and identify best technologies and practices for this equipment.

22. NYSDEC Inspection and Enforcement Program

Recommendation No. 29: NYSDEC must demonstrate in the DSGEIS that it has the personnel, equipment, technical expertise, and funding to carry out the inspection and enforcement procedures listed in the DSGEIS.

In its December 15, 2008 scoping comments to NYSDEC, the NRDC and its co-signatories requested the DSGEIS describe the current inspection program for gas wells including: budget, number of inspectors, inspector qualifications and expertise, and frequency of inspections. The DSGEIS does not demonstrate that NYSDEC has sufficient resources to oversee, inspect, and enforce Marcellus Shale gas development. A manpower and resource analysis specific to the Marcellus Shale gas development is needed.

23. Financial Assurance Amount

Recommendation No. 30: NYSDEC should require financial assurance adequate to fund long-term monitoring, publicly incurred response costs and the cost of properly remediating and abandoning operations.

In its December 15, 2008 scoping comments to NYSDEC, the NRDC and its co-signatories requested the DSGEIS examine whether NYSDEC requires sufficient financial assurance (in the form of a bond or other financial instrument) to ensure there is funding available to properly plug and abandon wells, remove equipment and contamination, complete surface restoration, and compensate nearby public for adverse impacts (e.g., well contamination). Long horizontal wells are more costly to plug and abandon than vertical wells. Also, surface impacts will be larger due to planned high-volume fracture stimulation treatments, multiple wells drilled from a single well pad, and the need for additional gas treatment and transportation facilities. Some states require as much as $100,000 to cover a single well. Yet, the DSGEIS does not provide an analysis on the current financial assurance requirements.

New York State (NYS) Casing Regulation Recommendations

Report to:

Natural Resources Defense Council (NRDC)

Prepared by:

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Contents

1. Executive Summary

Purpose of this Analysis:

This analysis responds to Natural Resources Defense Council's (NRDC) request for a review of the New York State (NYS) Oil and Gas Well Casing Regulations. NRDC requested a technical review of the existing regulatory language to determine if NYS's casing requirements are best practice and protective of the environment. NRDC's request follows up on a conclusion drawn in the 2009 University of California Hastings College of the Law Oil and Gas Exploration and Production Report (University of California Report) that NYS had "*disappointingly sparse*" oil and gas well casing regulation. The University of California Report concluded that NYS regulations "*provide very little guidance for the construction of well casing*" and that "*the only substantive requirements are that the operator set the surface casing below freshwater levels and cement the casing to the surface. The regulatory regime is silent on the use of intermediate or production casing, and requires no pressure testing or cement setting times. For environmental protection, the statute instructs operators to prevent the pollution of water. Thus, New York's casing and drilling requirement is well outside the norm*." NRDC requested that Harvey Consulting, LLC. verify if this conclusion is correct, and if so, make specific technical recommendations for improving NYS's casing regulations.

Analysis Approach

This analysis compares NYS's oil and gas casing regulations against casing regulations of four other states that have decades of experience and expertise in US domestic oil production (Texas, Alaska, California and Pennsylvania). The analysis is divided into four main categories of casing (conductor, surface, intermediate and production). An analysis of each class of casing is provided with summary conclusions drawn for potential improvements to NYS's casing regulations. Each casing string serves a different function, and warrants specific recommendations. This analysis applies only to <u>onshore</u> wells typical of those that may be drilled in NYS.

Due to recent proposals for extensive development in NYS's Marcellus Shale formation, NRDC is particularly interested in how the NYS Department of Environmental Conservation's (NYSDEC) casing requirements may apply to wells drilled into the Marcellus Shale. Thus, this analysis will comment specifically on casing standards relevant to that formation.

This analysis is intended solely to be a technical review and recommendation for areas where NYS's casing regulations may warrant improvement. Areas requiring legal review are identified for NRDC Legal Counsel.

Specific recommendations that are made in this analysis are highlighted in a blue text box. Many recommendations apply to more than one type of casing. To avoid repetition, recommendations are stated once, with an explanation as to which casing section the recommendations.

Overall Summary of Analysis Findings

NYS uses a combined approach of regulations, guidance documents, and permit stipulations to define and implement NYS oil and gas well casing requirements. The University of California Report is correct in identifying the limited regulatory language for oil and gas casing requirements found in the New York Codes Rules and Regulations (NYCRR), Chapter V, Resource Management Services, Subchapter B, Mineral Resources; however, the University of California Report did not examine the NYS guidance documents and permit stipulations used to regulate oil and gas wells. Combined, NYS's regulations, guidance documents, and permit stipulations are more technically robust than the University of California Report concluded. However, this analysis recognizes that there is a legal difference between a regulation,

guidance document, and permit stipulation, particularly in the ability to enforce guidance documents and permit stipulations that may not have solid roots in law or regulation. Thus, the most significant recommendation made in this report is that NRDC Legal Counsel should examine whether there is a need to codify guidance and permit stipulation requirements in regulation to strengthen NYS's ability to implement and enforce casing standards. Additionally, this report recommends new language that could be considered for the NYCRR based on Texas, California, Alaska and Pennsylvania casing regulations.

The value of local knowledge and experience cannot be emphasized enough when determining casing requirements for oil and gas wells. An agency must have a thorough understanding of the local geology, pressures, freshwater aquifer locations, and other site specific considerations unique to a development area. Any amendment to the NYCRR should include an extensive review of local practices, consultation with industry experienced in drilling the area, and a thorough examination of successful casing programs that have produced safe, high-quality wells, along with a review of poor-quality casing programs in order to glean lessons that can be applied in the future. The recommendations listed below are based on generally accepted good engineering practices and are indicative of state regulations where most of the US's oil and gas is produced. Local NYS casing experience and expertise should be sought and included in any final regulatory recommendation.

Recommendations to consider for amending the NYCRR are summarized below:

1. include casing requirements specific to wells drilled into the Marcellus Shale as the development pace continues to intensify in NYS;
2. include NYS's Casing and Cementing Practices and Fresh Water Aquifer Supplementary Permit Conditions;
3. include standard Good Engineering Practices (GEP) and Best Available Technology (BAT) language. This applies to all types of casing;
4. specify centralizer type according to American Petroleum Institute (API) Specification 10D and require additional centralizers in high angle or horizontal deviated wellbores. This applies to surface, intermediate and production casing;
5. clearly state that casing installation, cement methods must be designed and implemented to prevent vertical migration of fluids or gases behind casing during drilling, stimulations, or well operation. This applies to all types of casing;
6. require a 72-hour compressive strength standard of 1,200 psi for the cement mixture in the zone of critical cement, and require conformity with the API free water separation standard of no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B. Provide a provision for the NYSDEC to set more stringent local standards if needed for pollution prevention, and establish quantitative temperature limits for cement mixing water. This applies to surface, intermediate and production casing;
7. require operator certification that cement standards have been met on each well. This applies to all types of casing;
8. require casing and cementing record keeping for casing and cementing operations similar to the California Code of Regulations (CCR) at 14 CCR §1724. This applies to all types of casing;
9. specify casing and cementing program application content, similar to the Alaska Administrative Code (AAC) requirement at 20 AAC §25.030(a). This applies to all types of casing;

10. require the operator to perform a casing pressure test on all wells drilled to demonstrate that a surface pressure of at least 50% of the required working pressure of the blowout preventer (BOP) can be achieved. This applies to a casing that a BOP is installed on;
11. require a formation integrity test. This applies to surface and intermediate casing;
12. add a cement chemical and physical degradation standard similar to the Pennsylvania Code (Pa. Code) at 25 Pa. Code §78.85(a). This applies to all cement used;
13. add a requirement to report and repair defective casing, or take the well out of service similar to the Pennsylvania Code at 25 Pa. Code §78.86. This applies to all casing types;
14. add a casing standard in gas storage areas similar to the Pennsylvania Code at 25 Pa. Code §78.75, if there are sufficient well/gas storage intersection areas in NYS to warrant this additional requirement;
15. add a casing standard in coal development areas similar to the Pennsylvania Code at 25 Pa. Code §78.75, if there are sufficient coal seam intersection areas in NYS to warrant this additional requirement;
16. require casing and cement quality, cementing methods, testing, record keeping and reporting. This is especially true of the Marcellus Shale, where experience in Pennsylvania shows that industry recommends installing intermediate casing to provide an additional protective barrier in the wellbore, and to provide additional structural integrity;
17. clearly explain under what circumstances NYS will require intermediate casing to be set, what minimum requirements should be included in design and installation, and what the unique circumstances are that warrant additional NYS review and approval. Examples of how this regulatory goal was achieved in Texas, California, Alaska and Pennsylvania are provided in this report;
18. increase the amount of cement required to a minimum of 600’ behind production casing similar to Texas regulation at 16 TAC Part 1 §3.13;
19. require production casing testing and minimum overlap length standards similar to the California Code of Regulations at 14 CCR §1722;
20. add a cement quality, testing, and remedial repair standard similar to the Alaska Administrative Code (AAC) requirements at 20 AAC §25.030; and
21. add a casing quality and amount standard similar to the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71.

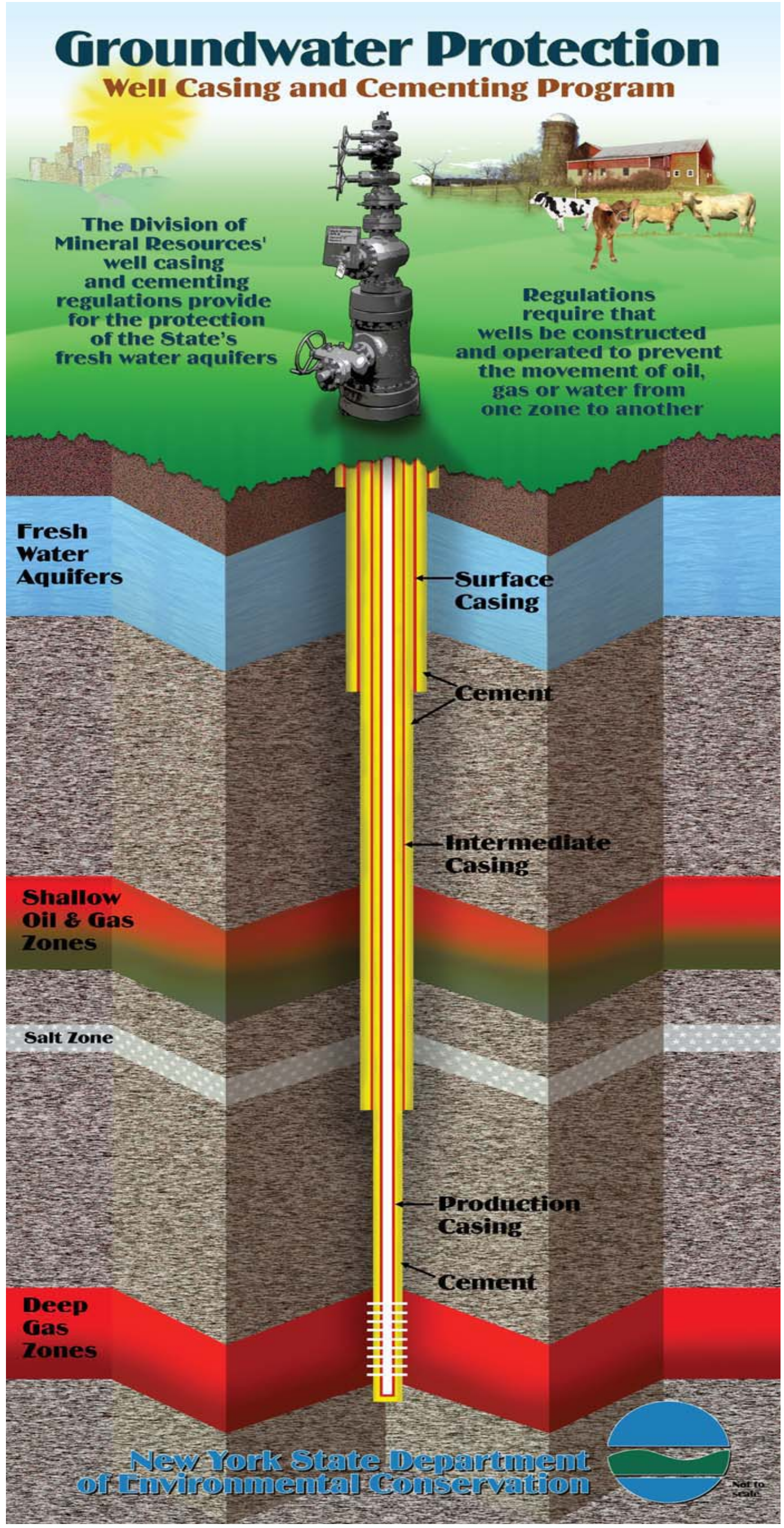
2. Casing Types and Function

Casing is metal pipe that is installed in oil and gas wells to serve many structural and safety functions, it:

- maintains wellbore structural integrity (so the hole does not cave in);
- isolates water zones from oil and gas production zones;
- contains well pressure during drilling, oil and gas production, and remedial well work (e.g. fractures, stimulations);
- isolates formations that contain different pressures;
- provides the structure and location to install blowout preventers, wellhead equipment, and hanging production tubing; and

- serves an important environmental protection function by preventing aquifer contamination and containing well blowouts or leaks that could result in oil spills or gas venting.

Multiple sections of casing are attached to create longer pipe sections (commonly referred to as a "casing string," or a "string of pipe").



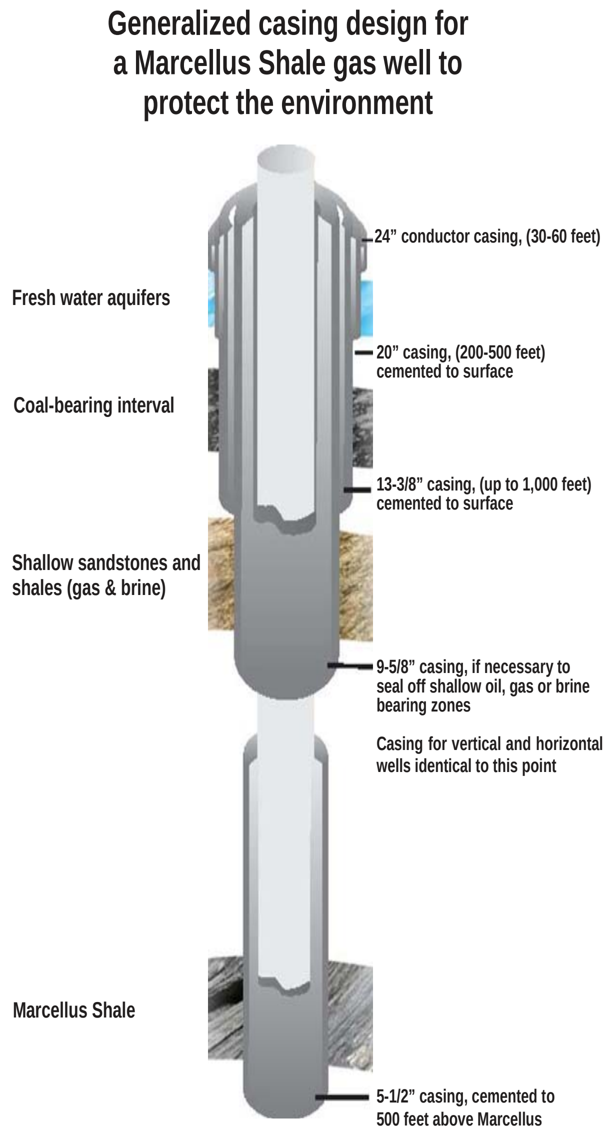
A typical well is constructed by installing conductor casing, surface casing, intermediate casing, and production casing, in that order. All wells include conductor, surface and production casing. Intermediate casing may be installed depending on local conditions (e.g. to isolate a gas or water zone), future well utility or stimulation treatment methods.

The conductor casing is the largest diameter, followed by the other types of casing, decreasing in size. Each successive casing type must fit inside the one installed prior to it (telescoping construction).

Conductor casing, surface casing and intermediate casing (if used) are run from the surface of the well to its design depth. Production casing may be set from the surface of the well or may be hung off the bottom of the deepest casing string above it. Thus, a wellbore may have at least one, and maybe up to three sets of casing, covering a freshwater aquifer for protection. In Pennsylvania, operators are installing all four sets of casing to protect freshwater zones, ensure well safety and provide for a solid wellbore construction in Marcellus Shale wells.

Since NRDC is particularly interested in development of the Marcellus Shale in NYS, and how casing standards in NYS may be formulated to ensure safe development of the Marcellus, a typical casing program currently recommended by NYSDEC is shown to the right.

As a comparison, a typical wellbore diagram[1] of the casing program recommended by the oil and gas industry and industry trade groups operating in the Marcellus Shale in Pennsylvania[2] is shown to the right. Industry recommends three sets of casing (conductor, surface, and intermediate), all cemented to the surface, putting freshwater behind three layers of casing and cement, and a fourth layer of production casing. Therefore industry's recommended casing practices and NYSDEC's recommended casing programs are similar.



In the industry recommended casing program diagram (shown to the right) intermediate casing is set at a shallow depth. Industry notes that cement is typically placed in the annular space behind the pipe all the way from the bottom of the intermediate casing (casing shoe) to surface. Cementing intermediate casing all the way to surface is possible when the intermediate casing is set at a relatively shallow depth. However, if the intermediate casing is set deeper (e.g. several thousand feet deep) it may not be possible to pump cement from the casing shoe all the way to surface. In this case, the lower section of the intermediate casing will be cemented in place by injecting cement at the casing shoe and pumping it up several hundred feet behind the lower section of the intermediate casing. This method cements the bottom section of the intermediate casing in place, ensuring that the casing will remain in place, and no drilling fluids will leak behind the casing as the well is drilled deeper. Then, production casing is installed and the production casing annulus is cemented across the Marcellus zone. Cement is also placed in the production casing annulus at least 500 feet above the top of the Marcellus zone.

The casing program recommended by industry for developing the Marcellus Shale is unique to the local conditions and depths encountered in Pennsylvania. General guidelines and standards can be set in regulation for casing size, depth, cement and testing, but the specific details of a casing program must be engineered to address local conditions and safety hazards.

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[1] http://www.pamarcellus.com/images/pdfs/casing_graphic-with_copy.pdf
[2] http://www.pamarcellus.com/about.php. "Founded in 2008, the Marcellus Shale Committee is an organization committed to the responsible development of natural gas from the Marcellus Shale geological formation in Pennsylvania and the enhancement of the Commonwealth's economy that can be realized by this clean-burning energy source. The members of the committee bring the strength of the Pennsylvania Oil and Gas Association and the Independent Oil and Gas Association of Pennsylvania together to address concerns with regulators, government officials and the people of the Commonwealth about all aspects of drilling and extracting natural gas from the Marcellus Shale formation."

3. Current NYS Oil and Gas Casing Requirements

NYS uses a combined approach of regulations, guidance documents, and permit stipulations to set oil and gas casing standards. NYS requires a ***Permit to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas and Solution Mining Law*** (NYS Permit to Drill). When issuing a NYS Permit to Drill, the NYSDEC must determine that the applicant is in compliance with the NYCRR[3] found in Chapter V, Resource Management Services, Subchapter B, Mineral Resources, including:

- Part 552 that establishes the requirements to obtain a permit;
- Part 554 that sets drilling practices and reporting standards (including casing requirements);
- Part 557 secondary recovery and pressure maintenance standards (including casing requirements); and
- Part 559 special regulations for oil and gas wells in the Bass Island pools (including casing requirements).

All wells drilled in NYS must adhere to the general requirements of Parts 552, 554, and 557. Additional, special requirements are applied to Bass Island wells.[4] For example, NYS's Bass Island wells are subject to these additional casing requirements:

> *Unless the department's studies show some other requirements to be more appropriate in a particular area, the operator of a well described in subdivision (a) of this section must set surface casing to the greater depth of 450 feet from the surface or 100 feet into bedrock and must cement that casing to the surface by circulating cement, using enough excess cement to ensure cement returns. That operator must use centralizers and baskets at appropriate intervals, and the surface casing must have a minimum bursting pressure of 1,800 pounds per square inch. That operator must notify the department of the start of cementing operations at least four hours before those operations start. If a State inspector is not present during cementing operations, that operator must attach a copy of the cement ticket to the well's completion report.*[5]
>
> *To ensure adequate cementing results, that operator must add material to control lost circulation to the cement used in cementing the conductor and surface casing strings. If a lost circulation zone is encountered, the operator must try to seal off that zone with lost circulation materials before pumping the cement slurry. If cement circulation is not achieved, that operator must grout the well from the surface using cement having materials to control lost circulation, to ensure a complete cement bond. If cement grouting is inadequate, the department may require a cement bond log and additional remedial measures to ensure adequacy of the bond.*[6]

The use of regulations unique to an oil and gas pool is common throughout the US (also referred to as "pool rules" or "field rules"). Most states establish a standard set of default casing regulations that must be followed, unless unique circumstances warrant a special set of rules for a pool or field ("pool rules" or "field rules"). Therefore, it is important for NRDC to keep a watchful eye out for pool/field specific rules that may be adopted in the future for the Marcellus Shale, or other formations of interest to the NRDC.

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[3] New York State Code of Rules and Regulations
[4] "A 'Bass Island' pool is a pool lying below the Tully horizon and above the base of the lowest Salina Group Salt horizon whose primary permeability results from faults or natural fractures, other than one in the Devonian shales as the department determines and other than one producing nonassociated gas with or without condensate, which is located in any of the following counties: Allgany, Genesee, Cattaraugus, Livingston, Chautauqua, Steuben, Erie, and Wyoming."
[5] 6 NYCRR V.B. §559.6(d)(1)
[6] 6 NYCRR V.B. §559.6(d)(2)

Based on this report, and in particular Pennsylvania's experience in developing the Marcellus Shale, NRDC may want to recommend that NYSDEC develop of specific casing standards for the Marcellus, rather than relying on generic NYS casing requirements. The casing program recommended by the Pennsylvania operators, and accepted by Pennsylvania, as shown in the diagram above is robust, and would be useful to adopt for NYS. This casing program requires all four sets of casing, providing extra ground water protection for horizontal wells that will sustain large fracture treatments.

Recommendation No. 1: Consider amending the NYCRR to include casing requirements specific to wells drilled into the Marcellus Shale as the development pace continues to intensify in NYS.

In addition to the NYS regulations cited above, NYS requires a permit to drill at 6 NYCRR V.B. §552, which requires operators to follow NYS's ***Casing and Cementing Practices*** Guidelines.[7] NYS's website states that the NYS ***Casing and Cementing Practices*** are minimum construction standards for all wells, unless a waiver has been approved by the regional minerals manager in response to a written request and justification.[8]

Photo by: Department of Labor, www.dol.gov

However, the statement/requirement to adhere to NYS's ***Casing and Cementing Practices*** is not found in NYS law or regulation. NRDC Legal Counsel will need to determine whether NYS's ***Casing and Cementing Practices*** are enforceable, or whether they could be subject to challenge by industry. There may be benefit in incorporating guidance and permit stipulations within the NYS code.

NYS also applies ***Fresh Water Aquifer Supplementary Permit Conditions*** to drilling in primary aquifer areas, ***Wildcat Supplementary Permit Conditions*** to wells drilled in new, unfamiliar areas, and/or high pressure areas, and ***Notification and Reporting Requirements.***[9] These conditions and stan applied as part of a final permit to drill and are enforced by NYS.

Recommendation No. 2: Consider amending the NYCRR to include NYS's Casing and Cementing Practices and Fresh Water Aquifer Supplementary Permit Conditions.

4. Conductor Casing

Conductor casing is the first pipe set in the wellbore; it is the largest [widest?] and shortest piece of piping. Oil and gas wells are started by excavating an initial hole at the earth's surface. This hole is called the well cellar. The well cellar is shallow (less than 6') and is typically 6-8' in diameter depending on the size of the wellhead equipment associated with the drilling project. Often corrugated pipe is inserted into

[7] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html.
[8] "The casing and cementing practices above are designed for typical production casing/cementing. The Department will require additional measures for wells drilled in environmentally or technically sensitive areas (i.e. primary or principal aquifers). The Department recognizes that variations to the above procedures may be indicated in site-specific instances. Such variations will require the prior approval of the Regional Mineral Resources office." http://www.dec.ny.gov/energy/1628.html.
[9] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html.

the well cellar and is cemented in place. Sometimes pre-fabricated "box cellars" are utilized instead of the corrugated pipe.

Once the well cellar is excavated, another hole is excavated about 60-80 feet into the ground and conductor casing is lowered in the hole (as shown in the photo above) and is cemented in place. Conductor casing is typically 20-24" in diameter. Cement is poured in the annulus (the space between the outside of the pipe and inside of the hole). Alternatively, if surface geology allows, conductor casing can be driven by mechanical percussion methods into unconsolidated strata. In this case, there is no annulus, and the casing is not cemented.

Conductor casing prevents the well cellar hole from caving in and provides a conduit for drilling fluids while drilling the next section of the well. This casing is much like a retaining wall for a house foundation.

4.1 Existing NYS Conductor Casing Requirements

NYS does not include any specific conductor casing standards in its regulations in the NYCRR. Although, NYS does require a permit to drill at 6 NYCRR V.B. §552, however, to which conductor casing and ground water protection stipulations can be attached.

NYS guidance informs the applicant that it must follow NYS's ***Casing and Cementing Practices*** guidelines when designing a well; however, there is no specific language codified in the NYCRR requiring compliance with the guidance.[10] NYS's website advises the applicant that the NYS ***Casing and Cementing Practices*** are minimum construction standards for all wells, unless a waiver has been approved by the regional minerals manager in response to a written request and justification.

NYS ***Casing and Cementing Practices*** include one requirement for conductor casing:

> *When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing).*[11]

Additionally, NYS state places ***Fresh Water Aquifer Supplementary Permit Conditions*** on permits to drill, after reviewing the applicants casing program design. The ***Fresh Water Aquifer Supplementary Permit Conditions*** for conductor casing include more restrictive conditions for wells drilled through primary and principal aquifers. Typical conditions applied to conductor casing are posted at the NYSDEC website and include a requirement to drill the conductor casing section of the hole with air, fresh water, or fresh water based muds, which excludes synthetic muds and oil based muds from being used while drilling this shallow section of the wellbore.[12] NYS also lists procedures for ensuring the conductor pipe is cemented from top to bottom, and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe.[13]

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[10] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html.
[11] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at 11.
[12] NYS Fresh Water Aquifer Supplementary Permit Conditions at 3. "Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing." http://www.dec.ny.gov/energy/1628.html.
[13]NYS Fresh Water Aquifer Supplementary Permit Conditions at 4. "If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results.""Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event

4.2 Conductor Casing Recommendations for NYS

Texas regulations do not set specific conductor casing requirements; however, Texas does instruct the operator to use good engineering practices, which would apply to construction of this initial section of the well.

California regulations include a maximum depth standard, limiting conductor casing to 100' unless approved otherwise.

> *This casing shall be cemented at or driven to a maximum depth of 100 feet. Exceptions may be granted by the appropriate Division district deputy if conditions require deeper casing depth.*[14]

Alaska regulations include a depth criterion requiring conductor casing to be set to a sufficient depth to provide a solid structural anchorage, designed on site specific engineering and geologic factors, and cemented in place from top to bottom.

> *For onshore wells, conductor casing must be set by driving, jetting, or drilling to a depth sufficient to provide anchorage for a diverter system…however, the commission will (A) approve a different casing setting depth if necessary to permit the casing shoe to be set in a competent formation or below formations that should be isolated; or (B) authorize an operator to drill without setting conductor casing based on information from wells drilled in the immediate vicinity and other available data, if the commission determines that the absence of conductor casing will not jeopardize well control;*[15]
>
> *Casing design and setting depth must be based on engineering and geologic factors relevant to the immediate vicinity, including the presence or absence of hydrocarbons, potential drilling hazards, and permafrost;*[16]
>
> *If conductor casing is set by drilling or jetting, the conductor casing must be cemented by filling the annular space with cement from the shoe to the surface; if the BOPE*[17] *is to be installed on the conductor casing, the adequacy of the cement to contain potential wellbore pressures and fluids must be demonstrated by a formation integrity test;*[18]

Pennsylvania regulations prohibit removal of conductor casing once set, and instruct the operator to design the conductor casing to meet best local, site-specific and industry practices.

> *Use of conductor pipe. If the operator installs conductor pipe in the well, the operator may not remove the pipe.*[19]

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that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified (to be determined by DEC on individual well basis) hours prior to cementing operations and cementing cannot commence until a state inspector is present."

[14] 14 CCR §1722.3(a) Conductor casing
[15] 20 AAC §25.030 (c)(2)
[16] 20 AAC §25.030(b)(1)
[17] Blowout Preventer Equipment (BOPE)
[18] 20 AAC §25.030 (d)(2)
[19] 25 Pa. Code §78.82

The operator shall equip the well with one or more strings of casing of sufficient length and strength to prevent blowouts, explosions, fires and casing failures during installation, completion and operation.[20]

The operator shall determine the amount and type of casing to be run and the amount and type of cement to be used in accordance with current prudent industry practices and engineering. In making the determinations, the operator shall consider the following: (1) Successful local practices for similar wells. (2) Maximum anticipated surface pressure. (3) Collapse resistance. (4) Tensile strength. (5) Chemical environment. (6) Potential mechanical damage. (7)Manufacturing standards, including American Petroleum Institute or equivalent specifications for pipe used in wells drilled below the Onondaga formation or where blow-out preventers are required.[21]

Overall, the NYS code, guidance documents, and standard permit stipulations for conductor casing are protective of the environment and essentially equivalent in all practical purpose to other major oil and gas producing states. However, NRDC may determine it would be preferable to codify these standards in the NYCRR, providing additional legal protection to ensure compliance, as well as an ability to enforce. If that is the case, four changes could be considered for inclusion in the NYCRR for conductor casing, and these general recommendations also apply to surface, intermediate and production casing:

1. Instruct the operator to use good engineering practices (GEP) and best available technology (BAT);
2. Require the casing depth to be based on regional engineering and geologic data;
3. Incorporate NYS's ***Casing and Cementing Practices*** requirement for a cement pad, at the surface, around the conductor casing to prevent the downward migration of surface pollutants that could originate from wellhead leaks, or other remedial/operational activities at the wellhead area; and
4. Incorporate NYS's ***Fresh Water Aquifer Supplementary Permit Conditions*** for mud type and cement integrity.

Recommendation No. 3: Consider amending the NYCRR to include standard GEP and BAT language.[22] This applies to all types of casing.

5. Surface Casing

Surface casing is the second casing set in the wellbore. Surface casing is set to protect ground water aquifers, provide the structure to support blowout prevention equipment and provide a conduit for drilling fluids while drilling the next section of the well. This section of the well can be hundreds to thousands of feet deep, depending on the well design and geologic formations. The drilling engineer will determine the depth of the surface casing with a few key factors in mind: (1) surface casing should stop above any significant pressure zone or hydrocarbon zone, to ensure the blowout preventer can be installed prior to

[20] 25 Pa. Code §78.71(a)
[21] 25 Pa. Code §78.71(b)
[22] Recommendation No. 2 above, already includes the suggestion to include NYS's Casing and Cementing Practices and Fresh Water Aquifer Supplementary Permit Conditions in NYCRR, therefore is not repeated here in Recommendation No. 3.

drilling into a pressured zone or hydrocarbons; and (2) surface casing needs to be set to provide a protective barrier to prevent hydrocarbons from contaminating drinking water aquifers when the well is drilled deeper (below the surface casing) into hydrocarbon bearing zones.

Surface casing is typically 13-20" in diameter, but size is a site-specific, well-specific function and can vary. The surface casing pipe is set into the earthen hole and the annulus is filled with cement. It is important that the casing is centered in the hole, so that an equal, continuous section of cement filling is placed from bottom to the top of the annulus. Casing centralizers are installed on the outside of the pipe to keep it centered in the hole while cement is pumped into the annulus and then sets the pipe in place. In high angle holes this is very important, because the heavy casing pipe will lie on the low side of the hole, unless casing centralizers are used to force the pipe into the center of the hole. Casing in a horizontal well that is not properly centralized, will have thinner, or possibly no cement where the pipe is near or contacts the earth wall.

The cement is allowed to harden and must be integrity tested (e.g. hardness, continuity, and proper seal). There is no blowout preventer (BOP) equipment in place while the surface hole is drilled and the surface casing is installed, because until the surface casing is installed, and cemented in place, there is insufficient casing or cement in the ground to anchor the BOP equipment. If shallow gas is encountered while drilling, the surface casing is vented to atmosphere through a diverter valve.

Once the surface casing is cemented in place, the blowout preventer is installed at the surface and is attached to the surface casing. The surface casing serves as a solid anchor in the ground holding the blowout preventer in place in the event high pressures are encountered as the well is drilled deeper into hydrocarbon bearing zones.

5.1 Existing NYS Surface Casing Requirements

NYS includes specific surface casing standards in its regulations in the NYCRR, including:

1. Pollution Prevention:
   Surface casing shall be run in all wells to extend below the deepest potable fresh water level. [23]

   The drilling, casing and completion program adopted for any well shall be such as to prevent pollution.[24]

   Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited.[25]

   On all wells where rotary tools are employed, and the subsurface formations and pressures to be encountered have been reasonably well established by prior drilling experience, the operator shall have the option of either running surface casing as provided in section 554.1(b) of this Part or of cementing the production casing from below the deepest potable fresh water level to the surface. In areas where the subsurface formations and pressures to be encountered are unknown or uncertain, surface casing shall be run as provided in section 554.1(b) of this Part.[26]

[23] 6 NYCRR V.B. §554.1(d)
[24] 6 NYCRR V.B. §554.1(a)
[25] 6 NYCRR V.B. §554.1(b)
[26] 6 NYCRR V.B. §554.4(a)

2. Cementing Method:
When surface casing is utilized, it shall be cemented by the pump and plug or displacement method with sufficient cement to circulate to the top of the hole. Drilling shall not be resumed until the cement has been permitted to set in accordance with prudent current industry practices.[27]

3. Testing:
On all wells where cable tools are employed, the surface casing shall be tested by bailing to insure a shutoff before drilling below the casing point proceeds.[28]

NYS requires a permit to drill at 6 NYCRR V.B. §552, to which stipulations can be attached. NYS also requires the operator to file a ***Well Drilling and Completion Report*** listing information on the size, grade and type of casing and cement used.

NYS guidance informs the applicant that it must follow NYS's ***Casing and Cementing Practices*** guidelines when designing a well; however, there is no specific language in the regulation requiring compliance with the guidance.[29] NYS's website states that the NYS ***Casing and Cementing Practices*** are minimum construction standards for all wells, unless a waiver has been approved by the regional minerals manager in response to a written request and justification.

NYS ***Casing and Cementing Practices*** include several requirements for surface casing:

1. Pollution Prevention:
Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).[30]

2. Depth:
Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper. However, the surface pipe must be set deeply enough to allow the BOP stack to contain any formation pressures that may be encountered before the next casing is run.[31]

3. Casing Quality:
All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi). Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.[32]

4. Cement Quality:
The operator shall test or require the cementing contractor to test the mixing water for ph and

[27] 6 NYCRR V.B. §554.4(b)
[28] 6 NYCRR V.B. §554.3(a)
[29] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html.
[30] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html, at 3.
[31] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at 2.
[32] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at 4.

temperature prior to mixing the cement and to record the results on the cementing ticket. The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement. After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The WOC[33] *time shall be recorded on the drilling log.*[34]

5. Cementing Method:
   The pump and plug method shall be used to cement surface casing. The amount of cement will be determined on a site specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless additional excesses are specified by the Department.[35]

   Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.[36]

   Cement baskets shall be installed appropriately above major lost circulation zones.[37]

6. Use of Centralizers to Center Casing in Hole:
   The diameter of the drilled surface casing hole shall be large enough to allow the running of centralizers in recommended hole sizes.[38]

   Centralizers shall be spaced at least one per every one hundred-twenty feet; a minimum of two centralizers shall be run on surface casing.[39]

7. Record Keeping and Variances:
   When requested by the Department in writing, each operator must submit cement tickets and/or other documents that indicate the above specifications have been followed. The casing and cementing practices above are designed for typical surface casing cementing. The Department will require additional measures for wells drilled in environmentally or technically sensitive areas (i.e. primary or principal aquifers). The Department recognizes that variations to the above procedures may be indicated in site specific instances. Such variations will require the prior approval of the Regional Mineral Resources office staff.[40]

NYS state places ***Fresh Water Aquifer Supplementary Permit Conditions*** on permits to drill, after reviewing the applicants casing program design. The ***Fresh Water Aquifer Supplementary Permit Conditions*** for surface casing include more restrictive conditions for wells drilled through primary and

[33] Waiting on Cement (WOC)
[34] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at 8-10.
[35] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at7.
[36] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html, at 6.
[37] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at 5.
[38] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at 1.
[39] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at 5.
[40] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html.

principal aquifers. Typical conditions applied to surface casing are posted at the NYS website and may include:

1. Pollution Prevention:
   If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.[41]

2. Drilling Mud Type:
   Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.[42]

3. Depth:
   A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater.[43]

4. Use of Centralizers to Center Casing in Hole:
   Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'.[44]

5. Cement Method:
   Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results.[45]

   In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified (to be determined by DEC on individual well basis) hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations. This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may

[41] NYS Fresh Water Aquifer Supplementary Permit Conditions at 6.
[42] NYS Fresh Water Aquifer Supplementary Permit Conditions at 3.
[43] NYS Fresh Water Aquifer Supplementary Permit Conditions at 5.
[44] NYS Fresh Water Aquifer Supplementary Permit Conditions at 5.
[45] NYS Fresh Water Aquifer Supplementary Permit Conditions at 5.

be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.[46]

6. Casing Quality Method:
   Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run.[47]

7. State Inspector to Oversee Stimulation Operations:
   This office must be notified (to be determined by DEC on individual well basis) hours prior to any stimulation operation. Stimulation may commence without the state inspector if the inspector is not on location at the time specified during the notification.[48]

8. Recordkeeping:
   The operator must complete the "Record of Formations Penetrated" on the Well Drilling and Completion Report, providing a log of formations, both unconsolidated and consolidated, and all water and gas producing zones.[49]

NYS state places ***Wildcat Supplementary Permit Conditions*** on permits to drill, for new, unique or high pressure areas. Typical conditions NYS may apply for surface casing are posted at the NYS website and may include:

1. Pressure Testing:
   The BOP, choke manifold and surface casing must be tested to a minimum of 1000 psi prior to drilling out the surface casing shoe, unless the Department grants a waiver in response to a written request from the operator which demonstrates to the Department's satisfaction that: a) the well is proposed as a deep wildcat that will be drilled through an established, shallow, low pressure pool and b) the well will have an intermediate casing string that is the first string intended for well control purposes. When intermediate casing is used, the BOP, choke manifold and intermediate casing must be tested to at least the maximum anticipated shut-in surface pressure plus a 5% safety factor prior to drilling out the intermediate casing shoe. A representative of this office must be notified six (6) hours prior to each test and a department representative may be present during the test. If the Department representative is not on location at the agreed time, the test may proceed with the results of the test and the name of the witness being noted in the driller's log.[50]

5.2 Surface Casing Standard Recommendations for NYS

Overall, NYS’s surface casing requirements are fairly robust, when the NYCRR, guidance documents, and standard stipulations are combined. However, similar to the recommendations outlined above in the conductor casing section, NYS’s regulations may benefit from codifying guidance and standard stipulations.

Additionally, other state regulations examined in this report point to possible improvements and refinements. Because each state’s surface casing regulations are very extensive, they are not repeated here

[46] NYS Fresh Water Aquifer Supplementary Permit Conditions at 7.
[47] NYS Fresh Water Aquifer Supplementary Permit Conditions at 5.
[48] NYS Fresh Water Aquifer Supplementary Permit Conditions at 8.
[49] NYS Fresh Water Aquifer Supplementary Permit Conditions at 9.
[50] NYS Wildcat Supplementary Permit Conditions at 5.

in entirety. Rather, selected regulations are listed below where a state has a more stringent, or more detailed, regulation that may benefit NYS.

Texas regulations that may benefit NYS include:

1. Use of Centralizers to Center Casing in Hole:
   Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. ***All centralizers shall meet API spec 10D specifications. In deviated holes, the operator shall provide additional centralization***[51] *[emphasis added].*

   Like Texas, NYS requires a centralizer at every fourth joint (every 120'). However NYS does not specify an industry standard for centralizers; Texas requires the American Petroleum Institute Specification (API) 10D. Texas also requires additional centralizers to be used in deviated holes. In high angle or horizontal holes, the casing pipe drops by gravity to the lowside of the hole making cementing difficult under the low side of the pipe. Additional centralizers placed around casing in a deviated wellbore helps to centralize the pipe in the hole, and allows a concentric cement barrier to be pumped around the casing.

Recommendation No. 4: Consider amending the NYCRR to specify centralizer type according to American Petroleum Institute (API) Specification 10D and require additional centralizers in high angle or horizontal deviated wellbores. This applies to surface, intermediate and production casing.

2. Prevent Vertical Migration of Fluids or Gas Behind Pipe:
   It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology.[52]

   Like Texas, NYS sets objectives for the protection of drinking water aquifers and sets cement method and integrity standards; however, Texas regulations go the extra step of overtly stating that ***all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing.*** NYS regulations do not specifically state the goal of preventing vertical migration of fluids or gases behind casing.

Recommendation No. 5: Consider amending the NYCRR to clearly state that casing installation and cement methods must be designed and implemented to prevent vertical migration of fluids or gases behind casing during drilling, stimulations, or well operation. This applies to all types of casing.

[51] 16 Texas Administrative Code (TAC) Part 1 §3.13(b)(2)(F)
[52] 16 TAC Part 1 §3.13(a)

3. Cement Quality:
   Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. ***The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi****. …In addition to the minimum compressive strength of the cement,* ***the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B*** *The commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area*[53] *[emphasis added].*

   Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. ***Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the commission prior to the cementing operation.*** *To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure. (i)* ***For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement. (ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater***[54] *[emphasis added].*

   Texas and NYS both set a cement compressive strength standard of 500 psi for the final cement bond; however, Texas includes an additional standard requiring the cement mixture in the zone of critical cement to have a 72-hour compressive strength rating of at least 1,200 psi. This places a quality standard on the type of cement mix purchased.

   Additionally, Texas requires API free water separation to average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B, and the commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicate a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.

   While NYS requires the operator to test and record the temperature of the mixing water, NYS does not set a temperature quality standard like Texas.

Recommendation No. 6: Consider amending the NYCRR to require a 72-hour compressive strength standard of 1,200 psi for the cement mixture in the zone of critical cement, and the requirement to conform with the API free water separation standard of no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B. Provide a provision for the commission to set more stringent local standards if needed for pollution prevention, and establish quantitative temperature limits for cement mixing water. This applies to surface, intermediate and production casing.

[53] 16 TAC Part 1 §3.13(b)(2)(C)
[54] 16 TAC Part 1 §3.13(b)(2)(D)

4. Record Keeping and Reporting:
   Cementing report. Upon completion of the well, a cementing report must be filed with the commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the commission. ***The operator of the well or his duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the commission***[55] *[emphasis added].*

   NYS requires the operator to file a ***Well Drilling and Completion Report*** listing information on the size, grade and type of casing and cement used. In addition, NYS's guidance documents state it can demand cementing records from the operator; however, Texas regulations go one step further and demand the operator to certify, under penalty of law that every cement job is in compliance.

Recommendation No. 7: Consider amending the NYCRR to require operator certification that cement standards have been met on each well. This applies to all types of casing.

California regulations that may benefit NYS include:

1. Recordkeeping and Reporting:
   Required Well Records. The operator of any well drilled, redrilled, deepened, or reworked shall keep, or cause to be kept, an accurate record of each operation on each well including, but not limited to, the following, when applicable: (a) Log and history showing chronologically the following data: (1) Character and depth of all formations, water-bearing strata, oil- and gas-bearing zones, lost circulation zones, and abnormal pressure zones encountered. (2) Casing size, weight, grade, type, condition (new or used), top, bottom, and perforations; and any equipment attached to the casing…(4) Casing pressure tests and pressure tests of the casing-tubing annulus, including date, duration, pressure, and percent bleed-off. (5) Hole sizes. (6) Cementing and plugging operations, including date, depth, slurry volume and composition, fluid displacement, pressures, calculated or actual fill, and downhole equipment… (9) Water shutoff and lap tests of casing, including date, duration, depth, and results. Records to Be Filed with the Division. Two true and reproducible copies of the well summary, core record, and history, and all electrical, physical and chemical logs, tests and surveys run, including mud logs shall be filed with the Division within 60 days after the completion, plugging and abandonment, or suspension of operations of a well[56]

   California requires extensive recordkeeping and reporting for casing and cementing installation on each well. NYS's ***Well Drilling and Completion Report*** form requires some of this information, but not all. NYS's guidelines announce these records can be demanded, but do not require them on a routine basis.

Recommendation No. 8: Consider amending the NYCRR to require casing and cementing record keeping for casing and cementing operations similar to the California Code of Regulations at 14 CCR §1724. This applies to all types of casing.

[55] 16 TAC Part 1 §3.13(b)(2)(E)
[56] 14 CCR §1724 and 14 CCR §1724.1

Alaska regulations that may benefit NYS include:

1. Casing and Cementing Program Application Contents:
   A complete proposed well casing and cementing program must be submitted with an application for a Permit to Drill (Form 10-401). Unless modified or altered by pool rules established under 20 AAC §25.520, a well casing and cementing program must be designed to: (1) provide suitable and safe operating conditions for the total measured depth proposed; (2) confine fluids to the wellbore; (3) prevent migration of fluids from one stratum to another; (4) ensure control of well pressures encountered; (5) protect against thaw subsidence and freezeback effects within permafrost; (6) prevent contamination of freshwater; (7) protect significant hydrocarbon zones; and (8) provide well control until the next casing is set, considering all factors relevant to well control including formation fracture gradients, formation pressures, casing setting depths and proposed total depth.[57]

   Both NYS and Alaska require the operator to describe its casing and cementing program in its application to drill, however, Alaska's application content requirements establish specific criteria for the application content, where, NYS does not.

Recommendation No. 9: Consider amending the NYCRR to specify casing and cementing program application content, similar to the Alaska Administrative Code (AAC) requirement at 20 AAC §25.030(a). This applies to all types of casing.

2. Casing Pressure Test:
   A casing pressure test must be performed if BOPE is to be installed on a casing. The casing must be tested to hold a surface pressure equal to 50 percent of the required working pressure of the BOPE as specified in the Permit to Drill under 20 AAC §25.035(e)(3) or 20 AAC §25.036 (c)(3). The results of this test and any subsequent tests of the casing must be recorded as required by 20 AAC §25.070(1).[58]

   Alaska requires the operator to perform a casing pressure test on all wells drilled to demonstrate that a surface pressure of at least 50% of the required working pressure of the blowout preventer can be achieved. Common blowout preventer ratings range between 5,000 psi to 10,000 psi, yielding pressure tests within 2500-5000psi. Blowout preventions of higher pressure rating may be required for deeper, higher pressure, or wildcat wells. NYS's pressure testing requirement only applies to a wildcat well and only requires a minimum 1000 psi pressure rating, regardless of blowout preventer size and rating.

Recommendation No. 10: Consider amending the NYCRR to require a the operator to perform a casing pressure test on all wells drilled to demonstrate that a surface pressure of at least 50% of the required working pressure of the blowout preventer can be achieved. This applies to casing that a BOP is installed on.

3. Formation Integrity Test:
   A formation integrity test must be performed if a BOPE is to be installed on a casing. The test must be performed to a predetermined equivalent mud weight, leak-off, or fracture pressure as specified in the application for the Permit to Drill. The test must be conducted after drilling out of the casing shoe into at least 20 feet but not more than 50 feet of new formation. The test results must

[57] 20 AAC §25.030(a)
[58] 20 AAC §25.030(e)

demonstrate that the integrity of the casing shoe is sufficient to contain anticipated wellbore pressures identified in the application for the Permit to Drill. The test procedure followed and the data from the test and any subsequent tests of the formation must be recorded as required by 20 AAC §25. 070 (1). [59] *For all casing strings on which blowout prevention equipment (BOPE) will be installed, cement may not be drilled out until sufficient compressive strength has been reached to obtain a valid formation integrity test.* [60]

Alaska requires the operator to perform a formation integrity test (FIT) at the casing shoe (bottom of casing string) to determine whether the wellbore will tolerate the maximum wellbore pressure anticipated while drilling the next interval. If a FIT test fails, then a cement squeeze is typically required to improve the casing/cement structural integrity before drilling deeper into the well. NYS does not require a formation integrity test.

Recommendation No. 11: Consider amending the NYCRR to require a formation integrity test. This applies to surface and intermediate casing.

Pennsylvania regulations that may benefit NYS include:

1. Cement Degradation Protection:
   The operator shall use cement that will resist degradation by chemical and physical conditions in the well. [61]

   NYS requires cement strength standards, but does not include a standard like Pennsylvania's that requires the cement formulation to resist future degradation by chemical and physical conditions that may be encountered in the wellbore over its service life. This standard would require the cement to be designed to resist naturally occurring corrosive fluids and gases, as well as stimulation or enhanced recovery fluids/gases that may be used to enhance production.

Recommendation No. 12: Consider amending the NYCRR to add a cement chemical and physical degradation standard similar to the Pennsylvania Code at 25 Pa. Code §78.85(a). This applies to all cement used.

2. Obligation to Report and Correct Defective Casing:
   Defective casing or cementing. In a well that has defective, insufficient or improperly cemented casing, the operator shall report the defect to the Department within 24 hours of discovery by the operator and shall correct the defect. The operator shall correct the defect or submit a plan to correct the defect for approval by the Department within 30 days. If the defect cannot be corrected or an alternate method is not approved by the Department, the well shall be plugged under § §78.91—78.98 (relating to plugging). [62]

   Pennsylvania requires an operator to report and repair defective casing. If the casing cannot be repaired the well must be plugged and abandoned. NYS does not have an equivalent standard. This standard would be particularly helpful to apply to existing wells that may have been designed and installed using older casing and cementing standards and techniques. This would require the operator to repair or take non-compliant wells out of service.

[59] 20 AAC §25.030(f)
[60] 20 AAC §25.030(b)(2)
[61] 25 Pa. Code §78.85(a)
[62] 25 Pa. Code §78.86

Recommendation No. 13: Consider amending the NYCRR to add a requirement to report and repair defective casing, or take the well out service similar to the Pennsylvania Code at 25 Pa. Code §78.86. This applies to all casing types.

3. Casing Requirements for Drilling Through Gas Storage Areas:
In addition to the other provisions in this subchapter, a well drilled through a gas storage reservoir or a gas storage reservoir protective area shall be drilled, cased and cemented as follows: (1) An operator shall use drilling procedures capable of controlling anticipated gas flows and pressures when drilling from the surface to 200 feet above a gas storage reservoir or gas storage horizon. (2) An operator shall use drilling procedures capable of controlling anticipated gas storage reservoir pressures and flows at all times when drilling from 200 feet above a gas storage reservoir horizon to the depth at which the gas storage protective casing will be installed. Operators shall use blow-out prevention equipment with a pressure rating in excess of the allowable maximum storage pressure for the gas storage reservoir. (3) To protect the gas storage reservoir, an operator shall run intermediate or production casing from a point located at least 100 feet below the gas storage horizon to the surface. The operator shall cement this casing by circulating cement to a point at least 200 feet above the gas storage reservoir or gas storage horizon. (4) When cementing casing in a well drilled through a gas storage reservoir, the operator shall insure that no gas is present in the drilling fluids in an amount that could interfere with the integrity of the cement.[63]

The well operator shall notify all coal owners and operators and gas storage operators of record of the proposal, by certified mail. The well operator shall state in the application that he has sent the certified mail notice to the coal owners and operators and gas storage operators of record, either simultaneously with or prior to submitting the proposal to the Department.[64]

The coal owners and operators and gas storage operators of record shall have up to 15 days from their receipt of the notice to file objections or to indicate concurrence with the proposed alternative method or material. If no objections are filed within 15 days from receipt of the notice, and if none are raised by the Department, the Department will make a determination whether to allow the use of the proposed alternative method or material.[65]

Pennsylvania requires specific casing standards for wells penetrating a gas storage area. NYS does not include these standards.

Recommendation No. 14: Consider amending the NYCRR to add a casing standard in gas storage areas similar to the Pennsylvaina Code at 25 Pa. Code §78.75, if there are sufficient gas storage intersection areas in NYS to warrant this additional requirement.

4. Casing Requirements for Drilling Through Coal Mining Areas:
Surface and coal protective casing and cementing procedures. If the well is to be equipped with threaded and coupled casing, the operator shall drill a hole so that the diameter is at least 1 inch greater than the outside diameter of the casing collar to be installed. If the well is to be equipped with plain-end welded casing, the operator shall drill a hole so that the diameter is at least 1 inch greater than the outside diameter of the casing tube.[66]

[63] 25 Pa. Code §78.87 (a)
[64] 25 Pa. Code §78.75(c)
[65] 25 Pa. Code §78.75 (d-e)
[66] 25 Pa. Code §78.83 (a)

Except as provided in subsection (c), the operator shall drill to approximately 50 feet below the deepest fresh groundwater or at least 50 feet into consolidated rock, whichever is deeper, and immediately set and permanently cement a string of surface casing to that depth. [67]

If no fresh groundwater is being utilized as a source of drinking water within a 1,000-foot radius of the well, the operator may set and permanently cement a single string of surface casing through all water zones, including fresh, brackish and salt water zones. Prior to penetrating zones known to contain, or likely containing, oil or gas, the operator shall install and permanently cement the string of casing in a manner that segregates the various waters.[68]

The operator shall set and cement a coal protective string of casing through workable coal seams. The base of the coal protective casing shall be at least 30 feet below the lowest workable coal seam.[69]

When a well is drilled through a coal seam at a location where the coal has been removed, the operator shall drill to a depth of at least 30 feet but no more than 50 feet deeper than the bottom of the coal seam. The operator shall set and cement a coal protection string of casing to this depth. The operator shall equip the casing with a cement basket or other similar device above and as close to the top of the coal seam as practical. The bottom of the casing shall be equipped with an appropriate device designed to prevent deformation of the bottom of the casing. The interval from the bottom of the casing to the bottom of the coal seam shall be filled with cement either by the balance method or by the displacement method. Cement shall be placed on top of the basket between the wall of the hole and the outside of the casing by pumping from the surface. If the operator penetrates more than one coal seam from which the coal has been removed, the operator shall protect each seam with a separate string of casing that is set and cemented or with a single string of casing which is stage cemented so that each coal seam is protected as described in this subsection. The operator shall cement the well to isolate workable coal seams from each other.[70]

If the operator sets and cements casing under subsection (g) or (h) and subsequently encounters additional fresh groundwater zones below the deepest cemented casing string installed, the operator shall protect the fresh groundwater by installing and cementing another string of casing or other method approved by the Department. Sufficient cement shall be used to cement the casing at least 20 feet into the surface or coal protective casing. The additional casing string may also penetrate zones bearing brackish or salt water, but shall be run and cemented prior to penetrating a zone known to or likely to contain oil or gas.[71]

When casing through a workable coal seam, the operator shall install coal protective casing that has a minimum wall thickness of 0.23 inches.[72]

The well operator shall notify all coal owners and operators and gas storage operators of record of the proposal, by certified mail. The well operator shall state in the application that he has sent the certified mail notice to the coal owners and operators and gas storage operators of record, either simultaneously with or prior to submitting the proposal to the Department.[73]

[67] 25 Pa. Code §78.83(b)
[68] 25 Pa. Code §78.83(c)
[69] 25 Pa. Code §78.83(g)
[70] 25 Pa. Code §78.83(h)
[71] 25 Pa. Code §78.83(i)
[72] 25 Pa. Code §78.84(c)
[73] 25 Pa. Code §78.75(c)

The coal owners and operators and gas storage operators of record shall have up to 15 days from their receipt of the notice to file objections or to indicate concurrence with the proposed alternative method or material.[74]

If no objections are filed within 15 days from receipt of the notice, and if none are raised by the Department, the Department will make a determination whether to allow the use of the proposed alternative method or material.[75]

Pennsylvania requires specific casing standards for wells while penetrating through coal seams. NYS does not include these standards.

> **Recommendation No. 15**: Consider amending the NYCRR to add a casing standard in coal development areas similar to the Pennsylvania Code at 25 Pa. Code §78.75, if there are sufficient coal seam intersection areas in NYS to warrant this additional requirement.

6. Intermediate Casing

Intermediate casing may be set if needed to provide a transition from the surface casing to the production casing. This casing may be required for protection of oil, gas, and freshwater zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may decide to set hundreds or thousands of feet of intermediate casing to isolate unstable hole sections (to prevent collapse), isolate high or low pressure zones, or isolate geologic "thief" zones that may be prone to robbing mud from the well bore (lost circulation), put gas or saltwater zones behind pipe before drilling into the production zone, or to provide additional wellbore structure.

Intermediate casing will be smaller than the surface casing (typically less than 14" in diameter) and will be lowered in the hole, and cemented in place using similar techniques as described for the surface casing.

Intermediate casing is typically set prior to drilling through the hydrocarbon bearing zone, and may be cemented behind the entire casing string from the top of the well to the bottom of the casing shoe if the intermediate casing depth is shallow enough. Intermediate casing provides a second protective barrier across a fresh water aquifer. However, it is not possible to cement the entire intermediate casing string if it is more than a few thousand feet deep. In this case the intermediate casing strings are partially cemented in place to secure the lower section of the pipe in place. Most states specify a minimum number of feet of cement placed behind the intermediate casing (e.g. 500').

6.1 Existing NYS Intermediate Casing Requirements

NYS does not include any specific intermediate casing standards in its regulations in the NYCRR. The general pollution prevention standard applies, as follows:

1. Pollution Prevention:
   The drilling, casing and completion program adopted for any well shall be such as to prevent pollution. Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited.[76]

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[74] 25 Pa. Code §78.75(d)
[75] 25 Pa. Code §78.75(e)
[76] 6 NYCRR V. B. §554.1(a-b)

NYS requires a permit to drill at 6 NYCRR V.B. §552, to which stipulations can be attached. NYS also requires the operator to file a ***Well Drilling and Completion Report*** listing information on the size, grade and type of casing and cement used.

NYS guidance informs the applicant that it must follow NYS's ***Casing and Cementing Practices*** guidelines when designing a well; however, there is no specific guidance on intermediate casing in this document. The guidelines state that:

> *Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.*[77]

NYS state places ***Fresh Water Aquifer Supplementary Permit Conditions*** on permits to drill, after reviewing the applicants casing program design. Typical conditions applied to intermediate casing are posted at the NYSDEC website and may include:

1. Pollution Prevention:
   If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval[78]*[emphasis added]*

Additionally, NYS state places ***Wildcat Supplementary Permit Conditions*** on permits to drill, for new, unique, or high pressure areas. Typical conditions applied to intermediate casing are posted at the NYSDEC website and may include:

1. Pressure Testing:
   When intermediate casing is used, the BOP, choke manifold and intermediate casing must be tested to at least the maximum anticipated shut-in surface pressure plus a 5% safety factor prior to drilling out the intermediate casing shoe. A representative of this office must be notified six (6) hours prior to each test and a department representative may be present during the test. If the Department representative is not on location at the agreed time, the test may proceed with the results of the test and the name of the witness being noted in the driller's log.[79]

6.2 Intermediate Casing Standard Recommendations for NYS

NYS's intermediate casing requirements are not specific or detailed. In the absence of regulatory standards or guidance, an applicant must submit a proposal for intermediate casing to NYS, and then wait for approval. The quality of the permit to drill and intermediate casing requirements will be a function of the quality of the operator's initial proposal, and NYSDEC's ability to negotiate or stipulate additional requirements to attach to the permit to drill.

[77] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html.
[78] NYS Fresh Water Aquifer Supplementary Permit Conditions at 6.
[79] NYS Wildcat Supplementary Permit Conditions at 5.

Many of the basic principles outlined above for surface casing should also apply to intermediate casing and are readily transferable, including, but not limited to, casing and cement quality, cementing methods, testing, record keeping and reporting.

> **Recommendation No. 16**: Consider amending the NYCRR to require casing and cement quality, cementing methods, testing, record keeping and reporting. This is especially true of the Marcellus Shale, where experience in Pennsylvania shows that industry recommends installing intermediate casing to provide an additional protective barrier in the wellbore, and to provide additional structural integrity.

A list of key intermediate casing provisions for Texas, California, Alaska and Pennsylvania is provided below, but it is hard to determine whether they compare to NYS, because NYS's requirements are not written and are currently subject to staff approval. Some of NYSDEC staff requirements for intermediate casing may mirror or include any of the other states' requirements, but the only way to verify that is to obtain copies of NYSDEC permits for wells that include intermediate casing and determine what type of requirements NYSDEC staff have included on a case-by-case basis. The lack of specificity in the NYS regulations for intermediate casing makes it impossible to conclude whether NYS's standards are sufficiently rigorous or not, since this determination is made on a case by case basis. While a permit may include site specific design and installation methods for intermediate casing, there are fundamental criteria that could be codified to clearly state when NYSDEC expects intermediate casing to be run, along with minimum technical requirements that must be met, and a list of technical issues that warrant NYSDEC staff review and approval.

> **Recommendation No. 17**: Consider amending the NYCRR to clearly explain under what circumstances NYSDEC will require intermediate casing to be set, what minimum requirements should be included in design and installation, and unique circumstances that warrant additional NYSDEC review and approval. Examples of how this regulatory goal was achieved in Texas, California, Alaska and Pennsylvania are provided in this report.

Texas regulations that may benefit NYS include:

1. <u>Cementing Method and Testing:</u>
   Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe up to a point at least 600 feet above the top of the shallowest productive horizon or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well. (B) Alternative method. In the event the distance from the casing shoe to the top of the shallowest productive horizon make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such possible productive horizons and prevent fluid migration to or from such strata within the wellbore.[80]

   When cementing any string of casing more than 200 feet long, before drilling the cement plug the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing string by 0.2. The maximum test pressure required, however, unless otherwise ordered by the commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be

[80] 16 TAC Part 1 §3.13(b)(3)(A)

condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes is proof that the condition has been corrected.[81]

California regulations that may benefit NYS include:

1. Requirement for Intermediate Casing:
   Intermediate casing. This casing may be required for protection of oil, gas, and freshwater zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards.[82]

   NYS's regulations include a basic requirement to install casing to protect freshwater zones, but do not specify other reasons for setting intermediate casing to prevent well control problems and potential blowout or spill hazards. California's regulations include a list of reasons for setting intermediate casing, but are also a bit weak in that the regulation only "may" require casing in these circumstances.

Alaska regulations that may benefit NYS include:

1. Requirement for Intermediate Casing:
   One or more intermediate casing strings must be set if required for protection of oil or gas or for protection against abnormally geo-pressured strata and lost circulation zones, or if otherwise required by well conditions.[83]

   If the intermediate or production string is a liner, a minimum of 100 feet overlap between the outer and inner strings is required; the interval of overlap must be made pressure competent and must be pressure-tested in accordance with (e) of this section.[84]

   Casing design and setting depth must be based on engineering and geologic factors relevant to the immediate vicinity, including the presence or absence of hydrocarbons, potential drilling hazards, and permafrost.[85]

   Alaska also sets general standards for when intermediate casing should be set.

2. Cementing Method:
   Intermediate and production casing must be cemented with sufficient cement to fill the annular space from the casing shoe to a minimum of 500 feet above all significant hydrocarbon zones and abnormally geo-pressured strata or, if zonal coverage is not required under (a) of this section, from the casing shoe to a minimum of 500 feet above the casing shoe; if indications of improper cementing exist, such as lost returns, or if the formation integrity test shows an inadequate cement job, remedial action must be taken.[86]

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[81] 16 TAC Part 1 §3.13(b)(1)(D)
[82] 14 CCR §1722.3 (c)
[83] 20 AAC §25.030 (c)(4)
[84] 20 AAC §25.030 (d)(6)
[85] 20 AAC §25.030(b)(1)
[86] 20 AAC §25.030(d)(5)

3. <u>Cement Quality Testing Requirement</u>
   If zonal coverage is required under (a) of this section, and the commission believes zonal isolation might not have been established, the commission will require a cement quality log or other method to demonstrate isolation of the zone.

   For intermediate or production casing in a service well used for injection, a cement quality log or other evaluation log approved by the commission must be run to demonstrate isolation of the injected fluids to the approved interval.[87]

Pennsylvania regulations that may benefit NYS include:

1. <u>Casing Type and Cementing Practice:</u>
   The operator shall determine the amount and type of casing to be run and the amount and type of cement to be used in accordance with current prudent industry practices and engineering. In making the determinations, the operator shall consider the following: (1) Successful local practices for similar wells. (2) Maximum anticipated surface pressure. (3) Collapse resistance. (4) Tensile strength. (5) Chemical environment. (6) Potential mechanical damage. (7) Manufacturing standards, including American Petroleum Institute or equivalent specifications for pipe used in wells drilled below the Onondaga formation or where blow-out preventers are required.[88]

   The operator shall install casing that can withstand the effects of tension, and prevent burst and collapse during its installation, cementing and subsequent drilling and producing operations.[89]

   Pennsylvania's regulations for intermediate casing essentially defer to industry standards, but set some specific criteria.

2. <u>Fresh Water Protection:</u>
   If additional fresh groundwater is encountered in drilling below the permanently cemented surface casing, the operator shall protect the additional fresh groundwater by installing and cementing a subsequent string of casing or other procedures approved by the Department to completely isolate and protect fresh groundwater. The string of casing may also penetrate zones bearing salty or brackish water with cement in the annular space being used to segregate the various zones. Sufficient cement shall be used to cement the casing at least 20 feet into the permanently cemented casing.[90]

   Typically surface casing is drilled to a depth below fresh groundwater and the surface casing is set. However, in areas where fresh water aquifers are not well mapped, surface casing may be set too soon. Drilling may resume below the surface casing shoe, encountering deeper fresh water aquifers. In this case, Pennsylvania's regulations require intermediate casing to be set to ensure any additional fresh water intervals are put behind pipe and a cement barrier is placed prior to drilling into hydrocarbon bearing zones.

[87] 20 AAC §25.030(d)(7)
[88] 25 Pa. Code §78.71(b)
[89] 25 Pa. Code §78.84(a)
[90] 25 Pa. Code §78.83(f)

7. Production Casing

Production casing is the last string of casing set in the well. It is called "production casing" because it is typically set across the hydrocarbon producing zone, but alternatively could be set just above the production zone.

If production casing is set across the hydrocarbon producing zone it is called a "cased hole" completion. In this scenario, production casing is lowered into the hole and cemented in place. Explosives are lowered inside the production casing (perforation guns) to perforate holes through the pipe/cement barrier to allow oil and/or gas to enter the wellbore. In some cases a drilling engineer may elect not to set production casing. This is called an "open hole" completion.

Production casing is used to isolate hydrocarbon zones and contain formation pressure. Production casing pipe and cement integrity is very important because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

Production casing is typically less than 9" in diameter; however, size is a site-specific, well-specific function and can vary.

7.1 Existing NYS Production Casing Requirements

NYS includes specific production casing standards in its regulations in the NYCRR, including:

1. Pollution Prevention:
   The drilling, casing and completion program adopted for any well shall be such as to prevent pollution. Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited.[91]

2. Cementing Method:
   If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing. In such instance, operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.[92]

NYS requires a permit to drill at 6 NYCRR V.B. §552, to which stipulations for production casing can be attached. NYS also requires the operator to file a ***Well Drilling and Completion Report*** listing information on the size, grade and type of production casing and cement used.

NYS guidance informs the applicant that it must follow NYS's ***Casing and Cementing Practices*** guidelines when designing a well; however, there is no specific language in the regulation requiring compliance with the guidance.[93] NYS's website states that the NYS ***Casing and Cementing Practices*** are minimum construction standards for all wells, unless a waiver has been approved by the regional minerals manager in response to a written request and justification.

[91] 6 NYCRR V.B. §554.1(a-b)
[92] 6 NYCRR V.B. §554.4(d)
[93] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html.

NYS ***Casing and Cementing Practices*** include several requirements for production casing:

1. Depth:
The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.[94]

2. Centralizers:
Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.[95]

3. Cement Method:
The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.[96]

4. Casing Quality:
The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.[97]

5. Cement Quality:
Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.[98]

6. Record Keeping and Variances:
When requested by the Department in writing, each operator must submit cement tickets and/or other documents that indicate the above specifications have been followed. The casing and cementing practices above are designed for typical surface casing cementing. The Department will require additional measures for wells drilled in environmentally or technically sensitive areas (i.e. primary or principal aquifers). The Department recognizes that variations to the above procedures may be indicated in site specific instances. Such variations will require the prior approval of the Regional Mineral Resources office staff.[99]

[94] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at12.
[95] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at13.
[96] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at14.
[97] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at15.
[98] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html at16.
[99] NYS Division's Casing and Cementing Practices, http://www.dec.ny.gov/energy/1628.html.

7.2 Production Casing Standard Recommendations for NYS

Overall NYS's production casing requirements are fairly robust, when the NYCRR, guidance documents and standard stipulations are combined.

Additionally, other state regulations examined in this report point to possible improvements and refinements. Selected regulations are listed below, where a state has a more stringent, or more detailed regulation, that may benefit NYS.

Texas regulations that may benefit NYS include:

1. <u>Cementing Method</u>:
   Cementing Method. The producing string of casing shall be cemented by the pump and plug methods, or another method approved by the commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at ***<u>least 600 feet above the shoe</u>****. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such possibly productive horizons by one of the methods specified for intermediate casing in paragraph (3) of this subsection*[100]*[emphasis added].*

   Texas requires an additional 100' of cement above the NYS standard for 500' for a total of 600' behind production casing. Most states require at least 500'. An additional hundred feet may be warranted in high angle wells and across high pressure zones.

Recommendation No. 18: Consider amending the NYCRR to increase the amount of cement required to a minimum of 600' behind production casing similar to Texas regulation at 16 TAC Part 1 §3.13

California regulations that may benefit NYS include:

1. <u>Cementing Method and Testing</u>:
   Production casing. This casing shall be cemented and, when required by the Division, tested for fluid shutoff above the zone or zones to be produced. The test may be witnessed by a Division inspector. When the production string does not extend to the surface, at least 100 feet of overlap between the production string and next larger casing string shall be required. This overlap shall be cemented and tested by a fluid-entry test to determine whether there is a competent seal between the two casing strings. A pressure test may be allowed only when such test is conducted pursuant to an established field rule. The test may be witnessed by a Division inspector.[101]

Recommendation No. 19: Consider amending the NYCRR to require production casing testing and minimum overlap length standards similar to the California Code of Regulations at 14 CCR §1722.

Alaska regulations that may benefit NYS include:

1. <u>Cementing Method, Quality and Testing</u>:
   Intermediate and ***<u>production casing</u>*** *must be cemented with sufficient cement to fill the annular*

[100] 16 TAC Part 1 §3.13(b)(4)(A)
[101] 14 CCR §1722.3(d)

space from the casing shoe to a minimum of 500 feet above all significant hydrocarbon zones and abnormally geo-pressured strata or, if zonal coverage is not required under (a) of this section, from the casing shoe to a minimum of 500 feet above the casing shoe; if ***indications of improper cementing exist, such as lost returns, or if the formation integrity test show an inadequate cement job, remedial action must be taken***[102] *[emphasis added].*

For intermediate or ***production casing in a service well used for injection, a cement quality log or other evaluation log approved by the commission must be run to demonstrate isolation of the injected fluids to the approved interval.***[103]

If zonal coverage is required under (a) of this section, and the commission believes zonal isolation might not have been established, the commission will require a cement quality log or other method to demonstrate isolation of the zone.[104]

Both NYS and Alaska require the operator to place at least 500' of cement behind production casing. Alaska's regulations add a quality standard, requiring remedial action in the case of poor cement quality.

Recommendation No. 20: Consider amending the NYCRR to add a cement quality, testing, and remedial repair standard similar to the Alaska Administrative Code (AAC) requirements at 20 AAC §25.030

Pennsylvania regulations that may benefit NYS include:

1. Casing Quality and Amount:
   The operator shall install casing that can withstand the effects of tension, and prevent burst and collapse during its installation, cementing and subsequent drilling and producing operations.[105]

   The operator shall determine the amount and type of casing to be run and the amount and type of cement to be used in accordance with current prudent industry practices and engineering. In making the determinations, the operator shall consider the following: (1) Successful local practices for similar wells. (2) Maximum anticipated surface pressure. (3) Collapse resistance.(4) Tensile strength. (5) Chemical environment. (6) Potential mechanical damage. (7) Manufacturing standards, including American Petroleum Institute or equivalent specifications for pipe used in wells drilled below the Onondaga formation or where blow-out preventers are required.[106]

Recommendation No. 21: Consider amending the NYCRR to add casing quality and amount standards similar to the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71.

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[102] *20 AAC §25.030(d)(5)*
[103] *20 AAC §25.030(d)(7)*
[104] *20 AAC §25.030(5)*
[105] *25 Pa. Code §78.84(a)*
[106] *25 Pa. Code §78.71(b)*

Technical Memorandum

Review and Analysis of DRAFT Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs
September 2009

December 28, 2009

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INTRODUCTION

The New York State Department of Environmental Conservation (NYSDEC) has prepared a Draft Supplemental Generic Environmental Impact Statement (DSGEIS) to consider the development of unconventional natural gas sources in the Marcellus Shale and other formations. This DSGEIS supplements the earlier (1992) GEIS that considered oil and gas development in the state. A supplemental analysis was needed to examine the additional potential impacts of the technologies proposed to be used in the Marcellus Shale and similar formations. Three supporting documents, Alpha**2 (2009), ICF (2009) and URS (2009) were prepared in support of the DSGEIS. The supporting documents are not particularly useful as additional sources, however, because the DSGEIS or its appendices present sections from the references virtually as written.

This review focuses on the water resource and hydrogeologic aspects of the DSGEIS and supporting documents. These primarily include the following:

- Contamination of aquifers and surface water sources, including from spills and from the fractured shale.
- Depletion of rivers, streams, and aquifers.

The review analyzes these elements and the proposed mitigation.

SUMMARY OF FINDINGS

The DSGEIS is poorly organized, which made it difficult to follow the thread of a subject. Often, a single subject was discussed in several chapters. The specific topics of this summary are aquifer contamination from the shale, the potential for spills, and the depletion of water sources as a result of water withdrawals for fracturing operations.

Aquifer Contamination from the Shale

Hydraulic fracturing changes the properties of the targeted shale by increasing the conductivity of the formation near the well so that it will release gas to the wellbore, but there is little data concerning the shale properties either before or after fracturing. To determine and verify the intrinsic properties of NYS shale formations prior to fracturing, industry should run well logs, collect core samples, and run appropriate geochemistry analysis of the cuttings and cores.

Fracturing by injecting fluids into the shale will cause conditions that make transport of contaminants from the shale to surface aquifers possible. The DSGEIS presents an erroneous analysis that concludes that contaminants in the shale are isolated and cannot reach the near-surface aquifers. A simple numerical analysis, completed in this review, demonstrated one simple conceptual flow pathway that would allow contaminants to reach overlying media; there are many other potential pathways. The transport may take decades or centuries, depending on conditions, but will occur much more quickly if the contaminants reach a zone of preferential flow.

According to the DSGEIS, fracturing operations average about 5.0 million gallons of fluid and about 65% of it does not return to the surface as flowback. The DSGEIS should explain the fate of this fluid.

No vertical offset would guarantee that contaminants will not flow from the shale to the aquifers. In areas with an upward gradient, the industry should complete adequate site-specific analysis for all well pads. The operator should determine the vertical gradient and media properties at the site with a core sample and water level measurements. The operator should then complete standard transport calculations to estimate the potential for contaminants to reach the surface aquifers. If the calculations based on measured data yield a travel time estimate of less than 500 years, the operator should be required to design the fracturing operation to end 25 feet shy of the edge of the shale and complete appropriate tests to verify that fractures did not reach into the overlying media. NYSDEC should require the industry to apply for an entire well pad or a series of adjacent well pads at one time. NYSDEC should also require more site specific data regarding the geology and additional analysis of vertical transport as outlined above in this section.

The potential for long-term contaminant transport to the near-surface aquifers is real, but determining exactly where the contaminants emanated from years into the future or assigning responsibility will be very difficult. NYSDEC should implement a long-term monitoring plan based on regional geology and flow and transport modeling to provide a lead time to identify the movement of contaminants and plan to mitigate such movement.

Contamination Due to Spills and Leaks

Hydraulic fracturing operations require that a large volume of fracturing fluid, or water chemicals, and propping agent, be stored on site in preparation for a fracturing operation. These could be spilled. Some of the water injected into the shale for fracturing will return to the surface as flowback. The operator must provide a means of capturing, handling, and storing the high volume of flowback which will occur at rates up to 130 gpm. NYSDEC appropriately proposes to require tanks at the well site to handle flowback. Because of the potential for leaks in the connection between the well and tank, the well pad should be set back from surface water sources by 2000 feet, and from domestic wells by 1000 feet, with a monitoring well system as described in the section concerning monitoring wells below (page 22).

The DSGEIS contemplates that centralized surface impoundments would be used to store flowback for substantial periods prior to treatment or for recycling. Use of surface impoundments is not recommended in this report, or by other NRDC experts and partner organizations. Closed-looped steel tanks and piping systems should be used for any centralized storage of flowback water because lined systems are subject to leaks.

In the DSGEIS, NYSDEC proposes that centralized impoundments use a double-liner system (or tank) with leak detection, with requirements based on landfill regulations. If permitted to be used at all, NYSDEC should require that centralized impoundments be

lined with a dual synthetic liner system and leak detection. Synthetic liners should have permeability of $1x10^{-11}$ cm/s. A GCL must have the equivalent conductivity of two feet of clay compacted to $1x10^{-7}$ cm/s. The leak detection system should not be designed as a drain, and be limited to 150 gpd for the entire unit, which may be a pond of many acres. All wells proposed to use such impoundments should be disclosed during the permitting process.

Leaks from the wellbores are another potential contaminant source. These could be leaks of methane gas or fracturing fluid. The DSGEIS basically ignores the potential for leaks, resting its failure to provide any analysis on an assertion that leaks have never been documented from properly constructed wells. This review documents incidents from other states, and from New York, where there have been leaks. NYSDEC must both evaluate and design a monitoring program which will detect contaminant movement before it affects nearby wells and must improve its design and inspection program so that wells actually are properly constructed.

The monitoring system should be vastly improved over the proposal of only monitoring existing domestic wells. Once contamination reaches these wells, it will be too late to prevent the degradation. NYSDEC should instead require dedicated, properly-screened monitoring wells between the well pads and nearby domestic wells. Monitoring should continue well beyond the end of production because of the long-term potential for transport from well pads to wells.

Depletion of Water Sources for Fracturing Fluid

The large amounts of water withdrawn from streams or rivers for fracturing may affect downstream surface waters by depleting flows sufficiently to affect public water supplies, natural habitats, and water quality during low flows. The discussion of withdrawals for fracturing downplays their potential impacts by considering the withdrawals only in the context of large river basins.

Four different areas regulate instream flows and the impacts on surface water differently. The primary mitigation for such impacts is the application of passby flow requirements. The Delaware River Basin Commission does not have a specified method for determining passby flow requirements and the Susquehanna River Basin Commission's method allows diversions at very low flow rates, even those approaching the ten-year low flows. These approaches are not protective of habitat. The Natural Flow Regime Method (NFRM), proposed for application in the area regulated by NYSDEC, would limit diversions during normal low flow periods and is to be preferred to the other methods discussed in the DSGEIS. However, the NFRM would still allow significant habitat degradation.

Diversions should be allowed only when aquatic habitat will be minimally affected. This standard would permit water withdrawals when the flow rate achieves a water level at or above the point where the wetted perimeter/flow area ratio is a minimum. The 30% of average daily flow proposed in the DSGEIS is only reasonable as long as the minimum

passby is 30% of average monthly flow which is essential to protect wet season flows responsible for channel forming processes. These recommendations may prevent diversions during much of the latter half of the summer and early autumn when the aquatic ecosystems are most stressed. The gas industry could be allowed to make diversions in advance of its late summer needs and store the water in tanks, lined ponds, or other reservoirs if the timing is going to be an issue.

Industry may propose to withdraw groundwater instead of or to supplement its surface water withdrawals. Most of the proposed mitigation provisions merely require that well operators report their pumping rates if they exceed certain levels, which vary among the various regulatory authorities who have jurisdiction in different areas that will have this development. Mere reporting is insufficient to protect the aquifer resource and its discharge to surface water. Calculating the direct effect in advance, based on pump tests or flow analysis (analytic or numerical model), is necessary but fraught with uncertainty. Trying to prevent the effects of a groundwater diversion on surface water flows requires a travel time or lag time consideration which adds uncertainty to the calculation.

NYSDEC should specify a limit to the amount of water that can be diverted from an aquifer based on the expected recharge to that aquifer. NYSDEC should also specify the conditions under which the withdrawal of sufficient water for fracturing would be a "depletion" of an aquifer or "potential" aquifer. A 5,000,000 gallon depletion is more than would be removed in a year by 15 domestic wells and could have significant impacts on the water balance of a small aquifer.

ANALYSIS

Contamination of Aquifers

Hydrogeology of the Marcellus Shale Area

The DSGEIS lacks a decent discussion of the base hydrogeology on which all of the proposed new gas development would be imposed. Such a discussion should be part of the basic description of the potentially affected environment and should occur prior to any analysis of the impacts from development. The absence of basic information is a problem because, without it, the DSGEIS cannot explain how the changes wrought by hydraulic fracturing may affect the groundwater flows and contaminant transport.

The project area is approximately the southern third of New York. Chapter 4 generally describes the geology, in particular the stratigraphy of formations showing that the Marcellus (and Utica) shale outcrop in the north and dip to near 5000 and 9000 feet, respectively. There is a very brief discussion of the conductivity in black shale (DSGEIS, page 4-4). That is the extent of the discussion. This DSGEIS should, as most environmental impact statements do, include a thorough discussion of the relevant hydrogeology, including:

- Properties of the formations, both target and intermediate;

- Flow properties and rates;
- Formation hydraulic properties;
- Groundwater levels for various formations;
- Discharge points, including springs, seeps, streams, and wetlands;
- Recharge rates and primary zones; and
- Water balance for the area including estimates of recharge, discharge, and pumping (the discussion of the number of wells does not include an estimate of pumping rates).

Formation properties are the most important. From a gas production perspective, porosity is an important parameter because it represents void spaces in which natural gas may be stored (Hill et al, 2003). The DSGEIS (page 4-4) indicates the Marcellus Shale porosity varies to 18%, a wide range also reflected in other literature. Permeability is another important parameter. Permeability is the intrinsic property of a medium to transmit a fluid, a function of the size of the openings through which fluid flows (Fetter, 2001, page 83). Low permeability also limits gas production (Arthur et al, 2008).

There are two types of permeability: matrix and fracture[1]. Matrix (or intrinsic) permeability is that found in unaltered rock (shale) and fracture permeability occurs in zones where the shale is fractured. Unfractured Marcellus Shale is very impermeable, with matrix permeabilities ranging from 0.01 to 0.00001 millidarcies (Arthur et al, 2008). For water at 15.6°C, this range is 0.000027 to 0.000000027 ft/d[2]. Unfractured shale is clearly an aquitard, but the Marcellus is not unfractured (Engelder et al, 2009). The only sample permeabilities for Marcellus Shale discussed within the DSGEIS convert to a conductivity ranging from 0.000011 to 0.00059 ft/d (DSGEIS, page 4-3). The larger end of this range would allow Darcian flow over a unit gradient for 100 years to be 21.5 feet. This may not seem like much distance at first consideration, but it represents the upper value of a range determined from just three samples; there are likely much higher values to be found throughout the “notoriously” heterogeneous shale (Boyer et al, 2006). It also represents an in-situ value to be found before fracturing occurs. Fracturing will likely increase the conductivity by two orders of magnitude, based on calculations in Appendix B, not including large fractures. For a unit gradient, the potential distance traveled in 100 years increases to greater than 2100 feet. Note that this is an illustrative comparison intended to demonstrate the difference in conductivity caused by fracturing. It is not an estimate of contaminant travel because the shale does not extend for that distance, fracturing does not change the conductivity that far from a wellbore, and there is not likely a unit gradient present in the shale before or after fracturing.

The in-situ conductivity is much greater in the horizontal direction than in the vertical directions because of the horizontal bedding. With horizontal drilling and hydraulic fracturing, conductivity in the vertical direction may be increased because fractures emanate perpendicular to the well transmitting the stresses.

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[1] Permeability should not be confused with conductivity which is fluid-type dependent; viscous oil flows more slowly through a formation than does water.

[2] A darcy consists of units of area with 1 darcy ≈ 10-8 cm^2. The conversion for pure water at 15.6°C is 2.7388 ft/d/darcy.

Recommendation: The DSGEIS must discuss the intrinsic properties of the shale, including porosity and permeability, and how hydraulic fracturing will change these properties. The DSGEIS should include data from other states that are developing the Marcellus and other black shales.

Hydraulic Fracturing

Hydraulic fracturing is the process by which large volumes of water, sand, and chemicals are injected at high pressure into the shale to increase the size of fractures and to cause new fractures. The amount of water used for fracturing the horizontal wells expected to be required in New York is the primary difference, according the NYSDEC, between these proposals and the natural gas production analysis in the 1992 GEIS. Horizontal drilling allows multiple wells to be developed from one pad. The length of each horizontal well will vary but may exceed 3,500 feet (DSGEIS, page 5-19).

Fracturing will be accomplished in stages commencing at the outer end of the wellbore; each stage will use from 300,000 to 600,000 gallons of fracturing fluid resulting in a total of 2.4 to 7.8 million gallons used to fracture each well, depending on the number of stages used and the amount of water used in each stage (DSGEIS, page 5-93). There will be from eight to thirteen stages ranging from 300 to 500 feet in length (*Id.*). The DSGEIS should reference the source for this information because it clearly varies among wells.

Each fracturing operation will require from two to five days and that high pressure (up to 10,000 psi) pumping at rates up to 3000 gpm would occur for from 40 to 100 hours of that time (DSGEIS, pages 5-93, -94). The DSGEIS should document these numbers with actual data or references to studies because the rates affect the environmental impacts and therefore the analyses.

There is a statement that seepage from the wellbore occurs at rates less than 10 feet per day and that only during pumping is there pressure for flow away from the wellbore:

> The time spent pumping is the only time, except for when the well is shut-in, that wellbore pressure exceeds pressure in the surrounding rocks (sic). Therefore, the hours spent pumping is the only time that fluid in fractures and in the rocks surrounding the fractures would move away from the wellbore instead of towards it. ICF International, under contract to NYSERDA, estimated the maximum rate of seepage in strata lying above the target Marcellus zone. Under most conditions evaluated by ICF, the seepage rate would be substantially less than 10 feet per day, or 5 inches per hour of pumping time. (DSGEIS, page 5-94)

This statement is incorrect for many reasons which are described in detail in Appendix D, a detailed review of ICF (2009). Basically, the description does not accurately describe the process because injection commences a pressure wave that moves away from the wellbore during injection and does not dissipate immediately, as outlined in Appendix A

and Appendix D. It is analogous to pumping from a confined aquifer – when pumping ceases, the drawdown at the well recovers quickly, especially initially, but the lateral extent of drawdown continues to expand.

The flowback of fracturing fluid could be up to 35% of 7.5 million gallons, based on numbers provided in the DSGEIS, for a total of about 2.7 million gallons. A U.S. Geological Survey Fact Sheet contradicts this statement: "For gas to flow out of the shale, nearly all of the water injected into the well during the hydrofrac treatment must be recovered and disposed of" (Soeder and Kappel, 2009, page 4). *The NYSDEC must consider the USGS study and explain why there is such a difference between the DSGEIS and USGS fact sheet.*

What would occur to the 65% or more of the fluid injected into the shale that does not return as flowback? A cylinder ½ mile long with 50 foot radius and 15% porosity could contain 23,000,000 gallons if all of the pores filled with fracture fluid. This is at least three times the amount of fluid expected to be injected, so the fluid does not reach all of the potential pores (many references indicate that although the pores are very small the porosity of shale ranges to 18%). The pore fluid that does not return must become bound in the pores, but Soeder and Kappel (2009) suggest this decreases the gas yield.

Recommendation: The DSGEIS must discuss the fate of the fracture fluid that does not return to the wellbore as flowback.

Properties of the Fractured Shale

Unfractured shale has a very dense matrix with some, mostly vertical, fractures (Engelder et al, 2009), which are loosened by hydraulic fracturing. The DSGEIS does not discuss just what the fractured shale will look like – what its properties will be. It should discuss how the fractures grow – vertically, horizontally, in a dendritic pattern, or otherwise; ICF (2009) describes some of the growth which increases the porosity and changes the permeability to allow more gas and groundwater to flow.

Recommendation: The DSGEIS should discuss how fracturing will change the properties of the shale and how these changed properties will affect flow through the system.

One major problem in the DSGEIS is the lack of data regarding the shale, both in-situ and after fracturing. As noted above, the DSGEIS depends on just three cores to describe the shale properties across all of NYS, even though it is very heterogeneous. Because the development would likely continue for years, the industry, State, and public can learn from experience, but only the industry collects data and makes it made publicly available, as required by the Bureau of Land Management (2007) for natural gas and oil development.

Recommendation: NYSDEC should require the industry to collect shale cores and well logs from the drilled wells and determine the intrinsic properties for shale in New York. Industry should run well logs for the entire well, including the vertical sections, and

submit them to the NYSDEC and public, so that the formations between the shale and freshwater aquifers can be better understood prior to fracturing.

ICF (2009) described the many uncertainties inherent with fracture modeling. ICF pointed out that the properties used for the modeling are heterogeneous but that the industry usually does not consider that heterogeneity. The use of incorrect parameters in the modeling or the presence of unanticipated faults or natural fractures may cause the hydraulic fracturing to extend beyond the width of the shale into the surrounding formations. Although industry does not want that to occur, none of the DSGEIS documents discuss the actual occurrence of fracturing errors – it is not even disclosed whether the industry knows when such an error occurs.

Recommendation: Because fracturing that reaches adjacent formations could be a source of contamination, NYSDEC should require that at least some of the fracture operations monitor the extent of the fractures and report back to the NYSDEC (and public). The report by Harvey Consulting, LLC, reviews methods for assessing the extent of fractures..

The DSGEIS does not discuss the extent of the shale that will be affected by fracturing. This depends on the distance from a horizontal well that fractures propagate during a fracturing operation, the density of horizontal wells, and the overall proportion of the shale that is developed (dependent on the total amount of the shale that is leased). Ultimately, the extent of the affected shale will be the shale that will have its permeability and porosity changed by hydraulic fracturing, and that could have fluids, both fracturing and brine, released into the overburden, as discussed in the next section on Subsurface Contamination. This is also the extent of the shale which should be monitored for upward contaminant movement, as also discussed in the following section.

Recommendation: The DSGEIS should discuss the amount of Marcellus shale that will ultimately be affected by fracturing. Because the final amount will depend on the success industry has in developing the gas, the DSGEIS should discuss the factors that will ultimately control the extent of development.

Subsurface Contamination: Vertical Transport from Targeted Shale

The DSGEIS claims that “hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers by movement of fracturing fluids out of the target fracture formation through subsurface pathways when certain natural conditions exist” DSGEIS (page 6-37). These conditions were specified as:

- Maximum depth to the bottom of a potential aquifer ≤ 1,000 feet;
- Minimum depth of the target fracture zone ≥ 2,000 feet;
- Average hydraulic conductivity of intervening strata ≤ 1 x 10^{-5} cm/sec; and
- Average porosity of intervening strata ≥ 10%.

This means that NYSDEC does not see a risk if the aquifer is less than 1000 feet bgs and the target shale exceeds 2000 feet bgs so that there is a minimum of 1000 feet of intervening strata with hydraulic conductivity less than $1x10^{-5}$ cm/s, or 0.028 ft/d. These conclusions are based on an analysis completed by ICF \ and summarize in DSGEIS Appendix 11 and section 5.11.1.1. The analysis leads to inappropriate assurances because it makes poor assumptions and fails to consider the actual problem.

Appendix D reviews ICF (2009) in detail. Appendix A provides a detailed numerical analysis of potential transport from the shale into the overlying formations.

The basic conclusions used in the DSGEIS to claim there can be no transport from the shale to the aquifers are presented it DSGEIS 5.11.1.1. Each of these conclusions, repeated in *italics*, is discussed below:

● *The developable shale formations are separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low conductivity.* This is true, but there are also fractures, faults and improperly plugged wells that could facilitate transport. It is unnecessary for a single fracture network to provide for the entire pathway to the surface. It is shown in Appendix D that advective transport can move substantial contaminants from the shale to the aquifer within a period of decades through centuries.

● *The fracturing pressures which could potentially drive fluid from the target shale formation toward the aquifer are applied for short periods of time, typically less than one day per stage, while the required travel time for fluid to flow from the shale to the aquifer under those pressures is measured in years.* This argument is conceptually wrong – it depends on a misunderstanding of the basic hydrogeology of the formations above the shale, the existing groundwater gradients, and the effect that injection would have on the flow pathways. The analysis assumes that the relevant gradient is between the wellbore and the level of the freshwater aquifer during the period that injection occurs. Because of the distance and low conductivity, there is no hydraulic connection between these points so a gradient calculated between them is irrelevant. During the time period of injection, the relevant gradient is between the wellbore and the extent of the outwardly flowing fluid (Appendix A). Over the distance, the pressure drops from the high pressure at the well to near background levels just beyond the extent of the shale being affected by the injection. Beyond that point, the shale effectively is unaffected by the injection and any gradient between the well and that point is meaningless. Even within the zone of elevated pressure, the gradient is extremely transient and varies along the profile according to the slope of the pressure versus distance from the well relationship (Appendix A). What is relevant is how the transient flow and pressure changes, effectively a pressure shockwave, drive flow from the shale into the surrounding formations. After that the natural gradient and dispersion may continue to drive the contaminants upward. Simple calculations in Appendix A showed that thousands of cubic feet of fluid could be transported from the shale.

It is not necessary for the injection process to drive the contaminants all the way to the freshwater aquifers. Long-term movement, which could take years or even decades,

would cause contaminant transport that will create problems in the future. A long-term potential for contaminant movement from the shale to aquifer zone should be part of the planning for gas development.

The DEIS should map head levels in various formations through the Marcellus Shale zone so that areas of potential vertical flow can be mapped. These are the areas in which contaminants could move from fractured shale to aquifers. This is discussed below under the section regarding setbacks starting on page 23.

● *The volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer.* Contaminant transport does not rely on replacing the fluid between the source and the receptor. Contaminants disperse into the existing fluid and move according to the principles of contaminant transport – advection and dispersion. See the discussion below under the "*Diffusion of the chemicals*…" bullet point.

● *Some of the chemicals in the additives used in hydraulic fracturing fluids would be adsorbed by and bound to the organic-rich shales.* This is correct, but the DSGEIS states that these properties are not known for fracturing fluids. Unless there is test data showing attenuation or adsorption, the DSGEIS should not state or even imply that these processes will diminish the potential for contaminant transport. Additionally, diffusion into a rock matrix may be confused with attenuation only to have the contaminant diffuse back into the general flow after the contaminant source has depleted; in other words, diffusion may retain contaminants, only to release them later.

● *Diffusion of the chemicals throughout the pore volume between the shale and an aquifer would dilute the concentrations of the chemicals by several orders of magnitude.* This argument suggests that the fluids escaping from the shale would be evenly dispersed among all of the pores between the shale and the aquifers. ICF suggests the concentration would be diluted by 300 times. This argument ignores the basic concepts of contaminant transport theory – flow occurs by advection and dispersion, the contaminants do not diffuse through the entire groundwater body between the source and receptor.

Contaminants moving from the shale to the overlying formations would resemble the transport of a slug of contaminants which would advect along with the general flow gradient, which would have an upward component if there is an upward gradient. A slug of contaminants is a mass of contaminants injected at a point in a flow system over a short time period (Fetter, 1999, page 70). Along the flow pathway, the slug would disperse so that the concentration decreases as the plume spreads out (Fetter, 1999, pages 70-74) but it would not have equivalent concentrations at the top of the shale and the bottom of the freshwater aquifer, as assumed in the DSGEIS and by ICF (2009). If just one fracturing operation injects fluid that reaches the formation above the shale, an expanding plume will move upward toward the aquifer. Preferential flow pathways may speed the flow in some areas and low permeability zones may impede it. Unless such a low permeability zone is continuous, it is risky to rely on it and assume that no

contaminants reach the freshwater. The final concentration reaching the aquifer will depend on aquifer properties, but transport of a significant mass of contaminant over a few thousand feet is not uncommon at waste sites (Fetter, 1999, 2001).

While the argument presented herein considers strictly vertical flow, there would likely be a horizontal component to the flow. This additional component would add uncertainty to the prediction of where the contaminants reach the surface which would by confounded by the cumulative effect of multiple fracturing operations over time.

The analysis above treated the source as a one-time slug of material, but there is another possibility. The shale could become a source of brine to the overlying formations that would last for a significant time period. Although gas production may create a small drawdown that would prevent some flow from the shale to the surrounding formations, because of the complex fracture patterns to be expected, it is also possible that further from the wellbore there could be less of chance for the production to establish a gradient toward the wellbore.

● *Any flow of frac fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow toward the production zone as pressures decline in the reservoir during production.* This is not correct because the influence of both the injection pressure and negative pressure created during production will not extend far beyond the shale. If contaminants are flowing away from the shale in a fracture, driven by a natural gradient, the production well drawdown will not reverse it. The next section summarizes the results of a simulation of the development and dissipation of pressure and the flow of water away from the shale.

DSGEIS section 7.1.5 notes the following assumptions were necessary to argue there is no potential for transport from the shale to surface aquifers:

> As explained in Section 6.1.5.2, the conclusion that harm to freshwater aquifers from fracturing fluid migration is not reasonably anticipated is **contingent upon the presence of certain natural conditions**, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone. In addition, as stated in Section 5.18.1.1, GWPC recommended a higher level of scrutiny and protection for shallow hydraulic fracturing or when the target formation is in close proximity to underground sources of drinking water. (DSGEIS, page 7-49, emphasis added)

NYSDEC's "conclusion" depends on certain natural conditions, but there is really no way to verify whether these conditions occur prior to drilling. Without permeability testing of the formations between the shale and aquifers, NYSDEC cannot know the properties of the sandstone or shale, which can be very heterogeneous – see DSGEIS Appendix 11, Table 4.

Interpretative Numerical Analysis

The DSGEIS' discussion on transport from the shale to surface layers is very basic and includes inaccurate assumptions. Using a numerical model, it is possible to consider more of the complexities involved with the potential transport. Appendix A contains an interpretative numerical analysis (Hill and Tiedeman, 2007) of the potential for fracturing to cause contaminants to move from the shale into surrounding formations. This analysis was completed to consider whether fracturing could cause contaminants to move from the shale to the overlying formations. Details of the numerical analysis, including the formation properties and descriptions of fracturing, are based on those provided by ICG (2009) and the DSGEIS. The numerical analysis included the injection of 5,000,000 gallons of fluid over five days into a layer of shale 100-feet thick; it also simulated flowback into the well for 60 days after injection. The model simulated the development of 28,000 feet of head at the well which corresponds with the pressure reported by industry during fracturing, its dissipation after injection, and the movement of fluid into surrounding formations. The model analysis is simple, but more complex than that completed by ICF (2009). The model considered conductivity values as reported in the DSGEIS for the shale and overlying formations and changed conductivity in the shale due to fracturing. Appendix A contains the details of the analysis, summarized here:

- It is possible to simulate the transient stresses caused by short-term, high-pressure injection in a low-conductivity aquifer.
- The model simulates the very high pressure created at the well by injecting fluid into the shale.
- The injection creates a very substantial pressure gradient, or head drop, from the point of injection to the overlying media.
- The head drop within the overlying media during and after injection is less than within the shale due to higher conductivity.
- The head drop dissipates as the pressure propagates through the shale and overlying media.
- There is substantial flow from the shale into the overlying media.
- The model overestimates the flowback which indicates the actual advective transport to the overlying media could be much higher than simulated because more of the fluid would remain underground in reality.

Once contaminants leave the shale and reach the overlying formations, advective transport and contaminant dispersion would control their movement according to the geology and gradients in that media. Additional shale layers could further contain it, but fractures could enhance its transport upward or laterally. These processes are beyond the scope of the analysis. A simple advective transport analysis assuming various reasonable gradients and sandstone thicknesses, conductivities, and porosity values yielded contaminant transport times ranging from a couple decades to centuries for transport over 4000 feet. It is apparent that any contaminants, fracturing fluid or shale brine, reaching the overlying formations, may reach the freshwater aquifers in a time frame that should concern NYSDEC.

Recommendation: NYSDEC must fully evaluate and consider the following in the DSGEIS.

- *Fracturing would likely cause contaminants to seep beyond the bounds of the shale.*
- *Natural gradients and properties in the overburden above the shale could allow the contaminants to continue to move upward according to the complexities of geology at that point.*
- *The potential flow from shale into surrounding formations should be analyzed and an accurate risk analysis of the potential for transport from the shale to the aquifers should be provided.*

Surface Contamination: Onsite Surface Storage of Fracturing Fluid and Flowback

Hydraulic fracturing operations require a large volume of fracturing fluid be stored on site in preparation for a fracturing operation. Based on the pumping rates discussed above, there could be up to 7,800,000 gallons required for a two-to-five day period with injection at rates approaching 3000 gpm. Because it is unlikely that sufficient water can be delivered fast enough, most of the fluid necessary for fracturing must be stored on site, having been delivered prior to the commencement of fracturing. Water will likely be stored onsite for fracturing operations in "500-barrel steel tanks" (DSGEIS, page 5-76). A 500-barrel tank holds up to 21,000 gallons, therefore more than 350 such tanks would be required for the largest operations. The DSGEIS does not discuss how the fracturing fluid will be mixed or be stored onsite in preparation for fracturing.

Recommendation: The DSGEIS should describe in detail how the water and fracturing fluid additives are mixed at the well and how or where they are stored prior to injection into the well.

The total flowback volume was discussed above; the operator must provide a means of capturing, handling, and storing the high volume of flowback expected to discharge from the well after a fracturing operation. According to NYSDEC, most flowback occurs within two to eight weeks with 60% returning within four days (DSGEIS, page 5-99, 100). Flowback will occur after each fracturing stage, a problem mentioned above regarding the potential for flowback and injection at the same time. Flowback from wells in PA has ranged from 60 to 130 gpm (DSGEIS, page 5-100).

Recommendation: Observed flow rates should be collected along with well depth and horizontal well length; a relationship of flowback rate with depth and length of bore exposed could be used to predict the rates to be experienced in New York. This would help the operator, regulators, and interested public prepare for capturing and treating the flowback.

It is difficult to discern in the DSGEIS exactly what is required for capturing and storing flowback. There are two different storage requirements for flowback, onsite in tanks and in offsite centralized impoundments, which are discussed in the next section. NYSDEC

proposes to require tanks at the well site to handle flowback from the well (DSGEIS, page 5-101). As discussed in section 7:

> The GEIS addresses use of the on-site reserve pit for flowback water associated with a single well. However, even in the single-well case, potential flowback water volumes associated with high-volume hydraulic fracturing exceed GEIS descriptions. Estimates provided in Section 5.11.1 are for 216,000 gallons to 2.7 million gallons of flowback water recovered within two to eight weeks of hydraulic fracturing a single well. The volume of flowback water that would require handling and containment on the site is variable and difficult to predict, and data regarding its likely composition are incomplete. Therefore, the Department proposes a requirement that flowback water handled at the well pad be directed to and contained in steel tanks. Even without this requirement, the pit volume limitation proposed above would necessitate that tank storage be available on site. (DSGEIS, pages 7-34, -35)

There is no discussion about the volume or number of tanks other than "[t]he EAF Addendum will require information about the number, individual and total capacity and location on the well pad of receiving tanks for flowback water" (DSGEIS, page 7-35). The lack of discussion and disclosure in the DSGEIS regarding exactly how the operators will capture and temporarily store the flowback is unacceptable, especially because it is at this stage in the operations that spills may be most likely to occur.

Recommendation: The DSGEIS must discuss the expected number and volume of tanks to be expected, and permitted, at a well site.

Recommendation: The DSGEIS should discuss how the flowback will be conveyed from the well to the tanks. This is where spills would potentially occur. It may be the primary cause of spills for which setbacks would be required, as discussed below (page 37).

Surface Contamination: Centralized Impoundments

NYSDEC apparently proposes to allow centralized surface impoundments to serve more than one well pad to store flowback in the longer term prior to treatment or for recycling:

> Operators may propose to store flowback water prior to or after dilution in the onsite lined pits or tanks discussed in Section 5.11.2, or in centralized facilities consisting of tanks or one or more engineered impoundments. Water would be moved to and from the centralized facilities by truck or pipeline. Operators have informed the Department that centralized impoundments constructed for this purpose would range in surface area from less than one acre to five acres, and would range in capacity from one to 16 million gallons. Depending on topography, such impoundments would serve well pads within up to a four-mile radius. (DSGEIS, page 5-115)

Most of the DSGEIS discussion regarding the storage of flowback water concerns these impoundments. This section will review some of the hydrologic and water quality issues associated with the impoundments and make recommendations for proper construction and design in case NYSDEC allows their use.

Centralized impoundments for the storage of flowback, if allowed at all, must be permitted as part of the permit process for the first gas well that will utilize that impoundment (DSGEIS, page 7-51). As part of the permit process, however, the DSGEIS should require that all wells proposed to use the impoundment be disclosed as part of the initial permitting process so that the total volume and rates of flow to be expected can be analyzed.

The DSGEIS specifies design requirements based on an assumption that the facilities will be temporary (DSGEIS, page 7-54). The DSGEIS must specify what is meant by "temporary" because NYSDEC is proposing to impose design requirements that are less stringent than usual on the grounds that the impoundments will be temporary.

Centralized impoundments would be open to the air. The NYSDEC should establish regulations that make it illegal for open waters in these ponds to kill wildlife species, primarily birds. Whether the flowback "is probably not acutely toxic to waterfowl" (DSGEIS, section 6.4.2) as Division of Fish, Wildlife and Marine Resources (DFWMR) staff "believe", the water quality could vary – the onus should be on industry from the beginning to prevent birds from using the water. The Federal Migratory Bird Treat Act, 16 USC 701-718, makes it unlawful to kill migratory birds without a license or permit, and no permits are issue to take migratory birds using toxic ponds.[3]

Single liner systems, described in Chapter 6, leak easily and should not be allowed under any circumstances. A liner will experience rapid head changes which would cause rapid flow through any breach in the liner (DSGEIS 6-38 and -39). A single liner provides no backup for a leak.

NYSDEC will therefore require a *double-liner system (or tank)* (DSGEIS, section 7.1.7), for centralized impoundments. The design could be significantly improved and better described. NYSDEC determined that the "existing regulatory structure established for solid waste management facilities, 6 NYCRR Part 360 (Part 360), is most applicable for the containment, operational, monitoring and closure requirements for centralized flowback water management facilities" (DSGEIS, page 7-52) based on its opinion that flowback water quality compares with landfill leachate and that the liner requirements "have been proven through time to be conservative and, more importantly, have been determined to provide the requisite level of protection to ensure preservation of the ground water quality resources at solid waste management facilities throughout the State" (*Id.*). This is an unsupported claim and should not be included in the DSGEIS without reference and/or supporting data.

[3] The language of this sentence is from a Fact Sheet issued by the Nevada Division of Environmental Protection for the renewal of a water pollution control permit – they use this language for all mines so a specific reference is not necessary.

Even if the flowback water quality is similar to that of landfill leachate, another unsupported statement, there are differences between containing liquid and solid waste, even if saturated. If filled to the same level, the head on the liner will be same for each system, but the difference is the volume and speed at which pure fluid can report to a liner leak. Fluid will flow through the solid waste to a leak at rates controlled by the conductivity of the waste whereas in a liquid-filled pond there will be no similar control on the flow rate. The DSGEIS, before using regulations for solid waste liners to hold flowback fluid, must support the decision with analysis.

Based on the impoundments being temporary, the DSGEIS proposes to allow a dual synthetic liner system rather than the permanent dual liner system required by state landfill regulations. "However, the relative short-term nature of the surface impoundments compared to landfills and the anticipated quality of the flowback waters supports use of subdivision 360-2.14(a) to allow, at the design engineers discretion, the substitution of a geosynthetic clay liner (GCL) in lieu of the 2-foot thick compacted clay barrier in the composite" (DSGEIS, page 7-54). This may be acceptable if there is a suitable substitute, but the DSGEIS is not clear about the difference between permanent and temporary, therefore the DSGEIS must specify how long an impoundment may be in operation to qualify for using a GCL in lieu of compacted clay. This would also be required to satisfy NYSDEC §360-6.2 which requires the applicant to specify the fluid to be stored, its volume, and a schedule for its removal. This last requirement, detailed at §360-6.2(c), would require the applicant to specify the length of time the impoundment will be used.

The proposed double liner description is very confusing: "The GCL must be directly below a geomembrane, which in turn would be overlain by an appropriately designed and specified geocomposite drainage system. The drainage system must be designed to be free flowing and be capable of monitoring flows for liner performance. Above this leak detection layer would be **another** geomembrane liner that would be selected by the design engineer to address durability matters associated with exposure concerns if the upper geomembrane is left exposed." (DSGEIS, page 7-54, emphasis added). This appears to require two geomembranes and a GCL, with a "geocomposite drainage system" between the two geomembranes.

The regulations require that impoundments expected to be in use for a long time use a 60-mil geomembrane over and be in contact with 2 feet of compacted clay (NYSDEC §360-6.5). The DSGEIS does not state the requirements for conductivity in the compacted clay, but NYSDEC regulation §360-6.5[4] shows that the compacted clay must have

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[4] §360-6.5 Surface impoundment requirements.(a) Any surface impoundment must be constructed a minimum of five feet above the seasonally high groundwater table, and a minimum of five feet of vertical separation must be maintained between the base of the constructed liner and bedrock.(b) Surface impoundments subject to this Part must be constructed with a liner system consisting of a minimum of two liners and a leak-detection system as follows:

(1) The top liner must be a geosynthetic liner with a minimum thickness equal to 60 mils. Ballast material, such as rounded gravel or sand, that will not cause damage to the geosynthetic liner must be placed on top of the liner to preserve liner integrity.(2) A leak detection and removal system must be installed between the two synthetic liners.

maximum conductivity of 1×10^{-7} m/s, or 0.028 ft/d. Flow could pass through this in less than a year; at a unit gradient, which would be the gradient with ponding on the liner and no tailwater, flow would pass in 71 days.

The statement at DSGEIS, page 7-54, "[t]he lowermost liner for a centralized flowback water surface impoundment must be a single composite liner and may be designed with a GCL in lieu of the 2 foot thick compacted low conductivity soil (1×10^{-7} cm/sec) specified in regulations" is appropriate except that the regulations it refers to in the heading of the section allow for a conductivity two orders of magnitude higher. Also, the geosynthetic clay liner, proposed as a substitute, must be used with care. The following abstract presents just a small representation of the problems with the liners:

> Samples of geosynthetic clay liners (GCLs) from four landfill covers were tested for water content, swell index, hydraulic conductivity, and exchangeable cations. Exchange of Ca and Mg for Na occurred in all of the exhumed GCLs, and the bentonite had a swell index similar to that for Ca or Mg bentonite. Hydraulic conductivities of the GCLs **varied over 5 orders of magnitude regardless of cover soil thickness or presence of a geomembrane**. Hydraulic conductivity was strongly related to the water content at the time of sampling. Controlled desiccation and rehydration of exhumed GCLs that had low hydraulic conductivity (10^{-9} to 10^{-7} cm/s) resulted in increases in hydraulic conductivity of 1.5–4 orders of magnitude, even with overburden pressure simulating a 1-m-thick cover. Comparison of these data with other data from the United States and Europe indicates that exchange of Ca and/or Mg for Na is likely to occur in the field unless the overlying cover soil is sodic (sodium rich). The comparison also shows that hydraulic conductivities on the order of 10^{-6} to 10^{-4} cm/s should be expected if exchange occurs coincidently with dehydration, and the effects of dehydration are permanent once the water content of the GCL drops below approximately 100%. Evaluation of the field data also shows that covering a GCL with a soil layer 750–1,000 mm thick **or with a geomembrane overlain by soil does not ensure protection against ion exchange or large increases in hydraulic conductivity.** (Meer and Benson, 2007)

As noted in this abstract, conductivity can be highly variable depending on conditions and that effective conductivity ranges in practice much more than the manufacturer's published conductivity values.

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(3) The lower composite liner must consist of a minimum of two feet of compacted soil with a maximum coefficient of permeability of 1×10^{-7} meters per second overlain by a geosynthetic liner at least 60 mils thick.(4) Quality assurance and quality control testing must be performed by the project engineer in conformance with the requirements identified in section 360-2.13 of this Part.(c) A minimum of two feet of freeboard must be maintained in all surface impoundments. Odor and vector control must be practiced when necessary.(d) A minimum of three groundwater monitoring wells, one upgradient and two downgradient of the surface impoundment must be installed and sampled in accordance with the requirements of section 360-2.11 of this Part.

The upper liner will be synthetic with a free-draining layer, a leak detection system, between it and the lower liner. "Above this leak detection layer would be another geomembrane liner that would be selected by the design engineer to address durability matters associated with exposure concerns if the upper geomembrane is left exposed" (DSGEIS, page 7-54). Other than free draining, the DSGEIS does not specify requirements for the material between upper and lower liners; the SGEIS should provide these requirements. Also, the DSGEIS allows a very high rate of leakage, 100 gpd per acre of pond. This system should hardly be called leak detection because it seems that the upper layer is designed to have seepage that the drainage layer is designed to evacuate. The lower geomembrane liner and GCL will be assumed to be impervious; yet, the design as required by the DSGEIS does not require any system to determine whether it leaks.

Similar liner systems under heap leach pads at western gold mines are limited to 150 gpd for the entire facility which may cover more than 100 acres[5]. The synthetic liners used in dual liner systems with an intermediate drainage layer are required to have permeability equivalent to $1x10^{-11}$ cm/s (Nevada Administrative Code 445.438.2[6]). The NYSDEC regulations require only that a liner be a given thickness, such as 40 or 60 mil, but a search did not locate where NYSDEC specifies a required conductivity.

Recommendation: The ***preferred alternative for centralized impoundments is to use closed-loop steel tanks and piping systems to minimize the potential for long-term leakage of the stored flowback water.*** *However, if NYSDEC can demonstrate that centralized impoundments, which will store changing volumes of water causing variable heads on the liner, are environmentally preferable, it should require the impoundments to be lined with a dual synthetic liner system and leak detection. Synthetic liners should have permeability of* $1x10^{-11}$ *cm/s. If a GCL is used, it must have the equivalent conductivity of two feet of clay compacted to* $1x10^{-7}$ *cm/s as specified at §360-*

[5] http://ndep.nv.gov/bmrr/permita.pdf

[6] **NAC 445A.438 Minimum design criteria: Liners. (**NRS 445A.425**,** 445A.465**)**

1. When placed on native materials, soil liners must have a minimum thickness of 12 inches and be compacted in lifts which are no more than 6 inches thick. Except when used in tailing impoundments, a soil liner must have a permeability of not more than that exhibited by 12 inches of 1x10-7 cm/sec material.

2. Synthetic liners must be rated as having a resistance to the passage of process fluids equal to a coefficient of permeability of 1x10-11 cm/sec.

3. The Department shall review for completeness the applicant's evaluation of the following design parameters, where applicable, for a liner:

(a) The type of foundation, slope and stability;

(b) The over liner protection and provisions for hydraulic relief;

(c) The load and means of applying load;

(d) The compatibility of a liner with process solutions;

(e) The complexity of the leak detection and recovery systems;

(f) The depth from the surface to all groundwater; and

(g) The liner's ability to remain functionally competent until permanent closure has been completed.

2.13(j)(1)(ii) for the secondary liner for the secondary composite liner for a landfill. The leak detection system should limit the leaks to 150 gpd for an entire impoundment.

Aquifer Contamination: Leaks from Wellbores

Aquifers could be contaminated by leaks from the gas wellbores. The leaks can be of either hydraulic fracturing fluid during hydraulic fracturing or flowback or they can be of methane gas during production. The DSGEIS, based on Alpha (2009), carefully specifies that such leaks do not occur from wells that are "properly constructed". For example, the probability that "properly constructed class II injection wells" will leak due to corrosion is very low (DSGEIS, page 6-35) and wellbore failures, of "properly constructed wells", that allow fracture fluids to reach aquifers, do not occur in properly constructed wells" (DSGEIS, page 6-37). The key is that the DSGEIS emphasizes that leaks rarely occur from properly constructed wells - the DSGEIS does not discuss how often wellbores are NOT properly constructed.

Recommendation: The DSGEIS should contain a discussion that estimates the percent of all wells that were not properly constructed.

Aquifer Contamination: Documented Contamination from Hydraulic Fracturing Operations

There is plenty of documentation that leaks have occurred from fracturing operations, although most of them are due to poor construction. The Pennsylvania Department of Environmental Protection has documented gas leaks from many operations; a list of incidents is attached as Appendix B.

The case near Dimock, PA is one of the most egregious examples. Appendix B describes it as follows:

> Dimock Migration, Dimock Twp., Susquehanna County - Cabot Oil and Gas – NCRO - 2009: The Department is actively monitoring domestic water supplies and investigating potential cause(s) of a significant gas migration that has been documented in several homes along Carter Road. Free gas has been encountered in six domestic water supplies and dissolved has (sic) been found in several of the wells. The operator has placed pilot water treatment systems on three water supplies. Of particular note is that this area has not experienced previous drilling and recent gas drilling in the vicinity has targeted the Marcellus Shale.

PADEP (2009) noted that they required Cabot Oil and Gas to cease operations in Dimock Township, PA, due to "three separate spills … in less than one week". Cabot signed a consent order, agreeing to pay a $120,000 fine, that outlined many instances of leaks and spills (Consent Order: In the Matter of**:** Cabot Oil and Gas Corporation, Dimock and Springville Townships, Susquehanna County, Clean Streams Law, the Oil and Gas Act, and the Solid Waste Management Act). Consent Order Exhibit D listed 13 domestic well owners, within 1300 feet of Cabot's wells, who had been affected by Cabot's operations.

Cabot had spilled carcinogenic chemicals into surface waters in Dimock, according to ProPublica:

> According to a Material Safety Data Sheet provided to the state this week by Halliburton, the spilled drilling fluid contained a liquid gel concentrate consisting of a paraffinic solvent and polysaccharide, chemicals listed as possible carcinogens for people. The MSDS form – for Halliburton's proprietary product called LGC-35 CBM – does not list the entire makeup of the gel or the quantity of its constituents, but it warns that the substances have led to skin cancer in animals and "may cause headache, dizziness and other central nervous system effects" to anyone who breathes or swallows the fluids. (http://www.propublica.org/feature/frack-fluid-spill-in-dimock-contaminates-stream-killing-fish-921

This was one of the spills that resulted in the order cited above.

There have been at least two explosions at homes, in Ohio and Pennsylvania, linked to the movement of methane from gas wells to domestic wells or basements (Ohio Dept. of Natural Resources, 2008; Lobins, 2009). Ohio DNR (2008) documents the effects of not properly constructing the well and that gas was found in a well 4700 feet away within about a month.

Methane movement to wells has occurred in other states as well. Thyne (2009) documented substantial gas movement in an unconventional natural gas field in Colorado. The author of this review has observed gas discharging from faucets and wells affected by coal-bed methane development in Wyoming, which is a different form of development but representative of the way methane gas can move through groundwater to wells.

Most of these incidents have one commonality – the production well construction is not always perfect. Mistakes occur and accidents happen, but the DSGEIS ignores their potential. The only way to improve well construction standards (see recommendations by Susan Harvey) and to minimize the chance for mistakes is to increase the inspection regime during construction.

Recommendation: NYSDEC must establish an improved inspection regime for well construction. At minimum, a qualified inspector should be onside during the placement of casing, cement around the casing, and during fracturing operations.

Insufficient monitoring.

Groundwater near well pads and centralized impoundments must be monitored to detect leaks and contamination before it damages aquifers significantly. The DSGEIS only proposed monitoring exceeding water wells, and even then only within 1000 feet of the proposed gas well, and within 2000 feet if there were no available wells (none in existence or no permission to sample) within 1000 feet (DSGEIS, page 7-38). This

proposed monitoring is not preventative - once contaminants are detected in a well, it is too late to protect drinking water.

Sampling duration is also too short. Sampling for just one year after operations cease would miss contamination due to long transport times. However, as long as a site is closed with no waste left onsite, the potential sources of contamination will have been removed so that five years is probably sufficient for monitoring for leaks around the well pad.

New York's monitoring policy apparently will be to sample for indicators rather than fracturing fluid constituents (DSGEIS, pages 7-39- 7-41). URS (2009, page 8-3) lists numerous parameters that increase during the first weeks of flowback, based on observations from other shales and the Marcellus Shale in Pennsylvania; these are primarily conservative inorganics such as TDS, chloride, bromide, and barium and probably result from the high salt content found in the shale (DSGEIS, Appendix 11). The DSGEIS does not, but should, provide the actual data for these observations or references to industry reports. The DSGEIS should also discuss why these constituents may increase with time.

Recommendation: NYSDEC must implement a monitoring well system around each well pad to detect whether contaminants are moving from the site and require mitigation to protect water resources. The monitoring must continue for at least five years after a well pad closure to observe slow-moving contaminant plumes.

A monitoring well system includes monitoring wells and piezometers used to monitor an area for contaminants. The monitoring plan includes the required sampling frequency, the length of screen and choice of aquifer levels to monitor. These depend on the purpose of the monitoring – leak detection, plume mapping, or trend analysis.

If the goal is leak detection, wells with long screens spanning the entire potentially contaminated saturated zone, as close to the source as possible, are preferable but the detection limits must be low. This presence/absence monitoring can work for substances not found in the natural groundwater of the area, such as a fracturing fluid chemical or shale-bed derived contaminants[7].

If the goal is to track a trend in concentration, wells must be targeted to specific aquifer zones but not be too long, usually no more than ten feet, to avoid dilution. This can be used to document the growth of a plume or detect a leak of a substance which naturally occurs in the aquifer. If the intent is to sample for inorganic indicators, such as potassium, the monitoring network must be sufficiently dense with short enough well screens so that natural variation in the background concentration does not cause a false alarm or too much uncertainty in the cause of changes. Background conditions must also be established. In either case, the well spacing should be based on the expected flow path accounting for the likely dispersion.

[7] See the discussion above regarding the fracturing fluid constituents and the review report prepared by Dr. Glenn Miller.

The overall design depends on the risk of missing contamination. Prior to designing any monitoring plan, it is essential to describe a well-conceived conceptual flow model, based on all available data supplemented with new data if necessary. A high density well network will minimize the potential of missing the leak.

Recommendation: NYSDEC should use the technical memorandum, presented in Appendix C, to provide guidelines for the design of monitoring plans near the natural gas development sites.

Setbacks

Distance is one way to mitigate against contamination from spills or leaks. NYSDEC proposes a series of setbacks "as a crucial element of protecting water resources against contamination" (DSGEIS, page 7-64). They considered similar rules from other states, various New York counties, New York City, and existing rules within various New York agencies (DSGEIS, pages 7-64 - -66).

Vertical Setback

The first and possibly most important setback is the one used to argue that contaminants would not be transported from the shale to freshwater aquifers. NYSDEC proposes that additional SEQRA analysis be performed for any proposed fracturing operation for which the top of the target formation is less than 2000 feet bgs with less than 1000 feet between the bottom of the aquifer and the target formation (DSGEIS, page 7-49). The review "would focus on local geological, topographical and hydrogeological conditions, along with proposed fracturing procedures to determine the potential for a significant adverse impact to fresh ground water" (id.) to determine whether an EIS would be required. The DSGEIS does not specify what would constitute a significant impact nor provide for appropriate mitigation.

The analyses above (page 9 – 14) demonstrate that 1000 feet does not guarantee there will not be vertical transport from the shale to the aquifers. It does not seem possible to specify a setback to guarantee there is no transport because it depends on conditions between the shale and aquifers. Mapping the stratigraphy also does not provide a guarantee because of the likelihood of preferential flow and the impossibility of knowing whether significant fractures exist away from any boreholes. The best way to increase confidence is to determine the vertical gradient in the vicinity of the project prior to fracturing. If there is no driving force, the contaminants would be effectively prevented from flowing upward.

Recommendation: NYSDEC should prepare a vertical gradient map for the formations directly above the shale to show areas where there would be no upward movement of contaminants that leak from the shale.

In areas with an upward gradient, there are no safe offsets unless the properties of the intervening layers are very well known. This is based on the travel time calculations in Table 1 of Appendix A and the related text. For this reason, the industry should complete adequate site-specific analysis for all well pads. The operator should determine the vertical gradient and media properties at the site. They would drill a borehole and measure the head along the borehole, log the hole, and do insitu tests to estimate the permeability. They could do standard transport calculations to estimate the potential for contaminants to reach the surface aquifers.

If there is a gradient, the calculations will yield a transport time for contaminants to reach the surface. As noted in Appendix A, these calculations probably underestimate the time because they ignore preferential pathways.

Recommendation: If the calculations based on measured data yield a travel time estimate of less than 500 years, the operator should take the following precautions:

- *The fracturing operation should be designed for the fracturing to end with a sufficient setback from the edge of the shale to minimize the chance of fracturing out of formation (see also recommendations in the review by Harvey Consulting, LLC).*
- *Appropriate verification of the fracturing must be completed. These could include monitoring of the pressure losses from the producing well. If there are indications that the shale could have been fractured to the edge or into the adjoining formations, the operator should drill a verification well to take a core sample in the adjoining formation and the shale to ascertain the state of the fracturing.*

Recommendation: The recommended site-specific analysis may not be cost effective for a single well, therefore NYSDEC should require the industry to apply for drilling permits for the entire well pad or preferably a series of well pads. A series would include all of the leases owned by a given company. One or two test wells as discussed above (pages 21-23) could provide the required data for a series of wells.

The analysis above (pages 9-14) makes clear that contaminants could move from the shale into the overburden and eventually reach near-surface freshwater aquifers, eventually meaning anytime from ten to hundreds of years. Because the development could extend over the entire Marcellus Shale region of southern New York, contamination could emanate from anywhere along the shale. Most of the analysis in this review has examined the possibility of contamination flowing vertically,, but it is important to understand that contaminants can also be transported along the horizontal gradient laterally. The ultimate location at which a contaminant seeping from the shale reaches shallow aquifers will depend on both vertical and horizontal advection and dispersion. It is unlikely that a contaminant reaching the surface decades into the future could be traced to a specific operation. However, NYSDEC cannot afford to ignore the potential for drinking water contamination by fracture fluids or formation water containing NORM because these pollutant sources well exceed drinking water standards

(see Dr. Glenn Miller's report to NRDC). Monitoring for such potential widespread long-term vertical and horizontal contaminant migration is clearly necessary, in addition to the previously recommended monitoring for transport from individual well pads. NYSDEC should thus plan for a long-term monitoring plan over the entire developed Marcellus Shale region.

Recommendation: NYSDEC should implement a long-term monitoring plan to detect and track contaminants potentially released from the Marcellus Shale. Funding for the plan should come from a long-term bond provided by the industry with each permit; part of the design of the monitoring system would include a cost estimate. The plan should follow the recommendations given on page 22 in the monitoring section and Appendix 3. Specifics should include:

- *Develop a conceptual model for regional flow and transport in the Marcellus Shale region of southern New York. A conceptual model is a description of flow paths through an aquifer or flow system, from the point of recharge to the point of discharge. Appendix 3 describes the necessary components of a conceptual model, but it must include the identification of points of recharge and discharge, connections between geologic formations, estimated formation hydrogeologic properties including extent of existing fractures, groundwater contours and gradients, and any other factors that would affect regional flow. The specific transport interest would be from depth, i.e., the level of the shale, to near surface aquifers.*
- *Develop a numerical flow and transport model for the conceptual model. The numerical model would simulate the existing flow conditions and the reasonable worst case changes caused by fracturing. The model would be interpretative in nature meaning that the results would be range of what could be expected rather than detailed predictions. It would also be a reconnaissance level model using basic geology and groundwater levels.*
- *The transport simulation would by necessity consider a range of possible sources based on the amount of the shale that has been fractured and which could become a source of fracturing fluid or shale-bed water containing NORM to the overlying formations. The goal of the numerical modeling would be to estimate the optimal spacing of regional monitoring wells.*
- *Both the flow and transport simulations would consider a range of flow and transport parameters representative of the area formations.*
- *A conceptual flow and transport model would assess lateral and vertical movement of contaminants above the shale. It would estimate how far laterally downgradient contaminants would move and provide a time frame for the transport.*
- *Monitoring well spacing would depend on the location of faults and fractures and the dispersion simulated with the numerical model. To be economical in the number of required wells, each should have multiport sampling capability with separate screens, or ports, for each significant formation, which will be identified as part of the exploration.*

- *Because of the long-term nature of the transport, the monitoring plan only needs to be implemented at some point during the production phase of development – not prior to well construction.*

Horizontal Setback

NYSDEC proposes various setbacks from water sources for different facilities as listed below. The setbacks are not prohibitions on constructing facilities, but specify distances required for the preparation of site specific SEQRA analysis. The following is a list of setbacks for water resources in the DSGEIS:

- Operators must make "diligent efforts" to identify all domestic-supply springs and public or private water wells within 2640 feet of a drilling location (DSGEIS, 7-66).
- There is a SEQRA threshold of 2000 feet from public water supply wells (DSGEIS, page 7-66).
- A well within 1000 feet of a public water supply well is deemed to have significant impact which means a site-specific SEIS is necessary (*Id.*).
- Between 1000 and 2000 feet of a public water supply well, the proposal requires site-specific analysis and SEQRA review to determine whether a SEIS is necessary (*Id.*).

Site-specific SEQRA review will be required for the following:

- Any centralized impoundment within 300 feet of a public supply well, based on the potential for surface spills.
- Any well pad within 150 feet of a domestic well of a centralized impoundment within 300 feet of a domestic well (DSGEIS, page 7-69). This applies outside areas where centralized impoundments are prohibited.
- Any well pad within 300 feet of a reservoir, reservoir stem, or controlled lake (DSGEIS, page 7-71).
- Any well pad within 150 feet of a watercourse, perennial or intermittent stream, storm drain, lake, or pond (*Id.*).
- Any centralized impoundment within 1000 feet of a reservoir, reservoir stem, or controlled lake (DSGEIS, page 7-72).
- Any centralized impoundment within 500 feet of a watercourse, perennial or intermittent stream, storm drain, lake, or pond (*Id.*).

The problem with all of the setbacks is they are not justified based on any kind of analysis. Rather NYSDEC considered regulation from different jurisdictions, as specified above. There is no disclosure of whether any of these setback distances is actually protective of the resource. Also, none of them are prohibitions on constructing within the specified distance but rather just require additional analysis.

A reasonably foreseeable worst case analysis is that flowback from a recently-fractured well would discharge on to the ground at the well pad. Regardless of the type of impoundment, steel tank or pond, provided to catch the flow, the connection could become disconnected and 130 gpm (the higher range of expected flowback rates) could

discharge for several hours; in three hours it would be about 23,000 gallons. Discharged into a swale or ditch, a flow rate of 0.28 cfs (23,000 gallons in 3 hours) could easily flow 2000 feet to a stream.

Recommendation: Rather than just accept what has been done in the past, NYSDEC should complete an analysis of whether the setback regulations have been effective in preventing water resource degradation.

Recommendation: Based on the possibility of a spill described above (page 20), the presumptive horizontal setback from surface water sources should be 2000 feet and there should be a berm around the well pad to create a detention volume of at least 25,000 gallons. Lesser setbacks could be approved on a site-specific basis if an applicant can demonstrate that the 2,000 foot setback is unnecessary for a particular proposed well pad due to local geologic conditions. Alternatively, there should be a site-specific analysis of the topography and geology to determine whether a 25,000 gallon spill during a short time frame could reach a surface water resource, in which case the setback would need to be greater.

Recommendation: Based on the contaminant transport considerations from the wellbore to a groundwater well, the offset from a well should be 1000 feet, but there should be a monitoring system installed to detect contaminant movement from the wellpad before it reaches the wells.

Depletion of Water Sources

Surface Water

The amounts of water used for hydraulic fracturing can be substantial. Historically, hydraulic fracturing of vertical wells used up to 80,000 gallon to stimulate a well (GEIS at 9-26), but stimulating horizontal wells will require millions of gallons. The exact diversion amounts are variable and depend on the shale properties and length of screened wellbore to be stimulated. The DSGEIS estimates up to 7,800,000 gallons may be needed to fully fracture a horizontal well.

Water withdrawals may affect downstream surface waters by depleting flows sufficiently to affect public water supplies, natural habitats, and water quality during low flows (DSGEIS, page 6-4). The DSGEIS mentions the "exacerbation of drought effects" as a potential impact, but because withdrawals during drought conditions exacerbate the listed effects, drought is mentioned separately here.

The DSGEIS provides only a cursory summary of how the items, including aquatic habitat, aquatic ecosystems, wetlands, and aquifers may be affected (DSGEIS, pages 6-4 to 6-7). This summary is inadequate because it is strictly qualitative. It does not discuss quantitatively, for example, how aquatic habitat or aquifer recharge relates to stream flow. It does not provide guidelines that can be used make these assessments. The discussion regarding cumulative impacts also considers similar impacts but only as

regards a proposed diversion with other diversions and uses on the system – it does not consider more than one diversion for fracturing occurring simultaneously (DSGEIS pages 6-7 to 6-8).

The discussion of withdrawals for fracturing (DSGEIS, pages 6-10, -11) downplays their potential impacts. For example, it compares the volume of water used for natural gas production with the total estimated use for the entire Susquehanna basin. Figure 6-2 (DSGEIS, page 6-13, the figure # is mislabeled in the DSGEIS) shows an estimate that about 25 mgd is the maximum consumptive use for natural gas production while estimates for water supply, power generation, and recreation are all substantially higher.

The DSGEIS also does not disclose how the 25 mgd total consumptive use for natural gas was estimated. Because the DSGEIS does not attempt to predict the rate that wells will be constructed or the level of recycling of flowback water and is very nonspecific even on the amount needed for one well, the 25 mgd estimate must be very uncertain.

Recommendation: The DSGEIS should document how the estimate of total water use for natural gas development was estimated.

The primary impact of surface withdrawals will be local and scale-dependent. Over the entire basin, they probably will have a minimal effect that will be difficult to even detect most of the time. At the local level with smaller basins and lower baseflow, without adequate passby flow requirements, the impacts could be devastating.

Mitigation for Surface Water Withdrawals

The DSGEIS divides the area affected by natural gas development, and therefore pertinent to the DSGEIS, by jurisdictions of the agency or commission with authority to regulate withdrawals – NYSDEC, Great Lakes/St. Lawrence, Susquehanna River Basin Commission (SRBC), and Delaware River Basin Commission (DRBC) (DSGEIS, section 7.1.1), for the regulation of instream flows and the impacts on surface water.

The primary mitigation discussed in the DSGEIS is the application of passby flow requirements (DSGEIS, section 7.1). A passby flow is a flow rate that must be allowed to pass a diversion point while a diversion is occurring; it is also a flow rate below which no diversion may occur (DSGEIS, page 2-32). Proposing a surface diversion that "is not consistent with the Department's preferred passby flow methodology" (DSGEIS, page 3-12) is identified as a reason for a project to need additional site-specific SEQRA review.

Chapter 7 discusses the passby requirements by merely specifying what the regulations for three different entities will be. In the Susquehanna and Delaware basins, the respective basic commission's policies will apply. Elsewhere, the NFRM will apparently apply. These methods will be discussed next.

Delaware River Basin Commission

DRBC policies are to protect water conservation in the basin, and all natural gas projects would have to get approval from the commission (DSGEIS, page 7-10). "The Commission shall approve a project whenever it finds and determines that such project would not substantially impair or conflict with the Comprehensive Plan and may modify and approve as modified, or may disapprove any such project whenever it finds and determines that the project would substantially impair or conflict with such Plan" (DSGEIS, page 7-8). Aquatic systems must be kept in a "safe and satisfactory condition" (DSGEIS, page 7-10) and diversions regulated to "reduce the likelihood of severe low stream flows that can adversely affect fish and wildlife resources" (DSGEIS, page 7-11). Water quality must also be maintained (*Id.*).

DRBC does not have adequate regulations to back up these goals. They do not have a passby flow requirement (DSGEIS, page 7-16) but rather rely on reservoir releases and use the Q7-10 flow for "water resource evaluation issues" (*Id.*). The Q7-10 flow is the seven-day low flow with a recurrence interval of ten years. The short passage in the DSGEIS provides no information as to how the DRBC might regulate the diversions required by the industry or how the diversions would affect the flow, and hence what the impacts could be.

Susquehanna River Basin Commission

The SRBC requires that a certain amount of water be allowed to pass the diversion for mitigation. SRBC allows three exceptions to the requirement. The first one (DSGEIS, pages 7-16 to 7-17) merely means that when there is substantial flow in the river or stream, there is no requirement for a passby flow because the river is providing enough flow that the diversion cannot harm the river flows. The second exception is difficult to interpret:

> For projects requiring Commission review and approval for an existing surface-water withdrawal where a passby flow is required, but where a passby flow has historically not been maintained, withdrawals exceeding 10 percent of the Q7-10 low flow will be permitted whenever flows naturally exceed the passby flow requirement plus the taking. Whenever stream flows naturally drop below the passby flow requirement plus the taking, both the quantity and the rate of the withdrawal will be reduced to less than 10 percent of the Q7-10 low flow. (DSGEIS, page 7-17)

The passby flow requirement depends on the value of the waterway and will be discussed below (page 33). This exception basically states that the diversion will be allowed if the diversion can be made and still maintain the passby flow requirement but that whenever the stream flow rates are low, less than the sum of the passby flow requirement and the taking, the "quantity and the rate of the withdrawal will be reduced to less than 10 percent of the Q7-10 low flow". One problem is that the Q7-10 low flow is a flow rate, not quantity. Presumably the intent is to reduce the withdrawal to less than 10% of the

volume of flow that occurs over seven days experiencing the Q7-10 flow. The requirement should specify whether the quantity limit is to a seven-day withdrawal, in which case it is redundant, or to a total withdrawal to be made at the diversion point.

To consider the remainder of this exception, it is necessary to examine the definition of a passby flow. For SRBC exceptional value waters, withdrawals may not cause more than a 5% loss of habitat and for high quality waters withdrawal may also not cause more than 5% loss of habitat with three exceptions that allow a loss up to 7.5% of habitat. For class B, coldwater fishery waters, withdrawals may not cause more than 10% loss of habitat. For class C and D, CWF waters, withdrawals may not cause more than 15% loss of habitat. The DSGEIS must explain this better. Because it is based on SRBC policy, passby flow requirements are as specified in Denslinger et al (1998), specifically Figures 6.4 through 6.13 in that report.

The DSGEIS must explain that these restrictions are of a loss of habitat as compared with what would exist without the diversion – not a loss of habitat below the optimum. Optimal habitat for a flow rate occurs at the point where a plot of wetted perimeter versus flow rate for a riffle section goes through a point of inflection, or bends, according to Denslinger et al (1998). The proportion of average daily flow (ADF) that this corresponds with varies with stream watershed type. The DSGEIS should define ADF; as the SRBC defines it, it is the average daily flow of all days in the period of record (Denslinger et al, 1998).

At low flow rates, small changes in the flow cause substantial changes in the habitat; it is at these rates that SRBC policy sets the minimum bypass flows. The DSGEIS should better analyze the loss of habitat that could occur due to the withdrawal.

The DSGEIS discusses requirements for the portions of the basin in which the habitat loss minimums do not apply. However, the DSGEIS should explain or provide a map to show which basins or for which streams the habitat-loss requirements do not apply. The passby flow requirements are specified as 25, 20, or 15 percent of average daily flow with a minimum requirement being that the passby flow must equal or be greater than the Q7-10 flow. The variation depends on the degree that acid mine drainage (AMD) affects the stream; a map of these streams in the New York portion of the Susquehanna basin should be provided. Also, to support this variation, the DSGEIS must provide an explanation as to how AMD affects the streams – for example, provide the relationship between trout biomass and levels of AMD. Without a substantial justification for decreasing the protection, the NYSDEC should use the 25% of ADF.

Meeting these requirements will be much easier for larger streams because the proposed diversion rates would be a small proportion of ADF. Baseflow in larger streams may be a higher percent of ADF because of the larger relative groundwater storage near the streams to support dry season flows. Streams with drainage areas exceeding 100 mi^2 tend to be warmer (Denslinger et al, 1998), therefore the habitat depending on cold stream temperatures may also be less sensitive. If diversions are necessary during the baseflow portions of the year, doing so from larger streams will cause less habitat loss.

Passby flows should be based on the ADF which should be based on a complete data set representative of year-round flows. Use of such an annual average would essentially establish periods during baseflow when no diversions would be allowed which is clearly preferable for protecting habitat. The limitation to 25% of the average daily flow, although the DSGEIS should the benefits to raising the level, would protect the stream during baseflow periods.

Great Lakes Compact Region

The Great Lakes Compact (GLC) prohibits the export from the basin of water in any container exceeding 5.7 gallons (DSGEIS, page 7-6), so obviously it would not be allowable to move water from the basin for natural gas development. The DSGEIS does not discuss how this affects movement of flowback water away from a basin for treatment. If the industry establishes a water treatment facility at a central location, the effect of trucking or piping flowback for treatment may be to deplete watersheds from which the water is removed.

The GLC also requires consultation for any project that will average 5,000,000 gpd consumptive use averaged over 90 days (*Id.*). New York has not implemented the compact, but once it does it will affect diversions within portions of New York. The only one that has the potential to cause even a minor impediment to diversions for fracturing would be the prohibition on transfers from the basin.

There are no other specific requirements in the Great Lakes Region for passby flows.

Recommendation: Neither the DRBC, SRBC, nor GLC have adequate requirements to protect streamflow from surface diversions to support hydraulic fracturing. NYSDEC should limit hydraulic fracturing permits in any area which does not have adequate passby flow requirements.

Natural Flow Regime Method

For areas under NYSDEC jurisdiction, the DSGEIS indicates that passby flow requirements will be determined on a case-by-case basis based on a new law for which the rules have not yet been written:

> Surface water withdrawals are subject to the recently enacted narrative water quality standard for flow promulgated at 6 NYCRR 703.2. This water quality standard generally prohibits any alteration in flow that would impair a fresh surface waterbody's designated best use.[1] Determination of an appropriate passby flow needs to be done on a case by case basis. However, the TOGS that is necessary to provide effective guidance on the application of the narrative water quality for flow has not been promulgated.
> (DSGEIS, page 7-4).

The DSGEIS is therefore analyzing a mitigation that it readily acknowledges will not be the chosen method. "**For the purpose of this SGEIS only**, the Department intends to employ the Natural Flow Regime Method as an interim protection measure in lieu of the flow standard pending completion of the flow standard TOGS (DSGEIS, page 7-4, emphasis added). Rather than promulgating the new technical operating guidelines (TOGS), the document will analyze the current method seemingly just to be able to finish the DSGEIS.

The remainder of this section evaluates the NFRM. When developing the new TOGS, the NYSDEC should consider recommendations made herein.

The NFRM will be used wherever the NYSDEC has jurisdiction - presumably outside the river watersheds. The DSGEIS should provide a map showing where it will apply. The method would "provide seasonally adjusted instream flows that maintain the natural formative processes of the stream while requiring only minimal to moderate effort to calculate" (DSGEIS, page 7-18). The NFRM brings seasonality into the calculation by estimating both the ADF and average monthly flow (AMF) values. The minimum passby flow must be greater than both 30% of the ADF and AMF. During the dry months, the 30% of ADF will control and prevent diversions much of the time. During the wetter months, a substantial diversion could occur, but the method would protect the channel formative processes that occur throughout the flow regime during these months which has benefits throughout the year including a smaller width/depth ratio that generally means better habitat (Poff et al, 1997).

If there is a nearby gaging station, the relevant flow statistics would be determined from those records; however, if there are no nearby stations, the ADF and AMF values would be scaled from an existing gaging station based on the ratio of area between the gage and the diversion point (DSGEIS, page 7-20). For this to be accurate, the user must accept several unstated assumptions, which the DSGEIS should acknowledge and state.

- The watershed area vs. flow relationship is constant with area.
- The relative contribution of geology and ecosystem type is the same between sites.
- Precipitation is the same throughout the watershed, which means that orographic effects, for example, are negligible.
- The amount of groundwater storage is proportionally constant throughout the watershed.

The method works best when moving between gaging stations within a small area range in the same watershed. It is not reasonable to expect that a 1000 square mile watershed will produce flow at the same rate and seasonal distribution as an internal 20 mi^2 watershed, but the relative relationship between watershed sizes has not been established within this DSGEIS. Ridgetops, the headwaters watersheds, receive more rainfall than valley bottoms. Floodplains store flood flows and allow them to return to the river during dry periods, but headwaters watersheds have little floodplain storage.

For the DSGEIS to propose a method for calculating the hydrology at an ungauged site, it must provide evidence to the efficacy of the results of that method. It must consider the issues just presented. The DSGEIS does not even provide a reference that can be consulted.

Recommendation: *Diversions should be allowed only when aquatic habitat will be minimally affected – a point that corresponds with the water level being at or above the point where the wetted perimeter/flow area ratio is a minimum. The 30% of ADF proposed in the NFRM is reasonable as long as the minimum passby is 30 % of AMF during wet seasons to protect flows which are essential for channel forming processes. These recommendations may prevent diversions during much of the latter half of the summer and early autumn, but these are periods when the aquatic ecosystems are most stressed.*

The gas industry could be allowed to make diversions in advance of its late summer needs and store the water in tanks or lined ponds if the timing is going to be an issue. Alternatively, the industry could arrange to store additional water in surface or groundwater reservoirs to use when surface water diversions would be limited. If proposed, the DSGEIS should discuss these potential alternatives and their impacts.

Depletion of Aquifers

Mitigation as described in the DSGEIS is described in two parts – aquifer depletion in section 7.1.1 and groundwater contamination in 7.1.4.

Aquifer Depletion

Aquifer depletion generally would refer to the process of taking more water from an aquifer than nature returns to it decreasing existing discharges from the aquifer, either to springs and stream baseflow or to wells. Any new discharge, such as a well to make fracturing water withdrawals, must take water from other uses – this is a simple concept of water balance where over the long term inflow equals outflow. If outflow exceeds inflow due to new diversions, water will be removed from storage and groundwater levels will be reduced, creating a deficit. The lowering water levels will propagate to springs and streams thereby affecting their flow rates and to other wells thereby increasing the necessary pumping lift or requiring the well to be deepened.

DSGEIS section 2.4.8 discusses aquifer replenishment but does not discuss that every diversion increases the amount of deficit to be replenished and decreases the amount of water available for replenishment. Increasing the anthropogenic withdrawals from an aquifer will increase the time the aquifer will be in a depleted condition. Natural discharges from the aquifer will be decreased for a much longer period. The DSGEIS should discuss how the diversions could affect discharges from the aquifer. Chapter 2 (page 2-31) refers to a pump test to determine the safe yield of a well. Safe yield **does not protect** the discharges to springs or streams, rather the pumping lowers water levels which draws groundwater away from these natural discharges and diverts them to the

well. Safe yield in a well is achieved by diverting groundwater from natural discharges and the DSGEIS should acknowledge this fact. DSGEIS section 2.4.8 also describes recharge, but does not estimate the rates or provide any other useful water balance information. Water balance data for aquifers would be useful because the proposed diversions could be compared to the fluxes flowing through the aquifer.

Depleted aquifers can decrease the flow in nearby streams by reducing discharge to the stream or drawing water from it. This is most problematic during hot summer months when the river baseflow may be primarily groundwater discharge. Therefore, any groundwater diversion that occurs sufficiently close to a river will affect that baseflow. By sufficiently close, the flow travel time would be short enough that the effect is felt in the river during the baseflow period. However, diversions that are large enough could be felt in streams, especially small ones, even if the primary effect does not reach the stream until wetter periods. Runoff during wet periods could go to refill the depleted aquifer thereby decreasing streamflow.

Regulations vary among the jurisdictions regulating water withdrawals. The DSGEIS does not report that any of the jurisdictions have regulations specific to fracturing withdrawal; any proposed pumping would be regulated according to existing laws and regulations. The DRBC's regulations as discussed in the DSGEIS intend to protect the aquifers from long-term degradation:

> Projects that withdraw underground waters must be planned and operated in a manner which will reasonably safeguard the present and future groundwater resources of the Basin. Groundwater withdrawals from the Basin must not exceed sustainable limits. No groundwater withdrawals may cause an aquifer system's supplies to become unreliable, or cause a progressive lowering of groundwater levels, water quality degradation, permanent loss of storage capacity, or substantial impact on low flows or perennial streams. Additionally, "The principal natural recharge areas through which the underground waters of the Basin are replenished shall be protected from unreasonable interference with their recharge function" (DRBC Water Code, Article 2.20.5). (DSGEIS, page 7-12, -13, legal citations omitted except for the sentence in quotations)

The DRBC requires well owners to report their water uses as follows.

- Any well or group of wells that averages 10,000 gpm or more for a month must register their well (DSGEIS, page 7-13).
- Groundwater withdrawals that exceed 100,000 gpm average for a month must report the discharge (*Id.*); presumably this requirement applies to a single well or group of wells.

The DSGEIS does not indicate if the DRBC would use this information to protect the aquifer. The 100,000 gpm reporting requirement may require fracturing operations to report the amount of water withdrawn, since the total that may be withdrawn per 30-day month without reporting would be 3,000,000 gallons, an amount less than the average reported fracturing requirements.

To put the reporting limit in perspective, 3,000,000 gallons is approximately 9.2 acre-feet. If the average recharge is 15 in/y, a rate common to parts of Pennsylvania (Risser, 2008), one relatively small fracturing project would withdraw the entire annual recharge for an area approximating 7.4 acres. *Comparing values such as this with the size of the aquifer being targeted for withdrawals would provide an assessment of how much the aquifer will be affected. The DSGEIS should establish limits on the total diversions that can be made during a given time period*.

The SRBC requires pump tests for proposed wells as described in the DSGEIS:

> Evaluation of ground water resources includes an aquifer testing protocol to evaluate whether well(s) can provide the desired yield and assess the impacts of pumping. The protocol includes step drawdown testing and a constant rate pumping test. Monitoring requirements of ground water and surface water are described in the protocol and analysis of the test data is required. This analysis typically includes long term yield and drawdown projection and assessment of pumping impacts. (DSGEIS, page 7-15)

The SRBC limits groundwater withdrawals similar to the way it limits surface water withdrawals - to maintain passby flows (DSGEIS, page 7-16). "Approved ground-water withdrawals from wells that, based on an analysis of the 120-day drawdown without recharge, impact streamflow, or for which a reversal of the hydraulic gradient adjacent to a stream (within the course of a 48-hour pumping test) is indicated, also will include conditions that require minimum passby flows" (SRBC, 2003, page 1). The DSGEIS must discuss in more detail the required groundwater analysis, analytical or numerical drawdown calculations, and identification of other wells and natural discharge points which may be affected the pumping. Basing passby flows on predicted surface water depletions due to groundwater pumping includes a large uncertainty that must be considered. This requirement also does nothing to protect or prevent deficits in the aquifer beyond the effect on streamflow.

Recommendation: The DSGEIS should be more specific as to the requirements for permitting groundwater withdrawals. Registering and reporting is not regulating aquifer depletion, but only documenting the degradation. NYSDEC should specify a limit to the amount of water that can be diverted from an aquifer based on the expected recharge to that aquifer. These limits should be to a certain percentage of the average annual recharge.

The DSGEIS should also specify the conditions under which the withdrawal of sufficient water for fracturing would be a "depletion" of an aquifer or "potential" aquifer (DSGEIS, page 7-12, 13). In smaller aquifers, a 5,000,000 gallon depletion (15 acre-feet) is more than would be removed in a year by 15 domestic wells; if gas production removes this much in a short period, it would create a substantial drawdown cone that would affect nearby wells.

Recommendation: The DSGEIS should specify conditions, required aquifer properties including transmissivity and storativity, antecedent moisture conditions (no pumping during drought), and distance from other users, that could be pumped for natural gas operations. These conditions should preserve and protect aquifers as required under "Aquifer depletion".

Recommendation: The DSGEIS should discuss whether the development of a well and related infrastructure is "unreasonable interference" with the recharge function of a "principle natural recharge area", prohibited under various basin-specific regulations, such as the Delaware River Basin (DSGEIS, page 7-13). NYSDEC should prohibit the development of gas wells in a recharge area because of the potential for spills, from the transport or storage of chemicals, to contaminate an aquifer at its recharge source.

Cumulative Impacts

The DSGEIS does not consider cumulative impacts adequately because it does not define the overall scope of the potential drilling adequately. Each well is defined as a separate project (DSGEIS, page 3-6), even if constructed on a multi-well pad.

Three cumulative impacts to resources are ignored in the DSGEIS.

1. The DSGEIS should consider the potential cumulative changes of the properties of the Marcellus Shale. Each fracturing changes the conductivity of the formation. For maximum efficiency in gas recovery, it is likely that the industry would site wells to optimize production which would change the conductivity over a much larger area.
2. The DSGEIS should also consider the cumulative effects of the fracturing fluid that will build up in the shale. If each operation recovers a maximum 35% of the injected fluid (DSGEIS, pages 5-99 to 5-100, Gaudlip et al, 2008), 65% will remain in the shale. Depending on the flow through the system, this represents a large potential contaminant source build-up and source of contaminants for future transport.

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Appendix A

Numerical Simulation of Hydraulic Fracturing and Flowback

Introduction

The DSGEIS made very simple calculations to support an argument that contaminants would not migrate from the shale to the overlying layers, based on an analysis provided by ICF (2009). That report was reviewed in the main body of this report and in detail in Appendix D. The simple argument was that the gradient established due to injection would last only as long as injection was occurring. This would not be long enough for contaminants to flow upward to the aquifers.

This report presents a simple numerical groundwater model of potential flow from the shale upward through the overlying layers. The numerical model is interpretative, following the concepts of Hill and Tiedeman (2007), because the purpose is to assess whether the injection could cause groundwater or fracturing fluid to flow upward from the shale into overlying layers. Interpretative means the model is not calibrated to observed data nor should it be used for predictions. The simulation is not intended to consider all of the potential complexities of the geology, such as very low conductivity aquitards and the fractures that will ruin the aquitard properties. Rather the purpose is to consider simply whether the vertical flow is possible within the expected range of aquifer parameters. The hydrogeologic properties of the model are simple so that the flow paths are easy to interpret.

There are two aspects to consider – the natural upward flow that would occur due to a potential natural upward gradient that preexists the fracturing and also the fracturing.

Model Setup

The simulation utilized the commonly used code, MODFLOW-2000 (Harbaugh et al, 2000). The model domain was approximately 6000 feet square and was divided into 42 layers. Because the sides were bound with no-flow boundaries, horizontal flow beyond the domain was not possible.

The forty-two layers were divided as follows. The shale was 100-feet thick, based on a relative average (DSGEIS, Figure 4.9) and divided into 10 equal thickness layers, from layer 41 to 32; the shale conductivity (K) equaled 0.0001 ft/d, based on permeability values reported in the DSGEIS and discussed the primary review of that document. Layers 31 to 1 and the underlying 42 were simulated with conductivity equal to 0.1 ft/d which was similar to the values used in the DSGEIS.

The injection causes rapid and substantial changes over small areas, and the model discretization must reflect that fact. The horizontal injection well was located in the middle of the domain, therefore one column of cells in layer 37 contains the well. Most of the injected water would flow perpendicular to the well and perpendicular to the

columns of cells which parallel the well. Because the gradients are expected to be steep within these near columns, they were just 10 feet wide. The width increased to 160 feet with distance to the edge of the domain (Figure 1). All rows were 40 feet wide.

There were flux boundary conditions at the bottom and top of the domain to simulate the vertical flow assumed to exist prior to the injection, as would be the case due to artesian conditions. The bottom, layer 42, had a constant head boundary with head equal to 5400 feet. Layer 1 had an evapotranspiration boundary and ground surface at 5280 feet. Together, at steady state there was a one-dimensional flow from bottom to top with most of the head drop occurring across the shale layer. The initial conditions of the model are a 120-foot head drop over the 5280-foot thickness of the domain. This was assumed to represent a small upward gradient which possibly exists over portions of the Marcellus Shale.

Simulation in steady state had numerical stability problems. If the K of the shale differed by more than three orders of magnitude from the overlying layers, the model was unstable in steady state. Therefore, initial head for each layer was set equal to the ground surface elevation and the model run for 100 years in transient mode to establish the initial conditions for injection. Running the model prior to injection also allowed a consideration of the natural upward flow rates that could exist pre-fracturing.

Injection was simulated in transient mode with a WELL boundary placed in a layer close to the middle of the shale, layer 37. The well was run with positive flow, meaning flow into the model domain, for one 5-day period to emulate the expected timeframe for fracturing (DSGEIS). Flowback was simulated with a DRAIN boundary set in the layer just above the well – the head in the drain was set at 5280 to represent an open well freely draining at the ground surface. The flowback rate was not sensitive to the conductance in the DRAIN because injection had added 5,000,000 ft^3 to storage in the cells around the well, creating a high pressure which can dissipate only by flowing back into the well or to the surrounding shale.

Calibration involved changing K near the injection well so that the head at the well at the end of injection approximated the pressure discussed in the DSGEIS for injection – about 10,000 psi or 28,000 feet of head including the thickness of the domain. Essentially K for the shale was changed for six model columns on either side of the well (Figure 1) for the entire thickness of the shale to emulate the fracturing process of changing the permeability. Effectively the injection created a fracture zone of shale about 110 feet in diameter, which corresponds to the estimated 10 ft/d of seepage for five days as mentioned in the DSGEIS. The selection process resulted in K equaling 0.0007 ft/d and the head at a point near the middle of the well length and well column maxed at 27,875 feet (Figure 3). The concepts used here are similar to those used by Contractor and El-Didy (1989) to simulate water quality impacts caused by underground coal gasification.

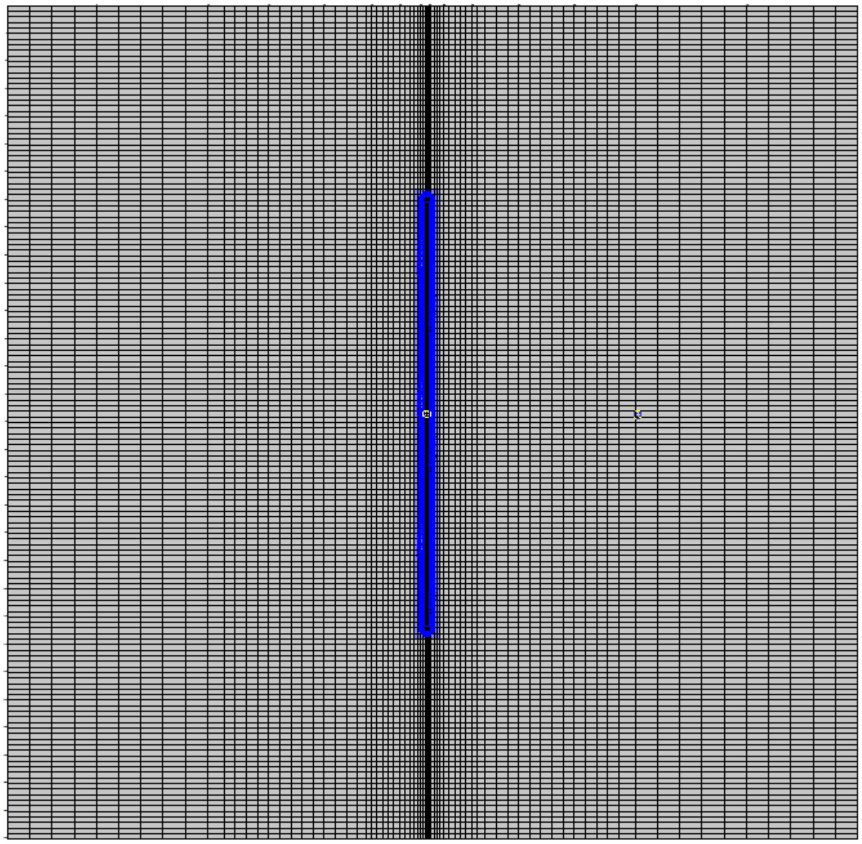

Figure 1: Figure showing grid layout and two conductivity zones in layer 37. The blue zone had K=0.0007 ft/d while the gray has K=0.0001 ft/d. The horizontal well is in the middle of the blue zone. The column spacing is 160 feet at the edges and decreases to 10 feet at the center near the well.

Interpretative Scenario

The simulation injects 5,000,000 gallons of water in five days over a horizontal well about ½ mile long. The head created at the well, its propagation into the shale and surrounding media, and the flowback to the well is simulated and monitored. The simulation was accomplished with nine stress periods. The first period, as mentioned, was 100 years long to establish steady conditions prior to simulating the injection. The second period was 5 days long over which the horizontal well injected water at 134,200 ft^3/d to simulate the injection of 5,000,000 gallons in five days. The third through sixth periods were for flowback simulation, being 1, 3, 10, and 50 days, respectively. The DRAIN was active during this period for flowback. The next two periods were one and five years long, and the DRAIN boundary was inactive so no flow back occurred. Each period had 20 time steps with a 1.2 time step multiplier.

Injection occurred at a constant rate for 5 days and most of it went into storage (Figure 2). After injection ended, the largest flux was water being released from storage – it became flowback and also went into storage at similar rates to the flowback. Water going into storage was primarily due to flow across layer boundaries such that water leaving storage

in one layer entered storage in the next layer, so the net change in storage was less than the full amount released.

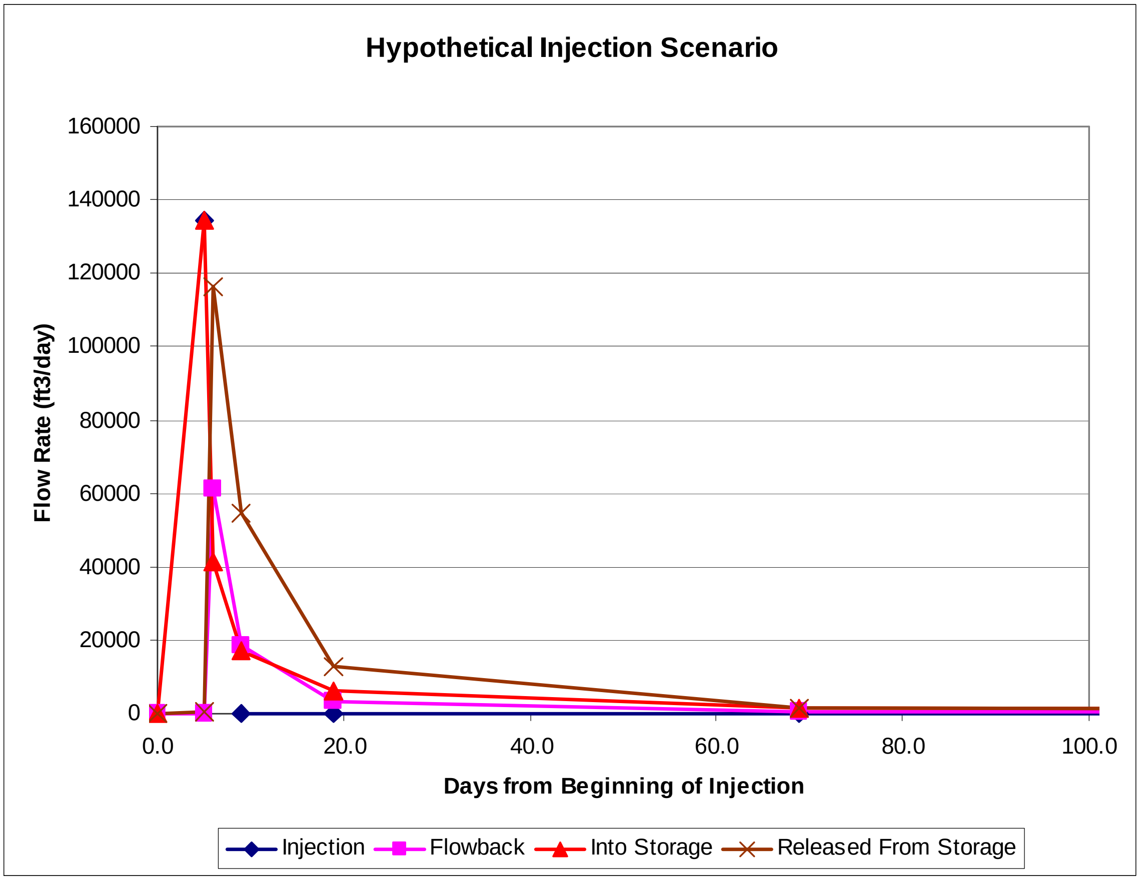

Figure 2: Hydrograph of simulated flux rates for the hypothetical injection scenario. Each flux rate is that occurring at the end of a stress period, as described in the text.

The total flowback volume was about 70% of injection, an amount that exceeds that observed in the operations elsewhere, as reported in the DSGEIS. Many scenarios were tested when calibrating the different K values near the well, but all had similar flowback volumes differing only in their rates. High K values allowed rapid flowback and lower K values caused much slower flowback – the similarity was in that the total volume reached from 70 to 80% of the injected amount. The smallest amount of flowback occurred when fracture K values were not considered – all K equaled 0.0001 – this scenario was abandoned because it caused the head to be three times higher than reported.

The industry reported values could be skewed to lower volumes because they close off the well to flowback sooner, or they stop reporting the water as flowback and refer to it as produced water. Alternatively, actual operations force more water beyond the point where pressure drops could draw it back to the well. The DSGEIS did not discuss whether flowback could occur during gas production nor did it simulate any suction pressure applied at the well to produce gas.

Maximum head values occurred at the center of the well at the end of the injection period. With distance vertically away from the well, the maximum head propagated over a period of days but the maximum decreased quickly (Figure 3)[8]. Within the shale at the well, the head was about 23,000 feet above background (ab), which dropped to 9000 feet ab after one day and 1500 feet ab after four days; it continued to be several hundred feet above background for another couple of weeks. While this may seem like a rapid dissipation, it shows the analysis in the DSGEIS Appendix 11 relies on an erroneous assumption – that the injection pressure distribution throughout the shale beyond the well dissipates immediately upon cessation of injection. At 10 and 20 feet above the well, the maximum head also occurred at the end of injection, but at 30 and 40 feet above the well the maximum head occurred after one day – head at the point 40 feet above the well barely changed between 1 and 4 days after injection, which indicates the peak may actually be higher but occur somewhere between those points. This indicates the peak pressure required between 1 and 4 days to propagate 40 feet through the shale.

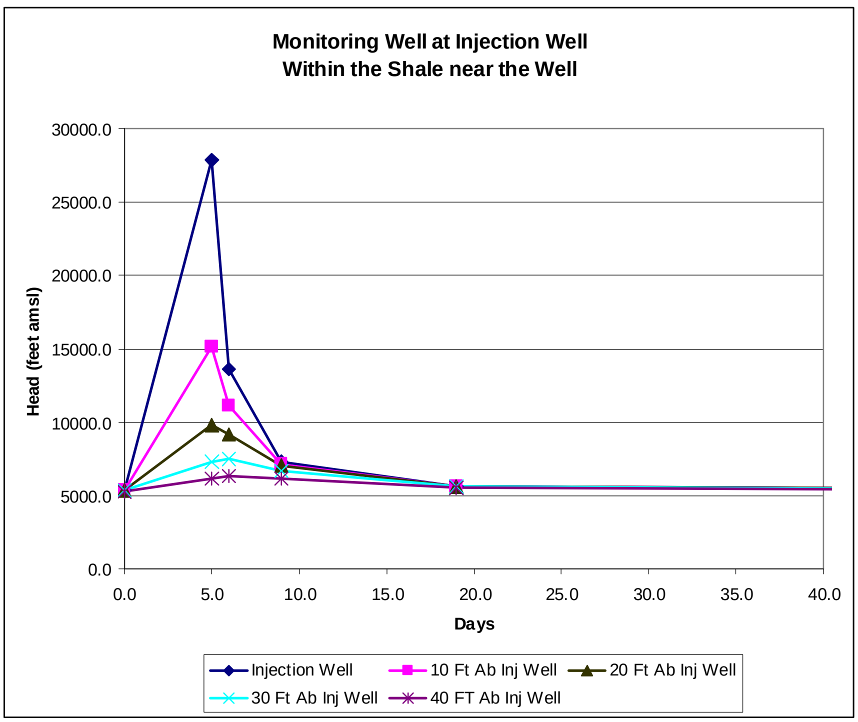

Figure 3: Hydrograph of head values in the simulated monitoring well located in the center of the model domain.

At 50 feet above the well, but still with in the shale, the highest peak occurred four days after injection, although that peak was just slightly higher than the value after one day (Figure 4). This reflects the likely dampening effect of the shale which dissipates the pressure and slows its travel. The layer above the shale had much less increase in head, only about 25 feet (Figure 4). The pressure change remained evident even 200 feet above the shale, with the head increasing about 10 feet at layer 20 (Figure 4) two weeks after

[8] It is possible the figures showing head value do not show the absolute peak because the peak could have occurred at a different lag time that was not reported from the model analysis.

injection. The head increased less within the overlying media because the conductivity was higher, therefore the gradient required for the flux crossing from the shale into the media, was much less.

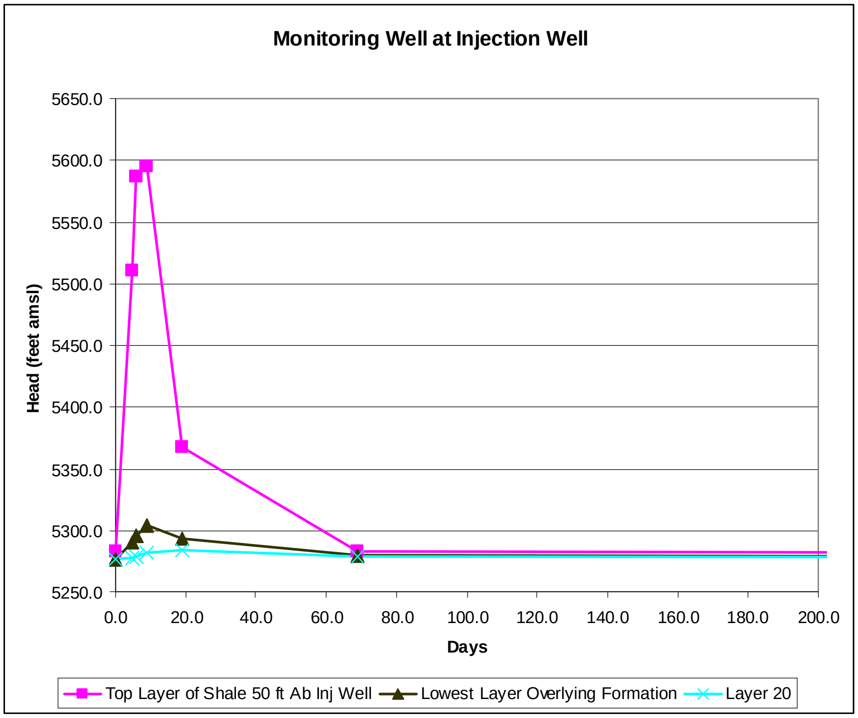

Figure 4: Hydrograph of head values located at the top of the shale and two points in the overlying media.

A monitoring well a quarter mile east of the horizontal well showed small, less than ½ foot, but positive increases in head more than 60 days after injection (Figure 5). The time lag and magnitude of the change again reflects the dissipating effect of the shale and overlying media. However, it also shows there are effects over at least half a mile centered on the horizontal well.

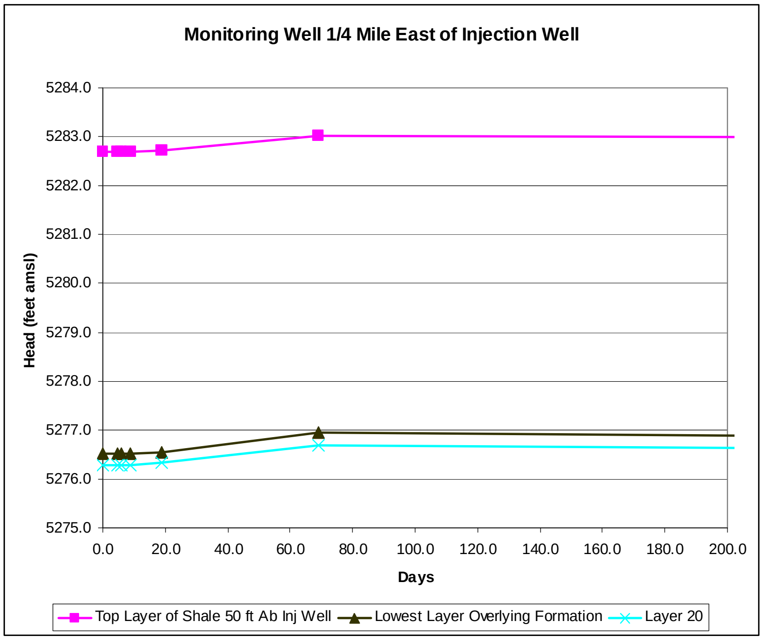

Figure 5: Hydrograph at three points in monitoring well 1/4 mile east of the horizontal well.

The head maximum that propagates through the model layers also causes flux among those layers. The steady state flux is about 4535 ft^3/d, so the injection caused the flux to increase to six times the background value at the well within the shale (Figure 6). One day after injection, the flux among layers 50 to 150 feet above the well ranged from 12,500 to 8000 ft^3/d (Figure 6). Although this value is spread over a 6000-foot square, it would be concentrated laterally within a couple hundred feet of the well. This is injection fluid moving away from the well and brine from the shale displacing away from the well.

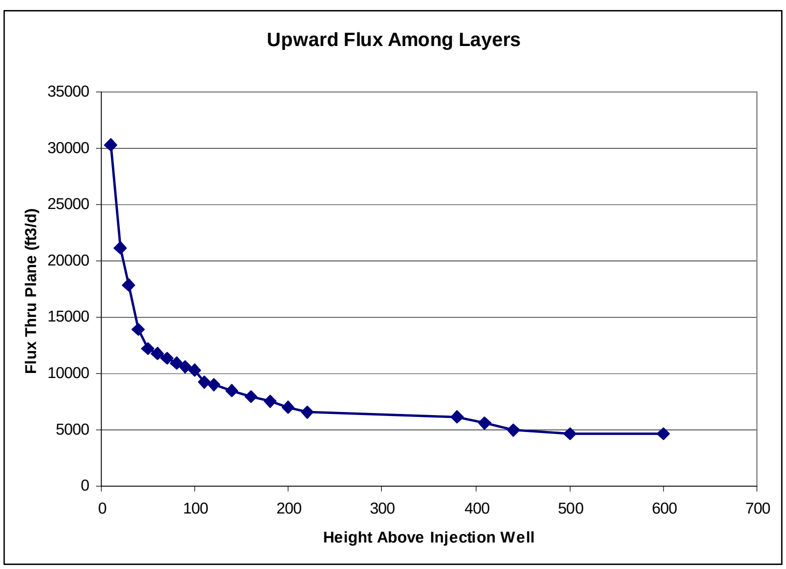

Figure 6: Upward flux among model layers in distance from the center of the shale one day after injection.

Figure 6 shows that injection can result in contaminants, either fracturing fluid or brine, getting into the overlying formation. Injection pressures do not last long enough to drive the contaminant to the shale layers, but that is not the question, and as pointed out in Appendix D, the review of ICF (2009), is truly irrelevant. The relevant question is whether contaminants will flow with the natural flow upwards to the freshwater aquifers.

The relevant point is the upward gradient and the conductivity and porosity of the intervening layers. Also, as noted elsewhere in this review, preferential flowpaths could increase the contaminant velocity or the flow rates substantially. The DSGEIS (Appendix 11, Table 4) notes that sandstone rock mass has conductivity which varies from 1E-9 to 1E-1 cm/s; these units convert to a more intuitive range of 0.000003 to 283 ft/d. There are obviously many potential combinations of sandstone K, head drop and distance between the shale and aquifers, and porosity. Table 1 presents a few based on travel distance of 4000 feet and porosity equal to 0.1. The water particle velocity, which is the advective velocity the contaminant particles travel at, equals the Darcy velocity divided by the effective porosity. Effective porosity includes only the connected pores.

Table 1: Calculation of particle travel times from the shale to the freshwater aquifers for a variety of possible hydraulic conditions.

Sandstone K (ft/d)	Head drop (ft)	Gradient (ft/ft)	Darcy V (ft/d)	Particle V (ft/d)	Particle Transport Time (years)
0.0001	10	0.0025	2.5E-07	2.5E-06	4383562
0.001	10	0.0025	2.5E-06	0.000025	438356
0.01	10	0.0025	0.000025	0.00025	43835
0.1	10	0.0025	0.00025	0.0025	4383
1	10	0.0025	0.0025	0.025	438
10	10	0.0025	0.025	0.25	43
100	10	0.0025	0.25	2.5	4
0.0001	50	0.0125	1.25E-06	1.25E-05	876712.
0.001	50	0.0125	1.25E-05	0.000125	87671.
0.01	50	0.0125	0.000125	0.00125	8767
0.1	50	0.0125	0.00125	0.0125	876
1	50	0.0125	0.0125	0.125	87
10	50	0.0125	0.125	1.25	8
100	50	0.0125	1.25	12.5	0.8
0.0001	100	0.025	2.5E-06	0.000025	438356.
0.001	100	0.025	0.000025	0.00025	43835
0.01	100	0.025	0.00025	0.0025	4383
0.1	100	0.025	0.0025	0.025	438
1	100	0.025	0.025	0.25	43
10	100	0.025	0.25	2.5	4
100	100	0.025	2.5	25	0.44
0.0001	500	0.125	1.25E-05	0.000125	87671
0.001	500	0.125	0.000125	0.00125	8767
0.01	500	0.125	0.00125	0.0125	876
0.1	500	0.125	0.0125	0.125	87

1	500	0.125	0.125	1.25	8
10	500	0.125	1.25	12.5	0.87
100	500	0.125	12.5	125	0.08
Sandstone thickness between shale and aquifers is 4000 feet. Sandstone porosity is 0.1.					

Table 1 shows an immense range of travel times, and both extreme are very unlikely. If K was high, for example, the gradient would be low. The low ranges of K also seem very unlikely over large thicknesses. If the porosity is half the value used in the table, all travel times will be halved. Of course, if the thickness is lessened from 4000 feet, the gradient, and Darcy velocity, will be increased for the same head drop, and the travel time will also be cut.

The conductivity used by ICF in their faulty analysis was 0.1 ft/d. The corresponding travel times in Table 1 range from 87 to more than 4000 years – if porosity were halved this would be cut to 44 to 2000 years. Using the 1000 foot recommendation by the DSGEIS for site-specific analysis would cut the travel time to 22 to 1000 years.

The DSGEIS recommended 1000 feet depends on a low sandstone K, and ignores the particle travel time analysis. Although the calculation is based on a constant K, the reality is that the K probably varies greatly

> Permeameter tests on core samples from sandstone strata indicate that the **conductivity can vary locally by a factor of as much as 10-100 in zones that appear**, on the basis of visual inspection, **to be relatively homogeneous**. Figure 4.6 is a schematic illustration of a vertical hydraulic conductivity profile through a thick, relatively homogeneous sandstone. Conductivity variations reflect minor changes in the depositional conditions that existed at the sand was deposited. (Freeze and Cherry, 1979, page 153, emphases added)

The figure referenced in the quote has conductivity ranging from 10^{-5} to $6x10^{-8}$ m/s.

The DSGEIS recommendation also ignores dispersion which causes the contaminant front to move faster than the bulk flow and results in contaminant breakthrough far faster than expected due to bulk flow considerations.

Discussion and Conclusions

The interpretative numerical model of injection and flowback emulates the descriptions of the process provided by gas developers in the DSGEIS very well. Injecting 5,000,000 gallons of water into a representative shale formation over a five-day period requires a pressure similar to that reported in the DSGEIS. Most of the flowback occurs over a 60 day period, also similar to that reported.

The only exception is that almost twice as much of the injected water returns to the well. The total flowback volume was not sensitive to the simulated conductivity within fractured shale around the well. This suggests the model misses something in the

simulation of the actual process of injection and flowback. There are several possibilities:

- The actual injection affects a much larger volume of shale and the injected water flows and is stored further from the well.
- The conductivity values do not adequately represent the tortured porosity that occurs due to fracturing. The pores may not be as connected as the model simulated.
- Operators may seal off the wells thereby rejecting flowback to the well and leaving the injected water in the shale or surrounding media.

Simulating more flowback than actually occurred may have caused the simulation to underestimate the potential effects of injecting fluid into the shale. This is because there is less volume to cause vertical flow across the layers. Removing more flowback from the model may also have caused the head to dissipate more quickly would actually occur. The simulation may have underestimated the impacts of flow upward from the shale.

The simulation showed that flow could cross from the shale into the surrounding media. This is not a simulation of a specific fracturing fluid flow rate from layer to layer but it does show that fluid leaves the shale and reaches the surrounding media. Based on water balance considerations, some of the injected fluid would leave the shale. The natural gradient is upward, and therefore the fracturing fluid would begin to flow vertically upward. Even after ten years of simulation, the vertical velocity over the horizontal well is about four times the background velocity. Injection has a long lasting effect on the groundwater flow in the shale and surrounding media. It may cause fracturing fluid to enter the natural flow gradient away from the shale and affect resources closer to the surface than the shale years or decades later.

Additional considerations with Darcy's law and basic advective transport considerations show that travel time could be on the order of less than 20 years if the conditions are right, even if there is 4000 feet between the shale and the aquifers. The potential range of travel times must be considered when considering setbacks for the analysis of flow from the shale to the aquifers.

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Appendix B

http://www.dep.state.pa.us/dep/subject/advcoun/oil_gas/2009/Stray%20Gas%20Migration%20Cases.pdf

Site last visited 11/29/09

Department of Environmental Protection
Bureau of Oil and Gas Management
Stray Natural Gas Migration Associated with Oil and Gas Wells

Commercial oil production started in Pennsylvania in 1859 when Colonel Drake drilled the famous Drake well in Titusville. From there, petroleum production expanded further into the Venango, Southern and Bradford oil fields of Venango, Warren, McKean, Clarion, Butler and Armstrong Counties. Eventually, the oil belt extended to the southwest corner of the state in the Washington County area. During this 150-year span, hundreds of thousands of gas and oil wells have been drilled in Pennsylvania.

With the number of gas wells drilled in the Commonwealth since the inception of the industry, the potential exists for natural gas to migrate from the wellbore (via either improperly constructed or old, deteriorated wells) and adversely affect water supplies, as well as accumulate within or adjacent to structures such as residences and businesses. Collectively, this may represent a threat to public health, safety and welfare, and is a potential threat of a fire or explosion. The Department has documented such occurrences and these cases are provided in this document.

It should be noted that the Department also receives complaints of stray gas from other sources such as methane gas due to microbial processes or caused by burial of organic matter, landfills, mining activity, transmission or distribution pipeline, or natural causes. These cases are not included in this paper. The discussion in this paper is limited to gas migration cases associated with oil and natural gas wells (i.e. thermogenic in origin).

The gas migration cases are organized into several categories: new wells, operating or active wells, legacy or abandoned wells, and wells associated with underground storage of natural gas.

New wells involve that initial phase of an oil or gas well when the well is being drilled or re-drilled, completed and put into production. For most wells, well completion involves hydraulic fracturing either immediately after the well is drilled or at a later date.

Operating or production wells include wells that are actively producing. It also includes wells that the operator is not actively producing and that are not plugged.

Legacy or abandoned well incidents are associated with natural gas and oil wells drilled from 1859, when Colonel Drake drilled his first commercial well in Titusville, until the present and there is no responsibility operator for the well. The well may have been abandoned by the operator and not properly plugged or plugged according to the standards or practices that were in place at the time. Some of the wells were constructed under the Oil and Gas Act, which was passed in 1984 when new standards for casing, cementing and plugging wells were established. Many were not.

These cases typically involved gas migration from old wells that were abandoned without proper plugging procedures. Often, these wells are associated with the old oil and gas fields surrounding the greater Pittsburgh area or the Bradford or Venango oil fields.

Underground Storage of Natural Gas includes gas migration problems associated with operating gas storage fields.

INVENTORY OF OIL AND GAS WELL STRAY GAS CASES

NEW WELLS – STRAY GAS MIGRATION CASES

McNett Township, Lycoming County - East Resources – NCRO – July 2009: A natural gas leak from an East Resources Oriskany well was confirmed on July 27, 2009. Methane gas from the well impacted multiple private drinking water wells and two tributaries to Lycoming Creek, forced one resident to evacuate her home, and required the closure of access roads near the well. Company personnel took necessary measures to stop the gas leak at the well and stream and drinking water well conditions improved. The suspected cause of the leak is a casing failure of some sort. East Resources continues to monitor homes and wells in the effected area (approximately 6000 foot + radius) where methane has been documented and reports to the Department weekly. Methane was evident in some wells and the subsurface. One gas extraction system was installed at a residence. The investigation is on-going. The Northcentral Regional office expects to receive a report regarding the incident from East Resources in approximately 30 days.

Dimock Migration, Dimock Twp., Susquehanna County - Cabot Oil and Gas – NCRO - 2009: The Department is actively monitoring domestic water supplies and investigating potential cause(s) of a significant gas migration that has been documented in several homes along Carter Road. Free gas has been encountered in six domestic water supplies and dissolved has been found in several of the wells. The operator has placed pilot water treatment systems on three water supplies. Of particular note is that this area has not experienced previous drilling and recent gas drilling in the vicinity has targeted the Marcellus Shale.

Hedgehog Lane, Foster Twp., McKean County – Schriener Oil and Gas – NWRO – April 2009: The Department is actively investigating the report of fugitive gas in domestic water well. Prior to Departmental involvement, the company drilling gas wells in the area provided a new water well to an affected residence. After stray gas was evident in the water well, apparently the concerned resident approached the company directly, a new water well was provided and the impacted well was plugged with bentonite. Some time later, neighboring water well became impacted with stray gas and the resident contacted the Department. During the investigation, four gas wells were discovered over-pressured. Packers were placed in those over-pressured wells and the wells were brought into regulatory compliance. At this time, a response in the affected water well has not been observed. Complaints of water quality degradation and water diminutions are also under investigation in the area.

Little Sandy Creek Migration, McCalmont Twp., Jefferson County – NWRO – April 2008: In April, 2008 the Department was informed of a large fugitive expression in Little

Sandy Creek. Subsequent investigation indicated the presence of combustible gas in the basement of a nearby residence. It was determined that the gas was entering the structure through an un-sealed sump opening in the concrete floor of the basement. The sump was vented through the wall and the threat to the home was minimized. During the investigation the Department discovered that two recently drilled gas wells were over-pressured and were producing from different geologic strata. Isotopic analysis indicated that a specific gas well was the probable source of the fugitive gas and measures were undertaken to reduce pressure on the casing seat. After continued monitoring at the residence, it was determined that the amount of gas in the sump was decreasing. The basement sump remains vented and the problem is dissipating.

Kushequa Migration, Hamlin Twp., McKean County – NWRO – September 2007: A stray gas migration caused a change in water quality and a minor explosion in a community water well. Combustible gas was also encountered in a few private water wells within the village. The Department investigated the stray gas occurrence in September of 2007 and through an investigation determined that a specific over-pressured gas well was the cause of the migration. Pressure was released from the potentially responsible gas well and a positive change in the impacted water well was rapidly noted. Additional production casing was placed in the suspect well to permanently resolve the problem. The responsible party was recently issued a Consent Order and Civil Assessment which they plan to comply. The Department issued a well plugging contract to plug 15 orphan wells adjacent to the water wells.

Alexander Migration, Hickory, Washington County – SWRO: It appears the operator affected an old abandoned well when completing a new well in the area. Stray gas occurs in the soils and contamination exists in private water supplies. DEP is evaluating several wells in the area. The investigation is ongoing.

Five Mile Run A, Knox Twp., Jefferson County – NWRO – April 2009: The Department was made aware that on April 18, 2009 fugitive gas began escaping from a domestic water well. During the investigation, the Department also encountered combustible gas in neighboring water well. At this time evidence is being gathered and it is likely that the cause of the fugitive gas migration may be linked to a recently drilled neighboring gas well. The Department is also investigating three reports of water quality problems that may be associated with the recent gas well drilling in the area. The fugitive gas in the water well is a recent problem and at this time is not linked to the gas in Five Mile Run that is approximately 2,500 feet away.

Five Mile Run, Knox Twp., Jefferson County – NWRO – 2008: Consistent gas streams have been identified at two locations within Five Mile Run. Isotopic samples were obtained in early 2008 and the analysis indicates that the gas is of thermogenic origin. It is unknown when the gas first appeared in the stream. At the time of sampling, only

older historic wells (pre-1920's) were in the vicinity. Presently the area is experiencing an increase in drilling activity. The permitted boundary for the Galbraith Gas Storage Field (operated by National Fuel Gas) is located approximately 4000 feet to the closest stream expression of fugitive gas. The source of the gas at this time is unknown.

Mix Run Migration, Gibson Twp., Cameron County – NWRO – Fall 2007: In the fall of 2007, the Department continued the investigation of fugitive gas reported in the water well of a seasonal residence. The presence of gas in the water well is sporadic with no apparent trends in its occurrence noted. The area has experienced no recent drilling although historic records indicate Oriskany gas was produced in the vicinity. All wells that could be identified and field verified within one mile of the stray gas location are in regulatory compliance. The closest gas well was plugged and a gas well with potentially compromised casing (approximately 3000' away) was repaired. Gas was not present in the water well at the time of the last inspection in May, 2009.

Ohl Complaint, Hebron Twp., Potter County – NWRO – June 2007: The Department responded to a complaint of fugitive gas in a water well that serves a seasonal structure in June, 2007. Isotopic analysis indicated a possible similar thermogenic origin of the gas in the water well to a neighboring gas well. Initial efforts to vent the suspected gas well to atmosphere for an extended time failed to reduce the amount of gas in the neighboring water well. The new well owner placed a down-hole packer and additional production casing in the well. This action did not produce a reduction in the fugitive gas in the water well. The Department continues to investigate the complaint.

Miller Gas Migration, Liberty Twp, McKean County – NWRO – January 2008: Departmental personnel responded to a report of fugitive gas in a domestic water well that serves a seasonal residence in January, 2008. Investigation by Departmental field representatives discovered that two recently drilled gas well was over-pressured (exceeding the amount of allowable pressure on the casing seat). The operator Placed packers and additional production casing in the gas well, thereby eliminating pressure on the casing seat. The water well was aggressively pumped and over time the amount of combustible gas in the wellbore decreased significantly. The gas well was brought back into production when the amount of gas was below the allowable amount.

Head Drive Migration, Millcreek Twp., Erie County – NWRO – fall 2007. In the fall of 2007, the Department initiated an investigation into the report of fugitive gas in the vicinity of several homes along Walnut Creek. The discovery of fugitive gas in the soil near the residences, forced the Erie County Health Dept. to evacuate the neighborhood. The residents were displaced for at least two months. Through the use of isotopic analysis and with a through investigation performed by the Department's field staff, it was determined that the recently drilled neighboring gas wells were the cause of the migration. Through a Consent Order with the Department, the responsible party plugged two defective gas wells and placed packers in the remaining gas wells. The case is presently in private litigation.

Hughes Migration, Hamlin Twp., McKean County – NWRO – June 2006: In June, 2006 the Department responded to two water quality/diminution complaints and determined that a change in water quality was evident. Over-pressured conditions were noted at a recently drilled nearby gas well. The gas well operator drilled new water wells for the impacted residences and gas was encountered during the drilling process. Subsequently, when the operator placed additional production casing in the gas well, the Department noted a marked decrease in the amount of gas in the recently drilled water wells. Over time the problem has diminished.

Foote Rest Camp Ground Migration. Hamlin Twp., McKean County – NWRO – Late 1990s: In the late 1990's, the Department responded to a complaint of gas escaping from an abandoned gas well located in a wooded area near a private campground. During the investigation, it was discovered that an extremely large amount of gas (estimated at more than 100 Mcf/day) was venting from the abandoned gas well. The old well became activated when fracing was completed on a new gas well approximately 4000'away. Installation of production casing placed in the new well prevented additional gas from migrating to the abandoned well and the problem was resolved.

OPERATING WELLS STRAY GAS MIGRATION CASES

Harper Migration, Jefferson County – SWRO and NWRO – March 2004: An operating gas well. House explosion resulted in three fatalities. Origin/mechanism of migration: Operating gas well. Pressurization of the annulus on one or more operating gas well(s) was the mechanism of stray gas migration that caused the explosion. Status: Final agreement pending. . Elements of DEP Compliance Order still outstanding.

Dayton Investigation, Armstrong County – SWRO - March, 2008: Area-wide stray gas migration. Evacuation of one residence. Newly drilled gas well was over-pressured and communicated with an abandoned gas well and other operating gas wells. Corrective action at the well resolved the problem.

Origin/mechanism of migration: Newly drilled gas well. Pressurization of surface casing resulted in migration. Frac communicated with abandoned gas well and other operating gas wells. Status: Resolved.

Tin Town Road Migration, Monroe Twp., Clarion County – NWRO – July 2008: The Department became aware of fugitive gas migration that resulted in the fatality in July of

2008. Apparently, fugitive gas migrated from a very old gas well (drilled early 1900's) through the septic system and entered the bathroom of the residence. It is reported that the explosion resulted when the resident attempted to light a candle in the room. It is possible that gas migrated from the gas well through casing that over time had become compromised. The suspect gas well was vented to atmosphere and the problem dissipated. Presently, the well has been plugged by the operator and the case is in private litigation.

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Toy Migration, Armstrong County – SWRO – October 2007: Explosion at a water well enclosure. Well pump was destroyed and damage to enclosure. No injuries. The source was a nearby operating gas well. The water well has been properly vented and is now back in service. The water well quality was affected during drilling and previously restored by the operator of the gas well. The investigation is ongoing.

Origin/mechanism of migration is a newly drilled gas well. Pressurization of the annulus on a recently drilled well was the mechanism of stray gas migration. Status: Investigation is ongoing.

Wilson Investigation, Armstrong County – SWRO - October, 2007: Explosion inside residence. No injuries or significant damage. Stray gas impacted private water supply well and entered home through conduit for waterline. Origin/mechanism of migration was a newly drilled gas well. Pressurization of the surface casing in newly drilled gas well. Status: Resolved

Montgomery Migration, Hamlin Twp., McKean County – NWRO – July 2007: A domestic water well became impacted by fugitive gas in July, 2007. With Departmental involvement, the operator of nearby gas wells initiated a program of pressure testing suspect wells and it was determined that the casing failed on a specific well. Apparently, without a check valve in the production pipeline, the suspect well was feeding pipeline gas into the gas well. The gas migrated through the compromised well casing and into the local aquifer. The operator plugged the suspect well and problem was resolved.

Alexander Investigation, Washington County – SWRO - September, 2006: Stray gas migration impacting several private water supplies, and surface soils. Frac in recently drilled well communicated with abandoned gas well and migrated to shallow groundwater and surface soils.

Origin/mechanism of migration: Operating gas well. Frac communicated with abandoned gas well. Abandoned gas well is constructed with wooden surface casing. Investigation

reveals frac at recently drilled well created pathway to abandoned well and further migration into the shallow groundwater system. Status: Investigation is ongoing.

703 Liberty Street Migration, Warren County – NWRO – January 2005: Gas migrating from an operating gas well resulted in an explosion in the boiler room of the house. There were no injuries. Two nearby wells provided house gas to the residence. The problem well was identified and repaired. The investigation lasted several months.

Chestnut Street migration, Washington County – SWRO - May, 2003: An operating gas well resulted in fire and caused house explosions, with two injuries and an evacuation. Origin/mechanism of migration is an operating gas well had leak in casing. Status: Resolved. Gas well was repaired; outcome of the civil court case is unknown.

Unknown name, Armstrong County – SWRO - ~ 1999: House explosion, resulting in destruction of residence and one fatality. Investigation is not well documented. Origin/mechanism of migration is an operating gas well. Pressurization of casing. Status: Resolved

Vtodian Investigation, Allegheny County – SWRO - January, 1992: House explosion, resulting in destruction of residence, one injury and an area-wide evacuation. Origin/mechanism of migration is an operating gas well. Pressurization of the casing was the mechanism of migration of stray gas that caused the explosion. The well has been repaired. Status: Resolved

LEGACY OR ABANDONED WELL CASES

Hulton Road Migration, Westmoreland County – SWRO - October 2009: This incident was first investigated in August of 2004. The stray gas occurs in the soils on private property and in the right of way of Hulton Road. Origin/mechanism of migration is an abandoned gas well. In 2009 the Department issued a contract to plug the suspected well and install venting.. Plugging the well did not alleviate the stray gas. The Department let another contract for an additional $10,500 to vent the stay gas..

128 Lilac Court Migration, Allegheny County – SWRO - June, 2009: The stray gas occurs in the soils in a suburban housing development. Currently, the gas is localized in an area in front of a single residence. Origin/mechanism of migration is an abandoned gas well, location and mechanism of migration unknown. Status: Investigation ongoing.

226 Thompson Run Road Migration, Allegheny County – SWRO - May, 2009: The stray gas occurs in the soils in the vicinity of a residence. The area has had historical stray gas incidents. Venting systems have been installed at several locations in the area. Origin/mechanism of migration: source of gas is an abandoned gas well. Its location is unknown. DEP investigation is ongoing.

Independent Valley News Migration, Allegheny County – SWRO - April, 2009: The stray gas occurs in the soils in front of a business. The gas is being vented with a temporary vent system. Origin/mechanism of migration: source of stray gas is an abandoned gas well. Its location is known. The well has been placed on the list for plugging/venting. Status: DEP contractor to properly vent or plug suspect abandoned gas well.

112 Buss Road Migration, Beaver County – SWRO - March, 2009: The stray gas occurs in the soils on private property. Origin/mechanism of migration: source of gas is an abandoned gas well; its location is known. Status: The leaking gas well is being evaluated for proper venting/plugging.

2526 Wexford Bayne Road Migration, Allegheny County – SWRO - March, 2009: Stray gas in soils and inside home. Origin/mechanism of migration: abandoned gas well; its location is unknown. Natural gas service was terminated at a residence. Status: Resolved. The owner installed a venting/alarm system at his own expense.

Wendt Drive Migration, Allegheny County – SWRO - June, 2009: The stray gas occurs in the soils on private property. Origin/mechanism of migration: source of gas is an abandoned gas well. Its location is unknown. DEP investigation is ongoing.

Charleroi Migration, Washington County – SWRO - March, 2009: Stray gas encountered in soils in close proximity to business. Origin/mechanism of migration is an abandoned gas well. The operator of the well refused to accept responsibility for the problem and take corrective actions. Gas was leaking from the well in the parking lot and was adjacent to the buildings slab foundation. DEP issued a contract to plug the well and initially vented the well until work on plugging the well could begin. Plugging was recently completed. DEP will pursuing cost recovery from the operator.

Tarentum Migration, Allegheny County – SWRO - March, 2005 to October 2009: This incident was initially investigated in March, 2005. Thermogenic source from an unknown location resulted in natural gas service to be terminated by the gas utility 3 years ago at 220 W. 7th Avenue. The DEP plugged one abandoned well. This well

plugging did not alleviate the stray gas in the 7th avenue area. There was another plugged well nearby, but did not show any signs of a problem. DEP is conducting follow-up work to the plugging contract to vent the area adjacent to the structure. Origin/mechanism of migration: abandoned gas well, location unknown (contracting is awarded and work is about to begin).

Versailles Migration, Versailles, Allegheny County – SWRO – 2007 through 2008: The natural gas migration problem in Versailles has been ongoing for many years. During the boom period from 1919 through 1921, over 175 wells were drilled in the Borough of Versailles which was part of the McKeesport Gas Field. Some wells produced little or no gas and were abandoned without casing or plugging the boreholes. Other wells produced for a few years and were also abandoned with out plugging the wells. During World War II, the call for scrap steel resulted in the removal of steel casings and wellheads. The abandoned wells were cover over or otherwise abandoned. Over the years many venting systems have been installed by the property owners, borough or by DEP. In 2007 and 2008, the Department let an emergency contract to rehabilitate a well on the Saraka property for to relieve the natural gas pressure in the area. The DOE's National Energy Technology Laboratory (NETL) conducted an extensive study of the area. The original budget for the study was about $1 million dollars. This case is ongoing.

Buckner Migration, Washington County – SWRO - December, 2008: The stray gas occurs in a private water supply well. Origin/mechanism of migration source of gas is an abandoned gas well. Its location is unknown. DEP is conducting an ongoing investigation. The water well has been properly vented. Stray gas was migrating into a residence. DEP discovered pathway into home. Gas appears to be migrating through an abandoned coal mine. Status Immediate danger resolved. Investigation as to specific source is ongoing.

2228 Private Drive Migration, Fayette County – SWRO - October, 2008: Stray gas in soils. Origin/mechanism of migration is an abandoned gas well. Its location is unknown. Status: Resolved. This case was resolved by venting gas away from the structure.

630 Tara Court Migration, Ross Township, Allegheny County – SWRO - September 2008: The source of gas is an abandoned gas well, probably located under the parking lot of the Ross Park Mall. Gas service was terminated at the house at 630 Tara Court in the adjacent subdivision. The Mall was contacted and they are to provide maps of the parking lot to help locate the abandoned wells. The stray gas problem at Tara Court was resolved by installing a venting system until the abandoned wells under the parking lot can be located. The case is ongoing.

Pottle Migration, Allegheny County – SWRO - October, 2007: Stray gas discovered in soils at location for new commercial building. Origin/mechanism of migration is an

abandoned gas well. Its location is unknown. Status: Resolved. The owners of a commercial building installed a mitigation/alarm system at their expense to resolve the problem.

1100 McCartney Avenue Migration, Allegheny County – SWRO - February, 2007: Stray gas along front of commercial business. The source of gas is an abandoned gas well; its location is unknown. The owner of the commercial building installed a mitigation/alarm system at his expense. Natural Gas service restored. .

Sturgeon Migration, Allegheny County – SWRO - September, 2005: Stray gas in close proximity to several residences. Natural gas service terminated. Origin/mechanism of migration is an abandoned gas well. Its location is unknown. DEP installed a venting system to mitigate the gas migration problem at two residences. Status: Resolved. Gas service restored and the occupants returned to their residence. DEP investigated a well between the two properties; however, it was determined during preparations to plug the well that it was an old water well and not the source of gas.

Childers Migration, Washington County – SWRO - June, 2005: Stray gas has impacted soils area wide on private property. The source of gas is an abandoned gas well; its location is known. A gas well was leaking at the surface. There is a dispute of ownership with the well. The Department suspects the integrity of the well may have been affected by deep mining as the stray gas occurrence coincides with documented mine subsidence in the area.

Origin/mechanism of migration: abandoned gas well. Suspected casing/cement failure possible caused by mine subsidence. Status: Investigation Ongoing

Mediate Migration, Westmoreland County – SWRO - November, 2003: The stray gas was impacting private residence. Origin/mechanism of migration: source of gas is an abandoned gas well; its location is unknown. Natural gas service to a structure was terminated. Status: DEP funded mitigation system installed. Structure is protected. Natural gas service restored.

Tanoma Migration, Indiana County – SWRO - July, 2001: The stray gas occurs throughout the soils on private property. Origin/mechanism of migration: The origin of the stray gas is likely coalbed/gas well mixture. The situation was resolved through venting. The specific sources have not identified. Status: Resolved

McDonald Sr. Care Home Migration, Washington County – SWRO - November 2002: Stray gas found inside a Senior Care home, resulted in temporary evacuation. Origin/mechanism of migration is an abandoned gas well. Its location is unknown. The home was evacuated. The problem was resolved by installation of a mitigation system.

Paiano Migration, Armstrong County, -SWRO - September, 2002: Stray gas inside private water supply well resulted explosion in well enclosure. No injuries. Well was properly vented. Origin/mechanism of migration is an abandoned gas well, location unknown. Status: Resolved. Water well properly vented. Well not found.

Bagdad Road Migration, Waterford Twp., Erie County – NWRO – July 2008:
The Department is in the process of investigating a complaint of fugitive gas in a domestic water well received in July of 2008. All area gas wells are in regulatory compliance and isotopic analysis does not indicate a specific source of the stray thermogenic gas.

Clarington Migration, Barnett Twp., Clarion County - NWRO
The Department has been aware of a soil gas seep in a remote area since at least 1987. The source of the gas is unknown, no active gas wells are in the vicinity and a search of historical records failed to indicate any record of oil and gas drilling. The site near Cherry Run has become a seasonal camping spot and the surface expression of the stray gas migration has been improved with stone fire-ring to serve as a campfire location.

Groshek Migration, Keating Twp., McKean County – NWRO – 2008. In 2008 the Department responded to a complaint of stray gas in a domestic water supply. The area of the complaint is in an old oil and gas field that was drilled near the turn of the 20th century. Historic maps were used to attempt to locate nearby abandoned wells. Without any new drilling activity vicinity, the Department plugged four abandoned wells. These efforts of find and fix the cause of the migration have been unsuccessful. A recently discovered gas well has been identified in the field and the well was placed on the department's plugging list.

Leichtenberger Migration, Howe Twp., Forest County - NWRO
In June 2005 stray gas was reported to have entered two springs that serve as domestic water supplies. Located in an area that experienced a long history of oil and gas drilling activity, it was discovered that the migration began near the same time that two gas wells, located more that 3000' away, were fraced. The new gas wells are in regulatory compliance and additional measures were taken to prevent a gas migration. The department has plugged three abandoned gas wells in the vicinity. All efforts to identify the cause of the migration have been unsuccessful.

Nicholls Migration, Rome Twp., Bradford County – NCRO – June 2007: Complaint received by the Department in June, 2007 of stray gas in a domestic water supply. Isotopic analysis of the gas indicates that it is of thermogenic origin although it apparently does not match any production gas in nearby gas wells.

Skinner Migration, Columbus Twp., Warren County - NWRO
The Department responded to a complaint of stray gas in a domestic water well in June, 2005. All wells within 6000' were inspected and found to be in regulatory compliance except two gas wells. Those two wells were brought into compliance with the addition of production casing. The water supply improved however small amounts of fugitive gas remain in the water well. An abandoned well discovered by the department during the investigation remains on the State's plugging list.

Wayland Road Gas Migration, East Mead Twp., Crawford County – NWRO – October 2008: The Department continues to investigate a fugitive gas migration expressed in a domestic water well first reported in October, 2008. No difficulties were reported by the drilling company during construction of nearby gas wells, all gas wells are in regulatory compliance and it is difficult to determine when the problem became apparent. Isotopic analysis indicates that the fugitive gas is thermogenic in origin although a match to a nearby gas well is not apparent.

Hetrick Gas Migration, Redbank Twp., Clarion County – NWRO – Spring 2007: In the spring of 2007 the Department initiated an investigation into the conditions surrounding the report of fugitive gas in a domestic water well. Isotopic analysis of the stray gas indicates a thermogenic origin potentially similar to neighboring gas wells. A legally defensible case against a potentially responsible party could not be demonstrated and the Department eventually provided the resident with an alternative source of water.

Julie Anne Lane, Summit Twp., Erie County – August 2008: In August of 2008 the Department responded to a report of fugitive gas near a private residence. During the investigation a nearby "plugged" National Fuel Gas well was leaking a very small amount of gas. Isotopic analysis of soil gas samples obtained by the DEP indicated that the gas was probably of microbial origin and fuel gas was restored to the residence.

Mainesburg Migration, Sullivan Twp., Tioga County – NWRO – 2004: The Department became involved with this larger scale stray gas migration in 2004. Elevated levels of fugitive gas were identified in approximately 15 residences. Through a joint action between the department and Township officials, and with funding through a Growing Greener Grant, treatment systems were placed on those affected water wells. Three abandoned gas wells were plugged by the Department.

McCommons Migration, Leidy Twp., Clinton County – NWRO – November 1998: In November 1998 the Department responded to a complaint of stray gas in three water supply wells. Through the course of the investigation it was discovered that because one of the affected water wells was located in the basement of a church, combustible gas migrated from the well and into the indoor air of the structure, causing a significant risk of explosion. Also discovered was that during a recent resurfacing project on Rt. 144, Penndot paved over an abandoned gas well. The Department proceeded to remove the recent pavement and plug the abandoned well. Two of the three impacted water wells returned to normal and a marked improvement in conditions were noted in the third water well.

Mt. Jewett Municipal Well-field Migration, Hamlin Township, McKean County: Three water wells for the municipality of Mt. Jewett were temporarily affected by a stray gas occurrence in 2008. The migration lasted approximately one week and went away for no apparent reason. After the event, the department plugged a nearby abandoned gas well.

Sara Coyne, City of Erie, Erie County – NWRO – April 2008: In April of 2008, the department responded to a complaint of gas bubbling in a large body of standing water in a campground near the entrance to Presque Isle State Park. Soil gas samples obtained for isotopic analysis indicated that the composition of the gas is consistent with shallow shale gas of the area. Excavation done by the property owner encountered an abandoned gas well approximately 6 feet below ground surface. The gas well was subsequently plugged.

Environmental Air Migration, Pittsburgh, Allegheny County
The source of gas is an abandoned gas well; its location is unknown. Natural gas service was restored following installation of a mitigation system.

Owens Migration, Allegheny County
The source of gas is an abandoned gas well; its location is known. A site developer disturbed the well and was required to properly abandon the well.

Marshall Avenue Migration, Chartiers, Washington County
The source of gas is a possible coalbed/gas well mixture. The area has been properly vented. DEP suspects a gas well was leaking into a mine void.

Elliot Migration, Armstrong County

The source of gas is an abandoned gas well; its location is unknown. The case was resolved by properly venting a water well.

UNDERGROUND STORAGE OF NATURAL GAS CASES

Tioga Junction Migration, Tioga Twp., Tioga County – NWRO - 2008: In January 2001, the Department responded to a report of gas in the soil near two buildings. Further investigation indicated the presence of a potentially widespread stray gas migration problem. In 2008, Dominion Transmission and PPL Gas Utilities Corp. initiate a voluntary program to ensure safe source of drinking water for residences near Tioga Storage Field. 288 letters were sent of area homeowners requesting the opportunity to sample individual water supplies. A large number of residents responded and the extent of the potential stray gas by sampling was delineated. Water treatment systems were provided, at no cost to the homeowner, to those water supplies that were shown to have been impacted. The companies and the Department remain in the investigation process.

Sabinsville Migration, Borough of Sabinsville, Tioga County – NWRO – 2005 ongoing: The Department is aware of a fugitive gas migration in the water supplies for several residences in Sabinsville. Initial sampling occurred in 2005 and elevated levels of methane/ethane were encountered. The homes are located within the footprint for the Sabinsville Gas Storage Field that is operated by Dominion Transmission Inc. Isotopic samples have been obtained from the affected water wells and gas wells within the storage field. The cause of the migration has not been determined.

Appendix C

Monitoring Groundwater Quality Near Unconventional Methane Gas Development Projects

A Primer for Residents Concerned about Their Water

June 7, 2009

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Introduction

The natural gas industry has recently begun to exploit geologic formations which could be considered unconventional. These include coal seams in basins such as the Powder River in Wyoming and Montana, the San Juan basin in Colorado, and West Virginia. These also include shale beds, primarily of Devonian age, in New York, Pennsylvania, and Texas, among other locations.

Industry and regulators expect neither of these methane sources to contaminate groundwater and therefore have given little thought to monitoring water quality near the developments. Regarding shale bed methane (SBM) development, the New York State Department of Environmental Conservation claims there has never been any groundwater quality issues documented. The problem is they have never looked, yet recently nearby domestic water well owners have reported methane in their water in Pennsylvania. The industry is at a loss to explain how such contamination could have occurred. Methane in nearby water wells has long occurred near coal bed methane (CBM) development, but this not difficult to explain because CBM development occurs in the same coal seams used for water supply.

This review considers the need for and type of monitoring which should occur for these types of development. It discusses background and baseline conditions, the difference between them, and how to determine representative water chemistry conditions. The review considers both the detection of contamination and its long-term monitoring if it occurs. It starts with the presumption that monitoring is necessary. While every site has different conditions, this review provides a boilerplate template for residents to use in requesting that agencies require or industries provide the required monitoring. Monitoring well and piezometer construction details are not provided, although they are defined in the next section along with several other necessary terms. Another short section discusses several details which should be considered, or which activists should ask of the agencies. This review also does not discuss the multitude of statistical methods available to determine trend or otherwise assess the results of monitoring.

Necessary Hydrogeologic and Well Construction Nomenclature

Prior to discussing the details of groundwater and contaminant flow, it is necessary to discuss some of the terms that will be used within the document. These include hydrogeology terms and those that describe well characteristics.

Groundwater: water contained in interconnected pores located below the water table in an unconfined aquifer or within a confined aquifer.

Aquifer: a saturated geologic formation from which an economically useful quantity of water can be used.

Terms Describing groundwater in an aquifer, above the aquifer, and types of formations

- Saturated: the condition of all pore spaces in a geologic formation being sufficiently filled with water that it will flow under the force of gravity.
- Confined aquifer: an aquifer that is overlain by a confining be which does not allow the water to easily flow upward. Typically, the water pressure within a confined aquifer pushes upward on the confining layer.
- Unconfined aquifer: an aquifer with a water table at the top. The water table is the uppermost level of saturation.
- Phreatic aquifer: an unconfined aquifer.
- Aquitard: a geologic formation which slows substantially the rate of flow passing through it.
- Aquiclude: low-permeability geologic formation that forms the upper or lower layer of a groundwater flow system.
- Unsaturated zone: the layer of soil or rock between the ground surface and a water table or a aquiclude. It is not saturated and any water within it is bound to soil/rock particles.
- Vadose zone: unsaturated zone above the saturated aquifer

Type of Monitoring Wells

- Monitoring Well: a well screened across the water table in an unconfined aquifer.
- Piezometer: a well screened within a confined aquifer or within the saturated zone intended to be within the saturated zone. It differs from a monitoring well in that it gives the pressure at point in the aquifer not the top of the aquifer.

Well Construction Terms: a few basic terms used in this report.

- Casing: the solid tube lining the inside of the wellbore.
- Screen: a casing with perforations to allow groundwater to enter the well. alternatively, a well may just be open if the hole is not in danger of caving.
- Wellbore: the vertical hole drilled into the ground (production well may be horizontal)
- Gravel pack: gravel or other soil used to buffer the space between the drilled hole and the casing or screen.

Water Level Terms

- Water table: the water level of the top of the saturated zone in a phreatic aquifer. At any given point, it is the water level in a well that is screened across the top of the saturated zone. A three-dimensional surface of water levels at all of the wells in an aquifer resemble a table, albeit sloping with undulations, and therefore the name.
- Potentiometric surface: the level to which the water will rise in a piezometer in a confined aquifer or at depth in a phreatic aquifer.
- Head: the pressure, water table, or potentiometric surface expressed in units of length of rather than pressure.

Groundwater Monitoring Terms

Sampling: the process of withdrawing a volume of groundwater from a well or a piezometer. May be referred to as a sampling event.
Frequency of sampling: how often a well is sampled.
Micropurge: the process of slowly withdrawing a sample from a well to not lower the water level within the well substantially.
Flushing: the removal of a number of wellbore volumes from a well prior to sampling. Often, a well is flushed to remove stagnant water for a fresh sample from the aquifer.

How Do Contaminants Reach and Move Through the Groundwater?

Kazmann (1981, page 29-30) attributed four principal causes to water quality changes: “the miscible displacement of the native fluid by the foreign fluid; ion exchange between the foreign fluid and clays and silts of the aquifer and the confining, or bounding, formations; interaction between the native and foreign fluids and interaction between the foreign fluid and the aquifer materials”. This can be reduced to two ways through which contaminants can reach groundwater: (1) leaks, spills and intentional discharges; and (2) changes caused to the aquifer system by the project. These processes determine the type of monitoring necessary for the development.

Most commonly considered is a leak or spill which reaches the groundwater or a direct discharge to the groundwater. A leak occurs when a process facility loses some kind of contaminant, typically fluid, onto the ground or directly into the subsurface, usually for a significant period of time; a leak is often a continuous until it is detected and stopped. A spill is exactly that – a one-time unplanned discharge of contaminant onto the ground surface or into the subsurface. A discharge is a planned, usually-continuous stream of contaminants to the groundwater. This may include, but not be limited to, underground injection, leach fields, or infiltration basins. It includes the disposal of produced water from CBM development, which may be reinjected or reinfiltrated to maintain the water balance (Myers, 2009) and the potential disposal of recovered hydraulic fracturing fluids. It also could include the unplanned long-term leakage from ponds used to store CBM-produced water, other waste, or fracturing fluids.

Contaminants also reach groundwater from secondary sources, primarily those which cause a release of contaminants that naturally exist in the area. Typically, a process alters the underground or above ground geologic properties in a way that changes flow paths and allows geochemical reactions which may release contaminants previously bound in the rock or that causes reactions which cause contaminants to form or the dissolution of natural constituents. A good example is acid mine drainage, for which the mining company moves rock around in a way that allows oxygen to reach sulfides in the rock which causes oxidation and the formation of acid which may then leach metals into the groundwater. Another secondary source may be artificial recharge of clean water for the purpose of increasing groundwater storage in an area; as water seeps through the unsaturated zone to the saturated groundwater, it may leach salts or other contaminants.

CBM and SBM development present their own unique sources of contamination due to the development changing properties in the target or surrounding geologic formations. CBM development lowers water pressure in the coal seams which releases methane gas which may reach wells or discharge from springs fed by the coal seam aquifer. CBM development also alters groundwater flow paths which could mix previously separated groundwater and rock types. Hydraulic fracturing may alter the hydraulic properties of shale beds or surrounding layers, often sandstone, which could allow contaminants which are bound by the extremely slow flow rates to migrate to wells or other discharge points.

Factors Affecting Contaminant Transport

Groundwater moves at rates ranging from a few feet per day to a few feet per millennia, a fact which must be considered when considering contamination. Contaminants move with the groundwater flow, but many things affect the rate, and within the groundwater flow. An individual water particle moves many times faster than the bulk groundwater flow (Darcy flow) because the actual pathways for flow through the pores are much narrower than the full cross-section. The rate equals the Darcy velocity divided by the effective porosity, and the Darcy velocity is simply the flow rate divided by the entire cross-sectional area.

Contaminants move within that flow, affected by advection, dispersion, diffusion, and attenuation (Fetter, 1999). Advective transport is a contaminant being carried along in the groundwater flow. It moves at the rate of a water particle, as described in the previous paragraph. Considering just advection, the contaminant load moves at the same concentration throughout the aquifer. If the geologic materials vary within an aquifer or among aquifers through which a contaminant is flowing, the different properties may result in the solute front spreading at different rates among the layers.

Diffusion is the movement of a contaminant from an area of high concentration towards areas of lower concentration. Just as a gas released in the corner of a room rapidly moves around the room so that the concentration becomes constant throughout, a mass of contaminants spreads slowly through groundwater, even if it is not moving.

Differing flow velocities throughout an aquifer causes mechanical dispersion. There are three basic causes of the differing velocities. First, water flows faster in the middle of a pore than on the edge, or boundary, of the pore due to the drag caused by the pore boundary. Second, the pores extend in all directions, although they may trend in one direction, which may allow a particle to move locally in all different directions; the bulk fluid movement follows the expected flow path. Some of the particles therefore follow much longer flow paths and lag behind those following shorter paths. This disperses the contaminant both horizontally, away from the primary flow path, and longitudinally along the flow path. Third, pores differ in size causing the bulk average velocity through each to differ. This causes longitudinal dispersion just as does differing flow paths.

Dispersion and diffusion are impossible to separate and are normally considered together as hydrodynamic dispersion.

Contaminants which move strictly according to these three processes are considered conservative. The entire load, or mass, of contaminant introduced into the ground flow system will pass through the system. However, both physical and chemical processes could attenuate the flow. Physically, the contaminant could adsorb to soil particles and be removed from the groundwater flow system. Chemically, the conditions in the groundwater could cause the contaminant to precipitate or react with other constituents in the groundwater; both remove the contaminant from the flow system. With attenuation, the load entering the flow system may never flow from it but some may reside within the soil for a long time period. Many remediation plans rely on natural attenuation; a concern with attenuation is that as the chemical conditions change, the contaminant could begin to move again. This may cause contamination to continue long after the source has been stopped. For example, leaching salt may attenuate by precipitating in the unsaturated zone, and then dissolve into natural recharge at the site (Pettyjohn, 1982).

Effect of Geologic Formation

Dispersion and attenuation vary among geologic and soil types and among contaminant types. Consideration of the variation among the geologic formation and among contaminants is essential for designing a monitoring system. Permeability is a measure of the ability of a media to allow a fluid to flow through it; conductivity is permeability with respect to water. Primary permeability is the permeability of the bulk media and secondary permeability is that with respect to the fracture zones within a media.

Groundwater moves through a classic porous media, such as alluvium or basin fill, like water through a sponge. The porosity may be as much as 40% of the media volume and most pores are connected. Primary permeability controls most of the flow. The actual conductivity may be high if the pores are large and low if the pores are small. A fact not immediately obvious to the layperson is that porosity in clay is very high, but the pores are very small and consequently so is the conductivity. The conductivity is low because more of the water molecules are in contact with the pore walls and therefore

experience substantial drag; a velocity profile for a section across the pore would show velocity near 0 on the edge and reaching a maximum in the middle of the pore. Contaminants would move in the middle of the pore much faster than the average flow rate, and much faster than if the pores were larger because much more of the flow will be detained by the surface tension in the pores.

If the sponge is replaced by concrete, the primary conductivity is very small because the small pores are not connected. However if that concrete has a crack or two in it, lots of water may flow through the cracks. This is the case for bedrock aquifers, including sedimentary rock. The secondary permeability controls the flow in this case.

Coal is an interesting combination of both types of permeability. While it is certainly a rock, the pores are connected through cleats and the conductivity can be relatively high (Stoner, 1981; Weeks, 2005, Morin, 2005); cleats are natural fractures, usually closely spaced, perpendicular to the bedding plane of the coal. See Myers (2009) for a brief discussion of coal hydraulic conductivity. Faults and fractures may affect coal, so the secondary conductivity may be locally high.

Marcellus Shale is very impermeable, ranging from 0.01 to 0.00001 millidarcies (Arthur et al, 2008). Boyer et al (2006) note the lowest intrinsic permeability from which gas may be obtained is 100 nanodarcies[9]. One darcy corresponds roughly to 10^{-9} x 1.4156×10^{-2} gal/min ft^2 or 2.205×10^{-9} ft/d for water at 20 deg C. At a gradient equal to 1 with an intrinsic permeability equal to 100 nanodarcies, water would flow only 0.00008 feet in a year. It is clearly an aquitard. However, it is important that the shale is considered "notoriously heterogeneous" (Boyer et al, 2006, at 45) with the changing conditions both horizontally and vertically posing fundamental challenges to SBM development. No specific references to faults and fractures were found; it is possible that fracturing adds to that heterogeneity.

Effect of Contaminant Type

To design a cost-effective monitoring system, it is essential to know the flow path a substance will follow through an aquifer. Substances that dissolve in water, such as salt, will follow the basic flow pathways and be affected by dispersion processes. Other substances that are not water soluble, which probably include some of the fracturing fluid constituents, will vary from the expected path of a water particle according to their properties. Substances lighter than water may float on the water table surface; substances denser than water may sink through the aquifer to the bottom, or to a point where the porosity impairs their downward motion. Substances more viscous than water, whether lighter or heavier, move slower than water.

[9] Permeability is an intrinsic property of the formation. A darcy has units of area which can be converted to conductivity, a more common hydrogeologic term, by multiplying by gravitational acceleration and dividing by kinematic viscosity. Darcies are used by reservoir engineers. 1 darcy equals 9.8697×10^{-9} cm^2 or $1.062 \times 10\text{-}^{11}$ ft^2. A nanodarcy is 10^{-9} darcies.

Hydraulic fracturing introduces chemicals that are not naturally present. The different chemicals are designed to help in fracturing, hold the fractures open after the pressure is released, make the other constituents flow more easily or kill bacteria and fungus that could clog the well screen or fractures. Many different chemicals are used, but the exact mixture is not known publicly and varies with location (Table 1). They dissolve, float, and/or sink in the groundwater; their propensity to attenuate or be retarded as they flow through the groundwater varies with aquifer formation type and background geochemistry. All of these variations in transport properties will affect their monitoring .

Table 1: Common Fracturing Fluid Additives (GPC and ALL (2009), Arthur et al (2008)

Additive	Common chemicals
Diluted Acid	Hydrochloric acid, muriatic acid
Biocide	Glutaraldehyde
Breaker	Ammonium persulfate, sodium chloride
Corrosion inhibitor	N,n-dimethyl formamide
Crosslinker	Borate salts
Friction reducer	polyacrylamide, mineral oil, petroleum distillate
Gel	Guar gum, hydroxyethy cellulose
Iron control	citric acid
Carrier fluid	Potassium chloride (KCl)
Oxygen scavenger	ammonium bisulfite
ph adjustment	sodium or potassium carbonate (NaCO4 or KCO4)
Proppant	sand
Scale inhibitor	ethylene glycol
Surfactant	Isopropanol

Methane is the other, obvious unique contaminant potentially resulting from CBM and SBM development. Methane will move through groundwater as a dissolved gas, which means that it may diffuse much faster than it transports by advection or dispersion. Domestic wells have been shown to be affected by methane in areas with substantial development (Thyne, 2009; Methane in groundwater will not likely react with other constituents.

Contaminant Transport Above the Aquifer

The preceding discussion has been concerned primarily with transport of contaminants within saturated aquifers. Most spills and leaks onto ground, however, most flow through the unsaturated zone to reach saturated aquifers. The travel time is often slower than in the saturated zone; although the principles are similar, the presence of air in the pore spaces may increase the drag and slow the flow; flow may occur through some pores which have filled with water while be essentially bound in others.

The difference between arid and humid regions in this regard may be huge, due to the thickness of the zone, the degree of saturation, the amount of natural recharge and the degree of soil development including the presence of organic matter. In either climate zone, a leak into a thick layer of unsaturated soil may build up a large load of contaminants before the contaminants ever reach, and can be detected in, the saturated zone.

Seasonal Effects

Contaminants advect and disperse through the unsaturated zone to the groundwater and through the groundwater according to many geologic and geochemical properties. Additionally, climate affects transport by providing the flow to advect the contaminants. The design of monitoring systems must account for the seasonal effects of recharge. Recharge events both leach contaminants through the unsaturated zone to the groundwater and increase the gradient causing advection to move faster. Downgradient from a contaminant source, recharge may provide clean water to dilute the contamination. If recharge occurs infrequently and the aquifer system is small, it is possible that recharge will move a contaminant load through the system between sampling events.

In the West, the annual runoff and recharge period may last much less the three months, therefore the primary driver of flow and contaminants occurs at a duration measured weeks. In arid regions, where the soil may start an event dry, the event may be measured in days. In the East, recharge events may be more frequent, but are event-based and at durations measured in weeks. The effect of recharge event duration varies with the size of groundwater basin, with smaller basins having short duration changes due to recharge.

Conceptual Flow Model

Kazmann (1981, page 30) describes the placement of observation wells depending on various interrelated parameters including "the relative density and viscosity of the foreign fluid as compared to the native fluid; the pre-existing potentiometric gradient of the native fluid; the aquifer dip; the storage capacity of the aquifer as compared to the cumulative volume of foreign fluid (the same volume of foreign fluid will utilize a much smaller area of a thick aquifer than it will of a thin aquifer, and this volumetric relationship will influence the distance from the point of injection, or entrance, at which any monitoring well should be placed) and the intended use of the target aquifer." Because of these factors, prior to designing a monitoring network, it is essential to establish a conceptual model of the flow through the system (Shosky, 1987).

A conceptual flow model is a description of where the groundwater in an aquifer, or portion of an aquifer, comes from and where it goes, and how it flows through the aquifer. For the purposes of tracking contaminants, the most important aspect of the model is the conceptual flow path. Only at the point of recharge can contaminants be carried from the ground surface to the groundwater. Natural recharge is the process by which precipitation infiltrates past the surface soils and vegetation to reach the saturated

groundwater; recharge can also occur from artificial sources such as infiltration basins. Determining the flow path necessarily includes an assessment of the material properties along the pathway to estimate the flow rates and contaminant transport properties. Also essential is knowledge of the contaminant being considered, as to whether it sinks, floats, moves slower than water, or just simply and conservatively passes along with the groundwater flow. These issues, the principles of transport, were discussed in the preceding section.

The conceptual model should be based on all levels of geologic and groundwater information available at the site, such as bed thicknesses, porosity, hydraulic conductivity, and hydraulic gradient. It should also include baseline water quality data, sufficient to determine the groundwater type. If the source or age of groundwater is useful to know, isotope and tritium analyses should be completed. In remote areas, there may be little date therefore the conceptual model must be based on professional experience and intuition. Even in developed areas, the design may be based on less-than-adequate well logs and tests associated with the development of production water wells.

New Unconventional Methane Source Development

CBM and SBM affect the conceptual flow model in substantially different ways and therefore represent different monitoring challenges. Their effect on the flow model will therefore be described differently. Fracturing may occur in each type, however, and will be considered separately.

<u>Coal-bed Methane Development</u>

CBM development involves the removal and ultimate disposal of large amounts of water from confined, coal-seam aquifers. The process lowers the potentiometric surface in the coal seam substantially which creates a drawdown cone and changes the flow paths of groundwater in surrounding aquifers (Myers, 2009). Groundwater originating in one aquifer may flow through another which could change its chemistry. The coal seam being developed is having water removed from it and therefore will have lower potentiometric surface than the layers above and below; this will cause water to enter the coal seam. The changed flow paths will draw water through other coal seams which could spread the extent of existing poor water quality. Developers target only the thickest seams so the thin seams remain potential contaminant sources.

The discharge of produced water may cause contamination because the natural water quality of the coal seams may be much poorer than exists in surrounding aquifers and streams. The water may especially be high in dissolved solids (Rice et al, 2000). However, the primary concern with produced waters has been to surface water sources (Wang et al, 2007) and to the impacts that land disposal could have to the soils

Containment of CBM-produced water in a surface pond could be a long-term contaminant source if the pond leaks, and these ponds require monitoring independent of

the actual CBM field monitoring (because the ponds may not be within the CBM field). Containment ponds should of course be lined and should have a leak detection system, which is a kind of double liner. The pond should be treated as a potential source of contamination and a conceptual flow model developed for leakage from the ponds to determine the best place to monitor.

Shale-bed Methane Development

SBM development targets very deep shale. Wells, both vertical and horizontal, access the shale and provide a sink for the gas. There does not appear to be substantial quantities of produced water, which would be water flowing to the wells from the shale; produced water is the water that naturally occurs in the shale and is released due to the well accessing the shale or the fracturing, but it differs from returning fracturing water.. The low flow rates of produced water could be due to the extremely low permeability of the shale, often on the order of 10^{-12} cm/s, which would not allow water to flow. However, a major concern is that hydraulic fracturing could change the properties of the shale and the current flowpaths and possibly produce some water.

The most likely apparent source of contamination, other than from hydraulic fracturing (see the next subsection), is leakage from the wellbore. If there is no produced water being withdrawn under pressure, methane gas would be the primary potential contaminant. The natural, background methane concentration is zero unless it is in a formation that produces gas; even in that case, the formation media holds the gas until a change, often a well, causes it to be released into the groundwater. It should be sufficient to just detect the presence of methane to prove a leak.

Spills and leaks from SBM gas collection wells are NOT likely to affect the flow because the volume of water released would probably be much less than the volume of water flowing through the aquifer.

Hydraulic Fracturing Issues

Hydraulic fracturing involves the injection of fracturing fluids at high pressure into the target formation to increase its permeability to more easily release the methane gas. Fluid volumes vary from 80,000 gallons used in a vertical well to 5,000,000 gallons or more used for a horizontal well in shale. The fluid is removed from the formation and well, although the recovery is not 100%. Leakage from the wellbore would be an infrequent occurrence because fracturing fluids are introduced to the well just once or a few times and should not be a continuous source of contamination. The amount of fluid injected at once is significant, but with substantial recovery, any mound created should be small and dissipate quickly. It should not cause significant changes in the flow path.

Fracturing's primary effect on the conceptual flow model is to change the properties of the target formation (coal or shale). If those changes extend to the edge of the shale or coal seam, the flow between the shale or coal and the surrounding formations could change. For example, when groundwater flows from one formation to another, it

always refracts depending on the hydraulic conductivity differences. Big changes could occur within shale because it has such low natural conductivity that fracturing could very substantially change the flow directions. The shale in its natural state is an aquitard; if the conductivity changes enough to affect this classification, fracturing will have caused an immense change in the flow model.

It is also possible that fracturing could affect natural fractures that extend through the target formation. Hydraulic fracturing could increase the conductivity along the fractures which would increase the flow. Fracturing would increase conductivity by enlarging the pores and breaking blockages among pores. Thyne (2009) showed that methane could move vertically along faults and fractures several thousand feet to contaminate near-surface domestic wells.

Design of a Monitoring Plan

There are two primary objectives in monitoring for water quality (detection v. assessment). The first is the simple detection of a contaminant being released from a site; the actual concentration may be less important. The second is the determination of the trend in concentration of a contaminant and the mapping of its plume. Tracking a trend could determine whether standards are being exceeded, whether there is a trend toward groundwater being degraded as compared to baseline conditions, or whether a remediation plan is working as intended, as a decreasing concentration trend would indicate. These objectives may require different monitoring well designs. This section considers how to determine baseline water quality, space the monitoring wells, and establish a sampling frequency.

Baseline Water Quality Determination

Background and baseline are often considered to be the same thing, but they really are not. Background is the condition naturally existing at the site and baseline is the line serving as a base for measurement or comparison. The difference is that the natural conditions may have been altered so that background water quality no longer manifests. Therefore, baseline water quality is the base against which monitoring data can be compared and may be either background or background altered by development.

It seems obvious that in a pristine environment, the baseline water quality is the water quality resulting from natural groundwater flows through the existing geologic formations. The quality may not be perfect for beneficial use; it may not even be potable as witnessed by the poisonous natural springs in Death Valley.

The question becomes more difficult in a developed area with existing sources of contamination. Existing development may be providing a stream of contaminants causing increasing concentration at the site resulting in there being no acceptable “number” to be used for comparison.

Another complicating factor is seasonal variation due to variations in recharge. In arid regions, recharge occurs as a result of the rare precipitation events; in humid regions, more recharge may occur throughout the year with peaks during the winter/spring periods when evapotranspiration is minimal. In either case, the recharge may drive contaminant loads to the groundwater.

Considering all of these factors, baseline is the water quality that would exist in an area without the proposed development, although it may include existing development. It may be pristine, without development-related contamination and only seasonal variation in natural constituents. Or, it may be a site contaminated to the point of Superfund status. In between the two extremes lie the regions of most interest to most people affected by unconventional gas development – rural areas affected by small-scale development, including agriculture, small industry, and domestic septic systems.

Baseline conditions in this standard case would likely be a quasi-equilibrium condition of natural geochemical conditions with small amounts of human-induced chemicals, such as nitrates in agricultural areas or hydrocarbon products near small industries. To determine baseline, the analyst should consider the natural constituents to be expected and the industries to estimate what constituents they could discharge. The analyst should also sample the standard ions so that the type of groundwater may be determined.

All of the existing wells in the area should be sampled for the potential contaminants for at least a year, to assess seasonal changes. Using the well logs for each well, the lithology for the area should be mapped. Groundwater samples for each well should be taken and analyzed to determine existing conditions. The focus is on basic groundwater types and constituents plus any contaminants expected only due to the development. Preferably, only wells that screen one lithologic layer should be sampled to avoid mixing water from different geologic types. A map of concentrations and hydrographs of seasonal changes would be the baseline against which future monitoring should be compared. If the site is disturbed, it may be necessary to use existing conditions to model the future; the results from the modeling should be used as the baseline against which monitoring could be compared.

Where there are insufficient wells to determine baseline, springs could be sampled, although the monitor must consider whether being near the ground surface could cause geochemical changes. If the aquifers are shallow, a push-point sampling regime, wherein shallow holes are dug with hand augers to just reach the top of the water table, could be used to map water quality in a phreatic aquifer. For confined aquifers, or deeper phreatic aquifers, it is essential to construct wells upgradient and down-gradient of the potential source. New monitor wells should be constructed in the flow path as determined by the conceptual flow and transport model. It is only possible to determine if an observed change in the concentration of a constituent which is naturally present in the water source is due to an unnatural source if the natural variation has been previously established (Pettyjohn, 1982). These monitor wells must be constructed sufficiently long

before the development of the source that seasonal trends can be established, as described in the next section.

Monitoring Well and Piezometer Spacing

The previous section discussed the use of existing wells to determine background conditions for an aquifer, but it is important to consider that such wells are generally poor for monitoring. Thyne (2009, pages 10-11) explains clearly why domestic wells are poor monitoring wells:

> It should be noted that all the groundwater samples except the WDC monitoring wells are taken from domestic wells. First, the number of domestic well sample points is far exceeded by the potential point sources (gas wells). Domestic wells are much less than ideal for sampling purposes. Domestic wells are not placed to determine sources of contamination in groundwater. They are not evenly spaced around gas wells or within close enough proximity to determine the presence of chemicals associated with methane that degrade rapidly. Domestic wells are generally screened over large intervals making vertical spatial resolution for samples difficult nor are the wells are not constructed to facilitate measurement of water table elevation or downhole sampling. This forces sampling to occur at the surface after pumping raising the possibility of sampling artifacts. In addition, since domestic wells are the sole source of drinking water for individual properties, it is difficult to arrange access to take samples due to privacy issues, and the County may bear potential liability for damage during sampling and interruption of water supply.

A monitoring well system should be designed so that a contaminant plume will neither pass horizontally between the monitoring wells nor above or below the screened interval. The best way to be certain of intercepting a contaminant passing a point in an aquifer is to span the entire aquifer with well screen. However, a long screen is not best for monitoring concentration because of dilution. A sample extracted from such a well will be a conglomerate of the chemistry of the entire aquifer; if the screen spans multiple lithologies, the water within the wellbore may dilute the concentration emanating from one of the lithologies (Shosky, 1987).

A long screen may increase the chances of detecting the presence of an expected contaminant which may indicate the site being monitored has developed a leak. This may also be the most cost-effective method because it requires less construction and less sampling cost. But it can only be effective on substances which do NOT naturally exist in the region of the aquifer because the estimation of concentrations will not be accurate for any specific lithology.

Monitoring concentrations requires more layer specific sampling to provide an accurate representation of the aquifer. In addition to the amounts released by the project, there is probably a background concentration, which will also vary by location due to the natural geochemistry and rock properties of the aquifer. The concentrations will vary

throughout the aquifer, both vertically and horizontally. Unless the monitoring requirements call for vertical averaging over the entire aquifer, the concentration determined from such a sample may have a downward bias and not represent the much higher concentrations that likely exist in some vertical sections of the well. If wells tapping the aquifer span the thickness necessary to produce the needed flow, a longer monitoring well screen will not provide an accurate picture of the water quality affecting the well owner. This is usually the shallower portion of the aquifer which is also the portion of the aquifer into which a contaminant would initially report. Therefore, to monitor trends in concentration, screens spanning more representative vertical sections should be used. Many laws, as suggested by Perry (1983), provide no guidance as to the thickness of well that should be screened.

Long well screens are also problematic if there is a vertical gradient which could establish an upper gradient within the well. If this is the case, water sampled from the well may result only from the deeper portion of the screened thickness because the water level will reflect the head, or water pressure, at the bottom of the screen which will prevent flow from entering at the higher levels.

The screen, or well length open to the aquifer, must span the width of aquifer that includes the water table and must also accommodate expected changes in the water table level due to seasonal or pumping stresses. If the water table will vary over a wider section of aquifer than the screen length, more than one monitoring well may be necessary.

The spatial layout of the monitoring well system should be based on the conceptual flow and transport model, which includes flow pathways and possible contaminant dispersion. Monitoring wells should be placed as close to the expected flow path as possible. The concentration will be highest along the flow pathway with lesser concentrations lateral to the flow path. However, there will always be uncertainty in the prediction of the flow path, therefore it is essential to have monitoring wells spaced laterally away from the flow path as well. These lateral wells should have lower concentrations than the one in the flow path. A comparison of concentrations should help to determine the actual flow path; if a lateral well has a significantly higher concentration, the regulator should consider adding monitoring wells a longer distance from the predicted flow path to improve the understanding of the flow.

Monitor wells should be placed close to the potential source for early detection, but also at a distance from the source to increase the chances that it will intercept the contaminant and to assess the rate of movement. If many wells detect the contaminant, the concentration variation would indicate the degree of dispersion. Denser well networks will have a lesser chance of missing the contaminant but will also be more expensive to construct and maintain.

One way to establish the spatial layout of a monitoring network is to complete a numerical model of the conceptual model of flow in the system (Ling et al, 2003). Because there will be little data available at the site, the model will have significant

uncertainty in both the hydrogeologic units and the parameterization. However, with an adequate uncertainty analysis, possibly stochastic, a reasonable estimate of the horizontal and vertical spread of the plume could be made to improve the selection of monitoring well locations.

Sampling Frequency

Just as the spatial layout of a monitoring system should be designed to minimize the chance that a plume could pass without being detected, the monitoring well system must be sampled frequently enough to minimize the chance that a plume will pass between sampling events. As discussed, many natural geologic and climatic features affect the rate of contaminant movement with and through the groundwater. A temporary leak that does not disperse may pass a site in just a few days whereas a continuous leak may cause a slow concentration increase occasionally diluted by natural recharge; even once stopped, a substance that leaked for several years may appear in monitoring systems for decades due to variable transport rates.

Regulatory agencies commonly require quarterly sampling of a suite of parameters of interest at the site; this sampling frequency has been used for decades even though concentration hydrograph often varies inexplicably. The variation is often due to short-term recharge events and it may be unknown whether the concentration at any given point is increasing or decreasing and how far it would be from the actual peak.

Sampling is costly, a factor that must be considered in any plan. The frequency of sampling should be sufficiently often to minimize the chance that contaminant plumes could bypass the monitoring system. Based on professional judgement and experience, most sampling regimes should include at least a year of monthly sampling to establish the seasonal changes. After the sampling frequency decreases to quarterly, there should be a plan to increase to monthly if a parameter of interest begins to increase or exceed standards. Additionally, the monitoring wells should include continuous sampling of ec, pH, and water level so that the time frames associated with recharge events and the potential short-term leak can be recorded and considered.

Specific Details for Unconventional Methane Development

Coal-bed Methane Development

The drawdown caused by development changes the natural flowpath in the aquifers, but the flow direction is obviously toward the CBM well; the flow paths through a well field may be more confused, with multiple drawdown cones and sinks for water imposed on the natural flow path (Myers, 2006). Because each well field creates a large drawdown cone which effectively draws water and contaminants inward toward the production wells, the operators should be required to sample the produced water. Of course, nearby private water wells may also be affected, therefore, the operator should be required to sample the private wells also. It is unlikely that a separate monitoring well system is needed for CBM development.

Containment ponds do require a separate monitoring system because they are likely located outside the CBM fields or will discharge to shallow aquifers in which flow is not controlled by the CBM development. Monitoring with existing nearby water wells is not expected to be sufficient because most containment ponds would be sited some distance from water wells and a large portion of the aquifer could be contaminated before the contaminant is detected in the existing well. If the pond is small and developed in a phreatic, alluvial aquifer, an up- and down-gradient monitor well, developed in the upper ten feet of the saturated zone should be sufficient. The upgradient well should be sufficiently far from the source as to avoid any dispersion that could go against the advection from the source. The downgradient monitor well should be as close to the source as possible to detect leaks as soon as possible. The location of the monitor wells should be determined with the conceptual flow model for the flow of leakage from the ponds. These wells should be developed sufficiently long before the source to develop an adequate baseline.

Shale-bed Methane Development

The monitoring regime for SBM could be simple because the objective, in addition to hydraulic fracturing, will be to target leaks from the wellbore. All SBM development wells should have a monitoring well downgradient from the vertical wellbore and as close to the gas well as feasible. An upgradient control well is not necessary if the downgradient well is sampling for a substance not present in the unaffected groundwater, as is likely for leaks from a producing gas well that is also used for fracturing.

The well screen should span all layers of concern through which the wellbore is constructed and which could be contaminated by a leak. Most important are those formations tapped by nearby wells for beneficial uses or which discharge to nearby springs or streams. The detection limit should be sufficiently low to detect methane within such a well.

Hydraulic Fracturing

Only a few of the fracturing fluid constituents are natural groundwater constituents, such as potassium and chloride,, therefore detecting them should suffice as an early warning that there is a problem. However, the large potential variety of chemical and their variable transport properties renders testing costly. The most important aquifers are near the surface where there are wells and springs, therefore it might not be necessary to monitor the deepest layers which could be affected. This should be considered on a site by site basis.

Some regulatory agencies have allowed the testing of one chemical which may serve as a marker, such as potassium (K). This occurs naturally in the soil and groundwater, but an increase could be due to a leak of fracturing fluid. If the monitoring of a marker fluid is to be used, chloride would be better than K because K transport can be retarded by cation exchange, wherein the K cations become bound to clay particles. Chloride is a more conservative marker. As found by Thyne (2009), an increase in chloride could mark pollution emanating from development.

Some of the fracturing fluid constituents will move through the groundwater slower than the conservative chloride, therefore if the cause for changes in chloride concentration can be determined, it could be a sufficient marker. Because of the potential other causes for changes in chloride, it would still be preferable to sample for other constituents, such as the mineral oil or petroleum distillate. It is also probable that inmiscible fluids, such as those lighter than water may float on the surface and move quicker than dissolved chloride. This is an additional reason to sample more than chloride and to screen the monitoring wells across the top of the water table (if the fluid is lighter than water it may float on the water table).

Construction of Monitoring Wells

Monitoring wells should be constructed of material that will not react with chemicals in the water which may contact it. The problem is that many contaminants will adsorb to the material which will reduce the measured concentration. This is particularly problematic for organic compounds which are being measured at the parts per billion level (PPB). This could be a particular problem for the organics found in fracturing fluid. The best material is probably stainless steel because most chemicals being monitored will not react with it or adsorb to it (Fetter, 1999).

Another potential problem is the potential for drilling fluid used to install a monitoring well to introduce the same substances to the groundwater that could also result from the development project (Johnson, 1983), most particularly the fluids used for fracturing. Rotary drilling fluids may contain polymers similar to those used for fracturing or for developing the gas well. Glue used on the casing seams may dissolve into the groundwater. Saw-cut screen slots may introduce pvc shavings into the groundwater. A monitoring plan should consider these issues and require the drilling contractor to not use materials that could confuse the monitoring.

Summary

A monitoring well system is therefore a schematic of monitoring wells and piezometers used to monitor an area for contaminants; a monitoring plan includes the required sampling frequency. If the goal is detection of a leak, wells with long well screens spanning the entire potentially contaminated saturated zone, as close to the source as possible, with low detection limits on the testing, are sufficient. This can work for a substance not found in the natural groundwater of the area. If the goal is to track a trend in concentration, wells targeted to specific aquifer zones but not too long, usually no more than ten feet, are necessary to avoid dilution. This can be used to document the growth of a plume or detect a leak of a substance which naturally occurs in the aquifer. In either case, the well spacing should be based on the expected flow path accounting for the likely dispersion.

The overall design depends on the risk of missing contamination. Certainty is impossible, but a well-conceived conceptual flow model, based on all available data supplemented with new data if necessary, will minimize the potential for missing a leak. Also, a high density well network will also minimize the potential of missing the leak and this depends on the likely dispersion.

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APPENDIX D

Review of ICF Report

Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs

Agreement No. 9679
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Reviewed by
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The New York State Energy and Development Authority (NYSERDA) contracted with ICF International to prepare a review of the hydraulic fracturing process as it will likely be applied to the Marcellus Shale in New York. It is a supporting document for the DSGEIS prepared by the New York State Department of Environmental Conservation. This is a review of that document.

ICF wrote a three part document – it is referred to as ICF in this appendix. The first is a review of the hydraulic fracturing process. The second is a discussion of the potential for fracturing fluid to move from the shale to freshwater aquifers. The third is a review of other state's hydraulic fracturing regulations to consider how they might apply to New York; it is not reviewed in this document. The second section is considered first because this review finds it to be technically incorrect and to make inaccurate representations of the potential for contaminants to flow from the fractured shale to freshwater aquifers. The first section is reviewed, but the descriptions in that section actually support the findings of the review of the second section.

In summary, ICF completed an analysis of the potential for contamination to flow from the shale to freshwater aquifers, but misrepresented the actual situation in many ways. The basic problem was they conceptualized the flow potential incorrectly. They considered the gradient incorrectly and assumed that if the transport did not occur within the time period of fracturing, it would not occur. They assumed that the fluids leaving the shale would completely disperse, and be diluted, by occupying and being retained in every pore between the shale and the aquifers. They ignored any potential pre-existing vertical gradient which would drive contaminants leaving the shale to reach the aquifers.

Although they presented a geochemical analysis which could explain why some attenuation could occur, they provided no site specific or fluid specific data to indicate that it would occur.

Exposure Pathways

ICF analyzes the potential for fracturing fluid to flow from the shale to the freshwater aquifers anywhere from 1000 to 5000 feet above. The first problem is that the potential contaminants are both fracturing fluid and ambient water existing in the shale before fracturing, which could contain extremely high concentrations of TDS, benzene, or radioactive materials (the constituents are discussed elsewhere in the main text of this author's review document and by Dr. Glenn Miller in his review). Therefore, ICF should have considered the potential for flow of both fracturing fluid and ambient water. Ambient water could both be pushed from the shale by the injection of fracturing fluid and just by the opening of the pore spaces which would increase the permeability and allow more of a natural connection.

ICF calculates the gradient between the fracture zone and the bottom of the freshwater zone, which they set at 1000 feet bgs to be conservative in because much of the groundwater below this level in southern New York is too salty for freshwater use. However, their calculation applied only during the period of injection.

They also assumed that pumping had lowered the head in the aquifer to the bottom of the aquifer. This decreased the head at the level of the aquifers and increased the gradient. Because of the problems discussed below, this did not change their conclusions. This is NOT a natural upward gradient, which could exist at any point in the Marcellus Shale zone. See the model analysis presented in Appendix A which discusses why a natural gradient likely exists.

ICF properly calculated the pressure that would occur in the shale during fracturing based on the effective stress in the formation and the amount of pressure required to overcome the in-situ horizontal stress (ICF, pages 25-26); accepting the assumptions in the following quote, equation 12, and equations 7 through 11 used to derive it, is an accurate description of the head applied to the shale during fracturing.

> Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of the geologic materials (estimated at 150 pcf average), times the depth. To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress… (ICF, pages 25-26)

ICF uses that equation with the gradient equation 6 to estimate the gradient between the shale and freshwater aquifer, "during hydraulic fracturing", for a variety of depths of the aquifer and the shale. The numbers are correct, for an aquifer depth of 1000 feet and shale depth of 2000 feet, they show the gradient to be about 3.6, but the **concept applied**

in the derivation is wrong. During hydraulic fracturing, variously estimated through the DSGEIS documents as occurring for up to 5 days, there is no hydraulic connection between the shale and the bottom of the freshwater aquifer and it is therefore inappropriate to consider the gradient across that thickness. The correct conceptualization is described in the next paragraph.

Upon applying a pressure in the shale, as occurs during the injection for fracturing, a very high pressure head is developed at the well and nearby shale. This pressure causes the gradient which drives the fluid away from the well into the shale, where it causes the shale to fracture. During the process, the pressure begins to increase away from the well which establishes a steep gradient near the well. Away from the well at any given time during injection, the pressure is less than at the well. The pressure drop from the well to any point in the shale away from the well is a function of the friction incurred by the flow away from the well. At some distance from the well, the pressure is only at background. The distance at which the pressure is only background is the point at which the injection fluid has not yet reached. Beyond the point to which the injection fluid flows, there is NO hydraulic connection. For this reason, the calculation for gradient between the injection pressure in the shale and the bottom of the freshwater aquifer is hydrogeologically incorrect. They are effectively analyzing a steady state situation that would occur if the injection pressure continued until the pressure stabilized between the shale and the freshwater aquifer.

ICF does acknowledge the reality that transient or non-steady conditions will prevail and that the actual pressure gradient will be higher closer to the shale.

> In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the **gradients will be higher than the average closer to the fracture zone** and lower than the average closer to the aquifer. It is important to note that these gradients only apply while fracturing pressures are being applied. (ICF, pages 26-27)

However, they do not carry the analysis any further and seem to argue that immediately after injection ceases, all upward gradient will cease. "**Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value**, which may be higher or lower than the total head in the aquifer" (ICF, page 27, emphasis added). The implication from this statement is that ending injection will cause the pressure in the reservoir to drop back to background, **immediately**. This is not possible, any more than it is possible for the drawdown in a pumping well in an aquifer to return to pre-pumping conditions immediately upon cessation of pumping.

For example, consider that during a five-day injection period, the pressure propagated outward from the well as described in Appendix A.. When injection ends, the pressure within the well may almost immediately return to background, but the pressure in the surrounding formation will still be very high. This is the pressure which will drive the flowback to the well, as described throughout the DSGEIS. The initial flowback is fluid right next to the well – the fluid that had just been injected. The pressure field created in

the formation away from the well is the pressure that causes a gradient to push the fluid back into the well.

As long as there is flowback, there is a gradient toward the well. This means that moving away from the well, the pressure increases (as required for there to be a gradient back to the well). With distance from the well, at any given time, there will be a point of maximum pressure beyond which the pressure becomes lower; in other words, a cross-section through the formation away from the well showing the pressure head would show the pressure rising from the well to the peak and falling from the peak to the point the pressure reaches background. (This is similar to the concept in hydrogeology that during pumping, the maximum drawdown caused by a well is at the well; when the well ceases to pump, the water level will initially rise quickly, but the drawdown away from the well will continue to expand for a period of time.)

ICF considers that local drawdown caused by production from the well will further prevent flow away from the well. "During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow" (ICF, page 27). This is probably correct, but the process described in the preceding paragraph likely causes some of the fluid to have moved beyond this propagating drawdown. The fact that only 35% of the injected fluid returns as flowback (DSGEIS; ICF, page 10 (ICF quotes 30%), Gaudlip et al, 2008) would seem to confirm that much of the injected fluid gets beyond the point where the reversing gradient would pull the fluid back to the well.

ICF also relies on there being no connection between the shale and surrounding formations, as indicated by the water quality difference. "Evidence suggests that the permeabilities of the Devonian shales are too low for any meaningful hydrological connection with the post-Devonian formations. The high dissolved solid content near 300,000 ppm in pre-Late Devonian formations supports the concept that these formations are hydrologically discontinuous, i.e. not well-connected to other formations" (ICF, page 27). This statement is probably correct for pre-fractured conditions, but the fracturing process could open a connection between formations. As described by ICF and reviewed above, the operators do not want to establish a connection because they would lose gas. ICF describes many uncertainties in the fracture modeling process and also describe that it is rare that the results of a model after applied to the field are rarely verified. It is therefore reasonable to assume that connections between the shale and surrounding formations do occasionally occur.

The analysis provided by ICF in section 1.2.4.3, Seepage Velocity, is irrelevant because it considers the velocity between the shale and the freshwater aquifer, using a gradient established in the previous section that only applies for as long as the injection. Their calculation of 10 ft/day (ICF, page 28) relies on that average gradient. They seem to acknowledge the fallacy of their assumptions by stating: "The actual gradients and seepage velocities will be **influenced by non-steady state conditions** and by variations in the hydraulic conductivities of the various strata" (ICF, page 28, emphasis added).

ICF then carries the same error into section 1.2.4.4, Required Travel Time, by calculating how long it would take for flow at the seepage velocity calculated in the previous section to reach the freshwater aquifers.

ICF's fourth argument is that even if all of the injected fluid moves vertically out of the shale towards the freshwater aquifer, it would have to disperse among all of the pore between the shale and the aquifer – a truly nonsensical idea. The calculation that 4,000,000 gallons of fluid would be evenly dispersed throughout a 40 acre well spacing. In other words, they assume that about 4,000,000 gallons of injected fluid would evenly disperse through all of the void, assuming porosity of 0.1, over a 1000-foot thickness 40 acres in area, or about 1.3 billion gallons of void space, would contain for a dilution of a factor of 300 (ICF, pages 30-31). This is wrong for the following reasons.

- An injected fluid would move as a slug along the gradient. In this case, with a natural upward gradient, any fluid that escapes the well bore (does not flowback) would disperse upward. It would not diffuse through every pore space between the shale and aquifer. Advective forces would move it upward as a slug with dispersion spreading it out both vertically and horizontally. It will dilute, but far less than postulated by ICF's analysis.
- The vertical flow would follow preferential flow paths rather than advecting upwards uniformly across 40 acres. The image painted by ICF is that the fluid would flow upward to the aquifer with a leading moving at exactly the same rate over the entire area. Even if there are no fractures, faults, or improperly plugged wells, simple finger flow would cause an uneven distribution of the contaminant.

The next section (ICF section 1.2.5) rejects the concept of fractures, faults, or unplugged wells by claiming it is "extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer" (ICF, page 31). They provide no data to assess the probability that such a network is "extremely unlikely". More importantly, for fractures to facilitate a connection between the shale and the aquifers, it is not necessary for the fracture to exist over the entire thickness. As ICF (page 5) mentions, the Marcellus Shale has substantial natural fractures, and therefore it must be assumed the surrounding formations, sandstone or shale, also have fractures. It is not necessary for the flow to follow a fracture all the way to the aquifers, but it could enhance the velocity of movement. Fractures could also further disperse the flow vertically.

ICF also mentions geochemistry as a reason that transport from the shale to the aquifers not occur. It is possible for contaminants to be attenuated as they move through a formation. Without site specific and chemical specific data, they should not make such an argument.

Description of Hydraulic Fracturing

ICF described the pre-frac simulation and modeling, how the industry designs a fracturing project and how the modeling has evolved over the years.

> Fracture propagation models attempt to mathematically describe the hydraulic fracturing process. Given a set of input parameters such as the geologic properties of the formation, the material properties of the frac fluid and proppant, and the injection volumes and rates, the models predict details of the fracture development such as fracture position, fracture dimensions, proppant placement, post-frac reservoir permeability, reservoir pressure, and gas recovery rates. (ICF, page 3)

This short paragraph essentially lists the input parameters to a fracturing model. There are three types of properties – geologic, fluid and proppant, and the injection volume and rate. The second two are known precisely because the fluid is mixed and measured on the surface prior to injection. The rate of injection is also controlled. Formation geology therefore is where most of the uncertainty occurs. Industry has numerous ways to measure the formation properties, but not all agree on the propriety of each method. "Some researchers assert that only direct measurements of in situ stresses such as from closure tests and microfracs produce reliable stress values, and dismiss the trustworthiness of stress measurements from dipole sonic logs" (ICF, page 4). The geologic properties also vary substantially due to heterogeneity. "Other in situ parameters such as formation permeability, porosity, and leakoff rates can vary due to anisotropy and formation heterogeneity, making accurate measurements difficult" (*Id.*). The actual result in the shale may vary substantially from the predictions.

> Expected outputs from the models include fracture spacing, fracture half-length, and width. The optimum half-length and width depend in part on the post-cleanup fracture permeability and the formation matrix permeability. **Hydraulically induced fractures often grow asymmetrically and change directions due to variations in material properties.** In formations with existing natural fractures, such as the Barnett and Marcellus shales, **hydraulic fracturing can create complex fracture zones** as fracturing pressure reopens existing fractures and as induced fractures and existing fractures intersect. **Actual fracture patterns are generally more complex than the current conceptual models predict**. (ICF, page 5, emphases added)

This passage indicates that the final fracture network depends on geologic properties and their heterogeneities. The modeling results and their accuracy depend on how well the shale is known and whether the operator injects fluid as modeled. It is impossible to fully characterize the target formation, and final fracture patterns are probably more complex than can be predicted.

> The success of this approach depends on the extent of the characterization of the rock mass, adherence of the stimulation treatment to the conditions modeled, and

> the ability of the model to predict fracture dimensions. Since the **characterization of the rock mass is always incomplete** and since even the **best currently available models only approximate the physical processes,** pre-fracture simulations can only **approximate the extent of induced fractures**. (ICF, page 17, emphases added)

Because the fractures are filled with proppant to keep them open and producing gas, the complexity and variation in the final fracture patterns probably causes variation in the amount of proppant used. ICF reports highly variable amounts used in the Barnett shale.

> Slickwater fracs generally use much lower proppant concentrations than conventional fracturing. Many wells have been successfully fractured with no proppant at all, but in some cases the high initial flow rates fell off shortly into production. Other horizontal wells in shale have attained commercial rates with only 5,000 to 10,000 lb. of proppant, although hundreds of thousands of pounds per well is more common in the Barnett Shale. Data on seven stimulation designs in Barnett Shale wells from 2001 to 2007 show proppant concentrations of 0.15 to 1.02 pounds of sand per gallon of frac fluid, and from 200 to 1500 lb per horizontal foot of well, with the higher sand quantities corresponding to multistage stimulations (ICF, page 12)

The implication that more sand is used in multistage stimulations is confusing because each stage affects a different portion the target formation, with the first stage developed being near the toe of the well and working backward, or inward, to the heal.

There are techniques that can be used to map or monitor the fracture development, but the description of the drawbacks with these techniques (ICF, page 5-6) indicates there can be significant inaccuracies, and due to cost, the methods are only used initially upon entering a certain type of shale (ICF, page 6). "Fracture mapping helps to confirm that fracture growth is sufficient for production and to confirm that induced fractures are limited to the target formation" (ICF, page 5). Without mapping, it would seem that the industry rarely verifies that the fractures do remain limited to the target formation, although it is acknowledged that it is in the interest of industry to not fracture beyond the target shale, at least to prevent losing gas.

More than half of the fracturing fluid remains in the shale.

> As the pressure is released near the end of a well stimulation, the fracturing fluid reverses flow to the wellbore in a process called flowback. Not all of the fracturing fluid is recovered, and the amount left in the formation depends on the fluid used, the fracture geometry, the reservoir pressure, and the geologic details of the formation. In the Barnett Shale, a typical well returns 20% to 30% of the injected fluid during flowback, with **most of this recovered in the first two or three weeks of production**. Recovery of frac fluid continues after flowback and into the production phase as additional frac fluid is flushed out of the formation with the produced water. The remainder of the trapped fluid may impedes (sic)

> gas withdrawal by filling pore spaces, reducing the fracture permeability, reducing the pore area available for flow, and reducing the effective fracture length. (ICF, page 10)

Because most of the flowback occurs within two or three weeks, it is likely that after that time period most of the gradient driving flow back to the wellbore has dissipated; most of the pressure caused by the injection is gone. Apparently up to 80% of the fluid flowed beyond the point in the shale where the reversing gradient would drive it back to the wellbore.

Fracturing also takes on shapes and follows directions according to the natural fractures in the shale. As described in this quote, the Marcellus Shale already has vertical fractures from it into the adjoining formations.

> Several geologists make a compelling case that the most prominent joint set in the Marcellus Shale was caused by natural hydraulic fracturing. According to this theory, fluid pressures created during hydrocarbon generation exceeded the in situ horizontal stress and drove vertical fractures upward out of the Marcellus and other black shales and into the gray shales above. This vertical joint set in the Marcellus Shale has typical spacing frequently less than one meter and strikes ENE (60º to 75º), perpendicular to the existing minimum principal stress. Induced hydraulic fracturing along horizontal wells is more likely to reopen this joint set rather than create new fractures, so the wells should be drilled in the NNW or SSE directions to optimize the intersection of these fractures for maximum gas production. (ICF, page 16)

Perhaps, the fracturing operation only has to enhance what exists naturally, a connection between the shale and surrounding formations, to allow contaminants to flow from the shale to the surrounding formations.

Reference

Gaudlip, A.W., L.O. Paugh, and T.D. Hayes, 2008. Marcellus shale water management challenges in Pennsylvania. Society of Petroleum Engineers Paper No. 119898.

Review of the DRAFT
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Toxicity and Exposure to Substances in Fracturing Fluids and in the Wastewater Associated with the Hydrocarbon-Bearing Shale

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This review is focused on the risk of exposure and adverse impacts from wastewater generated by shale gas development. The primary sources of wastewater are: (1) hydraulic fracture fluid waste that flows back out of the well after wellbore stimulation ("flowback") and (2) formation water that is produced along with shale gas (also called "produced water" or "production brines"). These two sources of waste combine to form shale gas wastewater streams that require careful review, consideration, and regulation by the NYSDEC.

Hydraulic fracturing flowback not only contains chemicals added during well stimulation, but also includes constituents present in the shale zone formation water that may be released during the hydraulic fracturing process. The data in the DSGEIS is insufficient to adequately evaluate this risk. The DSGEIS provides a general laundry list of chemicals that may potentially be used in hydraulic fracturing fluids; however, the actual formulation and the quantities of each chemical in use is only discussed in minimal terms. There is no information to describe the potential chemical interactions that may also result in additional contaminates formed in the wastewater.

The DSGEIS lacks sufficient information to conduct a risk assessment. A risk assessment for the hydraulic fracturing process requires an understanding of both the specific toxicity of each chemical used in fracturing or produced in waste and the quantities of each chemical used or produced, in order to estimate the potential for exposure. Neither requirement is satisfied in the DSGEIS.

Additionally, there is only scant information on the quality of the existing, in-situ formation water or the water that will be produced from the formation following hydraulic fracturing (produced water). Table 5-9 provides a small amount of data that indicates that the shale gas

formation water quality is very poor, and the produced water that flows out of the well as the gas is produced will contain a variety of toxic and carcinogenic substances, most of which are not contained in the fracturing additives. Clearly the produced water alone is a pollution source, and the addition of fracture treatment chemicals only degrades the water quality further. In my opinion, effectively *any* contamination of surface or groundwater with the combined wastewater produced (produced water and fracture fluid flowback) would render that surface or groundwater unusable for domestic purposes or, potentially, for wildlife. The level of naturally occurring radioactive material (NORM) in the water is very high and in some cases over 1000 times higher in specific contaminants loads than drinking water standards. Clearly the amount of radioactive material in the wastewater, alone, makes the shale gas wastewater a serious environmental and human health issue that must be attended to by NYS.

I. The additives used in the hydraulic fracturing process are not well defined, and the DSGEIS essentially provides only a laundry list of chemicals that *may* be used in the process.

The lack of information about the specific chemical components of the fracturing additives is a major concern regarding the hydraulic fracturing process. Many additives are reported simply as commercial products, without specific chemical information to show what the product is actually made of. While the full composition may have been disclosed to the regulatory agency for some of the additives (Table 5-3), only a partial chemical composition has been disclosed for others (Table 5-4). However, the lack of specific information on the identity, quantity, and use of the chemicals prevents the public, including scientists and health professionals, from assessing the risk posed by these chemicals. The chemicals are partially listed by use in Table 5-5, and a list of the approximately 258 chemicals extracted from the chemical compositions and Material Safety Data Sheets submitted to NYSDEC is presented in Table 5-6. However, this presentation is still insufficient to assess the overall potential for an impact on human health and the environment. The DSGEIS does not provide a firm list of chemicals that are allowed for use, does not verify which will actually be used, and does not describe the effects of the chemical combinations. There is no assessment of the actual range of chemicals that may be present in produced water, or in fracture flowback wastewater, or of the potential air or water pollution exposure. Quantities of the specific chemicals which can potentially be released into the environment are required for an assessment of exposure and, finally, of the risk of using these chemicals.

The DSGEIS's list of 258 chemicals contains chemicals that range from relatively non-toxic (e.g., isopropyl alcohol and acetone) to compounds that are known carcinogens (e.g., benzene and acrylamide) to compounds that are strong oxidants (hydrogen peroxide, chlorine dioxide, ammonium persulfate, and diammonium peroxiddisulphate), and finally compounds used to inhibit microbial (cellular) processes (e.g., 2,2-dibromo-3-nitrilopropionamide, and 2,2-dibromomalonamide). The DSGEIS recognizes that many of these chemicals can be toxic, but

provides information only on representative compounds or classes of compounds (pages 5-61 to 5.65) and two specific compounds (dioxane and formaldehyde) (pages 5-65 and 5-65). While toxicity data on many of the 256 compounds not specifically addressed may indeed be scant in the literature, additional information on the toxicity and hazards associated with these compounds is available, and should be considered. Under any circumstances, the simple listing of this very large group of chemicals falls far short of an analysis of the risks of using these chemicals in hydraulic fracturing applications. While the DSGEIS indicates that only a portion of the chemicals listed will likely be used at any one site, it is impossible for the public to understand which chemicals of this long list will be used at each site, in order to develop an assessment of the potential human health risks, or site-specific sampling plans for water quality if and when fracturing is permitted.

Below is a brief discussion of the risk concerns of some additional specific compounds. This discussion is certainly not exhaustive, and as is discussed above, it is limited to the toxicity aspect of risk assessment. The exposure aspect is impossible to assess because it is essentially ignored in the DSGEIS, and there is insufficient data available to complete an independent analysis.

Acrylamide: Acrylamide is a known carcinogen (Rice, 2005, Rice, J.M, Mutation Research, 580 (2005) 3-20), and it has been shown to cause tumors at multiple organ sites in both rats and mice, when given in drinking water or by other means. It is also a well-documented neurotoxin in both human and laboratory animals (LoPachin, 2004). While acrylamide is typically used to generate various polyacrylamide polymers, it has also been used as a grouting agent in the construction of reservoirs and wells and as sewer line sealing (EU, 2002). Use of acrylamide as a grouting agent requires placement of acrylamide and other chemicals into cracks, where the acrylamide will polymerize and, ideally, seal the crack. The polymerization process is often incomplete, and residues of acrylamide remain that are often orders of magnitude higher than when the polymerization is allowed to occur under controlled manufacturing conditions. At least in one case in Sweden in 1997, in which a railroad tunnel was grouted with an acrylamide product, residual acrylamide was released and resulted in worker exposure and neurotoxic effects, and cows drinking nearby water became paralyzed and died, as did fish in nearby breeding pools (Reynolds, 2002).

While residual acrylamide concentrations in manufactured polyacrylamide are generally sufficiently low not to present a serious water quality problem, use of acrylamide as a grouting agent is entirely different and has resulted in severe effects. Unfortunately, the DSGEIS does not indicate how the product will be used, although a use similar to grouting appears possible, based on the discussion in the DSGEIS. Unless the use is specified, as well as the extent of use, it is effectively impossible for the public to understand the risk that a chemical of this type would pose to human health and the environment.

This example is but one of chemicals in the list, but it is illustrative of the difficulty in evaluating the risk of the hydraulic fracturing process. In this particular case, a very toxic carcinogen and neurotoxic agent is included in a list with other chemicals (many of very low toxicity) and essentially no information is presented on how it would be used or the extent of use.

Biocides: Other chemicals with similar issues are the biocides, 2-bromo-2-nitro-1,2-propanediol (bronopol), 2,2-dibromo-3-nitrilopropionamide, 2,2-dibromo-malonamide, dazomet, 1,2-benzisothianzolin-3-one, dibromoacetonitrile, hydrogen peroxide, and glutaraldehyde. Each of these compounds may be used to reduce microbial activity in the hydraulic fracturing fluid. Each of these compounds offers varying amounts of toxic risk, depending on the use pattern and quantity used. While these chemicals may be used in low concentrations, the only data presented is the suggestion that up to 0.03% of the fracturing fluid would consist of biocide, although which chemicals would be used is not specified. Without these data, a risk assessment, even in a series of release scenarios, is precluded. The combination of the large number of chemicals in use is also a significant, secondary issue, since some of these chemicals can react to produce compounds with higher toxicity. Bronopol, although of low human toxicity by itself, can release nitrite, which in alkaline medium reacts with secondary amines (listed on page 5-52, Table 5-7) to produce the potent nitrosamine carcinogens. An example of a secondary amine on the list is coco-betaine, among others, indicating that such secondary reactions are possible with the reagents proposed in the hydraulic fracturing fluids. The data in the DSGEIS is insufficient to determine whether the proposed list of biocides, or secondary toxic effects of biocide chemical interactions, would pose a carcinogenic risk.

Dowicil 75 Preservative (3,5,7-triaza-1-azoniatricyclo{3.3.1.13.7} decane, 1-(3-chloro-2-propenyl) chloride) is an antimicrobial agent that is noted for high toxicity to aquatic organisms and algae, and releases of this compound to surface water are particularly problematic (Dow, 2008).

Mixtures: The list of compounds is sufficiently long that it is relatively easy to find additional examples of problematic and incompatible mixtures, in which two chemicals will mix to form a much more toxic or reactive substance. Two examples are provided here. The first example is given above for the release of nitrite. Second, the use of the large number of oxidants, particularly hydrogen peroxide, in the presence of bromide can produce compounds that are potentially carcinogenic. Bromide can react with hydrogen peroxide (or other oxidants) and produce bromine, which can ultimately react with a variety of organics to produce compounds that are potentially carcinogenic, as well as brominated and chlorinated methanes, which are listed as being found in the flowback water (Table 5-9). Other oxidants on the list include sodium hypochlorite, chlorine dioxide, and various persulfate salts.

Aromatic hydrocarbons and solvents: Benzene, toluene, xylenes, ethyl benzene, and a variety of other moderately water soluble aromatic compounds are listed in Table 5-6. Of these, benzene carries the greatest toxicity, due to its well-known carcinogenicity (EPA, 2008). These

compounds will tend to remain in water, and only be weakly sorbed. Again, however, the concentration and exposure routes are necessary for any risk assessment but are absent from the DSGEIS.

II. The DSGEIS does not demonstrate that contaminants found in produced water and/or fracture treatment flowback water are safe for environmental or human exposure.

The additives potentially present in flowback water mentioned above indeed present serious risks. In addition, the produced water generated during the hydraulic fracturing process contains contaminants that are released from the shale and generate very poor quality water (Table 5-9). After the well is completed, and an initial hydraulic fracture stimulation is conducted, there will be a period of time where fracture treatment flowback water will dominate the wastewater regime. Formation water will also be present in the flowback wastewater stream. Over time, the amount of hydraulic fracture fluid flowback will diminish and the wastewater will become predominately produced water.

The DSGEIS provides a very limited number of flowback water samples. These samples all contain very high levels of salts, with concentrations of total dissolved solids (TDS) ranging from 1530 mg/L to 337,000 mg/L, with a median concentration of 93,200 mg/L (9.3%). While the majority of the salt is sodium chloride, the median concentration would require nearly a 200-fold dilution to meet a secondary standard of 500 mg/L for drinking water. While sodium chloride is generally considered low toxicity, groundwater contamination of 1,000 mg/L would generally remove this water source for domestic purposes.

Benzene was found in nearly half of the samples. Whether benzene originated from the fracture treatment additives or was in-situ in the formation water is unclear. However, the fact that the combined wastewater stream contains benzene, a known human carcinogen, is a substantial human health and environmental concern that should be carefully examined by NYS, especially because the concentration of benzene (mean of 479 µg/L) is approximately 100 times higher than the drinking water limit of 5 µg/L. Other aromatic compounds were also observed (e.g., toluene) that exceed the U.S. EPA drinking water limit, although benzene is the aromatic compound of greatest concern.

Bromide is present at relatively high concentrations (mean of 616 mg/L) and will react with oxidants present in the hydraulic fluids to form bromine, which can subsequently react with hydrocarbons to form reactive carcinogenic compounds.

Antimony and arsenic were observed above drinking water primary standards in a limited number of samples. Barium, with a mean concentration of 661 mg/L, is over 300 times the 2 mg/L primary drinking water standard, and was found in each of the 34 samples analyzed. The highest concentration of barium observed (15,700 mg/L) is nearly 8,000 times the drinking water standard. Barium is a major constituent in drilling fluids, but may also be present in the Marcellus Shale. Barium is known to affect cardiovascular function, and causes hypkalemia,

which results in ventricular tachycardia, among other heart ailments. The heavy metals cadmium and lead also exceed primary drinking water standards in a limited number of samples.

Mercury was not mentioned as one of the analytes detected. It appears this was not even included in the analytical scheme.

Radioactivity: Only a limited amount of information on radioactivity is available for the flowback water, and it comes from just 8 wells in PA and WV, but the maximum concentrations found are very high, exceeding drinking water standards by several orders of magnitude. The EPA maximum contaminant level (MCL) for gross alpha in drinking water is 15 pCi/L; for radium total alpha (226 and 228) is 5 pCi/L; and for uranium is 30 ug/L. The maximum concentrations (Table 5-10) observed in the samples from PA and WV are: gross alpha - 18,950 pCi/L; for total alpha radium - 1,810 pCi/L; uranium concentrations were not specified. The greatest ratio of concentration observed to the drinking water MCL is for gross alpha and is 1,263 times the drinking water limit. No median concentrations were provided in Table 5-10. Additionally, no data were presented on how the NORM constituents change over time in the flowback water, although it is presumed that the NORM constituents will increase as the water changes from being primarily the fracturing fluid water to consisting primarily of the produced water.

Thus, if drinking water were contaminated with as little as 0.1% of certain shale gas wastewater, it would constitute a violation of a drinking water standard. The small percentage of wastewater that can cause serious contamination supports an argument that effectively *any* contamination caused by shale gas wastewater would be considered unacceptable. The lack of information on the expected wastewater characteristics from the New York section of the Marcellus Shale is a substantial deficiency in the DSGEIS, since it does not provide site-specific water quality data with respect to either the radioactivity that may be present in flowback and produced water or the concentration of other constituents that may prove problematic.

Concerns about the available analytical work on the flowback water: The list of chemicals found in the flowback water (Table 5-9) does not provide much assurance of the quality of information on the chemical composition of the flowback water and is simply a list of analytes that were found in a limited number of samples. While the analytical methods were not specified, they were apparently standard multi-residue methods that examined certain classes of compounds (e.g., EPA method 8270 and 8260 for organics, a metal scan, gross alpha radioactivity, metals and several anions). It appears that certain analytes potentially present in the fracturing fluids could not have been measured using those methods. Basically, if a gas production company is putting a chemical into a subsurface system that has the potential to contaminate surface water or usable aquifers, the company should be required not only to indicate the list of those chemicals and the quantities of each used, but also to monitor the quantities of those chemicals that are found in the wastewater.

For example, the DSGEIS admits that several of the monomers used in the process, either added directly or present as unreacted monomer in the polymer used, were not included in the analyses. (DSGEIS page 5-108: "Since this analysis targeted a polymerized reaction product and not the individual monomers, it is unclear from these data how much of the monomers, if any, occurred in the flowback.") Many other compounds were not measured in the flowback water analysis, including alcohols (e.g., the high use alcohol, methanol), amines, glycols (only one sample analyzed, but with high detection limits, 2 ppm), glycol ethers, the larger polycyclic aromatic hydrocarbons--many compounds of which are carcinogenic--organic acids, and the toxic biocides. Only one sample contained acrylamide as an analyte, and although it was not found, the measurement of acrylamide requires special methods (EPA Method 8032A). No information was provided on the method used for the determination, and no information was provided on even whether acrylamide was used in this specific well.

The observation of 4-nitroquinoline-1-oxide in the flowback water deserves some explanation. This highly carcinogenic compound was reported in all of the samples analyzed. In Table 5-9, it was included with the surrogates, and it may well have been added during analysis of the water samples. However, Table 5-9 does not indicate where it may have originated (as was done for other surrogates in the analytical method, such as 2-fluorobiphenyl). If this compound was indeed found in the flowback water, it would have serious implications for the health of workers as well as risk assessments for drinking water contamination. The concentrations observed (1,422-48,336 mg/L) are extremely high, with the highest being nearly 5% by weight. This concentration is substantially higher than the total organic carbon in the highest samples (1,080 mg/L), so it is unlikely that this compound was present in the flowback water. However, presence of the compound in the flowback is what Table 5-9 indicates, and the compound is also included in Table 5-8 as a parameter observed in flowback water from PA and WV. The explanation of its presence is necessary. Several quinoline compounds are noted in Table 5-7, although the presence of 4-nitroquinoline-1-oxide is unusual. It should also be noted that several of the surrogate compounds added during the water analyses (e.g., deuterated nitrobenzene) are also present in that table, but clearly would not be present in the flowback water.

Thus, despite the assertion that many of these chemicals are non-toxic and were not observed, the data suggests that effectively very little information is available to assess whether they would be present in quantities sufficient to adversely affect groundwater, if the wastewaters or the fracturing fluids were to leak in the wells to near-surface groundwater or surface water.

III. The DSGEIS fails adequately to consider scenarios where contamination of surface or groundwater may occur.

Because of the highly elevated radioactivity, it is reasonable to assume that, in many cases, the key water quality component of concern will be radioactivity, although the fracturing process additives and other components of the produced water are also serious concerns.

There are at least four scenarios (among many) that should be considered for potential leaks or spills of gas wastewater, including flowback and produced water

1. **Movement of the contaminated water upward following fracture of the shale.** This is a hydrology problem mostly and has been considered by others (see Myers report to NRDC). However, because the chemical composition of the total radioactivity is not presently known (radium is apparently not a major component, and uranium is not specified), it is impossible to know how much of the radionuclides will sorb onto soils or chemically precipitate in the pipes. We do not know what constituents carry the radioactivity, but many, if not most, are subject to changes in oxidation state, which are likely to affect the solubility. The solubility of certain radionuclides is indeed affected by chloride, and as that is diluted, the solubility of the remaining alpha emitters may change and be lowered. Changing solubility is an important point, but since we do not know what the chemistry is of the radioactive source, the changes in solubility are unknown, and without that information, we must assume that the solubility is unchanged with salinity or temperature. Since radioactivity is of such importance, full assessment of the geochemistry of the radionuclides present in the groundwater is required.

2. **Spills during flowback or removal of produced water.** Spills during wastewater removal (flowback and/or production brines) can be due to either leakage of the piping system or flow around the piping system that intercepts a potential drinking water source. This leakage may not even be known until it intercepts a monitoring well. As in other cases, the problem created would depend on the amount and toxicity of the water that is released. It might be argued that contamination by this wastewater could largely be remediated by a pump and treat technology, but the low solubility of many radionuclides suggests that there are likely to be continued releases of radionuclides from the sorbed state for a very long time. This type of slow release is a characteristic of arsenic contamination of groundwater systems. Arsenic is only slowly removed from the groundwater system since a large percentage of it is sorbed onto the matrix and released over a long period of time. Once an aquifer has been contaminated with arsenic, cleaning up that aquifer to restore domestic uses can be a very long-term problem. The same problem is likely for an aquifer contaminated with the wastewater that will be produced by hydraulic fracturing.

3. **Surface spills during hauling or piping of the wastewater.** As before, the problem created will depend on where the water goes, how much seeps into soil, and whether the contaminated wastewater is in communication with surface or groundwater. It will also depend on the toxicity and rate of migration of the specific compounds released.

4. **Leaks from surface impoundments.** A slow, undetected leak is a potentially very large problem, since it can occur for a long time, and move downward. This risk militates in favor of using above-ground steel tanks for flowback storage (where spills are very easily detected) or, if impoundments are permitted, for improving the quality of the lined ponds which will contain the flowback. From experience in Nevada with liners, leaks are

common, and it is prudent to assume that all liners leak and to include leak detection systems in surface impoundment liners. If properly installed, the leak detection system will improve the odds that, if and when a leak occurs, it can be rapidly detected and fixed. A remediation safety plan will also require inclusion of a plan where to put the wastewater remaining in the impoundment when the leak was detected, as well as a determination of the extent of the contamination, and a plan to remediate that contamination.

In each case, the potential for contamination is large, and if it occurs during a storm or during mid-winter (when it seems that most accidents are more likely to occur), the impact could be significant.

For spills of the fracturing fluid constituents, two primary accidents should be considered.

1. **Spills during transportation of the fracturing fluid chemicals.** This has been discussed in the DSGEIS, but is always a consideration, particularly in remote areas, where road access may be difficult and when weather conditions are poor.

2. **Spills at the site during mixing, unloading, or adding the chemicals to the hydraulic fracturing water.** These types of spills are generally smaller than an undetected leak in an impoundment, but are relatively common. Each site needs to have trained staff and plans both for minimizing spills and, when they occur, for immediately cleaning them up and legally disposing of the residue.

IV. The DSGEIS inadequately analyzes necessary groundwater monitoring.

Because the types of contamination from the combined flowback and formation water would be so severe, groundwater monitoring requirements are critical to protecting domestic drinking water wells, particularly those near a gas well site and those that can be potentially contaminated by release of flowback water (See Myers hydrology report). New monitoring wells should be drilled in appropriate locations between the source of contamination and the drinking water well, and samples should be tested on a quarterly basis (to obtain one full year's worth of data) prior to any drilling, hydraulic fracturing, or storage of flowback. The quarterly monitoring will not only establish baseline conditions, but also provide an indication of the seasonal changes in the groundwater quality.

The draft SGEIS suggests that monitoring can be discontinued one year after closure of the gas well. Since groundwater moves so slowly, this short period of time (one year) is insufficient to establish whether the groundwater has been contaminated, and at least 5 years of data should be required, as a permit requirement, following closure of the gas well. This period of monitoring is particularly important for protection of rural drinking water wells, since most rural homes rely on such wells, which are rarely tested. At least 5 years of groundwater monitoring at locations between the contamination source and the drinking water well are required to ensure that the homeowner learns of the risk of drinking water contamination before that contamination has

begun.   Increases in chloride are likely to be the first indicator of contaminated water, and significant increases in chloride (relative to a yearly fluctuation) will show if that domestic aquifer has been contaminated. If contamination is suspected, a full analysis of the water should be conducted. The monitoring and analysis should be pre-paid by the gas developer for the full period of analysis.

Concluding Comments

The DSGEIS falls short of an adequate assessment of the risk of using the fracturing additives for hydraulic fracturing of the Marcellus Shale in New York. It similarly falls short of assessing the risk of formation waters contaminated with high levels of TDS, heavy metals, and radioactivity, which will be transported to the surface both as a component of the flowback and during production. Specifically the following summary points should be considered:

I. Hydraulic Fracturing Additives

- The additives used in the hydraulic fracturing process are not well defined and the DSGEIS essentially provides only a laundry list of approximately 258 chemicals that *may* be used in the process.
- There is effectively no indication of the toxicity of each chemical, and insufficient information is provided that would allow the public to understand the hazard associated with individual or groups of chemicals.
- There is no clear indication of how much of each chemical will be used, and this lack of information is particularly troubling, because it eliminates the ability of the public to understand the risk of using effectively all of these chemicals.
- Certain of these chemicals will react with others and produce secondary products that are particularly problematic. Again, the lack of information on which chemicals will be used eliminates the opportunity to conduct a reasonable risk assessment for use of these chemicals.

Recommendation #1. A more complete listing of the use rates of these chemicals is required, as well the quantities of chemicals that will be used.

Recommendation #2. NYSDEC appears to place no restrictions on use of any of the chemicals, even though certain of these chemicals (e.g., acrylamide and benzene) pose significant risks, including carcinogenicity. NYSDEC should re-evaluate use of these 258 chemicals and propose use restrictions on the most toxic of the group.

II. Gas wastewater:

- The flowback water (containing both the shale fracturing water and the produced water) that will carry contaminants from the shale and the fracturing additives is likely to be highly contaminated with metals, salts, and radioactivity that, in some

cases, are greater than 1,000 times the drinking water standards. This level of contamination is sufficiently high that *any* level of contamination of surface and groundwater is unacceptable.

Recommendation # 3. NYSDEC needs to develop a much better data set on the expected concentrations of contaminants in the gas wastewater, and should require disclosure of both the identities of the chemicals being produced in the waste as well as the amounts of those chemicals.

III. Chemical analysis and monitoring issues:

- Many, if not most, of the hydraulic fracturing additives are not included as analytes in standard chemical analyses of flowback water. If a chemical is being injected into the subsurface (and thus has the potential to contaminate surface or accessible groundwater), that chemical should be measured in the flowback and in samples of groundwater withdrawn from strategically located monitoring wells.

Recommendation #4. The NYSDEC should require that the identity of the hydraulic fracturing additives be revealed at each specific well, and require the gas production entities to establish monitoring methods for those chemicals, as well as a protocol and plan for their monitoring.

Recommendation #5. Monitoring of wells for these contaminants should be conducted at least for a full year (monthly or at least quarterly sampling) before drilling begins to provide a baseline for seasonal changes in water quality.

Recommendation #6. Following plugging and abandonment of a gas well, monitoring should be required for a minimum of 5 years, with a special emphasis on testing for those contaminants that will move the most rapidly (e.g., chloride). Prior to installation of these gas recovery wells, site-specific plans for cleanup of contamination should be developed by the operator and approved by NYSDEC.

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Comments on the *Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, (DSGEIS), dated September 2009

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December 30, 2009

The New York State Department of Environmental Conservation (NYSDEC) released the *Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and the High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs* (DSGEIS), in September 2009, to assess the environmental impacts of horizontal drilling and high-volume hydraulic fracturing not addressed in the 1992 Generic Environmental Impact Statement for gas drilling and to present practices to mitigate such impacts. CEA Engineers, P.C. (CEA) was retained by Earthjustice, Inc. and Riverkeeper, Inc. to review and analyze NYSDEC's evaluation of environmental impacts to natural resources including surface waters, floodplains, wetlands, waterbodies, and watercourses, as well as the impacts to significant habitats and wildlife, including rare, threatened, and endangered species and associated required mitigation actions.

<u>Wastewater</u>

Chapters 5, 6, and 7 of the DSGEIS, present, among other things, NYSDEC's analysis of environmental impacts and mitigation measures to eliminate adverse environmental impacts resulting from the wastewater generated by horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale formation in New York State (NYS).

1. ***Comment*: The potential on-site and off-site wastewater treatment alternatives may result in significant adverse environmental impacts, including increased energy usage and increased roadway stormwater pollution from transportation of wastewater. In the DSGEIS, NYSDEC failed to assess and provide mitigation measures for significant adverse environmental impacts, either per well or cumulatively, from wastewater treatment energy use and increased stormwater pollution from transportation of wastewater.**

Discussion: On-site treatment and reuse of flowback water is considered beneficial by NYSDEC as a means of supplying a portion of the large quantities of water required for, and disposing of the voluminous wastes generated by, hydraulic fracturing.[1] Technologies evaluated for on-site treatment of Total Dissolved Solids (TDS) and its constituents include: reverse osmosis, thermal distillation, electrodialysis, and ion exchange.[2] Each of these technologies requires significant energy input and produces liquid or solid waste streams containing concentrated amounts of all pollutants removed from the flowback water. The potential significant adverse environmental impacts associated with on-site energy use, transport, and disposal of highly concentrated liquids, and the required mitigation methods were not evaluated in the DSGEIS.

When wastewater is not treated and reused on site, NYSDEC lists underground injection, treatment and disposal at Publicly Owned Treatment Works (POTWs), and treatment and disposal at private wastewater treatment plants (WWTPs) as available alternatives for treatment or disposal. Underground injection, properly conducted, does not impact surface waters and requires a site-specific evaluation under SEQRA. Treatment at POTWs and private WWTPs involves significant transportation of wastewaters with associated adverse environmental impacts including increased stormwater pollution. NYSDEC estimated that an eight-well pad would require between 1,600 and 2,400 truckloads to haul away flowback water.[3] NYSDEC offers no estimate of truck trips for hauling brines, a fluid produced from the Marcellus Shale formation.[4]

POTWs have limited ability to treat flowback water and brines produced by horizontal drilling and high volume fracturing as the flowback water and brines contain high TDS and individual components of TDS not normally treated by POTWs. As discussed by Dr. Glenn Miller in his comments on the DSGEIS, the produced wastewater also contains high

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1 DSGEIS, Section 7.4.1.2.
2 DSGEIS, Section 5.12.2
3 DSGEIS, Section 6.13.1.
4 DSGEIS, Section 6.6.9.

concentrations of radioactivity.[5] POTWs do not typically treat for radioactivity although incidental removal of radioactive metals may impact beneficial reuse of biosolids.. In order to meet SPDES effluent limits required for all POTWs, avoid interference with POTW operation, and maintain the beneficial reuse of biosolids, when treating the flowback and brine, the amount of flowback and brine that can be treated in any POTW is limited.
In addition to the limitations on contaminants contained in flowback waters and brine that a POTW can successfully treat, the flow volume that POTWs can take is also limited. Treatment capacity for both flow and pollutant loading for POTWs are designed based on anticipated population and industrial growth in the areas these POTWs service, and capacity of these POTWs is essential for future population and economic growth in those regions.[6] A POTW's acceptance of flowback water and brine limits its capacity to serve future municipal and industrial/commercial wastewater treatment needs. These inherent limitations are likely to limit the availability of POTWs to treat wastewaters generated during horizontal drilling and high volume fracturing.

Treatment of wastewaters generated during horizontal drilling and high volume fracturing wastewaters at private WWTPs involves transportation issues similar to those associated with treatment at POTWs and the same issues of transportation and disposal of highly concentrated residuals from TDS removal as discussed above for on-site treatment.

2. ***Comment*: NYSDEC fails to evaluate the significant environmental impacts of treatment and disposal of flowback and brine wastewaters in the DSGEIS, including: energy usage; increased roadway stormwater pollution from transportation of wastewater. NYSDEC must assess the regional cumulative impacts from horizontal drilling and high volume fracturing.**

Discussion*:* The DSGEIS states that: "The level of impact on a regional basis will be determined by the amount of development and the rate at which it occurs."[7] NYSDEC states that the rate of development of gas wells will, in great part, be determined by economic

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5 Miller, Glenn, Ph.D., "Review of the DRAFT Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Toxicity and Exposure to Substances in Fracturing Fluids and in the Wastewater Associated with the Hydrocarbon-Bearing Shale," December 21, 2009.

6 Water Environment Federation, American Society of Civil Engineers, *Design Manual of Municipal Wastewater Treatment Plants, Fourth Edition, MOP 8*, 1998.

7 DSGEIS Section 6.13.2.

factors that are not easily forecasted.[8] The DSGEIS acknowledges that cumulative impacts will occur, but provides no basis for limiting shale gas development to avoid those impacts or for designing appropriate mitigation if development is not limited. NYSDEC must provide a cumulative impact analysis of wastewater generated by the gas development operations, and the treatment of that wastewater if the agency is to identify adequate regulations for mitigation of environmental impacts from the transportation and treatment of wastewater.

The large volume of flowback water and other gas development wastewaters potentially generated mandates the evaluation of regional cumulative impacts. One estimate from the drilling industry contained in the Section 6.13.2.1 of the DSGEIS is that from 1,500 to 2,500 wells per year could be developed in Marcellus Shale in New York. Using the average flowback water volume of 1.5 million gallons per well, based on the range provided in Section 5.11 of the DSGEIS of 216,000 gallons to 2,700,000 gallons, and an average of 2,000 wells per year (the midpoint of the industry estimate), 3 billion gallons per year of flowback water could be generated. If all of that water were to be transported for treatment, assuming 9,000 gallons per tanker truck, it would require 913 trucks per day, 365 days per year. The additional trucks add to the environmental impacts associated with energy use, air pollution, and stormwater pollutant runoff. The amount of pollutants, including sediment, metals, oils and greases, etc, discharged in stormwater from roads increases as traffic increases. No evaluation of the cumulative impact of the pollutants generated by additional truck traffic on water bodies and other environmentally sensitive areas is included in the DSGEIS. Mitigation methods to minimize or eliminate the cumulative environmental impacts are not included in the DSGEIS.

3. ***Comment*: In the DSGEIS, NYSDEC fails to evaluate the cumulative volume and rate of production of gas wastewater requiring treatment; fails to verify whether identified POTWs or private wastewater treatment plants have adequate capacity to accept the generated wastewater; and fails to require that Applicants for well drilling permits have a contract to dispose of flowback water to be treated off-site at a POTW or other permitted WWTP.**

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8 DSGEIS Section 6.13.2.1.

Discussion: As much as 3 billion gallons of flowback water may require treatment per year (see previous comment) in addition to other wastewater such as production brines. Appendix 21 of the DSGEIS contains a list of POTWs with approved pretreatment programs but does not identify which of the POTWs are willing and capable of receiving and adequately treating flowback water and brines. Similarly, available capacity to accept wastewater at private wastewater treatment plants was not evaluated in the DSGEIS.

In the DSGEIS, NYSDEC appears to simply assume, without basis, that sufficient wastewater treatment capacity will be available in New York and other states, including Pennsylvania.[9] In Pennsylvania, Marcellus Shale development wastewater disposal is considered a significant water issue.[10] Because POTWs in Pennsylvania do not treat TDS, the State has been required to cap acceptance of gas drilling wastewater at many POTWs at 1% of total annual flows significantly reducing the ability of POTWs in Pennsylvania to handle the wastewater from its own gas development operations much less the volumes to be produced in New York State.[11,12]

The proposed Environmental Assessment Form (EAF) Addendum Requirements for High-Volume Hydraulic Fracturing (DSGEIS Appendix 6) requires that the Applicant identify the planned disposition of flowback water and brines and if water will be disposed of at a POTW or WWTP; and provide a copy of NYSDEC's approval of that POTW or WWTP to receive flowback water. Neither the application nor proposed EAF Addendum requires that the Applicant have a contract to dispose of flowback water at a POTW or WWTP nor do they require proof that the POTW has the available capacity to treat the flowback water at the time that treatment capacity is needed. Without a contract, there is no documentation that the POTW or WWTP actually has the treatment technologies and available capacity to accept the

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9 New York City, "New York City Comments on: Draft Supplemental Generic Environmental Impact Statement (dSGEIS) on the Oil, Gas and Solu7tion Mining Regulatory Program – Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs," December 22, 2009. [NYC Comments]

10 Pennsylvania State University, "Shaping Proposed Changes to Pennsylvania's Total Dissolved Solids Standard, A Guide to the Proposal and the Commenting Process," 2009.

11 Swistock Bryan, School of Forest Resources, Pennsylvania State University, "Wastewater Issues and Technologies," Pennsylvania Gas Drilling Summit: Challenges and Opportunities, December 10th - 11th, 2008.

12 NYC Comments.

generated wastewater volumes upon actual generation as opposed to when the permit is approved.

In the absence of a cumulative impact analysis demonstrating that wastewater treatment capacity would actually be available for all of the wastewaters generated by horizontal drilling and high volume fracturing, At a minimum, NYSDEC must require a contract verifying that the POTW or WWTP proposed by the applicant to accept the wastewater has the existing capacity and the technology/capability to treat the water at the time drilling is to be performed to avoid or minimize significant adverse impacts resulting from a dearth of certified treatment capacity..

4. ***Comment:*** **The minimum list of pollutants required by the DSGEIS in a headworks analysis must include barium and iron.**

Discussion: Table 6-2 of the DSGEIS shows that barium concentration in flowback water from Pennsylvania and West Virginia averages over 600 mg/l with a maximum measured concentration of 15,500 mg/l. The safe drinking water standard maximum contaminant level (MCL) for barium is 2.0 mg/l.[13]

Table 6-2 of the DSGEIS also shows that iron averages almost 48 mg/l with a maximum of 810 mg/l. The secondary drinking water standard for iron is 0.3 mg/l.[14]

For class A and AA surface waters the water quality standard for barium is 1.0 mg/l and the water quality standard for iron is 0.3 mg/l.[15] The Pennsylvania Department of Environmental Protection's Bureau of Oil and Gas Management explicitly requires the analysis of barium and iron among other constituents in wastewater produced from the Marcellus Shale drilling

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13 40 CFR 141.51.
14 40 CFR 141.3.
15 ECL §703.5 Table 1.

operations.[16] These contaminants are not included in the “minimum analysis list” in the DSGEIS.[17]

The minimum analysis list refers to the types of constituents required to be evaluated to meet the headworks analysis requirements. The minimum analysis list relies on the Priority Pollutant list to analyze for and limit all of the contaminants. Neither barium nor iron are included in the Priority Pollutant Metals list.[18] The fact that NYSDEC has failed to include required analysis of the flowback water for at least these two parameters, shows that NYSDEC has failed to evaluate or propose flowback water analysis requirements capable of detecting all of the potential contaminants. Without knowing the concentrations of all of the contaminants in the flow back water, NYSDEC cannot demonstrate the ability of wastewater treatment plants to treat the generated wastewaters to SPDES permit effluent limits without interfering with beneficial use of biosolids.

Stormwater

Chapter 5, 6, and 7 of the DSGEIS, present, among other things, NYSDEC’s analysis of impacts and recommended mitigation measures to eliminate adverse environmental impacts resulting from the discharge of stormwater generated by horizontal drilling and high-volume hydraulic fracturing operations and associated activities in NYS.

Section 6.1.2 of the DSGEIS provides a general description of beneficial and adverse environmental impacts from stormwater runoff. NYSDEC did not assess the adverse environmental impacts potentially caused by stormwater runoff from well pad site development and construction, as well as during hydraulic fracturing and other gas development operations, including soil erosion, increased stream erosion, and discharge of pollutants. Section 7.1.2 addresses mitigation consisting of Stormwater Pollution Prevention Plans (SWPPP).

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16 The Commonwealth of Pennsylvania, Department of Environmental Protection, Bureau of Oil and Gas Management, Bureau of Water Standards and Facility Regulation, Oil and Gas Wastewater Manifest Instructions, December 2008.

17 DSGEIS, Section 7.1.8.1.

18 40 CFR 401.5.

In Section 7.1.2.1, NYSDEC states that it plans to incorporate the General Permit for Stormwater Discharges Associated with Construction Activities (Construction General Permit) into Sector AD of the Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity (MSGP). NYSDEC also proposed the option of revising the MSGP to incorporate a required SWPPP for industrial activities that may reasonably be expected to affect the quality of stormwater discharges associated with hydraulic fracturing operations.

5. ***Comment*: In the DSGEIS, NYSDEC failed to account for the cumulative impact of multiple stormwater discharges to a stream or river that may result in higher than pre-construction stream flow and higher in-stream velocities. Increased in-stream velocities increase the risk of in-stream erosion. Increased in-stream erosion results in increased total suspended solids (TSS) and turbidity in receiving waters. In the DSGEIS, NYSDEC failed to evaluate adverse environmental impacts on faunal utilization of watercourses and waterbodies as a result of increased turbidity from the increased stormwater volume and failed to provide mitigation for such adverse impacts.**

Discussion: Increased impervious area created by well pads and access roads will generate greater stormwater discharge rates and volumes to the receiving streams as compared to undisturbed, pre-construction conditions. The Construction General Permit limits maximum post-construction flow rates to maximum pre-construction flow rates to protect the receiving streams from in-stream erosion.[19] The most commonly used stormwater best management practice (BMP) for matching pre- and post-development flow rates is detention basins. The Construction General Permit does not require that pre- and post-development stormwater discharge volumes match. Limiting the maximum post-construction flow rate does not prevent an increase in the total volume discharged to receiving water. An increased stormwater discharge volume results in a longer period of peak stormwater discharge flow rates to the water body.

When post-construction peak discharge flow rates occur over a longer period of time than pre-construction peak flow rates, and there are multiple discharges, higher in-stream velocities and in-stream erosion may result. Increased in-stream erosion in turn causes higher in-stream TSS and turbidity which has been shown to have a negative effect on fish species, such as trout and bass.

19 NYSDEC, *New York State Storm Water Management Design Manual*, August 2003.

Many studies have been conducted which demonstrate that high turbidity decreases reaction time and feeding rates among fish species, such as the rainbow trout, and the largemouth bass.[20,21] These studies indicate that high sediment-producing activities, such as road building associated with gas well drilling, have the potential to reduce foraging success among trout and bass species, and as a result, decrease growth rates.[22,23] Slower growth rates as a result of decreased forage efficiency may lead to a decrease in spawning potential, which could result in significant effects on population dynamics among fish populations.[24] Additionally, increased turbidity levels have the potential to cause an increase in the migration of fish species to less turbid waters, and result in the absence of fish for long stretches of streams, rivers, or watercourses affected by sedimentation.[25] In the past, NYSDEC has recommended maintaining a 50-foot wide vegetated corridor on each side of protected streams in order to maintain stable embankments and water quality.[26] Adopting this recommendation for Marcellus drilling activities would assist in preventing erosion and maintaining natural levels of turbidity within watercourses and waterbodies.

According to the New York City Department of Environmental Protection (NYCDEP) "Catskill Mountain stream bottoms and banks provide source areas that contribute to high suspended sediment loads and turbid stream water to reservoirs."[27] Stream bank erosion of Schoharie Creek, which supplies the Schoharie Reservoir serving New York City, has been

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20 Barrett, Jeffrey C., et. al. *Turbidity-Induced Changes in Reactive Distance of Rainbow Trout.* Transactions of American Fisheries Society, 1992.

21 Shoup, Daniel E., and David H. Wahl. *The Effects of Turbidity on Prey Selection by Piscivorous Largemouth Bass*. Transactions of American Fisheries Society, 2009.

22 Barrett, Jeffrey C., et. al. *Turbidity-Induced Changes in Reactive Distance of Rainbow Trout.* Transactions of American Fisheries Society. 1992.

23 Shoup, Daniel E., and David H. Wahl. *The Effects of Turbidity on Prey Selection by Piscivorous Largemouth Bass*. Transactions of American Fisheries Society, 2009.

24 Sweka, John A. *Effects of Turbidity on the Foraging Abilities of Brook Trout (*Salvelinus fontinalis*) and Smallmouth Bass (*Micropterus dolomieu), 1999.

25 Sweka, John A. *Effects of Turbidity on the Foraging Abilities of Brook Trout (*Salvelinus fontinalis*) and Smallmouth Bass (*Micropterus dolomieu), 1999.

26 NYSDEC Region 3, Comments on Draft Environmental Impact Statement, July 3, 2009.

27 New York City Department of Environmental Protection, *Turbidity in the Catskill Watershed, Preliminary Report*, April 2002.

identified as a source of high turbidity in the Schoharie Watershed.[28] In reference to streams in the Catskill Mountains, NYCDEP reported: "High total suspended solids concentrations and elevated turbidity values are associated with exposed and shallow buried clay sources…both increase as a function of stream discharge, velocity, and power."[29] In the DSGEIS, NYSDEC has failed to analyze the impact of increased velocity in streams and to provide mitigation measures to prevent adverse environmental impacts such as those discussed with regard to trout and bass.

Erosion of the stream banks is of particular concern in the New York City Watershed.[30] Erosion of stream banks results in additional TSS and turbidity in the watershed. The NYCDEP identifies turbidity as the first of three "significant issues and challenges that have arisen over the course of the past five years and that are important to the continuation of filtration avoidance."[31] The other two are compliance with new standards for disinfection byproducts and increased development.[32] The development of the well pads, roads, and other construction required for the gas drilling and production operations, as discussed previously, can significantly increase erosion and turbidity in nearby water bodies. The cumulative effect of increased TSS and turbidity could potentially result in the need for New York City to construct a filtration system for the drinking water supply at an estimated cost of $10 billion to construct and $100 million a year to operate.[33]

It is not possible to analyze the impact of extending peak flow discharge time from the development of well pads and associated roads without performing a cumulative analysis of multiple discharges to a river or stream. The analysis must include all potential drilling sites

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28 Memorandum to Phil DeGaetano, NYSDEC Division of Water, from Rene' VanSchaack, Greene County Soil & Water Conservation District, Re: Proposal for EPA Funding of Turbidity Programs in Schoharie Watershed, May 4, 1999.

29 New York City Department of Environmental Protection, *Turbidity in the Catskill Watershed, Preliminary Report*, April 2002.

30 United States Environmental Protection Agency, New York Filtration Avoidance Determination, July 2007.

31 United States Environmental Protection Agency, New York Filtration Avoidance Determination, July 2007.

32 United States Environmental Protection Agency, New York Filtration Avoidance Determination, July 2007.

33 Letter from Steven W. Lawitts, Acting Commissioner, New York City Department of Environmental Protection, to Alexander B. Grannis, Commissioner, New York State Department of Environmental Conservation, September 25, 2009.

on a river or stream. Furthermore, a cumulative analysis must be conducted in order to determine the potential impacts of increased turbidity on aquatic fauna, including trout and bass species.

6. ***Comment*: In DSGEIS Section 7.1.2, NYSDEC acknowledges that Section AD of the MSGP is not currently adequate to prevent adverse impacts to stormwater but fails to provide any specific mitigation measures that may ultimately be included in a revised MSGP. NYSDEC is only proposing the option of revising the MSGP not guaranteeing that it will be revised. Absent a revised MSGP, it is not possible to determine if revised permit requirements will result in avoiding or sufficiently mitigating adverse environmental impacts. Because the DSGEIS fails to provide any changes to Section AD of the MSGP, analysis of industrial stormwater environmental impacts and mitigation measures must be done for each individual permit. If and when NYSDEC modifies the MSGP, another SGEIS must be prepared that analyzes industrial stormwater environmental impacts and defines mitigation methods.**

Discussion: Section 7.1.2.2 of the DSGEIS contains a recitation of typical BMPs generally used to improve the quality of industrial stormwater runoff under the General Permit. Aside from a simple assertion that NYSDEC is proposing the option of revising the MSGP as necessary, the DSGEIS contains no assessment of adverse environmental impacts and merely promises that future unidentified and hypothetical mitigation measures will be adequate.

7. ***Comment:* In the DSGEIS, NYSDEC fails to identify and evaluate the impact of stormwater runoff containing highly erodible soils in Marcellus Shale drilling areas. The soil characteristics of these soils require stormwater BMPs above and beyond those commonly used to remove turbidity from stormwater runoff. The DSGEIS fails to identify adverse environmental impacts in areas where difficult to settle soils are likely to occur and fails to require specific mitigation measures for such areas. The DSGEIS must identify such areas and impose specific mitigation measures to avoid or reduce adverse environmental impacts from soil erosion.**

Discussion: Soil characteristics such as particle size and settleablity affect the efficacy of typical stormwater management systems. Typical BMPs, such as settlement and detention basins, do not effectively remove difficult-to-settle fine clay soils found in areas where the Marcellus Shale may be developed, including the New York City Watershed and in Sullivan County. As discussed earlier, absent the use of extraordinary erosion control measures,

construction of gas drilling operations and support facilities in fine clay soils can result in turbid stormwater discharges to receiving waters.

Flocculants can be used to improve settleability of fine clay soils. Flocculants, however, can have adverse environmental impacts. For example, Chitosan, a flocculent derived from shells, was recommended by a developer for use at the Belleayre ski resort in New York State to improve discharge TSS quality.[34] Chitosan has been reported to be toxic to Rainbow Trout at very low concentrations.[35] The DSGEIS does not contain any evaluation of the potential adverse environmental impacts resulting from the use of flocculants or other additives to enhance settling of poorly settleable soils nor does it contain limitations on their use.

8. *Comment:* In the DSGEIS, NYSDEC fails to evaluate the cumulative adverse environmental impacts on stormwater resulting from transport of flowback water to treatment facilities and to require mitigation measures to eliminate or minimize adverse impacts.

Discussion: As discussed in Comments 2 and 3, large quantities of flowback water will be generated by high volume hydraulic fracturing. A significant portion of the generated flowback water is likely to be transported by truck to central impoundments and/or transported to POTWs or other treatment facilities. Two to three times as much fresh water must be transported by truck or pipeline to the well sites for well construction and hydraulic fracturing. Additional truck traffic will be required to transport equipment and chemicals to the well sites. The amount of pollutants, including sediment, metals, oils and greases, etc, discharged in stormwater from roads increases as traffic increases. No evaluation of the cumulative impact of the pollutants generated by additional truck traffic on water bodies and other environmentally sensitive areas is included in the DSGEIS. Mitigation methods to minimize or eliminate adverse environmental impacts from this activity are not included in the DSGEIS.

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34 The LA Group, Landscape Architecture and Engineering, *Draft Environmental Impact Statement, for Belleayre Resort at Catskill Park, Town of Shandaken and Middletown, Ulster and Delaware Counties, New York,* September 2003.

35 Bullick, Graham, et. al., "Toxicity of acidified chitosan for cultured rainbow trout (Oncorhynchus mykiss)," Aquaculture, Elsevier Science, November 7, 1999

NYSDEC indicated in the DSGEIS that cumulative environmental impact analysis cannot be performed because of the uncertainty of the rate of drilling due to economic factors. NYSDEC, however, recognized in the 1992 GEIS that “the potential for negative impacts on water quality, land use, endangered species and sensitive habitats increases significantly” with increased density.[36,37] Nevertheless, the DSGEIS includes an estimate of 2,000 wells per year from one private company.[38] NYSDEC should include an analysis of the cumulative impacts of truck traffic on receiving waters from stormwater discharge for a reasonable, worst case scenario.

Spills

9. ***Comment*: The DSGEIS fails to include an analysis of the inevitable adverse environmental impacts resulting from unavoidable spills from fluids associated with gas well operations including, but not limited to, fracturing chemicals, flowback water, and brine.**

Discussion: In September 2009, a spill in Pennsylvania of 8,000 gallons of drilling fluids into a nearby creek resulted in fish kills.[39] The drilling fluids discharged to the creek contained a liquid gel concentrate consisting of chemicals listed as possible human carcinogens. The September 2009 discharge of chemicals to receiving waters was one of several spills from facilities operated by the same company, including an 800-gallon diesel spill from an overturned truck.[40] Additionally, ToxicsTargeting.com has listed over 270 spills from 1986 to date from the gas/oil well operations in NYS ranging from less than one gallon to over 100,000 gallons.[41] The majority of the spills listed were a result of human error and equipment failure, inevitable events for any major construction project. The DSGEIS fails to determine the potential impact chemical and fuels spills can have on the environment.

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36 DSGEIS Section 6.13.2, 2009.
37 DSGEIS Section 6.13, 2009.
38 DSGEIS Section 6.13.2.1, 2009.
39 Lustgarten, A., “Frack Fluid Spill in Dimock Contaminates Stream, Killing Fish,” ProPublica, September 22, 2009.
40 Lustgarten, A., “Frack Fluid Spill in Dimock Contaminates Stream, Killing Fish,” ProPublica, September 22, 2009.
41 ToxicsTargeting, Drilling Spills Profiles, http://www.toxicstargeting.com/MarcellusShale/drilling_spills_profiles.

Instead, the DSGEIS states: "Specific secondary containment requirements will be included in supplementary well permit conditions for high-volume hydraulic fracturing on a site-specific basis if the proposed location or operation raises a concern about potential liquid chemical release that is not, in the Department's judgment, sufficiently addressed by the GEIS, the SGEIS, inherent mitigation factors and well pad setbacks."[42] In other words, NYSDEC may exercise its discretion to impose secondary containment requirements for fracturing chemicals, but such containment currently is not required. NYSDEC did provide criteria for determining what types of locations or operations "raise a concern."

The DSGEIS must identify the adverse environmental impacts that will occur from unavoidable spills based upon the total number of well permits contemplated. NYSDEC must make a determination if those adverse environmental impacts are of sufficient magnitude to limit the number of permits issued or if any permits should be issued in sensitive areas such as the NYC watershed.

Floodplains

10. ***Comment*: In the 1992 Final Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (GEIS), NYSDEC states that flooding is likely to occur sometime during the typical 30-year producing life of a well that is located within a floodplain.[43,44] In the DSGEIS, NYSDEC states that centralized flowback water surface impoundments will not be approved in 100-year floodplains.[45] NYSDEC has failed to evaluate the environmental impacts to waterways associated with flood-related releases of contaminants from the well pads placed in a floodplain. Based on the risks acknowledged in the 1992 GEIS, NYSDEC should be wholly prohibiting the placement of well pads within floodplains.**

***Discussion*:** In the DSGEIS**,** NYSDEC proposes to prohibit the placement of centralized flowback water surface impoundments and aboveground flowback water piping and conveyances within the 100-year floodplain.[46] However**,** NYSDEC still proposes to mitigate the risk of surface water contamination from well pad operations by allowing closed-loop

42 DSGEIS, Section 7.1.3.3.
43 Final Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (hereafter "GEIS") Section 16.B.2.c., 1992.
44 GEIS Section 8.D.2.d., 1992.
45 DSGEIS, Section 7.2.
46 DSGEIS, Section 7.2.

tank and piping systems for drilling and completion operations in floodplains.[47] The NYSDEC has recognized numerous environmental impacts associated with the imminent event of a flood during the life of an operating gas well pad site within a floodplain.[48] A closed loop system will not mitigate the potential environmental impacts from contaminants such as brine, oil, spent fracturing fluids, chemical additives, and petroleum releases during a flooding event. Flooding is considered "one of the few ways that bulk supplies such as additives might accidentally enter the environment in large quantities."[49] Allowing closed-loop systems in a flood plain still leaves open the potential for environmental harm in the event of a flooding event from damage due to large pieces of debris impacting the well pad site. Because NYSDEC has recognized the danger of contaminants to watercourses in the event of a flood, no part of any well pad or ancillary well pad structures should be allowed in a floodplain. Without such a limitation, New York's gas development practices will lag behind those in Texas and Pennsylvania, where many communities have prohibited gas drilling and development within floodplains.[50,51,52,53] NYSDEC must eliminate the potential for flood related spills of contaminants by prohibiting gas drilling and hydraulic fracturing activities, including the placement of ancillary structures, within a floodplain.

Watercourses, Waterbodies & Wetlands

11. ***Comment*: A site-specific SEQRA review must be required for any proposed well within 150 feet of NYSDEC regulated wetlands and associated 100-ft wetland adjacent areas as well as federally and locally mapped wetlands as required for proposed well pads within 150 feet of a watercourse, perennial or intermittent stream, storm drain, lake or pond.[54] Additionally, NYSDEC must assess the potential impacts to water resources as a result of large volume spills and require larger setbacks from water resources accordingly.**

***Discussion*:** NYSDEC proposes that site-specific SEQRA review be required for any

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47 DSGEIS, Section 7.1.12.2.
48 DSGEIS, Section 7.1.3
49 DSGEIS, Section 6.2.
50 Lancaster Township Zoning Ordinance, Article XIII Regulations in the Applicable Flood Plain District. http://www.twp.lancaster.pa.us/planningZoning/articles/art13.htm. December 2001.
51 Town of Bartonville, Texas, Gas Well Development Plat Regulations, Ordinance No. 462-08, Section 2.8 J.3, October 2008.
52 Town of Flower Mound, Texas, Oil and Gas Drilling Ordinance, Section 34-420 (k), March 2007.
53 City of Grapevine, Texas, Code of Ordinances, Section 12-145(b)(10), August 2009.
54 DSGEIS, Section 7.1.12.2.

proposed well pad within 150 feet of a watercourse, perennial or intermittent stream, storm drain, lake or pond.[55] All watercourses and wetlands, inclusive of NYSDEC regulated wetlands and associated 100-ft wetland adjacent areas as well as federal and locally mapped watercourses and wetlands, must receive the same level of protection as the other surface water resources regardless of whether they are located within the NYC watershed.[56] The rationale behind the 150-foot buffer as referenced in the DSGEIS is "…the GEIS found that a 150-foot distance between the well site and a surface water supply would provide adequate protection in the event of an accidental spill." All state, federal, and locally mapped wetlands must be afforded the same protections from an accidental spill.[57]

Furthermore, as the potential exists for large scale spills, such as the recent 8,000 gallon drilling fluid spill in Pennsylvania, larger setbacks from water resources must be required by NYSDEC. [58] The analysis conducted by Dr. Tom Myers on the DSGEIS for the Natural Resources Defense Council, Inc. indicates that a setback of 2,000 feet should be maintained unless a site specific analysis is conducted.[59] A setback of 2,000 feet would afford protection for water resources, including wetlands, in the event of a large volume spill, and a site specific analysis would address the potential impacts associated with a facility being placed within the 2,000 foot setback.[60] NYSDEC must assess the reasonable worst case scenario impacts associated with potential large volume spills and require setbacks accordingly, with possible setbacks as great as 2,000 feet from water resources as suggested by the analysis performed by Dr. Myers.

<u>Water Withdrawals</u>

12. *Comment*: In DSGEIS Section 6.1.1.7, Cumulative Water Withdrawal Impacts, NYSDEC concluded that it was unable to calculate the total volume of water withdrawals from gas drilling and hydraulic fracturing. NYSDEC acknowledged that the withdrawal of large quantities of water would have significant cumulative environmental impacts, including stream flow and groundwater depletion; loss of aquifer storage capacity; water quality degradation; fish and aquatic organism

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55 DSGEIS, Section 7.1.12.2.
56 DSGEIS, Section 7.1.12.2.
57 DSGEIS, Section 7.1.12.2.
58 Lustgarten, A., "Frack Fluid Spill in Dimock Contaminates Stream, Killing Fish," ProPublica, September 22, 2009.
59 Myers, T., *Technical Memorandum* (Attachment D), 2009.
60 Myers, T., *Technical Memorandum* (Attachment D), 2009.

impacts; significant habitats, endangered, rare or threatened species impacts; impacts to existing water users and reliability of their supplies; and impacts to underground infrastructure.[61] Based on the development potential of the Marcellus shale, NYSDEC must evaluate the impacts of the total potential withdrawals on a cumulative regional basis.

Discussion: NYSDEC states that "The total volume of water to be withdrawn for horizontal well drilling and associated hydraulic fracturing will not be known until applications are received and reviewed, and approved or rejected by the appropriate regulatory agency or agencies."[62] Although NYSDEC signed compacts with other regulatory agencies governing water withdrawals, such as the Delaware River Basin Commission (DRBC) and Susquehanna River Basin Commission (SRBC), these compacts do not preclude NYSDEC from assessing potential cumulative environmental impacts associated with water withdrawals. One estimate from the drilling industry contained in the Section 6.13.2.1 of the DSGEIS is that from 1,500 to 2,500 wells per year could be developed in Marcellus Shale in New York. Using the SRBC's approximate average of approved volume water withdrawal of 1.5 MGD for an individual application currently identified, and an average of 2,000 wells per year (the midpoint of the industry estimate), results in the potential to withdraw approximately 3 billion gallons of water per day.[63,64] A cumulative assessment based on the projected number of wells established in the context of NYSDEC regulations and protections must be provided to ensure that critical water resources and wildlife habitat are not degraded, threatened or otherwise subjected to unmitigated impacts.[65]

<u>Wildlife</u>

13. ***Comment*: Within the DSGEIS, NYSDEC has failed to address the potential significant adverse cumulative impacts of surface impoundments for gas wastewater on wildlife, specifically, waterfowl and migratory bird species. NYSDEC must fully assess the potential cumulative impacts and provide appropriate mitigation measures to address the impacts of impoundments on wildlife.**

***Discussion*:** NYSDEC identifies the potential for waterfowl and migratory birds to utilize

[61] DSGEIS, Section 6.1.1.7.
[62] DSGEIS, Section 6.1.1.7.
[63] DSGEIS, Section 6.1.1.7.
[64] DSGEIS, Section 6.13.2.1.
[65] NYSDEC, SEQR Handbook, 3rd Edition, 2010.

impoundments as rest stops during seasonal migrations.[66] The potential toxicity of the flowback water stored in these impoundments is also briefly discussed; however, NYSDEC fails to address the potential significant adverse cumulative impacts that these impoundments would have on waterfowl and migratory birds and fails to require appropriate mitigation measures to address these impacts.

According to the federal Migratory Bird Treaty Act (MBTA), it is "unlawful at any time, by any means or any manner to...take...any migratory bird," and additionally, according to the Endangered Species Act (ESA), it is unlawful for any person to "take any [endangered] species within the United States."[67,68] The act of "taking" a species is defined as "to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such conduct."[69]

The MBTA and the ESA were enacted as a means to protect both migratory birds, and threatened and endangered species, as each species possesses an esthetic, ecological, educational, historical, recreational, and scientific value that should be conserved. The MBTA is an international treaty that is implemented by the United States to protect birds that migrate across borders between Canada and Mexico. The ESA is administered by both the United States Fish and Wildlife Service (USFWS) and the National Oceanic and Atmospheric Administration (NOAA), but it is the responsibility of all federal departments and agencies to conserve endangered and threatened species by encouraging the States and other interested parties, such as the NYSDEC, to develop and maintain conservation programs which meet both national and international standards for conservation.

Per both the MBTA and the ESA regulations harm caused by the exposure to toxic flowback water stored in impoundments would be considered an illegal taking of any species, inclusive of waterfowl and migratory birds.[70] As a result, NYSDEC has the responsibility to either determine the full, cumulative extent of the potential impacts of these impoundments on waterfowl and migratory bird species, or to provide adequate mitigation measures to prevent

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66 DSGEIS, Section 6.4.2.
67 Migratory Bird Treaty Act, 16 U.S.C.A. Subsections 703 (a).
68 Endangered Species Act of 1973, 16 U.S.C. Subsections 1538 (a)(1)(B).
69 Endangered Species Act of 1973, 16 U.S.C. Subsections 1532 (19).
70 USA v Exxon Mobil Corporation, US District Court – District of Colorado – MBTA Violation.

the taking of such species including bird protection measures such as netting, bird balls, or other approved measures of equal effectiveness (barrier-type device). Furthermore, NYSDEC should require facilities to enact routine surveillance activities to ensure that bird deterrent measures are being maintained, specifically through observing the area within 50 yards of any impoundments for the presence of deceased, injured, or sick migratory birds.[71]

14. *Comment*: In the DSGEIS, NYSDEC has failed to address the potential significant adverse cumulative impacts of noise associated with multi-well pad development on all wildlife species.

***Discussion*:** NYSDEC addresses noise impacts associated with individual well pad development to some species of wildlife within the context of the GEIS.[72] In the Section 6.10 of the DSGEIS, NYSDEC states that the duration of drilling associated with horizontal well development will take 4 to 5 weeks of 24-hour drilling to complete.[73] Additionally, it states that a significant increase in trucking and noise associated with fracturing will be generated as a result of increased truck trips to bring in water for drilling and to remove flowback.[74] NYSDEC provides a brief analysis on the impacts to people living in close proximity to multi-well pad sites and the measures taken to mitigate these impacts, citing proper well pad location and design.[75] However, this analysis is not sufficient, and the NYSDEC does not address the impacts of 4 to 5 weeks of 24-hour drilling on resident wildlife. Some species of wildlife are more sensitive to a greater sound frequencies and volume than humans, and therefore, these impacts should be addressed.[76]

Animals use auditory signals for a variety of reasons including evasion of predators, location of mates, offspring, and prey, and definition of their territories.[77] Undesired noise sources can cause masking of or the interference with auditory communication or signals.[78] If communication patterns among wildlife species are interrupted, there is the potential for

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71 USA v Exxon Mobil Corporation, US District Court – District of Colorado – MBTA Violation.
72 GEIS, Section 8.J.1.
73 DSGEIS, Section 6.10.
74 DSGEIS, Section 6.10.
75 DSGEIS, Section 6.10.
76 U.S. EPA, *Effects of Noise on Wildlife and Other Animals: Review of Research since 1971*, July 1980.
77 U.S. EPA, *Effects of Noise on Wildlife and Other Animals: Review of Research since 1971*, July 1980.
78 U.S. EPA, *Effects of Noise on Wildlife and Other Animals: Review of Research since 1971*, July 1980.

adverse behavioral or physiological impacts.[79] As a result, NYSDEC should fully assess the potential significant adverse environmental impacts from noise and propose necessary mitigation measures on a site-specific and cumulative basis in each individual application for a drilling permit.[80]

15. *Comment*: In both the GEIS and DSGEIS, NYSDEC failed to account for the individual and cumulative impacts of multiple disturbances to vernal pools that may result in wide-scale destruction or fragmentation of essential habitat. These cumulative impacts must be addressed in the DSGEIS.

***Discussion*:** Vernal pools provide breeding habitat for the group of woodland salamanders called the "mole salamanders," which include marbled, Jefferson, blue-spotted, and spotted salamanders, as well as wood frogs. As vernal pools are typically isolated, low in oxygen, and dry during the summer they do not support fish populations and therefore provide high-quality "nursery" habitat for the developing eggs and larvae of salamanders and frogs.[81] Seasonal field surveys must be conducted as part of the permit application process to determine whether any areas of vernal habitat exist on-site and to verify the presence or absence of breeding vernal habitat species. Field surveys must be conducted during the spring and fall to verify and evaluate if any vernal habitat-dependent species utilize the wetlands for part of their lifecycle. The DSGEIS must indicate the timing of surveys and survey methodology used to determine the presence of vernal pools.[82] In addition the DSGEIS fails to address the potential significant adverse impacts, site-specific or cumulative, to amphibians or vernal pool inhabitants with regards to exposure to toxic water in centralized flowback water impoundments during breeding cycles or in the event of an impoundment leak.[83] NYSDEC must evaluate the cumulative impacts to vernal pool habitat and provide details regarding avoidance or mitigation measures designed to offset, reduce, or eliminate losses to vernal habitat dependent species.[84]

16. *Comment*: In both the GEIS and DSGEIS, NYSDEC failed to account for the potential significant adverse individual and cumulative impacts of multiple

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79 U.S. EPA, *Effects of Noise on Wildlife and Other Animals: Review of Research since 1971*, July 1980.
80 NYSDEC, SEQR Handbook, 3rd Edition, 2010.
81 NYSDEC Region 3, Comments on Draft Environmental Impact Statement, July 3, 2009.
82 NYSDEC Region 3, Comments on Draft Environmental Impact Statement, July 3, 2009.
83 DSGEIS, Section 6.4.2.
84 NYSDEC, SEQR Handbook, 3rd Edition, 2010.

disturbances to bat species, including the state and federally endangered Indiana Bat (*Myotis sodalis*), that may result from impairment of essential habitat. These cumulative impacts must be addressed in the DSGEIS.

***Discussion*:** NYSDEC must identify known and potential bat hibernacula associated with Karst formations and abandoned mines.[85] Disturbances to bat hibernacula due to natural gas drilling have the potential to disturb air flow, temperature, and humidity which are critical components for bat survival.[86] In addition, surface water impoundments with potential toxic compounds would pose a danger to foraging bats.[87] As bat populations have plummeted more than 90 percent in Northeast caves due to "White Nose Syndrome," protecting critical habitat is essential to maintaining the health of the remaining bat communities.[88] NYSDEC must evaluate the potentially significant adverse individual and cumulative impacts to bat habitat and provide details regarding avoidance or mitigation measures designed to offset, reduce, or eliminate losses to bat species.[89]

17. *Comment*: NYSDEC must require the same analysis for the presence of Rare, Threatened, and Endangered Species (RTE) as it proposes for documenting the presence of Invasive Species in Sections 3.2.2.7 and 7.4.1.1 of the DSGEIS. NYSDEC does not address the cumulative impacts associated with the destruction and fragmentation of RTE habitat.

***Discussion*:** The State Environmental Quality Review Act (SEQRA) requires that the potential impacts to RTE species be considered, which requires consultation with the Natural Heritage Program (NHP) prior to any development projects that have the potential to impact Rare, Threatened, and Endangered (RTE) species.[90] Surveys for RTE species that are present or documented must be provided with the same analytical level of detail required for invasive species referenced in the DSGEIS because all flora and fauna within the area of potential

85 U.S. Fish and Wildlife Service (USFWS), Indiana Bat (*Myotis sodalis*) Draft Recovery Plan: First Revision, 2007.

86 U.S. Fish and Wildlife Service (USFWS), Indiana Bat (*Myotis sodalis*) Draft Recovery Plan: First Revision, 2007.

87 U.S. Fish and Wildlife Service (USFWS), Indiana Bat (*Myotis sodalis*) Draft Recovery Plan: First Revision, 2007.

88 NYSDEC, *DEC Survey Shows Bat Populations down 90 Percent in Caves Impacted by "White Nose Syndrome": Wide-ranging, Coordinated Research Effort Continuing; NY Gearing Up for Next Round of Winter Surveys*, http://www.dec.ny.gov/press/61104.html, December 16, 2009.

89 NYSDEC, SEQR Handbook, 3rd Edition, 2010.

90 6 NYCRR Part 617.7(C)(1)(ii).

impact must be equally considered prior to site development.[91] NYSDEC must evaluate the potential cumulative loss of RTE habitat on a reasonable worst case scenario estimating the number, duration, and location of proposed wells, and propose necessary mitigation measures to address such impacts.

18. *Comment:* NYSDEC must require a four season Natural Resource Inventory for individual and multi-pad well sites that provides a comprehensive analysis inclusive of all site flora and resident and migratory fauna.

Discussion: A four season natural resource inventory (NRI) should be conducted to fully characterize the floral and faunal species that inhabit all proposed gas development well sites.[92] NYSDEC should provide applicants with a list of resources available for consultation in order to conduct a comprehensive NRI including the following: Ecological Communities of New York State, the New York State Breeding Bird Atlas, Audubon Society, USFWS Environmental Conservation Online System, NatureServe Explorer and the Natural Heritage Program (NHP).

Mapping

19. *Comment*: NYSDEC has not provided detailed up-to-date maps for public review in the DSGEIS that provide for a comprehensive evaluation and understanding of regional cumulative impacts to watercourses, waterbodies, wetlands, and RTE species in areas overlying the Marcellus Shale and other low-permeability shales.

***Discussion*:** The NYSDEC has the ability to provide for public review**,** detailed maps utilizing department maintained GIS databases that include and integrate the following information:

- Total area of potential well pad development within Marcellus shale and other shale regions.
- Critical Environmental Areas (CEAs) as noted in the GEIS and defined in 6 NYCRR

91 DSGEIS, Section. 3.2.2.7 and 7.4.1.1; "A map (1:24000) showing all occurrences of invasive species within the project site must be produced and included with the survey as part of the EAF Addendum"; "…it is necessary to identify the types of invasive species within the project site as well as map the locations and extent of any established population."

92 CEQR Technical Manual – Chapter 3I.

617.2 (i)).[93]

- DEC regulated wetlands and associated 100-ft adjacent areas as defined in 6 NYCRR 664, inclusive of “eligible” wetlands that are not currently mapped but likely meet the requirements to be mapped.
- DEC regulated lakes, rivers, streams and other bodies of water defined as *Navigable waters of the state* per 6 NYCRR 608.
- Watercourses, reservoirs, reservoir stems, intermittent streams, perennial streams as defined by New York City Watershed Rules and Regulations (NYCWR).[94]
- Primary and principal aquifers.[95]
- 8 digit United States Geological Survey (USGS) Hydrologic Unit Code (HUC) watershed outline and associated watercourse flowlines based on USGS National Hydrography Dataset (NHD) data.
- National Wetland Inventory (NWI) mapped wetlands and watercourses regulated under Section 404 of the Clean Water Act.
- Rare, Threatened, and Endangered species which are present or documented.

In addition, as part of the EAF submission, NYSDEC must require applicants to provide color maps that clearly depict and delineate the above information so that the public can better assess the potential significant adverse site-specific impacts of a proposed permit and so that appropriate mitigation for any such impacts can be identified and imposed.

93 GEIS, Chapter 8, Section O, 1992.
94 Title 15, Rules of the City of New York, Section 18-16, Definitions.
95 DSGEIS, Section 2.4.4.1, Figure 2.1.

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Memorandum

To: File

From: Hillel Hammer

Date: December 3, 2009

Re: Marcellus Shale DSGEIS: Summary of Comments on Air Quality and Greenhouse Gas Analyses

The following sections summarize our comments regarding air quality and greenhouse gasses. Overall, both air quality and greenhouse gas sections include extensive and high quality analysis. NYSDEC is especially commended on the extensive greenhouse gas analysis. However, the DSGEIS does not require adequate mitigation for the potential significant adverse impacts, and permit limitations which would ensure that the impacts disclosed indeed represent the reasonable worst case were not included in the DSGEIS.

A. AIR QUALITY

Some of the assumptions used to model the emissions and dispersion of pollutants in the DSGEIS underestimate the potential emissions and resulting concentrations. In some cases, the difference between what was assumed in the DSGEIS and a reasonable worst-case assumption is significant. As a result, emissions and concentrations could be significantly higher and, based on the current results, this would likely result in undisclosed significant adverse impacts.

Furthermore, since the DSGEIS does not specify permit conditions setting operating or emissions limits for air pollution sources, there are no enforceable air pollution limits set. Therefore, air quality impacts could be substantially higher if actual pollutant sources are used in excess of the estimated durations or if actual equipment type and quantity exceed the estimates.

Equipment:

1. The reasonable worst-case air pollution emissions would be the operation of two concurrent drilling rigs,[1] not just one, unless simultaneous operation of two drilling rigs on a single pad is prohibited.
2. Engine Tiers:
    a. Since NYSDEC has not proposed limiting the engines by certification, assuming Tier 1 for the worst-case short-term emissions is not a reasonable worst-case, since any given site could employ uncertified ('Tier 0) engines. Uncertified engines have extremely high emission rates for criteria pollutants such as particulate matter.
    b. Similarly, using Tier 2 for typical average long-term (e.g., annual average) modeling is inappropriate, since any given site may use uncertified or Tier 1 engines.

[1] DSGEIS at Section 5.2.2 states:"*One operator has stated that on a well pad where six or more wells are needed, it is possible that two triple-style rigs may operate concurrently*."

c. While Tier 2 may be a reasonable estimate for region-wide emissions (e.g., NOx, VOC, regional $PM_{2.5}$), there is no calculation to demonstrate this. A better estimate would include a 'fleet average' emission (similar to those produced by EPA's NONROAD model).

As set forth below ("Mitigation"), given the results of the analyses, NYSDOT should require engines with higher Tier certification. If those requirements are included, the modeling could use the required higher-Tier assumptions as a worst-case.

3. It is not clear whether the modeling used the largest rig for the entire duration or a combination of small and large rig. While some operators may use a smaller rig for the upper section of the well, and then transition to a larger rig to drill the horizontal section of the well bore, the text of the DSGEIS states that sometimes the larger rig would be used for the full duration.
4. Shallow gas diverter valves are used to vent gas to atmosphere while drilling the first part of the well. Vented gas estimates should be included in the analysis.
5. The emissions factors used for modeling (listed in the ALL 2009 report, Table 5) are cited as "EPA Tier emissions factors" but no source is cited. If the reference indicates the use of EPA regulation levels as emission factors, this would not include engine deterioration, which results in higher emissions over time.

Duration, Production Rates, and Other Emissions Assumptions:

6. NYS has not set any limit, in the DSGEIS or elsewhere, on the type of chemicals that can be used in fracture treatment; therefore, there is no assurance that the air quality impact analysis in section 6.5.2, based on an assumed representative set of chemicals, represents a worst case scenario or is even representative of the emissions that will actually occur in the field.
7. The maximum number of drilling days appears to be underestimated. Section 6.5.2.3, p. 6-72, states the worst case air modeling was completed at a maximum of 250 days of operations for drilling engines, maximum of 20 days for hydraulic fracturing engines, and maximum of 30 days of flaring in a given year. Yet the operating assumptions found elsewhere in the document show that this is not a worst-case scenario:

   Page 6-53 states 10 wells per drill site per year, drilled and completed. Page 5-22 states that each well takes approximately one month to drill (4 weeks = 28 days). Ten wells times 28 days = 280 days not 250. Page 5-23 says that "*In summary, the rig work for a single horizontal well – including drilling, casing and cementing— would generally last about* ***four to five weeks, subject to extension*** *for slow drilling or other unexpected problems or delays.*" (emphasis added), while page 5-126 says that each well will take at least 4 weeks, explaining that it could be **2 weeks for vertical section and up to an additional 30 days** for the horizontal section—that would be 44 days per well maximum. Therefore, the maximum drill and completion timeframe is 44 days per well not 28. Ten wells per drill site equates to 440 days of drilling per rig. That could put an annual worst case drilling day estimate at 365 days per year, and more if multiple rigs are employed simultaneously.
8. Page 6-120 states that "*A flaring period of three days was considered for this analysis although the actual period could be either shorter or longer*." The modeling needs to represent a reasonable worst case. The longest reasonable expected flare period should be used.
9. Page 6-61 states that venting was only considered for short term impacts. Since there is no requirement listed which would preclude venting, this would not seem to represent the reasonable worst case.
10. Section 6.5.1.2 concludes that production is estimated to be below 3 MMSCFD. This contradicts the ICF International August 2009 report, Subtask 2.5 (p. 26), that concludes: "*Information gathered by NYSERDA and NYS DEC field trips to Marcellus Shale well sites indicate a potential production rate of 7 to 10 MMscf per day.*"

Dispersion Modeling and Concentrations:

11. Only 2 years of meteorological data were used. Due to the high variability, the standard modeling procedure is to use 5 years of meteorology to determine the worst-case dispersion conditions (EPA, 40 CFR Part 51 Appendix W, §8.3.1.2, November 2005). Data for all stations is readily available. Although the total set included data for 6 locations, and therefore a total of 12 data sets, since these were all from the same two actual meteorological years, they are connected and therefore do not represent a full range of annual and short-term conditions as would be represented in data from 5 separate years.
12. The use of the 98th percentile value for $PM_{2.5}$ increments is incorrect. Incremental values are normally calculated for the highest value, and may be combined with the 98th percentile background to estimate total

values. Alternatively, if the modeled increments dominate (i.e., are much higher than the background), the 98th percentile increment may be used to calculate total concentrations in combination with the highest background. However, the use of 98th percentile increment for the purpose of comparison with incremental thresholds such as the NYSDEC annual and 24-hour average values of 0.3 and 5 $\mu g/m^3$, respectively, is incorrect regardless of the total concentrations.

REGION-WIDE EMISSIONS ANALYSIS

The air quality analysis does not disclose the expected total region-wide criteria pollutant emissions for the various nonattainment areas. The SGEIS will represent a generic analysis of individual potential sites, but is also required to examine the total cumulative impacts of all of these potential sites. An obvious potential cumulative impact is the combined regional criteria pollutant emissions from all potential sites in all relevant nonattainment areas. The total potential emissions in each nonattainment area should be disclosed and discussed in the context of existing or future SIP emission budgets.

A best estimate of the reasonable worst-case overall operations likely to occur per year is required under SEQRA to evaluate the region-wide implications and determine the need for mitigation. The difficulty in "accurately" predicting the unique nature of the New York play does not absolve NYSDEC of its obligation to present a best estimate. This requirement is not covered under the "regulatory analysis" provided in the DSGEIS.

The State is likely to encourage natural gas usage while discouraging higher-carbon fuels in order to meet its greenhouse gas goals (as stated in Executive Order 24 of 2009 and in the State Energy Plan, 2009), through the Climate Action Plan it is currently developing. Therefore, the regional estimates should include an assumption regarding the price signal associated with those future policies and its impact on the annual production rate. The DSGEIS includes one estimate of the establishment of 2,000 wells per year (Section 6.13.2.1, Regional Cumulative Impacts), and indicates that over 1,100 permits were issued in 9 months in 2009 (through the end of August). These estimates are prior to the above mentioned future policy considerations, but these policies would likely result in higher production rates in future years.

In addition, the State will need to address the regional emissions via the State Implementation Plan (SIP) process for existing and future SIPs. As such, the State should disclose, in this SGEIS, how it will offset these emissions or otherwise meet its emissions targets while including these emissions.

MOBILE-SOURCE ANALYSIS

Mobile-source emissions are not addressed at all in the DSGEIS. Potential emissions should be screened at an intersection level to determine if there is a need for dispersion analysis and if there is potential for local impacts. In addition, the total region-wide emissions from mobile sources should be included in a regional emissions analysis, also missing (see above).

MITIGATION

1. Permit Operational Limits

The analysis and its conclusions are based on estimated operations levels, rather than on potential to emit, but there is no commitment to restricting operations via permit specifications. In order to ensure that the impacts do not exceed the disclosed levels, permit limits must be set for operations—hours and duration of operations, and equipment types and quantities at any given site.

In general, the mitigation section for Air Quality does not require any mitigation. Instead, it simply lists measures "*possible mitigation measures*". Currently, the DSGEIS does not identify any required mitigation or mitigation level, and therefore, does not demonstrate in any way that mitigation will be implemented, as required by SEQRA. As discussed above, the DSGEIS does not even acknowledge potential significant adverse impacts, underestimates the impacts disclosed, and does not demonstrate the effectiveness of mitigation or include many available mitigation measures (detailed below).

The Proposed Supplementary Permit Conditions (Appendix 10, §32) states that "*Fracturing products **other than those identified in the well permit application** materials may not be used without specific approval from this office. The Department will require submission and review of chemical information for any product which has not previously been reviewed, and **may** require a site-specific environmental assessment and SEQRA determination*

prior to approving commencement of hydraulic fracturing operations based on a change in fracturing products." (emphasis added). The conditions should state that if any substances identified in the well permit application were not included or would exceed the quantities identified in the FSGEIS analysis, and may result in the emission of toxic or criteria pollutant emissions, a site-specific environmental assessment and SEQRA determination would be required prior to approval.

2. Restricting Public Access and Stack Heights:

Since the definition of "ambient air" includes any area to which the public would have continuous access, the DSGEIS proposes to significantly enlarge sites to include any areas where potential significant adverse air quality impacts were predicted in order to restrict public access to these areas—in some instances to as much as a 1,000 meter distance. Note that the DGEIS identifies the need for a 500 **meter** buffer for particulate matter (p. 6-85, 7-88), and then requires a buffer of only 500 **feet** for mitigations (p. 7-89).

This type of "mitigation" would require additional land use, and result in impacts associated with disturbing those lands for fencing and creating access to those areas—an action which is not reviewed in the DSGEIS and which could result in additional undisclosed impacts, and would contribute nothing to reducing region-wide emissions. Since the preferred approach is always to mitigate potential impacts on-site to the extent practicable, and since practicable methods are available and commonly used elsewhere, it is not reasonable to rely on restricting public access to these areas and increasing stack heights as the preferred and only solution. Instead, proper mitigation can and should be required, as detailed in the sections below. The old adage "dilution is not the solution to pollution" is quite apt in this case.

3. Green Completions and Prohibition of Venting:

Section 6.5.1.3 of the DSGEIS states that green completions are not required in NY State. Although oil and gas exploration may not have been a major focus in the past, this action will enable large scale natural gas drilling operations throughout the state, and natural gas is likely to be encouraged further in the coming years due to its low-carbon and low-emissions properties when used as a fuel.

Therefore, we strongly advocate that state regulations require green completions once the first well on a pad is drilled and a pipeline is in place, and allow venting only in case of emergency, as is common in current operations of many industry members. For example, many industry members reporting to the EPA Natural Gas STAR program are voluntarily instituting this procedure and report substantial profits related to recovering the gas and selling it to market instead of venting to the atmosphere (http://www.epa.gov/gasstar). In cases where sales lines exist nearby, or where the likelihood of the first site producing marketable gas is high, green completions should be required prior to the first well being established. However, since such regulations are not yet in place, the FSGEIS must make green completions and the prohibition on venting a strict requirement for any drilling operation permitted under this action.

4. Dehydrators:

Section 6.5.1.2 concludes that dehydration units used for the gas development will be exempt from EPA's NESHAP requirements since production is estimated to be below 3 MMSCFD or benzene below 1 tpy. This conclusion conflicts with ICF International's August 2009 Report, Subtask 2.5 (p. 26), that concludes: *"Information gathered by NYSERDA and NYS DEC field trips to Marcellus Shale well sites indicate a potential production rate of 7 to 10 MMscf per day."*

5. Flowback Emissions:

Section 6.5.1.8 concludes that *"Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission* [estimate] *of **32.5 tons** (i.e., "**major" quantity of HAP**) is theoretically possible at a central impoundment."* (emphasis added).

The DSGEIS presents inconsistent approaches to mitigating this issue (p. 7-55, 7-88, 7-89, 7-90). It is very unclear what NY State is actually proposing. Is the operator required to eliminate toxic chemicals, stop using impoundments and flow to tankage, complete more site specific modeling, or just build a larger fence?

Flowback into central impoundments should not be allowed. Flowback should be routed to closed/controlled tank/pipeline collection and treatment systems and the use of toxic and bioaccumulating substances should be eliminated. NY State should clearly list the compounds analyzed and their assumed quantities, and include a requirement that any use of other substances not analyzed in the FSGEIS, or larger quantities of the analyzed substances, require full disclosure and analysis of potential adverse impacts as an action not covered in this SGEIS.

6. Dual Fuel and Electricity:

A basic and common mitigation approach, overlooked by the DSGEIS, is the use of cleaner engines and fuels. Specifically, in areas where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable. This would eliminate entirely the local diesel exhaust from those engines. Alternatively, if a connection is not available, but a site is producing usable natural gas (where separation and dehydration capability exists on-site), electricity could be provided using fuel cells fueled with natural gas, or, if fuel cells are not practicable, natural gas generator sets could be used.

For engines or situations where electricity is not a practicable option, but where a site is expected to produce usable natural gas, the use of dual fuel engines would enable switching from diesel to natural gas once it is available.

The use of electric and natural gas engines would result in reduced local pollutant emissions and overall greenhouse gas emissions (both grid power and natural gas have a lower carbon footprint than diesel), and would generally have associated cost savings due to the use of the fuel produced on-site, reduced fuel transportation and storage needs (double-wall tanks), and reduced risk of tank leakage and cleanup.

7. Diesel Particle Filters and Engine Tier:

As mentioned above, the DSGEIS identifies unacceptable increases in particulate matter concentrations, but determines that creating larger sites and increasing stack heights will mitigate the significant adverse impacts by making the area not accessible to the public. This solution would create additional problems and does nothing to reduce region-wide emissions. The most common mitigation measure for reducing particulate matter emissions from diesel engines, currently used for many construction projects in New York, is the requirement for best available control technologies, including the use of engines equipped with diesel particle filters (DPFs). This type of control program is legally required for all New York City construction, is routinely required for all large private and public construction projects in New York City including federal and State projects, does not add significant cost to implement, and is readily available. Since diesel particulate matter has been shown to be carcinogenic as well, one of the largest side benefits to such programs is the protection of the health of the workers on-site.

NYSDEC should require that:

- All engines with a power output of 50 horsepower or greater be equipped with a DPF, either original engine manufacturer or retrofit, including active DPF as necessary.
- All diesel engines (of any size) should be certified Tier 2 or higher.

B. GREENHOUSE GASES COMMENTS

MODELING ASSUMPTIONS

Many of the modeling assumptions called out as potentially underestimating criteria pollutant emissions (see "Air Quality", above) would also result in underestimated greenhouse gas (GHG) emissions. The following list indicates items which would impact GHG emissions, and full details can be found above in the air quality section:

1. *Simultaneous multiple drilling rig operations not accounted for*: This would result in higher per-year per-site GHG emissions.
2. *Drilling duration*: If drilling duration is longer than assumed, overall drilling emissions would be underestimated. This would result in higher first-year emissions, and in an overall longer duration of operations per site.
3. *Flaring duration*: A flaring duration of 3 days was assumed, but it is not clear if this represent an average per well. Representative flaring duration data should be obtained and presented.
4. *Venting*: NYSDEC states the importance of avoiding vented methane emissions, but sets no requirement to avoid such events and does not disclose emissions associated with longer events. A strict requirement to avoid venting other than in case of emergency should be enforced.

In addition, the following assumption was used only for the GHG analysis:

5. *Assumed only 20 miles for in-state round trip for on-road emissions:* presenting such a trip and the associated emissions as a reasonable low-end estimate, for the purposes of highlighting the potential benefits of local operations, may be reasonable. However, in most cases, this may be a gross underestimate even in-state since many remote locations will require transport for considerably longer distances. In addition to the scenarios presented, a reasonable estimate should be made representing average in-state distances and included in the per-site and statewide emissions totals (see more on total summaries below).

MODELED COMPONENTS

Fugitive emissions

Fugitive emissions were not disclosed. The DSGEIS acknowledges that it is appropriate to analyze fugitive emissions (p. 6-111), but goes on to state "*However, relative to combustion and process emissions, fugitive CH_4 and CO_2 contributions are insignificant*.", citing a 2003 report from the International Petroleum Industry Environmental Conservation Association and the American Petroleum Institute. Page 3-10 of that document states, "*General categories of direct emissions sources that should be included in inventories are … [f]ugitive losses from equipment leaks such as from gas pipeline systems.*" Page 3-15 states that, with respect to indirect emission sources, "*companies are encouraged to be able to account for selected indirect sources including … [t]hird party shipping of … petroleum products … by pipeline up to the point of custody transfer.*", and API provides methods for estimating these emissions, with an update in August 2009. Thus the DSGEIS is misleading in quoting the API as saying that pipeline leakage is insignificant.

Indeed, most greenhouse gas inventories including, for example, the US national inventory and the New York State inventory do include these emissions, precisely because they are not negligible and are mitigable. Distribution losses from natural gas systems are called out explicitly in the 2009 NY State GHG Inventory as 1.85 percent of total state-wide emissions, and are therefore a significant source. This fraction may be larger if large scale production and distribution in the State grows as a consequence of this action.

Since the SGEIS will enable widespread natural gas operations throughout the state, the undisclosed increase in fugitive emissions, if left unmitigated, is likely to be substantial.

Fuel Use

The NYSDEC guidance for GHG analyses in EISs states that "*Project proponents should not be required to include the emissions (either qualitatively or quantitatively) from the use of products that will be produced or sold at the project site, **except where the projects involve fuel production***." (emphasis added, NYSDEC 2009). According to that guidance, the use of the gas produced state-wide should be analyzed, to address—

a. The potential change in net fuel use (e.g., would the production reduce natural gas prices);

b. The fuel use that may be offset by this natural gas (e.g., reduction if replacing oil, increase if replacing other natural gas produced with a lesser carbon footprint).

SUMMARY OF EMISSIONS

Lack of Disclosure of Total Per-Site Emissions

The DSGEIS does not disclose the total GHG emissions expected per site. Unlike criteria pollutants, the annual rate of GHG emissions is only important for continuous emissions (e.g., development projects). There is little or no difference between the impacts associated with one well operating for two years and with two well operating for one year. Table 6.15 (p. 6-126) discloses the annual first-year and subsequent-year emissions, but does not include an estimate of the range and/or average number of years for which production will continue. Although much uncertainty exists, a best-estimate range and average duration and the total associated emissions should be presented.

Lack of Disclosure of Statewide Emissions

The GHG analysis does not disclose the expected state-wide GHG emissions expected for the duration of overall operations throughout the state. The DSGEIS represents a generic analysis of individual potential sites, but is also required to examine the cumulative impacts of all of these potential sites. An obvious potential cumulative impact is the combined state-wide GHG emissions from the sites.

A best estimate of the reasonable worst-case (e.g., assuming the full exploitation of the Marcellus Shale to the extent practicable by year X) is required under SEQRA in order to evaluate the long-term implications and determine appropriate mitigation. The DSGEIS states that "*It is estimated that the entire Marcellus shale may hold between 168 and 516 trillion cubic feet of gas".* (See more in the Air Quality section above, under "Region-Wide Emissions Analysis".)

It is likely that these activities will be included in the current efforts being undertaken by NY State to formulate a Climate Action Plan (CAP) that will identify policies to reduce GHG emissions from all sectors, including the Oil and Gas sector. The emissions associated with this project will need to be included in the State GHG Inventory as well as the potential mitigation programs included in the NY State CAP.

As an agency directly involved in the CAP effort, NYSDEC would do well to identify potentially practicable policies and requirement now, through this EIS process, and thus ensure that the proper requirements are included in drilling permits and enforced, rather than attempt to put restrictions in place after operations have begun and the State has less opportunity to do so, while losing years of sector emissions reductions in the process. By not addressing these issues at this juncture, NYSDEC would be at odds with the various State policies and guidelines regarding energy efficiency and GHG emission reductions.

MITIGATION

In general, the mitigation section for GHG emissions does not require any mitigation. Instead, it simply lists measures that "could be included". Certain mitigation, identified as practicable, should be required of all permit applicants. Failing to do so would be contrary to current state policies and to SEQRA. Currently, the DSGEIS does not identify any required mitigation or mitigation level, and therefore, does not demonstrate in any way that mitigation will be implemented, as required by SEQRA. The Proposed Supplementary Permit Conditions (Appendix 10, §1.c) states that operations must be conducted in accordance with a site specific "*greenhouse gas emissions impacts mitigation plan consistent with the SGEIS*", but since the SGEIS does not require anything, it is not clear what would be required or if any GHG reduction measures would be implemented as a result.

New York State Policy commits the State to achieving an 80 percent reduction in GHG emissions by 2050. This goal poses a significant challenge and cannot be achieved by focusing only on large sources—e.g., ignoring fugitive emissions, not considering the use of biofuels, and more, especially when considering the potential statewide implications of this action. National and state GHG inventories identify these sources precisely for that reason: to enable mitigation.

Furthermore, the exploitation of the shale natural gas reserves is presented as a mid-term solution to reducing GHG emissions by using the lower-carbon natural gas instead of oil and/or coal. The degree to which lifecycle GHG emissions associated with the use of natural gas would be lower than higher-carbon fuels is dictated not only by the nature of the fuel itself, but by the actions taken to avoid emissions during production and delivery of the natural gas. All practicable efforts should be made to ensure that the natural gas produced in NY State will have the lowest practicable carbon footprint.

The mitigation "options" presented in the DSGEIS focused on vented and flared emissions, which are obvious candidates for controls, but the DSGEIS does not require even those measures. Existing control methods for these emissions should be required as a matter of course:

1. *Green Completions and Prohibition of Venting*: see the air quality "Mitigation" section, above.
2. *Natural Gas Star:* Requiring participation in the Natural Gas STAR program would be a positive step toward identifying emissions reduction opportunities and sharing information.

However, focusing on these obvious sources should not serve to minimize the need to examine and require, as appropriate, other more standard GHG reduction measures, as outlined in the NYSDEC GHG EIS analysis guidance and required of all projects now reviewed by NYSDEC. Relevant measures include:

3. *Dual Fuel and Electricity*: see the air quality "Mitigation" section, above. The purchase of renewable electricity should be considered as well.
4. *Biofuels:* In cases where electricity and natural gas cannot be used, the use of biodiesel should be considered. Biodiesel blends of up to 20 percent (B20) can generally be used in diesel engines without any modification, although minor modifications are sometimes required for blends above 5 percent (B5). With the current biodiesel production methods specific to NY State, this would result in the reduction estimated to be between 3-13 percent on an energy basis, on average (based on NY-GREET model, NYSERDA, 2007), and the cost is relatively low. Higher level blends such as B80 or even full biodiesel (B99 or B100) are currently being used for many applications and should be investigated as well. These would achieve much higher GHG reductions, up to 67 percent on average. Note that although some engine manufacturers have stated that their warranty will not cover damage by these higher blends, they would still be required to honor the warranty conditions for any other damage, and a properly implemented program would not cause damage to engines as a result of the use of the fuel. Priority should be given to biodiesel produced from recycled oils and waste products.
5. *Reducing Distribution Losses and Other Fugitive Emissions:* Ensuring tightly sealed flow connections, and performing leak detection and corrective action should be required and an enforcement program implemented. Note that distribution losses from natural gas systems are called out explicitly in the 2009

NY State GHG Inventory as 1.85 percent of total state-wide emissions, and are therefore a significant source. This fraction would be even larger if large scale production and distribution in the State grows as a consequence of this action.

6. *Lighting and Other Electrical Uses:* the choice of energy efficient systems and practices can minimize electricity consumption.

7. *Best Management Practices:* USEPA's Natural Gas STAR Best Management Practices (p. 7-94) should be evaluated for each proposed permit application, and any measures found to be practicable should be required.

NOISE

INTRODUCTION

A noise assessment was performed to determine whether drilling activities in a well site would result in significant impacts at vicinity sensitive receptors. The New York State Department of Environmental Conservation (NYSDEC) noise guidance was used for this assessment. Below is a discussion of the methodology and the analysis results.

NOISE ANALYSIS METHODOLOGY

Noise Background

Following is a description of the noise terminology used in this assessment.

- Decibel—Noise is measured in units called decibels. A 1-decibel change in noise is about the smallest change detectable by the human ear under ideal laboratory conditions. Outside a laboratory, only a change of about 3 decibels or more can be easily detected without the use of instruments. A change of more than 5 decibels is an appreciable change in a community's noise level. A 10-decibel increase is large and is a doubling of loudness. (For example, 50 decibels sounds twice as loud as 40 decibels.)
- A-weighted decibel—Sound measured by scientific instruments is adjusted to correspond to human hearing: it is filtered to reduce the strength of very low- and high-pitched sounds. This adjusted unit is known as the A-weighted decibel, or dBA.
- L_{eq}—The L_{eq} is an hourly measure that accounts for the fluctuations in dBA from all noise sources combined during that hour. It incorporates the total noise during the hour, converted into a type of average. For example, if a fluctuating noise with L_{eq} equal to 70 dBA is replaced by a constant noise of 70 dBA, then the same total noise energy would enter a listener's ear (see Table 1 for examples of typical fluctuating and constant noise levels). The L_{eq} is equivalent to the constant noise in this sense. In accordance with the NYSDEC policy, the basic unit of noise used in this study is the dBA L_{eq}.

Table 1
Common Noise Levels

Sound Source	dBA
Military jet, air raid siren	130
Amplified rock music	110
Jet takeoff at 500 meters	100
Train horn at 30 meters	90
Busy city street, loud shout	80
Highway traffic at 15 meters, train	70
Predominantly industrial area	60
Background noise in an office	50
Public library	40
Soft whisper at 5 meters	30
Threshold of hearing	0

Note: A 10 dBA increase in level appears to double the loudness, and a 10 dBA decrease halves the apparent loudness.

Sources: Cowan, James P. *Handbook of Environmental Acoustics,* Van Nostrand Reinhold, New York, 1994.

Egan, M. David, *Architectural Acoustics*. McGraw-Hill Book Company, 1988.

NYSDEC Noise Impact Guidance

NYSDEC published a guidance document entitled *Assessing and Mitigating Noise Impacts* (October 6, 2000). This document states that increases from 0-3 dBA should have no appreciable effect on receptors, increases of 3-6 dBA may have the potential for adverse impact only in cases where the most sensitive of receptors are present, and increases of more than 6 dBA may require a closer analysis of impact potential depending on existing noise levels and the character of surrounding land use and receptors. It goes on to say that in terms of threshold values, the addition of any noise source, in a non-industrial setting, should not raise the ambient noise level above a maximum of 65 dBA, and ambient noise levels in industrial or commercial areas may exceed 65 dBA with a high end of approximately 79 dBA. Projects that exceed these guidance levels should explore the feasibility of implementing mitigation.

For purposes of impact assessment, the proposed project will have a significant noise impact if one of the following criteria is exceeded:

- The project results in an increase in noise levels of 6.0 dBA or more at sensitive receptors.
- At non-industrial areas, noise levels generated by the drilling activities are greater than or equal to 65 dBA.
- At industrial or commercial areas, noise levels generated by the drilling activities are greater than or equal to 79 dBA.

Noise Prediction Method

The noise assessment was performed for a period of drilling/fracturing activities which is the worst case based on types and number of pieces of equipment and number of trucks anticipated to be operating. Table 2 shows the noise levels for typical equipment that would be used for the drilling and fracturing activities.

Table 2
Equipment Noise Emission Levels (dBA)

Typical Equipment	Quantity	Noise Level at 50 feet*
Generator (Caterpillar 3408)	6	82
Generator (Caterpillar 3512c)	15	82
National 610 drill rig	1	85
SpeedStar 185K drill rig	1	85
Ingersoll Rand 1170/350 air compressors	3	80
National 9-P-100 water pumps	2	77
Diesel trucks	40	84

*Sources: Citywide Construction Noise Mitigation, Chapter 28, Department of Environmental Protection of New York City, 2007; Transit Noise and Vibration Impact Assessment, Federal Transit Administration (FTA), May 2006.

At sensitive receptor locations noise levels due to the each of the noise sources at a well site were calculated based upon using the following formula:

Leq = E.L. + 10log(U.F) - 20log(D/50) – Aair – Atree – Aenv

where: L_{eq} = predicted noise equivalent pressure level,

E.L. = noise emission level,

D = distance between noise source and receptor (feet),

A_{air} = attenuation by absorption in the air,

A_{tree} = attenuation by shrubbery and trees, and

A_{env} = attenuation due to ground effects.

ASSESSMENT RESULT

Based upon the analysis results, the project noise levels would exceed the NYSDEC noise threshold of 65 dBA for non-industrial land uses at approximately 700 feet from a well site, and the project noise levels would exceed the NYSDEC noise threshold of 79 dBA for industrial and commercial uses at approximately 100 feet from a well site. In addition, to determine whether significant noise impacts would occur using the NYSDEC noise threshold of 6.0 dBA increase, an ambient noise monitoring program in the vicinity of the well site in order to characterize the existing noise environment will be performed. Due to fairly low ambient noise levels expected in these rural areas, the project might result in significant noise impacts at vicinity sensitive receptor locations.

Noise Level Calculations - Drilling and Fracturing phases

	Emission Level at 50 ft			Use Factor		Distance Attenuation		Distance in meter			Air Attenuatio	Foliage Attenuatio	Aenv										
													As = (b*G)-1.5			Ar = (b*G)-1.5			Am = -3e(1-G)				
Noise Source	dBA / Unit	Qty. / 1hr	E.L. dBA	U.F.(%)	10log (UF)	Distance (feet)	20log (D/50)	Distance (D)	Source height (hs)	Receiver height (hr)	Aair	Atree	Factor (b)	Groun d (G)	As	Factor (b)	Groun d (G)	Ar	Factor (e)	Groun d (G)	Ar	Predicted Noise Level	Equivalent Noise Energy
Generator (Caterpillar 3408)	82	6	90	50	-3	1000	26	305	3.0	1.5	0.3	2.0	5.3	0.8	2.9	8.4	0.75	4.8	0.6	0.75	-0.4	51	129314.8
Generator (Caterpillar 3512c)	82	15	94	50	-3	1000	26	305	3.0	1.5	0.3	2.0	5.3	0.8	2.9	8.4	0.75	4.8	0.6	0.75	-0.4	55	323286.9
National 610 drill rig	85	1	85	20	-7	1000	26	305	3.0	1.5	0.3	2.0	5.3	0.8	2.9	8.4	0.75	4.8	0.6	0.75	-0.4	42	17201.1
SpeedStar 185K drill rig	85	1	85	20	-7	1000	26	305	3.0	1.5	0.3	2.0	5.3	0.8	2.9	8.4	0.75	4.8	0.6	0.75	-0.4	42	17201.1
Ingersoll Rand 1170/350 air compressors	80	3	85	40	-4	1000	26	305	3.0	1.5	0.3	2.0	5.3	0.8	2.9	8.4	0.75	4.8	0.6	0.75	-0.4	45	32636.8
National 9-P-100 water pumps	77	2	80	50	-3	1000	26	305	3.0	1.5	0.3	2.0	5.3	0.8	2.9	8.4	0.75	4.8	0.6	0.75	-0.4	41	13631.0
diesel trucks	84	40	100	40	-4	1000	26	305	3.0	1.5	0.3	2.0	5.3	0.8	2.9	8.4	0.75	4.8	0.6	0.75	-0.4	60	1093067.1
SUM																							1626338.8
Total Noise Level Leq(1)																							62

Note:

Leq(1) = E.L. + 10log(U.F) - 20log(D/50) - Atotal (Aair+Atree+Aenv).

E.L. is the noise emission level of the particular piece of equipment

U.F.=Usage factor that accounts for the fraction of time equipment is in full power operation throughout the workday

The following values are calculated based on the methods in "The Noise Manual" edited by E.H. Berger..., 5th Edition.

Atotal (Aair+Atree+Aenv)

Air Attenuation (Aair) = a'D/1000; a' is the air attenuation coefficient (see Table 15.1), assuming 68F with a relative humidity of 70% at 250 Hz, a' = 1.1

Foliage Attenuation (Atree) = 4-8 dBA attenuation due to approximately 300 feet of dense trees (see p621), 2 is used conservatively.

Aenv = As+Ar+Am (at 250Hz)

Source zone As= (b*G)-1.5 (see Table 15.3)
b=8.4 (see Table 15.3)
G=(30*3-15)/90, for the source zone 30hs=30*3=90, assume the source located in the center of 30m x 30m site, 15m of source zone is "hard," and the remaining 75m is "soft." (see p617)

Receiver zone Ar= (b*G)-1.5 (see Table 15.3)
b=8.4 (see Table 15.3)
G=0.75 assume 75% of ground is grass

Middle zone Am= -3e(1-G) (see Table 15.3)
e=(1-(30(hs+hr)/D
G=0.75 assume 75% of ground is grass