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
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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 1×10^{-11} cm/s. A 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 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.

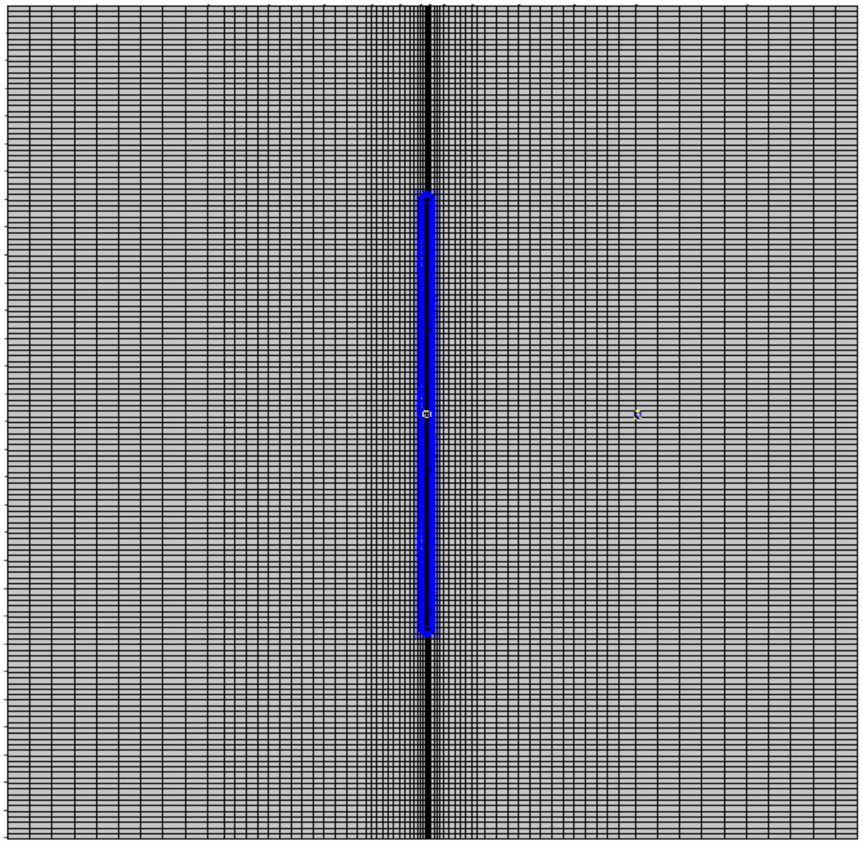

Figure 1: Figure showing grid layout and two conductivity zones in layer 37. The blue zone had K=0.0007 ft/d while the gray has K=0.0001 ft/d. The horizontal well is in the middle of the blue zone. The column spacing is 160 feet at the edges and decreases to 10 feet at the center near the well.

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.

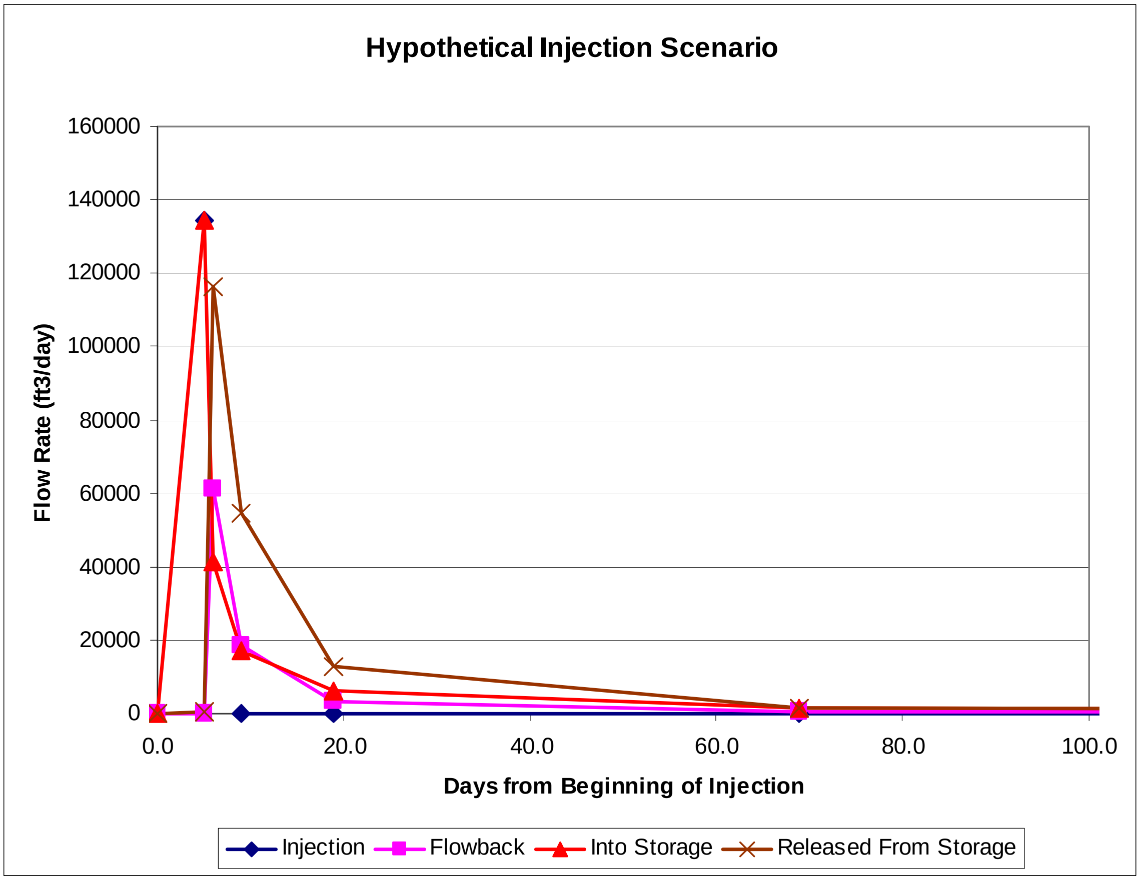

Figure 2: Hydrograph of simulated flux rates for the hypothetical injection scenario. Each flux rate is that occurring at the end of a stress period, as described in the text.

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.

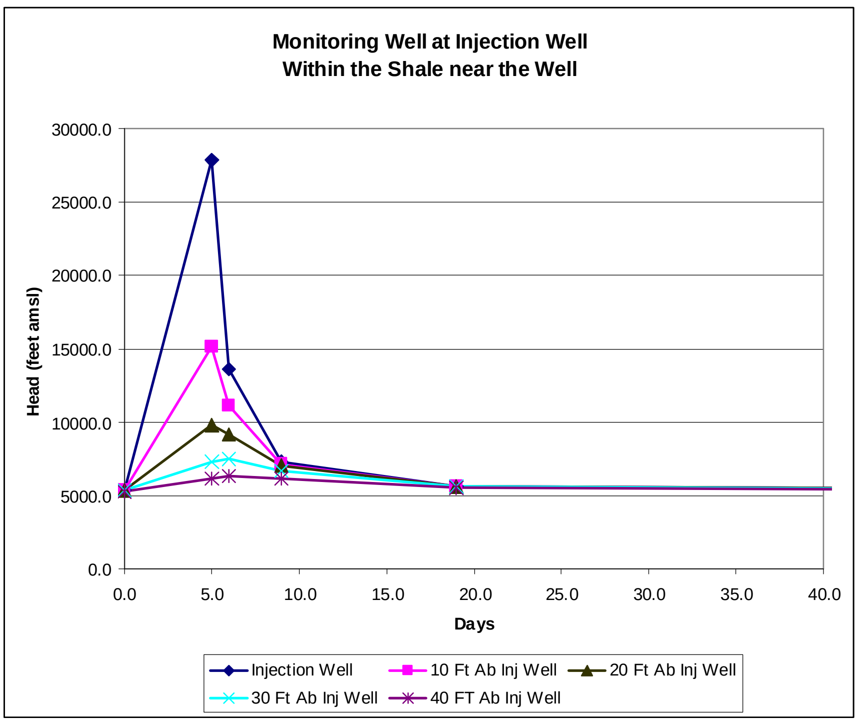

Figure 3: Hydrograph of head values in the simulated monitoring well located in the center of the model domain.

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.

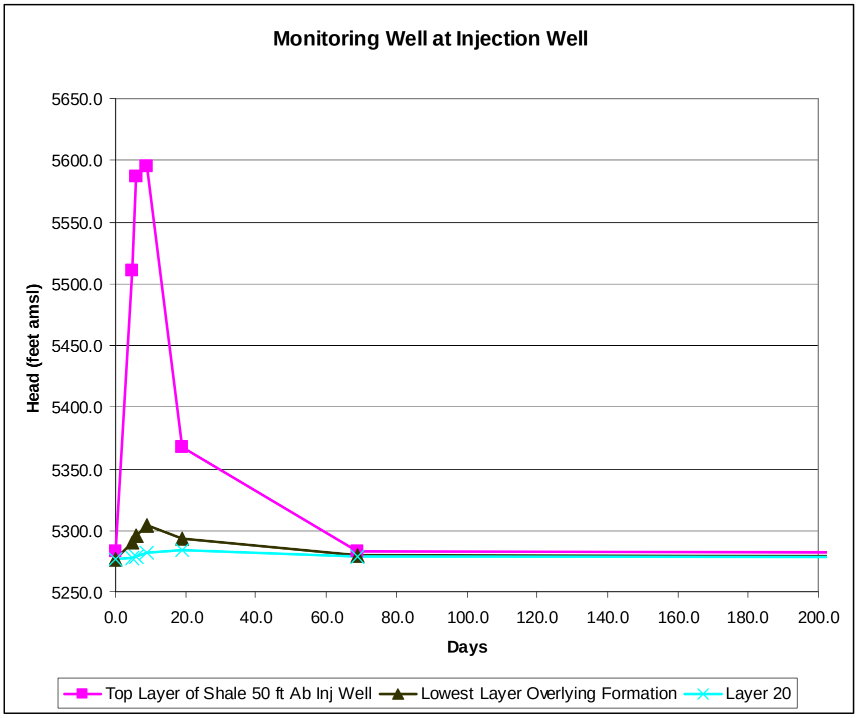

Figure 4: Hydrograph of head values located at the top of the shale and two points in the overlying media.

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.

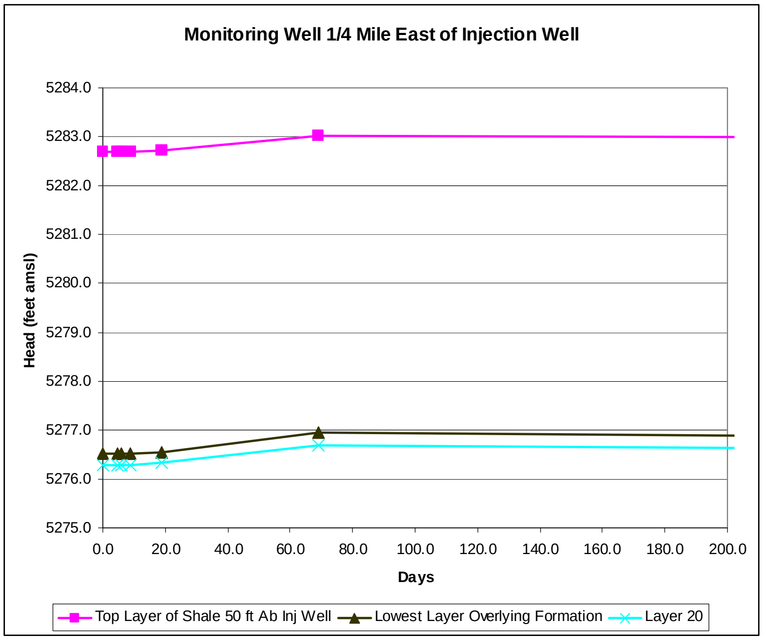

Figure 5: Hydrograph at three points in monitoring well 1/4 mile east of the horizontal well.

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.

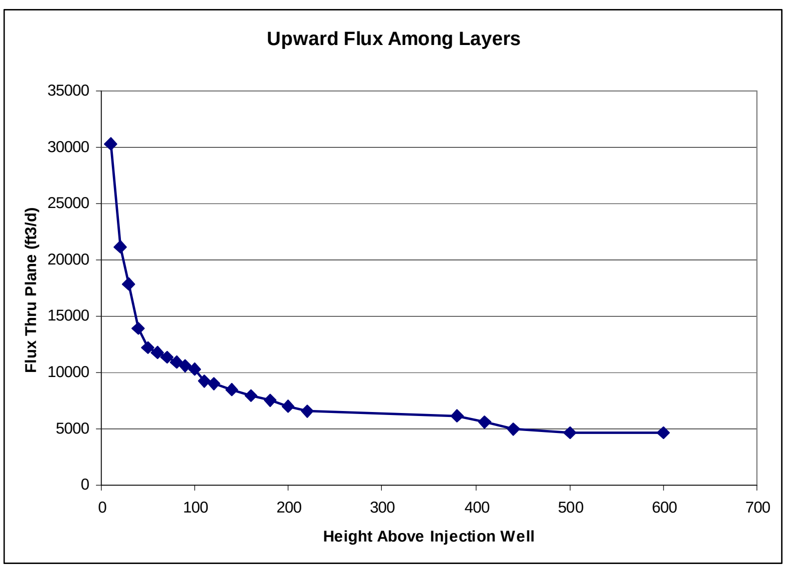

Figure 6: Upward flux among model layers in distance from the center of the shale one day after injection.

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 1.062x10-^{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

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Reviewed by
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Reno, NV

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.