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Technical Memorandum

Review of Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources

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SUMMARY AND CONCLUSION

EPA claims that hydraulic fracturing (HF) causes no widespread, systemic impacts on drinking water resources in the United States, but their report, reviewed herein, does not support that statement with data or analysis presented in the report. Throughout the report, EPA acknowledges the lack of data and support for this finding.

The statement is scale-based because there are many instances of local impacts. Effects on large watersheds, and therefore large water supplies, are minimized by dilution. EPA does not monitor large watersheds for the fracking fluid chemicals that would be most toxic at tiny concentrations because too often the EPA does not even know of their existence. EPA did not find incidences of widespread impacts partly because there is too little pre- and post-frack water quality data, and few long-term systematic studies. There have been hundreds of spills of fracking fluid and produced water, but the assessments are incomplete so impacts may have been undocumented. There is also difficulty separating HF impacts from other industrial impacts. Too much data and too many assessments of contamination incidents are proprietary or sealed in litigation settlements. Contaminants move slowly but also in slugs so that contamination may not be detected. Concentrations may be highly variable with time, with toxic levels reached occasionally but not coincident with sampling events. Contamination of an aquifer is a cumulative process of the HF of many gas wells. Fracking contamination may be short-term or transitory and therefore not detected by sampling which too frequently consists of before and shortly-after sampling of water wells. Failure to detect contamination does not mean that adverse impacts to water supplies have not occurred.

Contaminants from HF have reached shallow groundwater and surface water all over the country. EPA describes six different potential pathways for those contaminants, either liquids or gases, to travel vertically to water supplies from gas wells. The fact that the fluids found in the water resources can be identified in the sources based on geochemistry and isotopes proves that transport has occurred. Models have shown that all of the paths are possible. The pathways are mostly hypothetical, however, because the routes have never actually been mapped from source to water resource. EPA should push for more detailed monitoring of the actual fracking process and an improved understanding of the hydrogeologic properties of the shale and adjacent formations, post-fracking. Improved estimates of future flow and transport could be made with improved data.

Fluids move from gas wells into drinking water or from the target formation through geologic formations to shallow groundwater. Poor well casings or cement jobs on fracked wells are pathways for fluids to move upward toward drinking water and/or into various geologic formations much nearer drinking water. At least 3% of wells did not have adequate cementing across water-producing zones. EPA's descriptions and statistics of well failures are low-end estimates that depend on inconsistent industry or state agency reporting and very little actual monitoring.

Old wells may not have been designed to sustain the pressures of HF, but 6% of the 23,000 wells fracked in 2009-10, or almost 1400 wells, were over ten years old. It is unknown how many failed. Improperly abandoned historic oil and gas wells represent a significant risk to groundwater because they can provide a pathway for fluids to move upward through thousands of feet of overburden. Wells that are re-fractured, or which undergo fracking for a second time or more, present a host of additional issues regarding groundwater contamination that the EPA does not address.

EPA (and industry) improperly relies on the distance between the target formation and shallow groundwater to protect groundwater, but for many reasons this is a false sense of assurance. In some areas, fracking occurs very near the base of shallow aquifers. Between 2009 and 2010, 4600 wells were less than 2000 feet below shallow groundwater aquifers. In some areas, fracking occurs in formations that are parts of aquifers, but EPA has not estimated the number of incidents. Out-of-formation fractures provide pathways for fracking fluid to leave the target formation and reach formations closer to shallow groundwater and perhaps better connected to pathways to shallow groundwater. Fractures and faults provide flow pathways that vastly decrease the effect of having thousands of feet of overburden above the target formation.

Out-of-formation fractures occur far more often than EPA implies in this report, although it never directly addresses the issue. EPA should discuss the frequency that fractures extend beyond the target formation.

Overlapping fracture zones, referred to as “frac hits” and which sometimes cause problems on an existing offset well, demonstrate the potential for permeability to change over large areas. Frac hits can cause fluids from fracking to discharge into and up an offset well. Nearly 50% of wells within 1000 feet experienced such frac hits, which can also cause fluid movement through the offset well.

EPA ignores the potential changes that injection causes on a regional basis because it considers just the effects of developing one well at a time. Permeability could change over large areas which could affect groundwater flow, including allowing large-scale brine movement upward toward shallow groundwater.

Natural upward gradients can drive upward fluid flow if there is a pathway. Gradients are caused by glacial unloading, deep circulating natural recharge, and over-pressurization by methane development. EPA should discuss the studies indicating the presence of upward gradients and how an upward gradient combined with changed hydrogeology could lead to more upward flow of brine or fracking fluid.

Industry uses far more freshwater than necessary and reuses too little wastewater. EPA compares freshwater use for fracking with total water use by county, but should compare it with water availability. EPA should show fracking use as a proportion of groundwater recharge in areas where the source is predominantly groundwater (the West) and as a proportion of runoff in areas where surface water is the predominant source.

EPA estimated there were as many as 3700 spills of fracking fluid per year nationwide while mixing but could not assess the toxicity of many of the spills because many chemicals are considered proprietary, meaning the public does not know what industry is injecting into the ground. EPA should disclose the toxicity properties of the most commonly used fracking chemicals.

Produced-water chemistry is extremely variable and depends on the chemistry of the fracking fluid, formation fluid, and the target shale. Produced water from the Marcellus shale has extremely poor water quality with extremely high salinity and high levels of naturally occurring radioactive materials.

The proportion of injected fluid returning from Marcellus wells varies from about 10 to 25% suggesting that large volumes of fracking fluid remain underground. The vast difference in chemistry between fracking fluid and produced water in the Marcellus suggests much of the injected fluid leaves the shale and that most of the produced water is slowly released formation water with very high concentrations of TDS and radioactive materials. EPA vastly overstates the amount of fracking fluid that becomes imbibed, or bound, in the shale.

A majority of HF wastewater (mostly produced water) is reused with substantial proportions also injected or sent to centralized treatment centers. In the Marcellus, most had been treated and discharged but recently most is being reused with minimal treatment. Produced water presents treatment challenges not commonly found at publicly owned treatment facilities such as being high in TDS, bromide, radionuclides or fracking-related organic compounds.

The transient nature of the fracking business causes transitory water quality problems because the need for treatment facilities wanes before the facilities can be constructed. The need for high capacity treatment may not be met because doing so is not economic. Therefore the dangers of poor treatment or elicit disposal are very high for fracking wastewater.

This review reaches two primary conclusions:

- There is simply too little known about the fracking process to have widespread assurance that it is safe. Large-scale groundwater and surface water monitoring networks are necessary, with a recognition that long flow times may cause contamination to occur far into the future. Details of what happens underground during fracking should be studied with more emphasis on hydrogeology, not just engineering properties. There should be much more disclosure of the chemicals and their properties.
- There is enough known of the process to know that the risks to water resources into the future are very likely. Millions of gallons of toxic fluid are injected into the ground, some very near groundwater resources or near pathways that will connect to groundwater resources. The process significantly changes the hydrogeology of the formations so that natural flow patterns will change. The process also significantly changes the geochemistry of the fluids, rendering some very toxic. Flow along pathways may take a long time but once contaminants reach water supplies the effects could be devastating. There is simply no planning or even acknowledgement by the industry or EPA regarding these long-term effects.

INTRODUCTION

This technical memorandum reviews the draft report issued by the Environmental Protection Agency (EPA) regarding the effects that fracking can have on drinking water in the U.S. The title is *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources*. There are two volumes, the first is the report which contain 599 page in its pdf form and the second is a collection of ten appendices. Throughout this review reference to the report is simply to EPA without a year and includes page numbers and occasionally line numbers where useful. References to other EPA documents include a year in the reference.

The report had been authorized by Congress. EPA states that the report considers the "potential for hydraulic fracturing for oil and gas to change the quality or quantity of drinking water resources, and identifies factors affecting the frequency or severity of any potential changes" (EPA, p ES 1).

This review is both general and specific, meaning that it takes both big picture views of the topic but also drills into specific issues line-by-line or paragraph-by-paragraph.   This memorandum discusses and comments on the science in detail. Where possible, the memorandum provides bullet point recommendations for specific changes the EPA should make.

Throughout this memorandum, hydraulic fracturing is variously referred to as HF or fracking as appropriate. A play is a formation that contains hydrocarbons being developed in a rush, or in a boom/bust fashion. FracFocus is a publicly accessible website (www.fracfocus.org) managed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission where oil and gas production well operators may disclose information voluntarily or pursuant to state requirements about the ingredients used in hydraulic fracturing fluids at individual wells. EPA used this website as a source of industry-provided data on fracking, although the usefulness of this source is that reporting is voluntary and chemicals may be withheld as confidential business information.

The report had five primary focuses (EPA, preface):

- Water Acquisition: What are the possible impacts of large volume water withdrawals from ground and surface waters on drinking water resources?
- Chemical Mixing: What are the possible impacts of surface spills of hydraulic fracturing fluid on or near well pads on drinking water resources?
- Well Injection: What are the possible impacts of the injection and fracturing process on drinking water resources?
- Flowback and Produced Water: What are the possible impacts of surface spills of flowback and produced water on or near well pads on drinking water resources?
- Wastewater Treatment and Waste Disposal: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewaters on drinking water resources?

These focuses primarily line up as chapters 4 through 8. Additionally, Chapter 3 provided general discussion on water resources nationwide. Chapters 2 and 9 describe the HF process and provide a list of chemicals, respectively. The outline of this review follows Chapters 3 through 8, with minor references to Chapters 2 and 9, as useful.

EPA did not complete on-the-ground HF studies as it initially intended. This could have involved objective researchers collecting environmental and hydrologic data. It could have involved objective assessment of well logs to assess whether the cement is properly installed. It could also have involved objective assessment of surveys for out-of-formation fracturing.

CHAPT 3: DRINKING WATER RESOURCES IN THE US

This chapter provides a brief overview of where people obtain their water and how many of those sources could be affected by fracking simply by considering the distance a fracked well is from the water supply intake. A basic concept followed by EPA is that distance is primary factor regarding the potential risk to a water supply. However, this ignores other aspects of risk, including the potential pathways between a fracked well and a water supply. A water well producing from a fracture zone several miles from a fracked well may be at higher risk than a water well within a much shorter distance but across a fault that acts as a horizontal flow barrier.

EPA points out that the distance of fracked wells from public water supplies (PWS) ranged from 0.01 to 41 miles, with a mean and median equal to 6.2 and 4.8 miles. This is not very useful for at least two reasons. First, it mixes surface and groundwater PWS for which the pathways and therefore the relevance distances are quite different. Second, the base numbers as presented are not very informative. Neither the actual mean nor median values imply a significant risk unless there is a direct pathway between the fracked well and PWS. The median is substantially less than the mean, therefore the distribution is skewed toward shorter distances.

- EPA should present distance information as a histogram or frequency distribution so the reader can assess the relative proportion within shorter distances of a fracked well.
- Because of the different pathways, EPA should present these histograms or frequency distributions for surface and groundwater sources separately.

Spills can affect a stream, especially during low flow, very significantly whereas a reservoir could have substantial dilution potential. Reservoirs however present a different risk because dispersion of a contaminant through the reservoir can affect a much larger volume especially considered as the water supply stored for a given time period whereas the contamination in a river will flush out soon after a leak is stopped or remediated.

- EPA should also distinguish between surface water sources that draw directly from a stream and from a reservoir.

With respect to surface water sources, both distance and direction from the fracked well is important. If the fracked well is downstream from an intake or a reservoir, it may not be important that the well is within a mile. A fracked well upstream from an intake, even several or more miles, may present a substantial risk, especially during low-flow periods, to the water supply. The 8.6 million people served year-round by PWS within one mile of fracked wells seems to be a large number of people potentially at risk, but it is potentially a gross underestimate of the number actually at risk. All people served by PWS with fracked wells anywhere within the watershed are potentially at risk, although the risk posed by headwaters fracked wells in a large river system is smaller than the risk to PWS in much smaller watersheds. In a very large river, dilution may protect diverters of all but the most toxic contaminants even if the spill is less than a mile away whereas spills several miles upstream in a smaller stream could be much more dangerous.

- EPA should assess the number of fracked wells upstream of PWS in the same watershed, especially for PWS on low order streams.
- EPA should consider means of presenting the distance of wells from PWS that is sensitive to the potential toxicity of a leak or spill.

Approximately 6800 PWS sources nationally had a fracked well within one mile, with the majority in Colorado, Louisiana, Michigan, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, and Wyoming (EPA p 3-7). The average and maximum number within one mile was seven and 144 fracked wells.

EPA analyzed private water supplies and fracked wells on a county basis only. Private supplies are important because they have lesser standards than public supplies because they serve fewer people. For this reason, these supplies are less capable of dealing with, and possibly even detecting, a contamination issue.

EPA considered the number of people that obtain drinking water from private supplies, both surface and groundwater, in counties with any fracked wells and with more than 400 fracked wells, the latter applies to approximately 740,000 people in ten states including Pennsylvania (EPA p 3-7). EPA Figure 3-6 shows roughly 18 Pennsylvania counties with more than 400 fracked wells; the map in this figure does not show how many people use private water supplies in each county.

- EPA should discuss the distribution of private water supplies among surface and groundwater. Most private supplies are groundwater because surface water often requires treatment that a private system cannot afford. EPA should discuss because there are different contaminant pathways to each source type.

- EPA should expand the data on EPA Figure 3-6 to show how many people use private water supplies in the counties with over 400 fracked wells.
- EPA used 400 fracked wells as a threshold for reporting but does not justify that number. EPA should show a histogram or frequency distribution analysis of fracked wells by county and use that to justify thresholds.
- EPA should also provide the raw data in an appendix table.

The number of fracked wells in a county is not necessarily a good indicator of the risk that fracking poses to public or private water supplies. At least in states where the information is available, EPA should analyze actual distance from fracked wells to private water supplies, most especially to private water wells.

- EPA should provide GIS analyses of fracked wells by fault density because faults can be preferential pathways. This could increase the risk to underground sources of water, both public and private, even if further from the gas well.
- EPA should provide GIS analyses of fracked wells by drainage density[1] because the pathways across the ground surface to stream channels would be much shorter in high drainage density areas. This would show areas in which fracking is more risky to surface water.

CHAPTER 4: WATER ACQUISITION

The chapter acknowledges that the amount of water used from any source creates a potential to affect the "quantity of drinking water resources" (EPA p 4-1). This is correct but incomplete – water acquisition has the potential for larger effects on streamflows and the environment, which the chapter appears to neglect. Water acquisition has the potential also to affect water quality if it lowers streamflows during critical low flow periods.

The description of coal bed methane (CBM) development (EPA p 4-7) is not accurate. CBM development requires that hydrostatic pressure on the coal seam be lowered, but the seam should not be dewatered (Myers 2009). Industry fracks these formations only if the coal seam is very impermeable. The high injection pressures would almost be counter to the process required for CBM development. CBM is not the focus of this review and generally the differences with respect to water use will not be considered further. However, EPA should discuss the proportion of CBM wells that undergo fracking (EPA p 2-31).

The amount of water used for HF injection approximates the well bore volume and fracture volume in the formation that emerged from along the well bore. EPA describes this as the

[1] Drainage density is miles of stream channel per area.

“volume of the fractures in the geologic formation that fill with hydraulic fracturing fluid” (EPA p 4-7). This description implies that fractures occur only in the target formation and ignores out of formation fracturing. Some fracking fluid escapes from the target formation, although the amount may not significantly affect the issues discussed in Chapter 4.

EPA underestimates the cumulative national fracking water use (EPA p 4-8) by reporting the median water use rather than the average. The mean is the statistical representation of the expected value. Adding the water use reported for each well would yield a sum equal to the product of the mean and the number of wells. This explains why Vengosh et al. (2014) estimated a total 80,000,000,000 gallons per year by using an average of 4,000,000 gallons per well (Id.). EPA adopts this estimate for the U.S. as a whole; the estimate is approximately 135,000 acre-feet/year.

Fracking water use is a small proportion of total water use at either the national or state level (EPA p 4-8) due to scale issues, which makes these discussions relatively useless. At the county scale, the proportion is often much higher based on the size of the county (EPA p 4-8, -9). Counties with small population may have low water use that is increased substantially due to a fracking boom.

Most HF water in PA and other Marcellus states is surface water. Frack usage can be a significant proportion of total water use and of total water consumption in some counties (EPA p 4-10). In PA, Susquehanna, Sullivan, Bradford, Tioga, and Lycoming Counties have the highest water consumption for fracking as a fraction of total water consumption (Table 4-2). Susquehanna County has 123.4% which means that water is imported to the county for fracking. Frack water withdrawals would mostly impact streams during drought periods, but EPA does not consider environmental impacts of diversions during drought periods. Most deleterious impacts occur to small streams in small watersheds (EPA Text Box 4-5). A significant impact to drinking water quality could occur due to withdrawals of water for fracking that reduces flows and causes concentrations to increase at diversion points for treatment plants (4-35, -36).

The effects of HF water usage is more important where water is limited. Having HF be a high percentage of the local water use does not necessarily mean it is causing deleterious impacts, especially if the total water use is only a small fraction of the water availability. Large withdrawals in areas with lots of water may have less impact than small withdrawals in areas with little water.

EPA Appendix B compares water used for fracking to total water use by county. The tabulation attempts to show the amount of water used for fracking and the percent of water consumed by fracking. The table shows some stunning results, such as fracking uses 123.4% of total annual use (2010) in Pennsylvania's Susquehanna County. Because the fracking use exceeds 100%, there is obviously some water brought from other areas. This tabulation is not very useful then because withdrawals are harmful where they occur so the effects of fracking may harm watersheds far from the actual wells.

- EPA should compare fracking use of water to the actual water stress in an area. High water use in an area with low water availability increases water stress. Much of the West and portions of the upper mid-Atlantic states, including Pennsylvania, suffer significant water stress (Figure 1). EPA should compare frack usage of water against a similar metric.

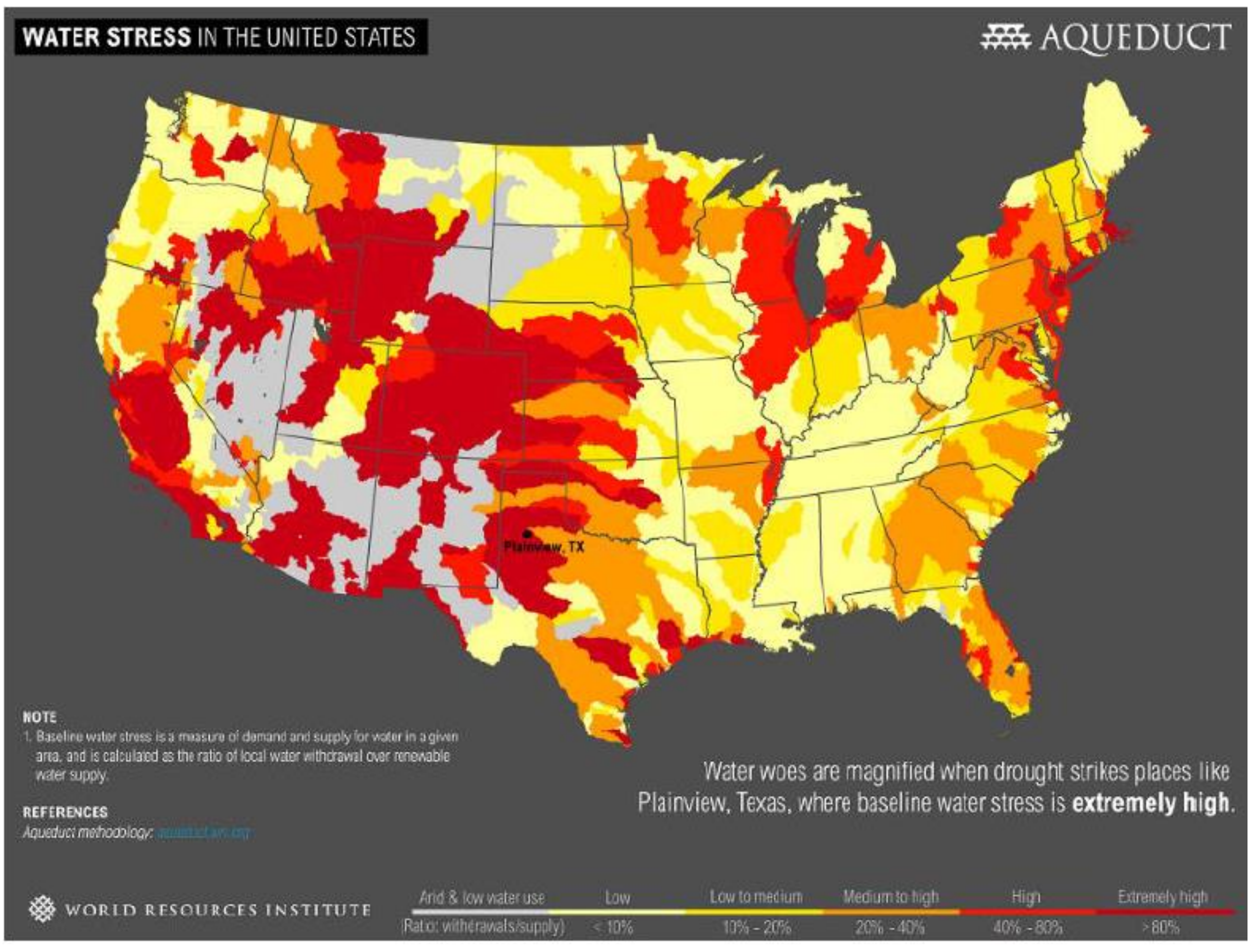

Figure 1: Water stress map for the United States. Baseline water stress measures the ratio of total annual water withdrawals to total available annual renewable supply, accounting for upstream consumptive use. Higher values indicate more competition among users. Source: World Resource Institute (www.wri.org/our-work/topics/water)

CHAPTER 5: CHEMICAL MIXING

EPA describes the fracking process after the well has been constructed as involving four phases – (1) acid cleanout of the wellbore, (2) HF fluid introduced to the well and into the formation, (3) proppant increased to keep fractures open, and (4) clean-up (EPA p 5-5). Phases 2 through 4 are repeated for each stage. There are usually from ten to twenty stages per well (EPA p 5-6), but there were as many as 59 observed in one well in the Bakkan. The number of stages has increased with time (Id.), probably as the industry improves the technology. Increasing the number of stages increases the risk of spills for each well pad because there is chemical mixing for each stage. To understand better the amount of chemicals used during fracking, EPA should specify the volumes of fluid introduced under each phase. Because the chemicals vary by stage, the chemical concentrations could be much higher than presumed when considering the mass of chemical as a concentration in the entire fracking fluid volume. EPA states that proppant varies from 5 to 9% of the fluid, but should specify whether that percent is of the total fluid volume or just of the volume injected during stage 3. This matters because the proppant would push fluid remaining from stage 2 further into or from the fracture. Injecting the proppant could further push the fluid from the fractures into forced imbibition or into fractures further from the well. A higher proppant proportion could more effectively push the fluid.

93% of HF fluids are water based, with from four to 28 chemicals used (EPA p 5-11).

- If non-aqueous base fluids are used (EPA p 5-12), EPA should actually list some non-aqueous fluids.
- EPA should explain what a water-sensitive formation is, or what makes a formation water sensitive (EPA p 5-12). EPA should also discuss where these occur.

Methanol is the most commonly used chemical (EPA p 5-18), and is highly toxic if ingested. Hydrochloric acid is also commonly used. Volumes of the most commonly used chemicals ranges into the thousands of gallons for each frack job.

EPA reviewed spills reported in different state databases, including from nine states with online reporting, nine HF service companies, and nine O&G companies (EPA Text Box 5-13). EPA (2015) examined spill databases in nine states, nine hydraulic fracturing service companies, and nine oil and gas operators. EPA had used industry data to determine which states had the most HF activity and searched for spill data in those nine states. States with online spill data were Pennsylvania, Colorado, Arkansas and New Mexico and states with other public spill data were Louisiana, Oklahoma, Texas, Utah, and Wyoming.

EPA surveyed databases reporting 36,000 total spills, of all types from all industries reporting in the state databases that occurred from 2006 through 2012. EPA identified 457 spills related to

HF, but 12,000 spills had insufficient information to identify whether it was related to HF (EPA 2015). The most common material spilled was flowback and produced water and the most common source of spill was storage units; this indicates that fluid returning up the well after fracking overflowed the container intended to contain it. 151 spills were specifically of HF chemicals, including from produced water. Over 50% were equipment failure or human error (EPA p 5-43). Of the 151 chemical spills, 97 reached soil and 13 reached surface water. None were reported to reach groundwater. EPA acknowledges a lot of uncertainty in the numbers due to inconsistent reporting. Spills could have reached groundwater but the companies may not have looked. Also, if the soil was not remediated, transport to groundwater could take longer. EPA estimates a spill rate from 0.4 to 12.2 spills per 100 wells for Pennsylvania and 1 spill per 100 wells in Colorado (EPA p 5-50).

The reporting of spills is not consistent and very likely underestimates actual spills. For example, spills of chemicals that occur before mixing with water could be much more serious (EPA p 5-50) even with a lower volume (most chemical containers contain from 200 to 400 gallons (EPA 2015)). Mixed fluids might have larger volume and therefore flow further into the soil or along the ground surface.

EPA discusses the movement of contaminants from spills through the subsurface potentially to water resources, (EPA section 5.8.1.2) but does not discuss preferential flow pathways which could hasten the movement of a spill to the groundwater. The section does mention that fractured rock may pass contaminants faster, but the implication is that the rock acts as a porous media (which it does only if sufficiently fractured). Just a few permeable fractures in an otherwise low permeability medium could effectively siphon the fluid to the groundwater causing much more rapid passage of a contaminant to groundwater.

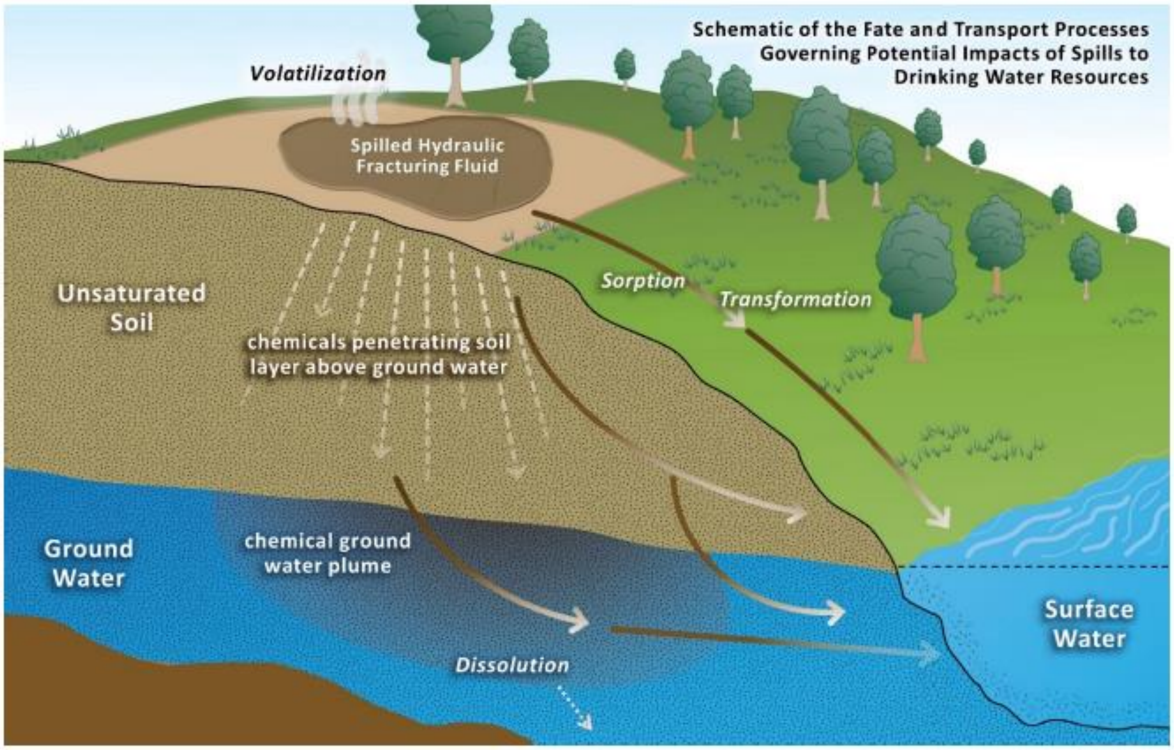

Figure 5-16. Fate and transport schematic for a spilled hydraulic fracturing fluid.

Figure 2: Snapshot of EPA Figure 5-16 showing the pathways from potential spills to drinking water.

EPA estimated physiochemical properties for 42% of the 1076 chemicals they had listed as used in HF. These are properties describing whether a chemical will sorb to soil and/or organic matter or whether it will remain in the water, whether it will dissolve in water, and whether it will volatilize (become gaseous and pass into the atmosphere). This data allows consideration of whether and how fast the chemicals will move to and through the groundwater. With 58% of the chemicals having no estimated data, it is obvious that it is difficult to predict movement for a large proportion of the chemicals used in fracking fluid. The histograms showing data for the known chemicals demonstrates a huge range in the parameters, so few general conclusions can be made regarding the transport of fracking fluid through groundwater or through the soil. Some of the chemicals may be completely immobile while others will go wherever water goes. One conclusion is that very few of the chemicals are volatile so it is not likely that that spills will self-remediate by dissipating into the air. EPA provides tables of the top 20 most mobile (Table 5-7), least mobile (5-8), and most frequently used chemicals (5-9), and an appendix table with all of the chemicals for which parameters could be estimated. EPA does not provide a table relating mobility for the most toxic parameters.

EPA acknowledges that the transport and transformation of many chemicals in the environment is highly complex and sometimes results in end products that are vastly different from their original chemical. Biodegradation can result in harmless or deadly end products. Chemical mixtures may increase the transport rate of a specific chemical, especially if cosolvency increases the solubility, such as the presence of methanol increases the solubility of BTEX which vastly increases BTEX mobility. The possible combination of chemicals and site conditions results in an almost infinite realm of scenarios.

- EPA should discuss the more dangerous end products and their likelihood
- EPA should provide a table in an appendix of transformation products and the site conditions that make such transformations likely for those which are known
- EPA should provide a table relating the most toxic parameters and their mobility

Site conditions can affect transport by providing pathways for transport, which will hasten the movement, but also particles to which chemicals can adsorb which will slow or stop the movement. High permeability increases transport but high porosity has high volume which lowers the concentration of those chemicals. Chemicals adsorb preferentially to organic matter, which could limit transport unless the organic matter is dissolved which could enhance movement.

- EPA should provide a table outlining the soil properties and discussing their effects on transport.
- EPA should conduct modeling scenarios similar to the one discussed in section 5.8.7 for common fracking fluid mixtures and site conditions.

Spills close to surface water will impact the water more than spills further away, but there is no quantitative analysis of the risks (5-72). EPA claims that the best way to prevent impacts to surface water is to avoid spills and to have adequate containment for the spills (5-73). EPA does not mention or discuss the roll of setback distances in protecting surface water at all.

- EPA should add a flow routing analysis to assess the probability that spills of a given volume could reach surface water over given distance and slopes; this could account for infiltration into unsaturated soils.

The proprietary nature of fracking chemicals continues to obstruct the ability of the public to know the chemicals being injected into its aquifers. EPA acknowledges that at least one and an average of five chemicals on more than 70% of the disclosure to FracFocus were listed as confidential business information (EPA p 5-73).

- EPA should discuss the problems the lack of disclosure due to the chemicals being proprietary poses to the public.

Only 8% of the 1076 chemicals identified in HF fluid have published toxicological values in any source, federal or international (EPA p 10-8). Only 7% of them have toxicological values published in U.S. federal sources (Id.).

- EPA should assess and discuss the risk that not having toxicological parameters on most HF chemicals poses to the public.
- EPA should discuss the value in funding toxicological studies of the HF chemicals for which there are no toxicological parameters.

A lack of baseline monitoring hampers the assessment of changes in water quality due to fracking (or any other activity). This is because there is no requirement for companies to establish monitoring programs such as monitoring wells in an area prior to the commencement of any fracking.

CHAPTER 6: WELL INJECTION

The introduction to the chapter establishes a misleading premise by implying that a fracking well and surrounding geology area provide a “closely linked system, often designed with multiple barriers” (EPA p 6-1, -4). The implication is the well has multiple barriers and the geology buries the well under thick formations, and that these act in concert to prevent fluids from reaching the surface or that a leak must pass through each barrier. The reality is that there are many pathways through both the well and geology for contaminated fluids from any level in the well to reach any level higher up in the well, including the ground surface or shallow groundwater.

A second reality regarding the pathways is that they break into natural and man-caused. Industry can remedy the man-caused pathways simply by improving well construction or the operations during injection, but the natural pathways require surveys and avoidance.

The review herein of this section will highlight these pathways, which include

- Poorly cemented well bores
- Weak casings
- Transmissive fractures or faults
- Out-of-formation fracturing

Well Construction Issues

These are either well casing or cementing issues. Casing prevents lateral movement of fluid into the formations and cement prevents vertical movement along the annular spaces. EPA considered five potential pathways (Figure 3), with four of them relating to cement.

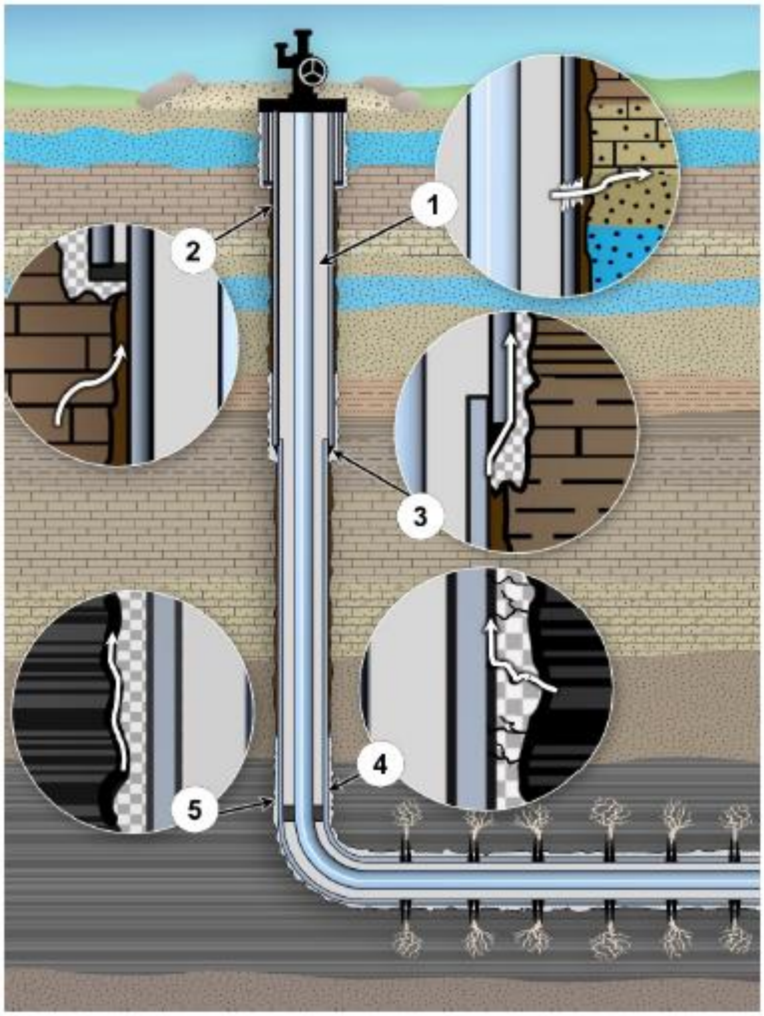

Figure 6-3. Potential pathways for fluid movement in a cemented wellbore.

These pathways include: (1) casing/tubing leak into a permeable formation, (2) migration along an uncemented annulus, (3) migration along microannuli between the casing and cement, (4) migration through poor cement, or (5) migration along microannuli between the cement and formation. Note: the figure is not to scale and is intended to provide a conceptual illustration of pathways that may develop within the well.

Figure 3: Snapshot of EPA Figure 6-3 showing potential pathways for fluid movement in a cemented wellbore.

Well Casing

There are different well designs, but all include up to three layers of casing designed to prevent fluids from leaving the well bore and entering the annulus between the casing and formation. The strength of the casing controls whether a failure could occur during high-pressure injection or other activities. Failure allows fluids to enter the annulus between the casing and formation, which could be filled with concrete, but if fracking pressure can break a casing it would also likely break the cement.

Wells intended to be fracked are not necessarily any better designed or constructed than wells that will not undergo fracking (EPA p 6-11). Six percent of recently fracked wells were more than ten years old meaning they probably had been designed and constructed without plans for fracking (EPA p 6-11, -12). Casing weakens with time due primarily to corrosion (EPA p 6-14) which probably increases the potential for old wells to fail if fracked. Some wells are fractured a second or third time to improve decreasing production, but the same precautions may not apply to fracking more than once. Fracking wells constructed into conventional formations may present an additional potential for contamination. EPA quotes industry consultants as saying that 79% of all wells and 95% of unconventional wells undergo fracking (EPA p 2-27). This suggests that many conventional wells are being fracked.

Surface casing is critical for protecting groundwater resources, but EPA cites a 1991 study suggesting that that the risk is just 7 in 1,000,000 if the surface casing extends below the groundwater but is 6 in just 1000 if it does not (EPA p 6-14). These are damning statistics but the date of the study indicates it is irrelevant with modern high-pressure fracking.

- EPA should complete a new study of the risk to groundwater from fracking without surface casing extending below the groundwater.

As noted, the number of fracking stages has increased. This refers to the number of segments the production section of the well bore is divided into. Each is fracked separately, which means that casing above the production zone experiences alternating high and low pressure. This both increases the opportunity for casings to experience fatigue or for errors to affect any given casing. EPA presented an example of failure of a casing at Killdeer, N Dakota during stage 5 of 23 proposed stages. The casing ruptured when the pressure reached 8390 psi.

- EPA should discuss the pressures that had been reached and operating procedures that had been in practice during previous stages at Killdeer.

EPA discusses the complex topic of how to identify the formation from which stray gas may emanate (EPA p 6-16). The gist of the discussion is that each methane source has a distinct signature that identifies the source. A simple aspect is that thermogenic gas, meaning formed deeply in shale, has higher chain gases such as ethane and methane. Each formation may have characteristic ratios of these gases and each gas has characteristic isotopic signatures. This can help to identify the source of the gas, recognizing also that the gas may have mixed as it travels to the surface.

The problem with the discussion regarding source formation is that fracking may release gases from formations not being fracked. Changes due to fracking, including from seismic vibrations, may release gas from formations not actually targeted. This could include shallow sources and biogenic gas. Pathways along the well may allow gas from nontarget formations to move. EPA found that gas from intermediate formations was present in surface layers in studies in NE Pennsylvania. Rather than implying that detailed signatures are necessary to identify the exact source, EPA should discuss fracking a given well may release gas from many sources.

Well Cementing

Critically, EPA identified that the most common cement logging tests fail to predict fluid movement along geologic formations (EPA p 6-9).

Sustained Casing Pressure

Pressure in a well annulus (referred to as "Bradenhead pressure" if detected in the annulus between the outer surface casing and production casing) that returns after being bled off indicates there is a leak from either a portion of the well that is pressurized or from a formation that is pressurized. The well annulus is the open space between layers of casing or between the outer casing and the wall of the hole. Sustained pressure can cause an inner casing to collapse or outer casing to burst. EPA indicates that "pressure is an indicator that pathways within the well related to the well's casing, cement, or both allowed fluid movement to occur" (EPA p 6-25, L 3-4), but counters this by saying not "every well that shows positive pressure in the annulus poses a potential problem" (EPA p 6-26, L 31-32). Based on EPA's references, there is a paucity of data regarding this problem on wells that have undergone fracking. EPA cites a study showing that more than 50% of wells more than 15 years old have sustained casing pressure but that less than 10% of wells under one year old does. With fracked wells expected to produce for more than 30 years, with corrosion potentially harming the casing, and with wells possibly being re-fractured to increase production in the future, wells will have more problems in the future even if they produce without problems for the first decade after completion.

Sustained casing pressure is a symptom of well failure, and will increase into the future as wells age and fail. It indicates a threat that occurs during normal production and its increase with time indicates well failures with time. Cement integrity is more difficult to achieve in a horizontal or deviated well (EPA p 6-25). If a well does not contaminate water resources during the fracking process, there is a strong likelihood, based on the evidence presented here by the EPA, that the well will contaminate water resources during its productive life if not properly monitored, maintained and mitigated by the operator.

Case Studies

EPA prepared special reports on at least three sites where well failures allowed the movement of gas or fluids and otherwise contaminated drinking water or, in one case, caused methane build-ups that led to an explosion (EPA p 6-52, -53, Bainbridge OH, East Mamm CO, Killdeer ND) and also discussed in detail one other site with severe methane contamination (Dimock PA). These effects occur in consort with natural pathways, such as faults, in some instances (East Mamm CO).

Failure Rates

EPA has identified numerous failure modes and pathways for contaminants to leave a well if and when it fails (EPA p 6-55). Unfortunately, there are few studies that document the frequency with which these failures occur (Id.). Failures are not the same as violations for which EPA cites a few studies or spills. This lack of well integrity failure studies leads to a great deal of uncertainty regarding the failure of wells, a major drawback to the EPA study which the EPA acknowledges (Id.). Some failures may be undetected and others may be undisclosed due to litigation settlements. Combined with the lack of monitoring of contaminant movement in the subsurface, the EPA really has little idea the extent of groundwater resource contamination that has been caused by fracking.

Transport along pathways from the target formation

If there is a pathway and a hydraulic gradient, fluids will flow from areas of higher pressure to lower pressure, just as water flows downhill. If there is sufficient pressure at depth under the earth's surface, fluid will flow upward. Pressure at depth may be natural or caused by the fracking operation, although the latter will dissipate not long after the fracking ends. In areas with substantial brines, buoyancy can also drive flow. Frack fluid has a lower density than the brine it is injected into and the differential pressure causes an upward force on the parcel of lower density fluid[2].

[2] Frack fluid may mix with the brine which could decrease the buoyancy, but this process is complicated and depends on the chemicals in the frack fluid.

EPA is wrong in its description of two different time periods with the potential for subsurface fluid migration into drinking water resources; there are really up to four periods. The first period is during the actual fracking process, during which frack fluid is injected at high pressure into the formation to fracture. The second period, if it occurs, is a shut-in period where the operator seals off the well without releasing the pressure. This is a short-term period with sustained casing pressure. This likely occurs between stages in longer, multi-stage wells. Reagan et al. (2015) found that a shit-in period increases the potential for gas to migrate away from the well. The third period is the production period in which the operator draws in fluids from the fracked formation. This period is important because the pressure gradient at the well ostensibly reverses. Because fracking is a transient process, the pressure distribution around the well is nonlinear and at some radius away from the well the pressure gradient remains directed away from the well (Myers 2012). The fourth period is post-production when the well is ostensibly abandoned and plugged. Previously mobilized fluids remain mobilized and will flow according to the natural gradients as altered by the injection pressure and changing hydrogeology (large-scale changes in conductivity due to fractured shale) (Gassiat et al. 2013, Myers 2012).

Rock fractures when the injected fluid attains a pressure that exceeds the component least principal stress. Most fractures from wells that are deeper than 4000 feet tend to propagate vertically from the well, while for wells less than 2000 feet, most fractures are horizontal.

- EPA should discuss any studies that discuss the actual distribution of fracture directions. If most are vertical, how many actually go horizontal? This is important regarding the spacing of horizontal wells.
- EPA should discuss the proportion of fractures that propagate vertically downward and upward. Connection with underlying formations can create problems with additional brine transport through the target formation.

EPA's list of the properties that control the actual fracture creation process demonstrates that accurate prediction is far more difficult than alluded. For example, "fracture height depends on a combination of parameters and processes including the material properties of geologic formations, pore pressures, stress differences in adjacent formation, shear failure (slippage) at the fracture tip, and the reorientation of the fracture as it crosses an interface between formations" (EPA p 6-30). Most of these factors vary with location in the formations. Numerical modeling of fracture creation and growth integrates the physics of fluid flow and geomechanics using parameters such as: permeability, porosity, Young's modulus, Poisson's ration, tensile strength, among others (Id.). These parameters are also highly variable and heterogeneous. It is impossible to know their exact distribution in formations thousands of feet below ground surface.

- EPA should not present model results, including from their own contracted modelers (Reagan et al. 2015, Kim and Moridis 2015) as detailed predictions of what fractures would look like.

Industry claims that monitoring pressure, flow rate, fluid density, and fracking additives during injection “ensure[s] that the operation is proceeding as planned” (EPA p 6-30), by which industry generally means the fracturing is contained. Yet, there is a huge incidence of out-of-formation fracking (Hammock et al. 2014, Fisher and Warpinski 2011). Simple fluid mechanics indicates that pressure or flow rate would not change much as the extent of a fracture leaves the target formation. Injection pressure goes to fracturing the formation and pushing fluid away from the well through the less-than-a-millimeter-thick fractures. Most of the pressure would go to countering the friction loss from pushing the fluid through tens or even hundreds of feet of tortuous fractures from the well. Some pressure may also be needed just to keep the fractures from collapsing before proppant has been added. It seems unlikely that the pressure changes that occur the moment a fracture reaches an adjoining formation on top of the pressure needed to force fluid through the fracture for 100s of feet would be that noticeable.

- EPA should discuss this if they rely on industry monitoring of HF to protect water resources.
- EPA should provide examples of how much change in these parameters indicate there are problems with the frack job.
    - How does pressure or flow rate change when fractures propagate upward into sandstone above the shale?
    - Is it sufficient for the operator to realize the fracture has left the target?

Monitoring injected flow volume to provide information on the fractures may not be useful because EPA has shown numerically that the fracture volume may be much higher than the volume of injected fluid due to the release of reservoir gas into the fractures (EPA p 6-31, L5-12). This may lead to the volume of fractures being greater than the injected fluid volume. This potentially explains why out-of-formation fracturing is much more common than presumed.

- EPA should expand this discussion and attempt to verify the modeling of Kim and Moridis (2015) with field data.

Subsurface pathways or causes of elevated gas in shallow groundwater

EPA lists four “potential subsurface migration pathways for fluid flow out of the production formation” (EPA p 6-31, -32):

- Flow of fluids into the production zone via induced fractures and out of the production zone via flow through the formation
- Fracture overgrowth out of the production zone
- Migration via fractures intersecting offset wells and other artificial structures
- Migration via fractures intersecting other geologic features

The first listed pathway should simply be the "flow of fluids out of the production zone into adjoining more pervious formations", although without the intersection of the fluids with artificial structures or faults the potential for transport from the formation may be slight.

Other studies have identified other causes for observed increase in CH_4 concentration within one kilometer of fracked wells, with the CH_4 being identified as thermogenic (Darrah et al. 2014; Jackson et al. 2013; Osborn et al. 2011). There is increased CH_4 in valley locations along faults and lineaments (Molofsky et al. 2013; Fountain and Jacobi 2000) which indicates that fluids move along natural fractures. Darrah et al. (2014) listed the following scenarios that can lead to higher methane concentrations in shallow groundwater:

> (i) in situ microbial methane production;
>
> (ii) natural in situ presence or tectonically driven migration over geological time of gas-rich brine from an underlying source formation or gas-bearing formation of intermediate depth (e.g., Lock Haven/Catskill Fm. Or Strawn Fm.);
>
> (iii) exsolution of hydrocarbon gas already present in shallow aquifers following scenario 1 or 2, driven by vibrations or water level fluctuations from drilling activities;
>
> (iv) leakage from the target or intermediate-depth formations through a poorly cemented well annulus;
>
> (v) leakage from the target formation through faulty well casings (e.g., poorly joined or corroded casings);
>
> (vi) migration of hydrocarbon gas from the target or overlying formations along natural deformation features (e.g., faults, joints, or fractures) or those initiated by drilling (e.g., faults or fractures created, reopened, or intersected by drilling or hydraulic fracturing activities);
>
> (vii) migration of target or intermediate-depth gases through abandoned or legacy wells

EPA's study did not consider the first three scenarios and scenarios one and two are not anthropogenic, but fracking could enhance the second scenario (Cai and Ofterdinger 2014;

Gassiat et al. 2013; Myers 2012). Warner et al. (2012) and Llewellyn (2014) provide evidence for the type of brine movement discussed in scenario 2. Drilling or vibrations caused by fracking can release dissolved gas or change its transport through shallow groundwater so that it affects water wells.

The third scenario is a mechanism by which fracking releases nascent gas into shallow groundwater through which it can flow significant distances. The fourth and fifth scenario describes the potential movement of gas from depth along the well, due to faulty construction, to shallow groundwater. The sixth scenario is the movement of gas from the target formation through natural pathways, such as faults or fractures, to shallow groundwater. Where there are abandoned wells, scenario 7 is an obvious potential scenario, although it includes transport through bedrock to the abandoned well. Regardless of the mechanism causing methane to reach shallow groundwater, either as dissolved or buoyant gas, it can flow to nearby wells, streams and springs.

Darrah et al. (2014) rules out transport of gas freshly liberated from the target shale through natural fractures because the diagnostic gas isotope ratios do not reflect the changes through fractionation that would occur as the gas migrates through the water-saturated crust. Their conclusion ignores the fact that transport from the well bore to shallow wells passes through Catskill sandstone in which most of the shallow wells were completed, which is up to 5600 feet thick and mostly have fault/fracture zones in drainages in northeast Pennsylvania (Taylor (1984):

> Wells in higher topographic positions (hilltops and hillsides) have smaller yields than those in lower topographic positions (valley, gullies, and draws). Valleys and draws often form where the rocks are most susceptible to physical or chemical weathering. Hilltops are generally underlain by more resistant rocks. Lithologic variations and weaknesses in rocks caused by bedding partings, joints, cleavage, and faults promote rapid weathering and can produce low areas in the topography. These types of geologic features often occur in high-permeability zones which yield significant amounts of water to wells. (Taylor 1984, p 29).

Much evidence supports natural movement of gas from source formations through fractures to shallow groundwater and surface water. Drainages in Pennsylvania (Molofsky et al. 2013; Fountain and Jacobi 2000) and New York (Heisig and Scott 2013) have more natural gas occurrences than other areas. Fountain and Jacobi (2000) mapped the presence of thermogenic NG in soils as a means of detecting underlying lineaments and fracture zones, based on the assumption of a fault/fracture connection between thermogenic gas sources and the surface. Thus, water wells near fault zones often have more natural gas occurrences.

Logically HF should increase the occurrence of gas in these areas. If HF releases gas from shale and/or increases the connection between the shale and fracture zones, it seems likely that HF will be responsible for increasing gas in the streams underlain by fracture systems (Jackson et al. 2013; Osborn et al. 2011).

Darrah et al. (2014) also ignores the fact that the gas would be transported through the same formations whether from depth, the layer of the shale, or for up to a kilometer through shallow aquifers which are similar bedrock types. Darrah et al.'s conclusions also require that the gas undergo the same transformation in weeks as gas would have undergone in millions of years of brine transport to shallow groundwater. Leaks from deep formations that occurred at a storage facility in Tioga County reached shallow groundwater, which suggests the transport of gas through pathways not accepted by Darrah et al. (Breen et al. 2007).

Additional evidence of gas movement along faults through the earth's crust to shallow groundwater may be seen through studies concerning CO_2 sequestration. Shipton et al. (2004) found that fluids (liquid and gas) can move vertically through low permeability faults, including those otherwise considered to be sealed with calcite. Gas migration is extremely heterogeneous with large fluxes occurring through high-permeability pathways resulting in large gas loads hitting very small areas (Annunnziatellis et al. 2008). The distribution of methane seeping through a fault is much more variable than the distribution of either helium or carbon dioxide following the same general pathway (Annunziatellis et al. 2008). These authors described the extreme variability in gas flow as "the'spot' nature of gas migration along spatially restricted channels" (Annunziatelis et al. 2008, p 363). Even along a single fault, the flux is highly variable and intersecting joints or faults add variability in an additional direction. The spot nature of gas flow is probably responsible for highly variable readings in domestic water wells even in small areas and for the fact that the concentration in some wells may decrease while in others it remains steady or increases.

More evidence for naturally occurring fractures in valleys

EPA did not cite Heisig and Scott (2013) although this USGS study provides ample evidence for natural transport of thermogenic gas and brine into shallow groundwater in New York valleys. From the abstract: "Wells completed in bedrock within valleys and under confined groundwater conditions were most closely associated with the highest methane concentrations. Fifty-seven percent of valley wells had greater than or equal to 0.1 mg/L of methane, whereas only 10 percent of upland wells equaled or exceeded that concentration. Isotopic signatures differed between these groups as well. Methane in valley wells was predominantly thermogenic in origin, likely as a result of close vertical proximity to underlying methane-bearing saline groundwater and brine and possibly as a result of enhanced bedrock fracture permeability beneath valleys that provides an avenue for upward gas migration."

Other studies have documented the rate at which gas released by HF can move through the groundwater. Gas tracers released during HF were found at production wells 750 feet away from the source within days (Hammock et al 2014). They also found evidence of gas migration to a sandstone layer 3000 feet above the Marcellus shale (Id., Figure 33). A model study based on conditions found at the southwest Pennsylvania site used in Hammock et al. estimated that gas can flow from a well bore leak through a sandstone rock matrix to a well 170 m away in times ranging from 89 days to 17 years depending on conditions (Zhang et al 2014). Darrah et al. (2014) found several gas wells within one kilometer of fracked wells that experienced large increases in gas concentration between annual sampling events which suggests that gas transport of up to a kilometer occurred in a time period of less than a year.

The previous paragraphs describe the various ways that HF can increase gas concentrations in shallow groundwater, streams, and springs on nearby land. Whether the gas is released directly from the shale or the well bore and whether the pathway is along a faulty well bore or natural fractures, a plethora of studies indicate that HF causes a significant risk that NG will reach shallow groundwater near stream channels. The risk is probably higher for streams in fault-controlled valleys.

EPA first considers advective transport vertically from the shale to upper formations. Ultimately the question is one of how much HF fluid remains after flowback that does not imbibe into the shale. It also depends on the conductivity of formations above the shale, a parameter not discussed by the EPA.

Sulfate-reducing bacteria and methane

EPA also failed to discuss how methane reaching shallow groundwater can cause quality changes in the groundwater beyond the methane concentration. One example is that sulfate-reducing bacteria can act on methane in groundwater to increase pH and dissolve aluminum, iron, and manganese from aquifer materials. Nickisch (2014) performed column experiments that showed reaction pathways that could explain some chemistry results observed at a well in Dimock PA.

EPA suggests that most of the injected fluid that does not return to the surface as flowback may be controlled by "processes such as imbibition by capillary forces and adsorption onto clay minerals" (EPA p 6-35). The EPA provides four references in support of this contention – Dutta et al. 2014, Dehghanpour et al. 2013, Dehgahnpour et al. 2012, Roychaudhuri et al. 2011. These studies are all based on laboratory measurements of imbibition, which of course is a much different condition than that occurring in the fractures. EPA does not acknowledge the difference.

- EPA should consider the difference between imbibition in a controlled laboratory setting and in freshly fractured shale or sandstone.

EPA also describes imbibition in the shale almost totally based on a presentation by Byrnes (2011) that attempted to establish that most fracking fluid imbibes into the capillaries of the formation (EPA p6-35, 7-3). The presentation was not peer-reviewed and grossly overstates the potential for especially unforced imbibition. Byrnes suggests that fluid could enter the shale up to six inches and that the volume could be near that of the injected fluid that does not return as flowback. However, his experiments are of core samples with static (not moving) fluid similar to those discussed in the previous paragraph whereas during fracking the flow through the fractures would certainly be quite high. The reality for flow in the fractures, in contrast to Byrnes' speculations, is that during and immediately following fracture stimulation, the vast majority of fracking fluid would follow the fractures – the secondary permeability – being formed by the high pressure injection. At the surface of the new fractures, some fluid would certainly flow into the very small pore spaces that make up the shale media and become freshly exposed. The conditions discussed by Byrnes would manifest only if the fractures do not leave the shale and fluid fills the fractures. This fluid would have a significant chance to imbibe but from the perspective of fluids escaping the shale, this would be irrelevant because it did not leave the shale during the process. Imbibition would be irrelevant for fluid that leaves the shale (some could imbibe in sandstone or limestone, but the process would be vastly different).

A preferable alternative explanation for the failure for fluid to return to the well as flowback is that the injection pressure pushes the fluid beyond the point where the pressure reversal will draw it back toward the well. EPA notes that the pressure creates a fracture system that may have a volume much larger than the volume of injected fluid (EPA p 6-31, lines 9-12). Fractures that extend beyond the target formation especially provide an opportunity for fluid to bleed off into other formations. This fluid would be just as lost to flowback as would fluid imbibed into small pores. Myers (2012) suggested that injection pressure would not subside immediately upon cessation of injection but rather would expand away from the well for a time. Because fracking is a transient process, the pressure distribution around the well is nonlinear and there may be a radius beyond which the pressure gradient remains directed away from the well (Myers 2012). This could continue to drive advection possibly to a point of intersection with a preferential flow pathway to the surface.

EPA presents proof that pressures continue to expand away from the fracked well, without recognizing it. Well communication at Innisfail, Alberta, shows that fracking pressure continues to spread after the HF injection has ceased (Text Box 6-4, ERCB 2012). The affected vertical well was 423 feet from the horizontally-fracked well in the same formation. Pressure began to rise at the vertical well "less than two hours after fracturing ended at the horizontal well".

Pressures were high enough and communication sufficient enough to force 19,816 gallons of fracking fluid, brine, gas, and oil from the vertical well. Frack communication observed at the Midway wellbore also indicates the pressure does not dissipate immediately. "Significant decreases in hydraulic fracturing pumping pressure can be an early indication of interwellbore communication. During stimulation of stages 3, 4, and 5, there was not a significant decrease in pressure during the fracturing operation. This is likely due to the fact that the actual breakthrough which resulted in the communication event did not occur until approximately 1 hour and 45 minutes later." (ERCB 2012, p 3). This means that pressure developed by fracking continued to expand away from the fracked well after the HF injection ceased, countering arguments made by EPA elsewhere in the fracking study.

Fracture overgrowth out of the production zone

Fracture overgrowth out of the production zone is also known as out-of-formation fracturing. In Pennsylvania HF fractures have extended as much as 1500 feet above the Marcellus shale (Hammock et al. 2014; Fisher and Warpinski 2011). EPA does not provide statistics on the frequency of frack jobs in which fractures extend from the target zone, but there is information in the literature that EPA should review. Hammock et al. (2014) documented 10,286 microseismic events as much as 1900 feet above the shale from 56 HF stages for six Marcellus wells. This implies that the formations have been fractured up to 1900 feet above the target, including many into and through the Tully limestone, which had been considered a barrier to fracturing. The fractures do not extend to shallow groundwater, but they provide a pathway from the shale to much more permeable formations, including those that consist of sandstone or limestone. The new fractures also potentially connect with natural fractures. It simply cannot be argued, in light of such out-of-formation fracturing, that all HF fluid that does not flowback to the surface through the well remains within the shale.

EPA should not imply that fractures are not a problem if they do not reach drinking water resources (EPA p 6-2) because fractures may provide a pathway from the shale into much more transmissive formations, such as the Tully limestone (Hammock et al. 2014), or to natural faults, which then provide pathways further to water resources. EPA also suggests that out-of-formation fractures are common in the Bakken of North Dakota and presented an example of failure of a casing at Killdeer, N Dakota being related to such fracturing.

Migration via fractures intersecting offset wells and other artificial structures

This pathway has fractures intersecting other anthropogenic factors, with Figures 4 and 5 showing two of the common potentialities. These figures show fractures that do not leave the formation but intersect an abandoned well within the target zone (Figure 4) or situate so that fractures from one gas well intersect the fractures or the producing portion of another gas well

(Figure 5). EPA calls this type of intersection between HF fractures and an offset well a frack hit.

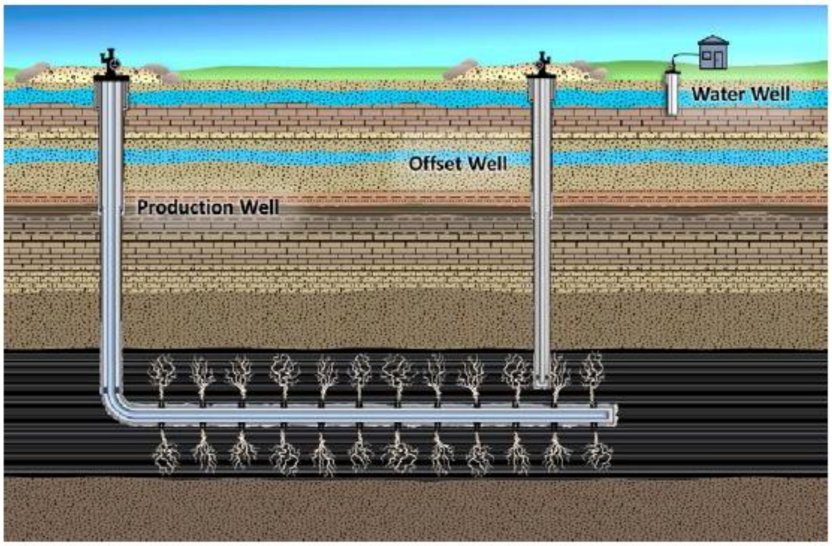

Figure 6-6. Induced fractures intersecting an offset well (in a production zone, as shown, or in overlying formations into which fracture growth may have occurred).

Figure 4: Snapshot of Figure 6-6 showing induced fracture intersecting an offset well

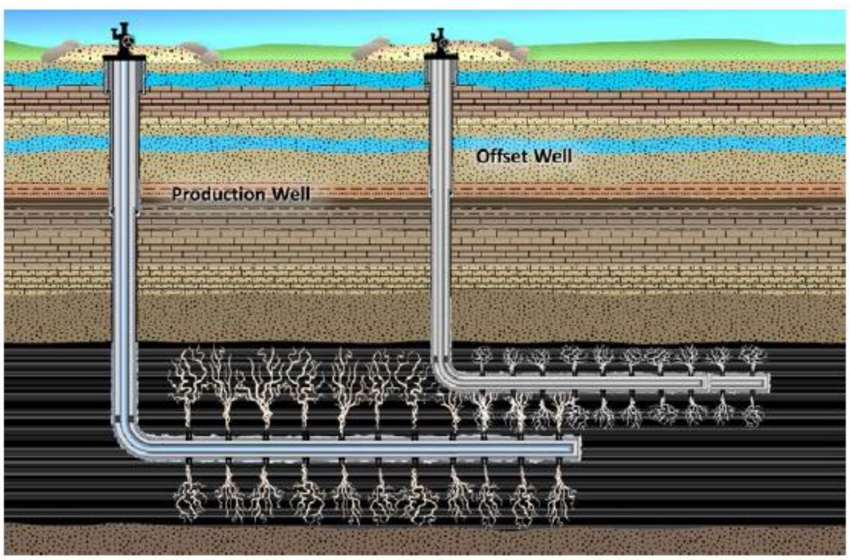

Figure 6-7. Well communication (a frac hit) via induced fractures intersecting another well or its fracture network.

Figure 5: Snapshot of EPA Figure 6-7 showing well communication with induced fractures intersecting another well or its fractures.

The risk of frack hits and interwell communication (6-43, -44) appears to be the pressure from HF in the new well reducing gas production and increasing liquid flow up the offset well. If the pressure is high enough, the increased liquid flow can discharge onto the ground surface or into a higher formation if there are leaks in the well casing. The additional pressure in the offset well could cause it to fail.

EPA presents studies that suggest that frack hits are more common that otherwise presumed (EPA p 6-44). These studies were based on changes in gas and water production rates at offset wells, and suggest that frack designs are not as accurate as supposed. It occurs more frequently in very low permeability reservoirs (Id.).

EPA found that the key factor in frack hits, as should be expected, is distance between the well undergoing HF and the offset well, citing a study that found the "likelihood of communication event was less than 10% in wells more than 4,000 ft apart, but rose to nearly 50% in wells less than 1,000 ft apart" (EPA p 6-45, L5-7). This indicates that fractures extend much further than expected. One study cited by EPA (Ajani and Kelkar 2012)[3] found that communication more than 8000 feet apart is not uncommon.

Well communication is more likely with wells drilled from the same pad (Id.), presumably because they are parallel with often much less than 1000 feet between the horizontal wells. EPA also states the obvious by claiming that well communication is more likely where there is less resistance to fracture growth (Id.). EPA lists many factors (EPA p 6-45, L 18-27) which could make fractures extend further than expected and which demonstrates the number of factors that must be estimated for frack design, and how easy it can be to estimate incorrectly. Older wells are also more likely to be affected for obvious reasons (Id.); specifically the offset well may not be rated to withstand the additional pressures or casings may have been removed.

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[3] The abstract: Advances in drilling and fracturing technologies in Woodford Shale have attracted the operators to drill horizontal wells with long laterals (up to 5,000 ft), and to fracture using multiple stages (up to 22) using large amounts of slickwater and sand. It has been observed that exploitation of shale plays relies on the ability to contact as much of the reservoir as possible using fracturing techniques by creating a network of interconnecting fractures between laterals placed as close as 660 ft apart. As the spacing gets closer, the operators have a vested interest in knowing the optimal spacing of infill wells. Ideally, an infill well should have as little interference with the existing wells as possible.

In this paper, we examine fracture data, and daily gas and water production data of 179 horizontal gas wells over five years in the Arkoma Basin to quantify the impact of interference between wells on their performance. We quantify the lost gas production from the surrounding wells; calculate the probability of interference as a function of distance and age of the surrounding well; determine the preferential direction of interference, and develop a new measure of spacing to understand the relationship between performance of the well and its surrounding wells. Finally, we provide recommendations regarding the spacing of infill wells.

In this discussion (EPA p 6-47, -48), EPA cited many results from Reagan et al. (2015) that somewhat counter all of the studies they cited previously in the section.   Reagan et al. found little gas movement to shallow aquifers and did not consider liquid movement due to a situation that would be considered a frack hit as described by EPA (Figure 5). One problem with citing Reagan et al. is that their study considered movement through induced fractures after injection ceased – they did not actually simulate the pressures generated during injection. The results discussed by EPA do not verify the results of Reagan et al. because they are for an entire HF sequence, not simple movement after injection with no residual injection pressure.

Migration via fractures intersecting other geologic features

This mechanism assumes the fractures from HF intersect a geologic feature such as a fault or fracture zone. EPA should not dismiss the idea of flow through "unfractured shale or tight sand formations" (EPA p 6-48) because there really is no such thing, as EPA essentially acknowledges by discussing microfractures and their role in affecting flow and gas production (Id.). Flow is mostly due to secondary permeability, which is what EPA should discuss. Gas is held in the very small primary pores and flow occurs through secondary fractures.

Formation brine has been documented to naturally flow from the Marcellus (Warner et al. 2012) or other deep Appalachian basins to shallow groundwater (Llewellyn 2014). The evidence is geochemical and isotopic. Both papers surmise fracture and fault connections to the surface and note that a natural upward gradient is necessary to drive the flow. Both papers warn that this flow and these connections could allow more rapid brine flow or portend the movement of HF fluid to shallow groundwater due to increased pressure or enhanced connections due to fracking. EPA briefly acknowledges this (EPA p 6-49), but downplays the meaning of these results. EPA should give more weight to this evidence, especially since model studies for years have simulated the potential for deep brine to circulate to the surface naturally (Deming and Nunn 1991; Person and Baumgartner 1995) or in conjunction with deep waste or CO2 injection (Birkholzer and Zhou 2009)). The role of fractures to allow flow through shale layers has also been known for years, with Bredehoeft et al. (1983) finding that at a field scale, the vertical conductivity of shale is up to three orders of magnitude greater than the conductivity estimated from a column in a laboratory.

EPA correctly notes that flow (fluids – liquids or gases) can occur through transmissive faults, but ignores the natural gradients that could drive such flow. These gradients include glacial unloading, natural Tothian deep circulating recharge (Bredehoeft et al. 1983), density differences (gas and HF Fluid have lower density than brine) or pressure from methanogenesis in the shale. These natural gradients will help to drive flow upward if the fluid parcel is beyond the effect of the production well. Fractures created thousands of feet from the well would move fluid beyond the effect of the well and into the natural flow gradients. As discussed elsewhere in these comments, injection pressure extends away from the well and creates a point beyond which fluids cannot be drawn back to the well.

- EPA should acknowledge and discuss the role of natural pressure gradients in driving brine and gas to the surface.
- EPA should discuss how fracking could enhance the natural vertical gradient.

Recent model studies have estimated that fluids could flow from the Marcellus, or similar shale layers in similar sedimentary basins, to shallow aquifers naturally and that the flow could be enhanced by HF to occur in less than 10,000 years depending on assumed conditions (Cai and Ofterdinger 2014; Chesnauw et al. 2013; Gassiat et al. 2013; Kissinger et al. 2013; Myers 2012). Most modelers found conditions that would allow transport of liquids to occur due to HF within a couple hundred years for some of the conditions they simulated. Myers (2012) found that transport from the Marcellus to shallow aquifers could occur over a period from 10 to more than a thousand years, depending on the conductivity assumed to result from fracking -- his model had the horizontal gas well intersecting a vertical fault connecting the shale to the near-surface. All of the models found the most rapid transport could occur through a vertical fault system. Gassiat et al. (2013) modeled a high permeability, continuous, 10-m wide fault zone from the shale to the shallow groundwater with HF simulated as a change in permeability over a 2-km long, 150-m thick zone. Kissinger et al. (2013) simulated a continuous 30-m thick vertical fault with a vertical head drop of up to 60 m to vertically drive a plume of HF fluid introduced into the lower aquifer. After 30 years under this scenario, simulated HF fluid had reached the shallow aquifer with the injected concentration reduced by a factor of 4000. Lateral migration of contaminants occurred at rates up to 25 m/y (Lange et al. 2013). Chesnauw et al. (2013) modeled flow along a fracture pathway between a target shale zone and surface aquifer in a two-dimensional framework, 3000-m long by 3000-m deep and 1 m thick. A key factor in all of the modeling studies is that they utilized generic stratigraphic and topographic cross-sections with idealized formation properties. Another key fact is that although they considered flow through a fault, they likely underestimated the potential for preferential flow through small but highly permeable fractures even within a preferential flow zone.

EPA correctly rejects the idea that faults would cause gas drainage from low permeability reservoirs because the gas flow is limited by capillary tension (EPA p 6-50). At the intersection of fractures with the shale, fractures may drain the gas but just a small distance from the fault the capillary pressures and extremely low permeability may prevent that drainage. Fracking that connects the shale to the fractures could allow more gas to drain to the fault and quickly move as far along the fault as connections allow. The same applies to other fluids pushed through the shale. Additionally, fractures in overlying formations may not extend through the shale or the properties may be vastly different, thereby preventing significant gas drainage.

Reagan et al. (2015) found a generally downward flow direction, but that is not evidence against an upward gradient or the potential for upward flow. They start with simple hydrostatic pressure, no induced natural gradients although they consider gas pressure. They do not consider changes in shale permeability due to fracking. The single fracture they assume reaches to the shallow groundwater is open after HF so that water simply drains into it. They also consider only one fracture for a pathway, rather than the over 10,000 found by Hammock et al. (2014) in a study of actual fracking. The Reagan et al. study is interesting but does not yield substantial information on the movement of fluid after HF.

At least two studies (Engelder et al. 2014; Flewelling and Sharma 2013) have opined that brine and HF fluid cannot reach shallow aquifers for various reasons – stratigraphic barriers, lack of a driving force, the Marcellus is dry, imbibition removes HF fluid like a sponge, etc. EPA cited only Flewelling and Sharma (2013) but the ideas presented in those papers should be refuted by EPA.

Flewelling and Sharma rely on arguments regarding permeability of the bulk formations and ignore the potential fault connections between the shale and the surface; they incorrectly claim that other studies (such as Myers 2012) rely on out-of-formation fracturing to provide a pathway all the way to shallow groundwater. The modeling studies cited above assume a fault connection to the top of the shale so that fracking fluid only must reach the top of the shale. Out-of-formation fractures that extend above the shale (Hammock et al. 2014; Fisher and Warpinski 2011) may short circuit the pathway making transport faster than simulated in any of the studies cited herein, but are not required for HF fluid to reach shallow groundwater. Flewelling and Sharma mistakenly assume the transport would have to be widespread across a large area when faults would focus brine migration and transport of HF fluid to spatially restricted discharge zones such as springs or shallow groundwater beneath valleys (Deming and Nunn 1991).

Engelder et al. (2014) make arguments that are not supported by facts. The first is that potential transport depends on “single phase Darcy Law physics” which they claim is inappropriate when there is gas and water present; they are wrong because most of the gas occurs within the bulk matrix of the shale layers and most flow occurs in fractures and joints which are predominantly water. Fractures are too large to bind gas. Even the well log presented by Engelder et al. shows substantial free water in a one-meter portion of the shale where the core likely crosses a fracture zone. Formations above and below the shale in the well log are also almost saturated which would ease transport from the shale. Additionally, the large model scale employed by the models listed above renders multiphase flow considerations irrelevant, as argued for modeling CO2 sequestration as a single phase (Cihan et al. 2013).

The second is they claim that even if all of the salt in the Marcellus shale reached the shallow groundwater it would be so diluted as to be irrelevant. The fallacy in their argument is they assume the salt disperses evenly and instantaneously through shallow groundwater when reality is a high concentration flow would enter at a small fault zone intersecting the shallow aquifers, such as at Salt Springs State Park.

The third is they believe that all HF fluid not returning to the surface as flowback becomes imbibed in the shale. Imbibition is a process whereby liquid enters the micropores and becomes bound to the shale matrix, like water soaking into a sponge. Certainly, some fracking fluid becomes imbibed, so their argument is more accurate if all HF fluid remains in the shale. However, much HF fluid leaves the shale through out-of-formation fractures which extend as much as 1500 feet above the Marcellus shale as described above. The new fractures also potentially connect with natural fractures. It simply cannot be argued, in light of out-of-formation fracturing, that all HF fluid that does not flow back to the surface through the well remains within the shale.

Inherent in their argument is a claim that the Marcellus shale is essentially dry, which is incorrect unless one considers only the bulk matrix in which most of the methane is bound. As shown on the well log presented by Engelder et al., fracture zones with higher secondary permeability within the shale contain free water. If new fractures connect zones of secondary permeability that contain free water, fracking will have provided a pathway for Marcellus brine, the free water, to flow to the gas well, probably becoming dominant after the HF fluid remaining most closely near the well goes back up the well as flowback. Based on the rapid increase in concentrations of various constituents, including TDS, Cl, Br, Na, Ca, Sr, Ba, and Ra, in the flowback to levels several times that of seawater, Haluszczak et al. (2013) concluded the flowback was brine, not HF fluid that had dissolved rock minerals from the shale as claimed by Engelder et al. Kohl et al. (2014) use strontium isotope ratios found in flowback to isolate the source formation; the strontium signatures would not be as representative of the source formation if its presence was due only to high velocity dissolution during HF. Rowan et al. (in press, abstract, emphasis added) conclude that the "δ18O values and relationships between Na, Cl, and Br, provide evidence that the water produced after compositional stabilization is **natural formation water**, whose salinity originated primarily from evaporatively concentrated paleoseawater".

- EPA should reject the idea that most of the injected fluid is imbibed because there is little evidence supporting the idea.

Injection into drinking water

EPA documented at least 4600 incidents in which HF occurred with less than 2000 feet of overburden between the gas production and drinking water (EPA p 6-53). EPA also noted there are instances where HF has occurred in water with TDS less than 10,000 mg/l, which is classified as drinking water. HF occurred within an underground source of drinking water in Wyoming (DiGuilio et al. 2011). These occurrences all did or could have contaminated groundwater resources. They represent a failure of laws, regulations, or enforcement by the appropriate authorities in the various states where these incidents occurred.

- EPA should identify the locations where these incidents occurred and acknowledge an improvement in laws or enforcement is necessary to prevent direct injection into drinking water.

Uncertainty in Contaminant Movement

EPA acknowledges that there is little "[i]nformation on fluid movement within the subsurface and the extent of fractures that develop during hydraulic fracturing operations" (EPA p 6-56). There is almost no monitoring of how fracking changes groundwater flow movements, although studies have suggested these changes can occur but they require verification. Industry relies on modeling of HF to show the extent of fractures, with some seismic monitoring to show how far fractures extend from the well. No studies have actually core sampled a fracked rock to assess its hydrogeologic properties. No studies have actually sampled HF fluid or formation water from nearby monitoring wells to show how the fractures develop, flow occurs through those fractures, or document the actual geochemical changes; produced water is simply an analogue that may not represent these processes well at all.

- EPA should strongly acknowledge the need for monitoring flow near fracking sites and post-HF studies of formation properties.

Little is also known about regional changes to hydrogeology. "Ideally, data from ground water monitoring are needed to complement theories and modeling on potential pathways and fluid migration" (EPA p 6-56). Until such data is available, the models (Reagan et al. 2015, Kissinger et al. 2014, Gassiat et al. 2013, Myers 2012) are simply theoretically plausible but unverified hypotheses.

- EPA should conduct modeling studies of the changes in flow due to overall change in hydrogeologic conditions due to fracking.

Most impacts described in the report are expected to occur quickly, probably because that is the focus of most concern (consider post-HF sampling regimes that only require samples for a year or so after HF). EPA does not consider impacts in "slow-moving, deep ground waters" that may "be detected on much longer timescales" (EPA p 6-56) in the report.

- EPA should take a longer time scale view of the potential for water resources damages.

Finally, EPA acknowledges that the lack of information just discussed hinders their "ability to evaluate whether – or how frequently drinking water impacts are occurring (or the potential for these impacts to occur)" (EPA p 6-57). Based on this, the EPA's report should not be used to claim that HF does not affect drinking water supplies.

- EPA should not claim that HF does not pose a threat to drinking water supplies.

Summary

Contaminants from HF have reached shallow groundwater and surface water all over the country. EPA describes six different potential pathways for those contaminants, either liquids or gases, to travel vertically to water supplies. The fact that the fluids found in the water resources can be identified in the target formations or other deep formations based on geochemistry and isotopes proves that transport has occurred. Models have shown that all of the paths are possible. The pathways are mostly hypothetical, however, because the routes have never actually been mapped from source to water resource. Until this can be done frequently, there will be continuous arguments over the potential paths, the time that transport requires, and the concentration of the contaminant once it reaches the water resource.

The review of this chapter resulted in few specific recommendations because of the hypothetical nature of much of the discussion. EPA should recommend comprehensive, long-term monitoring of all areas that have been or are being fracked. This should include groundwater monitoring of all potential pathways frequently enough that plumes will not pass undetected and for a long enough period that contaminants have had a reasonable opportunity to reach the monitoring point. Monitoring should occur between the potential source, the targeted formation, and the water resource.

EPA should also push for more detailed monitoring of the actual fracking process, similar to that done by Hammock et al. (2014) but including nearby monitoring wells. There is little knowledge of the post-fracking hydrogeologic properties of the shale, or adjacent formations. EPA should obtain core samples before and after fracking to assess these properties. With this information, informed estimates of flow and transport time can be made. Models could be better parameterized and calibrated so they would yield more realistic insights to the fracking process. Some of the ongoing controversies regarding fracking could at least be better understood and perhaps settled with additional hydrogeologic data.

CHAPTER 7: FLOWBACK AND PRODUCED WATER

Fracking fluid is the fluid injected into the formation to induce fracturing and formation fluids are the fluids contained in the formation prior to HF; fluid can be a mixture of liquid and gas. Once injection is finished, either by stage or for an entire well, fluids return to the well under residual injection pressure and flow up the well to the surface. The fluids are naturally a mixture of HF fluid and formation fluids, including gases released from the formation. The fluid reporting to the surface after fracturing initially resembles HF fluid chemically, probably because the injected HF fluid is nearest the well and mobile. As the flow continues, the chemistry begins to resemble that of the formation waters with salts and naturally occurring radioactive materials (NORM) increasing and HF chemicals decreasing. It is reasonable to assume the fluid reporting to the well is always a mixture but the literature uses the terms flowback to describe the initial water that emerges from the well after injection ceases and produced water to describe that which returns later.

EPA fails to consider adequately the definition of flowback and produced water and effectively mixes the two types of water by defining produced water as “water that flows from oil or gas wells” (EPA p 7-2, line 7) or it “can variously refer to formation water, a mixture of spent hydraulic fracturing fluid and formation water or returned hydraulic fracturing fluid” (EPA p 7-2, line 14-16). The report also refers to flowback as “fluids predominantly containing hydraulic fracturing fluid that returns to the surface or to a process used to prepare the well for production” (EPA p 7-2, line 18-19). The plethora of definitions does not allow an accurate measurement of the quantity or an assessment of the chemistry of either flowback or produced water. Fluid that emerges from the well when it is opened to allow water to flow varies from a high concentration of fracking fluid chemicals initially to a high proportion of formation chemicals and contaminants in the long term. Typically, the initial flow rate is high, and it is during this period that spills are most prevalent. The EPA has not adequately established a definition but used the definition the authors they are citing.

- A preferable definition for flowback would be the water that returns from the formation under the pressure caused by HF, which could then be assumed to be all water that returns prior to production. Produced water would be the water that flows to the surface as a byproduct of pumping gas/oil. The difference would essentially be the source of the pressure – HF or gas production. Spills would be more likely with flowback due to the potential high volume flow.

Flowback and produced water present different contamination threats due to the different pressures and flow rates they report to the well under. The toxicity also varies, with flowback spills being toxic due to the HF chemicals involved. Produced water contains more formation fluid so the high TDS and radium may be more easily captured but must be treated prior to discharge or reuse. Thus, the issue differences may require more toxic spill containment for flowback and more treatment for produced water.

The volume of each varies substantially among formations and plays (Tables 7-1, -2, and -3). These tables refer to produced water with various time frames after HF, rather than being definitely identified as flow back. For example, Table 7-1 reports amounts of produced water within 10 days of completion. The Table should indicate whether the well was open the entire 10 days because it is possible the operator limited flow back. The arbitrary 10-day cutoff indicates this table may not be accurate with respect to returning fracking fluid.

Table 7-2 presents all water returning as a percent of the injected fluid for short-, mid-, and long-term periods. For example, for Marcellus shale after 10 days, 30 days, and up to 115 months, the produced water is 10, 8, and 10-30%, respectively. This means that at least 70% of the injected water in Marcellus shale remains underground, either imbibed into capillaries or flowing through the target or other nearby formations in fractures and joints, after as much as 115 months. Out-of-formation fracturing could provide pathways for the fluid to leave the target formation (Hammock et al. 2014).

Interestingly the Barnett in Texas produced more water over the long term, up to 115 months, than was injected during HF, although short term production was similar to other shales. This contradicts the findings of Bruner and Smosma (2011) that the Barnett and Marcellus shales have similar water saturations of 20 to 30% (Bruner and Smosma 2011, p 3). Consistent high water production indicates that the fractures frequently connect to other formations that may contain excess water that then flows into the Barnett shale.

- EPA should attempt to explain where the extra produced water in the Barnett comes from – adjoining formations, the shale, or somewhere else?

EPA completely ignores the issue of groundwater quantity with respect to flowback and produced water. If a gas well, fracked or not, produces more water than was put into as part of the development process, the well could be depleting an aquifer. This could be problematic in the shallower gas wells (<2000 feet below an aquifer) and those with drinking water quality, especially if their recharge rate is low as would be the case in many semiarid regions.

- EPA should consider the potential that high water producing gas wells (EPA p 7-11) could draw water from and draw down the water levels in nearby aquifers.

Injected water that does not flow back either escapes the target formation or is imbibed. Many concepts of imbibition were reviewed in the previous section, but EPA also references Engelder (2012) as suggesting that imbibition would sequester fluids in the producing formations (EPA p 6-35, -36, 7-13). Although published in the *Proceedings of the National Academy of Sciences*, a peer-reviewed journal, the article is simply a letter discussing another article and would not have been peer-reviewed. He claims that the half that returns is gradually salinized by "what little free brine … comes in contact with the frack fluid" (Engelder 2012). Produced water from the Marcellus has TDS approaching 300,000 mg/l and other chemicals not found in the generally fresh (with respect to TDS) frack fluid. Engelder implies that a small amount of formation water causes returning frack fluid to have such high TDS but this is not possible from a mass balance perspective. Once TDS approaches formation fluid TDS, a large proportion of returning flow must be mostly formation fluid which indicates there is lot more free water than some suggest. Simple TDS mixing considerations proves Engelder's claims that the Marcellus is "unlikely to leak natural brine" (Id.) to be wrong. His statement that "[d]rawing brine into a Marcellus well from the Onondaga Limestone below can cause extreme salinization in flow-back" is out-of-context and without any reference or data regarding there being water from the Onondaga. Additionally, this process would require that fracking somehow connects the fractures in the middle of the shale downward to the Onondaga; most HF fractures are vertical upwards (the literature does not discuss downward fracturing).

Similarly, EPA cites DOE (2011a) (Bruner and Smosma 2011) as its sources for claiming the Utica and Marcellus shales are dry – "the characteristics small amount of produced water from the Marcellus shale was due either to its low water saturation or low relative permeability to water" (EPA p 7-13, L4-6). It is noted here that Bruner and Smosma do not discuss the Utica shale except for including it in a thermal maturity graph, so EPA should not include it the citation here.

- EPA should explain how claims of the shale being dry is contradicted by the concept that Marcellus brine has and continues to discharge to the surface (Llewelyn 2014, Warner et al. 2012). Both could be correct because there could be much more brine in areas that are more naturally fractured whereas the shale holds the gas better in the matrix.

EPA Section 7.3 is titled Background on Formation Characteristics. However, it provides no information on characteristics and only a very brief description on how shale, sandstone, coal and tight sands are formed.

- EPA should provide appropriate statistics of various characteristics including porosity, permeability, formation thickness, fracturing, etc. of the formations by name.

EPA's study leaves the impression that little fluid remains in the formations and available to move away from the target formation. There is simply no evidence to support this contention other than the unverified modeling presented by Byrnes.

- EPA should provide statistics regarding the length of time a well remains shut in after stimulation and prior to reducing the pressure to recover the injected fluid. This will create a pressure that can continue to drive injected fluid along natural and induced fractures away from the well.

TDS increases with time and volume of produced water extracted, from 1000 to 200,000 mg/l in 90 days in the Marcellus (EPA p 7-17). There is debate as to whether this is formation water or returning fracking fluid that has dissolved the salt. Radium increases with TDS because it remains adsorbed at low TDS (EPA p 7-18). However, tests for radium and glycols, and probably others, are hampered by high TDS concentrations (EPA p 7-15). These can lead to false negatives. Carbon, as dissolved organic carbon (DOC), decreases as TDS increases (EPA p 7-20). It is difficult to assess actual organic compounds because of the lack of knowledge of the specific chemical (EPA p 7-22). There is a huge variation in geochemical parameters of produced waters, and CBM water is not that similar (Table 7-4). Strontium and barium are highest in Marcellus shale.

Section 7.5.7 deals with organics in produced water, including volatile organic compounds, semi-volatile organic compounds, and non-VOCs (EPA p 7-28). The EPA cannot be certain that any of the organics in produced water are naturally there, unless the data is taken from exclusively conventionally produced water, such as in Table 7-5. There is no pre-HF sampling of formation water.

- EPA should recommend that sampling associated with fracking include a pre-frack sample of HF fluid, including samples for the different periods.

Spills of flowback or produced water

The EPA discusses the various methods that produced and/or flowback fluid can reach environmental receptors through spills or leaks (7-32 to 7-36). There is little discussion as to the adequacy of the data reviewed. The EPA discussed only studies done by state DEPs or researchers that had access to these databases. A lack of information for a given state does not mean there have been no or few spills in that state. Of the reported spills, the EPA acknowledges that the impact on water resources of the 76% of spill volume reported as unrecovered and 8% reported as unknown with respect to recovery is unknown; **the lack of information regarding the potential for impacts demonstrates the need for monitoring around the facilities.**

- EPA should discuss that the lack of monitoring around well pads makes it difficult to assess the frequency and fate of spills

The assessment of spills and other accidents of produced water, oil, or flowback often identify soil as the primary or only environmental receptor (EPA p 7-33). This reporting may be incomplete if the soil is not the final point the chemical reaches. Infiltration through contaminated soil can leach contaminants to the groundwater, if the soil has not been removed or otherwise remediated. The EPA may be reporting incomplete results here simply due to the site assessment being incomplete.

The general description of flow pathways from surface spills to groundwater is accurate (EPA p 7-41) but incomplete due to its failure to estimate travel time along preferential pathways. The shortest travel time between a spill or leak and shallow groundwater is not through an extensive aquifer or unsaturated zone as discussed (Id.), but through preferential pathways. Such pathways are rarely monitored so contamination becomes apparent only once the groundwater has been contaminated. EPA did not attempt to estimate potential travel times from spills to water resources.

- EPA should complete its own modeling studies with a 3-d version of HYDRUS or other appropriate software that can include preferential flow pathways to estimate the travel

XTO's Marquardt 8537H well pad in Lycoming County

The description of the spill indicates that the spill was much worse than described and also suggests that even discovering it was fortuitous. EPA provides additional details of their analysis at http://www2.epa.gov/enforcement/xto-energy-inc-settlement.

1. EPA describes that an "estimated 6,300 gal to more than 57,000 gal of Marcellus Shale produced water was illegally discharged … and flowed into the Susquehanna River watershed in November 2010" (p 7-36, L21-23). The suggestion is it was a one-day spill that an inspector managed to find "after a routine inspection by the Pennsylvania Department of Environmental Protection" (Id., L29-30). EPA suggests that discharge had occur for over two months (p 7-37). If the inspector had not discovered this, it is likely the operator would have eventually stopped the discharge and the public (and EPA) would not know it occurred.
2. The spill impacted surface water with various chemicals characteristic of produced water, including barium, bromide and strontium.
3. EPA also documented flowpaths across the ground surface and through fractures. The path to the stream was approximately 2000 feet.

times.

EPA's discussion of specific spill case studies indicates that the prevalence and impacts of spills may be far greater than suggested by the statistics. A couple case studies discussed here in text boxes on this and the next page illustrate the points. Failure to assign cause is a common problem with the data reporting of many events in the EPA report.

EPA analyzed 225 spills of produced water, analyzing the cause and which type of failure leaked the most water. The median was 990 gallons, or more than double the volume of spills of fracking fluid (during the mixing prior to injection phase) (EPA p 10-12). The causes were human error, equipment failure, container integrity failure, miscellaneous, and unknown, with container integrity being responsible for 74% of the total volume (Id.). This likely reflects the difficulties of capturing and properly storing water as it emerges from a well at potentially high pressure. It highlights the need for back-up containment at the well pad.

- EPA should assess the number of events for which secondary systems, such as at the well pad, fails.

Towanda Creek, Bradford County PA

The second incident reported by EPA shows how difficult proof of cause is to establish. EPA indicates that 10,000 gallons of flowback fluid spilled into a tributary of Towanda Creek. They also sampled seven wells and provided the data to the Agency for Toxic Substances and Disease Registry (ATSDR) to determine whether the wells had been harmed. ATSDR (2013) claimed only that the data "suggested" the wells had been impacted by gas activities even though there were factor of 10 and 7 increases in geochemical parameters that can be linked to HF.

1. Chesepeake could not control the spill for six days (ATSDR 2013, p 1), but the EPA does not report this.
2. ATSDR does not conclude the fracking caused the increases in the wells due to data limitations.
    - There is no information on potential groundwater pathways.
    - The post-HF data is limited to just one sampling event while the ATSDR suggests there should be multiple samples to establish trends.
    - There is no information regarding connections between the water wells and aquifers.

ATSDR's failure to affirm that fracking caused the well contamination results from the failure to consider a pathway and to adequately sample the wells. The gas well is on a hillside of a distinct drainage, according to the map provided in ATSDR (2013). Most water wells appear to be in the valley bottom, but unfortunately the seven sampled wells are not presented on the map. In northeast PA, this topography indicates the likelihood of faults and fractures providing connections from depth to the water wells. Adequate monitoring would include dedicated monitoring wells on the pathways from the gas wells to the water wells; this would include along the fracture zone beneath the drinking water wells.

Table EW-1 shows flowback and long-term produced water characteristics for wells in unconventional formations, by basin and formation.

- Table EW-1 should specify time periods for defining flowback – in other words, at what point after the frack job does the flowback become produced water.

CHAPTER 8: WASTEWATER TREATMENT AND DISPOSAL

Wastewater is primarily produced water, meaning a mixture of formation water and fracking fluid. EPA does not consider drill cuttings or other waste created by HF. EPA considers only impacts of treatment that could affect water resources. EPA does not consider impacts caused by injected oil and gas wastewater into underground injection (UI) wells because EPA assumed them to not impact water supplies. The volume of wastewater created by oil and gas development in the US is highly variable both geographically and temporally. A majority of HF wastewater (>50%) is reported to be reused with substantial proportions also injected or sent to centralized treatment centers. The variation depends on geography.

- EPA should acknowledge the failure rate of UI wells, especially in light of the substantial increases in volume caused by HF waste water.
- EPA should acknowledge and discuss the findings that UI wells with HF wastewater have caused earthquakes, especially the potential for earthquakes affecting groundwater quality.

EPA notes the difficulty in determining wastewater strictly from fracked wells because many states do not break down the data that way. Wastewater production of course parallels O&G development. Much more is produced during well development than during well production. As plays boom and bust, the wastewater production increases and decreases. As will be discussed, treating the wastewater can be difficult due to high TDS or radium concentrations. Because it is not economical to develop treatment capacity for a temporary waste stream, there is a risk that companies will find illicit ways to dispose of highly toxic wastewater.

- EPA should discuss treatment issues raised by rapidly changing wastewater volumes

This review does not focus so much on volumes because they change substantially with time as the industry booms and busts. In the west, industry injects most wastewater. In the Marcellus, there are few acceptable injection wells in or near Pennsylvania. Prior to 2012, most wastewater was sent to publically owned treatment (POTWs) facilities and discharged into surface water, but since 2012, most has been treated and reused. The early discharge caused many problems with surface water quality in Pennsylvania streams (Brantley et al. 2014, States et al. 2013, Olmstead et al. 2013, Vidic et al. 2013), for example. This was primarily due to most

Marcellus wastewater being high in TDS (EPA p 8-10) which most POTWs cannot easily treat. EPA requested that industry stop sending Marcellus wastewater to POTWs (EPA p 8-13) so now industry reuses much of its wastewater in the Marcellus zone.

As noted, produced water presents treatment challenges not commonly found at POTW facilities. Examples include:

- Constituents that wastewater treatment plants do not remove well, such as bromide, also are not easily treated at water treatment plants so will remain in the discharge.
- Radionuclide treatment can lead to longer term pollution problems in receiving waters, long after waste water is no longer delivered to the treatment plant. Radionuclides remain in sediments downstream from the plants and in the pipes of the plant itself.
- Salt can upset the biological treatment processes at POTWs (EPA p 8-33)

In 2013, 90% of Marcellus wastewater reported to centralized zero-discharge treatment facilities (EPA p 8-26). In Pennsylvania, they are zero discharge because the effluent is reused for HF fluid. The primary negative is that treatment results in toxic solids for disposal, although this disposal is not likely different than for many industries that treat hazardous materials. EPA discusses many factors that go into reuse, but does not discuss any negatives.

EPA also discusses spreading of produced water on roads for ice control (EPA p 8-35). In general, the use of salt on roads increases the salt content of soils and waters near the roads. Most often measured as chloride (Cl) concentration, road salt has significantly increased the salinity of water bodies. Use of brine from conventional gas wells has increased the concentration in soils of radium, strontium, calcium, and sodium. EPA presents no data concerning either the effects of using Marcellus brine or its frequency on roads.

- EPA should strongly recommend against using produced water from any shale play on roads because of the high concentrations of toxic metals and NORM and the potential for fracking fluid chemicals to be included.

EPA cannot determine whether treatment facilities, many of which are in PA, effectively treats metals and organic compounds because industry collects very little comparative influent and effluent data. Produced water delivered to treatment facilities would likely not coincide with NPDES-required discharge monitoring reports. Testing labs cannot test for HF fluid chemicals that are not disclosed. EPA really has little idea about the presence of fracking-related organic compounds in surface water because their transport is very complex and concentrations may vary substantially so that a grab sample is not representative.

- The transient nature of the fracking business causes transitory water quality problems. A boom cycle with HF creates significant wastewater without the means to treat it. Once adaptations occur, with better collection facilities at the well pad and better treatment processes, the demand lessens.
    - The need for high capacity treatment may be short-lived therefore the dangers of poor treatment or elicit disposal are very high for fracking fluid. This is because the treatment needs are complex and expensive to establish for only short time periods.
    - Fracked wells produce the most wastewater for just a few weeks after fracking after which it decreases and levels off.
    - A boom in fracking creates a boom in wastewater requiring treatment. Areas can produce lots of gas but very little wastewater once a large number of wells have been completed and are just producing gas.

CONCLUSION

The primary conclusion presented by EPA is that HF has not caused a widespread systemic impact to water supplies in the United States. The data presented in the review do not support this conclusion. There is no widespread systematic monitoring of either surface or groundwater, so the extent that fracking impacts water resources is unknown. EPA documents many impacts to smaller areas mostly due to reported incidences of leakage and acknowledges that many impacts are not reported due to litigation settlements. Even where monitoring does occur, testing may not include the most toxic fracking fluid chemicals or their byproducts because industry does not disclose many of them.

Two primary conclusions may be reached from this review.

- There is simply too little known about the fracking process to have widespread assurance that it is safe. Large-scale groundwater and surface water monitoring networks are necessary, with a recognition that long flow times may cause contamination to occur far into the future. Details of what happens underground during fracking should be studied with more emphasis on hydrogeology, not just engineering properties. There should be much more disclosure of the chemicals and their properties.
- There is enough known of the process to know that the risks to water resources into the future are very likely. Millions of gallons of toxic fluid are injected into the ground, some very near groundwater resources or near pathways that will connect to groundwater resources. The process significantly changes the hydrogeology of the formations so that natural flow patterns will change. The process also significantly changes the geochemistry of the fluids, rendering some very toxic. Flow along pathways may take a long time but once contaminants reach water supplies the effects could be devastating. There is simply

no planning or even acknowledgement by the industry or EPA regarding these long-term effects.

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