Technical Rebuttal to Article Claiming a Link between Hydraulic Fracturing and Groundwater Contamination

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INTRODUCTION AND PURPOSE

The Pennsylvania Council of Professional Geologists (PCPG) and the Pennsylvania Geological Survey (PAGS) have conducted a formal review of "*Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers,*" a paper written by Tom Myers and published by the National Ground Water Association, first on their website in April 2012, and subsequently in print in the November-December 2012 issue of *Ground Water* (now *Groundwater*). The print release included not only the original article (Myers, 2012) but also an associated *Discussion of Papers* (Saiers and Barth, 2012) and *Author's Reply* (Myers, 2012a).

In the original paper, Myers presents the results of a groundwater modeling simulation intended to predict how hydraulic fracturing (correctly abbreviated "fracing") of deep shale gas wells can be expected to impact shallow groundwater aquifers in less than ten years. Given that hydraulic fracturing of horizontal unconventional deep shale wells has been ongoing for "less than 10 years" in the Appalachian basin, this implies that aquifer contamination is practically upon us, and due to processes already set in motion, there is little we can do at this point to stop it, other than monitor its inevitable arrival. In actuality, however, the author's selective use of modeling parameters, misrepresentation and/or misapplication of existing technical references to justify his modeling scenario, and omission of certain key data and widely accepted principles regarding subsurface geology and fluid flow through porous media, highlight two major deficiencies of this work: 1) lack of objectivity, and 2) lack of understanding how to develop a credible hydrogeological conceptual site model.

We agree that computer model simulations can be useful in answering scientific questions, but a hydrogeologic system cannot be properly simulated without a credible conceptual site model that describes the hydrogeologic system's physical and hydraulic framework and sufficient real-world data gathered from the area of interest. When constructed properly, such computer models can: 1) serve to identify where additional data are required, and 2) be used to predict future system responses to similar stresses, upon proper calibration to collected data and measured stresses (e.g., pumping). A numerical computer model based on flawed or incomplete conceptual models and constrained by scanty and/or

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less-than-representative data, will produce unreliable results that are not representative of real-world conditions.

Based on the numerous weaknesses and shortcomings associated with the original paper, we felt compelled to prepare this technical rebuttal.   The comments are presented in the following sections titled: Conceptual Site Model and Groundwater Modeling Effort.

CONCEPTUAL SITE MODEL

Myers (2012) presents the results of a modeling effort intended, in his own words, to "consider several potential scenarios of transport from shale, 1500 m below ground surface (bgs) to the surface, beginning with pre-development steady state conditions to establish a baseline and then scenarios considering transport after fracking [sic] has potentially caused contaminants to reach formations above the shale." Myers' efforts not only mischaracterize pre-existing subsurface geologic and hydrodynamic conditions in the portion of the Appalachian basin where the Marcellus shale exists, but also miss the mark when it comes to conceptualizing the effect that fractures created by the stimulation (fracing) of a horizontal shale gas well may have on subsurface fluid flow. Specifically, we maintain the following:

- Myers' model is not realistic from either a lithostratigraphic or structural standpoint, and is not consistent with what the scientific community has documented regarding the depositional and tectonic history of the sedimentary sequence in the Appalachian basin;
- Myers fails to discuss the critical aspect that fracture connectivity plays in fluid migration (Odling and others, 1999) and assumes high connectivity with no corroborating data;
- Myers fails to discuss how the orientation of fractures relative to the contemporary stress field affects fracture aperture and orientation, and hence rock permeability; and
- Myers does not accurately represent the composition and relative saturation of pore fluids in the Marcellus shale and overlying geologic units.

In order to properly conduct the modeling effort attempted by Myers, the conceptual site model must comprise the following: 1) an accurate representation of the study area's geology – including a sufficient understanding of both the lithostratigraphy and structure of thousands of meters of geologic formations in the Appalachian basin, the impact that previous tectonic events have had on these rocks, and how current-day in-situ stresses influence rock physical properties, 2) how fracing can be expected to modify the shale reservoir's natural fracture characteristics, and 3) proper insight into the hydrodynamic and pore conditions of the rocks through which not only water but also petroleum hydrocarbons flow. The first item is crucial for setting realistic baseline conditions, to which modeling results can be compared. The second and third items are necessary to evaluate whether and how fracing modifies subsurface flow conditions, which could contribute to shallow groundwater contamination. Accordingly, the remainder of this section addresses the geology and tectonic history of the basin, discusses how the fracing process is designed to maximize production from shale gas reservoirs, and addresses multi-phase fluid flow in these subsurface rocks of the Appalachian basin.

Geologic Considerations

Lithostratigraphy

Myers' conceptual geologic model included 1,500 meters (m) (4,921 feet [ft]) of "predominantly sandstone" overlying the Marcellus shale. The characterization of the geology overlying the shale as mostly sandstone is not consistent with the data gathered from more than 100 years of subsurface drilling in the basin. The sedimentary sequence is, in fact, an alternating series of sandstones, siltstones, shales, and carbonate rocks that vary in thickness, extent, and rock physical properties depending upon location in the Appalachian basin. Even in southern New York, which Myers describes as his modeling area, a significant portion of rocks overlying the Marcellus shale is comprised of shales and siltstones of much lower permeability than the sandstone he ultimately uses in his numerical model. Many reports describing Appalachian basin lithostratigraphy and petroleum reservoir potential have been published, but perhaps the most prominent, at least since the U.S. Department of Energy's Eastern Gas Shales Project (EGSP) of the late 1970s (see Roen and Kepferle, 1993, for summary information), is the Atlas of Major Appalachian Gas Plays (Roen and Walker, 1996).

Geologic Structure, Tectonics, and Fluid Migration

With respect to structure and faulting, Myers assumes a continuous 6-m (19.7-ft) wide, vertical, high-permeability fault (10-1,000 times more permeable than the rock matrix) extending from the Marcellus Formation at depth to ground surface. This fault geometry and hydraulic characterization are unsupported by any empirical data collected by the scientific community for the Appalachian basin (or anywhere else, for that matter). There are very few faults mapped at ground surface on the Appalachian Plateau, and those faults that have been imaged in seismic surveys are: 1) mostly confined to Middle Devonian and lower stratigraphic units, and 2) not vertically-dipping. This is consistent with our understanding of how in-situ stress fields influence the orientation of rock fractures, that is, fractures always propagate perpendicular to the orientation of least principal stress. As an example, in the shallowest portions of a sedimentary basin, the least principal stress orientation is vertical, so fractures will propagate horizontally. With depth, however, as more and more layers of overburden rock are added, the orientation of least principal stress will eventually become horizontal, which in turn will allow fractures to grow vertically (Willis and others, 2005). Furthermore, Nickelsen (1976) established that, across Pennsylvania, polygenetic origins of joint patterns are controlled by lithology and bedding thickness. In short, fracture orientations in rock vary with both depth and lithology, and certainly cannot be presumed vertical throughout an entire sequence of sedimentary rock.

While there has been much speculation about topographic and geophysical lineaments representing faults, with the exception of the Clarendon-Linden fault of western NY (Jacobi, 2002) and the moderately-dipping Towanda fault of Bradford County, PA (Pohn and Purdy, 1981), these have not been demonstrated to offset Upper Devonian stratigraphic units. We would argue, in fact, that even if all the lineaments interpreted by various researchers (*including* Isaachsen and McKendree, 1977, and Gold, 1999, cited by Myers, 2012a) represented faults with measurable offsets through most of the stratigraphic section, that does not imply that they are necessarily modern-day conduits for fluid flow. Rather, the hydraulic character of faults is highly variable and dependent on a range of variables –

movement history, fault rock type (e.g., gouge, breccia, mylonite), associated fracture networks, fluid migration and secondary mineralization, and orientation of the fault relative to the in-situ stress field (Gentier and others, 1998; Haneburg and others, 1999, and references therein). Faults can act as either a barrier to fluid migration or an enhanced conduit for fluid flow, with the same fault undergoing orders of magnitude changes in intrinsic permeability over time (Moretti, 1998). Faults in the Appalachian Plateau sedimentary section formed and accumulated their primary offsets during Paleozoic deformation more than 250 Ma ago. At that time, the Appalachian sedimentary basin was undergoing diagenesis, catagenesis, burial, and tectonic compaction in association with the Alleghanian orogeny. It was during this period that extensive fluid (both aqueous and gaseous) migration was most active. There is no evidence to suggest that upward fluid migration has been continually occurring in the Appalachian basin. In fact, were this an active process throughout geologic time, the fresh groundwater aquifers currently sourcing more than one million private water supplies in Pennsylvania alone would not be fresh – instead, they would be unpotable.

In response to Saiers and Barth (2012), Myers (2012a) goes so far as to cite additional works to justify his high-permeability, reservoir-to-surface fault concept. In particular, Myers cites Harrison (1983; 1985) as justification for upward contaminant transport via faulted sandstone units. This is a complete misrepresentation of Harrison's work. In neither *Ground Water* paper did Harrison reference faults as the culprit for shallow groundwater contamination. Further, he never implicated natural fractures as the sole cause for gas migration to shallow groundwater aquifers, or that gas from deep Medina Group wells contaminated shallow aquifers. Instead, through his case studies, Harrison demonstrated that when gas wells are located too close to the valley walls of major drainage ways (which typically have steeper hydraulic gradients, shorter groundwater flow paths, and an abundance of natural bedrock fractures) and are constructed poorly (i.e., overpressured well annuli), shallow groundwater aquifers are more susceptible to oil, gas, brine and/or stimulation fluid contamination. In other words, contamination was largely the result of anthropogenic activities, not geologic structure, in these scenarios.

Hydraulic Fracturing

Contrary to some media reports, hydraulic fracturing has been used to stimulate gas wells in the Appalachian basin since the early 1950s. In Pennsylvania, the first deep gas well to be fraced was the State of Pennsylvania Tract 28 No. 3 well, which produced from the Lower Devonian Oriskany Sandstone in Elk County. Subsequently, hydraulic fracturing was applied to more and more wells, both shallow and deep, to develop the many low-porosity petroleum reservoirs in the Commonwealth (Carter and others, 2011).

Important differences between the well completion activities of the mid-20th century and those currently employed by shale gas operators include: 1) oriented drilling techniques, which are used to access a larger portion of the reservoir with minimal surface footprint, 2) the larger volumes of water used in the fracing process (on average, 500,000 gallons of water per frac stage), and 3) avoidance of existing folds, faults, or tectonic fractures during exploration activities (which hinder, rather than enhance, production). Like most shales, the Marcellus has very low permeability (100 to 500

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nanodarcies), so in order to successfully produce from it, operators drill horizontal wells and engineer their frac jobs to take advantage of naturally occurring joint sets in this unit – the J1-J2 joint sets recognized by Engelder (2004; also see Engelder and Whitaker, 2006; Engelder, 2008; Lash and Engelder, 2009). J1 joints are oriented southwest-northeast, approximately parallel with the Appalachian basin's contemporary tectonic stress field. So, horizontal Marcellus wells drilled perpendicular to the J1 joint orientation (i.e., typically in a NW-SE direction) will intersect many J1 joints, and fracing multiple stages along this horizontal course will prop them open and maximize their interconnectedness, which provides optimum gas drainage from the reservoir to the well bore (Carter and others, 2011). In addition, avoidance of existing structure, although it may seem counter-intuitive, is important to ensure successful production from Marcellus shale gas wells. Such structure (whether folds, faults or tectonic fractures) may provide undesirable flow paths for formation fluids or frac water. In order to best control the flow of fluids to the reservoir during stimulation and flow of hydrocarbons from the reservoir during production, geologic structure is to be avoided.

Hydrodynamics

Gradients and Flow Regimes

Myers' conceptual model of the hydrodynamics of the sedimentary section between the Marcellus shale and shallow groundwater aquifers is not supported by either field measurements or theory. He provides neither information on measured vertical hydraulic gradients for his study area nor acknowledges the abundant empirical evidence of a fundamental hydrologic boundary between an upper (<245 m), active, freshwater flow system and a deep, static, locally water-undersaturated, brackish-saline system (Buckwalter and Moore, 2007; Williams, 2010).

Myers assigns a one-dimensional vertical flow system. This is not plausible for any aquifer system, because when one stresses an aquifer, the water mainly moves horizontally within it and not vertically (unless it is downward from the land surface through the unsaturated zone). In the case of the Marcellus shale, there are many layers (thousands of meters) of higher and lower hydraulic conductivity between it and the production (fresh groundwater) aquifers near the surface, with each low-conductivity unit (aquitard) hindering vertical flow, and each high-conductivity unit (aquifer) having horizontal flow components that flow from recharge areas to discharge areas, with longer paths for the deeper flow systems.   Said another way, each aquifer system in the sedimentary section has its own flow regime, based on the basin's recharge and discharge dynamics or due to geologic pressurization events for the deeper systems. As a result, both upward and downward gradients occur between the aquifers in a given multiple aquifer system. Myers' scenario defies these theoretical concepts of hydrogeology.

Myers assumes that the driving mechanism of fluid transport is a continuous upward-directed hydraulic gradient from the Marcellus Formation to freshwater aquifers. He bases this on sparse, pre-1980 measurements from Cambrian units reported for the northern margin of the Appalachian Plateau in western New York (TAL, 1981) and the interpretation that brines with very high total dissolved solids concentrations, found in Lower Devonian sandstone units, migrated vertically at least 1,000 m from a

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deeper source (Dresel and Rose, 2010). We agree with Saiers and Barth (2012) that it is inappropriate to use dated gradient measurements from wells that: 1) are not local to the study area, and 2) are associated with rock units deeper than the Marcellus shale, the focus of Myers' modeling effort. In addition, it is unacceptable to cite brine data quality as justification of upward flow of connate groundwater without acknowledging the timing and nature of this migration. Myers implies that density-driven, upward flow has been occurring continually over geologic time, but the wealth of research regarding the movement of fluids and emplacement of hydrocarbons in the Appalachian basin indicates that this activity, although recurrent, has been intermittent (Harper and Laughrey, 1987; Harper, 1989). In fact, as stated above, were there a vertical hydraulic gradient forcing continuous upward fluid migration in the basin, existing shallow groundwater supplies would have long ago been contaminated by brines and petroleum hydrocarbons, and known oil and natural gas reservoirs would likely have been depleted long ago, causing this entire discussion to be moot.

Pore Conditions

Myers' assumption of continuous upward flow from the Marcellus shale to shallow groundwater aquifers would require that the entire sedimentary sequence between the Marcellus and shallow water-bearing rocks was completely saturated with water (whether saline or fresh) prior to hydraulic fracturing. Several lines of evidence, however, contradict this assumption – most notably, the production of hydrocarbons from several formations overlying the Marcellus shale during the past 150 years; empirical observations made during shale gas drilling, flowback, and production periods; and data collected from petrophysical logging of shale gas wells. Each of these is summarized below.

Extensive oil and gas drilling and production throughout the Appalachian basin have revealed the existence of water-undersaturated geologic formations in Devonian and younger strata that have produced oil, gas, and/or brine (PA*IRIS/WIS, 2013). In addition, the occurrence of natural gas in Middle to Upper Devonian units stratigraphically above the Marcellus Formation has been well documented in New York (Martin and others, 2008), which Myers uses as the study area for his modeling scenarios. The existence of this gas in the shallow portion of the section will inhibit the rate of movement of aqueous fluids through these gas-bearing units, were hydraulic fracturing to cause upward migration of fluids in the first place.

Shale gas drilling and petrophysical logging activities demonstrate that the shale is highly undersaturated with respect to water (<25 percent, McKeon, 2011). The return of only a percentage of the water injected during the fracing process (estimates of <10 to about 40 percent, depending on source; Carter, 2010; McKeon, 2011) is another testament to the less-than-saturated conditions in the shale's porosity structure. Because of high capillary pressures, any imbibed fracturing fluid is locked in the shale matrix for geologic time intervals (Byrnes, 2011), and therefore, does not contribute to the fluid pressures modeled by Myers. Imbibition of fracturing fluid into water-undersaturated Marcellus shale also negates Myers' assumption that fracturing fluid can cause contaminants to reach shallow aquifers by "simple displacement of fluids from the shale into the overburden."

Like Saiers and Barth (2012), we cannot stress enough the difference that multi-phase fluid flow in water-unsaturated media will have on a groundwater flow and transport model. Myers' assumptions regarding the pore environment in these subsurface rocks is too simplistic, and therefore, unrealistic.

GROUNDWATER MODELING EFFORT

Myers' groundwater modeling effort is lacking in several respects: consistency between model purpose and development; choice of modeling software; model parameterization; and absence of model calibration. We address each of these items in turn below.

Model Purpose

Myers (2012) presents five model scenarios designed to address natural and post-fracing groundwater flow and contaminant transport from the Marcellus shale horizon to shallow aquifers. His modeling effort, however, does not include solute transport and is not designed appropriately to answer the question of whether fracing can accelerate flow and transport from depth to ground surface. To evaluate that, one would need to run the model for flow and particle-tracking travel times before and after reservoir stimulation, and then take a difference between the results of the pre- and post-fracing cases. Without calculating a pre-fracing result for travel times from the model, one cannot analyze the effects of fracing. What's more, attempting to use a numerical model to simulate the fracing process itself is inappropriate and frankly, irresponsible. The scientific community has yet to produce a numerical model that can accurately predict the results of hydraulic stimulation of a petroleum reservoir flow on groundwater.

Software Selection

Myers utilized the U.S. Geological Survey's MODFLOW-2000 numerical computer model (Harbaugh and others, 2000) in his groundwater flow and transport simulations. The use of MODFLOW-2000 to simulate fully saturated one-phase flow (i.e., groundwater only) is fundamentally flawed in the complex system of the Marcellus shale and its overlying geologic formations. Specifically, MODFLOW-2000 is not equipped to model fracture porosity, multi-phase flow, or density effects, all of which are known to impact subsurface fluid flow in the Appalachian basin. In addition, Myers' fifth model scenario attempts to simulate the hydraulic fracturing process, something that MODFLOW-2000, or any other numerical groundwater model for that matter, cannot do with any degree of certainty.

Model Parameterization

Based on the length and detail we provided above regarding Myers' conceptual model, it is not surprising that we found his model parameterization to have numerous flaws as well. First and foremost, the subsurface geologic and hydraulic conductivity conditions prescribed to the model – shale overlain by a 1,500-m thick layer – equivalent to homogeneous sandstone – is not realistic. The subsurface geology of the Appalachian basin is comprised of alternating layers of varying lithology, each with unique thickness, extent, porosity, permeability, and geomechanical characteristics. Second, the use of a single hydraulic gradient data point from an area far-removed from his study area and associated with rock units deeper than the Marcellus shale is not valid. Third, the assumption of vertical, fully saturated single-phase (i.e., groundwater) flow throughout the entire post-Marcellus

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sedimentary section is not correct. Fourth, inclusion of a continuous, vertically oriented, high-permeability fracture zone (6 m x 6 m – equivalent to two SUVs back to back in each direction – with a height of 1,500 m) is implausible. These items underscore an important shortcoming in Myers' work – failure to incorporate realistic and factual data into his numerical model.

Myers' model is also lacking in terms of boundary conditions. Specifically, for a small-scale saturated simulation of 450 square meters, a groundwater model would have to have lateral boundaries to enable simulation of the governing behavior (e.g., constant head boundaries, prescribed fluxes, etc.). Groundwater flow will essentially be predominantly horizontal in the shale materials or any of the overlying aquifer materials sandwiched between low-permeability units (a multiple aquifer system). Lateral boundaries in aquifer materials are, therefore, very important for such a small areal scale of simulation. Instead, Myers assigned no-flow boundaries and thus artificially forces groundwater to flow only vertically upward.

Further, Myers' treatment of fractures is inadequate. He fails to: 1) discuss how the orientation of fractures relative to the contemporary stress field and overburden conditions affect natural fracture aperture, and hence permeability (Putra and others, 2003; Carter and others, 2011), 2) take into account how the fracing process is engineered to enhance the natural fracture network, 3) incorporate dual porosity (matrix and fracture) effects that exist in a shale gas reservoir that has been hydraulically stimulated (Harper and Kostelnik, 2010), and 4) incorporate fracture orientation as a parameter in his computer models. Fracturing and frac pressures would dissipate more rapidly horizontally than vertically due to shale anisotropy. Injected water would fill void space and not displace existing water or fill compressible storage.

Finally, aside from misapplying a groundwater model to simulate hydraulic fracturing, several aspects of Myers' fifth model scenario are also improbable. He injects 500 gallons of water per minute for five days, but the impact of that injection at the lateral boundary (approximately 20 m away in the longitudinal direction of the well and just 225 m away in the transverse direction) is only permitted to dissipate that water vertically. This is fundamentally flawed – flow dissipates horizontally in aquifers. The drain is subsequently only active for 60 days; after that, the pressure only dissipates through the formation vertically. In contrast, the pressure will actually dissipate through the path of least resistance, which will be the well itself, and will continue to do so from the well even after 60 days. In addition, a drain conductance that limits pressure dissipation through the well (such that only 20 percent is recovered) is a conceptual misrepresentation (why should the well be so resistant to outflow and not to inflow?). This construction is actually compensating for another misrepresentation; in reality, the fluid injected into unsaturated shale displaces mostly gas, which is why water is not being fully recovered – it subsequently remains within pore storage. Myers treats this as a "calibration" of his conceptual model, thus refuting all physical activity at the well, the purpose of which was to dissipate pressures for fluids (both water and gas) without disrupting the formation, and then seal it off altogether.

In contrast to Myers' model, Byrnes (2011) documented how high pressures along induced fracture faces in a shale reservoir result in the imbibition of fracing fluid into the highly water-

undersaturated shale.   As long as pressures are high (during fracing and if a well is subsequently shut in), this process continues. Once the well is flowed back and put into production, capillary pressures sufficient to cause further imbibition no longer exist, but enough capillary pressure is still present to effectively lock the already imbibed water in shale pores for geologic time. Specifically, Byrnes (2011) estimated that 70% +/- 10% of the frac fluid remains in the shale. The results of this modeling effort discredit the assumptions in Myers' model.

Another way to explain the inadequacies of Myer's model parameterization is to compare it to the analytical modeling efforts of ICF International (ICF, 2009). ICF prepared a technical evaluation of hydraulic fracturing, which included analytical modeling, in support of the New York State Energy Research and Development Authority (NYSERDA)'s Supplemental Generic Environmental Impact Statement (SGEIS) for New York's Oil, Gas and Solution Mining Regulatory Program. Such analytical efforts, although fairly simplistic, are helpful in assessing the reasonableness of more complex numerical models. ICF (2009) concluded that shale gas fracing does not pose the risk of significant environmental contamination to freshwater aquifers. This conclusion is based on the results of their analytical model, namely that: 1) the pressures associated with the hydraulic fracturing process would have to be sustained for a number of years before frac water and/or brine would reach shallow groundwater aquifers, 2) the volume of water used for fracing would only fill a small percentage of the void spaces that exist in subsurface rocks between the shale and aquifer, which precludes the existence of a fully saturated rock column, 3) a portion of the injected frac chemicals would not migrate with groundwater because they would become adsorbed to the organic-rich shale surfaces, 4) diffusion would also serve to substantially dilute the concentration of frac fluid chemicals in groundwater, and 5) groundwater flow directions induced by the fracing process (even if vertical toward shallow aquifers) would be reversed as the well is flowed back and subsequently produced for gas, based on pressure differentials between the shale reservoir and well bore.

Model Calibration

The standard modeling process follows a logical progression where data are systematically collected and integrated into a conceptual site model and then used to construct and calibrate a numerical model. During the calibration process, the model is calibrated and verified based upon existing data sets, subjected to sensitivity analysis, and if necessary, refined (through additional data collection and simulation). Calibration to enable prediction is therefore a multi-stage process where static and stressed conditions are evaluated to assess model responses to various measured conditions. Such multi-stage calibration is not presented. In fact, nowhere in the original paper or *Author's Reply* did Myers address model calibration in earnest, assign calibration targets, or compare real and simulated data from an actual test site. In contrast, the generalized simulation results presented in the article are discussed in the context of model setup, and the model's sensitivity to parameter changes are the results. At presented such sensitivity analyses should not be used for predictive simulation but to assess the critical data required to improve the conceptual and numerical models. However, Myers' model is not useful in this regard due to its unrealistic conceptualization, which has been discussed at length above. These flaws are clearly indicated by the presented simulation results. For example, Myers indicates for Scenario 5 that simulated flowback varied little with K_{sh} because it had been calibrated to

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20% of the injection volume. This statement indicates that Myers' model is insensitive to the value of K_{sh}. In reality, this variable likely exerts strong control on the flowback rate, and should be reflected in the model. During a proper calibration, the insensitivity of the K_{sh} parameter would have been corrected by revision of the conceptual model and boundary conditions, especially given the importance of this parameter to flow system. Given the inadequacies of the model and its misapplication, Myers' conclusion that fracing of the shale could lead to advective transport to aquifers in less than 10 years is highly suspect and not supported. In addition, the other findings presented are generally overstated and framed as if they were derived from a properly calibrated predictive model. Myers' claim that the interpretive model accurately and realistically simulates long-term steady state flow conditions is inaccurate and misleading as there are no data sets presented to ground the simulations to real-world conditions. He also indicates that most of the injected water in the simulation flows vertically rather than horizontally through the shale. We strongly believe this finding is an artifact of the model conceptualization and is not verifiable based on the model simulation or supported by real world data. The other findings suffer from the same model inadequacies and should certainly not be considered as facts as is claimed in the paper's discussion section. Based on the shortcomings we have noted, the simulation results cannot be considered calibrated or realistic and they should not be applied to draw conclusions on real-world scenarios.

CONCLUSIONS

The November 2012 *Groundwater* paper entitled "*Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers*" brings the American populace ever closer to the slippery slope of misinformation perpetuated by media regarding the shale gas industry. The lack of objectivity in Myers' work, along with an insufficient conceptual site model and inappropriately parameterized and calibrated numerical model, result in the polarizing conclusion that fracing-induced aquifer contamination in the Appalachian basin is imminent and unavoidable. In this rebuttal, we have identified the weaknesses of Myers' modeling effort and addressed each of them in turn, citing scientifically vetted research studies and peer-reviewed papers that speak to the data gaps we found.

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