EPA Science Advisory Board
Hydraulic Fracturing Research Advisory Panel
Public Teleconference February 1, 2016
Oral Statement of Bryce Payne

From: Payne, Bryce
Sent: Wednesday, February 10, 2016 11:10 AM
To: Hanlon, Edward <Hanlon.Edward@epa.gov>
Subject: Re: Bryce Payne written comments for oral comments made on 1 Feb

Mr. Hanlon,

Please find attached my written comments in follow up on my oral comments of 1 Feb to the HF water impacts Research Advisory Panel. Please replace any prior version I may have submitted with the attached version. Also, please note that Dr. Dennis Lemly and Dr. Brian Redmond have joined me in submission of this written.

Please confirm you have received the attached comment and that it has been posted and available to the Panel members.

Thank you,
Bryce Payne, PhD

Bryce F. Payne Jr., PhD comments to the

Hydraulic Fracturing Research Advisory Panel review of EPA draft Assessment Report on Hydraulic Fracturing during the meeting of 02/01/2016.

This comment was specifically written and intended for immediate delivery to and convenience of members of the Panel.

My name is Dr. Bryce Payne. I am the Director of Science and Technology for Gas Safety Inc., and a Senior Fellow with the Center for Energy, Environment and Sustainability (CEES) at Wake Forest University. This is the written comment submitted in conjunction with my oral comments delivered during the Panel teleconference on 1 February 2016. In submission of this comment I am joined by Dr. Dennis Lemly, of the Department of Biology, and Senior Fellow with CEES, at Wake Forest University, and, Dr. Brian Redmond, Department of Environmental Engineering and Earth Sciences, Wilkes University.

[Note: HF is used throughout this comment as an abbreviation for “hydraulic fracturing”, “hydraulically fractured”, or other variants referring to the hydraulic fracturing process or effects]

We want to commend this panel for the diligence and integrity displayed during your review of the EPA Assessment of the Potential Impacts of Hydraulic Fracturing …on Drinking Water Resources. While reading the 1/7/16 draft of this Panel's report noticed the following on Pages 11-12:

> "The conclusory discussion in Chapter 6 notes that fractures created during hydraulic fracturing can extend out of the target production zone and upwardly migrate. The EPA should delete these conclusions from the draft Assessment Report unless the EPA supports these statements with data or modeling."

My objective is to suggest that literature on out-of-zone HF is not rare, and, that the available literature clearly suggests a substantial likelihood that contamination of overlying shallow aquifers could occur when out-of-zone HF contacts a pre-existing fault or fracture system. It is important that "The conclusory discussion in Chapter 6 [that] notes that fractures created during HF can extend out of the target production zone and upwardly migrate" be retained in the report. We further suggest, that, as a subject within the EPA draft assessment and any related "conclusory statements", the subject of HF beyond the target production zone merits much more thorough and explicit consideration, not the unsupported arbitrary dismissal recommended in the current draft of this Panel's report to the EPA. In this regard, please consider the following.

OUT-OF-ZONE FRACTURING

HF can produce fractures that extend outside the target production zone, a result known as out-of-formation, or out-of-zone (OOZ) fracturing, which:

- Is a well known, documented, and studied problem (Fisher and Warpinski, 2012).
- Is known to routinely occur during HF of unconventional oil/gas fields (Fisher and Warpinski, 2012) where target production zones are often only 10s of meters thick (Bruner and Smosna, 2011).
- Results in common occurrence of fractures that extend 100s of meters vertically upward from the lateral bore of shale gas wells, extending more than 350 meters upward in 1% of HF intervals (Davies et al., 2012).
- Further results in such fractures routinely connecting with natural fracture systems to generate fluid communication pathways that extend 1000s of meters from the lateral bore of shale gas wells (Lacazette and Geiser, 2013).
- Consequently, OOZ fracturing can be reasonably expected to result in flow-permissive pathways extending from the depth of the fractured target production zone to shallow aquifers or the surface in profiles with natural faults or perforated by the many old or abandoned wells in heavily drilled oil/gas fields that often overlie shale gas fields.

The wording of the comment quoted above suggests that either data or modeling regarding "out-of-zone hydraulic fracturing" (OOZ HF) is scarce, or that it is a matter of little functional concern. Both are misrepresentations. Further, most reports on OOZ HF have been prepared by, for, or based on data from, industry. OOZ HF is of operational interest to industry because it results in nonproductive expenditure of financial and material resources, and because it can lead to problems during production, such as increased loads of produced water in the production stream. By at least as early as 2011 investigators reported data confirming hydraulically induced fractures extend hundreds of meters. When more sensitive seismic methods have been used to assess the extent of interaction of hydraulically induced fractures and pre-existing natural fracture systems, the effects of single HF stages were found to extend for kilometers.

Almost all such reports include explanations that such OOZ HF does not pose a threat to shallower aquifers, because the OOZ fractures do not extend vertically to the surface, or the shallower depths of aquifers. It should be noted, however, that each such argument for no plausible effects of OOZ HF on ground water quality requires highly, and inappropriately, compartmentalized reasoning. Two prominent cases in point are the review "Hydraulic Fractures: How Far Do They Go?" by Davies et al (2012), and a few months later a comment on that review by Lacazette and Geiser (2013), based on their data collected using tomographic fracture imaging (TFI).

Davies et al. (2012) reported that on average, over several gas shale plays, the probability of the longest fracture in a single HF stage extending over 350 meters vertically upward from the lateral well bore was about 1%. Closer examination of their presentation of data reveals that probabilities of upward vertical extents exceeding 200 meters were about 19% in the Marcellus Shale and 4% in the Barnett. Given many target shale formations are only tens of meters thick (Bruner and Smosna, 2011), it obviously follows that OOZ HF must occur in many more than 1% of HF stages. Even if one uses 1%, assumes that only 350-meter fractures will extend beyond the functional target zone, and an average of 8 HF stages per lateral well bore, then it would still follow that on average there will be a 350-meter OOZ fracture in at least every 12.5 HF lateral well bores. Nevertheless Davies et al. repeat the contention of other authors that,

"… stimulated hydraulic fractures have been proposed as a mechanism for methane contamination of aquifers located 1-2 km above the level of the fracture initiation in the Marcellus shale
(Osborn et al., 2011). Because the maximum upward propagation recorded to date in the Marcellus shale is 536 m this link is extremely unlikely (Davies, 2011; Saba and Orzechowski, 2011;
Schon, 2011)."

The proposed extreme unlikelihood, that stimulated hydraulic fractures could cause contamination of aquifers 1-2 km above, is dependent upon there being no pre-existing natural fracture system with which the induced fractures could interact. Other contentions by Davies et al. indeed suggest that such a natural fracture system should exist. For example, Davies et al. suggest that strata comprised of porous, low-strength rock dissipate the HF fluid and, therefore, provide one factor limiting the vertical extent of HF fractures. It follows necessarily that the same porous rock strata would be functional components of and imply the existence of a pre-existing natural fracture system. Further, there is the more general recognition that the sedimentary rock profiles, between local source rock and the overlying seal rock, must have durable or dynamic natural fracture systems in order to accommodate the movement of gas/oil from deep source rock to accumulate beneath the shallower seal rock to form conventional oil/gas deposits. Fountain and Jacobi (2000), and others, report such sedimentary rock bodies may often be faulted from surface or near surface to basement rock, and that such faults sustain fluid flow from deep formations. Then there are the findings discussed by Lacazette and Geiser (2013).

Lacazette and Geiser (2013) point out that fluid communication effects develop when HF fractures interact with natural fracture systems, and that the data reviewed by Davies et al was generated using microseismic methods incapable of assessing the extent of such effects. The fluid communication effects of induced artificial-natural-fracture interactions may extend for kilometers from the point of application of stimulated HF. Lacazette and Geiser report that in a single experimental well investigation, within an hour of HF, nitrogen gas from a single HF treatment reached a tomographic sensor observation well 1.5 km away. Such findings clearly suggest the interaction of stimulated fractures and natural fracture systems can provide plausible pathways for contamination of aquifers 1-2 kilometers above. That is, such contamination due to HF should not be merely dismissed as "extremely unlikely".

However, Lacazette and Geiser (2013) also state that the vertical extent of stimulated and natural fracture interactions ended at the overlying seal rock, which occurred at a depth of 725 meters. This would, once again, seem to provide an opportunity to invoke the occurrence of seal rock formations as providing an assurance of a barrier to vertical fracturing extent that could prevent contamination of shallower aquifers. Additionally, Fisher and Warpinski (2012) point out that the oriented stresses in rock that determine the direction of stimulated fractures cause such fractures to become horizontal at depths shallower than 300 to 600 meters below surface. That is, Fisher and Warpinski argue that stimulated fractures cannot reach the shallow depths of most used aquifers, 100-300 meters. Both these arguments (Lacazette and Geiser, and Fisher and Warpinski), though, require one to ignore commonplace reality of most shale gas fields, the spatial resolution of the seismic methods used, and the volumetric limitations of the HF process.

Shale gas fields often underlie developed conventional gas fields. Presumably in most such cases the deep gas shale, or other deep source formations, have provided some or all gas in the conventional deposits. That is, the intervening rock formations, between the source and seal rock, must have been flow-permissive, but not the seal rock, or the gas would not have accumulated. The current reality is that most such fields have been extensively drilled to produce the conventional gas, often to commercial depletion. This, in turn, implies that there is at least one type of pathway through the shallow, horizontal-fractures-only zone noted by Fisher and Warpinski, and through seal rocks at shallower depths, as noted by Lacazette and Geiser, i.e., old oil/ gas wells. In the U.S. and Canada there are millions of such old wells, a substantial portion of which are conducting fluids to surface (Dusseault et al., 2000; Kang et al., 2014). Consequently such wells provide pre-existing pathways at least for flow of fluids from below the conventional deposit seal rock, or horizontal-fractures-only zone, into shallower formations, including aquifers. If those aquifers are themselves overlain by aquitards, or comprised of layers with intervening aquitards, then the resulting contamination may be confined to the deepest or some specific layer within the aquifer, and will only be apparent where the contaminated aquitard is tapped.

We have observed in the field in the Trinity aquifer area in southern Parker County, Texas, that methane contamination appears to be confined to the water below the deepest aquitard. In areas of known methane contamination of ground water, we observed no elevated ambient air methane levels. However, near water well heads, or at night when irrigation systems using well water were operating, ambient air methane levels were elevated, in some cases over extensive areas indicating heavy methane contamination was present. That is, field observations of local rock, and the lack of methane emissions except through the contaminated aquifer below the deepest aquitard, suggest that the underlying seal rock is largely intact, but still heavy groundwater contamination is occurring. A plausible explanation is fluids pass up through the seal rock into the aquifer in select locations, perhaps old wells. Contamination is not observed at the surface except through water wells that penetrate the deepest aquitard, which functions as a secondary "seal rock" above the original.

Deep gas shale formations may exist under areas where conventional oil/gas deposits did not accumulate. As pointed out by Fisher and Warpinski and others, this condition can be expected to occur where faults allowed gas to leak off over geological time. In such areas there will be no old conventional wells to provide gas-carrying extensions of hydraulic-fracturing-activated deeper natural pathways to shallow aquifers or the surface. However, in such areas old wells are not needed to extend the hydraulic-fracturing-activated natural pathways, since the natural faults are themselves prominent components of those natural fracture systems reaching to depth and preventing accumulation of conventional gas/oil deposits.

The spatial resolution of tomographic fracture imaging (TFI) and other microseismic methods is about 5 meters. That is, such methods cannot resolve events or pathways less than 5 meters apart, in the case of TFI, differences within cubic volumes of rock 5 meters on a side (Lacazette and Geiser, 2013). Massive volumetric flows of gas can occur through features with dimensional limits much smaller than 5 meters, e.g., poorly cemented or uncemented old wells, natural faults and fracture systems.

Fisher and Warpinski (2012) point out that volumetric constraints on the HF process limit HF fractures to vertical extents of a few hundred meters. The HF process simply cannot pump sufficient fluid to fill and pressurize fractures longer than a few hundred meters. TFI is based the ability to detect seismic signals arising from slight movements of rock particles along the fracture path due to fluid pressure changes only, whether or not there is fluid flow or fractures are opened. That is, while HF requires actual fluid flow, the pressure-only impacts of HF on contacted fracture systems reach beyond the zone of induced fracturing. Consequently, it follows that the conclusion of both Fisher and Warpinski, and Lacazette and Geiser regarding observed upper limits of HF fracture extent are the result of an inability of the HF process to impose pressure increases at distances over a few hundred meters from the HF application point. There will similarly be a limiting distance past which the energy of the HF process cannot push the associated fluid pressure wave. Consequently, TFI simply cannot assess the flow-permissiveness of the locally contiguous fracture system beyond the limited distance over which the HF pressure effects dissipate. The TFI-unmapped remainder of the contiguous fracture system may or may not be permissive of fluid flow. It then also follows that just because the HF process cannot sustain sufficient pressures and flows to extend fractures beyond a few hundred meters, and TFI-detectable effects of the HF pressure wave a few to several hundreds of meters further, does not mean that there is not a pre-existing fracture system, contiguous with the HF-stimulated and TFI-imaged fracture system, capable of transmitting flows much further when the pressures of the HF stimulated shale are sustained. It also does not follow that the simple massiveness of the remainder of the overlying rock profile can be relied upon to provide a competent seal against upward movement of fluids from the target production zone through OOZ fractures to shallow aquifers or the surface. It would seem that the data and information available places the burden of proof on industry to confirm the widely industry espoused position that contaminating transmission of produced gas from the target production zone due to OOZ HF is not occurring.

OTHER IMPLICATIONS AND CONCERNS

“Blindness” due to Impracticality of Direct Measurement, and Implied Contamination Risks

For convenience and clarity, Wewill refer to the complex fracture systems that result from OOZ HF as reported by Lacazette and Geiser (2013) as hydraulically activated artificial-natural (HAAN) fracture systems. It is important to recognize that when natural gas migrates non-productively out of target production zones through HAAN fracture systems, there is no means in current gas wells to detect the volume or location of that loss. Some or all the fugitive gas may migrate back to an uncemented interval of the vertical well bore, accumulate in and migrate up the bore, and become apparent as pressure in one or more well annuli at the well head. In the importantly longer history of conventional wells, recurring annulus pressures are an important diagnostic of well integrity problems, but in unconventional wells annulus pressures are not reliably diagnostic for gas losses through HAAN fracture systems. Consequently, well integrity failure statistics based on annulus pressures (Davies et al., 2014) do not provide reliable insights into the frequency of occurrence (or non-occurrence) of gas loss through HAAN fracture systems, or related occurrences of contamination.

If the gas migrating in a HAAN fracture system moves away from the well bore, the gas will not be detected as annulus pressure, but will become apparent when it appears as gas contamination hundreds to thousands of meters above and away from the source area in the production zone. Gas migrating away from the production zone and well bore through HAAN fracture systems may arrive at shallow depths as relatively concentrated flows through more confined pathways, such as faults, old well bores, or much more diffuse pathways of unconfined natural fracture systems, or both. Consequently not all cases of contamination of aquifers by gas migrating from unconventional wells through HAAN fracture systems will be readily apparent. Only contamination cases heavy and localized enough to cause obvious problems will be recognized, but that recognition will not provide any reliable indication of the contaminating unconventional well.

In a conventional gas well, gas migration away from the well would be regarded as a loss of well control or a well integrity problem, and by rule and effect a contamination threat for other underground resources, e.g., groundwater. In contrast, in unconventional wells gas movement through HAAN fracture systems to the well bore is essential to production, but such wells have no means by which to determine if, when, or how much gas flows away from the well bore, and how much related contamination, is occurring, or where. In the absence of any such information, it is necessary to interpret information from methods that provide insight into the extent and capacity of HAAN fracture systems.

When considered collectively, the available data, as reviewed by Davies et al. (2102) and reported by Lacazette and Geiser (2013), the numbers of unconventional wells being drilled, and the geological context and history of unconventional gas fields suggest that such gas migration problems are likely, as is associated contamination of aquifers. Estimating the actual likelihood will require reliable data from rigorous and thorough studies of a sufficient number of gas contamination cases. Candidate cases should be those suspected to have been caused by non-productive underground gas flows from unconventional gas wells. The three most prominent and well documented such cases, Parker County TX, Pavilion WY, and Dimock PA have been specifically excluded from the data considered in the EPA HF water impacts assessment. Industry commitments to cooperate with EPA prospective studies in return for EPA abandoning the Parker County TX investigation were not fulfilled. Consequently, there are apparently no other comparably investigated cases with publicly available data for consideration by this Panel or in the EPA assessment. In addition, recently published reports on results of TFI indicate HAAN fracture systems extend much farther than previously believed (Moos et al., 2011; Lacazette and Geiser, 2013; and others by those authors and their colleagues), but, as nearly as we can tell, the EPA study coincidentally also did not include any of those publications. Consequently, the EPA HF water impacts study excluded relevant, recent literature and the most potentially informative cases of possible contamination due to OOZ HF. The study cannot be reasonably regarded as comprehensive or objective without inclusion of such sources and potential sources of information on the extent and effects of OOZ HF, which is inherent in the utilization of HF in shale gas and other unconventional gas/oil wells.

CONCLUSIONS

In conclusion, literature reporting actual data on OOZ HF is not rare. Reported data establish that OOZ fracturing is common, indeed, inherent in HF of shale gas and related wells. When interpreted in the context of broader literature and information, available data clearly suggest a substantial likelihood that when OOZ HF contacts a natural flow-permissive fault or fracture system, it is reasonable to expect contamination of overlying shallow aquifers. It follows logically that the same data also indicate that if faults are contacted even by within-zone hydraulically stimulated fractures, there is a plausible potential for contamination of overlying, shallow aquifers. It is, therefore, important that at least “The conclusory discussion in Chapter 6 [that] notes that fractures created during hydraulic fracturing can extend out of the target production zone and upwardly migrate” be retained in the Panel’s report. We further strongly suggest, that, as a subject within the EPA draft assessment, the subject of OOZ HF merits explicit and much more thorough consideration, along with resulting implications with respect to hydraulically fracturing into faults, whether within or outside of the target production zone. Further, OOZ fracturing presents serious implications with respect to the inability to detect, measure, and control nonproductive gas flows away from wells at depth, prevent and manage the long term increased shale gas release rates that HF will cause, including potential dangers of applying conventional well control practices to unconventional wells, and potential for such situations to result in effectively perpetual contamination (not detailed in this comment).

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