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Interactive comment on "Hydraulic fracturing in thick shale basins: problems in identifying faults in the Bowland and Weald Basins, UK" *by* David K. Smythe

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We want to voice our concerns about a number of issues with "Hydraulic fracturing in thick shale basins: problems in identifying faults in the Bowland and Weald Basins, UK" by David Smythe. Smythe seems to misunderstand a number of arguments from the literature (e.g. Fisher and Warpinski (2012); Llewellyn et al. (2015)). In their summary of numerical models of hydraulic fracturing fluid migration they focus much of their discussion on one of the first models (Myers, 2012) while offering little discussion of, or entirely neglecting subsequent models that account for shortcomings that were identified in the early model. The following paragraphs expand upon these misunderstandings, which should be addressed before the review of Smythe (2016) is complete.

1. Misunderstandings in the Literature:

There are two instances where Smythe seems to misunderstand arguments in the literature. The first, relatively minor, misunderstanding is about an argument in Fisher and Warpinski (2012). This misunderstanding reduces the evidence for Smythe's premise that faults can commonly communicate fluids from the depth of typical shale gas units to shallow drinking water aquifers. The second, more important, misunderstanding is about Llewellyn et al. (2015), which Smythe uses as a cornerstone of his paper to "prove" that hydraulic fracturing fluids have traveled via permeable faults from great depths to contaminate shallow drinking water aquifers.

1.1 Misunderstanding of Fisher and Warpinski (2012):

In the Introduction, Smythe (2016) writes of Fisher and Warpinski (2012), "The authors argue that if faults were conduits they would have leaked all the gas away by now. This is clearly false; the whole point of fracking is to release gas which is trapped and therefore unable to migrate." In this excerpt, Smythe has confused the order of the argument. Various publications (Fisher and Warpinski, 2012; Flewelling and Sharma, 2015) suggest that because there is still gas in the shale reservoirs there must not be highly permeable faults near or through the shale reservoirs. If highly permeable faults did exist, the hydrocarbons would have leaked out of the reservoir during the millions of years since the hydrocarbons were generated. Smythe has misunderstood the qualitative argument that the presence of hydrocarbons indicates that either there are no faults near the shale reservoir, or that if there are faults, they do not conduct fluids at a high rate.

Admittedly, recent modeling papers have shown that overpressure can exist near a permeable fault for longer than 300,000 years (Gassiat et al., 2013; Lefebvre, 2015), which counters the arguments of Fisher and Warpinski (2012) that the presence of gas within a reservoir indicates that there are no permeable/conductive faults nearby. But 300,000 years is a relatively short amount of time compared to the age of many source rocks, and there was some decrease in overpressure during the course of the simulation (Gassiat et al., 2013). So perhaps it is better to think of the Fisher and Warpinski (2012) argument in terms of rates. For example, if there is a highly permeable fault near a source rock, then the gas in the source rock would leave at a fast enough rate that the source rock would not have a high gas concentration remaining today (assuming it has been longer than 300,000 years since hydrocarbon generation). On the other hand if there is a fault near a source rock that still has a high concentration of gas present, then we can conclude that the rate of gas leakage via the fault is extremely slow and the permeability of the fault is small. There is an extremely low chance that this low-permeability fault could transmit a large amount of moderately buoyant fracturing fluid over the course of tens to thousands of years since it transmitted a very small amount of highly buoyant gas over the course of hundreds of thousands to tens of millions of years. The general concept of the Fisher and Warpinski (2012) argument stands: if there is a high concentration of gas in a source rock, there probably is not a highly permeable fault nearby.

1.2 Misunderstanding of Llewellyn et al. (2015):

In Section 5.3, Smythe summarizes and discusses a paper in which a chemical 2-BE and organic unresolved complex mixtures (UCMs) are found in a drinking water aquifer overlying the Marcellus shale (Llewellyn et al., 2015). Smythe misrepresents the findings as an unambiguous example of hydraulic fracturing fluids migrating from the depth of the Marcellus shale and misunderstands that gas found in the aquifer could have come from a different source and location than the 2-BE and the UCMs.

In an attempt to interpret Llewellyn et al. (2015) as proof that fracturing fluids migrated from the depth of the Marcellus to the aquifer Smythe writes, “Birdsell et al. (2015) have recently stated, in their review of frack fluid migration, that Llewellyn et al. conclude that ‘if fracturing fluid did contaminate the shallow aquifer, it is much more likely that the fluid came from a surface spill or from a shallow subsurface leak rather than from the Marcellus’. This statement is completely wrong and misleading. In fact Llewellyn

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et al. conclude that the most likely pathway for the groundwater contamination is initial passage up the wells from the Marcellus, followed by lateral passage along bedding planes, inclined gently upwards to the south, and finally by travelling vertically upwards along bedrock joint planes and fractures. Overpressured gas well annuli are also implicated as a possible driving mechanism." The statement of Birdsell et al. (2015a) is not incorrect as evidenced by: (1) a direct quote from a co-author of Llewellyn et al. (2015) (SC4, Engelder comment on Smythe (2016)), and (2) the following excerpts from Llewellyn et al. (2015) (bold added for effect):

1) "If HVHF fluids did contaminate the water wells, **it would be surprising if such contamination were due to fluids returning upward from deep strata**, given that (i) this has never been reported (6), (ii) the time required to travel 2 km up from the Marcellus along natural fractures is likely to be thousands to millions of years (31), and (iii) Fig. 6 shows that the Cl:Br ratios in the drinking waters indicate the absence of salts that would be diagnostic of fluids from the Marcellus Shale (e.g., flowback/production waters). **The most likely way for HVHF fluids to contaminate the shallow aquifers would therefore be through surface spillage of HVHF fluids before injection or by shallow subsurface leakage during injection.**"

2) "The data released here **do not implicate upward flowing fluids along fractures from the target shale as the source of contaminants but rather implicate fluids flowing vertically along gas well boreholes and through intersecting shallow to intermediate flow paths** via bedrock fractures. Flow along such pathways is likely when fluids are driven by high annular gas pressure or possibly by high pressures during HVHF injection. Such shallow to intermediate depth contaminant flow paths are not limited to HVHF but rather have been previously observed with conventional oil and gas wells. As shale gas development expands worldwide, problems such as those that occurred in northeastern PA will only be avoided by using conservative well construction practices, such as intermediate casing strings, proper cementation, and mitigating overpressured gas well annuli."

In addition to misrepresenting the certainty that 2-BE and UCMs came directly from the Marcellus, we feel that David Smythe misunderstands the argument that stray gas could come from one source (e.g. the target formation or any intermediate gas-bearing formation that is intersected by a well with a poorly cemented annulus) while the UCM and 2-BE come from another source. Even if the source of the 2-BE and UCM is related to drilling, it does not necessarily implicate that hydraulic fracturing fluids came from the Marcellus shale. For example, one possible source of the UCM and 2-BE is suggested to be drilling fluids associated with well remediation at much shallower depths. Excerpts from Llewellyn et al. (2015) follow:

3) "It is possible that the **provenance of the UCM and 2-BE was different from that of the stray gas.** Indeed, the most reasonable explanation for the natural gas impacts to water wells is that gas migrated from Welles 3-2H or possibly from multiple gas wells drilled on the Welles 3–5 pads due to excessive annular pressures and lack of competent annular cement that allowed gas to move vertically upward along the wellbore and into shallow uncased portions of bedrock fractures, including an identified fault zone (Table S1, Fig. 1, and Figs. S9 and S10)."

4) "Notably, the Welles 1 gas well pad was the location of a drilling fluid pit leak in August 2009 (Table S1). Further, well construction issues required remedial efforts in the Welles 3–5 series gas wells. Therefore, drilling fluids used in their installation could reasonably account for the observed foam impacts to household Wells 1–6 (Fig. 1C). **Since 2-BE and the UCM were identified together, drilling fluids might be the source of both.**"

2. Numerical Modeling of Fracturing Fluid Migration:

Smythe discusses previous numerical modeling studies of fracturing fluid migration towards aquifers at length, but he neglects at least one important critique and one modeling study. One critique that applies to the modeling studies of fracturing fluid migration (Myers, 2012; Gassiat et al. 2013; Kissinger et al., 2013; Cai and Ofterdinger, 2014),

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is the neglect of capillary imbibition (comment on Myers, 2012 by Saiers and Barth, 2012), which can sequester large volumes of fracturing fluids in the target formation so that they cannot migrate towards an overlying aquifer (Engelder, 2012; Engelder et al., 2014; Birdsell et al., 2015b). Reagan et al. (2015) accounts for imbibition, but their analysis focuses on gas migration rather than fracturing fluid migration.

Birdsell et al. (2015a) identify five stages of a well lifetime with respect to hydraulic fracturing: prior to drilling, injection of fracturing fluids, shut-in during which capillary imbibition can occur, production of hydrocarbons and other fluids, and after the well is plugged and abandoned. In addition to reviewing fracturing fluid migration, Birdsell et al. (2015a) set up numerical models that faithfully account for all five stages of the well lifetime while addressing the major concerns raised about the other numerical modeling studies (e.g. buoyancy due to salinity, capillary imbibition, injection and production, and overpressure). Their results are significantly different from previous numerical modeling studies that did not represent the combined influence of injection, imbibition, well suction, and buoyancy. For instance, well suction and capillary imbibition significantly reduce the amount of hydraulic fracturing fluid that can reach an overlying aquifer. Birdsell et al. (2015a) in fact considers a worst-case scenario of a high permeability overburden with a continuous fault or poorly cemented wellbore directly connecting the top of the shale to the bottom of the aquifer, but shows that adding well production and capillary imbibition can drastically reduce the amount of HF fluids reaching overlying aquifers. Birdsell et al. (2015a) also investigate the sensitivity of amount of fracturing fluids reaching an aquifer to a large number of parameters including fault/wellbore parameters, well suction, amount of overpressure, imbibition rate, relative permeability, overburden heterogeneity, and buoyancy. The Birdsell et al. (2015a) paper should be included in the discussion of modeling studies in Smythe (2016) Section 5 and Figure 9 since it represents the most current peer-reviewed modeling study of fracturing fluid migration and faithfully accounts for the five stages of a well lifetime and the dominant processes within each stage.

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