Seepage pathway assessment for natural gas to shallow groundwater during well stimulation, production and after abandonment

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ABSTRACT
Hydraulic fracture stimulation (HFS) of unconventional oil and gas reservoirs has become the focus of public concern with respect to fugitive gas emissions, fracture height growth, induced seismicity and groundwater pollution. We evaluate the potential pathways of fugitive gas seepage during stimulation and production and conclude that the quality of surface casing and deeper casing installations is a major concern with respect to future gas migration. The pathway outside the casing is of greatest concern, and likely leads to many wells leaking natural gas upwards from intermediate, non-depleted thin gas zones, rather than from the deeper target reservoirs which are depleted during production. We substantiate this argument with isotopic data from the Western Canada Sedimentary Basin. These paths must be understood and the probability of leakage addressed by mitigating methods such as casing perforation and squeeze, expanding packers of long life and controlled leak-off into saline aquifers. With a few exceptions, hydraulic fracture stimulation itself appears not to be a significant risk. These exceptions include situations involving fluids during the high pressure stage of HFS when (1) old well casings are intersected by fracturing fluids and (2) when these fluids pressurize nearby offset wells that have not been shut in, and particularly offset wells in the same formation that are surrounded by a region of pressure depletion where the horizontal stresses have also been diminished..

RÉSUMÉ
Stimulation de fracture hydraulique (HFS) des réservoirs de pétrole et de gaz non conventionnel est devenu le centre des préoccupations du public en ce qui concerne les émissions fugitives de gaz, la croissance de la hauteur de fracture, sismicité induite et de la pollution des eaux souterraines. Nous évaluons les voies potentielles d'infiltration d'eau de gaz fugitif pendant la stimulation et de la production et de conclure que la qualité du tubage de surface et profondes installations boîtier est une préoccupation majeure en ce qui concerne la migration de gaz avenir. La voie de l'extérieur du boîtier est de grande préoccupation, et entraîne probablement des nombreux puits qui fuient vers le haut à partir de gaz naturel, les zones de gaz minces non-épuisement des intermédiaires plutôt que de profonds réservoirs cibles. Nous avons l'appui de cette thèse avec des données isotopiques du bassin sédimentaire de l'Ouest canadien. Ces chemins doivent être comprises et la probabilité de fuite abordés par des méthodes d'atténuation telles que boîtier perforation et compression, l'expansion emballeurs de longue durée de vie et induit de fuite dans des aquifères salins. Stimulation de fracture hydraulique lui-même ne semble pas être un risque important à quelques exceptions près. Il s'agit notamment de situations impliquant des fluides pendant la phase haute pression de HFS lorsque (1) vieux tubages de puits sont traversés par des fluides de fracturation et (2) lorsque ces fluides sous pression les environs compensés puits qui n'ont pas été fermés dans et en particulier compensés puits dans la même formation qui sont entourées par une région de déplétion de la pression lorsque les contraintes horizontales ont également été diminué.

1 INTRODUCTION

There can be little doubt that the future energy supply of choice in North America will be natural gas, particularly from shale gas formations. The US Government's Annual Energy Outlook 2013 (US EIA, 2013) indicates rapid growth in natural gas use by industry, in electrical power generation and for export. To place the well issue into context, full development of the Marcellus Shale, which underlies much of northeastern United States, would require (with today's techniques) approximately 500,000 horizontal wells, each 2 km (6500 ft) long (~$7-10 million), with 15-20 fracture stages along the horizontal section of each well and 500 to 2000 m^3 (100,000 to 500,000 gallons) of water-based hydraulic fracture (HF) fluid for each fracture stage. Similar intense development has already begun in northeastern British Columbia, Canada. In the Horn River Basin play during 2011, slickwater HF volumes averaged 80,000 m^3/well (20 million gallons per well) over 20 stages in horizontal wells that were at least 2 km long (Johnson and Johnson, 2012).

The Energy Institute of MIT (2011) considered this expansion of the natural-gas industry in a " *carbon-constrained world*" and concluded that the "*environmental impacts of shale development are challenging but manageable*". An indication of this challenge is the recent evidence from the National Oceanic and Atmospheric Administration and the University of Colorado that " *a mix of venting emissions (leaks) of raw natural gas and flashing emissions from condensate storage tanks can explain the* (gaseous hydrocarbons) *we observe in air masses impacted by oil and gas operations in northeastern Colorado*" (Petron et al., 2012). These findings have recently been further substantiated by

NOAA and the University of Colorado using isotopic measurements to differentiate between industrial and feedlot sources (Tollefson, 2013).

While public concern has been expressed over the potential for shale gas development to cause environmental damage, such as flammable tap water and earthquake tremors, we believe that the real concerns are latent and long term in consequence. Foremost among these is contamination of the atmosphere and potable groundwater arising from inadequate annular sealing of natural-gas production wells. This is an old and stubborn problem (Cooke et al., 1983; Harrison, 1985; Erno and Schmitz, 1996; Dusseault et al., 2000; Watson and Bachu, 2009) that has not been resolved, a fact that is acknowledged by industry.

We believe that the contamination is latent in that it is not readily apparent or visible. We believe that documented natural gas emissions to the atmosphere strongly suggest that the emitted gas is a fraction of that which is migrating uncontrolled in and adjacent to the annulus of production wells because of faulty, ruptured or incomplete primary cement seals. There is new isotopic evidence from British Columbia to indicate that ¾ of casing gases are associated with non-target formations that discharge gas to the annulus of production wells (Muehlenbachs, 2012; Tilley and Muehlenbachs, 2013). Gas that leaks up around the casings or can otherwise escape the wellbore is then available for invasion of shallower formations including fresh-water aquifers.

The history of groundwater contamination is replete with such cases of latent and long-term contamination by chlorinated solvents, gasoline, pesticides and perchlorate. Identification emerges through new analytical instruments, disruptive technical paradigms and field-focused research (Pankow and Cherry, 1996; Jackson, 2004).

Therefore in this article we argue that the principal environmental concern from increased use of natural gas comes not from hydraulic fracture stimulation but rather from the leakage of gas from non-target formations into poorly cemented borehole seals that allow the gas to escape to the surface or to be vented from the well casings. We begin by discussing the structure of an well. as it is central to this argument that the well itself, not hydraulic fracture stimulation, is of primary concern.

We then consider how deep hydraulic fractures develop during stimulation and how they might interact with shallow groundwater zones or with pre-existing conduits and then consider wellbore leakage between deep zones and the surface. We conclude by substantiating our argument that the intermediate zones are the source of gas-well leakage and by discussing monitoring criteria for groundwater quality and hydraulic head characterization in areas undergoing shale gas development.

2 UNCONVENTIONAL GAS WELLS

Figure 1 represents a typical well construction for an unconventional gas well. One may view the entire depth as being comprised of three zones that are approximately defined as:

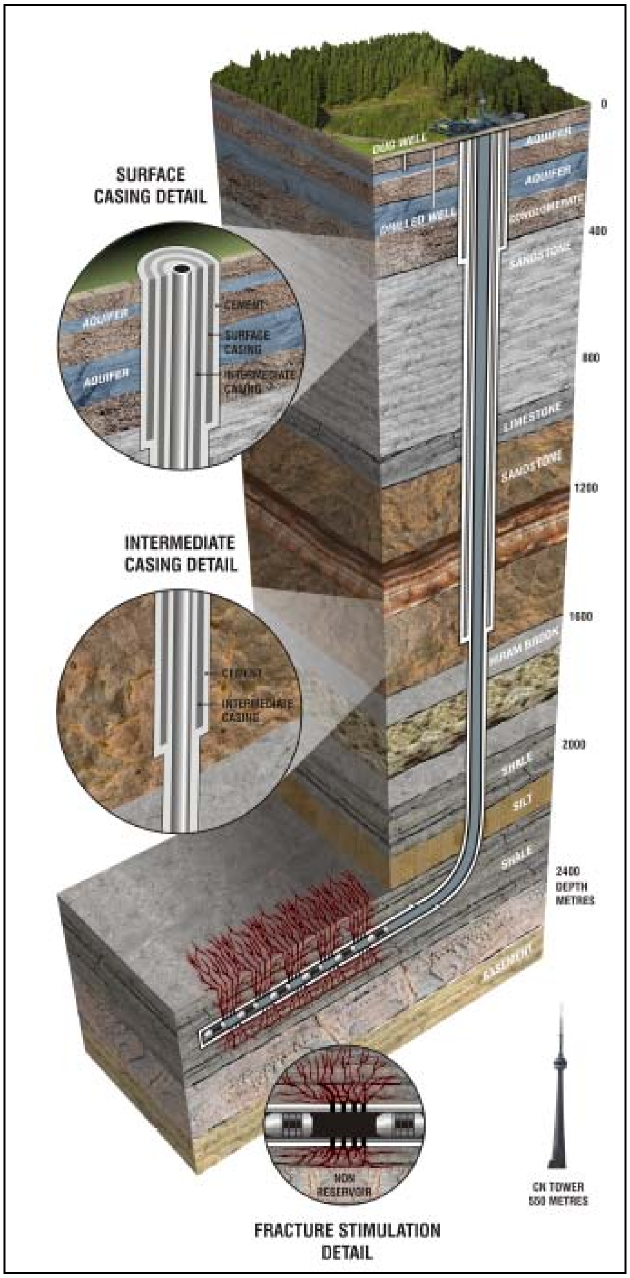

Figure 1. Schematic of a horizontal well with induced shale fractures and shallow aquifers. Note casing details and depth of stimulation (Courtesy: Apache Canada).

1) A shallow zone containing potable groundwater or slightly brackish water that may be suitable for a variety of agricultural or industrial uses.
2) A deep zone consisting of the target production formation and its cap rock including all strata affected directly by hydraulic fracture stimulation of the horizontal wellbore as well as several hundred meters of overlying strata.
3) An intermediate zone between these two zones, where there exists a sequence of strata of

differing porosities and permeabilities containing formation fluids (saline water, natural gas, oil) in contact with the production casing, which may or may not be cemented to the adjacent rock.

The conductor casing or pipe shown in Figure 1 prevents soils from caving into the borehole during drilling operations. The surface casing (a) guides drilling fluids to the surface without interaction with shallow strata during the drilling phase of well construction, (b) protects shallow strata from all produced or injected fluids during the life of the well, and (c) is used to affix a wellhead so as to provide control of flow and pressures of fluids going into and coming out of the wellbore. It is considered good practice by most regulatory agencies to place the bottom of the surface casing below the base of potable water.

The surface casing is cemented completely to surface, and if there is any difficulty in getting the cement to the surface, it is necessary to do remedial cementing using a small tube ("tremie pipe") lowered behind the casing, a challenging process that is difficult to execute with excellent results. Alternatively, remedial cementing is conducted by perforating the casing and injecting cement to seal off a saline aquifer or an annular space ("squeeze cementing") that might conduct fluids.

Sometimes the production casing is cemented all the way to the surface, or a substantial distance into the surface casing if it is deep enough. The standard cement slurry should be placed at a minimum density (~ 2.05 g/cm^3), although there are light-weight cements for cases of lost circulation of cement during casing cementing operations. The production tubing is hung in the production casing, attached to the wellhead, and isolated from the production casing with a pressure sealing mechanical packer at the base of the tubing as shown in Figure 1.

3 HYDRAULIC FRACTURE STIMULATION (HFS)

The large volume of liquids used in a single unconventional gas well during fracturing (up to 80,000 m^3 in some Horn River wells in British Columbia over a 10-day, 20-stage fracture treatment) means that the scale of volumetric strains placed on the reservoir is an order of magnitude greater than in almost any previous conventional oil and gas well fracture treatments.

Consequently, HFS has caused concern; it has been cited as being responsible for contamination of shallow groundwater above the Marcellus and Utica Formations in Pennsylvania (Osborn et al., 2011), a process of vertical migration of "fluids and contaminants" to the surface that has been simulated by Myers (2012). We now consider this possibility.

HFS proceeds from the toe to the heel of the horizontal well in individual fracture stages as shown in Figure 2. The fractured length is about 1.5-2.5 km (1-1.5 miles) and, because of the geometry of the well, the last fracture stage at the heel is kept far from the vertical part of the well so that the fracture volume does not intersect with the vertical section of the well through the intermediate depth zone.

Figure 3 is a schematic cross-section, not to scale, of the disposition of the fractured horizontal well section in a shale gas reservoir, with the overlying strata represented schematically. The hydraulic fractures at each stage are represented as a series of thin lines to indicate that the fracturing process, which is implemented at fluid injection rates of up to 10 m^3/min, opens several natural fractures hydraulically and allows these fractures to be propped open with a granular agent (proppant). The induced fractures predominantly develop in the plane perpendicular to the orientation of the least principal stress, which in deep gas reservoirs (> 2 km or >6.500 ft) is usually one of the two horizontal stresses (Zoback, 2010; Zoback et al., 2012).

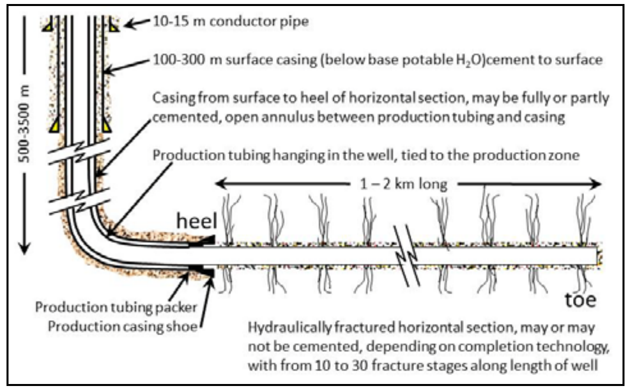

Figure 2. Schematic of the heel and toe of a horizontal well that has been hydraulically fractured

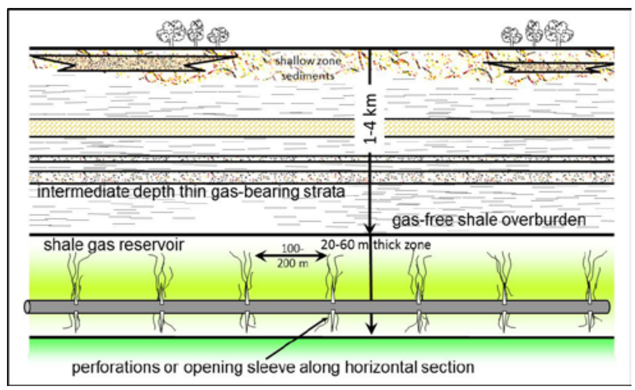

Figure 3. Schematic of vertical fracture propagation as a function of depth of stimulation. Note the presence at an intermediate depth of thin gas-bearing strata.

However, it is now understood that the volume of the rock mass that has an enhanced transmissivity – the product of permeability x rock volume thickness – because of the fracturing operation can be far larger than the volume of rock that has been reached by the proppant itself. This effect arises because the significant volumetric strains in the region close to the fracturing point cause strains in the rock mass and the high injection pressure reduces the frictional strength along natural joints. These processes lead to wedging open of more distant fractures, and most importantly, to shear displacement across pre-existing natural fractures (see Figure 4). Because a natural fracture is a rough surface, a small shear displacement (millimeters in scale) will prevent it from fitting back together symmetrically when the active fracturing pressure is allowed to dissipate following stimulation. This is called shear dilation and it leads to an enhancement of the transmissivity of the naturally fractured shale-gas reservoir, opening up minute flow paths far from the proppant zone but still within the shale-gas reservoir.

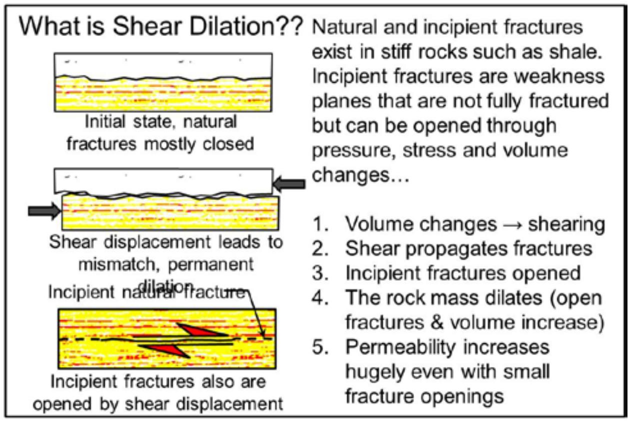

Figure 4. Shear dilation enhances the flow capacity of the shale gas rock mass

There is nothing to be gained commercially in forcing shear dilation to take place any significant distance outside of the shale- or tight-gas reservoir, and monitoring and modeling are used to design each fracture stage so that the fractures remain within the target zone (see Fisher and Warpinski, 2012; Davies et al., 2012). The propped zone, combined with the zone of shear dilation, is called the "stimulated rock volume or SRV". This is generally considered to be an ellipsoidal volume, as shown in Figure 5, which has grown upward more than downward with its shape being a complicated function of the natural stress field, the natural fabric of the rock mass, and the strategy used during HFS.

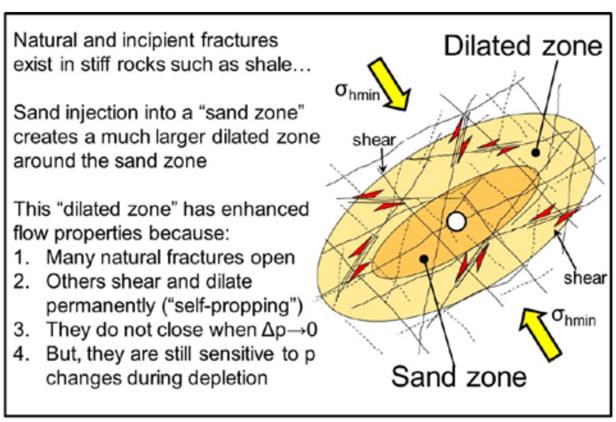

Figure 5. The stimulated rock volume (SRV or SV) is the total volume of rock mass surrounding the fracture point where enhanced transmissivity has been generated.

It is conceivable that HFS, when conducted in structurally-deformed regions or areas where the deviatoric stresses are close to a critical slip condition (see Zoback, 2010, chapter 11), may cause lateral pore-pressure transmission to nearby stressed faults or deep fracture systems and may temporarily enhance gas seepage before production begins (i.e. when the pressures in the production horizon are still elevated before drawdown). Such eventualities involve complex processes requiring further research and seem limited to distances of a few hundred meters. Identification of faulted zones and stipulation of a stand-off distance for HFS activity seems like a reasonable conservative approach in such cases.

4 SEEPAGE PATHWAYS ASSESSMENT

Several factors inhibit the migration of induced fractures to the surface. We consider these in turn.

4.1 Production well construction

HF is done through the production tubing that is sealed from the production casing (see Figure 2), not through the production casing itself, and the annular pressure on the production casing is monitored. If there is a breach in the production casing, it is detected immediately, so the risk that the production casing becomes pressurized and then loses fluid confinement ("seal") somewhere along its length becomes extremely small.

The bottom part of the production well is almost always extremely well-cemented because the cement, as it was placed and as it set, was under a high hydrostatic head, densifying it through some water loss to the surrounding strata and producing an optimum seal for the quality of cement used. Therefore, there is a very low probability for a HF in the horizontal section of the well to move laterally, intersect the vertical section of the wellbore a considerable distance away, and propagate up along the wellbore during injection. This is especially so because the horizontal section is drilled parallel to the minimum principal stress in situ, so induced fractures should be propagating dominantly at 90° to the horizontal section.

4.2 Orientation of induced fractures

HF in zones where the principal stress orientations are appropriate (i.e., the minimum principal stress is horizontal) will cause the fractures to rise preferentially, rather than be vertically symmetric around the fracture point (Figure 5). This is because the fracture gradient (the minimum stress gradient) is on the order of 18-23 kPa/m (0.80-1.0 psi/ft) depending on the geological history, but the density of the fracturing fluid is perhaps 1,000 to 1,300 kg/m^3 (i.e., a specific gravity of 1.0-1.3, depending on the amount of suspended proppant), producing a vertical pressure gradient in the fracture of about 10 to 13 kPa/m (0.44-0.58 psi/ft).

The gradient difference leads to a greater driving pressure at the top of the fracture than at the bottom, leading to preferred fracture rise. The maximum fracture growth height appears to be of the order of 600 m in various US shales including the Marcellus and Barnett shales, and around 1100 m offshore (Davies et al., 2012; Fisher and Warpinski, 2012) in exceptional circumstances. Beyond such vertical heights, natural fractures in the form of joints, faults and bedding-plane partings arrest vertical growth by allowing leak-off into multiple naturally fractured horizons or saline aquifers (Warpinski and Teufel, 1987).

4.3 Imbibition of Injected Fluids and Associated Strain

Some portion of the injected HF fluid flows back at the end of each HF stage, some is accommodated within open or partially open fractures in the shale gas reservoir, or is absorbed by the shale itself. For example, the Marcellus Shale has a water-phase porosity approaching irreducible saturation (Soeder, 1988; Ryder and Zagorski, 2002), meaning that the water is held by strong capillary forces. Therefore, irrespective of any potential gradient, the availability of brine for migration from the Marcellus to shallower horizons as claimed by Warner et al. (2012) is unlikely.

There is some permanent volumetric strain associated with hydraulic fracturing, but it is likely to be on the order of 10-30% of the volumes injected during the fracturing. Furthermore, it is feasible to measure this strain indirectly through the use of sensitive inclinometers (‘tiltmeters’), therefore this is amenable to explicit quantification and, if required, reporting to the regulatory authorities (i.e., not on all wells in a field, but perhaps for every 20th HFS well, or for the first ones in a region).

4.4 Effect of Uplift and Surface Erosion

In most parts of the world where sedimentary basins have been uplifted and subsequently eroded (all shale gas basins identified to date are uplifted, eroded basins), the stresses in the earth become redistributed in such a way as to create a zone from 100 m (300 ft) to perhaps as much as 1000 m (3,000 ft) thick where fractures will not tend to rise vertically, but will turn and propagate horizontally, parallel to bedding, because the vertical stress is now the least principal stress (Dusseault, 1977).

For example, Figure 6 shows a carefully measured case in southeastern Alberta, showing that above a depth of ≈350 m (~1,100 ft), the natural stress regime leads to horizontal fracture propagation and, below ~400 m (~1,300 ft), induced fractures will propagate vertically (Nadeem and Dusseault, 2013). A HF initiated in a horizontal well at a depth of 425 m (1,400 ft) rises because induced vertical HFs tend to rise much more than they tend to drop, but it will encounters the depth region where the stress turnover exists and start to propagate horizontally, and also be more influenced by the bedding. This stress condition provides a further barrier to the upward migration of fracturing fluids in most onshore geological environments.

4.5 The Nature of the Overlying Strata

There generally exist significant thicknesses of low-permeability strata overlying shale-gas reservoirs. These overlying strata may range from stiff, naturally fractured rocks as above the Utica Shale, or they may, as in the case of the Western Canada Sedimentary Basin, be overlain a thousand meters or more above the reservoir by ductile fine-grained strata that have essentially no natural fractures. In the latter case, the ductile shale strata

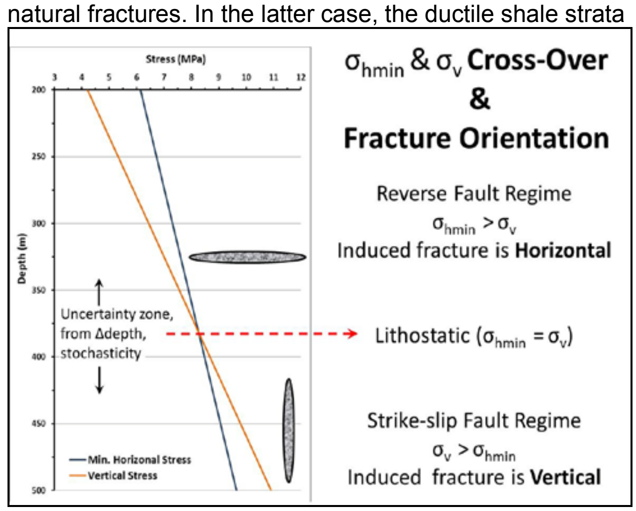

Figure 6. The orientation of fractures, stresses and gradients, Milk River Fm., north of Medicine Hat, Alberta

at shallower depths would not be impaired as seals because the actual hydraulic fracture openings are far deeper, and the strains at the depths of the shallow ductile shales are infinitesimal. In the case of stiff, naturally fractured overburden, it is clear that the overlying strata have acted as seals against upward migration of gas because the shale-gas reservoirs are still intact, several hundred million years after the gas formed.

Even where there is gas seepage from depth (e.g., Stahl et al., 1981; Fountain and Jacobi, 2000) it has been shown (Brown, 2000) that such gas seepage can be low enough to not deplete the reservoir. Nevertheless, there is a concern that the volumetric changes from deep fracturing could cause rotational distortion (bending) of the overlying strata, perhaps enough to open new pathways far above the zone in which the fracturing took place. Suffice it to say, naturally-occurring gas seepage in shallow bedrock is well documented (e.g., Rauch et al., 1984; Fountain and Jacobi, 2000; Molofsky et al., 2011) even if the gas-migration pathways are poorly understood.

4.6 Hydraulics of Upward Fracturing Fluids Migration to Shallow Groundwater

Myers (2012) postulates that hydraulic fracturing might cause a condition whereby a shale-gas reservoir, similar to that shown in Figure 1, is connected with pre-existing vertical fractures to the shallow zone aquifers shown at the top of this Figure. The critique by Cohen et al. (2013) is sufficient to dispense with the extraordinary simulation of this hypothesis by Myers (2012) but omits addressing the improbability of it occurring because of hydraulic fracturing.

It is possible to estimate the minimum hydraulic head in a shale-gas reservoir needed to lift HF fluid 1,500 meters (~4900 ft) through sandstone and shale " to near-surface aquifers through natural pathways" (Myers, 2012, p.873). In theory, the hydraulic head (i.e. elevation head + pore-pressure head) in the reservoir must at least equal the head in the shallow aquifer, and an open pathway must exist. A hydraulic head of 1500 m or ~4,900 ft (pore pressure = 0 or atmospheric at the water table) above the shale-gas reservoir, which is chosen as the reference datum (elevation = 0 m), must be sustained for a long time to allow the HF fluids to flow to the aquifer.

Assuming a fluid density of 1050 kg/m^3, the hydrostatic reservoir pressure is ~16 MPa at 1500 m depth. High pressure injection is used for HFS to achieve injection rates (>8 m^3/min) to counteract the leak-off potential of the formation being fractured. The high rates are needed to achieve rapid so that the HFS stimulation can result in sufficiently distant proppant transport and maximization of the stimulated volume. The surface pressure can be as high as 50-60 MPa (~8500 psi). 50 MPa is equivalent to a static head of > 6km! (i.e., 50+16 = 66 MPa ÷ 1050 kg/m^3 ÷ g = 6400 m) at the fracturing depth, but this is not the pressure in the reservoir some distance from the well because of all the pressure losses in the wellbore, through the fracturing ports in the near-wellbore environment. The actual reservoir pressure some distance from the well (e.g. 50 m) during HF is on the order of 10% to 20% above the fracture opening pressure.

For vertical fractures in shale gas cases, the fracture pressure is about 0.8 to 0.9 × $\rho_r \cdot \bar{g} \cdot Z$, where ρ_r is the mean density of the rock column, usually on the order of 2400-2500 kg/m^3. At Z = 1500 m, this is ~30 MPa, still a pressure equivalent to ~3000 m of fluid head. However, the induced fractures are open only a modest distance beyond the proppant transport zone because of further dynamic pressure losses in the small aperture fractures, so the high pressures decay fairly rapidly with distance from the hydraulically opened zone.

Once the proppant is placed, a slickwater injection period usually takes place to promote shear dilation and stimulation beyond the propped zone to generate the stimulated volume. This may last from an hour to perhaps 5-6 hours for a very large fracture treatment stage, but, as mentioned previously, the treatment is designed so that the fracture height is not significantly beyond the height of the target horizon, and as soon as the HFS is finished, flow back is immediately initiated, so that the pressure is dropped back to the original reservoir pressure. The whole fracture stage may last up to 12 hours, usually far less for thinner horizons, therefore the high pressure phase lasts for a short time, relatively speaking.

To intersect aquifers 1500 m above the fracture zone requires that a pathway exists or is generated during the fracturing process. The probability of either of these is extremely small. The reservoir fluid pressure at 1500 m depth will be about 16 MPa in typical shale gas plays. Hence, the pressures applied at the surface are not relevant.

Should significant volumes of HF fluid migrate out-of-zone, i.e., above the target formation, leak-off into pre-existing fracture systems or aquifers (de Pater and Dong, 2009) takes place to dissipate the remnant excess pressures. Therefore the short-term additional pressure increment applied at the ground surface by a fleet of HFS trucks is largely unavailable to lift the HF fluid to the surface, and this explains the measured fracture height growths of less than 600 m (~1800 ft) reported by Davies (2012) and Fisher and Warpinski (2012).

It is also known that the microseismic volume back-calculated during HFS is much smaller than the injected fluid volume; the energy recorded by microseismic arrays is typically well below 1% of the HFS treatment energy that gets to the reservoir. This difference reflects the large frictional losses occurring during the process of HFS as well as the aseismic behavior of the hydraulic fracture dilation (Cipolla et al., 2012). Opening a fracture involves a great deal of work: qualitatively, $W \sim F \cdot d \sim \Delta\sigma \cdot A \cdot \hat{w}$, where $\Delta\sigma$ is the difference between the induced fracturing pressure in the formation and the fracture closure pressure, A is the area of the fracture (thousands of m^2), and $\hat{w}$ is the mean fracture aperture. This work is aseismic, and consumes almost all of the energy that is not dissipated by frictional losses in fracture flow. Only a small (but important) remnant amount of energy is dissipated by the seismic slip of surfaces giving rise to the measured microseismicity that is used to delineate the stimulated volume in the rock mass.

Significant out-of-zone vertical migration of fracturing fluid will occur only in the case of the target formation being penetrated by a nearby abandoned or producing well with poor cement completion, a corroded casing, or some other pathway (open perforations) that could allow the fluid injected above fracture pressure to escape from the target formation. Such an event occurred in Alberta recently (see below) when a horizontal well came within 129 m (423 ft) of an off-set well producing from the same formation; the result was a surface release of fracturing fluid, brine and oil around the off-set well.

4.7 Design of Hydraulic Fracture Stimulation

The companies that undertake hydraulic fracturing use mathematical models and monitoring data to design their fracturing patterns in such a way that the actual fracturing zone, including the region within which there is a beneficial perturbation of the natural fractures (the stimulated rock volume or SRV), does not extend significantly beyond the top of the shale-gas target zone. To go beyond the zone in which the shale gas is found is merely a waste of money.

It also requires a great volume of additional fluid injection to go far beyond the top of the stimulated zone. As a fracture grows in height, it also grows in length and aperture. To double the height of an ellipsoidal fracture requires a volume increase of eight times (L^3). Models and predictions in HFS may be poor, but, once calibrated, not by such a factor. Errors that lead to fracture growth 100's of meters above the top of the target zone are extremely unlikely because of the huge additional volumes needed.

It is understood that mathematical models of high-pressure, high-rate HFS are semi-quantitative because of simplifications made regarding the stress field and the presence of natural fractures whose orientations are unknown (Tutuncu et al., 2012), while at the same time a deeper understanding of the HF process is undergoing rapid improvement (e.g., Gu et al., 2012; Zoback et al., 2012) and will presumably be incorporated into future mathematical models.

4.8 Production from Shale-Gas Reservoirs

Depletion during production of the shale-gas reservoir is the goal of drilling and HFS. It is expected that from 40% to 60% of the total gas in place will be produced from the shale gas zone over a 10-25-year well life. The volumetric strains associated with the depletion of the pressures are extremely small because the framework of the rock is exceptionally stiff. Calculations suggest that these volumetric strains will generate only small strains in the overlying rock, not sufficient to affect the natural fractures in those cap rocks. Following production, the depleted shale-gas formation become a zone of low regional pressure and is more likely to induce brine flow into it than to allow gas flow to escape.

5 SUMMARY AND CONCLUSIONS

Based on a consideration of the mechanisms and pathways, it seems reasonable to conclude that the risk of HF fluids or gas from the stimulated zone rising up into the intermediate zone during or after fracturing is remote, albeit not impossible. Because operators have an economic incentive to avoid loss of HF fluids into overlying zones that are non-productive, and because a great deal of additional driving volume is required to significantly grow the fracture height, there is reason to believe that the chances of dramatic fracture rise toward shallower depth and intersection with shallow aquifers, remote as they are, will become even lower as the companies perfect their techniques.

This analysis ignores the possibility that an inexperienced operator or human error may lead to an event where HF fluids penetrate a shallow aquifer because of. This happened recently in Alberta where instead of a 1.5 km (4900) HF injection, it took place at 136 m (446 ft) depth because of a botched perforation operation (ERCB, 2012b), followed by errors that led the operators to believe they were fracturing at target depth.

Abandoned or active wells that intersect the hydraulic fracturing volume wells constitute the seepage pathway of greatest risk for hydraulic fracture fluids. The most serious fluid communication risk during hydraulic fracturing is the possible intersection of the fractured zone with offset wellbores that pass through the SRV created by the hydraulic fractures. If the quality of the cement and completion of the offset well is poor, it is feasible for fracturing fluids to move laterally to the offset vertical cased wells then upward along the annulus between the casing and the rock.

If the offset well is an old producing well exploiting the same formation as a new shale-gas horizontal well, the effect of ‘stress depletion’ associated with its pressure depletion due to production from that formation will influence the extent of the SRV. This effect reduces the horizontal stress in the depleted region so that hydraulically induced fractures will tend to propagate preferentially in that direction. In such a case it is essential that the old producing well be shut in prior to hydraulic fracturing of the new well.

A recent case in Alberta (ERCB, 2012a) determined that a horizontal well had been drilled to within 129 m (423 ft) of an offset well that subsequently discharged ~ 500 barrels (21,000 gallons or 80 m3) of hydraulic fracturing and formation fluids at the surface when the new well was fractured. Experience in the Barnett Shale of Texas indicates that a distance of ~200 m (~600 ft) is sufficient to allow such interwellbore communication (M.D. Zoback, Stanford University, personal communication, 30 November 2012).

It appears to us that the migration of hydraulic fracturing or formation fluids including natural gas to the surface as a result of deep hydraulic fracturing of typical shale-gas reservoirs is most unlikely. Rather, the actual threat to shallow groundwater contamination is likely to come from a combination of factors involving the characteristics of annular cement seals of production wells and the presence of natural gas in intermediate zones between shallow aquifers containing potable groundwater and the deep shale-gas formations to be developed. This possibility is considered by Dusseault et al. (2000) and Jackson et al. (2013).

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