Numerical modeling of gas and water flow in shale gas formations with a focus on the fate of hydraulic fracturing fluid

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ABSTRACT (150-200 words)

Hydraulic fracturing in shale gas formations involves the injection of large volumes of aqueous fluid deep underground. Only a small proportion of the injected water volume is typically recovered, raising concerns that the remaining water may migrate upward and potentially contaminate groundwater aquifers. We implement a numerical model of two-phase water and gas flow in a shale gas formation in order to test the hypothesis that the remaining water is imbibed into the shale rock by capillary forces and retained there indefinitely. The model includes the essential physics of the system and uses the simplest justifiable geometrical structure. We apply the model to simulate wells from a specific well pad in the Horn River Basin, British Columbia,
where there is sufficient available data to build and test the model. Our simulations match the water and gas production data from the wells remarkably closely and show that all the injected water can be accounted for within the shale system, with most imbibed into the shale rock matrix and retained there for the long term.

TEXT

Introduction

The combination of high-volume hydraulic fracturing (HF) and horizontal drilling has enabled a boom in natural gas (and oil) production from organic-rich shales in North America over the past decade.\(^1\) HF involves the injection of large volumes of aqueous HF fluid (typically around \(2 \times 10^4\) m\(^3\) per shale gas well\(^2\)–\(^5\)) into the target shale formation at high pressure in order to fracture the rock. Figure 1 shows a diagram of a typical horizontal shale gas well. The HF fluid used to fracture the shale is predominantly water (so-called “slickwater”), but also contains sand proppant to hold the created fractures open as well as chemical additives to modify the fluid properties.\(^6\) Much of the injected HF fluid does not return from the well as “flowback” or “produced water” after gas production begins. The proportion of HF fluid that returns is commonly between 10–30\% but varies among wells and formations, from as low as 5\% in the Marcellus Shale to as high as 100\% in the Barnett Shale.\(^2,3,6-10\) Uncertainty over the fate of the HF fluid that remains underground has driven both public concern about potential environmental contamination and interest from the oil and gas industry to determine the impact of the remaining HF fluid on gas production.\(^6,10-12\)
Figure 1. Illustration of a horizontal shale gas well (top) with the model representation shown below it. Hydraulic fractures are created at regular intervals along the horizontal well. The fractures are represented in the model as rectangular prism fractures perpendicular to the well. The model fracture representation includes the dark gray propped inner region of the hydraulic fracture that contributes to gas flow, and the light gray un-propped outer region of the hydraulic fracture that is open during HF injection but closes afterward. The dashed orange box shows the numerical model domain. The red arrows represent gas flow out of the shale matrix during production, and the blue arrows represent HF fluid flow into the shale matrix during hydraulic fracturing. Not to scale.

From an environmental perspective, there is concern that HF fluid could migrate upward and contaminate drinking water aquifers.\textsuperscript{6,10,13-17} Chemical additives typically comprise 0.5–2% of the HF fluid, and while most of the commonly used chemicals are biodegradable and/or non-toxic,
many others are of unknown toxicity, and some are toxic and/or confirmed or suspected
carcinogens.\textsuperscript{10,18-22} Once injected into the shales, the HF fluid mixes with the resident brines that
often contain metals, salts, and radionuclides.\textsuperscript{10,23-25} Most North American shale gas formations
are deep (the mean HF depth is 2,500 meters\textsuperscript{4}) with substantial vertical separation distance between
the top of the hydraulic fractures and drinking water aquifers (often 1,000 meters or more).\textsuperscript{10,26-28}
Observational and modeling studies indicate that HF fluid is very unlikely to migrate upward
directly through such a substantial geological barrier.\textsuperscript{15,16,28-30} However, natural subsurface
features, such as faults and fractures, and man-made features, such as oil and gas wells, could
potentially provide permeable pathways for upward flow, especially if intersected by hydraulic
fractures.

Several numerical modeling studies have found that HF fluid could migrate upward along
permeable pathways from deep shale formations to drinking water aquifers under certain
conditions.\textsuperscript{13-16} Those studies have been notably criticized for unrealistic model conditions
because, among other reasons, they are one-phase models that do not include the two-phase flow
process of capillary water imbibition into the shales.\textsuperscript{30-34} Gas-producing shales are typically water-
wet, have low water saturation, and have very small pores with associated very high capillary
pressure, which suggests that water injected into fractures in those rocks would spontaneously
imbibe into the shale rock “matrix”.\textsuperscript{34-40} One prominent hypothesis proposes that capillary
imbibition draws the injected HF fluid into the shale, that the capillary pressure will retain the HF
fluid in the shale for the long term, and that imbibition explains the low proportion of HF fluid
return.\textsuperscript{34,35,41,42} Thus, in order to evaluate the potential for HF fluid to migrate, it is critical to
understand and quantify imbibition behavior. If all the injected HF fluid is imbibed and retained
in the shale formations, it will not be free to migrate elsewhere.
HF fluid imbibition is also of great interest from the perspective of maximizing gas production from shale wells. Imbibed water near the fracture-shale matrix interface occupies pore space and impedes the flow of gas into the fractures (sometimes called “water blocking” in the oil and gas industry).\textsuperscript{43-46} While there is a large body of oil and gas industry-focused literature investigating the imbibition of water into shales, these studies mainly concentrate on the implications of imbibition for hydraulic fracturing design and gas production rather than the questions of migration potential and the ultimate fate of the HF fluid.\textsuperscript{11,12,37-62} Several studies show a large amount of water could be stored in the fractures or matrix of shale formations, but they do not consider how mobile that water will be, particularly in the long term.\textsuperscript{8,41,61-64} In addition to capillary pressure, clay water absorption/hydration and osmosis have been investigated as additional drivers of imbibition,\textsuperscript{12,48-52,60} but capillary pressure appears to be the main driver of imbibition and the most likely to be prevalent under in-situ conditions.\textsuperscript{55,56}

Birdsell et al.\textsuperscript{64} quantified capillary imbibition of HF fluid into shales using a one-dimensional, incompressible, semi-analytical model of imbibition from a fracture face into the shale matrix. Their study found that a large proportion of the injected HF fluid could imbibe, assuming typical shale formation and HF fluid parameters. However, the Birdsell et al.\textsuperscript{64} imbibition model has significant simplifications limiting its ability to represent the flow of water and gas within shale gas formations. Their simulations only consider imbibition during a 5-day shut-in period after HF injection, and the constant-saturation fracture-face boundary condition is not able to represent the condition in the fracture during shut-in and the subsequent production period, as water flows out of the fracture. Furthermore, the assumption of incompressible fluids means that the model cannot simulate gas compressibility during high-pressure HF injection, or gas flow and pressure drawdown during production. These factors can have significant effects on the movement of HF
fluid in the shale formation, and their omissions make the model of limited use in answering questions about both the initial imbibition of the HF fluid into the shale matrix, and particularly the long-term fate of the HF fluid within the shale formation.

In the work reported herein, we implement a two-phase model of water and gas flow in a shale gas formation including fluid compressibility and fracture water dynamics. We aim to determine the long-term distribution of injected HF fluid in the shale, and whether it is plausible that all injected HF fluid remains in the shale. We consider gas production and HF fluid flow behavior as inter-related processes within one physical system, and we compare our model simulations with externally observable data from that system. We apply our model to shale wells in the Horn River Basin in British Columbia, Canada, for which high-quality water and gas production data are available. We investigate the following questions: how much HF fluid could be imbibed into the shale, and over what timescale? What is the long-term fate of imbibed HF fluid after the initial injection period? Is it plausible that all the HF fluid remains in the shale formation? Is the hypothesized capillary imbibition of HF fluid consistent with observed water and gas production from shale gas wells?

Methods

Modeling Approach

We implement a two-phase (water and gas) numerical model of a shale gas formation and apply the model to simulate wells from a specific well pad in the Horn River Basin where there is sufficient information available to build and test the model. The aim of our modeling is to quantitatively and qualitatively explain the long-term behavior of injected HF fluid within the shale formation while being consistent with the externally observable water and gas production data.
We develop a model containing the simplest justifiable geometry, physical processes, and parameters. We constrain the system geometry and select parameters using directly observed well and geological formation data from the Horn River Basin. We also calibrate unknown and uncertain parameters while being constrained by the Horn River data, as well as corresponding data from similar shale formations.

Model Data

Our study uses data for 12 wells located on one well pad in the Horn River Basin. The wells are drilled into the adjacent Muskwa and Otter Park members of the Horn River Formation. Early-time (first 2-6 weeks) water and gas production data with hourly time resolution, in addition to long-term (4 years) gas production data with monthly time resolution, are available for the wells. The raw short-term data are noisy and have been smoothed by a weighted average for presentation in the figures. Additional available well data include depth, horizontal well lateral length, fracture (well perforation) spacing, hydraulic fracturing injection pressure, injection flow rate, total injected fluid volume, and well pressure during production. Geological formation data include thickness, porosity, initial water saturation, gas composition, gas pressure, and temperature. More information about the data and sources is included in the Supporting Information.

Modeling Methodology

Shale gas production data from thousands of wells in several major formations have been modeled remarkably accurately by simple one-dimensional, one-phase, continuum-scale, diffusive (Darcy flux) natural gas flow in a finite domain. The implied conceptual model for the shale
gas formation is a homogeneous shale matrix between parallel, vertical, planar hydraulic fractures spaced at regular intervals along the horizontal well (illustrated in Figure 1). This planar fracture model was shown by others to most closely match production data (in comparison to other fracture representations) for Horn River Formation wells nearby to those considered in this study. We adopted the homogeneous shale matrix, planar fracture conceptual model and extended it to two-phase (water and gas) flow.

We began our modeling by using the one-dimensional, one-phase gas flow model to obtain the unknown shale formation parameters by history-matching simulated gas production with the observed production data. The unknown parameters (effective matrix permeability and hydraulic fracture area) were also constrained by permeability, formation thickness, and fracture size data for the Horn River Formation. All other required model parameters were known from the available well and formation data. Each well on the well pad has nearly identical characteristics except for the spacing between hydraulic fracturing perforations along the horizontal wells: some of the wells have 25-meter spacing between fractures, while others have 40-meter spacing.

Cumulative natural gas production data for each of the wells is shown in Figure 2 with the history-matched one-phase model simulations. Cumulative production data from the wells clearly fall into two groups of higher and lower-producing wells. The excellent history-match of the one-dimensional model simulations to both groups of production data were achieved by varying only the fracture spacing (25-meter and 40-meter) while holding all other well and formation parameters constant. Although production data for thousands of wells across different shale formations have been matched closely using the one-dimensional model representation, there are some other wells for which the one-dimensional model appears to be too simple. These include 6 wells on the
same Horn River well pad that are drilled into the underlying Evie member of the Horn River Formation. The production data from the Evie wells were able to be matched using a more complex three-dimensional geometrical model representation; further details are included in the Supporting Information. The following work focuses on the Muskwa and Otter Park member wells.

Figure 2. Cumulative natural gas production data (billion standard cubic feet) versus time for individual Muskwa and Otter Park member Horn River Formation wells (orange lines) compared with history-matched one-phase model simulated production with 25-meter fracture spacing (black line) and 40-meter fracture spacing (green line). All parameters are held constant between the two simulations except for fracture spacing.

The history-matched formation parameters from the one-phase modeling (effective matrix permeability and hydraulic fracture area) were used as input for the two-phase model. We used the two-phase model to simulate the shale gas well completion and production process. The process includes three distinct periods: (1) the hydraulic fracturing period, where HF fluid is injected into the well at high pressure; (2) the shut-in period, when the well is closed for a period of time following HF; and (3) the production period, when the well is opened, the pressure inside the wellbore decreases, and water and gas flow into the wellbore. The two-phase numerical
modeling was performed using the open-source MATLAB Reservoir Simulation Toolbox (MRST) automatic differentiation two-phase black oil model.\textsuperscript{78,79} Although the HF fluid and resident formation brine have some differing properties, they are miscible and represented by a single water phase in the model (described interchangeably as “water” or “HF fluid”). We assume water is initially near residual saturation within the shale.

The hydraulic fracture was represented in the model as a rectangular prism (a three-dimensional extension of a plane) with a defined aperture and resolved as grid cells with volume, porosity, and permeability. Explicitly resolving the fractures was important for the system behavior because storage and flow of water within the fracture volume is significant in the water dynamics. The numerical model domain included half of the aperture of one hydraulic fracture and the adjacent shale matrix region extending to the plane of symmetry with the neighboring fracture (illustrated in Figures 1 and 3). Fractures in the model were static (i.e. initiation, growth, and closure were not modeled). The implicit assumption is that fractures are created instantaneously at the beginning of injection (justified by microseismic data showing that fractures are mostly created early in the HF injection period\textsuperscript{80}), and that the fracture volume does not change with time. An illustration of the numerical grid structure used in the simulations is shown in Figure 3, with the fracture and matrix grid cells identified. There were no-flow boundaries on all sides of the model. Fluids were injected and extracted from the model domain through a pressure-dependent source/sink in the central hydraulic fracture cell representing the well (see Figure 3). Water was injected through the well cell at high pressure during the HF period, and the cell was a low-pressure sink that drew in both water and gas during the production period.
Figure 3. Schematic illustration of the model domain and hydraulic fracture model representation and discretization. The illustration is not to scale and does not show the actual number or spacing of grid cells, but it is representative of the structure. More detailed information about the model discretization is included in the Supporting Information.

A substantial amount of literature indicates that the created area of hydraulic fractures is much larger than the area that is “propped” open by sand proppant and able to effectively contribute to gas production. The remaining “un-propped” fracture area closes after HF injection and does not contribute significantly to production. We interpret the hydraulic fracture area that was history-matched for the one-phase gas production modeling as the propped fracture area. The larger un-propped fracture area (and volume), however, is important for water flow and imbibition during HF injection. We therefore modified the conceptual model of the shale gas formation for the two-phase model by increasing the area and volume of the initially created hydraulic fractures. Fracture size was increased in the simplest way: by extending the rectangular prism fractures with a narrower-aperture un-propped fracture region outside of the inner propped fracture region (illustrated in Figures 1 and 3). The permeability of the un-propped fracture region was decreased immediately at the end of the HF injection period (with the implicit assumption being that un-
propped fractures close immediately), based on evidence that the fracture closure time-scale is short compared to our simulation duration,77,81 and measurements of closed un-propped fracture permeability for the Horn River Formation (supported by data from other formations).66,82,84,85 The permeability of the closed un-propped fractures is sufficiently low that the outer region effectively does not contribute to flow during the production period. The simple fracture representation in the model was effective for capturing the long-term behavior of the system that is the focus of our study, but created limitations for matching the very early-time (initial days) behavior where fracture dynamics are important. These limitations are discussed further in the results and the Supporting Information.

The model of two-phase flow in a shale gas formation implemented for our simulations is a homogeneous shale matrix, rectangular prism fracture model with un-propped and propped hydraulic fracture regions. The model was implemented in MRST to simulate the completion and production procedure for the specific wells we are modeling: a 4-hour HF injection, followed by a 60-day shut-in, and then indefinite gas production.41,68,76 Most additional formation parameters required for the two-phase model (capillary pressure, relative permeability, residual saturations, hydraulic fracture height and width) were selected based on data for the Horn River Formation and other shale gas formations.66,76,86-88 Hydraulic fracture aperture (volume) and permeability were the key parameters varied to history-match water injection and production while also being guided by typical reported values for these parameters.8,66,84,89 The total fracture volume in our model (2.4–3.9×10⁴ m³) is consistent with independent estimates of total fracture volume for neighboring Horn River Formation wells (2.8–6.3×10⁴ m³).8,89 HF injection pressure and the production bottom-hole well pressure (as a function of time) are the external driving force parameters for the system, and were known from measured data.67,68 The water and gas fluid phases were
compressible, with the non-linear gas pressure-density and pressure-viscosity relationships prescribed by the known shale formation temperature and gas composition. Capillary pressure was modeled using the van Genuchten\textsuperscript{90} equation with parameters matched to shale capillary pressure data.\textsuperscript{86,87,91} Further information on the two-phase model, including a description of parameter selection and full list of parameter values, is included in the Supporting Information.

Results and Discussion

The two-phase model results match the gas and water production data closely. Figure 4 shows simulated long-term cumulative gas production compared with data for the individual Horn River Formation wells. The simulated gas production curves are very similar to the one-phase model simulations presented in Figure 2. However, the one-phase model required an artificial adjustment to early-time (first two weeks) production rate to account for reduced flow rates due to two-phase flow effects during early-time. The two-phase model simulation needed no such adjustment. Figure 5 shows simulated gas production rate during the first 50 days of production compared with individual well data. Gas production is initially suppressed by water impeding the flow of gas from the shale, but increases with time during the first 10 days of the simulation as water is removed. The simulated initial production rate is lower than the data, but the simulation reproduces two key common characteristics of the data: the peak gas production rate after about 10 days and the subsequent rate of decline in production. The close agreement of the model to gas production rate data is more evident in Figure 6, which compares the simulation result with less noisy, longer-term, monthly time resolution data (in addition to the early-time, hourly resolution data).
Figure 4. Cumulative natural gas production (billion standard cubic feet) versus time since the beginning of gas production for individual wells (orange lines) compared with two-phase model simulated production with 25-meter fracture spacing (black line) and 40-meter fracture spacing (green line).

Figure 5. Natural gas production rate (thousand standard cubic feet per day) versus time since the beginning of gas production for individual wells (yellow-orange-red lines) compared with two-phase model simulated gas production with 25-meter fracture spacing (black line) and 40-meter fracture spacing (green line) for the first 50 days of production.
Figure 6. Natural gas production rate (thousand standard cubic feet per day) versus time since the beginning of gas production for individual wells, showing early-time hourly resolution data (yellow-orange lines) and longer-term monthly resolution data (red lines) compared with two-phase model simulated gas production with 25-meter fracture spacing (black line) and 40-meter fracture spacing (green line) for the first two years of production.

Simulated water production rate during the first 50 days of production is shown in Figure 7 along with individual well data. After an initial pulse of water within the first day, simulated water production rate increases for the first 5 days of production, followed by a peak, and then a continuously decreasing rate. Similar to the gas production, simulated water production matches the qualitative and quantitative characteristics of the data except at very early time. The very early-time gas and water behavior could be matched under some parameter scenarios, but not without compromising the amount of water that could be injected and the longer-term quantity of water production. Since the focus of our modeling is to determine the plausibility of all water being retained within the shale long-term, it was more important to match the water quantities and long-term behavior. This limitation of the model is due to the simplified fracture representation and is further explained in the Supporting Information.
The long-term water balance for the simulated shale system is presented in Figure 8, which shows the distribution of the injected water volume between the fractures and shale matrix with time throughout the HF injection, shut-in, and production. Total volumes of water injected into the system during the 4-hour HF injection period were $5.7 \times 10^4$ m$^3$ for the 25-meter spacing model and $3.5 \times 10^4$ m$^3$ for the 40-meter spacing model. These volumes were matched to the average of $4.8 \times 10^4$ m$^3$ actually injected into the 12 Horn River Formation wells. During the injection period, a substantial fraction of the water imbibes into the shale matrix, but the majority (about 70%) remains in the fractures. During the 60-day shut-in period, water continues imbibing from the fractures into the shale matrix. The total amount of water in the system does not change, but its distribution within the system changes. At the commencement of the production period, water flows from the fractures into the well and the total amount of water in the system declines. About 17% of the injected volume is ultimately produced from the well. There is also a small decrease of water in the shale matrix at the beginning of production due to some water flowing from the matrix back into the fractures driven by the very high pressure gradient toward the fractures. However, after a short period, the pressure gradient reduces sufficiently and capillary-driven imbibition of water from the fractures into the shale matrix resumes (even as gas flow continues in the opposite direction). Within two years, almost all remaining mobile water has imbibed from the fractures into the shale matrix.
Figure 7. Water production rate (liters per second) versus time since the beginning of gas production for individual wells (light-dark blue lines) compared with two-phase model simulated water production with 25-meter fracture spacing (black line) and 40-meter fracture spacing (green line) for the first 50 days of production. The truncated water rate for the 25-meter spacing simulation at very early time reaches 6.1 liters per second.

Figure 8. Simulated shale system water balance for the 25-meter fracture spacing (40-meter is almost identical), showing water volume as a percentage of total injected water volume versus time. The graph shows the total amount of water in the system (grey) and the distribution of water
within the shale system between the fractures (dark blue) and the shale matrix (light blue). The vertical dashed black line shows the transition between the shut-in period (2) and the production period (3). The HF injection period (1) is 4 hours at the start of the simulation, which can only be seen in this graph by the near-vertical increase in water volumes near time zero.

Our simulations match the observations from the wells using a model that includes the essential physics of the system but maintains a simple structure. The results also show that all the water injected into the wells can be accounted for within the shale system, with most of the injected water stored in the shale rock matrix in the long term. We observe that the simulated total injected water volume and early-time water production rate are dominated by the storage and flow of water in the hydraulic fractures, and are therefore sensitive to the fracture geometry, volume, permeability, and closure timescale. However, the long-term distribution of water within the system (imbibition into the shale rock matrix) is insensitive to both these hydraulic fracture parameters and different capillary pressure parameters (discussed further in the Supporting Information). Since the focus of our investigation is on the long-term behavior of the system, we conclude that the model captures the dominant physics of the system, with a strong focus on capillary imbibition, phase pressures, and compressibilities.

We note here that the amount of water injected into the 12 Horn River Formation wells (average $4.8 \times 10^4 \text{ m}^3$) was considerably higher than is typical for the major shale gas plays in the United States (around $2 \times 10^4 \text{ m}^3$ per well$^{2-5}$). While the Horn River Formation is particularly thick, the ability to match the unusually high volume adds confidence that typical injected volumes can be accommodated in shale formations. We also note that the simple rectangular prism fracture representation is a conservative model for investigating the plausibility of water remaining in the shale formation because more complex fractures with increased fracture surface area and volume
would enable more imbibition and water storage within the system. Another important note is that
the no-flow boundaries of the model meant that water could only remain within the shale system,
so our simulations show the plausibility of all water remaining in the shale, rather than the
impossibility of water flowing out of the shale. Water could flow out through fractures during the
HF period, but the water dynamics within the model suggest that long-term upward water flow is
unlikely. Any mobile water present in the fractures will imbibe into the shale matrix. Furthermore,
pressure drawdown in the formation due to gas production means that even if fractures extend out
of the shale formation and contain mobile water, the direction of water flow will be into the shale,
rather than out, until the formation pressure re-equilibrates in the very long-term.

The simulations also revealed important characteristics regarding the driving forces and
timescale of water imbibition into the shale matrix. During the 4-hour HF injection period, forced,
pressure-driven imbibition dominated due to the high-pressure water injection compressing gas in
the shale matrix. About 50% of the total imbibition into the shale was pressure-driven. After HF
injection, during shut-in and production, spontaneous capillary-driven imbibition occurred, but at
a considerably slower rate than the pressure-driven imbibition during HF injection, and over a
much longer time-scale. Most previous studies that quantified water imbibition into the shale
matrix used incompressible fluid models and therefore could not capture the important role of
pressure-driven imbibition during HF injection.\textsuperscript{29,57,62,64} Regardless of the driving force of
imbibition, capillary forces retain imbibed water in the shale matrix. In particular, the low capillary
pressure in the hydraulic fractures compared to the shale matrix (due to the large difference in pore
sizes) results in a strong capillary pressure gradient into the matrix. Once water has imbibed,
capillary forces similarly drive the water to move even farther into the shale. Water saturation
distribution graphs that illustrate the imbibition processes are included in the Supporting Information.

Environmental Implications

Our simulations of two-phase flow in a shale formation support the hypothesis that injected HF fluid is imbibed into the shale matrix and retained there in the long term by capillary forces. HF fluid residing in the fractures at the end of HF will be imbibed into the shale in the long term and will not be able to migrate elsewhere, even if a permeable pathway is present. The model results are robust for a wide range of parameters: even a halving of capillary pressure does not significantly change the system behavior and sees almost all mobile water imbibed into the shale within two years. Other factors besides capillary imbibition also decrease the likelihood that HF fluid will migrate upward in the long term (as has been shown by others\textsuperscript{30}), including the lack of strong buoyant drive (compared with gas), a very short-lived pressure drive during HF, and long-term pressure drawdown during gas production that will draw fluids toward the well.

However, the simulation results do not imply that HF fluids cannot flow out of shale formations under any circumstances. The time-scale of capillary imbibition of water into the shale matrix is much longer than the HF injection period. Therefore, the HF injection period, when a high-pressure driving force exists and water in the fractures is mobile, is the highest risk period for water migration. If a direct hydraulic connection is present or created during HF, water could flow along that pathway. For example, water could migrate along deficient well cement or an adjacent well if the hydraulic fractures intersect that well. Where evidence of HF fluid migrating out of the target formation exists, those pathways have been implicated.\textsuperscript{10,92,93} Furthermore, while HF fluid may be unlikely to migrate out of the formation, natural gas is both buoyant and not spontaneously imbibed
like water, so it is more likely to migrate in the subsurface. Modeling and field observations support this hypothesis.\textsuperscript{17,94-98}

We applied our simulations to one well pad in the Horn River Formation and consequently our results are only directly applicable there. The imbibition behavior of other shales will vary depending on differences in permeability, porosity, fracture network size and geometry, and rock mineralogy and wettability. However, the major shale gas formations in North America, such as the Barnett, Marcellus, Haynesville, and Fayetteville shales, all share characteristics similar to the Horn River Formation shales, including depth, well design, HF techniques, and many shale rock properties (see data tables in the Supporting Information).\textsuperscript{7,75,99} In particular, all available literature indicates that shale gas formations have similar pore size, wettability, and capillary pressure characteristics, and therefore capillary imbibition behavior.\textsuperscript{35,37,40,60,86,87,100,101} Since our results are robust for a large range of capillary parameters, the implications are therefore generally relevant for similar deep gas shales with large vertical separation between the shale and aquifers.

Our analysis was possible due to the public availability of high-quality data for oil and gas operations in British Columbia, Canada. More high-quality, publicly available data in the United States would enable similar analyses to be performed directly for gas shales there, where the most public concern has been raised over potential environmental impacts.

\textbf{ASSOCIATED CONTENT}

Additional material is available as indicated in the text. This material is available free of charge via the Internet at http://pubs.acs.org.
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Notes

The authors declare no competing financial interest.

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