EEET ECOLOGICAL ENGINEERING & ENVIRONMENTAL TECHNOLOGY

Ecological Engineering & Environmental Technology, 2025, 26(2), 27–44
https://doi.org/10.12912/27197050/196518
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Received: 2024.11.19
Accepted: 2024.12.23
Published: 2025.01.01

Effect of hydraulic fracturing of shale gas reservoirs on groundwater in Algeria

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ABSTRACT

The exploration of shale gas reservoirs in Algeria has led to significant debate in the oil and gas sector due to potential risks to the country's declining water resources. This study focuses on assessing the risk of groundwater contamination from hydraulic fracturing (HF) in the Algerian southeast region, where the Frasnian shale gas reservoir lies between 3575 m and 3720 m deep, and the nearest aquifer Lias Horizon B is located at 1572 m. A model was developed using MODFLOW software, incorporating the characteristics of the geological layers traversed by well P-1, recently drilled in the region. A hypothetical, homogeneous, and continuous permeable pathway connecting the top of the Frasnian reservoir to the Lias Horizon B aquifer was included in the model. The study is based on simulating a reference scenario to which values observed in the region were assigned for factors influencing the migration of HF fluid. Subsequently, due to incomplete data regarding the real-world case study, a sensitivity analysis was conducted through the simulation of 11 scenarios to evaluate impact of each factor. The tracking of HF fluid pathways was performed using MODPATH software. The results show that HF fluid can reach the aquifer in 99.05 years. Sensitivity analysis identifies key factors in HF fluid migration, including the hydraulic conductivity of the permeable pathway, the fractured shale, and the extent of the induced fracture. In contrast, the lack of a permeable pathway and the limited length of the induced fracture prevent any migration of HF fluid to the aquifer.

Keywords: hydraulic fracturing, migration of hydraulic fracturing fluids, groundwater contamination, MODFLOW, MODPATH, permeable pathway.

INTRODUCTION

The global energy demand, estimated at 102.3 million barrels per day in 2023, could reach 105.4 million barrels per day by 2030 (International energy agency, 2024) coupled with the decline of conventional hydrocarbon reserves, has driven countries to explore alternative sources of hydrocarbons in extreme areas on land and at sea. Among these sources, unconventional hydrocarbons, such as shale gas and oil, now play a significant role in global energy supply and represent a highly attractive alternative for many countries, including the United States of America (USA), Canada, Europe, Russia, China, and some African nations (McGlade et al., 2013) Unconventional gas resources are estimated to be more than four times greater than conventional gas resources. Efficient exploitation of these resources could significantly transform global energy policy. (Picot et al., 2011). Extraction of shale gas and oil primarily relies on two techniques: (1) horizontal drilling, which allows shale formation to be traversed with a horizontal wellbore in order to maximize contact with hydrocarbon-bearing rock layers; and (2) hydraulic fracturing, which involves injecting a high-pressure mixture of fluid (composed of water, sand, and chemicals), called hydraulic fracturing fluid, into reservoir rock to create fractures. These fractures increase the rock's permeability, thus facilitating flow of hydrocarbons toward the well (Kerr, 2010)

The extraction of unconventional hydrocarbons, including shale gas, has already begun in many countries, such as the USA and Canada (Rivard et al., 2014; Carroué, 2022) and is expected to spread globally, notably in South America, Africa, Europe (Montcoudiol et al., 2017; Pfunt et al., 2016), Asia, China (Hu and Xu, 2013; Xingang et al., 2013), and Australia. Shale gas reserves are estimated at approximately 716 trillion cubic meters (Boyer et al., 2011; Kuuskraa et al., 2013; Reig et al., 2014; Cooper et al., 2016). The decision to exploit shale gas resource in these countries has sparked a heated public debate regarding potential impacts on the environment and human health. The main risks associated with the exploitation of unconventional hydrocarbons include: (1) water-related risks, comprising groundwater (Warner et al., 2012) and surface water pollution as well as depletion of water resources due to the large quantities required (Vengosh et al., 2014; US Environmental Protection Agency, 2012; Kargbo et al., 2010); (2) environmental risks, such as greenhouse effects (Howarth et al., 2011) and climate change, air quality degradation, impacts on human health, and landscape alteration; (3) soil-related risks, linked to presence of chemicals, radioactivity, land use and seismic activity (Hwang et al., 2023).

Several studies have been conducted to examine and assess the risks of water pollution associated with the exploitation of unconventional gas resources. The risks affect (1) surface waters through (a) leaks and spills of fracturing fluids and flowback water (i.e., water that returns to the surface after hydraulic fracturing operations), and (b) the discharge of inadequately treated wastewater into the environment; and (2) groundwater, through the migration of fluids (such as fracturing fluids and brine) and gases from deep fractured shale reservoirs to shallow aquifers (Taherdangkoo et al., 2020; Lange et al., 2013; Veloso Gargur et al., 2022).

The potential for upward migration of hydraulic fracturing fluids, brine, and gases from the fractured shale formation to shallow aquifers following hydraulic fracturing operations is one of the most frequently debated topics in this field. This issue has led to several modeling studies aimed at assessing this risk, with studies conducted in basins in the USA (Myers, 2012; Birdsell et al., 2015), Canada (Gassiat et al., 2013), Germany (Kissinger et al., 2013), England (Wilson et al., 2017), the Netherlands (Schout et al., 2020), and other regions (Reagan et al., 2015; Taherdangkoo et al., 2017; Taherdangkoo et al., 2020).

Studies on the migration of hydraulic fracturing fluids have shown varied results. (Myers, 2012) estimated that these fluids could reach aquifers within 10 years under certain conditions. (Gassiat et al., 2013) developed a more realistic model to assess migration along conductive faults, showing that, in the worst case, hydraulic fracturing fluids would reach shallow aquifers in less than 1000 years, with 90% of their initial concentration. (Birdsell et al., 2015) built a model incorporating buoyancy, well operation parameters, relative permeability, and capillary imbibition, revealing that hydraulic fracturing fluids could reach aquifers with low concentrations within 1000 years, provided a permeable pathway exists between the shale reservoir and the aquifer. In (Wilson et al., 2017), 91 scenarios were simulated, 18 of which indicated that hydraulic fracturing fluids could migrate from shale formations at a depth of 2000 m to aquifers located between 300 and 200m in less than 10,000 years, or even under 1000 years, depending on the characteristics of the fractured formations, permeable pathways and the parameters applied during hydraulic fracturing.

Algeria is one of the world's leading producers and exporters of natural gas. Conventional natural gas is the primary source of energy in the country, accounting for 55.7%, followed by oil at 32.4%. At the end of 2019, Algeria's proven reserves of conventional natural gas were estimated at 153.1 trillion cubic feet (Tcf), approximately 4335 billion cubic meters, equivalent to about fifty years of consumption at the rate of 2018 (Adjout and Bendib, 2021). However, the increase in natural gas consumption and the low renewal of reserves are prompting the country to consider exploiting its shale gas resources. Algeria has 707 Tcf of recoverable shale gas reserves (approximately 20,000 billion m^3), placing it third in the world after China and Argentina (U.S. Energy Information Administration, 2015; Kuuskraa et al., 2013; Azubuike et al., 2018; Kaced et al., 2013). In 2013, Algeria decided to turn to the exploitation of the shale gas. However, this decision sparked a large popular protest movement due to concerns about groundwater pollution and risks to human health. This movement quickly spread across the country, ultimately prompting the authorities to suspend activities related to shale gas exploitation (Adjout and Bendib, 2021).

Algeria has undertaken to assess and demonstrate its shale gas resources by drilling pilot wells in each region containing shale reservoirs. In this context, the present study aims to evaluate the risk that shale gas extraction poses to groundwater, focusing on the migration of hydraulic fracturing fluids from fractured shale towards aquifers. To this end, we examined well P-1, recently drilled in southeastern Algeria, targeting the Frasnian shale reservoir. We analyze the potential migration of hydraulic fracturing fluids from this fractured shale to the nearest aquifer, Lias Horizon B, by developing a model using MODFLOW software, while the migration path was tracked using MODPATH software. Additionally, a sensitivity analysis was conducted to assess the impact of each factor on this migration.

MATERIALS AND METHODS

Software presentation

MODFLOW/ModelMuse

Modular finite-difference ground-water flow model (MODFLOW) is a three-dimensional model designed to simulate groundwater flow using the finite difference method. Developed by the U.S. Geological Survey (USGS) in the early 1980s, MODFLOW offers a standardized and versatile tool for modeling aquifer flow. Over the years, it has evolved through several versions, including MODFLOW-NWT, MODFLOW-USG, and MODFLOW-6, each addressing specific requirements and accommodating increasingly complex phenomena. Its robustness, flexibility, and open-source nature have led to rapid adoption by the global scientific community and consulting engineers (McDonald et al., 1984; Harbaugh, 2005; Hughes, 2017).

In the current study, MODFLOW 2005 was used, which is capable of simulating groundwater flow in both steady-state and transient conditions within systems with irregular geometries, subject to external constraints such as wells, surface recharge, evapotranspiration, drains, and watercourses. MODFLOW 2005 has been utilized in several simulation studies on the migration of hydraulic fracturing fluids, including those by (Myers, 2012; Wilson et al., 2017; Brownlow et al., 2016).

ModelMuse is a graphical user interface (GUI) developed for the MODFLOW-2005 and PHAST models of the U.S. Geological Survey (USGS). This software allows users to create the input files necessary for simulating groundwater flow and transport for PHAST, as well as for MODFLOW-2005. A key feature of ModelMuse is its independence of spatial data from the modeling grid, as well as its independence of temporal data from the stress periods. This enables users to freely modify the spatial and temporal discretization of the model. Additionally, ModelMuse allows users to run simulations and visualize the results produced by MODFLOW (Winston, 2009)

MODPATH

MODPATH is a post-processing program designed to calculate three-dimensional (3D) trajectories of groundwater flow, functioning as a complement to MODFLOW. Developed by the U.S. Geological Survey (USGS) and based on the finite difference method (Pollock, 2012). It allows for tracking movement of particles within aquifers. In the present study, particle tracking was used to predict the long-term migration pathway of the injected fracturing fluid and to estimate the time required for this fluid to reach the shallow aquifer.

Study area

Algeria contains two significant formations of shale gas and shale oil: the "Silurian" and the "Frasnian," located within seven basins (Fig. 1). Among these are the Berkine (called also, Ghadames) and Illizi basins in the eastern part of the country; the Timimoun, Ahnet, and Mouydir basins in the central-southern region of Algeria; as well as the Reggane and Tindouf basins in the southwest (Kuuskraa et al., 2013; Kaced et al., 2013).

In the context of assessing shale gas reserves in the Berkine basin, a well (P-1) was drilled targeting the "Frasnian" shale formation at a depth ranging from 3575 m (top) to 3720 m (bottom) for hydraulic fracturing. The drilling of this well passes through two main groundwater aquifers and several geological formations (Fig. 1). From top to bottom, the well traverses: (1) the terminal complex, consisting of Senonian carbonate, anhydrite, and Turonian formations, and (2) the intercalary continental, which includes the formations of Cenomanian, Albian, Aptian, Barremian, Neocomian, Malm, Dogger, and Lias/Horizon B (Sonatrach Exploration, 2019), Subsequently, it intersects eight other geological formations over a thickness of 1983m, which are: Lias shale, TAGS (Upper triassic), Triassic carbonate, TAGI (Lower triassic), Carboniferous, Strunian F2, and

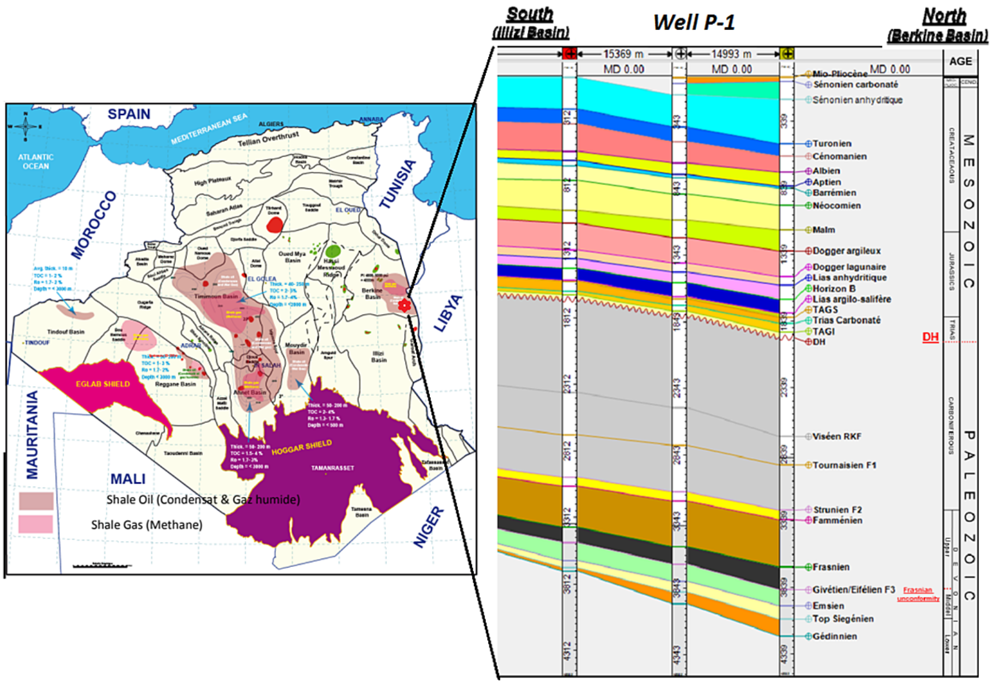

Figure 1. Geographical location of well P-1 _left_ and the stratigraphic column traversed by well P-1 _right

Famennian. The latter formation is characterized by low hydraulic conductivity. Thus, it is assumed to protect the upper aquifers from the migration of fracturing fluids, ultimately reaching the "Frasnian" formation. A horizontal drain of 1000 m will be drilled there, with hydraulic fracturing planned in ten stages. Figure 2 illustrates a simplified schematic of well P-1, the formations encountered, and the horizontal drain.

Model design

Based on the formations traversed by the well P-1, a 3D model measuring 1000 × 1000 × 4000 m, consisting of 11 geological layers, was created for this study using MODFLOW 2005/ModelMuse. Minor adjustments were applied on the model to facilitate model construction. The 11 geological layers were assumed to extend parallel

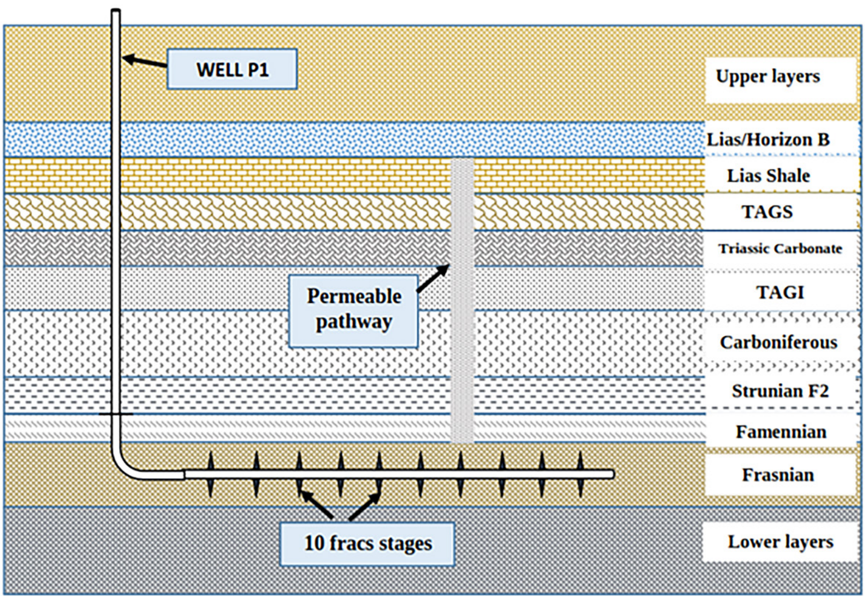

Figure 2. Simplified schematic _not to scale_ of well P-1 showing the encountered formations_ fracturing stages_ and the permeable pathway

throughout the modeled domain. Fig. 3 shows the top view of the established model, with 10×10 m grid. Figure 4 presents a 2D cross-section of the model. The upper layer, starting from the surface to the depth of 1572 m, covers the formations of the Senonian carbonate, Anhydrite, and Turonian, as well as those of the Cenomanian, Albian, Aptian, Barremian, Neocomian, and Malm/Dogger. Beneath the aforementioned formations lies the "Lias Horizon B" aquifer, located between 1572 m and 1592 m. It is the closest aquifer to the shale reservoir that will be fractured, the Frasnian, situated between 3575 m and 3720 m. Between these two formations lies an overburden zone composed of seven layers, spanning from 1592 m to 3575 m, as previously mentioned. The layer extending from 3720 m to 4000 m, underlying the Frasnian, is considered the lower boundary of the model.

The region remains largely unexplored, with P-1 being the first well drilled in this area. The hydraulic fracturing project has only recently started in Algeria. Therefore, we relied on data gathered during the drilling of this well. To supplement this information, we also drew on insights from experience in the United States, particularly regarding hydraulic fracturing operational parameters. The data are listed in Table 1, and the values have been adjusted based on conservative assumptions, incorporating the maximum realistic permeability of the overburden (Sonatrach - Exploration, 2019; Edwards and Celia, 2018)

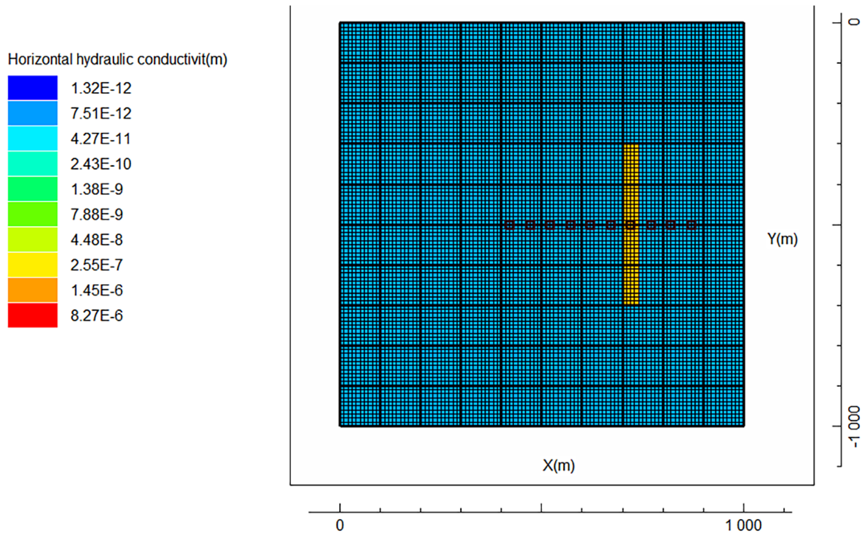

Figure 3. Top view of the established model_ showing the 10×10 m grid_ horizontal hydraulic conductivity of Upper Famennian shale_ the permeable pathway and the frac stages

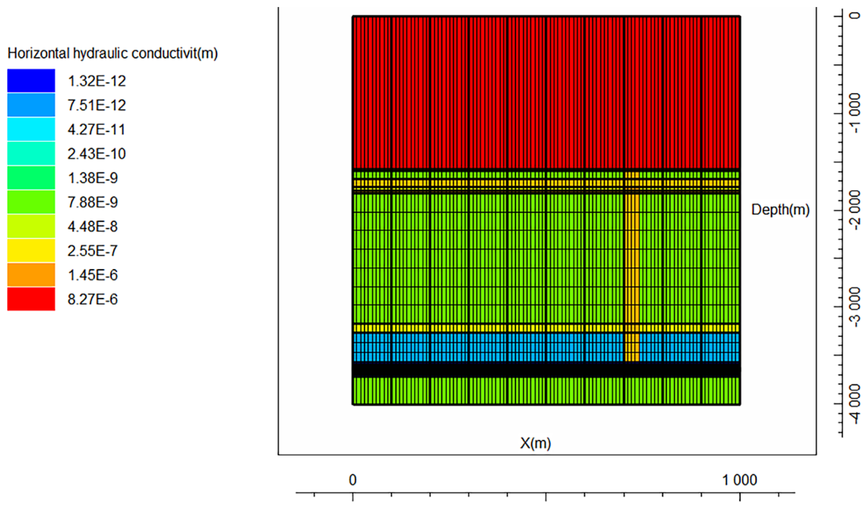

Figure 4. Horizontal hydraulic conductivity at the initial state of the different formations _front view_

Table 1. Model parameters for reference scenario

Formation	Depth (m) bottom	Horizontal hydraulic conductivity K_h(m/s)	K_h/K_v	Effective porosity
Upper layers	1572	8.27×10^{-6}	10	0.25
Lias/Horizon B	1592	8.27×10^{-7}	10	0.20
Lias/shale	1676	8.27×10^{-9}	10	0.15
TAGS	1765	8.27×10^{-7}	10	0.20
Triassic carbonate	1797	8.27×10^{-8}	10	0.20
TAGI	1825	8.27×10^{-7}	10	0.20
Carboniferous	3176	8.27×10^{-9}	10	0.15
Upper/Strunien F2	3269	8.27×10^{-8}	10	0.2
Upper/Famennian shale	3575	8.27×10^{-12}	10	0.07
Upper/Frasnien shale	3720	$1.32 \times 10^{-12(*)}$ $1.32 \times 10^{-6\,(**)}$	10	0.06
Lower layers	4014	8.27×10^{-9}	10	0.15
Permeable pathway	From 3575 m to 1592 m	1.0×10^{-6}	10	0.2

Note: (*) Horizontal hydraulic conductivity of the Frasnian shale gas reservoir before its fracturing, (**) Horizontal hydraulic conductivity of the Frasnian shale gas reservoir after its fracturing (reference case).

Permeability was converted into hydraulic conductivity by assuming a gravitational acceleration of $g = 9.81$ m/s^2, as well as a fluid density and viscosity of $\rho = 1000$ kg/m^3 and $\mu = 0.001$ kg/(m×s), respectively. The permeability values assigned to the geological formations were cautiously optimized, favoring the highest estimates while remaining realistic. Effective porosity represents the portion of the matrix porosity available for fluid flow. All layers were modeled as homogeneous and anisotropic. This anisotropy, frequently observed in natural environments, was introduced by considering a horizontal permeability greater than the vertical permeability (Freeze and Cherry, 1979; (Neuzil, 1994). Therefore, an anisotropy factor ($K_h/K_v = 10$) assigned to all layers.

The horizontal drain of 1000 m crossing the Frasnian formation is represented in MODFLOW-2005/ModelMuse using the "WELL" package for each fracturing stage. There is a fracturing point every 100 m, for a total of 10 stages. Hydraulic fracturing is simulated as an instantaneous and uniform increase in horizontal hydraulic conductivity. This increase ranges from 1.32×10^{-12} m/s to 1.32×10^{-6} m/s, with $K_h/K_v = 10$ (reference scenario case), in the Frasnian fractured reservoir. The fracturing fluid is injected at a flow rate of 0.35 m^3/s for 2 hours during each stage.

A continuous and homogeneous zone has been incorporated into most simulation scenarios. This zone extends vertically from the base of the Lias Horizon B at 1572 m of depth to the top of the Frasnian fracture reservoir at 3575 m of depth, traversing the intermediate overburden formations. This area represents a hypothetical permeable pathway of indeterminate nature, which could correspond to a poorly cemented and improperly abandoned borehole, a fault, a natural fracture, or any other geological discontinuity. Considering a continuous fault zone is an assumption that promotes the migration of HF fluid, similar to those employed in previous studies, such as (Myers, 2012; Gassiat et al., 2013; Kissinger et al., 2013; Birdsell et al., 2015; Brownlow et al., 2016). The existence of such a permeable pathway has been debated by (Warner et al., 2012; US Environmental Protection Agency, 2012; Ingraffea et al., 2014)

The model domain is subdivided into 380,000 elements, assuming 100 × 100 × 38 elements along the x, y, and z axes, respectively. The grid spacing is uniform horizontally at 10 m (Fig. 3), while the vertical discretization varies according to the layers (Fig. 4 and Fig. 5).

Boundary conditions

The Frasnian shale reservoir is a gas reservoir characterized by very low permeability and an abnormally high pressure of 441.29 bar, equivalent to a hydraulic head of 4500 m. This pressure exceeds the average vertical pressure gradient, estimated at 0.106 bar/m (or 1.09 m/m). The Lias Horizon B aquifer is a highly active aquifer in the region, with a hydraulic head of 168.7bar, approximately 1722 m of hydraulic head (Sonatrach Exploration, 2019). In the present model, an initial hydraulic head of

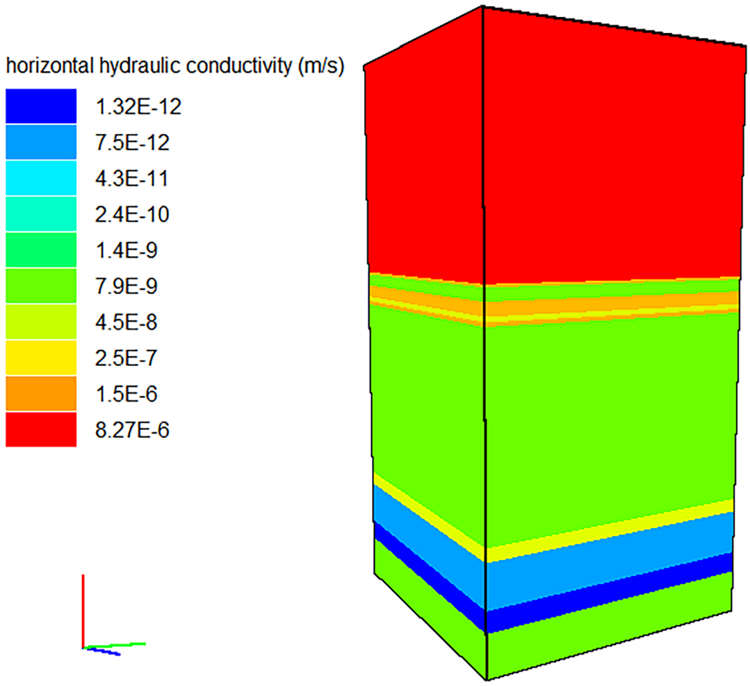

Figure 5. 3D domain model showing the hydraulic conductivities of the formations at the initial state the permeable pathway is located in the center of the model and hidden from view

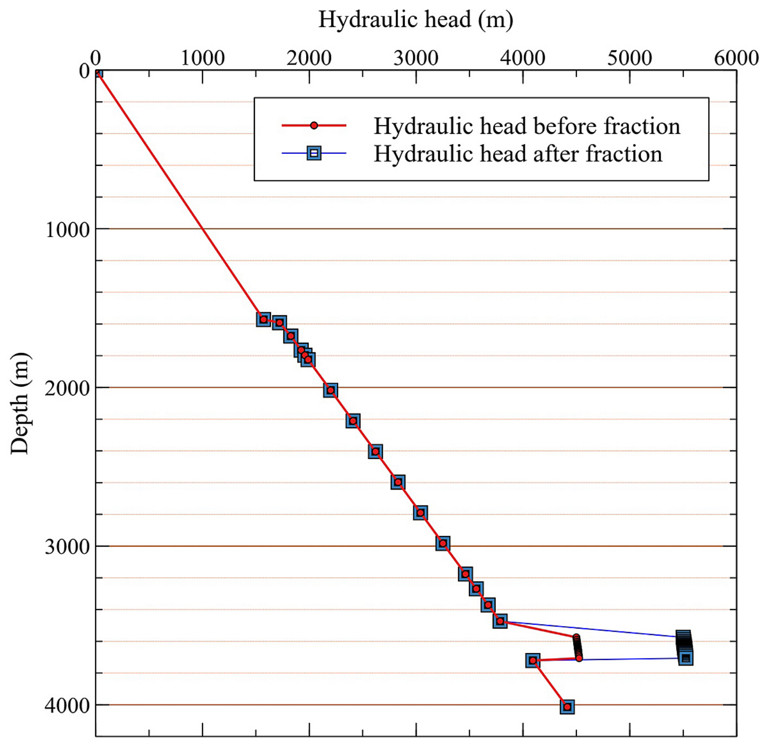

Figure 6. Hydraulic head profil before and during hydraulic fracturation

441.29 bar was applied at the top of the Frasnian shale gas reservoir, increased to 539.35 bar during hydraulic fracturing operations. A hydraulic head of 1722 m was assigned to the Lias Horizon B aquifer, while the intermediate formations follow a hydraulic head gradient of 1.09 m/m. No recharge from precipitation was included at the upper boundary of the model, as the Berkine Basin is a desert area and rainfall is negligible. Figure 6 shows the hydraulic head profil before and while hydraulic fracturation.

Periods of hydraulic fracturing operation

Each simulation scenario is structured into five successive periods (Table 2), each corresponding to a specific phase of the hydraulic fracturing operation. Each phase is associated with a set of boundary conditions, allowing for accurate modeling of the different life phases of a hydraulically fractured shale gas well. Table 3 indicates the duration and description of each period of the hydraulic fracturing operation.

The first period of the simulation corresponds to an initial steady-state period, representing the state before any intervention on the well. Next, a second period of 2 hours in transient state simulates the injection of HF fluid at a flow rate of 0.35 m^3/s per stage, accompanied by an increase in pressure in the shale reservoir to 539.35 bar or 5500 m of hydraulic head and an instantaneous increase in hydraulic conductivity to 1.32×10^{-6} m/s for the reference scenario. The third period, lasting 7 days in transient state, corresponds to the opening of the well and the partial removal of the HF fluid, modeled by the WELL package in MODFLOW/ModelMuse, simulating the recovery of approximately 30% of the injected fluid (Wilson et al. 2017). The fourth period, extending over 5 years in transient state, represents the gas production phase, although the effective lifespan of such wells is uncertain, averaging less than 10 years. To extend production, refracturing operations are often necessary after 4 to 5 years (Birdsell, et al. 2015). The fifth and final period, which can last more than 1000 years, corresponds to the definitive closure of the well, sealed with cement plugs to prevent any fluid exchange with the reservoir. During this extended phase, the residual fracturing fluid slowly migrates towards the Lias Horizon B aquifer.

Table 2. Values of the different factors influencing the migration of hydraulic fracturing fluids

Factor	Value	
Horizontal hydraulic conductivity of "Frasnian" shale K_h (m/s)	High	1.32×10^{-4}
	Medium (*)	1.32×10^{-6}
	Low	1.32×10^{-8}
Effective porosity of "Frasnian" shale (fraction)	High	0.2
	Low (*)	0.06
Horizontal hydraulic conductivity of the permeable pathway K_h (m/s)	High	1.00×10^{-5}
	Medium (*)	1.00×10^{-6}
	Low	1.00×10^{-7}
	Absence	/
Length of the induced fracture (m)	Up to the top of the Frasnian (*)	73
	Half the length of the reference scenario	36.22
Overpressure (m)	Low (*)	5500
	High	6500
Injection flow rate of HF fluid (m^3/s)	High (*)	0.35
	Low	0.20
Effective porosity of the permeable pathway	High	0.30
	Low (*)	0.2

Note: (*) reference scenario.

Table 3. The five periods of the hydraulic fracturing operation

N°	Name of the period	Duration	Description
1	Initial state	/	Stabilization state before hydraulic fracturing
2	Injection of hydraulic fracturing fluid	2 houres	Hydraulic fracturing operation (injection volume = 25,200 m^3, injection pressure = 539.35 bar (5500 m)
3	Partial elimination of hydraulic fracturing fluid	7 days	Return of a portion of hydraulic fracturing fluid (30%)
4	Gaz production well	5 years	Pressure drop in the shale reservoir
5	Permanent shut in well	1000 years	Migration of hydraulic fracturing fluid

Modeling assumptions

The results of this study are subject to several limitations due to simplifying assumptions. These include the assumption of homogeneity within the geological formations and a constant anisotropy with a K_h/K_v ratio of 10 for all layers. All stages are assumed to fracture simultaneously. The concentrations of additives in the fracturing fluid are considered constant throughout the simulation, with no degradation or absorption by the formations. Additionally, a continuous and homogeneous permeable pathway is assumed, and the effect of temperature is neglected. The model simulates the transport of an aqueous solution (with dissolved additives), without a gas phase, focusing on the migration of soluble additives (Pfunt et al., 2016). These particularly conservative assumptions tend to maximize estimates of the upward migration of the fracturing fluid.

RESULTS AND DISCUSSION

Reference scenario

A reference scenario was developed to simulate the entire hydraulic fracturing operation process. This scenario incorporates the following parameters: the horizontal hydraulic conductivity of the Frasnian shale after fracturing is 1.32×10^{-6} m/s or permeability to 1.55×10^{-11} m², with $K_h/K_v = 10$, and a porosity of 6% with an induced fracture length of 73 m, reaching the bottom of the upper Famennian shale formation. A permeable pathway is assumed to extend from the top of the Frasnian shale to the bottom of the Lias Horizon B aquifer, which has a horizontal hydraulic conductivity of 1.0×10^{-6} m/s ($K_h/K_v = 10$) and a porosity of 0.2. The injection of HF fluid was performed at a flow rate of 0.35 m³/s at a pressure of 539.35 bar equivalent to 5500 m. A hydraulic fracturing fluid removal was introduced during the period following the well fracturing (3rd period, Table 3) with a flow rate of 1.25×10^{-2}m³/s for 7 days. This was followed by gas production period of well for 5 years (4th period), which causes a decrease in pressure within the fractured reservoir. The 5th period represents the well closure and migration of the HF fluid remaining in the reservoir.

The reference scenario promotes upward fluid migration, which is not always realistic in practice. However, it helps identify extreme parameters that may influence the migration of hydraulic fracturing fluids. This scenario serves as a useful starting point for more refined sensitivity analyses, where parameters will be varied to cover a broader range of situations.

Figure 7 illustrates the distribution of hydraulic head at the initial state before any hydraulic fracturing operations. Figures 8–11 illustrate the evolution of hydraulic pressure during each simulation period after hydraulic fracturing fluid. During the 2nd period, which consists of the hydraulic

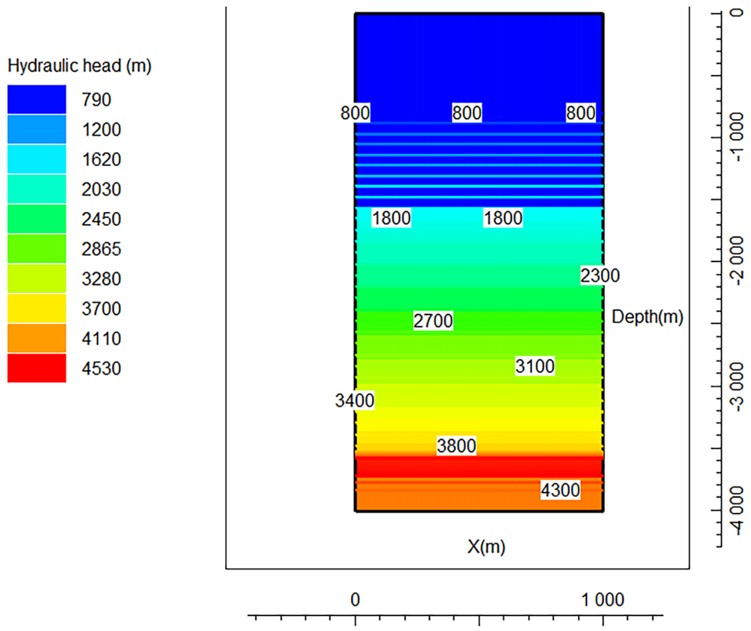

Figure 7. Hydraulic head at 0 s for the 1st period _initial state before hydraulic fracturing

fracturing phase, the hydraulic pressure reaches 5500 m at the perforation stages due to the injection of fracturing fluid. The resulting in an increase in the horizontal hydraulic conductivity of the Frasnian shale with $K_h = 1.32 \times 10^{-6}$ m/s (Fig. 8). At the end of the 3rd period at $t = 6.12 \times 10^{+5}$ s or 7.08 days, a portion of the fracturing fluid is extracted (30%), reducing the pressure in the shale reservoir. However, the propagation of hydraulic pressure begins to extend into the permeable pathway (Fig. 9). At the end of the 4th period at $1.58 \times 10^{+8}$ seconds or 5.02 years, gas production leads to decrease in hydraulic pressure in the shale reservoir, slowing the upward migration of fracturing fluid. Nevertheless, propagation continues along the permeable pathway (Fig. 10). Finally, during the 5th period, where the well is abandoned and closed, the fracturing fluid continues its migration toward the aquifer, reaching the Horizon B aquifer after $t = 3.13 \times 10^{+10}$ seconds approximately 99.05 years

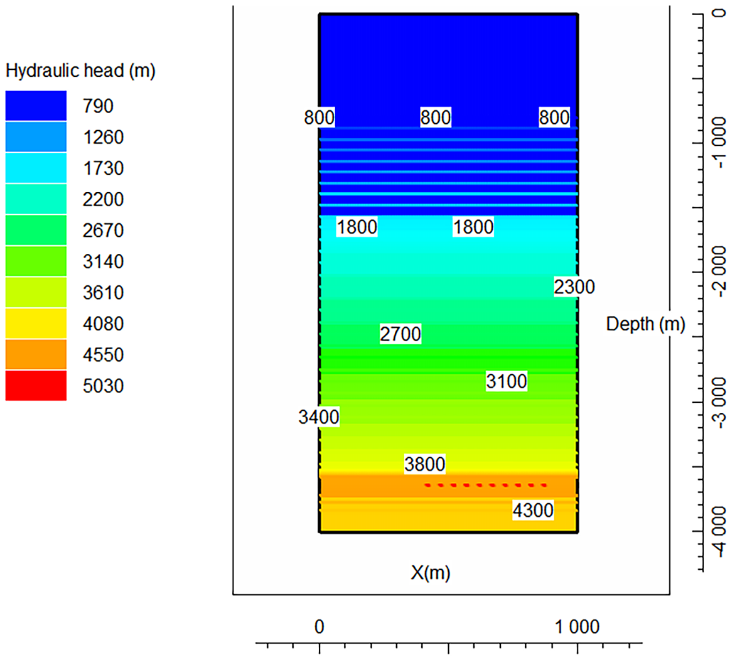

Figure 8. Hydraulic head at 7200 seconds the 2nd period hydraulic fracturing of the Frasnian

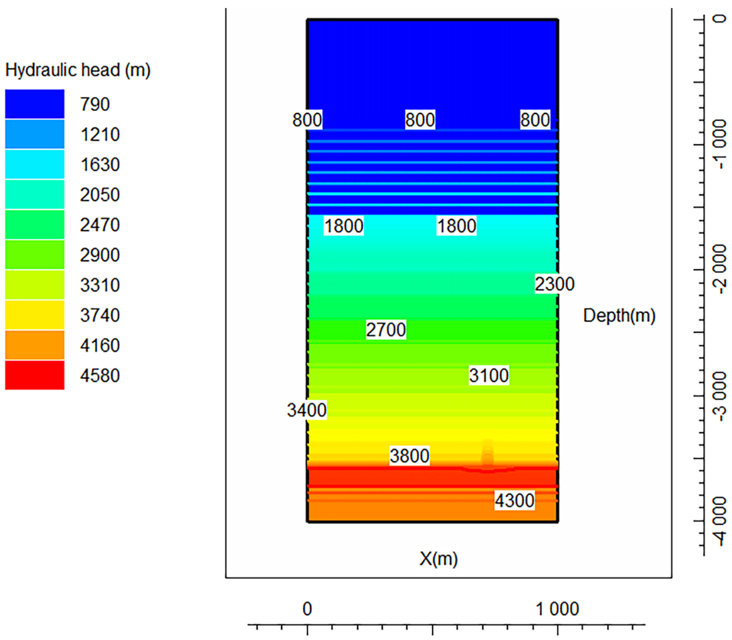

Figure 9. Hydraulic head at 6.12E5 seconds the 3rd period removal of 30% of hydraulic fracturing fluid

(Fig. 11). Figure 12 shows the paths taken by the fracturing fluid from the fracturing stages to the aquifer via the permeable pathway.

Sensitivity analysis

Based on the results of the simulation from the above reference scenario, a sensitivity analysis is conducted to identify the key parameters that control the potential migration of hydraulic fracturing fluids into the aquifer and the factor that has the greatest effect on this migration.

Scenarios design

The design of the scenarios is based on the combination of factors such as the hydraulic conductivities and porosities of the Frasnian shale formation as well as the permeable pathway, the overpressure applied during hydraulic fracturing, and the extent of the induced fracture (Table 2).

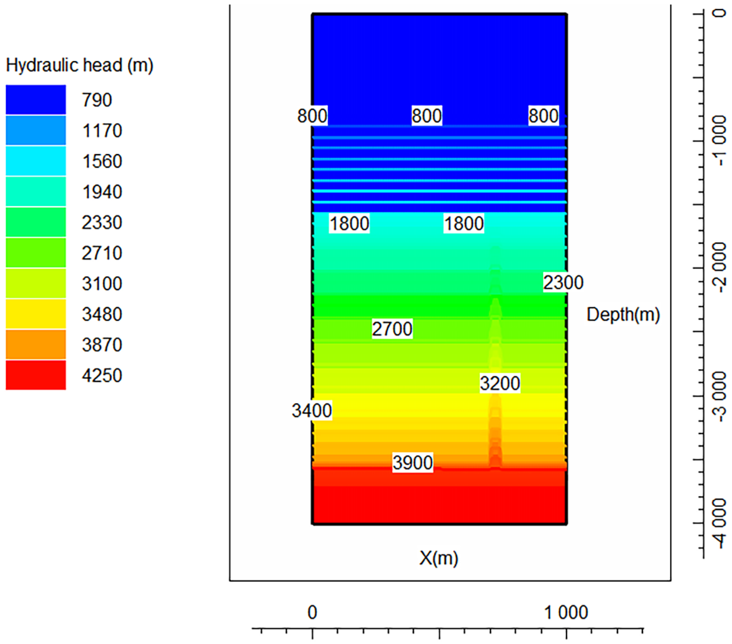

Figure 10. Hydraulic head at 1.58E8 seconds 4th period gas production of well

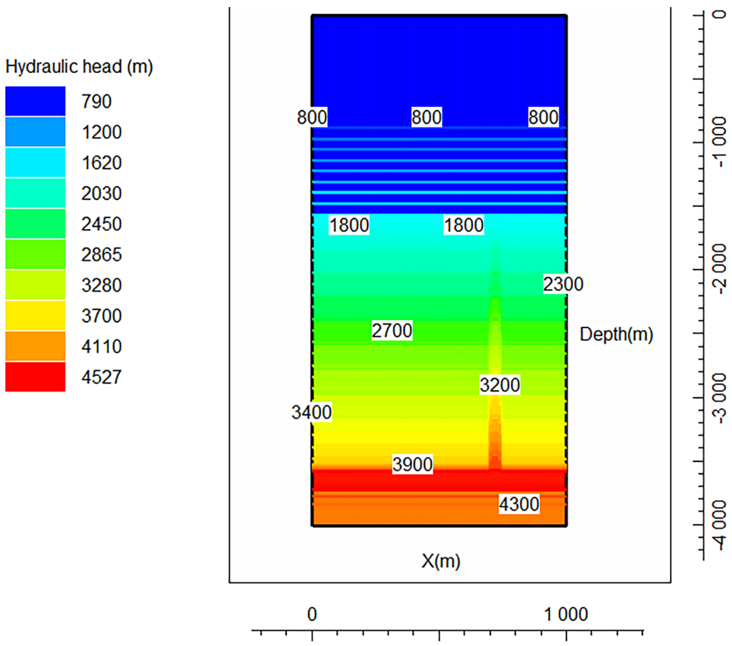

Figure 11. Hydraulic head at 3.13E9 seconds 5th period migration of hydraulic fracturing fluid

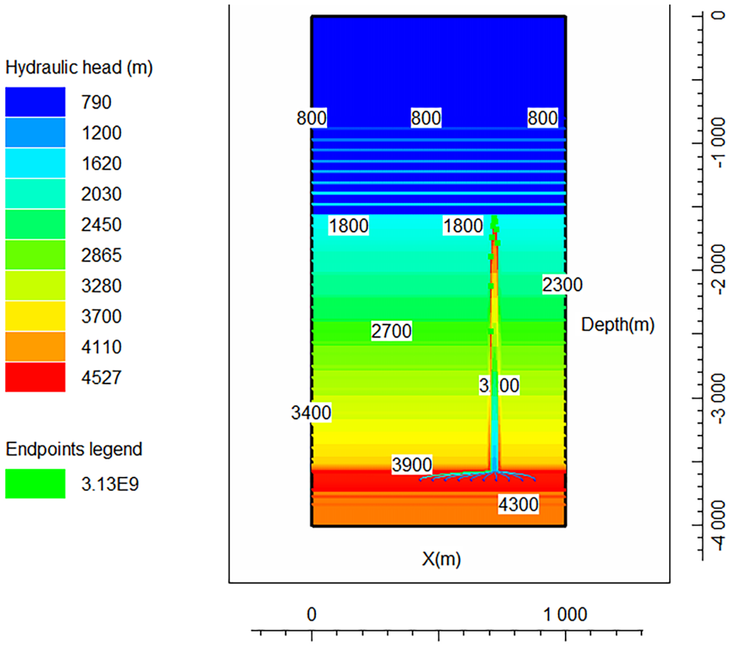

Figure 12. Migration pathways of hydraulic fracturing fluid at 3.13E9 seconds 99.05 years

These combinations, which can reach hundreds of cases, generate a wide variety of scenarios. In this study, we focus particularly on 11 scenarios (S2–S12), excluding the reference one, as certain factors have a predominant influence on the migration of fracturing fluids.

To assess the influence of each parameter, we followed a scenario design strategy for scenario S2 to S11, based on modifying only one parameter at a time, keeping all others at the reference value. One scenario was also simulated (scenario S12) by applying minimum values for the conductivity of the fractured shale and the permeable pathway to observe the combined impact of these two factors.

Hydraulic conductivity effect of the permeable pathway

Four scenarios including the reference one (S1, S2, S3, and S4) were simulated to assess the hydraulic conductivity impact of a permeable pathway on the migration of HF fluid. The scenarios included low, medium, high hydraulic conductivity values (Table 4), as well as a scenario without a permeable pathway (S3**)**. All scenarios use an anisotropy factor K_h/K_v equals 10.

In the reference scenario (S1), with a medium hydraulic conductivity of $K_h = 1 \times 10^{-6}$ m/s, the hydraulic fracturing fluid reaches the aquifer in 99.05 years. When a low conductivity value of $K_h = 1 \times 10^{-7}$ m/s is applied, the migration time increases to 975.81 years. Conversely, with a high conductivity value of $K_h = 1 \times 10^{-5}$ m/s, the time is reduced to 11.66 years. In the absence of a permeable pathway, no migration of hydraulic fracturing fluid was observed. Therefore, the migration time of hydraulic fracturing fluid strongly depends on the hydraulic conductivity of the permeable pathway, where even a slight variation in this value can lead to significant differences in migration duration.

In the high-conductivity scenario, the hydraulic head along the permeable pathway rises rapidly after hydraulic fracturing, surpassing the values of surrounding formations and thus accelerating the migration of hydraulic fracturing fluid towards the aquifer. According to Darcy's law, which governs fluid flow in porous media, higher hydraulic conductivity results in an increase in volumetric flow rate. This increase directly accelerates the migration velocity of fluids through the porous medium (Freeze and Cherry, 1979; Domenico and Schwartz, 1998; Whitaker, 1986). This relationship highlights the significant influence of the hydraulic conductivity of permeable pathways on the migration speed of fluids from hydraulic fracturing operations.

Hydraulic conductivity effect of the fractured Frasnian shale reservoir

The fracturing of the Frasnian shale reservoir is simulated by instantaneously increasing its hydraulic conductivity after the injection of hydraulic fracturing fluid. To evaluate the impact of the

Table 4. Migration times of hydraulic fracturing fluid for different scenarios

Scéna-rio	Description	K_h Shale (m/s)	K_h permeable pathway (m/s)	K_h/ K_v	Length of the induced fracture (m)	Hydraulic head (m)	Injection flow rate (m^3/s)	ϕ Frasnian	ϕ permeable pathway	Migration time (years) (*)
S1	Reference scenario	1.32×10^{-6}	1.00×10^{-6}	10	73	5500	0.35	0.06	0.2	99.05
S2	Effect of the hydraulic conductivity of the permeable pathway (High/ Absence/Low	1.32×10^{-6}	1.00×10^{-5}	10	73	5500	0.35	0.06	0.2	11.66
S3		1.32×10^{-6}	No permeable pathway	10	73	5500	0.35	0.06	0.2	No migration
S4		1.32×10^{-6}	1.00×10^{-7}	10	73	5500	0.35	0.06	0.2	975.81
S5	Effect of shale hydraulic conductivity (High/Low)	1.32×10^{-8}	1.00×10^{-6}	10	73	5500	0.35	0.06	0.2	159.36
S6		1.32×10^{-4}	1.00×10^{-6}	10	73	5500	0.35	0.06	0.2	98.13
S7	Effect of induced fracture length	1.32×10^{-6}	1.00×10^{-6}	10	36.22	5500	0.35	0.06	0.2	No migration
S8	Effect of overpressure	1.32×10^{-6}	1.00×10^{-6}	10	73	6500	0.35	0.06	0.2	99.04
S9	Effect of injection flow rate	1.32×10^{-6}	1.00×10^{-6}	10	73	5500	0.2	0.06	0.2	99.45
S10	Effect of Frasnian porosity	1.32×10^{-6}	1.00×10^{-6}	10	73	5500	0.35	0.15	0.2	112.58
S11	Effect of porosity of the permeable pathway	1.32×10^{-6}	1.00×10^{-6}	10	73	5500	0.35	0.06	0.3	144.66
S12	Combined effect (conductivity of Frasnian and permeable pathway)	1.32×10^{-8}	1.00×10^{-7}	10	73	5500	0.35	0.06	0.2	1046.43

Note: (*) the minimum simulated time for the migration of hydraulic fracturing fluid to reach the bottom of the Horizon B aquifer.

hydraulic conductivity of the Frasnian shale after fracturing on the migration of hydraulic fracturing fluid, two scenarios (S5 and S6) with varying conductivity levels are simulated. Initially, before the fracturing operation, the shale's hydraulic conductivity was $K_h = 1.32 \times 10^{-12}$ m/s with an anisotropy of $K_h/K_v = 10$.

The simulation results indicate that the migration rate of the hydraulic fracturing fluid towards the aquifer is directly related to the hydraulic conductivity of the fractured shale. For a high conductivity ($K_h = 1.32 \times 10^{-4}$ m/s), the fluid reaches the aquifer in 98.13 years, whereas for a low conductivity ($K_h = 1.32 \times 10^{-8}$ m/s), this time is 159.36 years. The results above indicate that the hydraulic conductivity of the shale created by hydraulic fracturing significantly influences fluid migration. However, this effect is less pronounced compared to that of the permeable pathways. This is due to the distance the fracturing fluid must travel to reach the Horizon B aquifer: approximately 73 meters through the shale, versus 1983 meters through the permeable pathway, making the impact of the hydraulic properties of the permeable pathways far more dominant.

To assess the combined impact of the hydraulic conductivity of the Frasnian shale and the permeable pathway, scenario S12 was simulated, low hydraulic conductivity values were assigned to both the Frasnian shale; $K_h = 1.32 \times 10^{-8}$ m/s and the permeable pathway $K_h = 1 \times 10^{-7}$ m/s. The results show that the migration of hydraulic fracturing fluids is significantly delayed, with the fluid taking 1046.43 years to reach the aquifer.

Effect of induced fracture length

To evaluate the impact of the induced fracture length, the scenario S7 (Table 4) was simulated with the fracture length reduced by half (i.e., 36.22 m) compared to the base case (73 m). In this case, the Frasnian reservoir was divided into two distinct zones: a high-conductivity fractured zone around the horizontal well drain with $K_h = 1.32 \times 10^{-6}$ m/s, and an unfractured zone with the initial conductivity of 1.32×10^{-12} m/s (Fig 13), the results show that the hydraulic fracturing fluid remains primarily confined within the fractured zone without reaching the aquifer. The extremely low conductivity of the shale before fracturing, equal to 1×10^{-12} m/s considered impermeable, prevents any flow of fracturing fluid and even limits the propagation of hydraulic pressure changes caused by fluid injection. This explains the results obtained in scenario S7, where the non-fractured part of the reservoir acts as a barrier. Similarly, in scenario S3, where there is no permeable pathway, the overlying formation, the Famennian shale, with a very low conductivity of $K_h = 8.27 \times 10^{-12}$ m/s, prevents the migration of fracturing fluid into the aquifer.

Effect of effective porosity in fractured Frasnian shale and permeable pathways

The two simulated scenarios evaluated the influence of the fractured shale effective porosity and the permeable pathway porosity on the migration of hydraulic fracturing fluid are S10 and S11 (Table 4). The results show that the two effective porosities have opposite effects on the migration velocity of hydraulic fracturing fluid. By increasing the effective porosity of the shale to 0.15, the migration time extends to 112.58 years. Similarly, increasing the porosity of the permeable pathway to 0.3 results in a migration time of 144.66 years. Porosity (ϕ) is defined as the ratio of the volume of voids to the total volume of a material. In this case, higher porosity values create more void space, allowing the flow to traverse a larger volume, which consequently prolongs the migration time (Nield and Bejan, 2006; Domenico and Schwartz, 1998). This explains the results of the two scenarios.

Effect of overpressure

The initial pore pressure in the Frasnian shale was equivalent to a hydraulic head of 4500 m or 441.29 bar. To induce fracturing in this shale, a hydraulic head of 5500 m was applied, generating an overpressure of 1000 m. This increase in pressure was sufficient to create fractures within the shale, allowing gas to escape through the newly formed pathways. To assess the impact of this overpressure on the migration of hydraulic fracturing fluid, a scenario S8 with a higher overpressure 2000 m of hydraulic head was simulated. The result shows a slight effect on hydraulic fracturing fluid migration, with a migration time of 99.04 years (Table 4). Although overpressure plays a crucial role in fluid flow through porous media, as stated by Darcy's law, its limited duration during the fracturing operation, applied only for two hours of hydraulic fracturing fluid injection, prevents a significant effect on migration time from being observed.

Effect of injection rate

The scenario S9 simulated with an injection rate of 0.2 m³/s shows a minimal impact on the migration velocity of hydraulic fracturing fluid, with an estimated migration time of 99.45 years

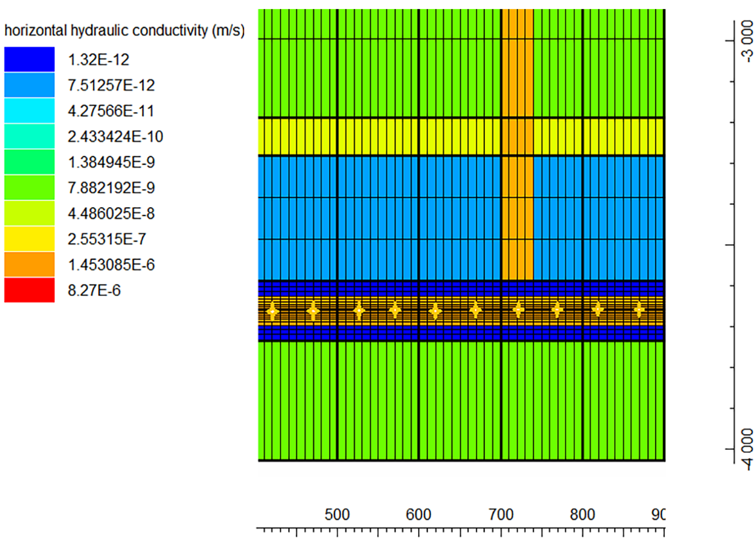

Figure 13. Horizontal hydraulic conductivity (m/s) at the shale reservoir shows the fractured and unfractured zones Scenario S7

(Table 4). Similar to Scenario S8, the very short injection duration of only 2 hours did not allow for a significant change in the migration time to be observed.

Other effects

Other parameters can influence the migration of hydraulic fracturing fluids and are not modeled in the present work due to limitations of the software used. The injection of hydraulic fracturing fluid into the shale leads to several multiphase flow phenomena, including capillary imbibition and relative permeability. Capillary imbibition refers to the sequestration of a portion of the hydraulic fracturing fluid within the shale, preventing it from migrating to an overlying aquifer, while relative permeability reduces the ability of one fluid phase to migrate in the presence of another fluid phase. Here, when a non-wetting phase is present in the porous medium, it occupies certain pores and reduces the ability of water to flow through those pores (Engelder, 2012). These two mechanisms contribute to slowing down the migration of fluid towards the aquifer (Byrnes, 2011; (Birdsell et al., 2015).

CONCLUSIONS

In the face of declining conventional oil and gas reserves, Algeria, the third country in the world in terms of shale gas reserves, has decided to explore and then develop this new resource. Extracting this type of gas requires specific techniques such as horizontal drilling and hydraulic fracturing, which allow for the release of gas trapped in shale rock. The extraction of shale gas through hydraulic fracturing raises numerous questions and debates, particularly regarding the contamination of groundwater, a resource that is becoming increasingly scarce in a country facing a water crisis in recent years.

To assess the risk of aquifer contamination following hydraulic fracturing operations in the Fasnien shale, a model using MODFLOW/MODPATH software was developed. This model incorporates the geological formations traversed by well P-1, drilled recently in the southeastern region of Algeria. Additionally, a homogeneous and continuous permeable pathway connecting the fractured Frasnian shale to the Lias Horizon B existing aquifer was included. The study strategy involves simulating a reference scenario by introducing values close to reality for the various factors influencing the upward movement of hydraulic fracturing fluid. Subsequently, a sensitivity analysis was conducted to determine the impact of each factor. All scenarios faithfully reproduce the five periods of the hydraulic fracturing operation: initial phase, injection of hydraulic fracturing fluid, partial removal of HF fluid, well production, and migration of hydraulic fracturing fluid towards the aquifer.

The results of the reference scenario indicate that the hydraulic fracturing fluid reaches the aquifer in 99.05 years. In comparison, some previous studies on this topic have shown results ranging from less than 10 years (Myers, 2012) to several hundred years (Birdsell et al., 2015) and even thousands of years in other works (Wilson et al., 2017). The sensitivity analysis reveals that the conductivity of the permeable pathway and fractured shale, as well as the extent of the induced fracture, are the factors that play a decisive role in the migration of hydraulic fracturing fluid towards the aquifer. The applied overpressure and the injection rate during the hydraulic fracturing fluid operation have a lesser impact compared to the previous factors. In contrast, the effective porosities of the shale and the permeable pathway have an opposite effect on the migration rate of hydraulic fracturing fluid.

The migration of hydraulic fracturing fluid to the aquifer is only possible if several conditions are met, which we consider conservative: (1) the existence of a permeable pathway connecting the shale to the aquifer; and (2) the extent of the induced fracture must cover the entire thickness of the shale and be in communication with the permeable pathway.

It is worth noting that such a scenario is extremely improbable. The results obtained suggest that the probability of migration of hydraulic fracturing fluid to the aquifer under such conditions is very low. This conclusion is reinforced by scenario S12, where we combined low values of hydraulic conductivity for the shale and the permeable pathway, resulting in a migration time of 1046.43 years. Furthermore, this calculation does not take into account the phenomena of capillary imbibition and relative permeability, which would further slowdown the migration rate of the HF fluid towards the aquifer.

Although this study on hydraulic fracturing fluid migration has provided a better understanding of the mechanisms of hydraulic fracturing fluid migration, due to the complexity of geological and hydrogeological systems, as well as the lack of reliable data, it remains difficult to assert with certainty that no contamination of aquifers occurs. Therefore, it is necessary to continue research and develop new investigative methods to better understand the processes at play and reduce the associated uncertainties.

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