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REVIEW

Current opinions on foam-based hydro-fracturing in deep geological reservoirs

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Abstract Natural gas extraction is a greener solution to world energy resource depletion and water-based hydraulic fracturing is traditionally used to produce gas from deep and tight geological formations. However, since this practice fails to produce a commercially viable amount of gas and raises many environmental issues, better alternatives are being tested in the field, among which the usage of foam-based fluid is a comparatively novel but effective technique. The aim of this review is to understand the current opinion on foam-based fluid fracturing, its merits and demerits and the associated environmental footprint. Foams are made by mixing a gas phase with a liquid phase using a suitable surfactant, and the foam quality is composition-dependent, with high quality foams having higher percentages of gas. The properties of the injecting foam, including its rheology and viscosity, are important for the fracturing process. According to current studies, foams have two separate flow regimes (low and high quality) and a unique multiphase flow pattern. Foam viscosity should be low to enter the ends of the fracture and high to have a good proppant-carrying capacity. Greater proppant-carrying capacity, lower water consumption and chemical usage, quicker and easier fluid flowback and less environmental damage are the advantages of foam-based fracturing, and lack of knowledge, high capital cost, and potential damage to the environment from surfactants are the limitations. However, foam-based fracturing has been tested in very few locations to date.

Keywords Unconventional reservoirs · Foam-based fracturing · Rheology and viscosity · Shale gas · Oil · Tight gas

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1 Introduction

Although the extraction of natural gas and oil from deep geological formations such as shale, tight gas and coal beds is a potential solution for the energy resource depletion crisis in the world (Xie et al. 2015), the extraction of economically viable quantities of gas/oil from these formations has become a challenge due to their extremely low permeability. Therefore, research into advanced permeability enhancement techniques has become essential in the petroleum industry. Among the various possible permeability enhancement techniques, hydro-fracturing is the most common practice in the industry (Kinnaman 2011; Nehring 2010). During the hydro-fracturing process high-pressure fluids are injected into deep rock formations to generate a network of fractures that enhance the reservoir permeability by making easy flow paths for fluid movement (Gu and Mohanty 2014), resulting in greater fuel extraction from the reservoir. In addition, the mixing of an appropriate propping agent with the fracturing fluid (proppant) is used in the hydro-fracturing process to keep the fractures open after releasing the fluid pressure (Liu et al. 2010). These agents can be made using resin-coated or uncoated sand, sintered bauxite, ceramic materials, and glass beads (Fink 2012). For this reason, an appropriate proppant-carrying capacity is necessary for the fracturing fluid to prop open the fractures all around the wellbore, including the lower and upper surfaces of the wellbore.

Currently, various types of hydraulic fracturing fluids are used in the petroleum industry, including water, foam, gas and hydrocarbons, and each has advantages and limitations. This paper reviews current findings on the usage of foam-based fluids for the fracturing process in deep geological formations. In general, foam can be made by mixing a gas with a liquid, and it therefore consists of gas bubbles inside a liquid phase, where the liquid act as the external phase for the gas. The two-phase fluid flow nature of foams leads to a high viscosity [up to about 150 mPa s (Ding et al. 2013)] and low density (similar to air) fracturing fluid, both of which ensure a greater proppant-carrying capacity. The selection of the liquid phase depends on economic constraints and reservoir conditions (permeability, water availability, clay content and temperature etc.), and water, acid, alcohol or hydrocarbon are commonly used (Gandossi 2013). However, this foam-based fracturing fluid technique is comparatively novel and requires large production costs for the necessary technical and logistical facilities. This paper discusses the advantages and limitations of this technique, based on a thorough literature review of current findings related to foam-based fracturing fluids.

2 How to produce foam?

As stated previously, foams consist of two phases, internal and external, and the internal phase is normally a gas such as N_2 or CO_2 and the external phase is a liquid such as water, CO_2, acid or alcohol (Gandossi 2013). However, a suitable foaming surfactant must be used to combine the internal phase with the external phase during foam production to maintain the stability of the foam during the fracturing process (Montgomery 2013). The most widely used foam types in the industry and their constituents are described in Table 1 (Gandossi 2013). The quality of any foam must be well maintained during the production and this can be quantified using the volume percentage of gas in the foam fluid [Eq. (1)].

$$Q = \frac{(V_f - V_l)}{V_f} \times 100 \quad (1)$$

where Q = foam quality, V_f = total volume of foam, V_l = volume of liquid in the foam.

In the foam production process, careful mixing of the foaming surfactant with the liquid phase is the first stage and then co-injection of gas and surfactant solution will take place to mix the fluids (Haugen et al. 2014). This can be effectively done using a mechanical mixer, knowing the mixing proportion of surfactant solution and gas, which is normally determined using a special type of basic test, called a half-life experiment (Saxena et al. 2014). During this experiment, different portions of foaming surfactants are mixed with the liquid phase and generate foams with different qualities. The prepared forms are then kept under atmospheric pressure and the time taken to re-generate half of the liquid used is checked. More stable forms will take longer to re-generate the liquid. In foam-based fracturing, poor foam stability may lead to a frequently repeated foam treatments to continue an economical gas extraction rate (Solbakken 2015). After selecting the optimum surfactant percentage by

Table 1 Types of foams with constituents

Type of foam	Main constituents
Water-based foams	Water + foaming surfactant + $N_{2(gas)}$ or $CO_{2(gas)}$
CO_2-based foams	$CO_{2(liquid)}$ + foaming surfactant + $N_{2(gas)}$
Acid-based foams	Acid + foaming surfactant + $N_{2(gas)}$
Alcohol-based foams	Methanol + foaming surfactant + $N_{2(gas)}$

this method, the liquid and the surfactant are first mixed and then the resulting liquid and the gas are simultaneously injected into the foam generator (Sun et al. 2014; Haugen et al. 2014). Foam generators consist of a series of screens, and simultaneously passing the liquid with surfactant and gas through these screens will produce foam, the quality of which can be adjusted by maintaining the proportion between the liquid and gas flow rates (e.g.: 60, 70, 80 %). In addition, foam stability can be further enhanced by adding some additives such as iodine, hydrogen peroxide, cupric sulphate, and zinc bromide to the foam (Fink 2013). After making the foam, it is mixed with suitable proppants and then injected into the geological formation through an injecting wellbore. Separate storage of liquid, gas, surfactants, and proppants at the site is therefore necessary for an effective and easy foam generation process. As this is quite expensive, this is one of the main drawbacks of the foam-based fluid fracturing process, despite its numerous technical advantages.

3 Important properties of foam-based fracturing fluids

3.1 Rheology

The rheology of the hydraulic fracturing fluid is critically important for an effective hydro-fracturing process. Although this can be easily described using general fluid flow equations for conventional hydro-fracturing fluids such as water, acid and alcohol, the derivation of the rheology for foam-based fracturing fluid requires some additional considerations due to its multi-flow behaviour. Many models and methods have recently been developed to address this issue (Gajbhiye and Kam 2011, 2012; Edrisi and Kam 2012; Darley and Gray 1988; Edrisi et al. 2014). For example, Edrisi and Kam (2012) have identified the two separate flow regimes in foams by plotting the pressure contours as a function of gas and liquid velocities, and according to these researchers foam rheology can be represented using pressure and gas/liquid velocities (Fig. 1). As Fig. 1 shows, in the low quality regime pressure contours are almost horizontal below the boundary line, implying that pressure development in the foam in this region is mainly gas velocity (U_g)-dependent and the liquid velocity (U_w) has only a minor influence. (U_g and U_w can be calculated using Eqs. 2 and 3, respectively). However, inclined pressure contours can be seen in the high quality regime, implying that pressure variation is dependent on both gas and liquid velocities (Edrisi and Kam 2012).

$$U_g = \frac{Q_g}{A} \tag{2}$$

$$U_w = \frac{Q_w}{A} \tag{3}$$

where Q_g = gas flow rate, Q_w = liquid flow rate, A = internal cross-sectional area of pipe.

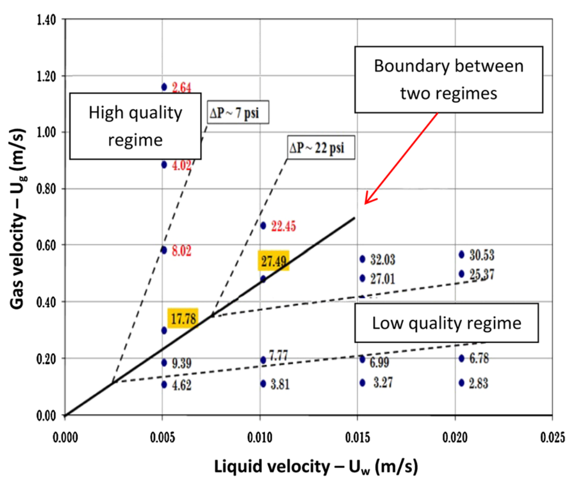


Fig. 1 The two foam flow regimes with pressure contours (Edrisi and Kam 2012)

According to Gajbhiye and Kam (2011), the high quality regime with relatively higher gas fraction is characterized by fine-textured foams and the low quality regime with relatively lower gas fraction is characterized by the stable flow of homogeneous foams. In addition, Gajbhiye and Kam (2011) identified a similar trend in the apparent viscosity and pressure of foam (Fig. 2). The apparent viscosity (μ_{app}) was calculated using Eq. 4 and shear stress at the wall (τ_w) and wall shear rate (γ_w) were calculated using Eqs. 5 and 6, respectively.

$$\mu_{app} = 47880\left(\frac{\tau_w}{\gamma_w}\right) \tag{4}$$

$$\tau_w = 3\left(\frac{d\Delta p}{L}\right) \tag{5}$$

$$\gamma_w = 39.216\left(\frac{Q_t}{d^3}\right) \tag{6}$$

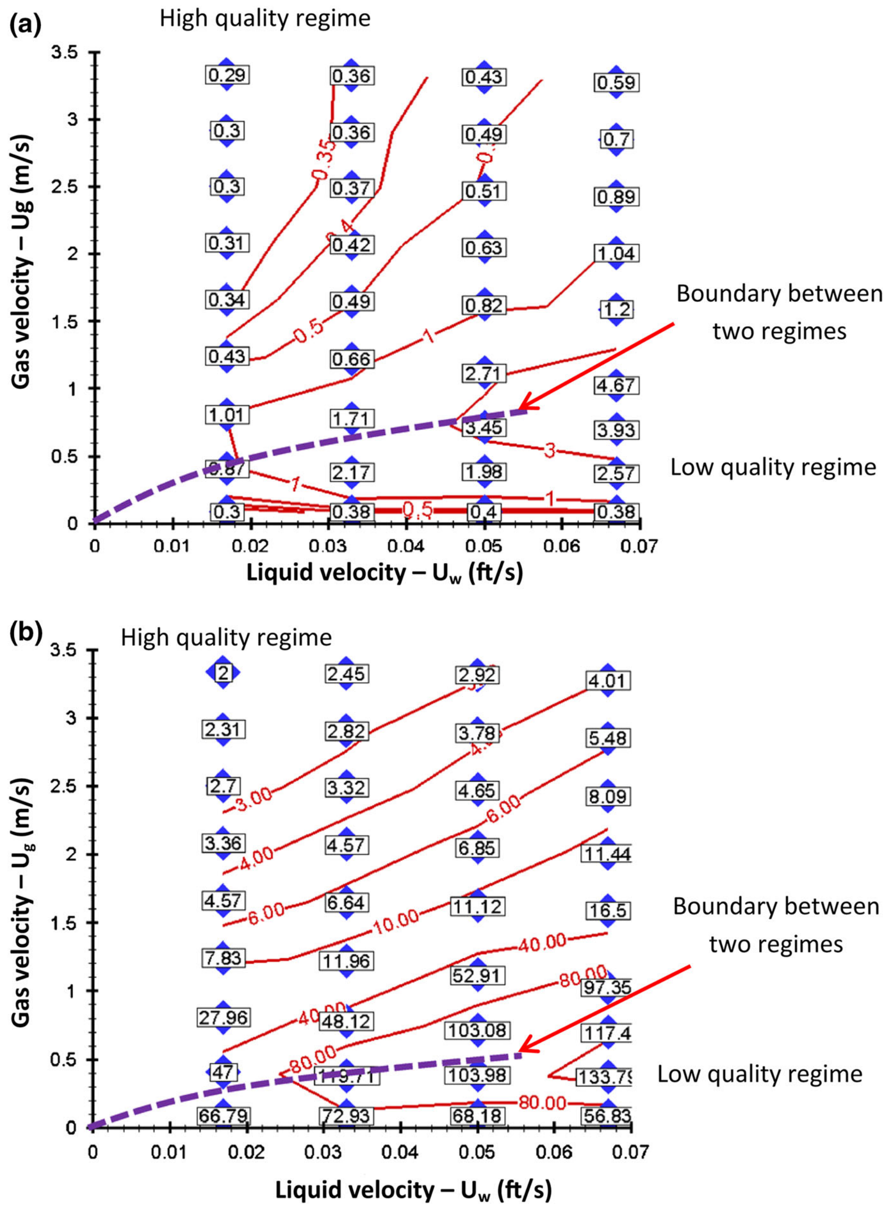


Fig. 2 **a** Pressure contours (psi) and **b** apparent viscosity contours (cp), with liquid and gas velocities (Gajbhiye and Kam 2011)

where μ_{app} = apparent foam viscosity (cp), τ_w = shear stress (lbf/ft^2), γ_w = wall shear rate (s^{-1}), Δp = pressure drop (psi), d = diameter of the pipe (ft), L = length of the pipe (ft), Q_t = total flow rate (gal/min).

3.1.1 *Flow patterns*

Since foam is a multiphase system with internal and external phases, a multiphase fluid flow pattern can be seen as a bubble, slug, plug, annular, stratified, disperse or wavy flow (Rutqvist et al. 2011; Crowe et al. 2011; Han 2012; Kreitzer et al. 2013; Fig. 3), and the flow patterns may vary with the application stage and location of the foam in the fracture network. However, most of the time foam flow can be categorized as plug flow or slug flow, based on its quality (Edrisi and Kam 2012). In general, foams exhibit a stable plug flow pattern in low quality regimes and an unstable slug flow pattern in high quality regimes (Edrisi and Kam 2012). However, it should be noted that other flow patterns also exist in any foam flow and precisely differentiating each of them is difficult. In addition, the properties of the pipelines also affect the flow pattern of the foam. For example, in the case of the plug flow pattern in foam, according to Edrisi and Kam (2012), the slip effect at the pipe wall creates an important influence on the flow pattern of the foam. In this case, the total volumetric flux (U_t) can be expressed as follows (Eq. 7):

$$U_t = \frac{Q_t}{A} = U_f + U_s \tag{7}$$

where U_t = total volumetric flux, Q_t = total flow rate, U_f = fine-textured homogeneous bulk foam velocity, U_s = pipe wall slip velocity, A = internal cross-sectional area of pipe.

These complex behaviours of foam flow patterns directly affect the modelling work on foam fracturing, as modelling results are influenced by the assumed flow patterns under different conditions.

3.2 Viscosity

The viscosity of foam is also important for an effective fracturing process, as it is a key controlling parameter for foam rheology, governs the fracture propagation pattern, and controls the proppant-carrying capacity. Moreover, the apparent viscosity of foam is foam velocity dependent and gas velocity (in the fracture) dependent (Farajzadeh et al. 2012). High viscosity foam cannot enter the ends of the fractures with tiny openings, which limits fracture propagation. On the other hand, high viscosity is necessary for a suitable proppant-carrying capacity (Harris and Holtsclaw 2014), and it is therefore clear that foam needs moderate viscosity for an effective fracturing process.

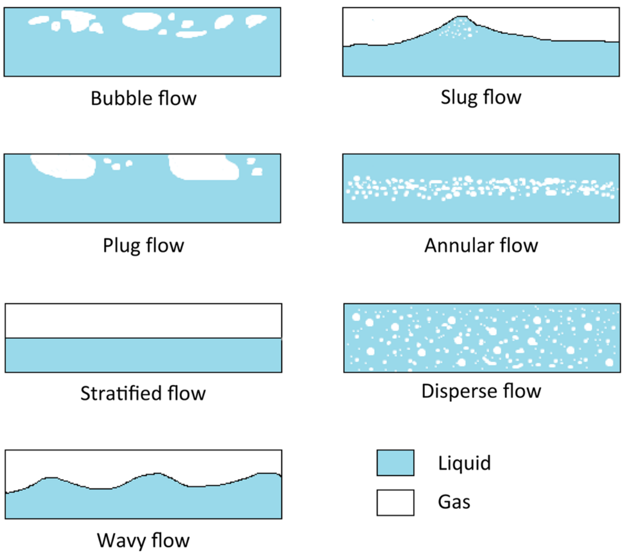


Fig. 3 Various possible foam flow patterns

Although normal foam viscosity is about 50–250 mPa s (Ding et al. 2013), this value can be significantly changed by the applied pressure, the temperature of the reservoir, and the composition (quality and constituents) of the foam. Therefore, correct evaluation of foam viscosity is required in the first stage of the fracturing process, which is initiated by checking the viscosity of the individual phases in the foam such as nitrogen and water, and how these vary with reservoir conditions such as pressure and temperature. For example, Fig. 4 illustrates how the nitrogen and water viscosities vary with temperature. Increasing the temperature from 25 to 100 °C causes water viscosity to be reduced from around 1000 µPa s at 25 °C to 250 µPa s and N_2 viscosity to be slightly increased from around 19 µPa s at 25 °C to 22 µPa s. However, it should be noted that the viscosity values of these individual components are much lower than that of the foam produced by mixing these two phases, which is around 150 mPa s at 0.1 MPa (atmospheric) pressure and 30 °C temperature. This implies that the viscosity of the created foam is much higher than that of the base constituents used to generate it.

According to Fig. 4, water viscosity exponentially decreases with increasing temperature, and nitrogen viscosity linearly increases (in a slight increment) with increasing temperature. Therefore, the foam viscosity created from these phases should follow a decreasing trend with increasing temperature due to the higher variation of the viscosity of water. According to Luo et al. (2014), CO_2-based foam-fracturing fluids also exhibit a similar trend, a reduction of viscosity with increasing temperature (Fig. 5). On the other hand, the viscosity variation with foam quality is rather different, showing an increasing trend with increasing foam

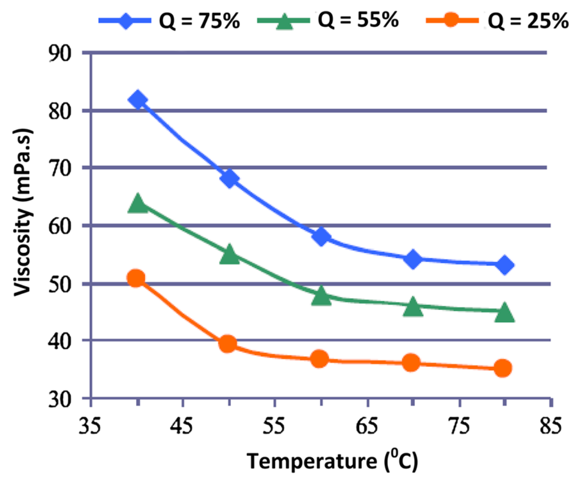


Fig. 5 Variation of CO_2 foam viscosity with temperature (Luo et al. 2014)

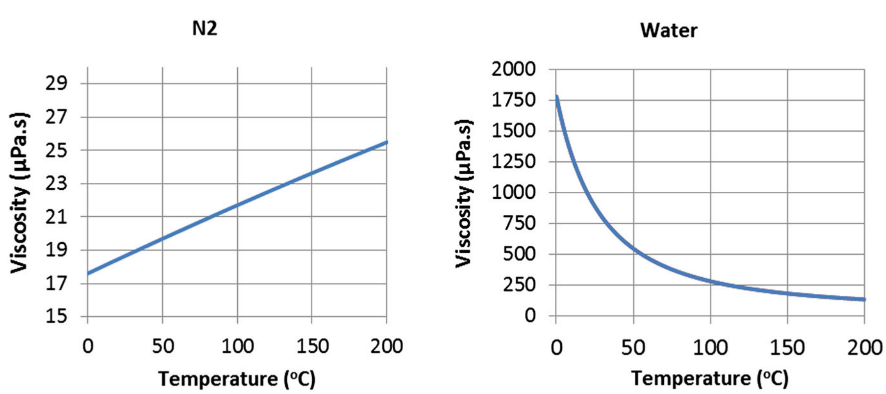
quality when the foam quality is low, and a reducing trend with increasing foam quality when the foam quality is high (Gajbhiye and Kam 2011). This implies that there is an optimum foam quality which can be used to achieve the highest viscosity, which is the optimum situation to achieve the highest proppant-carrying capacity of fracturing foams.

4 Technical advances in foam-based fluid racturing

4.1 Proppant-carrying capacity

Keeping open the generated fractures after the fracturing process is essential to enhance reservoir permeability in hydraulic fracturing, and proppants play a vital role in this regard, which will assist in

Fig. 4 Variation of viscosity with temperature (REFPROP Database)



extracting economically viable volumes of unconventional gas from reservoirs (Deng et al. 2014). Many proppant types can be used for this purpose, such as sands with higher strengths, sintered bauxite, ultra-lightweight proppants (UWPs), and low-density thermoplastic proppants (Khanna et al. 2012). However, the effectiveness of this process depends not only on the type of proppant used for the fracturing, but also on the proppant-carrying capacity of the fracturing fluid. For example, if the proppant density is higher than that of the fracturing fluid, proppants tend to settle within the fracturing fluid (Fig. 6), which causes insufficient proppants in the deep and upper surfaces of the fractures (Gu and Mohanty 2014; Sun et al. 2014). This issue can be overcome by using lightweight proppants or high-viscosity fluids like foam. Its two-phase fluid system brings a high viscosity to foam compared to other conventional fracturing fluids such as water, and that assists in even mixing of the fracturing fluid during the fracturing process and reducing proppant sedimentation (Table 2). According to McAndrew (2014), even though the slickwater fracturing create longer fractures compared to 70 % quality N_2 foams, slickwater leaves much of the fracture un-propped compared to the N_2 foams and therefore foams are more suitable to carry the proppants throughout the fractures.

In addition, the distribution of the injected proppants in fractures greatly affects the reservoir performance. According to Yu et al. (2015), possible proppant distribution in fractures can be divided into three main categories: (1) uniform distribution with high proppant concentration, the optimum design for the field, (2) uneven distribution with a proppant concentration ratio of 1:1.5:2.5:4 in four consecutive fractures, commonly the real field condition, (3) uniform distribution with low proppant concentration, a poor design for the field (Fig. 7). The usage of foam-based fracturing fluids offers a greater opportunity to create the first category, the optimum proppant distribution with uniform and high proppant concentration, compared to other conventional fracturing fluids such as water, oil, alcohol and acids. This is because of the higher proppant-carrying capacity of foam due to its higher viscosity.

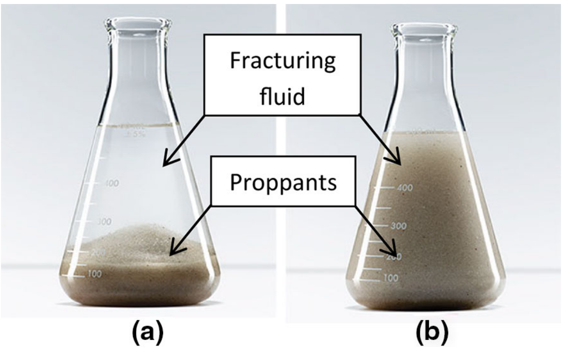


Fig. 6 **a** Proppants settled due to gravity, **b** Proppants suspended due to viscosifiers

4.2 Environmental compatibility

One of the main drawbacks of the hydro-fracturing process is its potential harmful impacts on the environment and eventually human health, especially its possible effects on surrounding fresh water aquifers (EPA 2012; Osborn et al. 2011; Cooley et al. 2012). This has led to ongoing international debate on the safety and environmental sustainability of unconventional natural gas extraction using hydraulic fracturing (King 2012). However, these possible environmental impacts depend on many parameters, including reservoir characteristics, hydraulic fracturing process characteristics, number of hydraulic fracturing operations, and the quality (amount and composition) of the fracturing fluid (Olsson et al. 2013; Vaughn and Pursell 2010). In this regard, the use of conventional fracturing fluids like water causes enhanced hazard potential due to the large quantities of wastewater generated. According to Arthur et al. (2010), a typical water-based hydraulic fracturing operation may require 3–5 million gallons (11–19 million litres) of water per well, which will generate approximately the same amount of wastewater after the fracturing process that has been mixed with large quantities of heavy metals such as chromium, nickel, lead, zinc, arsenic and selenium available underground (Olsson et al. 2013; Balaba and Smart 2012). In addition, the wastewater generated by the hydro-fracturing process in deep underground reservoirs has high saline concentrations. Dumping of this saline wastewater with heavy metals onto the ground surface causes this water to leach into surrounding fresh water aquifers and will eventually affect the quality of drinking water and the water used for agricultural purposes (Osborn et al. 2011). According to API (2010), water management associated with hydraulic fracturing is very difficult

Table 2 Settling velocity of proppants in fracturing fluids (Ding et al. 2013)

Parameter	Water-based fluid	Foam-based fluid
Height (cm)	13.7	14.5
Sedimentation time (s)	3	470
Sedimentation velocity (cm/s)	4.566	0.031

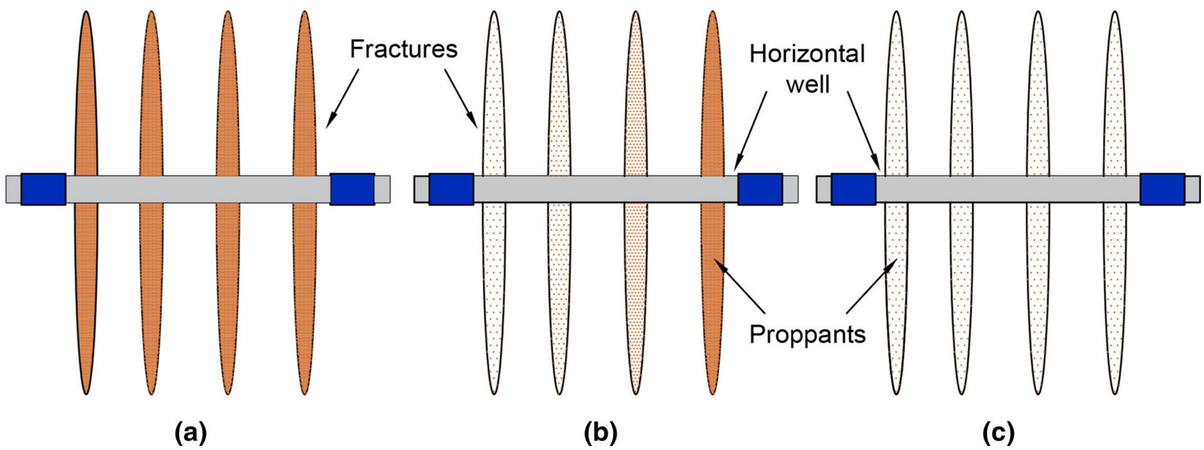


Fig. 7 **a** Uniform distribution with high proppant concentration, **b** Uneven distribution with proppant concentration ratio of 1:1.5:2.5:4, **c** Uniform distribution with low proppant concentration (Yu et al. 2015)

when the wastewater quantities generated are high API (2010). Table 3 illustrates some case studies on the impact of hydro-fracturing on drinking water aquifers. Although this issue can be reduced by recycling the flowback and re-using the fracturing fluid in another fracturing well (Paktinat et al. 2011; Table 4), there is an unnecessary cost and time associated with the fracturing process with large quantities of wastewater. Foam-based fracturing requires less water due to the higher foam quality (Edrisi and Kam 2012; McAndrew et al. 2014; Palmer and Sito 2013), which directly influences the amount of wastewater generated, resulting in minimum environmental impact.

In addition, conventional hydraulic fracturing fluids contain large quantities of chemicals to enhance the gas production rate, which may be acids, biocides, breakers, corrosion inhibitors, friction reducers, pH adjusting agents, or cross-linkers (Smith and Senjen 2011). Since most of these affect the safety and environmental sustainability of the process, it is therefore necessary to reduce their usage to have an environmentally safe hydro-fracturing process. This can only be achieved by using a fracturing agent with the function of each chemical additive (Table 5). Foam is such a fracturing fluid (Sun et al. 2014). It requires lower quantities of chemicals and therefore has greater environmental compatibility (Edrisi and Kam 2012). For example, as foam itself has high viscosity to carry proppants, it does not require additional water-based polymers or viscosifiers to enhance its viscosity. Furthermore, it does not require friction reducers or other water-wetting prevention surfactants due to its high gas percentage. For all these reasons, foam-based fracturing fluids have many beneficial properties compared to other fracturing fluids. However, it should be noted that foamers or foaming surfactants are required to generate the foam during the foam production process, which will clearly have some negative influences on the environment. However, the amount of chemicals used for foaming surfactants is far smaller than the chemicals used by other conventional fracturing fluids, as around 0.05–0.1 wt% of foaming surfactant is required to generate foams (Aarra et al. 2014), while water-based fracturing fluids require more than 1 wt% surfactant (Cooley et al. 2012).

Table 3 Case studies related to impact on drinking water due to hydraulic fracturing (US Environmental Protection Agency (EPA) 2012)

Location	Description
Las Animas and Huerfano Counties, Colorado	Investigation of potential drinking water impacts from coalbed methane extraction in the Raton Basin
Dunn County, North Dakota	Investigation of potential drinking water impacts from a well blowout during hydraulic fracturing for oil in Bakken Shale
Bradford County, Pennsylvania	Investigation of potential drinking water impacts from shale gas development in Marcellus Shale
Washington County, Pennsylvania	Investigation of potential drinking water impacts from shale gas development in Marcellus Shale
Wise County, Texas	Investigation of potential drinking water impacts from shale gas development in Barnett Shale

Table 4 Cost comparison of fresh water only and 50 % flowback water (recycled) fluid fracturing

Description	Only fresh water			50 % Flowback water recycled		
	$/bbl	Volume (bbl)	Total cost ($)	$/bbl	Volume (bbl)	Total cost ($)
Trucking + fresh water cost	3.35	339,606	1,137,680	3.35	169,803	568,840
Flowback disposal cost	8.00	169,803	1,358,424	8.00	0	0
Cost to recycle/re-use flowback + transfers	2.75	0	0	2.75	169,803	466,958
Total cost/well			2,496,104			1,035,798

Table 5 Chemicals associated with hydraulic fracturing

Component	Function/remark
Water-based polymers	Thickener, to transport proppant, reduces leak-off in formation
Friction reducers	Reduce drag in tubing
Fluid loss additives	Form filter cake, reduce leak-off in formation if thickener is not sufficient
Breakers	Degrade thickener after job or disable cross-linker
Surfactants	Prevent water-wetting of formation
pH-Control additives	Increase the stability of fluid
Foamers	For foam-based fracturing fluids
Biocides	Prevent microbial degradation

4.3 Fracture density and propagation

The term fracture density (intensity) is used to identify the effectiveness of the fracture network connectivity in the hydro-fracturing process. This can be represented in a 1-D, 2-D or 3-D space, and the definition of the term is dependent on the nature of the defined space; in 1-D space it is the number of fractures per length of scan line, in 2-D space it is the number of fractures per area of exposure, and in 3-D space it is the number of fractures per volume of rock mass. Of these, the definition of real 3-D space, or the number of fractures in a unit volume of rock, is the most widely used definition in the field (Berg 2012). The fracture density represents the connectivity of both artificially-generated fractures and natural fractures, because, in addition to the formation of new fractures in the hydraulic fracturing process, there are also natural fractures in any rock mass (Tokhmchi et al. 2010; Wasantha et al. 2015; Padmanabhan et al. 2015).

Fracture length, height and connectivity are all largely dependent on the nature of the fracturing fluid. This has been clearly shown by McAndrew et al. (2014), who simulated the fracture conductivity of the Utica shale formation located in north-eastern United States and adjacent parts of Canada. Simulations were carried out using slick water, 75 % quality CO_2 foams, and 75 % quality N_2 foams. According to their findings, although slick water can create longer fractures, it fails to deliver proppants throughout the fracture due to the lower permeability of water, and as can be seen in Fig. 8, proppants are distributed in only limited space of the fractures, which reduces productivity. For foam-created fractures, as can be seen from Fig. 8, although the fracture length is smaller, the number is higher and the proppants are delivered to a larger area of the fracture, at a rate more than 7 times higher than the distribution of slick water fracturing-created proppant distribution of foam. This implies that, although foam-based fluid generates comparatively shorter length fractures, the fractures created are greater and have evenly distributed proppants, resulting in higher productivity.

4.4 Fluid flowback properties

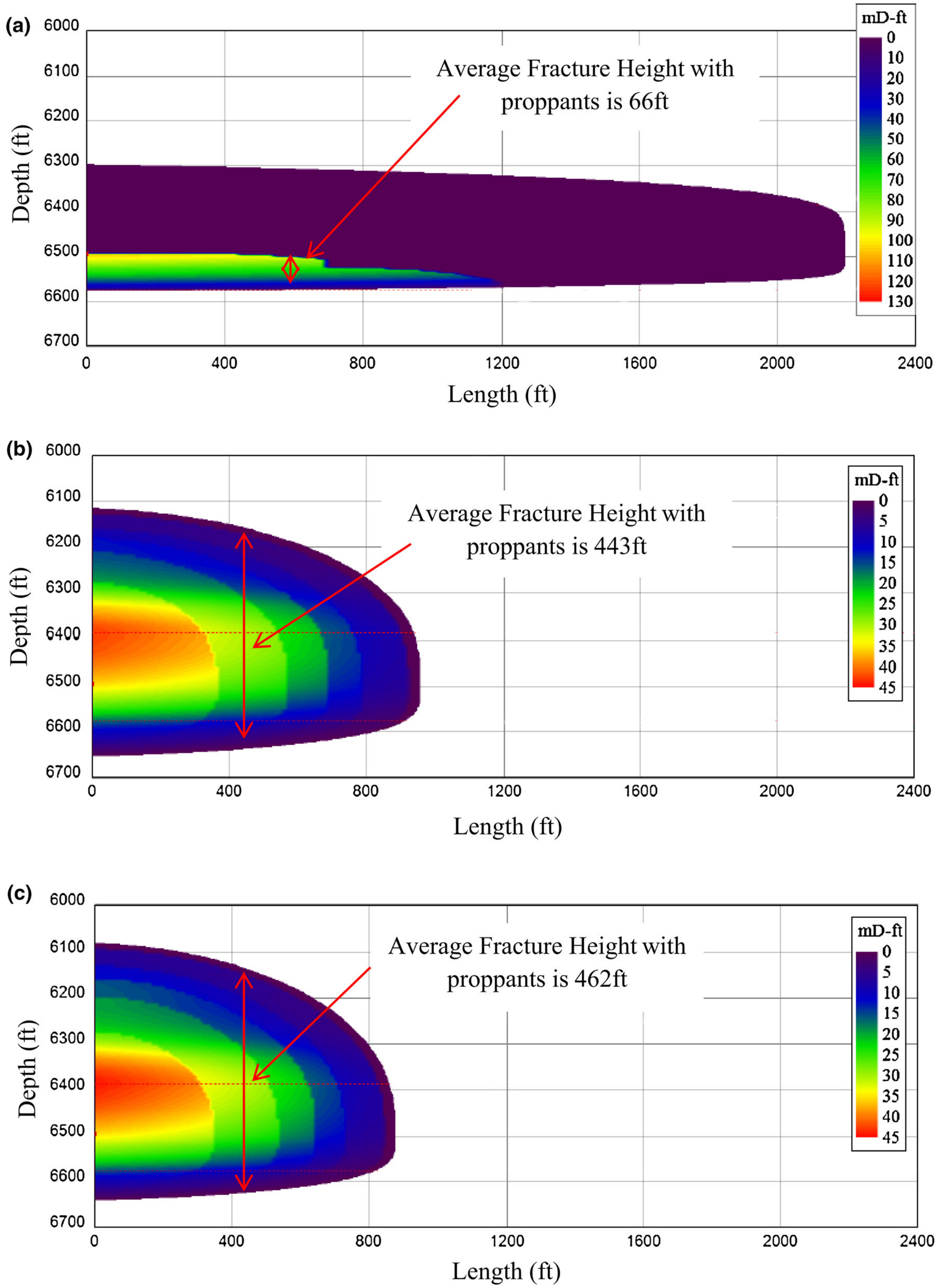
Fluid flowback ability or returning the injected fluid is also highly important for the effectiveness and productivity of the hydraulic fracturing process and quite important for environmental safety. In general, after the fracturing process, the fracture fluid is returned using the fractured well, prior to the commencement of gas production. However, the total amount of fluid that can flow back is dependent on the formation characteristics, the fracturing fluid properties, and the operating parameters of the well (Gregory et al. 2011), and gas/oil production can only be initiated after removing a considerable volume of fracturing fluids from the formation. This implies that the ability to have a greater flowback is crucially important for the effectiveness and economy of the gas/oil production process. On the other hand, the usage of foams reduces the water trapping in formation pores, which increases the gas permeability in the later production stage. In conventional water-based fluid fracturing, the injected water is absorbed into the clay minerals in the formation, which results in extended flowback time. In addition, this adsorption also creates swelling in the formation rock matrix, which reduces the pore space available for fluid movement. This eventually enhances tortuosity for oil/gas movement and therefore reduces the formation permeability for these fluids, resulting in reduced productivity (King 2012). However, if foam-based fracturing fluid is considered, the high surface pressure of foam due to its high compressibility causes easier fluid flowback, which reduces the flowback time and liquid waste generation.

Fig. 8 Fracture properties of **a** slick water-, **b** 75 % quality CO_2 ▶ foam- and **c** 75 % quality N_2 foam-created fractures (McAndrew et al. 2014)

5 Limitations of foam fracturing

Although the use of foam-based fluid fracturing in hydro-fracturing has many advantages, the logistical and technical issues associated with the process cannot be ignored and cause it to have critical limitations (Liu et al. 2010). The shorter lifetime of foam is a well-known fact. Therefore, foam production has to be done at the fracturing site just before the initiation of fracture fluid injection (Ding et al. 2013). For this reason, the chemicals and the two main fluid phases (i.e. liquid phase and gas phase) must be stored at the fracturing site. Although foam generation can be done at a different location, this should be done within a short time and is not economical when considering the associated transportation costs. Preparation of the foam at the fracturing site involves space and maintaining all the required equipment (Liu et al. 2010). This may require the acquisition of more land surrounding the fracturing location and lead to the need for greater compensation to be paid to the area's residents.

In addition, the foam fracturing process is comparatively novel and involves more advanced technology compared to the conventional hydro-fracturing processes. The necessary technical and logistical facilities lead to an additional large surcharge to the capital cost of the hydro-fracturing process and reimbursement may take many years. For example, separate storage facilities for chemicals, gas and liquids have to be constructed and foam generators have to be installed in


(a)
Average Fracture Height with proppants is 66ft
mD-ft
0 10 20 30 40 50 60 70 80 90 100 110 120 130
Depth (ft)
6000 6100 6200 6300 6400 6500 6600 6700
0 400 800 1200 1600 2000 2400
Length (ft)
(b)
Average Fracture Height with proppants is 443ft
mD-ft
0 5 10 15 20 25 30 35 40 45
Depth (ft)
6000 6100 6200 6300 6400 6500 6600 6700
0 400 800 1200 1600 2000 2400
Length (ft)
(c)
Average Fracture Height with proppants is 462ft
mD-ft
0 5 10 15 20 25 30 35 40 45
Depth (ft)
6000 6100 6200 6300 6400 6500 6600 6700
0 400 800 1200 1600 2000 2400
Length (ft)

addition to the fluid pumping system required for fracturing fluid injection. As a result, small- to medium-scale contractors are more likely to use other conventional fracturing fluids that require only limited facilities and less advanced technology, such as water and gas. This will reduce the applicability of foam-based fluid for hydro-fracturing.

6 Current field application of foam-based fracturing fluids

To date very few field applications have used foam-based fracturing fluid, and no significant recent application can be found. The first documented foam-based fracturing application was in Youngstown, Ohio, USA in 1975, where the foam generation was done by mixing water and nitrogen (Frohne 1976). In this project, initially two wells were used to create fractures, and one was used to inject foam-based fluid and the other to inject conventional hydraulic fracturing fluid. They used 68,500 gallons of foam mixed with 52,500 pounds of sand proppants and foam was injected at 1700 psi pressure. In the case of water-based fracturing, they injected 58,000 gallons of water mixed with 50,000 pounds of sand at 3050 psi average pressure. Frohne (1976) could clearly see the better performance of foam-based fracturing fluid compared to conventional water fracturing fluid for the selected reservoir conditions, including less fracturing fluid clean-up time and higher initial gas production, and the fluid flowback began around 1.5 h later in the foam-based hydro-fracturing process and 1 h later in the water-based hydro fracturing process. Most importantly, the cost associated with foam-based fracturing was about 25 % lower than water-based fracturing.

Later in 1976, a large-scale foam fracturing operation was successfully performed in a Devonian shale well in Jackson Country, USA using about 42,000 gallons of water, 160,000 gallons of nitrogen and 155,000 pounds of sand proppants (Frohne 1977). Foam made with CO_2 (liquid) and N_2 (gas) was used to create hydro fractures in more than 350 locations, and the majority were used to stimulate the Belly River and Bow Island formations in Canada. A similar type of foam ($CO_2 + N_2$) has been used successfully in other formations in the Western Canadian Sedimentary basin, including Edmonton Sands, Bearpaw, and the Nisku Gas and Viking Gas formations (Gupta 2003). Foam-based fluid fracturing has also been tested in Russia, in the Western Siberia basin using nitrogen/water foam and successfully enhanced production from depleted mid-permeable oil wells (Oussoltsev et al. 2008). Although foam-based hydro-fracturing has been tested in some countries around world, the technique has still not been tested in the field in many countries, including Australia.

7 Conclusion

This paper reviews current research on foam-based hydro-fracturing including effective foam properties, advantages and limitations of the processes, and existing field applications. A summary of the existing studies is as follows.

Foams are made by mixing a gas phase such as N_2 or CO_2 (internal phase) with a liquid phase such as water, CO_2 (external phase), and a suitable foaming surfactant is used to maintain the stability of the foam produced, such as iodine or hydrogen peroxide. The quality of the form depends on its composition, and high quality foams have higher percentages of gas.

The properties of the injecting foam greatly influence the effectiveness of the fracturing process, and its rheology, including flow pattern and viscosity, is dominant. Regarding the rheology, two separate flow regimes exist in any foam when the developing pressure/viscosity contours are plotted as a function of gas and liquid velocities. The pressure/viscosity of the foam in the low quality regime is mainly gas velocity-dependent and both gas and liquid velocity-dependent in the high quality regime. Since foam is a multiphase system, a multiphase fluid flow pattern can be seen as a bubble, slug, plug, annular, stratified, disperse or wavy flow, and the flow patterns may vary with the application stage and the location of the foam in the fracture network. A moderate foam viscosity is important, as foam with less viscosity has greater ability to enter the ends of fractures with tiny openings and foam with high viscosity has a greater proppant-carrying capacity.

Foam-based fracturing fluid has many merits compared to traditional water-based fracturing fluids, including higher proppant-carrying capacity, lower water consumption and chemical usage, more efficient and easier fluid flowback and less environmental damage. However, it also has some limitations, of which the lack of related knowledge, high capital costs associated with the facilities required including equipment and space, and potential damage to the environment from surfactant chemicals are dominant.

To date very few field applications of foam-based fracturing fluid have been used, and no significant recent application can be found. Most of the relevant field applications have been in the USA and Canada, and the technique has still not been tested in the field in many countries in the world, including Australia.

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