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CO_2 Foam as an Improved Fracturing Fluid System for Unconventional Reservoir

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Abstract

Unconventional reservoirs have gained substantial attention due to huge amount of stored reserves which are challenging to produce. Innovative recovery techniques include horizontal drilling coupled with hydraulic fracturing are required to optimize the production of hydrocarbons. There are numerous concerns associated with the utilization of conventional water-based polymeric solutions for fracturing shales. However, the gas utilization has been found as an exceptional stimulation approach providing various benefits. CO_2 foam, an energized fracturing fluid, has been used to overcome the limitation of conventional fracturing fluid. CO_2 foam is able to enhance hydrocarbon production by addressing the critical issues associated with the conventional technique. The rheological property of CO_2 foam fracturing fluid is a key factor controlling the efficiency of overall processes. Different models describing the foam flow behavior have been produced and numerous investigations have been conducted to explain the rheological behavior of foam for fracturing purpose. Various process variables, such as foam quality, temperature, pressure, shear rate, surfactant concentration, and salinity strongly affect foam rheology behavior giving an impact on designing foam fracturing fluid at required fracturing conditions. In-depth analysis and information gathering are substantially required to ascertain the performance of CO_2 foam as an improved fracturing fluid system.

**Keywords:** fracturing fluid, shales, CO_2 foam, foam rheology

1. Introduction to unconventional reservoirs

Global energy consumption has been increasing rapidly whilst existing oil and gas fields are being depleted day by day. In addition, insufficient amount of hydrocarbons produced from conventional reservoirs to fulfill the increasing energy demand has led to global challenges. Due to these factors and also environmental reasons, the use of natural gas that is considered as a green energy, is demanding. The large volume of natural gas stored in tight formation such as shale and tight sand has been practically developed recently. According to the report of EIA Annual Energy Outlook 2015, the total energy consumption in 2040 will rise to 105.7 quadrillion Btu from 97.1 quadrillion Btu which is about 8.9% of the total energy

consumption [1]. Most growth is found in the consumption of renewable energy and natural gas. However, energy from the renewable and sustainable resources cannot compete with the nonrenewable and cheap fossil fuel energy in technical and economic aspects. Therefore, unconventional reservoir is considered as an immediate alternative for overcoming the production decline of the conventional reservoirs. These unconventional reservoirs originally come in different forms which include shale gas and oil, tight gas and oil, coal bed methane (CBM), shale oil, and natural gas hydrates as shown in **Figure 1(a)** [2]. The illustration of global gas resources including the general features and the worldwide endowment for each resource is presented in **Figure 1(b)**. Endowment is the sum of undiscovered gas, reserves, and the cumulative gas production. The endowment for the natural gas as shown in **Figure 1(b)** is about 68,000 trillion cubic feet (Tcf) and 70% of it is approximately in shale gas and tight gas reservoir [2].
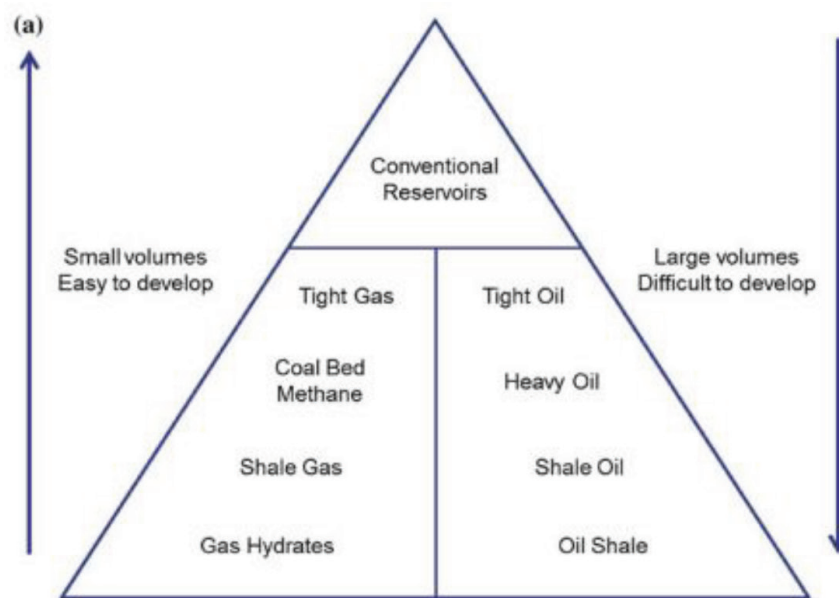

(a)
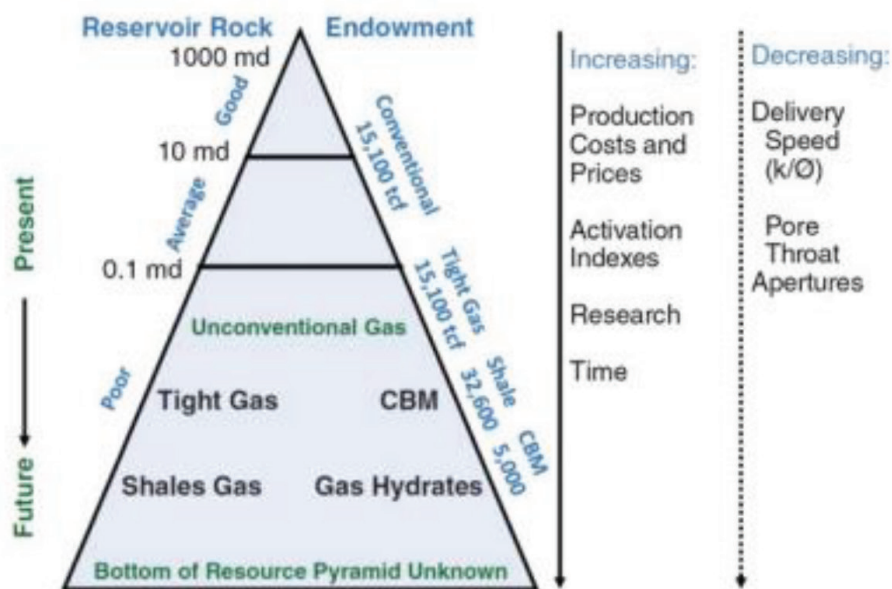
(b)

Figure 1.
Pyramid of world oil and gas resources for (a) oil and gas, and (b) natural gas with endowment [2].

Unconventional reservoirs have been significantly important due to their huge amount of stored hydrocarbon. Unconventional reservoirs are defined as those hydrocarbon reservoirs that require stimulation techniques including the alteration of rock permeability or fluid viscosity in order to develop them economically and to produce the hydrocarbon at commercial rates [3]. Unconventional reservoirs, however, come with various challenges that include a complex system having hydraulically induced fractures, natural fractures, and a complex matrix system comprising of different minerals and kerogen [4]. It is of great interest to develop and refine new and existing techniques to recover more oil and gas from these types of unconventional reservoir.

Tight gas is the natural gas present in sandstone or limestone having very low matrix permeability, less than 0.1 millidarcy (mD), and porosity of less than 10% [5]. Shale gas is the trapped natural gas produced from the shale formation with minimal migration. Moreover, coalbed methane is methane gas trapped in coal beds or seams which is stored on the coal internal surface during the coalification process. Natural gas has been called "sweet gas" because of the absence of hydrogen sulfide content which makes it different from the typical conventional gas reservoir [6]. According to the estimate of Energy Information Administration (EIA), recoverable gas in the world is about 7299 trillion cubic feet (Tcf) [7]. The production of natural dry gas produced from shales in the US in 2015 was about 9.96 Tcf which is about 43% of the total US gas production. A continuous increasing trend in shale gas production was observed from 1999 to 2015 as shown in **Figure 2** [8].

The permeability range of shale gas and tight gas reservoir is usually between nano-Darcy (nD) and micro-Darcy (µD). The size of pore throat in shale is in nano-meter and there are some cracks present which assist connection between pores [9]. The shale gas reservoir possesses high capillary pressure, high irreducible wetting phase saturation, low porosity, and extremely low permeability [9]. In order to produce gas commercially from these extremely low permeability reservoirs, horizontal drilling and hydraulic fracturing stimulation technology are required to execute [7].
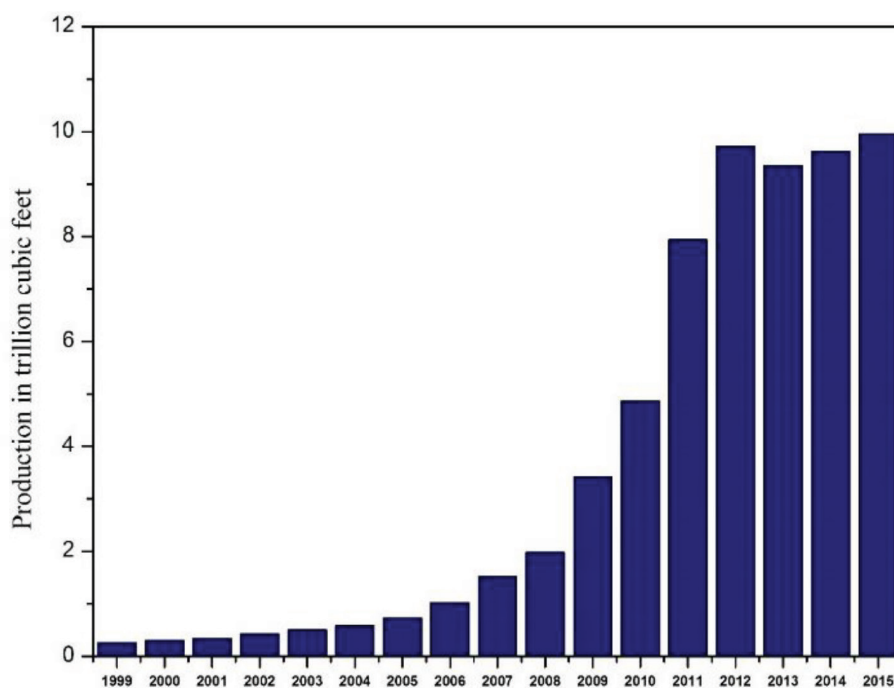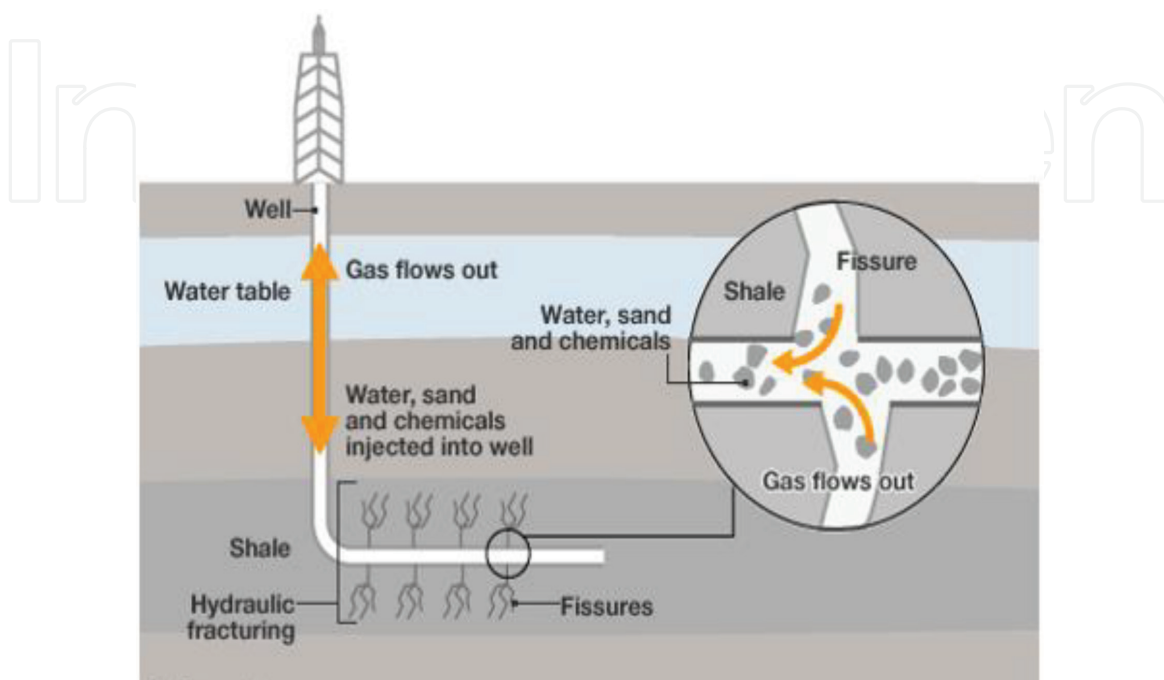

Figure 2.
Production of natural gas from shales in United State from 1999 to 2015 (in trillion cubic feet) [8].

2. Hydraulic fracturing technology

Hydraulic fracturing is classified as formation stimulation technique in which reservoir rock is fractured by pumping fracturing fluid with high pressure to create a fracture networks in order to increase the hydrocarbon production rate. This stimulation process has been used in 9 out of 10 gas wells in the United States [10, 11]. Water-based fracturing fluid has been widely used for fracking rock formation. In particular, shale reservoirs are characterized by their extremely tight rock formations with very low pore connectivity. The matrix permeability of a typical shale gas reservoir is about 1–100 nano-Darcy (nD) [12, 13], whereas the porosity is mostly less than 10%. To develop such ultra-low permeability formations, hydraulic fracturing is proven to be a successful method. In applications for shales, millions of gallons of water as the base fluid and sands in combination with a small amount of chemical additives are pumped into the reservoir [1, 14]. The injected fluid breaks the rock at high pressure and releases the free and adsorbed gas as shown in **Figure 3**. An immensely high permeability can be achieved by applying hydraulic fracturing that also aids in connecting the fracture networks [1]. During fracture generation and propagation, the sand or other coarse materials, the so-called proppant, is employed to expand the fractures as it holds the fractures open when the pressure is eventually relieved. The proppants can be classified into three types which are silica sand, resin coated sand, and ceramic proppant [15]. The utilization of proppant must be appropriate and its selection is strongly based on type and characteristic of well and reservoirs which will be hydraulically fractured. Proppant selection including its type, size, and shape is a critical element for the stimulation process whereby proppant characteristics such as weight, strength, consistency in size, and inert nature must be taken into account for effectively maintaining cracks from fracturing operation [16].

Furthermore, different types of fluids and treatments have been used and continuously developed for fracturing application. The effectiveness of fracturing fluids such as water, micellar solution, crosslinked-gel, polymer foam, and polymer-free foam has been studied and its selection is generally based on various factors including pressure gradient, reservoir temperature, formation Young's modulus, fracture half-length requirements, the presence of natural fracture, and

Figure 3.
Hydraulic fracturing of shale gas reservoir [1].

height of the pay zone. In addition to the aforementioned factors, chemical usage in the fracturing process is also adjusted depending on its environmental impacts and economics. On the other hand, there are several constraints associated with shale hydraulic fracturing processes that include usage of high volume of water, aquifer contamination, and methane infiltration in aquifers.

In general, fracturing fluid is composed of 99.5% of water and sand proppant, and 0.5% of chemical additives [17]. Potential additives for enhancing the performance of fracturing fluid include surfactant, friction reducers, biocides, and scale inhibitors [18]. In order to optimize fracture treatment for improving overall recovery efficiency, reservoir characterization is essential as specific treatment is required depending on the rock and fluid properties. Besides hydraulic fracturing, other techniques such as explosive fracturing and dynamic loading that do not utilize water-based fluid have been taken into consideration [19]. Nonetheless, these aforementioned techniques are not extensively implemented due to their performance and environmental concerns.

3. Fracturing fluids

The formation of fractures in reservoir rocks is initiated by fracturing fluid injection under high pressure to hydraulically break the rock, hence producing the stored hydrocarbons. Fracture treatment and fracturing fluid design are essentially dependent on the unique properties of reservoirs. Alteration of fracturing fluids is important in order to meet the targeted reservoir and operating conditions. Oil-based fracturing fluids were initially developed for fracturing job; however, due to the environmental and safety concerns, it was shifted to water-based fracturing fluids. An excessive amount of water utilization which can cause damage to water-sensitive formations has led to the use of liquefied natural gas as an alternative. Besides the use of slickwater, chemical solutions for hydraulic fracturing have also been known as an effective technique for complex reservoirs which are naturally fractured, brittle, and tolerant of high water volume [20]. Other innovations such as water-based viscous polymeric fracturing fluids have been proposed, but they are still associated with some challenges, such as degradation of different molecular weight polymers and the formation of internal filter cake leading to undesirable damage to the reservoir rocks [20]. Slickwater which is mainly composed of water with a low concentration of chemical additives, or combination of different fracturing fluids has been commonly used for shale gas wells. As mentioned earlier, owing to different purposes of fracturing jobs, the utilization of other additives including acid, surfactant, potassium chloride, friction reduces, corrosion inhibitors, and pH adjusting agent at low concentration has been considered [21, 22].

3.1 Hydraulic fracturing fluids for shales

Shales have great variations with their typical characteristics that essentially determine the required hydraulic fracturing technique and fracturing fluid design. For shale fracturing jobs, fracturing fluid comprises of base fluid, additives, and proppant. Slickwater treatments using high injection rates and lower proppant concentrations have provided some advantages such as lower cost, reduced fracture height growth, and reduced gel damage within the fracture. However, the use of high volumes of fluids, poor proppant transport and suspendability, higher leak-off, and low fluid viscosity causing complex fracture geometries are disadvantages associated with slickwater usage as fracturing fluids [21]. Surfactant-based fluids were then proposed as fracturing fluid because surfactant molecules can undergo

self-association to generate micelles that can increase viscosity in the absence of polymer. Some modification of surfactant-based fluid system, such as nanoparticle addition, has been considered to stabilize the system at high temperature [23].

Furthermore, single gas system has been reported to effectively increase the amount of energy required to recover the fluid and reduces water volume in shales that are classified as water-sensitive zones. However, there is a major disadvantage associated with the gas fracturing process which is the reduction in the amount of proppant that can be placed. The cost of operation also increases due to capturing, pressurizing, and transportation of the gas, for instance CO_2. Additionally, separation of CO_2 and CH_4 during flow back would need additional facilities which will increase the expenses and the produced natural gas along with CO_2 during the flow back period will also reduce. Supercritical CO_2 has the ability to dissolve some amount of the water formed. When the amount of water reduces in order to achieve equilibrium with supercritical CO_2, the remaining super saturated brine would cause salt precipitation which could block the flow channels and restrict the production [24].

In water-sensitive reservoirs possessing high clay contents, fracturing fluid containing a small amount of water and large gas volume is preferred in order to reduce formation damage caused by high capillary pressure and permeability discontinuity as the impacts of clay swelling [25]. Foam also can reduce the damage around wellbore due to invaded fluid which eventually reduces the water volume used for hydraulic fracturing. Mixture of dispersed gas (N_2 or CO_2) and surfactant solution resulting in foam system has become another innovation whereby the foam can carry proppant efficiently with minimum residue left in the fracture. This system, i.e., N_2 foam or CO_2 foam, which is also known as energized fluid, has higher propagation ability into more complex fracture networks due to its mobility control ability. In other words, foam is able to carry proppant deeper in the formation in more efficient manner. CO_2-based energized fluids have been reported to provide a better foaming performance leading to a higher recovery [26]. In ductile reservoirs, an efficient proppant placement is essentially required and fracturing techniques such as N_2 foam and CO_2 polymer have been implemented in ductile reservoir, e.g. Montney Shale in Canada [27]. CO_2-based fluids can eliminate the need of water, provide extra energy due to gas expansion, and help in decreasing the flowback time.

Recent developments of unconventional reservoirs including shale and tight gas and coalbed methane have put more emphasis on fracturing treatment with little use of water as the interaction between these reservoirs and the used fracturing fluids can negatively impact gas production [28]. The attempt to reduce water use in the fracturing process has been driven by several factors explained below in detail.

3.1.1 Water-sensitive formations

The recovery of water, oil, and gas from unconventional reservoirs is essentially affected by the mineralogy of the rock formation. Ultra-tight formation with small propagated and natural fracture widths results in high capillary forces which are important for hydrocarbon production. The injection of water causes capillary barrier leading to production decline. In the case of water-sensitive formations having high clay content, clay swelling occurs during fracturing processes with water-based fracturing fluid which can reduce formation permeability due to peeled pore surface and pore throat plugging. Changes in permeability due to clay swelling lead to capillary pressure and relative permeability shifts. These effects become more dominant when moving from micro to nano-Darcy permeability ranges [21, 29]. The excessive fine migration including clays in the near-wellbore region can also reduce the productivity. To avoid clay swelling and fine migration, different

fracturing treatments utilizing a little amount of water, such as oil-based fluids, high quality foams, and liquefied petroleum gas are preferred.
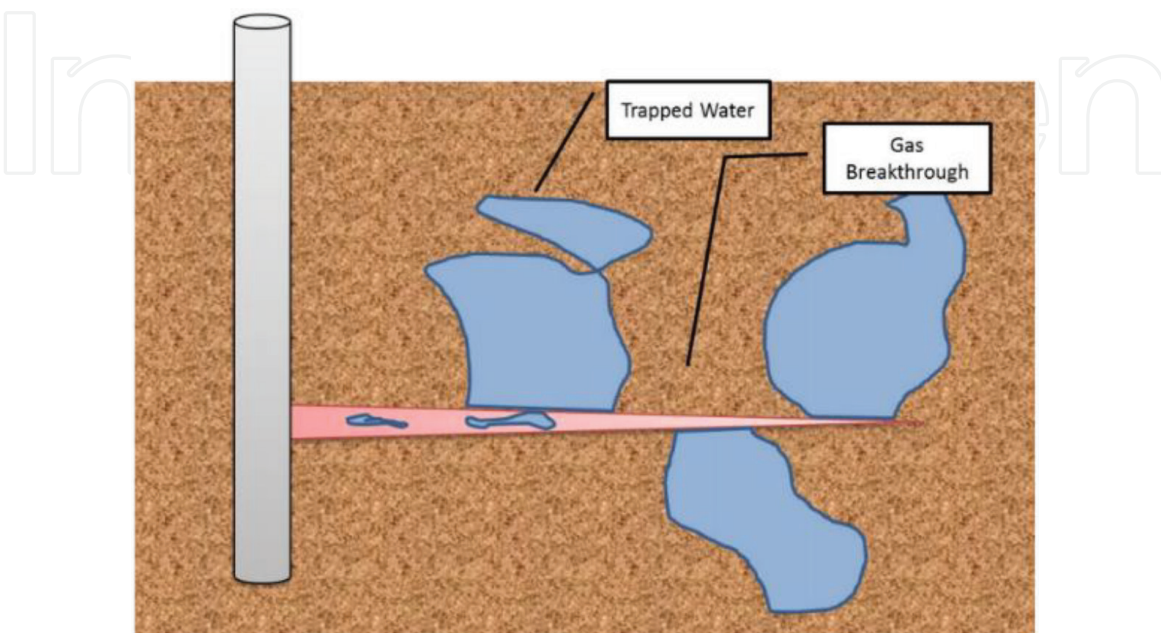
3.1.2 Water blocking

During fracturing fluid injection, water invasion occurs in the formation due to high capillary forces. High surface tension in pores and the hydrophilic characteristic of rock surfactant result in a significant water block in the formation, illustrated in **Figure 4**. This effect will be detrimental to gas productivity [30]. The increase of water saturation due to water trapping or water blocking considerably decreases the relative permeability of the gas [31].

As compared to conventional fluid, CO$_2$-based fluid can assist the clean-up of injected liquid phase during flowback. As the pressure decreases, the expansion of the gaseous phase assists the flow to the surface and provides a rapid fracture and reservoir clean-up which accelerates the onset of the production phase after speeding up the flowback phase [30].

3.1.3 Proppant placement

The slickwater/water-based fluid fracturing process generally creates longer and skinny fractures. However, a poor delivery of proppant has been reported along much of the fracture and much of the fractures remain un-propped allowing it to close after the pressure is released and fracturing job is over, particularly in ductile rock formation [32]. In addition, the near wellbore region, in this process, is dominantly propped due to rapid sand settling. Gels are used to avoid this rapid settling of proppants; however, the adverse effect which is damaging the proppant pack and the fracture surface can occur. In previous studies, it was suggested to replace sands with ultra-lightweight proppants in order to achieve efficient transport of proppant. Foam fracturing treatment reportedly gives an efficient transport of proppant as compared to the slickwater fluid treatment. Therefore, use of foams can be considered to effectively improve the performance of proppant placement. In foam fracturing, water exposure is avoided alienating the reservoir matrix from the softening effect and hence proppant embedment could be reduced [30].

Figure 4.
Water blocking due to high capillary pressure.

Moreover, the interaction between bubbles of gas at high foam qualities gives a large energy dissipation which results in good effective viscosity hence providing more effective proppant placement. Whereas at low foam qualities, the interaction among gas bubble is minimum and the fluid viscosity behavior is similar to that of base fluid. **Figure 5** shows the condition of proppant pack formed using three different fracturing fluid systems [33]. It is clear that energized fluid or CO_2 foam provides efficient proppant placement, whereas the water and gel-based proppant have poor permeability due to proppant embedment and gel residue, respectively [33].

3.1.4 Water availability and cost

The amount of water required for the fracturing process depends on the type of formation which is being fractured. The utilization of a huge amount of water is a major concern and the equipment and the fluids are limited on the fracturing site. The widely used fracturing technique employs water-based fluid which consumes a large amount of water, has high water leakage in formation, and imposes high water disposal costs. Besides, the cost and supply of fluids such as LPG, N_2, and CO_2 highly depend on the field location.

3.2 Foam fracturing fluid

Foams have been found to be the most promising and appropriate fluid to fracture shales and improve the recovery efficiency. Although the cost of operation increases, the benefits are much higher than the incremental cost [35]. The structure of foams has the ability to provide an increased effective viscosity without plugging reservoir pores and causing formation damage by forming any filter cake [28]. It has an increased efficiency due to reduced fluid loss coefficients, high viscosity inside induced fractures and negligible sand settling velocities [28, 36]. Foam application also gives an increased capability of proppant distribution and proppant placement over the entire fracture length. Due to high foam apparent viscosity, it is achievable to have an improved proppant suspension and placement. In foam fracturing, the utilization of gas as a replacement to a significant amount of the liquid phase assists hydrocarbon recovery by decreasing formation damage and water blocking. Foam utilization eliminates the need of any additional additives such as cross linkers, gel breakers, etc. It also decreases the amount of produced water and its treatment cost. Moreover, the expansion of gas assists liquid flow back and helps fracture cleanup.

Foams are typically generated by a surfactant solution (base fluid), in some cases, in combination with a small amount of polymer as a stabilizer and other additives. Surfactants that are used as a foaming agent may help to lower the surface
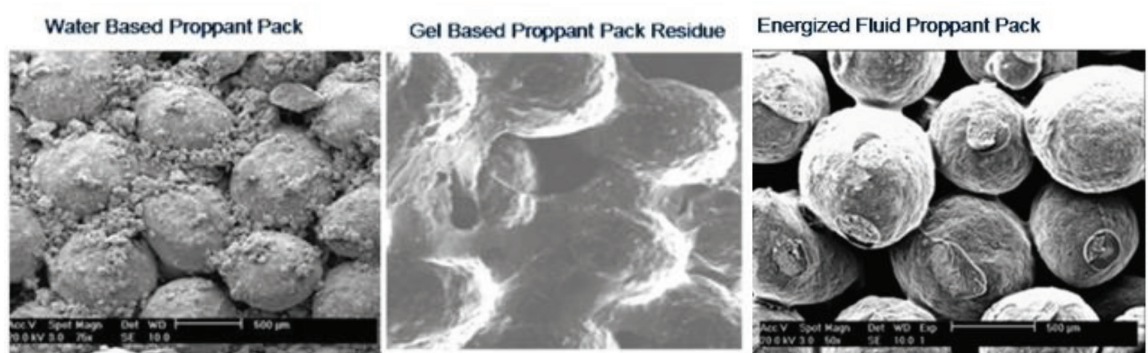
Figure 5.
Proppant conditions after performing fracturing job using different types of fracturing fluids [34].

tension of the fracturing fluid and avoids water blocking by recovering fracturing fluid after the job completion [37]. Both laboratory and field scale tests have shown that the addition of surfactant increases the gas production by reducing the capillary forces and altering the wettability of shales. The rheology of foam has great importance in fracture treatment design and has been discussed by multitude of studies [8, 36, 38–40].

4. Foam rheology

Determining foam rheology is complex and it is considered difficult to predict the behavior of foam flow [20]. The performance of foam-based fracturing job is highly dependent on the rheology of the foam under downhole conditions and the efficiency of fracturing job depends on non-Newtonian behavior of foam [41, 42]. Foams are considered versatile, complex, and unique due to their high viscosity and low density characteristics [43]. Foam apparent viscosity is determined by accounting for the contribution of foam film thickness, bubble deformation, and the expansion of foam interface due to surface tension gradient [44]. The apparent viscosity of foam is strongly dependent on various process variables such as foam quality, shear rate, temperature, pressure, surfactant concentration, and salinity [8, 41, 42]. The effects of these parameters are discussed below.

4.1 Effect of foam quality and texture

Foam quality and its texture have a strong impact on the viscosity of CO_2 foam [45, 46]. A simultaneous study of foam texture is important during the foam rheology measurements [47–49]. Before starting the viscosity measurements, it is important to ensure that the flow loop is completely filled with the foam of known foam quality. It has been reported by many researchers that the rheology of foam is dependent on foam quality and foam apparent viscosity [38, 48, 50–53]. Foam quality (f_q) is defined as the volume fraction of gas in foam [54–56] and is expressed as Eq. (1).

$$f_q = \frac{V_g}{V_g + V_l} \qquad (1)$$

where v_g and v_l are gas and liquid volume in foam, respectively.

When the foam is relatively wet, i.e., at low quality, the foam bubbles are less in number and are far apart with no interaction with each other during the foam flow. Therefore, the foam viscosity is low.

When the foams have low foam quality (i.e. relatively wet foam), the interaction of dispersed gas bubble is insignificant during the foam flow and due to this reason viscosity of foam decreases ; whereas at high foam quality, i.e., when the foam is dry, the interaction of bubble will be quite significant during the foam flow and the friction between the individual bubbles will result in the drastic increase in foam apparent viscosity. In the case of dry foam with very high foam quality, the bubble cannot sustain and breakdown occurs during which a sharp decrease in foam viscosity occurs [43].

4.2 Effect of shear rate

The applied shear rate has a significant impact on foam apparent viscosity. The changes in the foam apparent viscosity at different shear rate display power law behavior. Ahmed et al. [84] tested high quality polymer free foams and reported

a typical shear thinning behavior within the shear rate range (10–500 s^{-1}). The viscosity of foam decreases in shear flow due to Rayleigh-Taylor instability, which causes the tensile deformation, stretching, and rupturing of lamella [41, 57].

4.3 Effect of temperature

Foam is a metastable state system which goes through coarsening and rupturing when the liquid drains from the lamella and plateau borders [58]. An improved stability foam could be achieved when the viscosity of foaming solution is increased [59]. The increase in temperature causes thermal thinning of foam film which quickly drains liquid leaving behind thin lamella [60]. **Figure 6** shows the foams generated using a mixing approach at two different temperatures (20 and 50°C). It is clear that the foam texture at high temperature is relatively coarser and it has a wide range of bubble size distribution whereas at low temperature, uniform and fine textured foam is noticed. Hence, when the temperature is increased, the rate of foam lamella drainage and coalescence of bubbles are quick, resulting in a significant decrease in foam apparent viscosity [8, 60–62]. High fluctuations in temperature may form holes in the lamella which would increase both bubble coalescence and lamella rupturing [62]. Hence, the rising temperature causes significant reduction in the apparent viscosity of supercritical CO_2 foam [8, 63].

4.4 Effect of pressure

When the pressure increases, the size of foam bubble significantly decreases, whereas the lamella size becomes thinner and larger which results in slow liquid drainage [59]. This is due to the reason that the generated foams at high pressure are exceptionally strong possessing high apparent viscosity [8] and if the pressure is extremely high, it may be possible that the lamella could not withstand and it ruptures [59].

4.5 Effect of surfactant concentration

Proper selection of foaming surfactant and its concentration under reservoir and fracturing conditions is an essential task. Aronson et al. discussed the disjoining isotherm of foam film at two different surfactant concentrations
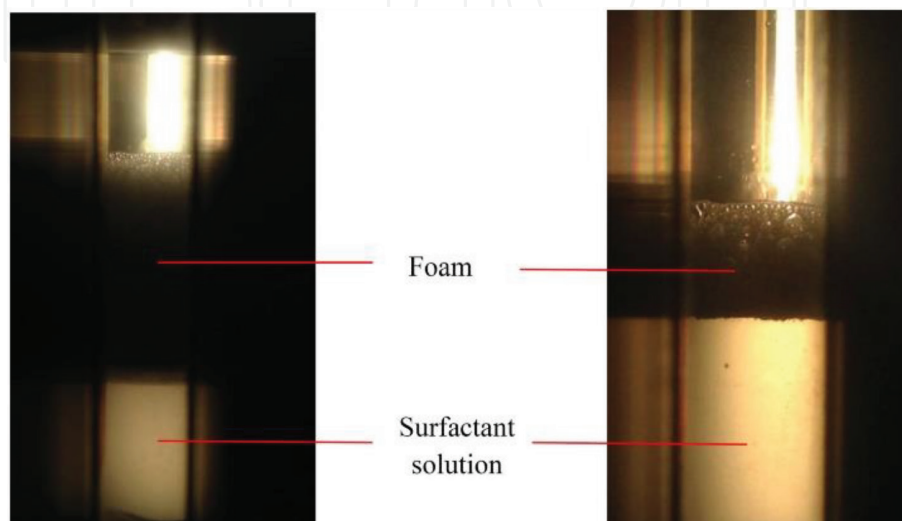
Figure 6.
Pictures of foam column stabilized by surfactant (Triton X-100) at 20°C (left) and 50°C (right) [64].

[65]. They found that higher surfactant concentration is able to provide high disjoining pressure to the foam lamella which significantly increases the pressure gradient and the resistance to the foam film during the foam flow process. Apaydin and Kovscek discussed the impact of surfactant concentration and noticed that at low surfactant concentration, weak foam generates which offers low resistance to flow [66]. Gu and Mohantay discussed the apparent viscosity of polymer free foam considering two different surfactant concentrations (0.1 and 0.5 wt%) and it was noticed that the higher concentration is able to generate highly viscous foam under fracturing conditions [8]. The increase in viscosity is accredited to the increment in total interfacial area of the foam structure which induces additional lamella stability [8]. Foam lamella should be elastic in order to withstand any deformation and the force which restores lamella comes from the Gibbs-Marangoni effect [67]. Some authors presented that direct and strong relationship exists between surface elasticity of lamella and foam stability [68–72], whereas others disagree and reported no direct relationship [67, 73]. A maximum foaming performance is usually noticed at intermediate surfactant concentration dictated by the Gibbs-Marangoni effect [69]. When the surfactant concentration is high, the surface elasticity of lamella decreases, which negatively affects the foam endurance due to reduced counteraction towards the deformation forces [69].

4.6 Effect of salinity

The shape of surfactant micelles (known as aggregates of surfactant molecules) changes with the change in surfactant packing parameter. The packing parameter is expressed as $P = v/a_o l_c$, where a_o is the area of the surfactant headgroup, v is the volume of the surfactant tail, and l_c is the tail length of the surfactant molecule [74]. Due to the increase in salinity, the transformation of spherical shape micelles of ionic surfactants into wormlike micelles takes place. These micelles are elongated spherocylindrical having two hemispherical end caps and a cylindrical body. The neutralization of repulsive forces between micelles due to the addition of salt reduces the effective area of surfactant head and alters the packing parameter of surfactant [14, 75]. The wormlike micelles entangle with each other and generate three dimensional networks, which impart viscoelasticity, and therefore, the behavior of surfactants becomes similar to that of viscoelastic polymer solutions [74]. Anionic surfactants have the ability to form such wormlike micelles when sufficient electrolyte is added [76]. For surfactants, such as sodium lauryl ether sulfate (SLES) and sodium dodecyl sulfate (SDS), the addition of electrolyte increases the surfactant packing parameter as well as solution viscosity [74]. It has also been reported that surfactant ability to form a strong foam depends on its hydrophilic/lipophilic balance (HLB) which may vary due to the addition of salinity [77]. Foam of decyl-trimethylammonium bromide (DTAB) surfactant has been reported to decrease the foam viscosity with the increase in salinity; however, the cetyl trimethylammonium bromide (CTAB) provided an increasing trend as the salinity in the solution was increased. Another surfactant, Mackam CB-35, by Rhodia provided a decrease in foam viscosity until 3 wt% salinity, and beyond that a prominent increase in foam viscosity was reported [77].

4.7 Foam rheological models

The rheology of foam determines various characteristics of fracture growth, and therefore, it is important to accurately estimate the rheology in order to predict the fracture geometry. Different rheological models have been developed that describe

the foam flow behavior, from the widely used power law model to the Herschel-Bulkley model, which have different degrees of success [8, 32].

The Herschel-Bulkley model incorporates a yield stress for non-Newtonian fluid. In this model, the yield stress becomes negligible at high shear rate and the model becomes similar to the power law model. Mathematically, the Herschel-Bulkley model is presented as Eq. (2) [8].

$$\tau = \tau_o + K\gamma^n \tag{2}$$

where τ is the shear stress, γ is the shear rate, τ_o is the yield stress, K is the consistency index, and n is flow behavior index.

Power law or Ostwald-de Waele model is one of the most commonly used models for describing the non-Newtonian behavior of foam [8, 63, 78–80]. The power law model can be mathematically expressed as shown in Eq. (3) below [63, 81].

$$\mu = K\gamma^{n-1} \tag{3}$$

where μ is the viscosity, K is the flow consistency index, γ is the shear rate, and n is the flow behavior index.

A straight line appears when log μ is plotted versus log $_\gamma$. By taking the logarithm of both sides of Eq. (5), the parameters of the power law model can be determined as shown below.

$$\log\mu = \log K + (n - 1)\log\gamma \tag{4}$$

If the solution viscosity of the solution is plotted against the corresponding shear rate on a log-log paper, a straight line appears with the intercept as K at a shear rate (1/s), and as shown in **Figure** 7, $(n - 1)$ will be the slope of the straight line.

The n value explains the behavior of the solution, i.e., when $n < 1$, the fluid shows shear thinning behavior, whereas for the shear thickening fluids, $n > 1$. For foams, $n < 1.0$ indicates a pseudoplastic behavior. The extent of shear thinning behavior of solutions can be quantified by the value of n. The value of n is significantly lower than unity if the solution is highly shear thinning, whereas if the n value is equal to unity which is the case of Newtonian fluid, the K value will become the Newtonian viscosity.

Foam behavior indices (K and n) are the function of foam quality, chemical concentration, temperature, and pressure. The rheological behavior of the foam is somewhat similar to the polymers. Foam system is considered complex and its model parameters are reliant on foam geometry, temperature, pressure, and foam properties [8, 41, 78]. Previous studies performed on foam rheology concluded that it is important to control various parameters such as gas volume fraction (i.e. foam quality), foam texture, pressure, temperature, chemical types, concentrations, etc. while measuring the foam apparent viscosity [82]. Many studies also reported higher performance of CO_2 foam fluid with higher recoveries as compared to other fluids [21, 83]. However, it is difficult to understand and model the behavior of such energized fluid [83].

Ahmed et al. investigated the effect of various process variables such as pressure, temperature, salinity, surfactant concentration, and shear rate on CO_2 foam apparent viscosity under high pressure high temperature conditions and presented a set of empirical correlations [39, 84]. In their study, the polymer free foam was generated using a conventional surfactant, i.e., alpha olefin sulfonate (AOS) and a
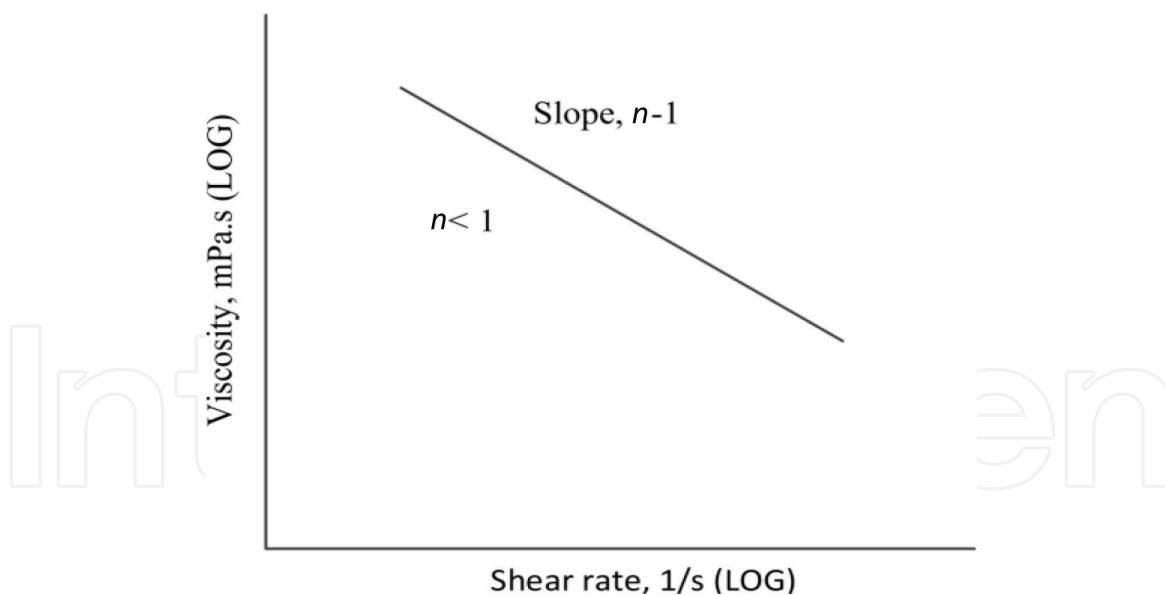
Figure 7.
Power-law model [8, 78].

foam stabilizer, and it was noticed that all the aforementioned process variables are strongly dependent on foam apparent viscosity (discussed above in Section 4). All the foams exhibited a typical shear thinning behavior within the tested shear rate range (10–500 s^{-1}) and the power law model was fitted on experimental data. They presented a set of empirical correlation to predict apparent viscosity of CO$_2$ foam. Power law indices were found to be strongly dependent on all process variables. The new equations for K and n were developed as a function of process variables which were then substituted in the power law model. These correlations could cover a wide range of conditions and were found accurate in predicting the viscosity of CO$_2$ foam fracturing fluid. These developed models could be integrated into any fracturing simulator in order to evaluate the efficiency of foam fracturing fluid.

Gu studied foam fracturing using polymer free foam considering ultra-lightweight proppants (ULWPs) [8, 32]. They also developed empirical correlations through the modification of the power law model, which were then applied in a fracturing and reservoir model using a commercial simulator CMG IMEX. They used ULWPs to predict the formation productivity with both slickline and polymer free foams. They have been able to present foam-based hydraulic fracturing fluid which has efficiently propped the fractures and utilized less water compared to that of slickline fluid. Furthermore, he evaluated the designed foam fluid and proppant using a combined experimental and computational modeling technique which helped in identifying the optimal proppant amount and gas liquid fraction (or quality) of foam.

4.8 Experimental study of foam rheology

Numerous experimental studies used pipes with a small diameter to investigate foam rheology. This is a more reliable method of studying foam behavior in wellbores. Foam deteriorates due to its unstable nature which is caused by liquid drainage under the action of gravity [85]. Accumulation of the liquid takes place at the bottom of the samples and foam cannot be taken as a homogeneous system. Foam is made to flow through a steel recirculation loop in which pressure drop over a certain length is measured and apparent viscosity was calculated. Hagen-Poiseulle equation is used to compute the apparent viscosity of foam in pipe or tubing and it is represented in Eq. (5) [41, 53, 57, 74, 77].

$$\mu_{app} = \frac{D^2 \Delta P}{32LU} \tag{5}$$

where μ_{app} is the foam apparent viscosity, D is the diameter of tubing, ΔP is the differential pressure between the test sections, L is the tubing length, and U is average velocity determined from the total volumetric flow rate of foam.

Before carrying out any measurements, a constant shear rate needs to be set to ensure uniformity across the foam. Once the foam is equilibrated in the recirculation loop, the pressure drop is measured rapidly at different flow rates while ensuring that the foam texture does not vary over time. Patton et al. measured foam viscosity as a function of shear rate using a viscometer apparatus [86]. They mixed constituents of the foam and passed it through the foam generator, i.e., packed bed. Flow rates, temperature, and pressure drop were measured after displacing the foam through the small diameter tube [87].

Xue et al. [74], Li et al. [57], and Sun et al. [41] recently used a flow loop system for fracturing foam studies by using CO_2 foam. These rheology studies involved foam as fracturing fluid and the investigation was made at downhole condition using a flow loop system. The effects of temperature, pressure, foam quality, and shear rate on fracturing foam were studied. Sudhakar and Shah (2002, 2003), Bonilla and Shah [88], and Sani et al. (2001) used a recirculation loop rheometer to investigate the rheology of polymer foam and the power law behavior was observed [88]. These experiments determined that foam behaves as a non-Newtonian fluid. The foam apparent viscosity decreases as the shear rate increases and such behavior is termed as pseudoplastic.

5. Foam fracturing fluid performance: laboratory studies

5.1 Foaming agent and water recovery

Prior to the implementation, it is important to investigate the performance of fracturing fluid at reservoir conditions. The measurement of fundamental properties of the used foaming agent such as interfacial tension and contact angle that are the basis for reducing capillary pressure are also essential to perform [89, 90]. Additionally, the adsorption of surfactant as a foaming agent is equally important to study in order to estimate the chemical loss in the reservoir during the recovery process. The recovery of injected fluid as well as chemical performance can be experimentally evaluated based on core flow tests. Furthermore, it has been reported that several field pilot tests were conducted to check the performance of surfactant for fracturing applications. Most of the pilot tests were conducted in the Barnett and Marcellus shales utilizing conventional surfactants which include nonionic alcohol ethoxylate surfactants and amphoteric and cationic surfactants [89]. The water recovery using conventional surfactants has been reported to achieve approximately 60% (an average of 3 wells) [89]. Barnett shale is considered notorious for retaining water. Another case study was conducted considering a conventional surfactant and only 2300 bbl of water was recovered out of injected 6430 bbl giving about 28% recovery [89]. A nanofluid has also been employed in fracturing job to reduce the chemical adsorption whereby the recovery of injected water reached about 40% in this case [91, 92]. Both laboratory and field studies revealed that the addition of surfactants to the fracturing fluid system helps in increasing the recovery of additional water. Besides, an increase in overall gas production was also observed.

5.2 Foam screening and optimization

The proper selection of foaming agent for generating foam fracturing fluid is required to optimize the process under desired conditions. Lin et al. investigated different surfactants at high temperature and the results were compared with those of a conventional foaming agent used previously as fracturing fluid [93]. They performed surface tension, foam stability, and foam viscosity experiment in order to evaluate the surfactant performance for foam generation. It was ascertained that the results from foam stability experiment could give the indication of surfactant performance for foam generation but the foam behavior under fracturing conditions could not necessarily be deduced. The utilization of flow loop foam rheometer has enabled the study on foam viscosity under reservoir operating temperature and pressure conditions. Based on extensive laboratory studies which mainly include foam rheology, a superior performance foam formulation was obtained which was able to provide a stable foam with both CO_2 and N_2 in a high temperature environment especially where other conventional foamers failed to generate the stable foam. The selected foamer was also found to be having good compatibility with other chemicals in fracturing fluid systems and it has also provided low emulsification as compared to other foamers. When the selected foam formulation through this detailed screening and optimization procedure under reservoir conditions was employed in various fracturing treatments in fields, successful results were achieved.

5.3 The role of chemical additives

Many attempts have been carried out to find the formulation of foam fracturing fluid that can meet the requirement of targeted reservoirs and provide an optimum performance. The synthetic polymer with high concentration has been reported to meet the need of higher viscosity of fracturing fluid. However, the increase in polymer loading would give more severe formation damage due to the formation of fluid residue.

Some viscoelastic surfactants (VES) have been proposed to generate highly stable and viscous foam fracturing fluid with minimum water contents at high temperature conditions. The increase in surfactant concentration may form worm-like micelles which impart viscoelastic property to the foam lamella, hence generating high strength foam which is a relatively clear approach as compared to that of polymer solutions. The addition of nanoparticles (zinc oxide (ZnO) and magnesium oxide (MgO)) has also been found to improve the temperature tolerance of this type of surfactant from 93 to 121°C [94].

The evaluation of different types of polymer as additives for achieving stable and viscous foam has also been performed by Ahmed et al. [38]. They utilized both conventional HPAM polymers and new associative polymers (possessing higher level of hydrophobes) for bulk foam stability tests using FoamScan as well as foam viscosity measurement using HPHT foam rheometer. It was concluded that the use of conventional polymers was not preferable under harsh reservoir conditions as they are more prone to degradation instead of stabilizing the foam. Meanwhile, associative polymer provided dramatic increase in the viscosity and stability of CO_2 foam without undergoing degradation under testing conditions.

More complex system of CO_2 foam has been presented by Xue et al. in which the foam was stabilized with betaine surfactant and silica nanoparticles in the absence and presence of synthetic polymer [95]. The texture of foam was observed from the view cell connected to foam generator having glass bead pack with a permeability of 23 Darcy and the viscosity of foam was measured using a capillary viscometer. It has

been reported that an extremely dry (90–98% foam quality) supercritical CO_2-in-water-foam prepared in brine presented a high viscosity and stability at 50°C. The data on such high quality foams are very limited [95, 96] and the proposed combination (i.e. surfactant/nanoparticle/polymer) has indicated the possibility of having the strong foam with minimum water content which is desirable for fracturing application. Lauryl amidopropyl betaine, the used surfactant, was able to lower the CO_2/water interfacial tension to 5 mN/m. This surfactant attracted anionic NPs (and anionic HPAM in the systems containing polymer) to the CO_2/water interface. Nanoparticle presence in the CO_2 foam system has remarkably slowed down the Ostwald ripening phenomena, whereas, the polymer slowed down the liquid drainage by increasing the viscosity of continuous phase and surface viscosity [95].

5.4 Consideration of different process variables

The rheological properties of foam as fracturing fluid have been evaluated by Wilk et al. using flow loop rheometer with a purpose of reducing the amount of water during fracturing operation [97]. They reported that the concentration of foaming agent and polymer prominently impact the foam rheological parameters. The evaluation in rheometer was performed on the basis of two different foam qualities, i.e., 70 and 50%. Their results showed that the 70% quality foam was able to provide stronger foam due to favorable changes in the foam structure and distribution. The foam texture study also revealed that the bubble sized distribution was altered due the presence of different additives and in this case, polymer additive was able to further reduce the bubble diameter which resulted in high viscosity foam.

Ahmed et al. has investigated polymer free foam performance with different process variables such as surfactant concentration, salinity, temperature, pressure, and shear rate utilizing a high pressure high temperature flow loop system [39, 84]. The rheology of CO_2 foam was presented under a wide range of different parameters such as temperature (40–120°C), pressure (1000–2500 psi), salinity (0.5–8 wt%), surfactant concentration (0.25–1 wt%), and shear rate (10–500 s^{-1}). They presented that 80% foam quality which was found to provide the best performance, expected to be favorable for fracturing job at targeted conditions. These experimental studies found that the foam apparent viscosity under supercritical conditions considerably increases with the increase in surfactant concentration up to 5000 ppm, whereas a continuous increasing trend in foam viscosity appeared as the salinity in the foaming solution was increased. Besides that, the increase in temperature resulted in thermal thinning of foam lamella whereby dropping the foam viscosity. Also, the increment in pressure provided stability to the foam lamella which resulted in high viscosity foam. It was reported that all the foams behaved as shear thinning fluid within the tested shear rate range and power law was fitted on foam viscosity data. The flow behavior indices were found to be the strong function of aforementioned process variables and using viscometric data, the new empirical correlations have been developed, which gives accurate prediction of the apparent viscosity of CO_2 foam as a function of process variables. These empirical models may help in predicting the optimum fracturing conditions and also for the fracture simulation modeling study.

5.5 Proppant transport effectiveness

The experimental study in Hele Shaw slot (**Figure 8**) was presented by Tong et al. for visualizing the proppant transport behavior during foam injection [98]. The foam was generated using conventional surfactant in combination with low molecular weight (8 million Da) polymer solution as viscosifier. In their study, static

Figure 8.
Laboratory scale Hele-Shaw fracture slot for mimicking induced fracture [98].

foam stability and foam viscosity tests were conducted to study the durability and strength of the generated foam. The visualization of foam-based fracturing fluid was studied at different foam qualities and it was reported that proppant transport was quite efficient with high quality foam due to its high viscosity and stability. They reported that the low quality foam was not an effective proppant carrying medium due to high liquid drainage and low apparent viscosity of foam during its transport through the fracture system. It has also been reported that the dry foam allows extremely slow proppant settling compared to wet foams even during high proppant loading.

6. Conclusions

Advanced horizontal drilling and hydraulic fracturing have been widely applied for unlocking a huge amount of hydrocarbon reserves from tight shales. Conventional water-based polymeric solutions have been commonly utilized for fracturing jobs due to their ability to transport proppants deep into the reservoir. However, the use of polymer tends to cause plugging of nanopores and detrimentally affects the shale productivity. Moreover, many environmental constraints are associated with the use of a huge amount of fresh water and the disposal of contaminated water during flow back period is continuously reported, driving a need of waterless fracturing fluid system.

CO$_2$ has been known as alternative fracturing fluid with various added benefits including releasing the adsorbed gas, water flow back improvement, and carbon sequestration. However, the use of single CO$_2$ system has limitations affected by the low viscosity of gas, limited proppant carrying ability, and limited possibility to operate at depth. An innovation to have waterless fracturing fluid has also been attractively developed resulting in less water consumption, less formation damage, and less liquid to recover during the fracturing process.

The combination of surfactant with CO$_2$ generates foam which is considered as a highly attractive and unique solution to all the above associated concerns during fracturing operation. CO$_2$ foam has high viscosity, good thermal stability, better proppant transport and placement ability, stable rheological performance as compared to polymers, ability to reduce clay swelling and fine mitigation issues, and increased flow back due to gas expansion. Additionally, surfactants in the base fluid reduce capillary forces and alter shale wettability, which assists water flowback, and increases gas production. Therefore, selection of an appropriate surfactant is of prime importance. However, available literature studies on the evaluation of surfactant and foam performance as fracturing fluid are limited.

In spite of all exceptional benefits, a good understanding of foam rheology is required for the design of optimum foam fracturing treatment. The foam fracturing process highly depends on foam viscosity and it is highly desirable that the foam

should provide sufficient viscosity for efficient job completion under reservoir design and operating conditions. According to the previous studies explained in this chapter, besides the evaluation based on foam stability, an analysis of the applicability of foam-based fracturing fluid could be derived from several experimental investigations including foam viscosity measurement using flow loop foam rheometer which also could provide the information of foam texture at different foam qualities and fracturing conditions. A thorough screening and optimization of foam considering different variables under fracturing conditions could effectively improve the efficiency of fracturing job. Studies also have implied that the foam rheological property is challenging to estimate due to numerous variables involved.

Conflict of interest

The author declares no conflict of interest.

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