

Review

Residual Damage, Its Consequences, and Remedial Measures on Post Hydrofrac Well Productivity: Learnt Lessons

Bisweswar Ghosh *, Mumin Abdelrahim and Hadi Belhaj 

Department of Petroleum Engineering, Khalifa University, Abu Dhabi P.O. Box 127788533, United Arab Emirates

* Correspondence: bisweswar.ghosh@ku.ac.ae

Abstract: Hydraulic fracturing or hydro-frac fluids can impede well production due to the damage caused to the reservoir formation and fracture face, generated from adverse interactions with reservoir rock. Understanding the mechanisms of hydraulic fracturing, optimum treatment designs, and pumping/pressure profiles is critical for hydro-frac success. However, to realize the full potential of fracturing and the mitigation strategies for reservoir and fracture conductivity damage during and after its occurrence, fracturing must be considered during the design phase itself. This article provides a brief overview of hydro-frac techniques, including design, optimization, modeling, commonly used proppants, and fracturing fluid benefits and consequences based on critically reviewed case studies. However, the primary focus of this article is on the potential of fracture conductivity damage and the intrinsic mechanisms in hydraulic fracturing. The article presents updated information on various damage mitigation processes established through laboratory investigation and field implementation. The authors expect that the provided workflow in this article will be helpful to researchers and stimulate engineers to a great extent.

Keywords: hydraulic fracturing; fracturing damage; fracture conductivity; guar breaker; enzyme breaker; mannanase; galactase



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1. Background

Tight hydrocarbon reservoirs are oil or gas reservoirs with a matrix permeability of less than $0.1 \times 10^{-3} \mu\text{m}$ [1]. Fluid flow through tight and unconventional reservoirs encounters restrictions governed by a number of mechanisms, such as viscosity, convection, absorption and adsorption, and capillary and inertial forces [2]. These trapping forces restrict fluid flow in micro- and nano-pores, although most hydrocarbons may remain in these pore domains. The macro-pores are considered to be the main contributor to the flow, which may naturally exist or is induced through fracturing [3]. Hydraulic fracturing is one of the fracturing methods in which reservoir rocks are fractured, which extends from the borehole into the formations and is informally called “fracking” or “hydro-frac” [4].

Thus, the primary goal of a frac job is to create contact with high conductivity fracture networks with tight reservoir rock matrices to the maximum possible extent. Hydrofrac is also vital for improving water injection rates in sandstone and carbonate reservoirs [5,6]. Thus, hydrofrac treatments are typically designed to achieve appropriate fracture length, width, and permeability, in commensurate with the formation properties [7]. In general, long and narrow fractures are desired, particularly for tight gas reservoirs [8]. To perform a fracturing job appropriately, the frac fluid must be sufficiently viscous to exert sufficient hydraulic pressure to overcome the rock's tensile strength and effectively disseminate the fracture through a certain formation length. The fracturing fluids must also be capable of transporting the proppants further into the fracture to ensure that the fracture remains propped even after releasing the injection pressure. A single fracture with the ability to pump large volumes of fluids creates penetration potential for the fracture to a widespread formation. This is the most widely used method within the coalbed methane industry.

The second type is explosive fracturing, which involves rapid pressurization of the target formation, thus, resulting in a highly fractured zone of 10–15 ft around the wellbore. This method avoids using liquids for fracturing and propping; thus, sensitive formations can be saved from damage [9]. In this design, a radial fracture pattern is formed because the peak pressures exceed the minimum and maximum horizontal in situ stresses; thus, a favorable fracture geometry with near-wellbore stimulation is achieved. The last method of hydrofrac is pulse fracturing, defined by situ stresses exceeding maximum and minimum stresses and creating a radial fracture pattern. Multiple vertical fractures are formed when this method is applied due to radial extension from the wellbore exhibiting penetration in the order of 10–20 ft [9].

In proppant-packed hydrofrac jobs, the outcome or well productivity would be less than expected unless several possible reservoir- and propped-frac damage mechanisms are understood. Firstly, the effective fracture volume could be reduced by up to 30% due to fracture closure and reservoir pressure drop during the early stage of flowback [10], resulting in the crushing and embedment of the proppants in the fracture surface [11]. The frac-fluid itself is the second most crucial concern for damage as the volume of flowback fluid could be as low as 10–50% of the total injected fluids [12], which means that a large volume of fracturing fluid remains in the reservoir, causing water-phase trapping damages [13] and carbonate and sulfate scale deposition, resulting in pore blockage [14] and, most notably, the loss of permeabilities due to residual polymers and other grouped solids [15]. Thus, to maximize the fracture conductivity and to realize the effectiveness of the fractures within the network, various post-fracturing damage mechanisms must be understood based on the fluid and formation properties for the economic development of tight and unconventional reservoirs [16,17].

1.1. Fracture Orientation, Propagation, and Conductivity

Production optimization through the fracturing process aims to maximize the contact area between the matrix reservoir and the fracture system within the technical and economic limits (see Figure 1 for schematic of fluid flow through a fracture). Creating hydraulic fractures in situ causes stress conditions to the formation and the real-time change along the near-wellbore-controlled fracture propagation [18]. The real-time near-wellbore stress controls not only cause the fracture initiation process but also the fracture propagation and fracture orientation, which is governed by a combination of formation stress properties and the stress provided by the fracturing fluids [19]. However, in the case of a naturally fractured reservoir, the orientation and length of an induced fracture could be severely affected by the existing natural fracture. From a finite-element-based numerical model, it is established that if the angle of approach is sufficiently high, an induced fracture may cross a natural fracture. At a low angle of intersection, it would dilate the natural fracture and break out from one of the tips of the natural fracture [20]. Fracture conductivity is the ability of the fractures to allow fluid flow from the reservoir to the wellbore. As the fracture closing pressure increases, the conductivity decreases. The conductivity of the fractures is among the most critical aspects of hydrofrac success and is therefore included in fracture modeling as one of the primary design parameters. In general, conductivity is the product of propped fracture width (f_w in ft) and fracture permeability (k in mD) adjusted under in situ stress and understood as the flowback potential and is measured in mD-ft [21]. Dimensionless fracture conductivity (F_{cd}) is a more appropriate design parameter, defined as fracture conductivity, Kf_w (mD-ft), divided by reservoir permeability (k) multiplied by the fracture half-length, X_f (ft), considered for differentiating finite and infinite conductive fracture. Factors influencing the width/diameter of the fracture include propping density, proppant filling ratio, residual gel filter cake, and embedding tendency. Factors influencing the permeability of the proppant are usually proppant size, sphericity, strength, fines content, and damage due to the residual gel [22].

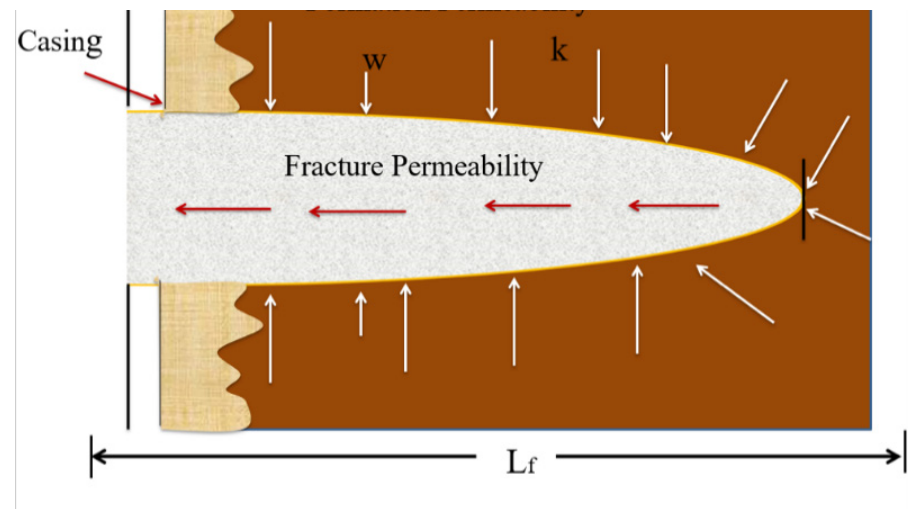


Figure 1. Schematic of fluid flow through a fracture.

1.2. Frac Fluids and Their Properties

The effective suspension and transportation of the proppant into the fracture is achieved when the fracturing fluid rheology is adequately balanced with appropriate viscosifying agents. The success depends on an intricate job design, which includes fracturing fluid design, proppant selection, optimizing injection rate, injection volume, proppant loading schedule, and post-treatment flowback efficiency. Most fracturing fluids use an optimum dose of guar-based polymers (guar and its derivatives). The guar derivatives most commonly used in fracturing fluids include carboxymethyl guar (CMG), hydroxypropyl guar (HPG), and carboxy Methyl hydroxypropyl guar (CMHPG), with each having unique properties [23]. It is of paramount interest to select the correct type of guar at an optimized concentration when designing fracture treatments to deal with the rheology and temperature constraints. A strong comprehension of the polymer consequence towards fracture conductivity and behavioral cleanup is paramount when considering the correct long-term production and cleanup process in a tight gas reservoir. High viscosity, enormous material source, low friction, easy penetration, low filtrate volume, cost-effective utilization, and minimum formation damage characterize an ideal optimal fracturing fluid.

Nowadays, many specialty chemicals are applied in fracturing fluids for special applications. Table 1 provides a brief list of their categories and functions.

Table 1. Ingredients of hydrofrac fluids.

Component/Category	Function/Remark
Water-based polymers	Thickener, transport proppant, reduces leak off information
Friction reducers	Limits drag in the tubing
Fluid loss additives	Filter cake formation, reduce leak off
Breakers	Disable cross-linkers
Cross-linkers	Improves the viscosity of the thickener
Gel stabilizers	Keep gels active longer
Defoamers	Breakdown foam
Crosslinked gel systems	Increase viscosity
Oil-based systems	Applied in water-sensitive formations

The fracturing fluids are water- or oil-based [24] and are further subdivided, as below.

1.2.1. Slick-Water-Frac or Water-Frac

Slick-water-frac is a fracture treatment that utilizes a large volume of water to create adequate fracture geometry and conductivity. It is often a combination of water and friction-reducing chemicals. The reasons that slick-water-frac technology is given serious consideration include (1) its cost-cutting in fracturing lower permeability reservoirs, (2) overcoming the challenge of the effective “cleanup” of residual gel from the fracture, and (3) shorter effective half-lengths that are seen more often than not compared to the predicted design [25]. However, most entities embrace conventional crosslinked gel fluid as some aspects of the traditional frac designs are diametrically opposite and not applicable to slick-water-fracs. A slick-water treatment is also referred to as water-frac. Slickening water with either low concentration (~10 ppg) linear gel or polyacrylamide friction reducer is a common ingredient within the fluid system [26]. Slick water fracturing fluid offers extremely low viscosity as compared to a fully crosslinked gel. Poor proppant transport is exhibited by slick-water-frac due to low viscosity and a narrower pumping width compared to the crosslinked gel fluids. Slick water dilates the micro-natural fractures/fissures in a tight formation, increasing the fracture conductivity. It is paramount to pump slick-water-fracs at higher rates of above 100 BPM to deal with the above-mentioned concerns and offer a solution to stimulating long horizontal sections. The pumping rates are of the order of 50–80 BPM for more conventional tight gas reservoirs.

There are benefits and disadvantages when considering slick-water-frac, as far as any design technique is concerned. The potential reduction of gel damage in the fracture doubles up as the primary technical advantage of slick-water-fracs. Compared to 20–40 pptg of polymer in a typical crosslinked gel in the fluid and a metal cross-linker, a slick-water-frac uses only a linear gel (5–10 pptg) or a friction reducer. However, slick-water treatments use substantially higher volumes of fluid despite reducing the gel loading and friction reducer, thus, risking depositing a significant volume of polymer into the fracture. This creates additional difficulties for the industry to break a polyacrylamide friction reducer with effective temperature, time, and suggested breakers as the only way the concern can be solved [27].

Additionally, there is a degree of distributed gel damage and filter-cake formation from the commercial guar derivatives. If the use of light gel continues, then the flow capacity of the fracture is compromised. The potential cost savings are another reason for a move toward slick-water-fracs. A much-reduced chemical package is required during slick-water treatments for easy fluid recycling. The costs for the total treatments are often lower with slick-water treatments when there is a plentiful water supply. However, there is a cost-prohibitive nature when using slick-water treatments in remote locations or areas with a limited water supply, offsetting the benefits of larger required fluid volumes. The cost advantage may not be as great as initially anticipated, given that more horsepower (resulting from the higher injection rates) is required since slick-water jobs are typically much longer. Thus, the structure of the pumping contractors’ bid package and water availability are the predetermining factors in establishing cost savings [28,29].

Slick-water-fracs provide more complex fracture geometry than conventional crosslinked gel-fracs, given that the exercise is affected by higher injection rates and lower viscosity. It has been demonstrated in some shale plays that higher production results from the stimulation of larger areas, thus making the slick-water-frac the preferred design. Better fracture containment (reduced height growth with lower-viscosity fluid) is another potential and proven advantage for a slick-water-frac, which is realized when trying to stay out of underlying water. This is evident in the case of the Ellenberger in some Barnett Shale completions [30]. Finally, there is a possibility of reusing load water flowing back from the existing wells to make up frac fluids on subsequent wells, given that a slick-water-frac typically has a simpler fluid system. Reusing load water is also helpful in areas with expensive or difficult water disposal methods.

Proppant placement/transport is one of the biggest concerns with slick-water-fracs. There is little chance to suspend and transport proppant due to low-viscosity fluids in slick-water fracturing. Additionally, failure to suspend and transport the proppant leads to vertical coverage across the pay zone(s) and lateral placement in the fracture. Later, lateral coverage will be discussed in the proppant transport section. The vertical coverage concern is generated from the fact that, in stimulating the thick intervals, there are possibilities of settling a bank of proppant that fails to cover the entire height of the pay zone. However, vertical coverage can be addressed through an increased number of stages with a limited vertical interval target for each pay zone. The amount of required water for a frac is another concern regarding slick-water treatments since slick-water-frac must be designed for tremendous volumes of water that exceed millions of gallons to place large masses of proppant at low pumping concentrations. However, such an exercise may lead to two potential problems. First, the slick-water-frac will allow greater leak-off and induce more significant formation damages, particularly to water-sensitive formations, due to minimal wall building capacity and massive injection volumes and rates, offsetting the material cost advantages [31]. Second, there could be friction between stakeholders (land owners, environmental groups, farmers, regulators, etc.) and operators due to the limited freshwater availability for oilfield use, adding a high cost to the operation [32].

Finally, there is a narrower pumping width for slick-water-fracs as compared to their crosslinked counterparts due to a direct relationship between fluid viscosity and fracture geometry. It is difficult to place larger diameter proppants and higher pumping proppant concentrations, despite the availability of higher pump rates and pressure, which is one of the major concerns. Thus, many operators have chosen to utilize smaller-sized proppants, including 30/50, 40/70, and in some cases, 100 mesh, and pumped highly diffused concentrations of about <2 PPA for the bulk of their treatment [33].

1.2.2. Water-Based Gelled Fluids

Guar gum and its derivatives are the most common polymers used in water-based fracturing fluids, accounting for nearly 90% of all gelled fracturing fluids. Natural guar is chemically modified through etherification, esterification, and crosslinking reactions to achieve enhanced properties [34,35]. These modified guar derivatives gained popularity because of their unique properties, such as high molecular weight (ranging from 1 to 2 MD), helping to generate high viscosity at low concentration, quick hydration, stability at a higher temperature, and a greater pH range (pH 4.5–10). They also crosslink with metals, biocompatible, biodegradable, and non-toxic nature [23].

Natural Guar Gum

Natural guar gum is an extract from guar (*Cyamopsis tetragonolobus*) seeds. It is a natural polysaccharide with a β -D mannopyranosyl (mannose) backbone linked with D-galactopyranosyl (galactose) units as side branches (Figure 2) and bonded by α -1,6 linkages [36]. The mannose to galactose ratio is usually between 1.8:1 and 2:1 [37], which governs its rheological properties [38]. Guar-based hydrofrac fluids are known as standard fracturing fluids within the oil industry. Natural guar has impurities to different degrees, which provides increased fluid loss control through the creation of filter cakes at the interface. It is observed that guar easily hydrates at a wide range of pH, given that the optimal pH for guar hydration ranges between 6.5 and 7.5 [39]. The guar is stable at a high pH and unstable at a low pH when hydrated, and thus, as a linear guar gel, is stable up to 80 °C. However, its thermal stability may go up to 150 °C for short periods, provided the gel is crosslinked with a metal ion [40].

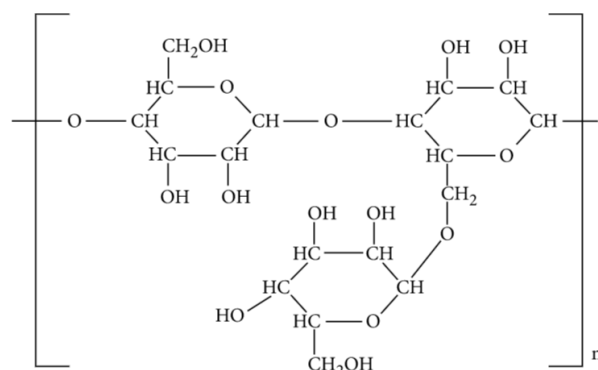


Figure 2. Molecular Structure of guar gum [41].

Hydroxypropyl Guar (HPG)

A reaction between propylene oxide and a highly purified guar stock is used to manufacture HPG. The guar endosperm splits are exposed to a series of water and acid soaks to remove the embryo as well as the majority of the hull before grinding to achieve a highly purified guar. The impurities of the guar are further reduced by approximately 2% of insoluble material through the purification process. HPG is a versatile viscosifier compared to guar since its resulting molecule is nonionic and, therefore, is associated with many advantages [42]. The hydration process for HPG is faster than it is for guar, and it is characterized by higher viscosity at similar concentrations to the guar. The addition of the propylene oxide group to HPG helps it gain better temperature stability due to stabilized polymer that withstands thermal degradation. Filter-cake buildup fails to regenerate on the fracture face due to the reduction of residue and is thus a challenge exhibited during a high-permeability zone fracturing. Therefore, despite having a higher fluid loss, HPG is compatible with methanol, exhibits higher temperature stability, and is less damaging [43]. Figure 3 shows the molecular structure of HPG.

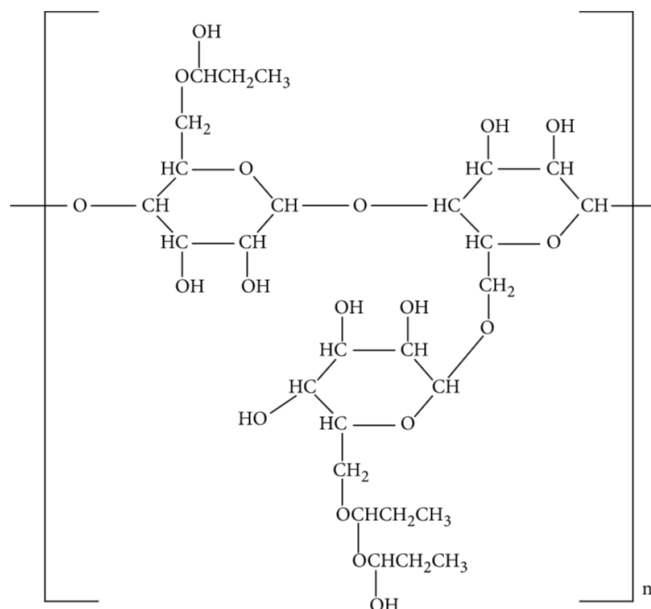


Figure 3. Molecular structure of HPG [41].

Carboxymethyl Hydroxypropyl Guar (CMHPG)

Compared to HPG, CMHPG has lower residue with only 1 to 2% impurities. Moreover, the temperature stability of CMHPG and the rate of hydration are way better and faster than that of guar and HPG. From another perspective, CMHPG provides a super “clean” gel system due to its high tolerance for methanol, which is one of the best water-miscible

solvents. CMHPG is characterized by extra potential energy to assist in the load fluid cleanup and recovery since it is compatible with carbon dioxide (CO₂). Another associated advantage of CMHPG is that it allows crosslinking both at a high and low pH. However, there exists a common disadvantage of CMHPG and HPG as both exhibit reduction during fluid-loss control, thus, increasing the cost of CMHPG over guar and HPG [44]. Figure 4 displays the molecular structure of HPG.

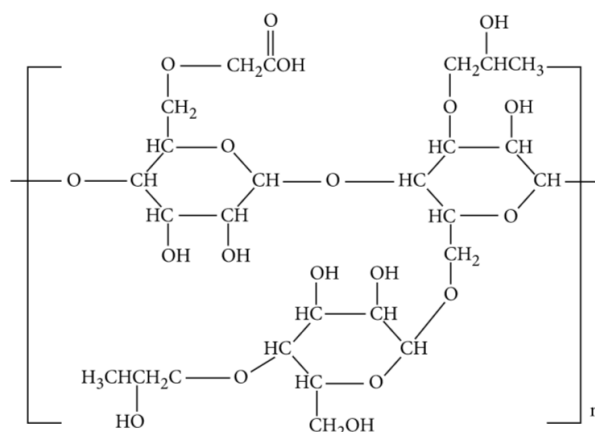


Figure 4. Molecular structure of CMHPG [41].

Foam-Based Fracturing Fluids

Due to the limitations of traditional fluids and the advantages of foam as a fracturing fluid, foam stability and rheological qualities have been extensively studied for fracturing applications [45]. Foam-based fracturing fluids carry proppants through impermeable hydrocarbon reservoirs. Carbon dioxide and nitrogen are the gases required for the formation of foam-based fracturing fluids. The foam's gas components are capable of providing the additional drive necessary to remove water from the fracturing zone. The purpose of polymer-free foams is to mitigate the clogging of pore throats and the formation damage caused by clay swelling. Nonetheless, the primary concern with foam fracturing fluid applications is the foam's stability and propagation in micro- and nano-fissures that occur randomly in natural fractures under reservoir conditions associated with high-temperature and high-pressure reservoirs [46]. The durability of foam is a major concern, which can be improved by adding polymer to bentonite clay via adsorption at the foam's air–water interface [47].

Viscoelastic Surfactant (VES) Fluids

VES was developed to come up with a fluid that had the potential to eliminate the shortcomings of water-based gelled fluids. VES is viscous under extreme shear conditions and produces no residue as opposed to polymeric hydrofrac fluids. VES has been applied to gas wells and, in some cases, in coal seams. VES systems may possess worm-like micelle structures, vesicles, or lamellar structures [48]. VES also acts as a thickener, making it very significant to the performance of the fracturing fluid. The most commonly used VES are anionic, cationic, zwitterionic, single-chain, and Gemini surfactants. VES prepared by Gemini surfactants is superior to conventional surfactants because they are composed of two identical or different amphiphilic moieties [49,50]. Because of the presence of two hydrophobic groups in the structure, Gemini surfactants have higher water-solubility and hard-water tolerance and can also self-associate into micelles quicker [51]. VES is often preferred as a hydrofrac fluid instead of polymer-based fracturing fluids due to its gel-breaking mechanism. The gel breaks into a water-thin solution when the residual VES comes into contact with hydrocarbon fluids. VES fluids can be used to treat virtually all gas and oil wells below 240 °F [52].

The ability of VES to reduce the fracturing fluid's surface tension facilitates water flow in the pores within the rock [31]. It is important to note that VES is not recommended

for high permeability reservoirs above 200 mD as it would increase leak-off rates and, thus, cannot reduce their surface tension [53]. Sullivan et al. [54] optimized VES for high-permeability sandstone formation and advised that VES should only be used in reservoirs under 100 mD. It is also important to note that the thermal stability of VES can be unreliable in temperatures exceeding 135 °C unless a concentration above 60 pptg is used [55].

The surfactant in VES has a low molecular mass, a long hydrophobic tail, and a hydrophilic head. This provides it with complex micellar structures when exposed to salts such as ammonium chloride, ammonium nitrate, and potassium chlorides. Because of their ability to build complex structures, they can quickly form high-viscosity mass. Some of the historical events that utilized VES in similar processes include the south Texas wells, which had an 82 °C bottom-hole temperature with a 0.1 mD reservoir permeability. The well produced ten times the amount of gas, which indicates a high level of success [56].

The main concern for VES is its leak-off rates, especially in >100 mD permeability reservoirs. The reason behind the high leak-off rate is the lack of polymer. The polymer gels are three-dimensional, thus, reducing leak-off rates as they form filter cakes. According to Huang et al. [53], zinc oxide can reduce leak-offs in VES by creating crosslink formations that can help create filter cakes. The zinc particles used in this case measure 100 nm in size, with a diameter of 35 nm. A combination of zinc particles and VES results in the creation of electrostatic and van der-Waals forces, which hold the particles together, thus, enhancing their structure. In another study, a ten ppg concentration of amidoamine oxide was added, resulting in a viscosity enhancement from just 15 poise to an average of 1100 poise. The settling time also increased to 90 min from 15 min after the formulation of the nano-VES system. To confirm the effectiveness of the solution, the researchers pushed the fluid through a 400 mD and 0.25-inch thick ceramic disk under a less than 300 psi pressure drop. The results indicated that the leak-off rate was 80 mL per 70 min compared to 425 mL in 5 min. However, when the authors increased the concentration to 30 pptg, the leak-off rate increased [57,58]. Though the studies conducted in a laboratory environment were promising, the field results were not so. According to the studies conducted in the 1990s, where VES was applied in a relatively large number of wells, there was a need for reviving fractured wells by adopting remedial actions. In this aspect, Mahdaviara et al. [59] noted that hydrocarbons could break VES fluids more efficiently when specific amounts of salts are removed from the brine. The authors concluded that it is not possible to achieve these two conditions in most cases as the wells might fail to produce sufficient hydrocarbons to break the VES solutions. In this case, the authors advised adopting breakers such as iron, ascorbic acid, and sodium citrate, among other chelating agents. When metallic ions are used, they break the gel by attacking the micellar structures. However, sodium citrate and other chelating agents are only used in fine-tuning the breaking process and reducing the number of metals used in the breaking process.

Crosslinking of Guar and Guar Derivatives

The crosslinking of polymer chains with multivalent ions creates a 3D superstructure, resulting in enhanced gel viscosity and improved thermal stability with a lesser polymer load. This process enhances the proppant suspension and transport capacity by many times more than that of uncrosslinked polymer (linear) fluids. The proven crosslinking agents for guar-based polymers are borate and metal compounds of zirconium (Zr) and titanium (Ti).

Borate-Cross-Linked Guar Gel

Highly viscous frac gel can be prepared by crosslinking guar gum with borax (disodium tetraborate and heptahydrate) in a single step and at room temperature (Figure 5).

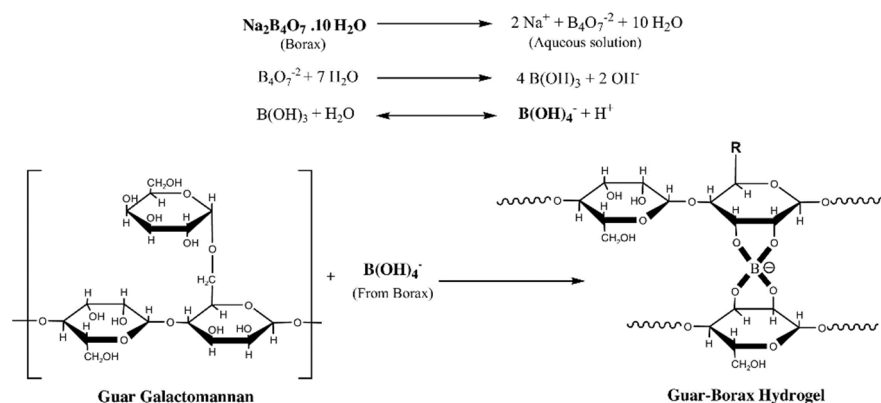


Figure 5. Borax crosslinked guar gum hydrogels [60].

In field applications, a higher fluid pH is required when borate crosslinked guar fluids are subjected to bottom-hole temperatures of above $\sim 200^\circ\text{F}$. Using bicarbonates, amines, hydroxides, and/or carbonates as buffers helps to achieve and maintain a high fluid pH. This sometimes allows the use of produced water in preparing borate crosslinked frac fluid [61]. However, when produced water contains high concentrations of calcium and magnesium, these precipitate out at a high fluid pH, consuming the buffering materials and reducing the fluid's stability at high temperatures. Additives such as scale inhibitors can help to arrest the precipitation and stabilize the borate-crosslinked fluids when produced water is used. Otherwise, it is limited to the use of freshwater on high-temperature wells above about 200°F [62]. More than 200 fracturing stages were successfully pumped in the Delaware basin, West Texas, through the implementation of scale inhibitors [63].

Li et al. [64] reported the possibility of bacterial degradation while formulating borate-crosslinked guar fluids with produced water. Bacterial enzymes quickly break the polymer chain when exposed to polymers like guar. There are several mitigation methods available, and one such method is the introduction of zirconium compounds in the frac fluid [65].

Offshore operations such as frac-and-pack and hydrofrac jobs use borate-crosslinked guar fluids formulated with seawater. Maintaining the stability of the crosslinked structures requires borate-crosslinked guar gels to have a pH of about 9 or higher. The fluid pH usually drops when the calcium or magnesium ions present in seawater precipitate out with the hydroxide anions and, in the process, destabilize the borate-crosslinked fluids. However, borate-crosslinked guar fluid prepared using typical seawater (close to the fluid pH of 9.2–9.3) does not precipitate magnesium hydroxide or calcium hydroxide. Thus, the borate-crosslinked guar fluids with a fluid pH should be slightly above 9 for offshore fracture jobs [63].

Metal-Crosslinked Guar Fluids

Guar polymers can also be crosslinked with metal cross-linkers such as zirconium and titanium compounds [66]. The advantage of metal crosslinking over borate is their enhanced thermal stability and the stability of the gel below pH 7. Thus, metal cross-linkers are preferred in cases of foamed fluid with CO_2 (which lower the fluid pH). The low fluid pH also prevents scaling when produced water is used with high concentrations of divalent cations such as calcium, strontium, and barium ions [67]. Zr- and Ti-crosslinked guar fluids provide better thermal stability than borate crosslinked gels when produced water is the only source of water. Leiming et al. [68] reported the successful application of metal crosslinked gels in wells at bottom hole temperatures up to $\sim 250^\circ\text{F}$, with the produced water sources having TDS up to $\sim 300,000\text{ mg/L}$, and a hardness of up to $\sim 44,000\text{ mg/L}$.

1.3. Proppants and Their Role in Fracturing

Proppant is an essential material in fracturing to provide structural support for the fractures to remain conductive [69]. Proppants are solid materials, usually natural sand,

resin-coated sand, or ceramic beads, designed to sustain a hydrofrac under a specific formation closure stress, avoiding fracture healing [70]. Various types of proppants are used in the oil industry based on their formation characteristics. The properties of the proppants are strength, grain size, grain-size distribution, amount of impurities, roundness and sphericity, proppant density, and proppant-pack porosity. All these properties affect the initial and long-term fracture permeability, affecting the effective conductivity. Accurate placement of the proppant into the fractures is one of the critical requirements of successful hydrofrac jobs, which largely depends on proppant selection, fluid rheology, and the pumping program. Proppant transport and proppant placement and flowback after the end of stimulation treatment are covered in a review article with detailed information on designs and modeling by [71].

1.3.1. Sand

Frac sand is a crystalline silica/quartz mineral. Natural sand is prevalent and well known to be the most used proppant for hydraulic fracturing. There are several different types of frac sands: northern white sand, Texas brown sand, and several varieties of silica sand. Frac sand is available in sizes from 12/20 to 40/70 mesh [72].

1.3.2. Ceramics

The ability of ceramic to overcome high closure stresses gives it an edge over the sand proppant. Ceramic proppants are produced utilizing minerals like bauxite and magnesium silicate. Furthermore, it tends to be uniform in shape, and is spherical, which results in a more desirable porosity and permeability for the proppant bed. Lastly, its thermal capacity is of optimal levels to withstand the excruciating pumping process [32]. Ceramic proppants are characterized as intermediate strength proppants (ISPs) and high strength proppants (HSPs), where HSPs are required if the closure stress is greater than 10,000 psi.

1.3.3. Resin Coated Proppant

Resin-coated sand was developed to raise the level of conductivity of frac sand. There are curable resin-coated polymers and procured resin-coated sands [32]. Resin-coated proppants were also developed to limit proppant flowback during post-fracture hydrocarbon production. The coating materials generally used are epoxy resins; however, ceramic coats are also used for high closure stress applications [69].

1.3.4. Lightweight Proppant

Lightweight proppants mostly consist of intermediate-strength sintered bauxite [32]. With regards to this, specific gravity is an influential aspect that is considered as it affects many facets. For instance, the fracture volume and expense are heavily correlated to the specific gravity. Lightweight proppant is favored in certain tasks because it hinders the proppant from settling, advances the propped length pathway, and improves wettability [73].

1.3.5. Advanced Proppant Technology

As the industry develops, many innovations are witnessed. The concern with conventional proppants is that conductivity reduces rapidly as the closure stress increases. At closure stress of 20,000-psi and higher, which is encountered in lower tertiary formations, in addition to the harsh chemical and thermal conditions, higher-strength proppants are in demand. Palisch, T. et al. [74] reported the development of one such proppant, which achieved twice the baseline conductivity of any conventional proppant with increased durability. Traceable proppant was developed to alleviate the dilemma of treatment, shipping, storage, and environmental issues when handling radioactive material required for logging purposes [33]. The development of hydrophobic proppants through surfactant modification, silane-coupling agent modification [75], and resin coating modification [76] has provided the proppant with a monomolecular hydrophobic layer, resulting in faster flowback.

1.4. Fracturing Fluids Rheology

The reason why most fracture fluids are affected by yield stress is mainly because of their non-Newtonian behavior. The impacts of yield stress have attracted tremendous attention, igniting interest in several further studies. Such studies include [77], which mainly focused on producing yield stress simulation to understand its impacts on fluid cleanup. The authors primarily used fracture geometry, focusing on length and width and fracture properties such as permeability, pressure, proppant diameter, and porosity. Another study by Yin and Wang [78] utilized the parametric analysis approach to understand the rheological parameter effects and injection rates. The author concluded that there is likely to be no polymer flow when the gradient pressure is inadequately adjusted to reduce the yield stress. May et al. [79] conducted the same study earlier; however, their focus was on the impacts of yield stress on cleanup rates. She adopted the numerical simulation model and concluded that there were no effects on the flowback amount even when the drawdown rate was increased; however, the author noted an increment in the fracture length effectiveness when the fracture conductivity increased. The primary failure of the study was that it never considered the effects of fracture face damage and the results of capillary pressure, among other factors. Other experiments were conducted to determine the fluid viscosity for treatment designs, including the model test, which mainly describes the fluid flow between two plates moving in parallel directions. This is termed the shear rate and is determined by calculating the velocity of the distance between the two plates based on the range separating them. This study also failed to determine the capillary pressure effects and the fracture face damage. One of the best fluid laws that perfectly describes the fluid's fracturing process is the power law fluid. The model is characterized by shear rate data on a log-log scale [31].

1.5. Fracture Treatment Optimization

Hydrofrac treatment design optimization is a problem that involves finding the optimum values of the surface controllable treatment parameters (injection rate and time, fracturing fluid rheology, end of the job proppant concentration, and its loading schedule [80]. These parameters must satisfy operational constraints, fracture growth control, and financial requirements and must improve the objective function (maximum production and minimum treatment cost or maximum net present value) as much as possible. These issues have been addressed by [81] using an optimization algorithm, linking the variables and constraints. Once the optimum treatment parameters are executed, it would theoretically create an appropriate fracture geometry (length, height, and propped width with the desired conductivity). Later, post-fracturing well testing will be necessary to confirm the success of this treatment for tight carbonate reservoirs with limited natural fractures. In this regard, [82] created a mechanical earth model (MEM) using the petrophysical data, formation, and core data to optimize injection parameters, such as the optimal injection rate and volume optimal number of stages of injection. The authors claimed a 51% increase in production rate after fracturing the tight Middle East carbonate formation. Optimizing the gel and proppant injection parameters is even more crucial for water injection wells. Although fractures can improve water injection capacity to a great extent, particularly in tight reservoirs, if extended too far, communication between the injector and producer wells may result in a rapid water breakthrough [83].

1.5.1. Fracturing Model Selection

Numerous numerical simulators have been developed to simulate fracture propagation, geometry, and the degree and path of stress difference across fractures. There are two-dimensional, pseudo-3-dimensional (P-3D), or three-dimensional (3D) hydrofrac models available, depending on the magnitude of the problem and the volume of rock to be stimulated [84]. These models are beneficial for researching the fundamental nature and physics of the basic hydrofrac procedure. In all hydrofrac models, the fracture is propagated by injecting fracking fluid from an injection point at the bottom hole or along a line reflect-

ing the casing pipe's perforations. A total of three classic fracture modeling methodologies were used to test these hypotheses: (1) the two-dimensional Khristianovic Geertsma de Klerk (KGD) model, (2) the two-dimensional Perkins Kern and Nordgren (PKN) model, and (3) the radial fracture geometry or penny-shaped model [85]. The 2D models using the leakoff coefficient (Carter equation II) are indicated as 2D PKN-C and 2D KGD-C. The PKN-C model, on the other hand, is chosen in the oil sector because its vertical plane strain assumption is more physically acceptable for the suggested height-contained fractures, where the fracture length becomes significantly longer than the fracture height [86]. The PKN-C model predicts fracture lengths more similar to those computed by the 3D model for proper fracture heights than in the KGD-C model. The KGD model depicts a fracture with a substantially lesser horizontal penetration than a vertical penetration, resulting in a constant and uniform height and rectangular cross-section at the wellbore. The KGD fracture height is greater than the half-length of the fracture, which is not desirable [86,87].

To anticipate fracture progression in a 3D space, an entirely 3D-fracture model paired with the 2D fluid flow is necessary. This model is based on fundamental fracture mechanics coupled with the impacts of complicated fluid flow patterns in bi-wing fractures. Its growth is simulated sequentially using a mixed-mode fracture propagation criterion, utilizing a competent finite element approach. The fracture is permitted to propagate laterally and vertically and to change the plane of origin, depending on the presence of natural fractures/flaws, induced perforation, well deviation, local stress distribution, and rock qualities [88]. A fully 3D model requires a large amount of data to justify its use. Also, it is highly intensive computationally, making it unsuitable for use in a design optimization schemes [87]. However, it is included in a large number of commercial numerical simulators. By contrast, the pseudo-3D model is a modified 2D-PKN model with variable fracture heights and widths along the fracture length. When multi-layered rocks exhibit a range of stress intensities, this model describes the stress contrast between the layers, net fracturing pressure, and fracture height migration at the wellbore. Warpinski and Smith [89] proposed an equation for calculating the height migration of the layers with varying stress intensity factors at a given wellbore pressure. Although this model is not as precise as the numerical simulator, it requires less computation time and is simpler to operate [90]. Based on the basic models, [91] further improved the pseudo-3D fracture model, demonstrating better compatibility relationships between reservoir properties, treatment parameters, and fracture growth. In this work, the genetic algorithm and evolutionary operation were combined, resulting in a robust optimization algorithm that can help design optimization. Fracture propagation paths have been investigated by [6] at different initiation angles using the extended finite element method incorporating the enriched function approach and phantom mode technique. It was found that the main factors influencing fracture propagation during fracturing are the initiation angle, production time, stress difference, and mechanical effects.

1.5.2. Multi-Stage Fractures in Horizontal Well

Multi-stage fracturing in a horizontal well is essential to increase stimulated reservoir volume (SRV), making maximum reservoir contact with the wellbore. This process increases production tremendously in tight formations from otherwise uneconomic or un-producible shale or deep tight gas formations [92]. Tight formations are mostly at a deeper depth where natural fractures are randomly distributed and highly stressed. A horizontal well intersects these natural fractures, increasing the dual-porosity fluid flow system and enhancing production. While fracturing the horizontal well transversely in multi-stages, each transverse fracture intersects with several natural fractures, increasing the natural fractures' drainage rate into the main transverse fractures. Thus, the fluid flows from the main fractures to the wellbore and simultaneously from the matrix to the main fractures. This fluid-flow system is called the tri-linear dual-porosity dual-permeability system [93–95]. To create multi-stage transverse fractures, the horizontal well is divided into several clusters with a 50–100 ft spacing between the two consecutive clusters. One

cluster may have four–five stages with a spacing of about 100 ft. Each cluster is perforated with a certain perforation shot density. Each stage is then fractured hydraulically (usually with proppant), and more than one fracture will be created in one stage. Hydrofrac treatment is completed for all the clusters using the plug and perforation method in each stage [96]. Then, the well is ready for completion, flowback, and transient testing to confirm the success of the treatment. Despite several success stories, this hydrofrac technique still has several concerns. The major factor is the hydrofrac face, and natural fractures tend to get damaged by gelled fracture fluids. This gelled fracturing fluid entering the fracture faces does not degrade/break fully to retain the fracture conductivity [97]. To avoid this and depending on the rock's mechanical properties, water or foam fracs can be useful; however, in some formations, even this may still not be the best solution [96]. Therefore, the design of fracturing fluid rheology for formation conditions and shear rates in the fracture is a critical aspect of this technique, which requires more attention for further research.

1.5.3. Post-Fracture Well Behavior

There are several considerations the engineer needs to make when evaluating a well's behavior after it has been tested for fracturing. Before and after the fracture operation, the engineer can determine the well's productivity rating. Other relevant considerations are final oil and gas recovery and measurements to assess the duration of the propped fracture, the conductivity of the fracture, and the well's drainage region [98].

Post-fracture management analyses of data on fracture treatment, output data, and pressure data may be very detailed and time intensive. Nevertheless, it would be challenging to begin the method of improving the fracture treatment on subsequent wells via an appropriate post-fracture assessment. Theoretically, hydrofrac should always improve a well's productivity index, and the hydrofrac will, in some conditions, improve ultimate recovery. Post-fracture well-test analyses are used to estimate the formation's propped fracture volume, fracture conductivity, and drainage area [13].

2. Fracture Conductivity Damage

A fracturing fluid inevitably causes reservoir damage, categorized by two types: external damage and internal damage. The crushing of the embedded proppants mainly causes external damage in the form of the fracture plugging. Residual polymers and chemicals, after the flowback, cause fracture face damage, which is also a type of external damage [99]. On the other hand, internal damages are caused by high fluid leak-offs, relative permeability hysteresis, capillary effects, and clay swelling. Residual gel fracturing fluid, proppant crushing, embedment, and particle migration are the main causes of fracture conductivity damage [100]. Ref. [101] reported that FC was reduced by over 90% in fracture conductivity because of the abovementioned factors.

The extent of internal damage depends on the water sensitivity of the rock, the extent of water or gas lock, and the quantity of macromolecule adsorption, in addition to pore blockage due to fines migration. Ultimately, several factors will impact the cleanup process, including fracture geometry, conductivity, non-Darcy flow effects, heterogeneity fluid viscosity, formation temperature, breaker, gel residue, operational procedures, and, most importantly, pressure drawdown [102]. The main drawbacks of hydrofrac are clay swelling, fluid leak-off, precipitation of fines migration, and fracturing fluid residues. According to some studies, gel fracture treatments show excessive residual damage compared to slick-water fracture [103]. However, contradictory results reported by [104] say that damage by slick-water could be more severe than HPG fracturing fluid due to higher water sensitivity and higher macromolecule adsorption.

The studies also indicate that the rate of flowback of residual polymer from reservoirs below 250 °F is less than 40%. This results in the failure of an adequate polymer cleanup process. Research conducted by [105] to assess the main hindrances to water and gas flow in wells suggested that relative permeability and capillary pressure should be considered when conducting the cleanup process as they affect the results of the entire process. There

is also a possibility of a substantial pressure drop in cases where fluid invasion damages the reservoir rock permeability or when a gas blockage is likely to occur. In scenarios where the permeability of the reservoir is undamaged, there will not be any water or gas blockage if the capillary pressure is lower than the pressure drawdowns. According to [106], however, when the relative formation permeability is lower than the fracture conductivity, there will not be much damage, and the cleanup process would go on smoothly since the fracture fluid would easily break, providing lower viscosity after treatment. There would also be a possibility of recovering up to one-half of the injected fracturing fluid in 2–6 days, as long as there is gel degradation and adequate fracture conductivity [106]. The author also stated that, in situations where the fracture conductivity is low, the gas is sure to enter into the wellbore fracture. This can also be enhanced by ensuring adequate fracture length and well productivity time. The main disadvantage of Tannich's model is that it did not allow for the capillary forces, the damage in the fractures, and the closure stress effects surrounding the fracture.

In a study by Gdanski et al. [107], a large reduction in gas production and increment water production was experienced when a 90% fracture face permeability damage occurred. This was calculated based on the measures established by [108], who aimed to determine the relationship between well productivity and fracture face damages. Another study that examined the impacts of fracture conductivity damage was conducted by [109]. They used water-based fracturing fluid and concluded that higher gas production, faster fracture fluid cleanup, and relatively longer fracture lengths could be achieved when water-based fluids were used to increase the conductivity rate. This means that fracture conductivity results in high gas flow rates and faster fracture cleanup processes than formation permeability, water mobility in the reservoirs, and fracture closure effects. The researchers mainly used Newtonian fluids in this study.

2.1. Guar Polymer Damage

The residue of the guar-based fracturing fluid can lead to gas sorption and diffusion issues because of the guar-coating. The gel remnants cause more permeability damage to the natural fracture in contrast to the induced fracture. Fortunately, in the case of decent gel-breaking conditions, the fracture permeability can regain its normal levels through water flushing in a high-temperature environment [110]. The level of damage by hydroxypropyl guar (HPG) frac fluid was quantified by [104]. Their NMR-based study showed that the HPG fracturing fluid caused 30.43% core permeability damage, of which 23.26% was due to water block, and only 1.11% was due to polymer adsorption. In a study conducted by Ghosh et al. [111], it was established that crosslinked guar gels are less prone to fracture face damage compared to linear gels by a factor of two or more.

2.2. Fracture Face Skin

Fracture face skin (FFS) is described as an impairment of the fluid flow from the matrix into the fractures. However, fracture face skin has little effect on the productivity of multi-fractured horizontal wells. The worst possible scenario of well productivity damage may not exceed the five percent marker, according to [108], who suggested against using low-damaging high-cost fracturing fluids that do not justify the incurred expenses in most hydrofrac operations. However, in many actual field practices, this argument was not valid.

2.3. Damage Due to Frac Fluid Invasion

Swelling and migration constitute the main reasons for formation damage caused by hydrofrac treatments in shale formations. Throughout the process, the water sensitivity of the shale causes a reduction in fracture conductivity due to proppant embedment and pore blocking. Flowback fluid causes significant damage since it produces carbonate and sulfate deposits, allowing more scale creation within the reservoir. Consequentially, remnants of the fracturing fluids after gel breaking and other solid residues clustering and causing some sort of blockage to the fractures, leads to permeability damage. Hydrofrac produces a

complex fracture network, yet few are useful for production because the damages prevent their operative growth [112].

The fracturing fluids retrieved during the flowback also lead to several unwarranted conditions. Firstly, the alteration of relative permeability to hydrocarbons in the rock. Additionally, it damages and disturbs the chemical equilibrium of the rock/fluid system, causing a physically- and chemically-altered zone of rock near the fracture face, and ultimately leads to a reduction in rock strength because of the fluid invasion [113]. To attain higher levels of production, it is essential to comprehend how the rate of combined fluid leak-off and imbibition (and the amount of fluid invading the rock matrix) correlate [114]. Slick water fracturing is a poor choice for water-sensitive shale and clay-rich formations. A 39.08% permeability impairment was observed due to the water sensitivity of shale alone, resulting in the hydration, swelling, dispersion, and migration of the clay fines and deposition of the scales [104].

2.4. Polymer Filter Cake Damage

The fracture fluid leaks off into the reservoir formation during fracturing, while most polymers remain within the proppant pack, creating a filter cake [115]. A polymer filter cake is beneficial during fracturing as it helps to reduce the leak-off of the base fluid into the reservoir formation, keeping the hydraulic pressure inside the fracture and increasing the propagation of the fracture. Conversely, the filter cake must be removed after a fracture treatment to attain maximum conductivity and generate a hydrocarbon flow path. The polymer concentration in the gel can increase from 20–40 to 300–1000 lbm/1000 gallons upon closure. Sometimes the polymer concentration becomes so high that it cannot be fully degraded by the breaker additives anymore, as evidenced in low and high permeability formations.

Moreover, the temperature-resistant additives used for high-temperature reservoirs provide long-term resistance to thermal degradation of the cake, are another cause of concern [116]. Therefore, the goal is to eliminate or minimize the filter cake to obtain optimum fracture conductivity. Unfortunately, though the general physical procedures for filter-cake buildup are well understood, the fundamental property and filter cake removal mechanism has not been adequately understood [107].

2.5. Fracture Conductivity Damage Due to Proppant

Significant factors influencing the fluid conductivity of a proppant-packed fracture include proppant size, shape, and size distribution. The selection of proppant type generally relies on the formation temperature and the predicted closure stress. Soft formations facilitate the embedment of the proppant into the formation and cause formation spalling, leading to conductivity damage. This is often alleviated by using a reduced-size proppant [117]. Proppant embedment leads to mechanical damage or pseudo-skin and, as a result, hinders the normal operation of the near-hydrofrac zone. As per [118], productivity and flow assurance significantly deteriorates when near-fracture mechanical damage is exhibited. The proppant embedded layers thicken when the proppant penetrates the matrix of the reservoir formation, causing further mechanical damage as well as fracture conductivity damage.

Closure stress increase is exhibited during production following hydrofrac, but the increase rate depends on the proppant concentration, size distribution, type of reservoir formation, and hydrofrac surface geometry [119,120]. As observed by [121], proppant embedment results in the deformation of the formation grain, near-fracture-face matrix damage, grain crushing and disintegration, and fine particle generation. The stress-induced mechanical interaction between the fracture surface and proppant is responsible for the above. Thus, pore spaces are compacted or plugged, and the region's permeability is reduced, confining the fine particles internally, which may get released gradually during production. The realization of the fractured skin parameters has been described by [108] as damaged and non-damaged proppant-packed zones, characterized as hydraulically

near-fracture or created fracture reservoir formation damage. Proppant crushing due to high closure stress is a great concern that necessitates a judicious selection of proppant based on laboratory experiments. Liang, X. et al. [122] proved that low-strength sand proppants are subjected to higher crushing compared to ceramic proppants, resulting in significantly higher fracture conductivity damage (Figure 6).

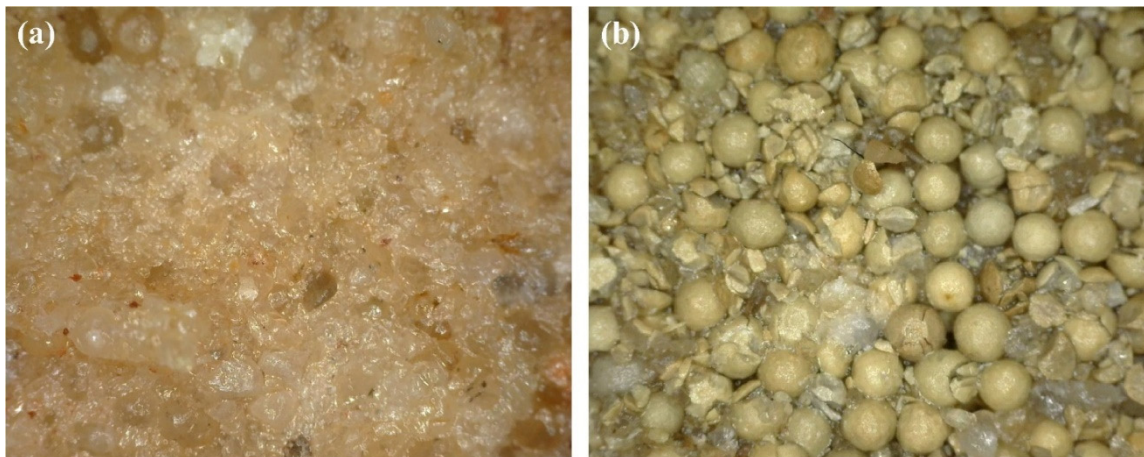


Figure 6. Crushing of proppant after fracture closure ((a): sand proppant, (b): ceramic proppant) [122].

2.6. Salt, Fines, and Water Phase Trap

The original formation water within the reservoir may have salt precipitate in natural fractures or shale pores which is consumed through the shale gas accumulation process, hydrocarbon generation, and gasification, as well as compaction and drainage. Mixing frac fluid with high-salinity connate water leads to the dissolution of soluble salt, thus, increasing the salinity of the flowback fluid. Soluble salts are driven in the liquid phase to seed out. This happens when the reservoir retains water phases in the high-mineralization fracturing fluid as it evaporates in the form of hydrocarbon gas through the pressure depletion process [123]. The space between shale fractures is filled with salt crystals, decreasing permeability. However, the worst damages happen when there is a lower initial permeability.

Water phase trapping and the blockage of micro-fractures are the primary damages caused during the preliminary liquid phase flowback stage, where the well is open. This is due to suspended solids within the flowback fluid. The shale reservoir pressure usually decreases with more water phase flowback, thus, leading to gas absorption in the shale matrix pore wall as it diffuses into micro-fractures [124]. As a result, gas saturation in the fractures increases with the continuous increase in the permeability of the gas phase and the constant decrease of the water phase permeability. The gas and water phase flow exists in the gas reservoir, with the gas phase carrying fluids to mitigate the water phase trapping damages effectively. However, a significant decrease in the adhesion strength of those solids retained in micro-fractures leads to the migration of fine particles in the reservoir. The gas flows to the surface as water phases in the retained fracturing fluid gradually evaporate during the later flowback stage, thus, driving soluble salts in the liquid phase to seed out [124]. Therefore, not only fine migration and water phase trapping but the solid-phase residual blockage resulting from salt precipitation needs to be taken care of to optimize the flowback procedures in case of high-mineralization of flowback fluids [125].

2.7. Damage Mechanism and Quantification

The hydrofrac fluids used to enhance production in shale-gas reservoirs always causes damage through leak-off, thus, leading to spurt loss. The microscopic invasion of polymer into the threads of fracturing fluid, and their retention mechanism in fracture face regions,

are explained by [126]. The performance of a hydrofrac, and the exposure time to hydrofrac fluids, are the main factors that help to retain another damaging parameter, i.e., water [127]. There is an increase in water saturation within the near-fracture formation as the water from the fractures enters into the formation through leak-off and water imbibition processes, causing hydraulic damage. There are three ways to explain how injected water storage occurs. First, the isolation of water from the fracture is carried out by injecting the naturally saturated fractures due to fracture closing. Second, the injected water in natural fractures may be retained by capillary pressure. Third, the formation matrix may get embedded by the injected water [128]. However, the water is forced to move to the reservoir formation to reduce the water content within the near-fracture surface due to narrow passages that create high capillary pressure [129,130]. However, a decrease in water saturation caused by tiny matrix pores and high capillary pressure, which spreads the invasion of the water region with increased water saturation, is caused by low matrix relative permeability due to limits to the water invasion region. Under the pore proximity effect, and through the vaporization process, the imbibed water into the porous formation disappears as the interface disappears [127,131].

Formation-damage mechanisms in post-fractured tight gas reservoirs were investigated based on numerical simulations and special-core analyses. The conclusion was that “there is no permeability damage caused by polymeric-fracturing fluids invasion, in tight reservoirs having similarities between the sizes of pore throats and the size of the polymer molecules” [132]. At low invasion rates, the filter cake does not form since spurt-loss is insignificant. This phenomenon is observed from the linear cumulative filtrate invasion trends during the tests conducted using non-clay-damaging fracturing fluids. However, [133] indicated that there is a delayed liquid invasion from the wellbore into the reservoir formation that lasts for a time, which is allowed for by the weak mud-cake formation from the low-porosity strong-capillary suction and wellbore conditions. This creates a filtrate invasion problem in naturally fractured shale reservoirs where filter-cake lifting becomes a non-issue of importance during the cleanup period.

A residual fracturing fluid causes proppant-packed fractured permeability or conductivity damage, thus, leading to a hydrofrac well pseudo-skin [134]. As per [118], when the unbroken crosslinked gel is poorly cleaned, proppant-packed fracture and fracture conductivity gets damaged since both are internally damaged fractures. Fracture conductivity can be reduced significantly due to the presence of unbroken viscous gel within the proppant pack. Additionally, the flow of a fluid system, with gas and a mixture of gel and the formation water, significantly affects fracture cleanup [129]. Thus, poor fracture conductivity leads to a hydrofrac (proppant-pack) positive skin.

A drop in fluid pressure measured via an evenly distributed proppant bed in a core of a constant height and length, is a common experimental method used to determine fracture conductivity. A laboratory measure of conductivity under the same field conditions and stress state helps determine the force associated with the damage mechanisms and fluid interactions [122]. It also offers a solution on how the fluid- and proppant-selection process can be customized. Damage mechanisms can, therefore, be observed closely to control the stress state for the laboratory results. Formation spalling, fines migration, proppant embedment, rock-proppant-fluid interactions, and a change in proppant resistance to cyclic stress are part of the damage mechanism that requires close observation. However, creating a local stress state in the laboratory can help to observe the damage mechanism and the extent of damage due to proppant embedment [135]. Nevertheless, multiphase flow, gravity, non-Darcy flow, reservoir flow capacity, and viscous segregation are among the mechanisms that contribute to fracture conductivity; however, it is a challenge to experimentally measure them all [135].

Fluid- and proppant-related conductivity damages can be quantified through laboratory studies, and various established methods are reported in the literature. The traditional sensitivity analysis is being replaced by the response surface method as an alternative method, as it can vary multiple parameters simultaneously and explain the influence

and interaction of multiple factors to reduce test times and expenses [136–138]. Though popular, accurate conductivity predictions and long-term fracture conductivity tests are rarely performed. In a recent study by [139], single-factor tests were designed based on the Box–Behnken design method to investigate the degree of damage caused by different parameters to the propped fracture conductivity. The study concluded that with an increase in the fracture conductivity damage came a lower proppant concentration, higher fracturing fluid viscosity, and longer fracturing fluid retention time.

Rock matrix is induced by high-stress concentrations throughout the HF process, leading to micro-channeling along pre-existing discontinuities and bulk material failing. The established failure-induced changes alter the localized region's permeability, as they indirectly intersect the conducive pathways connected to the wellbore. Theoretically, an increase in permeability due to exhibited changes directly affects the reservoir drainage since the damage in some rock types increases except for pore-collapse-failure mechanisms. These problems can be examined using laboratory HF tests as multiple data types are monitored to illustrate the density of the fracture network generation. Research utilizing HF laboratory tests collected pump information such as pump flow, pressure, and volume data, with the analysis carried out to examine acoustic emissions (AEs), confining stresses and head pressure [68]. The study of damage evolution and the phenomenon of fracture generation, utilizing AEs as the primary method, have been reported previously [140]. From the definition point of view, AEs represent “the phenomenon in which elastic waves are emitted by the sudden frictional sliding and occurrence of fractures along discontinuous surfaces and grain boundaries and are characterized by an irreversible and localized release of stress-energy” [141]. Interpretation of AE signals can provide information related to the stages of development of fractures [142], event locations [143] and rock tensile, shear, or mixed-mode type [144,145]. The passive monitoring process makes AEs monitoring a non-destructive technique, despite referring to the elastic wave emission as a partial system coupled with permanent damage. The wealth of information regarding fractured regions provided by AEs on aspects such as orientation, volume change, location, slip length, geometry, direction, and source mechanism, among other elements, are well described by [146].

3. Fracturing Fluids Damage Mitigation

3.1. Damage Mitigation through Microbes

As mentioned earlier, guar is a polysaccharide macromolecule consisting of a backbone of mannose units bound together by β -1,4 glycosidic bonds and randomly attached galactose units linked to the mannose backbone by α -1,6 linkages [36]. The length of the mannose backbone and the mannose/galactose ratio govern its rheological properties in an aqueous medium [38]. The mechanism behind the microbial degradation of guar is through the release of hydrolase enzymes such as β -1,4-mannanase, β -mannosidase, and α -1,6-galactosidase, which attack the β -1,4 and α -1,6 linkages, breaking the backbone and side branches into simple water-soluble sugar molecules [147]. Various microbes have been identified that release these hydrolase enzymes. Some of the preferred characteristics of the microbial strain are mesophilic, alkalophilic, thermophilic, and halophilic, commensurate with the reservoir environment [115,148,149]. In general, the techniques adopted to screen the microbes are based on the rheological parameters and the average molecular weight of guar gum before and after exposure. Particle size distribution studies help to measure the extent of insoluble residues. Sand-packed/core-flooded studies are also used to measure the residual permeability damage of the pack/core [150]. *Bacillus sonorensis*, one such guar gum degrading bacterial strain, was isolated from produced water and found to have the qualities mentioned above [151]. These studies achieved a viscosity reduction of more than 95% and more than 90% regained permeability in sand pack column experiments. Other guar-gum-degrading microbes isolated from the produced water are *Bacillus Aeri*, *Anoxybacillus rupiensis*, and *Geobacillusstearo thermophiles* [151]. All these strains have shown a reduction in apparent viscosity and the average molecular weight of guar gum, of

which *Bacillus aerius* has displayed the fastest degradation ability and highest permeability restoration (above 93%) in the sand pack column. Bacterial strains generally express their activities within narrow temperature windows. The earlier strains discovered for application in hydrocarbon reservoirs were seen to be effective at low temperatures. For example, mannanase extracted from *Aspergillus niger* was seen to have an activity window that effectively degraded guar at temperatures between 15 and 60 °C [152]. In contrast, later investigations with thermophiles, such as *Thermotoga maritima* [148] and *Rhodothermus marimus* [149], showed optimal galactomannan degradation activity at around 85 °C. The hyperthermophile, *Thermotoga neapolitana*, is found to have an activity window at about 100 °C [147]. These developments have paved the way for microbial application in deeper, higher-temperature reservoirs.

3.2. Silica Nanoparticles (SNP)

The application of (SNP) and its ability to hinder and falter adsorption resulting from HPG has been discussed [64]. The HPG will be adsorbed in the sandstone and damage the permeability of the reservoir. SNP is applied to the HPG-fracturing fluid to diminish the adsorption capacity of the HPG molecules on the rock's surface and reduce fluid leak-off, which alleviates the damaging effect of the HPG-fracturing fluid on the reservoir [113]. Also, adding SNP is found to enhance the temperature and shear resistance of CO₂-sensitive fracturing fluid in high CO₂ environments [153]. Several other nanoparticles were evaluated for their efficacies in enhancing the quality of the fracturing fluids. They were found to have applications as cross-linking agents as well as gel breakers, leak-off control additives, rheology modifiers, foam stabilizers, proppant surface modifiers, and emulsion stabilizers in different types of stimulation fluids [154]. However, despite the exceptional performance displayed in the laboratories, their field application is still limited.

3.3. Remediation through Foam

Foam fluids were initially introduced to low-pressure gas reservoirs because the gas in the foam expanded (following treatment) to remove the fracturing fluid from the well, minimizing formation damage [46]. Foams have also been used in various wells, whether they be low or high pressure, gas or oil, where the minimization of damage was critical. Due to the low liquid content of foams, minor residues of residual liquid are permitted. Foam fluids' two-phase structure enables the generation of high-viscosity fluids for fracture propagation. The advancement and deployment of continuous internal phase design models allow for the application of proppant to foam fluid while maintaining its viscosity [155].

3.4. Remediation through Delayed Mechanisms

In the past few years, the invention of different polyamino-borates cross-linkers [156] and other innovations, such as adopting delaying agents and ligands, including N-methylglucamine, dipentaerythritol sorbitol, and pentaerythritol, has brought positive results to fracture conductivity. Ligands are mainly used in producing polyaminoborate (PAB) cross-linkers, which delay crosslinking reactions. According to [157], zirconium and titanium metals can be used as delaying agents with carboxylic acid, amine functional groups, and alcohol, which are found to be effective at up to 275 °F. A study by Kalgaonkar and Patil [158] focused on developing a Zirconium-cross-linking agent, which is a shear-stabilizing chemical. To achieve this, they used two primary buffers: sodium carbonate and potassium carbonate, at high concentrations, raising the solution pH level to 10.2. The resulting gel took approximately 75 min to crosslink, while the reference solution took less than 5 min.

3.5. Remediation through Breakers

Breakers are chemicals usually applied at the later stages of the fracturing project to downgrade the viscosity of the gelling agent as a way of aiding the release of the proppant, facilitating the flowback of the fracturing fluid [159]. When fracturing a conventional

reservoir, an ideal fracturing fluid should possess sufficient viscosity to transport proppant into the fractures. After the placement of the proppant, the fluid should lose as much viscosity as possible to facilitate the flowback of the injected fluid and maximize fracture conductivity. In hydrofrac treatments, linear and crosslinked biopolymers, as well as synthetic polymers, are used. In acid-fracturing operations, however, synthetic polymers are preferred. The high viscosity fluid must be removed from the proppant matrix after completing the fracture initiation and subsequent proppant placement. Besides, the filter cake formed on the fracture face needs to be cleaned to provide a matrix-to-fracture fluid transport. Due to fluid leak-off, the polymer concentration in the formed filter cake can be several times larger than the original polymer gel [160]. Thus, breakers are used to initiate a chemical reaction by which the polymer backbone is broken, and gel viscosity is reduced to a minimum. This chemical reaction is a function of temperature, the concentration of the breaker, polymer concentration, and the pH of the surrounding area. Table 2 shows the type of breakers suitable for various frac fluids.

Table 2. Breaker comparison.

Breakers	Metal-Crosslinked Bipolymers	Borate-Crosslinked Bipolymers	Metal-Crosslinked Synthetic Polymers	Phosphate Esters (Gelled Hydrocarbons)
Oxidizers	Applicable	Applicable	Applicable	x
Weak acids	x	Applicable	x	x
Decrosslinking agent	Applicable	x	Applicable	x
Calcium and magnesium oxides	x	x	x	Applicable
Enzymes	Applicable	Applicable	x	x

3.5.1. Enzyme Breakers

Enzyme breakers are proteins consisting of a complex structure of amino acids [161]. Enzymes work on a lock and key principle; thereby, an enzyme can attack only a specific chemical bond to facilitate a reaction [162,163]. This site-specific attack effectively breaks guar into monosaccharides or oligosaccharides, thereby avoiding undesirable reactions with the wellbore and downhole equipment [164]. As biocatalysts, enzyme breakers offer significant advantages over traditional oxidative breakers or oxidizers [165]. The enzyme-polymer reactions are mild, and their rate is controllable, which enables the gel strength to remain for a sufficient time to support the delivery of the proppant [166,167]. Because enzymes function as catalysts in breaking reactions, they do not get consumed, unlike oxidizers. The reaction can continue allowing the degradation of the polymer to a further extent than oxidizers can. Another benefit is that they almost totally break down the guar and do not involve any unintended reactions. On the contrary, the oxidizers degrade a polymer chain randomly and show an uneven residue removal ability. Although oxidizers are relatively cheaper and readily available, they also display incompatibility with many commonly used frac-fluid additives, such as organic materials, which limit their deployment as a breaker [168]. Despite the comparative advantages, however, the application of enzymes as frac-fluid breakers has not been widespread mainly because of the reservoir environmental factors, such as temperature and pH [169]. To carry out its function as a catalyst or breaker, the enzyme protein must acquire a particular shape through a type of self-assembling called “folding.” In a favorable environment, proteins undergo a structural adjustment from an unfolded to folded state and become active. The process is reversible, and at higher temperatures and an unfavorable pH, the three-dimensional conformation of the protein changes from an active folded state to an inactive unfolded state [170]. Possible folding pathways illustrating the unfolded and folded states are derived by [70] using the Markov state model and are depicted in Figure 7. Thus, researchers have been making efforts to develop enzymes that can operate under alkaline

and higher temperature reservoir conditions to effectively mitigate fracture damage in high temperature and alkaline (carbonate) environments.

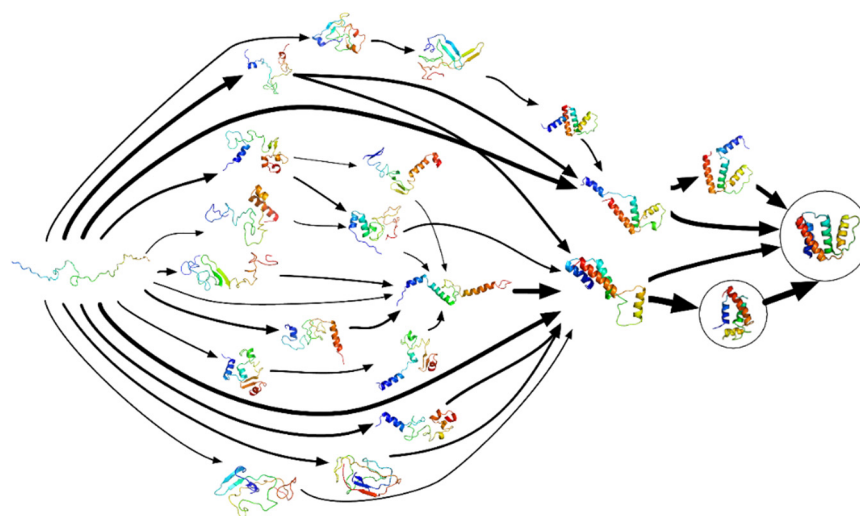


Figure 7. Model of a protein's possible shapes and folding pathways from its initial randomly coiled state (left) into its native 3D structure (right) [70].

Sarwar et al. [165] investigated the effectiveness of oxidizers, such as ammonium persulfate, sodium persulfate, and sodium and calcium peroxides. They compared them with the galactomannanase enzyme over a wide temperature range from 75 to 300 °F. The residue-after-break was used as one measure of the effectiveness of the breaker. All of the breakers generated residues from 5 to 7 wt.%. The development of mixed enzyme gel breakers containing oxidizers is seen to be effective in reducing gel viscosity to a great extent. A mix of beta-mannanase, cellulase, pectinase, glucanase, xanthanase, sulfate, and persulfate broke the macromolecules into a sugar-like structure; however, the optimum breaking temperature is seen to be 20–60 °C only [171]. A bacterium (*Paenibacillus cookie*) was identified that can produce a high quantity of mannanase [172]. The extracted and purified mannanase was found to be optimally active at a wider pH range; however, the thermal limit was restricted to 50 °C. Mohapatra [173] reported a superior Mannanase enzyme (mannanase-II) for breaking borate-crosslinked guar gum gel and found that, compared to oxidizer gel breakers, mannanase II exhibited superior and homogeneous gel-breaking performance, leaving far fewer residues. It also demonstrated a wider range of temperature (40–65 °C) and pH (7–8.5) tolerance, making it suitable for application in sallow carbonate formations. The development of a protein-engineered galacto-mannanase enzyme that works at temperatures as high as 120 °C and a pH range from 6–8.5 has been tested successfully in carbonate reservoirs [23]. The breaker system can degrade the damaging polymeric residues on the fracture face and regain matrix-fracture permeability to the extent of 80–95%. They also explained the benefits and consequences of applying the enzyme breaker in single-step and two steps. This is the highest temperature and pH range tolerant enzyme breaker reported as to date.

3.5.2. Breakers for Acid-Fracturing Gels

These breakers are applied to minimize the gel's viscosity and limit the quantity of polymer remaining in the reservoir and fractures. Examples of such breakers include fluoride, phosphate, and sulfate anions. Oxidizers (persulfates) degrade the guar-based polymer by a free radical reaction with sulfur. This reaction defragments the polymer into shorter molecules, reducing its molecular weight and viscosity. On the other hand, enzymes degrade the polymer by the hydrolysis of certain side chains. Acids de-crosslink the gel by lowering the pH and are mainly used for borate-crosslinked gels that require a high pH for crosslinking [158].

3.5.3. Delayed Breaker System and Carriers

Delaying polymer breaking activity is occasionally necessary for deep and long horizontal wells and high-temperature formations to avoid prematurely reducing the frac gel's viscosity. To accomplish this goal, breakers have been encapsulated to render them inert during the injection. The relatively large size of the capsule, typically meant to split open when the fracture re-closes at the end of injection, may result in insufficient filter cake decomposition. Polyethyleneimine dextran sulfate polyelectrolyte complex (PEC) nanoparticles were studied, initially created for drug distribution but adapted for oilfield uses to entrap and delay the release of enzymes in a controlled manner. PECs are formed when nonstoichiometric ratios of polyanions and polycations are mixed at low concentrations in aqueous solutions. The electrostatic attraction between oppositely charged polymers causes the polymers to self-assemble into particles, and the excess charge on the outer surface contributes to their colloidal stability. If another charged object is introduced into the polyelectrolytes during mixing, it can be absorbed into the particles via electrostatic and steric interactions [174,175]. The scale, charge, stability, and entrapment efficiency of PECs can be adjusted by altering the molecular weight, charge intensity, and relative concentrations of the polyelectrolytes and the order in which the individual components are combined (mainly pH and shear). To be effective in breaking frac fluids, this approach must have a high enzyme efficiency, homogenous dispersion, and a variable release duration [176].

3.5.4. Summary of Hydrofrac Damage Mitigation

From the above discussion, it is evident that the damage to fracture conductivity and, to some extent, the reservoir matrix is inevitable during and after the fracturing process. It is also understood that the primary cause of the damage is the remaining frac fluid residues within the fractures and the pore spaces. The most economical and logical way of realizing the maximum benefit of a high-cost fracturing job is to reduce the polymeric ingredients into small and low viscous entities to facilitate an efficient flowback using suitable breakers. Table 2 summarizes the type of breakers suitable for various frac fluids.

4. Conclusions

Although hydraulic fracturing has matured over the past half a century, fracture conductivity and reservoir matrix damage are still concerns. In this review article, we tried to provide basic as well as advanced information in a structured way, summarizing the rich technical content of this field in a logical framework divided into three sections: the background of the fracturing process, fracture conductivity damage and its underlying mechanisms, and finally, various damage mitigation techniques.

Section 1 discusses fracture orientation, propagation, conductivity, fracturing fluid ingredients, properties, crosslinking methods and mechanisms, treatment optimization, model selection, and post-fracturing well behavior analyses. Proppants, and their application, are also discussed in this section in brief. Since guar-based fracturing fluids are the primary focus of this article, we addressed their properties and crosslinking mechanisms in detail.

In Section 2, we reviewed the fracturing damage mechanism and process of quantification in post-fractured reservoirs. This section addressed various sources of damage, such as polymers, crosslinked gels, residual filter cakes, Salts, fines, water phase traps, and also damage due to proppant embedment. This section ends with valuable information on damage mechanisms and damage quantification methods, including acoustic emissions.

Section 3 is the main essence of this article, which covers the updated information on various damage mitigation methods. Among the various methods, breaking the residual frac gel with guar-specific enzyme breakers has been found to have gained importance in recent years. Also covered in this section are breaker delivery and delayed-release methods applicable to high-volume fracture jobs.

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