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Laboratory Testing of Fracture Conductivity Damage by Foam-Based Fracturing Fluids in Low Permeability Tight Gas Formations

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Abstract: In the case of fracturing of the reservoirs using fracturing fluids, the size of damage to the proppant conductivity caused by treatment fluids is significant, which greatly influence the effective execution of hydraulic fracturing operations. The fracturing fluid should be characterized by the minimum damage to the conductivity of a fracture filled with proppant. A laboratory research procedure has been developed to study the damage effect caused by foamed and non-foamed fracturing fluids in the fractures filled with proppant material. The paper discusses the results for high quality foamed guar-based linear gels, which is an innovative aspect of the work compared to the non-foamed frac described in most of the studies and simulations. The tests were performed for the fracturing fluid based on a linear polymer (HPG—hydroxypropyl guar, in liquid and powder form). The rheology of nitrogen foamed-based fracturing fluids (FF) with a quality of 70% was investigated. The quartz sand and ceramic light proppant *LCP* proppant was placed between two Ohio sandstone rock slabs and subjected to a given compressive stress of 4000–6000 psi, at a temperature of 60 °C for 5 h. A significant reduction in damage to the quartz proppant was observed for the foamed fluid compared to that damaged by the 7.5 L/m^3 natural polymer-based non-foamed linear fluid. The damage was 72.3% for the non-foamed fluid and 31.5% for the 70% foamed fluid, which are superior to the guar gum non-foamed fracturing fluid system. For tests based on a polymer concentration of 4.88 g/L, the damage to the fracture conductivity by the non-foamed fluid was 64.8%, and 26.3% for the foamed fluid. These results lead to the conclusion that foamed fluids could damage the fracture filled with proppant much less during hydraulic fracturing treatment. At the same time, when using foamed fluids, the viscosity coefficient increases a few times compared to the use of non-foamed fluids, which is necessary for proppant carrying capacities and properly conducted stimulation treatment. The research results can be beneficial for optimizing the type and performance of fracturing fluid for hydraulic fracturing in tight gas formations.

Keywords: nitrogen foamed stimulation fluids; foam rheology; fracture conductivity; reservoir stimulation

1. Introduction

Hydraulic fracturing together with horizontal drilling is a commonly used enhancement technology to stimulate hydrocarbon production by creating a network of highly conductive fractures in the area surrounding a wellbore. Exploitation of unconventional reservoirs is economical only after performing many stimulation treatments, leading to the formation of numerous fractures in the rock system [1–4]. The basic intention of the hydraulic fracturing process is to increase the productivity of the stimulated well by maximizing the surface contact with the reservoir and creating high conductivity fractures [5–7]. The flow of gas from created fractures is conditioned by their appropriate filling, for which various types of proppants are used. The purpose of the proppant is to keep the created fracture open after the hydraulic fracturing operation is completed. Quartz sand, Resin Coated Sand, Ceramic Proppants, and High Strength Proppants are used as proppants [8–11]. An ideal proppant material should have the following characteristics: have adequate uniaxial compressive strength, do not deform, be chemically inert to the fracturing fluid containing various chemical compounds, have a low density, be easily accessible and cheap, prevent flowback, and not be pressed into the rock (embedment) [12,13].

Many scholars have conducted significant research into the damage of fracturing fluid to permeability [14,15]. In the case of fracturing of the reservoirs rock using fracturing fluids, the size of damage to the proppant conductivity caused by treatment fluids is significant, which greatly affect the effective execution of hydraulic fracturing operations. Thus, the subsequent long-term production from the reservoir. The issues with cleaning the fracture from treatment fluids is particularly visible for gas reservoirs with low temperatures, reservoir pressures, and permeability [16]. In the case of such reservoirs, to avoid contamination of fracture by fracturing fluid residue, foamed fluids (fluids with addition of nitrogen, carbon dioxide) are used [17,18].

The use of a gas component in fracturing fluids helps to reduce the hydrostatic pressure, provide low formation damage, and ensure no reduction of fracture conductivity due to fluid ingredients [19]. If the used fracturing fluids are prepared on the basis of water and polymer, they may reduce the permeability of the fractures caused by, among others, hydration of clay minerals, collamation of the pore space, etc. Reducing the permeability is an undesirable phenomenon because it clearly restricts the inflow of reservoir media to the production well. The minimization of these unfavorable phenomena is possible thanks to inter alia, limiting the amount of water in fracturing fluids and replacing some of it with gas. The key differences between polymer gel and foam-based fluids are primarily that fracturing fluids foamed either with N_2 or CO_2 minimize the amount of liquids introduced into the formation. Foam fracturing typically uses 65–80% less water than in conventional treatments and enhance recovery of flowback and cleanup in low-pressure formation [20–26]. Guar, a long-chain, high-molecular-weight polymer, has been widely used to increase the viscosity of water for fracturing applications, but generated residues which reduce the conductivity of the proppant pack [27]. Some studies have been carried out on the microscopic mechanism of fracturing fluid damage in the process of fracturing. The cause of insoluble substances in the process of gel breaking was the difficulty in the complete degradation of guar molecules and the reduced solubility of guar gum [28]. According to McAndrew et al. (2014), fracture length, height, and conductivity are mostly dependent on the fracturing fluid type. Although slick water provides a longer fracture compared to 70% quality N_2 foams, it does not deliver proppant in the whole fracture length and height [29]. Polymer-based fluids are still the most commonly used type of fracturing fluids [30,31]. Concerns over fracture conductivity damage by fluids in tight formations found in unconventional reservoirs and constraints on local water availability prompted the industry to develop alternative fracturing fluids, such as energized and foam fluids [32].

As many years of experience have shown, the fracturing fluid should be characterized by the minimum damage to the reservoir formation and conductivity of a fracture filled with proppant [32]. A research procedure has been developed based on the available literature on the study of damage effect caused by fracturing fluids in the fracture filled with proppant material [33–35].

Over the last 30 years, many experimental studies have showed the importance of study the fracture conductivity and how the proppant pack is affected by the fracturing fluid [36–38]. For example, Parker and McDaniel (1987) showed that gel damaged decreased the fracture conductivity under the same closure stress over time [38]. Hawkins (1988) studied the reduction of fracture conductivity caused by fracturing fluids. The necessity of breaker and minimization of crosslinker and polymer concentration was concluded in this research [39]. Marpaung (2007) designed a new experimental apparatus for the dynamic fracture conductivity test to investigate damage resulting from polymer gel in the proppant pack. Marpaung conducted a series of experiments using the dynamic fracture conductivity procedure to identify the effect of production rate on fracture conductivity by simulating field condition for tight gas reservoirs [40]. These above experiments indicated that the fracturing fluid could cause damage to proppant packs, and also showed how closure stress could affects the final conductivity. However, there is very little data on damage to the proppant conductivity caused by foamed treatment fluids. Therefore, better understanding of the behavior of fluid and proppant within a fracture and their relationship to fracture conductivity is of great practical interest.

The goal of this study is to provide experiments on the phenomenon of damage to the fracture filled with proppant material by treatment fluids: foamed and non-foamed, using the developed research procedure. Thanks to the combination of two devices, the Pipe Rheometer with a Foam Generator—Foam Loop Rheometer and a Proppant Conductivity Unit, it was possible to get results that have not been discussed in the literature but that appear to be very important in determining fracture conductivity with non-foamed compared to foamed fluids. This article reviews both the traditional linear gel fluids used in hydraulic fracturing operations as well as the high-quality foamed fluids being developed for both traditional and unconventional reservoirs in terms of fracturing fluid damage to the proppant pack.

2. Materials and Methods

2.1. Materials

2.1.1. Rock Samples

The tests were conducted with the use of Ohio sandstone slabs, quartz sand, ceramic light proppant, and fracturing fluids, which were mixed following the recipe with the desired polymer and other additives concentrations. Ohio sandstone rock was chosen because of its low permeability, which closely represents a tight reservoir. This rock is quarried sandstone of low permeability with minimal clay reaction. The dimensions of the cores used in this research are 17.70–17.78 cm length, 3.71–3.81 wide, and at least 0.9 cm high with a cross-section area of 64.52 cm^2 (10 in^2). The ends of the sandstone cores were rounded to fit into the API Conductivity cell. Additionally, to provide a perfect fit and seal inside the cell, the core samples were surrounded with a silicone sealant. Table 1 shows the petrophysical and mechanical properties of the core samples used in these experiments.

Table 1. Core properties of Ohio Sandstone.

Property	Value
Permeability, md	0.01–0.1
Porosity, %	16–18
UCS, psi	8000–9000
Average Poisson's ratio@1500/2500psi	0.163/0.189
Components, %	SiO_2 86.47, Al_2O_3 7.31, FeO/Fe_2O_3 1.14, TiO_2 0.70, CaO 1.21, MgO 0.11, Alkalies 1.65, H_2O 1.20, Undetermined 0.21

2.1.2. Proppant Description

The proppant used in the experiments was 20/40 quartz sand proppant and ceramic light weight proppant. The proppant concentration for these experiments was 9.76 kg/m^2 (2 lb/ft^2). The weight of this type of proppant is considered optimal for proppant transportation in common fracturing operations in tight gas reservoirs using low viscosity fracturing fluids.

2.1.3. Fracturing Fluid Composition

The fluid composition was selected based on previous experiments conducted in the laboratory and based on previous works by Wilk et al., 2016. The fracturing fluid composition resemble typical fracturing fluids of an actual tight gas fracturing operation, which allowed the assessment of the best additives for the foamed fluids, Wilk et al., 2018.

The fracturing fluid selected for these experiments is a water-based guar consisting of a mixture of biocide, nanoemulsion, foamer, inhibitor of inorganic deposits, and inhibitor of clay minerals. The composition of the fracturing fluids used for the series of experiments is shown in Table 2. Foamed fracturing fluid was created based on tap water with the addition of N_2. At first, the following components were added to water with a temperature of 23 °C: an anionic foaming agent (4 mL/l), a nanoemulsion (2 mL/l), a clay-swelling inhibitor (2 mL/l), and a scale inhibitor (1 mL/l), followed by polymer (natural, fast hydrating guar gum for oil field applications) in an amount of 7.5 mL/l in liquid or 4.8 g/L in powder form.

Table 2. Fracturing fluids components.

FF1A	FF1B
7.5 mL/l natural polymer in the form of a guar-based suspension dispersed in a mixture of hydrocarbons (3.6g/l HPG content) 0.125 mL/l biocide 4 mL/l foamer 2 mL/l nanoemulsion 1 mL/l Inhibitor of inorganic deposits 2 mL/l inhibitor of clay minerals	FF1A foamed with N_2 up to 70% foam quality
FF2A	**FF2B**
4.8 g/l natural polymer, HPG containing an internal dispersant and a pH buffer 0.125 mL/l biocide 4 mL/l foamer 2 mL/l nanoemulsion 1 mL/l Inhibitor of inorganic deposits 2 mL/l inhibitor of clay minerals	FF2A foamed with N_2 up to 70% foam quality

2.2. Methods

To accomplish the goals, this study was divided in four main parts: Design of experiments, experimental apparatus and setup modification, experimental procedure, and experimental conditions. The adopted research concept is shown in Figure 1.

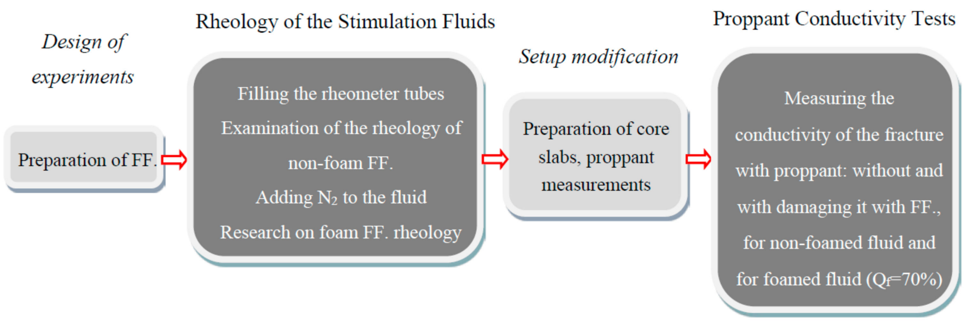

Figure 1. Flow chart diagram of the research.

In the flow chart diagram, the first part represents the preparatory work. Selection of the polymer and additives were carried out based on previous research. Then, the rock material for testing and the composition of fracturing fluids were selected and prepared for the type of tight rock and basic properties of the proppant materials were determined. The next stage of work was conducting a rheology of non-foamed fluid and foamed FF. To test technological fluids energized with gas, it was necessary to modify the device Pipe Rheometer with a Foam Generator—Foam Loop Rheometer M9200 by Grace Instruments and Proppant Conductivity Unit. At the final stage, damage to conductivity and permeability of the fracture filled with proppant selected for formation conditions was carried out.

2.2.1. Basic Properties of the Proppant Materials

First, the basic properties of the proppant materials were determined in the laboratory of the Oil and Gas Institute—National Research Institute, in accordance with the ISO [International Standard [41,42]. The basic properties of the proppant material include: sieve analysis, average grain diameter, sphericity and roundness, acid solubility, impurity content, bulk density, apparent density, absolute density, and uniaxial compressive strength of the proppant: crush test. Basic research is aimed at determining whether the tested proppant can be used as a proppant for hydraulic fracturing treatments. They are performed in accordance with the measurement procedures described in detail in the standards. Limit values of individual tests for various types of proppants, the exceeding of which may prevent the tested proppant from being used in hydraulic fracturing of reservoirs.

2.2.2. Viscosity of the Fracturing Fluids

The procedure described in Section 2.1. was followed in order to prepare fracturing fluids for rheological measurements. The fluid was introduced into the tubes of the rheometer, which allows the measurement of the rheological properties of the foamed fluids under high temperature and pressure, after which it was mixed at a rate of 350 s^{-1}. About 500 mL of the test fluid was placed in container for fluid and the base fluid was foamed with nitrogen to test the rheological properties of the foamed fluids. Then, the fluid was introduced into the measuring system, which was vented. After reaching a stable temperature and pressure (6.89 MPa, T = 60 °C), the fluid circulation in the measuring system was started. Additional gas was then pumped into the measurement system, continuing to circulate the fluid at a shear rate of 350 s^{-1} and collecting some fluid from the system at the same time, causing an increase in the proportion of gas in the foam. The quality of the foam was controlled with a density meter. After obtaining 70% of the foam quality, a test lasting 38 min was carried out, allowing the measurement of rheological parameters. The rheology test was performed at 1000 psi. During the measurement loop, the shear rate was maintained at 40, 100, 200, 300, 200, 100, and 40 s^{-1} for 60 s each. Foam was mixed for 10 min at a rate of 100 s^{-1} between the measuring loops.

2.2.3. Proppant Conductivity Tests

For the needs of laboratory tests, the Foam Generator and a Pipe Rheometer connected to a Proppant Conductivity Unit stand was set up for testing the conductivity of the proppant. In order to analyze the extent of damage to the fracture filled with proppant by the fracturing fluid, its conductivity was recorded throughout the test period. The values of conductivity were compared with the results obtained for the conductivity of the fracture filled with proppant without damaging it with the fracturing fluid. Proppant damage in the fracture was measured, tests aimed at assessing the degree of damage to different proppants caused by energized fracturing fluids listed in Table 3. For these experiments, quartz sand with a size of 20–40 mesh were used, as well as ceramic light proppant with grain size of 20–40 mesh. Proppant was placed between two shaped rock slabs (Figure 2) in the API cell, and together with the API cell, it was placed in a hydraulic press and kept under compressive stress of 27.6 and 41.4 MPa and a temperature of 60 °C [43]. Based on the tests results, damage of the fracture was determine for non-energized fracturing fluids as well as with the addition of nitrogen (Figure 3).

Table 3. Data of proppant basic parameters.

Proppant Type	Turbidity [FTU]	Apparent Density [g/cm^3]	Acid Solubility [%]	Sieve Analysis [%]			Roundness X	Sphericity Y
Quarc sand 20/40	0.80	2.71	1.9	<20 mesh^ > 40 mesh: 97.2	>16 mesh: 0.0	<50 mesh: 0.0	0.68	0.72
LCP 20/40	14.91	2.82	4.6	<20 mesh^ > 40 mesh 98.2	>16 mesh 0.0	<50 mesh 0.1	0.89	0.83

(**a**) (**b**)

Figure 2. The photo of the fracture filled with quartz sand 20–40 mesh (**a**), and light ceramic proppant 20–40 mesh (**b**), with a surface concentration of 9.76 kg/m^2, between two Ohio sandstone rock blocks, before compressing it on the hydraulic press.

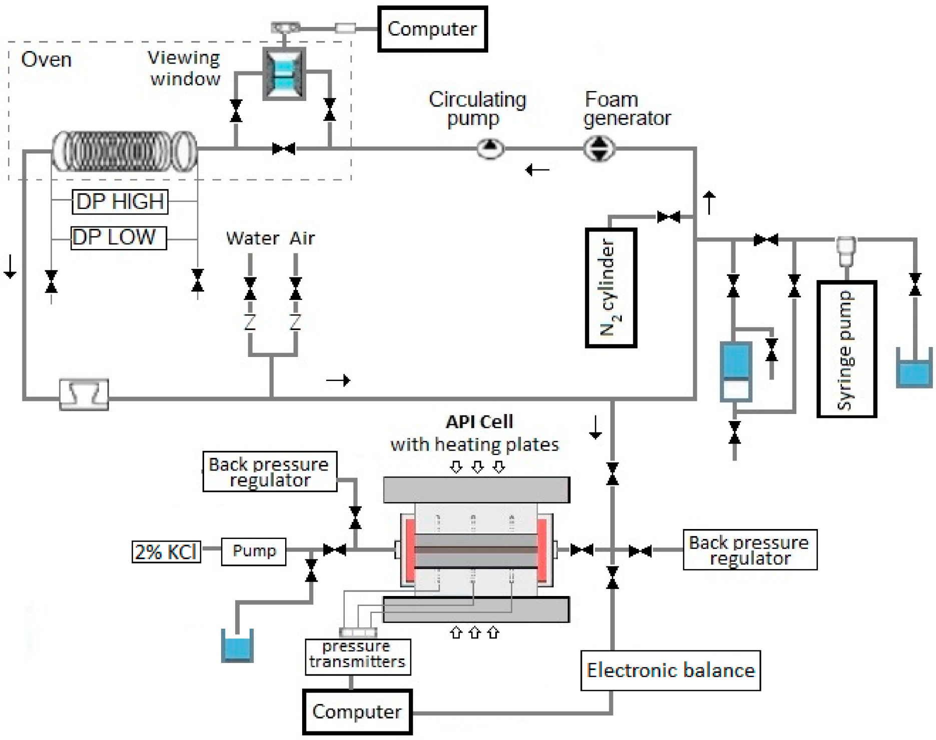

Figure 3. The simplified diagram of the measurement unit for testing the fracture conductivity and damaging it by foamed fracturing fluids.

To determine the permeability of the fracture filled with proppant Darcy's basic, the characteristics for fluids with laminar flow are used in Equation (1):

$$k_f = \frac{\mu \cdot Q \cdot L}{100 \cdot A \cdot (\Delta P)} \quad (1)$$

where:

k_f—the proppant pack permeability [um^2];

μ—the viscosity of fluid used for testing at the test temperature [cP];

Q—the flow rate [cm^3/s];

L—the length between pressure ports (12.70 cm, i.e., 5.0") [cm];

A—the cross-sectional area of test unit perpendicular to flow, determined according to Equation (2) [cm^2];

ΔP—the pressure drop between measuring ports [kPa].

$$A = w \cdot W_f \quad (2)$$

where:

w—fracture height (i.e., the width of the API cell inlet hole, w = 3.810 cm, i.e., 1.5") [cm];

W_f—width of the fracture filled with proppant [cm].

Equation (3) is used to determine the permeability k_f of the fracture filled with proppant:

$$k_f = \frac{\mu \cdot Q \cdot L}{100 \cdot w \cdot W_f \cdot (\Delta P)} \quad (3)$$

To determine the conductivity of the proppant pack, Equation (4) is used:

$$k_f \cdot W_f = \frac{\mu \cdot Q \cdot L}{100 \cdot w \cdot (\Delta P)} \quad (4)$$

where:

$k_f \cdot W_f$—proppant pack conductivity [10^{-15} $m^2 \cdot m$].

The damage to the original conductivity and the fracture filled with proppant and fracturing fluid for 2% KCI are determined according to Equation (5):

$$DCF = \frac{\left(k_{f_o} \cdot W_{f_o}\right) - \left(k_{f_d} \cdot W_{f_d}\right)}{k_{f_o} \cdot W_{f_o}} \cdot 100\% \quad (5)$$

where:

DCF—the damage to the original proppant pack conductivity of the fracture filled with proppant, in %;

$k_{fo} \cdot W_{fo}$—the original conductivity of proppant pack (without damaging it with fracturing fluid) [10^{-15} $m^2 \cdot m$];

$k_{fd} \cdot W_{fd}$—the damage to the original conductivity of the proppant pack with fracturing fluid [10^{-15} $m^2 \cdot m$].

The uncertainty of the viscosity measurements at a given shear rate was estimated using the total differential method (Tables 4 and 5). The uncertainty of estimation of average values k, W_f, and $k \cdot W_f$ calculated from the series of n = 10 measurements was assessed. It was assumed that the maximum calibration error was $\Delta k = 0.01$ [10^{-12} m^2] for k and $\Delta W_f = 0.01$ [m^{-3}] for W_f. The calibration uncertainty k and W_f were determined from the formulas:

$$\frac{\Delta k}{\sqrt{3}} \quad (6)$$

$$\frac{\Delta W_f}{\sqrt{3}} \quad (7)$$

Table 4. Rheological parameters of non-foamed fluids (FF1A) and fluids energized with N_2, foam quality of 70% (FF1B) at 60 °C.

Fluid Type	t (min)	n′ (-)	K′ (Pa·s$^{n'}$)	Dynamic Viscosity at a Given Shear Rate (γ) * (mPa·s)		
				40 s^{-1}	100 s^{-1}	170 s^{-1}
Non-foamed FF1A	13	0.5840	0.0049	50.4	34.4	27.6
	25	0.5809	0.0050	50.6	34.5	27.6
	38	0.5917	0.0047	49.5	34.1	27.4
70% N_2 FF1B	13	0.5557	0.0249	231.1	153.8	121.5
	25	0.5809	0.0214	218.3	148.7	119.1
	38	0.5718	0.0223	220.2	148.7	118.5

* The uncertainty of viscosity measurements at a given shear rate ranged from 3.9% to 5.4%.

Table 5. Rheological parameters of non-foamed fluids (FF2A) and fluids energized with N_2, foam quality of 70% (FF2B) at 60 °C.

Fluid Type	t (min)	n′ (-)	K′ (Pa·s$^{n'}$)	Dynamic Viscosity at a Given Shear Rate (γ) * (mPa·s)		
				40 s^{-1}	100 s^{-1}	170 s^{-1}
Non-foamed FF2A	13	0.6938	0.0026	40.5	30.6	26.0
	25	0.6743	0.0029	41.2	30.6	25.7
	38	0.6862	0.0027	40.2	30.2	25.5
70% N_2 FF2B	13	0.5082	0.0261	203.3	129.6	99.8
	25	0.4853	0.0290	207.7	129.6	98.6
	38	0.5391	0.0221	193.4	126.8	99.3

* The uncertainty of viscosity measurements at a given shear rate ranged from 4.2% to 5.5%.

The standard uncertainty of the mean value k and Wf was determined on the basis of the standard deviation from the average value, taking into account the critical coefficient t0.683.10 = 1.059 determined for the confidence interval of 68.3% for a series of 10 measurements.

$$U_s(\mathrm{k}) = t_{0.683.10}\sqrt{\frac{\sum_{i=1}^{n}\left(\mathrm{k}_i - \overline{\mathrm{k}}\right)}{n(n-1)}} \tag{8}$$

$$U_s(\mathrm{W_f}) = t_{0.683.10}\sqrt{\frac{\sum_{i=1}^{n}\left(\mathrm{W_{f\mathit{i}}} - \overline{\mathrm{W_f}}\right)}{n(n-1)}} \tag{9}$$

The uncertainty of the total average value of k and W_f was determined from the following formulas:

$$U_c(\mathrm{k}) = \sqrt{U_s^2(\mathrm{k}) + \frac{(\Delta \mathrm{k})^2}{3}} \tag{10}$$

$$U_c(\mathrm{W_f}) = \sqrt{U_s^2(\mathrm{W_f}) + \frac{(\Delta \mathrm{W_f})^2}{3}} \tag{11}$$

The total uncertainty of the average value $\mathrm{k} \cdot \mathrm{W_f}$ was determined from the following formula:

$$U_c(\mathrm{k}\cdot\mathrm{W_f}) = \sqrt{\left(\frac{\partial(\mathrm{k}\cdot\mathrm{W_f})}{\partial \mathrm{k}}\right)^2 \cdot U_c^2(\mathrm{k}) + \left(\frac{\partial(\mathrm{k}\cdot\mathrm{W_f})}{\partial \mathrm{W_f}}\right)^2 \cdot U_c^2(\mathrm{W_f})} \tag{12}$$

In this research, the proppant was placed between two Ohio sandstone core samples places in the API cell. It was the quartz proppant with a grain size of 0.850–0.425 mm (i.e., 20–40 mesh) for FF1 and light ceramic proppant 20/40 in case FF2. Surface concentration of the proppant was (9.76 kg/m^2). Before taking measurements, the 2% KCl solution must be deoxygenated. The oxygen content must not exceed the maximum permissible value, i.e., 10 ppm. The cell with pistons was placed in a hydraulic press. Under these conditions, the cell was vented and saturated with a 2% solution of KCl (previously deoxygenated and siliconized). The brine was saturated with silica in a high-pressure cylinder filled with sand. The above steps prevent the dissolution of the proppant material. The API cell was heated to the test 60 °C using heating plates. After obtaining the test temperature in the API chamber and after saturating the proppant with 2% KCl (pumping rate of salt solution 2 mL/l), we proceeded to the actual conductivity test. The stress was increased to a given value at a constant speed. The compressing stress was 27.6 MPa for FF1 and 41.4 MPa for FF2. Effect duration of the stress compressing the fracture with proppant (5 h). Damaging the fracture by fracturing fluid consists of pumping through the proppant and Ohio rock block (fluid filtration into the fracture walls), in total approximately 10 proppant pore volumes of the fracturing fluid through proppant layer with a rate of 5 mL/min, with a set backpressure of 2.8 MPa (i.e., 400 psi). Subsequently, approximately five proppant pore volumes of the fracturing fluid was pumping through the proppant layer, with a 5 mL/min rate and a set backpressure of 2.8 MPa (i.e., 400 psi). Conductivity and permeability were defined as the arithmetic average of the obtained results for each fluid flow rate of the last 10 measurement points, recorded at the end of a 5-h test. The test records cell pressure, differential pressure, fracture height, proppant stress, cell temperature, rate, and fluid flow through the proppant layer. Measurement of conductivity $k_f \cdot W_f$ was conducted over 5 h, with data recording every 2 min. The following fluids were used for the tests: 2% KCl, then the non-foamed fluid, and finally the foamed fluid produced in the rheometer and foam generator (in accordance with the rheological measurements described in Sections 2.2.2 and 3.2).

During testing of conductivity of the fracture filled with proppant, the following are registered: temperature (Tk) in the API cell, pressure (PK) in the API cell, pressure drop on the measurement section with the length L (ΔP), i.e., differential pressure (dP), width of the fracture (W_f), i.e., LVDT indication, stress compressing (σ) the fracture with proppant, pumping rate 2% of KCl solution (Q).

3. Experimental Results

3.1. Measurement of Proppant Basic Parameters

Laboratory tests began with measurements of the properties of the proppant materials in accordance with the ISO 13503-2: 2006 (E) standard.

3.2. Viscosity Measurement

Rheological parameters are of key significance for fracturing fluids, since they largely decide about the conductivity damage and transport properties for proppant materials during fracturing process. The rheological parameters (n′ and K′) of non-foamed and foamed fluids are presented in Tables 4 and 5 and Figures 4 and 5, where n′ is the dimensionless flow index and K′ is the consistency factor. Tables 4 and 5 present test results for foamed fracturing fluids with 70% foam quality and non-foamed fluids. The data showed that an increase viscosity is particularly visible for both foamed fluids FF1B and FF2B (Tables 4 and 5). The FF2B-based foamed fluid at 60 °C was characterized by a lower viscosity then FF1B. During tests for each fluid type, tree measurements of dynamic viscosity was recorded.

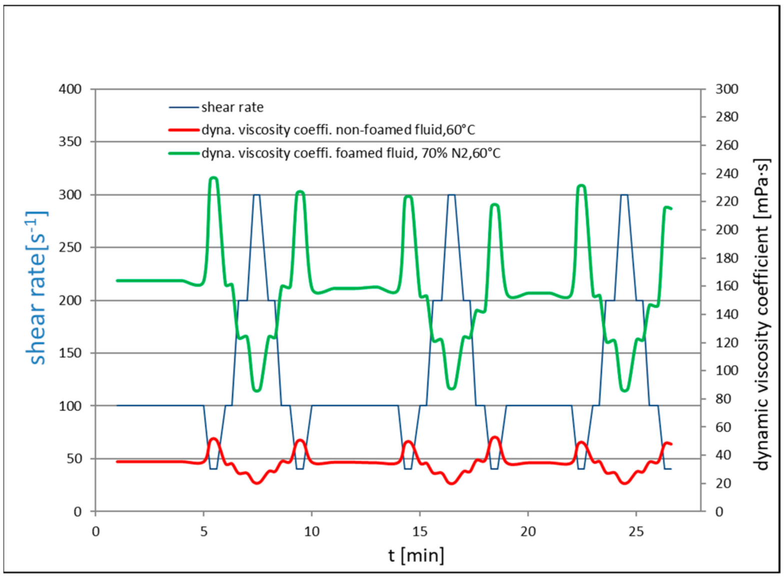

Figure 4. Viscosity of non-foamed FF1A and N_2-foamed FF1B fluid of 70% quality at 60 °C.

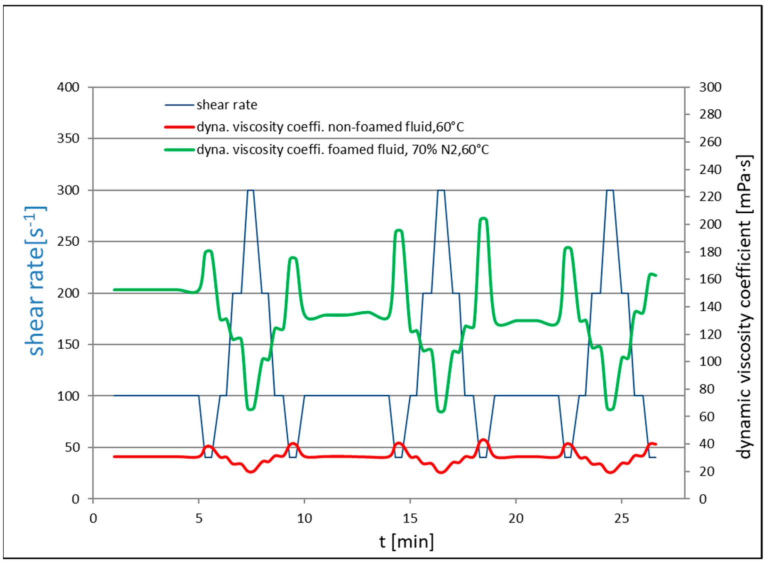

Figure 5. Viscosity of non-foamed FF2A and N_2-foamed FF2B fluid of 70% quality at 60 °C.

3.3. Proppant Conductivity Measuments

This part of the experiment was conducted on Ohio sandstones. The results of the Proppant Conductivity are shown in Tables 6–11 and Figures 6 and 7.

Table 6. The measurement results for the determination of the original conductivity and permeability of the fracture filled with quartz sand 20/40, without damaging it with fluid, at 60 °C; compressing stress 27.6 MPa.

No.	**Permeability of Fracture with Proppant** k_{fo} **[10^{-12} m^2]**	**Conductivity of Fracture with Proppant** $k_{fo} \cdot W_f$ **[10^{-15} m$^2 \cdot$m]**
1	71.56	377.7
2	64.32	339.4
3	65.86	347.5
4	69.50	366.7
5	67.77	357.6
6	69.38	366.1
7	67.47	356.0
8	68.61	362.0
9	67.71	357.3
10	66.61	351.5
Average	67.88 ± 0.684	358.2 ± 3.63

Table 7. The measurement results for the determination of the original conductivity and permeability of the fracture filled with quartz sand 20/40 damaged by the fluid FF1A at 60 °C; compressing stress 27.6 MPa.

No.	**Permeability of Fracture with Proppant** k_{fd} **[10^{-12} m^2]**	**Conductivity of Fracture with Proppant** $k_{fd} \cdot W_f$ **[10^{-15} m$^2 \cdot$m]**
1	18.80	99.0
2	19.18	101.0
3	18.79	98.9
4	18.65	98.2
5	18.88	99.4
6	18.94	99.7
7	18.90	99.5
8	18.91	99.5
9	18.84	99.1
10	18.74	98.6
Average	18.86 ± 0.048	99.3 ± 0.28

Table 8. The measurement results for the determination of the original conductivity and permeability of the fracture filled with quartz sand 20/40 damaged by the fluid FF1B at 60 °C; compressing stress 27.6 MPa.

No.	**Permeability of Fracture with Proppant** k_{fd} **[10^{-12} m^2]**	**Conductivity of Fracture with Proppant** $k_{fd} \cdot W_f$ **[10^{-15} m$^2 \cdot$m]**
1	50.28	260.6
2	45.83	237.5
3	46.75	242.3
4	46.10	238.9
5	50.69	262.7
6	47.70	247.2
7	47.22	244.7
8	46.02	238.5
9	46.53	241.1
10	45.97	238.2
Average	47.31 ± 0.596	245.2 ± 3.10

Table 9. The measurement results for the determination of the original conductivity and permeability of the fracture filled with light ceramic proppant 20/40, without damaging it with fluid, at 60 °C; compressing stress 41.4 MPa.

No.	**Permeability of Fracture with Proppant** k_{fo} **[10^{-12} m^2]**	**Conductivity of Fracture with Proppant** $k_{fo} \cdot W_f$ **[10^{-15} m$^2 \cdot$m]**
1	83.02	458.3
2	86.70	478.6
3	85.66	472.9
4	87.23	481.5
5	83.32	460.0
6	83.27	459.7
7	83.20	459.3
8	84.26	465.2
9	82.49	455.4
10	82.89	457.6
Average	84.20 ± 0.571	464.8 ± 3.19

Table 10. The measurement results for the determination of the original conductivity and permeability of the fracture filled with light ceramic proppant 20/40 damaged by the fluid FF2A at 60 °C; compressing stress 41.4 MPa.

No.	**Permeability of Fracture with Proppant** k_{fd} **[10^{-12} m^2]**	**Conductivity of Fracture with Proppant** $k_{fd} \cdot W_f$ **[10^{-15} m$^2 \cdot$m]**
1	30.65	165.5
2	31.13	168.0
3	30.45	164.4
4	30.17	162.9
5	30.15	162.7
6	29.86	161.1
7	30.08	162.3
8	30.22	163.1
9	30.19	162.9
10	30.15	162.7
Average	30.30 ± 0.120	163.6 ± 0.67

Table 11. The measurement results for the determination of the original conductivity and permeability of the fracture filled with light ceramic proppant 20/40 damaged by the fluid FF2B at 60 °C; compressing stress 41.4 MPa.

No.	**Permeability of Fracture with Proppant** k_{fd} **[10^{-12} m^2]**	**Conductivity of Fracture with Proppant** $k_{fd} \cdot W_f$ **[10^{-15} m$^2 \cdot$m]**
1	66.31	362.5
2	62.76	342.9
3	61.00	333.3
4	62.85	343.4
5	63.62	347.6
6	62.48	341.4
7	62.73	342.8
8	61.97	338.5
9	61.81	337.6
10	61.45	335.7
Average	62.70 ± 0.495	342.6 ± 2.73

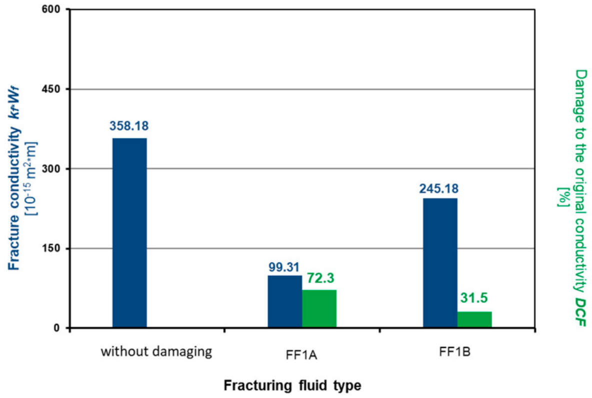

Figure 6. The damage to the primary conductivity of the fracture filled with quartz sand proppant 20/40 done by fracturing fluids FF1A and FF1B at a temperature of 60 °C; compressing stress 27.6 MPa.

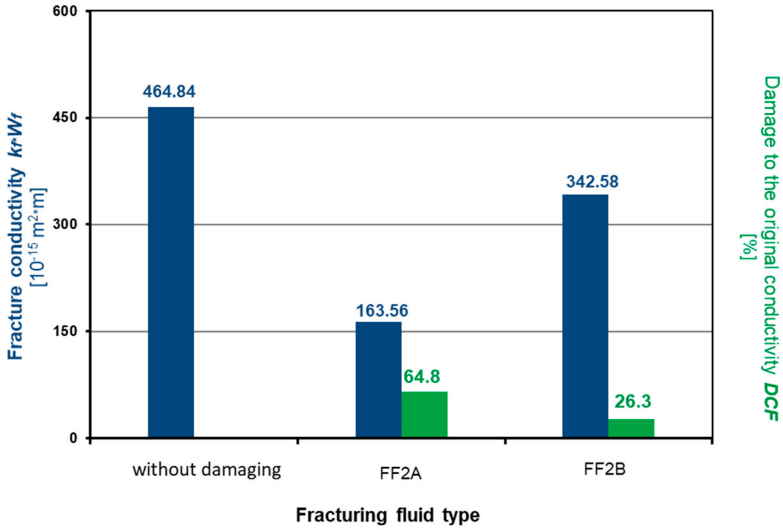

Figure 7. The damage to the primary conductivity of the fracture filled with light ceramic proppant 20/40 done by fracturing fluids FF2A and FF2B at a temperature of 60 °C; compressing stress 41.4 MPa.

A research methodology was developed, which was confirmed by laboratory tests with the use of foamed fluids used for damaging the packed fracture through which the fracturing fluids were forced. Quartz sand with grain size of 20/40 mesh and light ceramic proppant of 20/40 mesh were used for testing. It was placed between two Ohio sandstone rock blocks and subjected to a set compression stress of 4000–6000 psi., at a temperature of 60 °C for 5 h. Within the part of the work shown in this article, we determined the magnitude of the damage to conductivity and permeability of the fracture filled with proppant selected for formation conditions. The Table 2 characterizes treatment fluids, and Table 3 the types of proppant materials used for testing. An aqueous solution of an HPG—a natural polymer as a hydrating gelling agent in the form of a guar-based suspension dispersed in a mixture of hydrocarbons (7.5 mL/l)—was used as the fracturing fluid together with additives for treatment fluids dedicated to tight formation. Three tests were performed in this case. The first of them consisted of measuring the conductivity of the fracture with proppant (without damaging it with fracturing fluid) at set measuring intervals. The second test consisted of measuring the conductivity of the fracture filled with proppant through which non-foamed fracturing fluid was forced. Next, the foamed fluid (of 70% quality) was tested. After that, a modified guar containing an internal dispersant and a pH buffer 4.8 g/L with additives was used. Subsequently, the damage to the fracture with proppant was done each time performing three tests: non-damaging for fluids, for non-foamed fluid, and for foamed fluid N_2. Based on the achieved results from the above tests, the magnitude of damage to the packed fracture done by fracturing fluids was determined.

When analyzing the tests with the use of FF1, a significant drop in damage to the quartz proppant of 20/40 mesh can be observed for foamed fluid (FF1B) as compared to the one damaged by the linear fluid—FF1A. The damage was 72.3% for non-foamed fluid and 31.5% for the fluid of 70% quality. In the case of a fracture with proppant damaged by fracturing fluid FF1A, one has noted the drop in permeability, correspondingly from $67.88 \times 10^{-12} \cdot m^2$ for proppant not damaged by the fluid to $18.86^{-12} \cdot m^2$ for the non-foamed FF1A type fluid, and $47.31 \times 10^{-12} \cdot m^2$ for fluid foamed with nitrogen FF1B. Conductivity for 2% KCl brine was $358.18 \times 10^{-15} \cdot m^2 \cdot m$, for fluid FF1A it was 99.31×10^{-15}, and for FF1B it was $245.18 \times 10^{-15} \cdot m^2 \cdot m$, which constituted 31.5% of the original damage to the conductivity caused by brine.

At the beginning of testing FF2, the conductivity for brine was $464.84 \times 10^{-15} \cdot m^2 \cdot m$, and the permeability was $84.20 \times 10^{-12} \cdot m^2$. For the fracture with proppant (damaged by fluid FF2A), the conductivity was $163.56 \times 10^{-15} \cdot m^2 \cdot m$, and the permeability was $30.30 \times 10^{-12} \cdot m^2$. On the other hand, for the fracture with proppant damaged by foamed fluid (FF2B), the conductivity was $342.58 \times 10^{-15} \cdot m^2 \cdot m$, and the permeability was $62.70 \times 10^{-12} \cdot m^2$. The size of damage to the fracture conductivity done by the non-foamed fluid was 64.8% and 26.3% for foamed fluid.

4. Conclusions

The studies to confirm the reduction of damage to the fracture with proppant by foamed fracturing fluid compared to non-foamed fracturing fluids was performed. The Pipe Rheometer with Foam Generator combining with a Proppant Conductivity Unit was adapted for testing of first fluid rheology and then the proppant conductivity. The following conclusions were drawn based on the experimental results and the findings of the study:

1. The viscosity of the non-foamed fluids at different shear rates was similar for FF1A and FF2A. A significant increase in viscosity was noticed for foamed fluids FF1B and FF2B. The viscosity of foamed fluids with a shear rate of 40 s^{-1} was approximately 4-fold higher in case of FF1A and about 5-fold higher in case of FF2B compared to non-foamed fluids. Both fluids were characterized by a stable viscosity throughout the rheological test (38 min), while maintaining similar values of viscosity coefficients in each measurement loop. Despite similar initial viscosity coefficients (for non-foamed fluids), the FF2B-based foamed fluid at 60 °C was characterized by a lower viscosity than FF1B.
2. All the used foamed fluids were of 70% quality, characterized by small spherical bubbles; however, it was observed that the fluid with the addition of 7.5 mL/l natural polymer in the form of a guar-based suspension dispersed in a mixture of hydrocarbons (FF1B) had smaller bubbles. The measured half-life of foam for the FF2B fluid was 20 min and was shorter than FF1B by about 10%. Despite the higher polymer content in the FF2 fluid, the fluid at 60 °C showed a lower viscosity than FF1B, thus causing less conductivity damage, as confirmed by laboratory tests.
3. During the tests, a significant reduction in damage to the 20/40 mesh quartz proppant was observed for the foamed fluid compared to that damaged by the 7.5 l/m^3 natural polymer based non-foamed linear fluid. The damage was 72.3% for the non-foamed fluid (FF1A) and 31.5% for the 70% foamed fluid (FF1B). For tests based on natural polymer 4.88 g/l, the damage to the fracture conductivity by the non-foamed fluid (FF2A) was 64.8%, and 26.3% for the foamed fluid (FF2B).
4. The foamed fluids used during the tests contains only 30% of water with additives such as polymer, inhibitors, etc. (Table 2), which may damage the conductivity. In this case, the use of a 70% quality fluid results in a proportional reduction in the amount of polymer used, and thus, the difference in the conductivity between the foamed

and non-foamed fluid is significant in both cases, FF1 and FF2. Typically, when using non-foamed fluids, as the polymer concentration and fluid viscosity increase, the damage to the permeability and conductivity increases. If foamed fluids are used, the conductivity damage decreases while the viscosity of the fluid increases 4-fold.

These results lead to the conclusion that foaming fluids could damage the fracture filled with proppant much less during hydraulic fracturing treatment, thus maintaining the appropriate rheological parameters and ensuring sustained suspending capacity of the proppant. Test results indicate that the developed testing methodology may be used for evaluation of the fracturing fluid and proppant for hydraulic fracturing treatment of tight gas rocks.

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Abbreviations

LCP	Ceramic light proppant
HPG	Hydroxypropyl guar
FF	Fracturing fluids
UCS	Unconfined compressive strength
FF1A	Fluid based on natural polymer in the form of a guar-based suspension dispersed in a mixture of hydrocarbons
FF1B	Foamed with N_2 up to 70% foam quality fluid based on natural polymer in the form of a guar-based suspension dispersed in a mixture of hydrocarbons
FF2A	Fluid based on natural polymer, HPG, containing an internal dispersant and a pH buffer
FF2B	Foamed with N_2 up to 70% foam quality fluid based on natural polymer, HPG, containing an internal dispersant and a pH buffer
Qf	Foam quality (%)
T	Temperature (°C)
T	Test time (min)
γ	Shear rate (s^{-1})
K′	Consistency index (mPa·s^n)
n′	Power law exponent (-)
k_{fp}	Permeability of fracture with proppant without damaging it with fluid (10^{-12} m^2)
$k_{fo} \cdot W_f$	Conductivity of fracture with proppant without damaging it with fluid (10^{-15} m^2·m)
k_{fd}	Permeability of fracture with proppant damaged by the fluid (10^{-12} m^2)
$k_{fd} \cdot W_f$	Conductivity of fracture with proppant damaged by the fluid (10^{-15} m^2·m)
DCF	The damage to the original proppant pack conductivity of the fracture filled with proppant (%)

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