doi:10.20944/preprints201904.0310.v1

Type of the Paper (Article)

Modeling efficiency of energized fluid fracturing in tight gas formations

Klaudia Wilk [1*]

[1] Oil and Gas Institute – National Research Institute, Lubicz 25A Str., 31-503 Cracow, Poland; office@inig.pl
* Correspondence: Oil and Gas Institute – National Research Institute, Armii Krajowej 3 Str., 38-400 Krosno, Poland; klaudia.wilk@inig.pl

Abstract: Hydraulic fracturing is the most effective method of stimulation for hydrocarbon reservoirs. However the use of water-based fracturing fluids, can be a problem in water-sensitive formations due to the permeability damage hazard caused by clay minerals swelling. For this reason, the foamed fracturing fluids with addition of natural, fast hydrating guar gum were examined. The rheology and filtration coefficients of foamed fracturing fluids were examined and compared to the properties of conventional water-based fracturing fluid. Laboratory results provided the input for numerical simulation of the fractures geometry for water-based fracturing fluids and 50% N_2 foamed fluids. The results show, that the foamed fluids were able to create shorter and thinner fractures compared to the fractures induced by the non-foamed fluid. The simulation proved that the concentration of proppant in the fracture and its conductivity are similar or slightly higher when using the foamed fluid. Moreover such fluids are able to significantly reduce the amount of water necessary for fracturing treatments, limiting clay minerals swelling, and reducing the reservoir permeability damage. The foamed fluids, when injected to the reservoir, provide additional energy, that allow for more effective flowback, and maintain the proper fracture geometry and proppant placing. The results of laboratory work in combination with the 3D simulation showed, that the foamed fluids have suitable viscosity which allows opening the fracture, and transport the proppant into the fracture, providing successful fracturing operation.

Keywords: hydraulic fracturing; energized fracturing fluid; tight gas; reservoir stimulation; frac fluid rheology

---

1. Introduction

Considering the continuing depletion of energy resources in the world [1,2], the extraction of natural gas has become a priority and it is believed to be a more ecological solution than the acquisition of emission-intensive solid fuels. Hydraulic fracturing is the most efficient method for stimulating hydrocarbon deposits, used for many years to produce gas from deep and poorly permeable geological formations. According to forecasts, it is predicted that in 2040 it will satisfy 25% of global energy needs. However, fracturing process may cause numerous environmental problems [3,4], which is why alternative solutions are tested, among which the use of foamed fluid is a relatively new but effective technique [5]. Foamed fluid is generated by mixing the gaseous phase with the liquid phase, in the presence of a proper surface-active agent. The primary parameter of such fluid, described as the so-called foam quality, depends on the percentage of gas in the fracturing fluid [6,7]. The quality of fluid is determined by the following formula: Eq. (1).

$$Q=(V_g)/(V_g+V_l)\cdot 100 \tag{1}$$

Preprints (www.preprints.org) | NOT PEER-REVIEWED | Posted: 28 April 2019 doi:10.20944/preprints201904.0310.v1

where Q = foam quality, V_g = gas volume, V_l = volume of liquid in the foam.

The properties of foam injected into a deposit, including its rheology and viscosity, are important for the success of the fracturing process. The viscosity of foamed fluid should be high enough at the beginning to provide good proppant transport, and low enough at the end of fracturing treatment to get good clean up of fracture and formation. Better transport properties for the proppant, lower consumption of water and chemicals, a faster and easier flow of fluids and potentially a lower environmental impact - these are the advantages of fracturing with foamed fluids [8]. On the other hand, there is still inadequate knowledge and an insufficient amount of experimental research related to the use of foams. Furthermore, high costs and potential harm to the environment caused by surface-active agents constitute limitations in the use of this technology. The search for new technologies stimulating extraction from unconventional deposits is associated with the issue of saving the water [9,10], as well as with the aspect of sensibility of clay minerals to contact with water [11]. The elimination or reduction of the amount of water as a basis for the fracturing fluid can constitute a serious asset in the dissemination of alternative technologies.

The process of hydraulic fracturing of unconventional deposits, especially those which are characterised by low reservoir pressures, and vulnerable to contact with water, are performed very frequently with the use of foams or energized fluids [12,13]. Compressed gas. which is present in the foam (e.g. nitrogen), decompresses during the reception of fracturing fluid, facilitating the removal of liquid from the fracture. Foams accelerate the reception of liquid from a propped fracture (the so-called flowback) and this is why they are suitable for use in deposits with low reservoir pressures [14]. In the case of water-based fluids, their foaming causes a considerable decrease in the amount of liquid which is in contact with the reservoir formation [15], since such a fluid contains up to 95% by volume of gas. This is why foams are also recommended in the case of deposits particularly sensitive to contact with water. Their use allows a significant reduction in the amount of water necessary for fracturing operations [16,17]. Due to this, there is a considerable decrease in the costs of its purchase, transport and preparation, including clean up or filtration, and the costs of chemical additives, as well as the costs of storage and subsequent flowback of post-treatment fluids.

Currently, on the market there are several available commercial simulators for designing and analysing hydraulic fracturing operations [18,19]. Based on the collected data on deposits, boreholes, data on fracturing fluids and proppant, precise and advanced design of hydraulic fracturing operations is possible [20], including the use of foamed fluids.

2. Materials and Methods

2.1. Sample preperation

Foamed fracturing fluid was created based on tap water and addition of N_2. At first, the following components were added to water with a temperature of 23° C: an anionic foaming agent P-1 (4 ml/l), a microemulsion M-1 (2ml/l), a swelling inhibitor for clay minerals C-1 (2ml/l), an inorganic sediment precipitation inhibitor S-1(1ml/l), followed by polymer W (natural, fast hydrating guar gum for oil field applications) in an amount of 3.6 g/l. Additives to fracturing fluids were used based on previous works, which allowed an assessment of the best additives to the foamed fluids [21,22].

The tests used samples of rock material representing Rotliegend sandstone from the Poznań Trough – Poland (a tight-type formation). The analysed cores represent aeolian sandstones originating from a deposit situated in the top part of upper Rotliegend sediments belonging to a Permian-Mesozoic structural unit. Numerous natural fractures occur within Rotliegend rocks. The medium which saturates the sandstones is a nitrogen-rich natural gas with a methane content of approximately 75-80 vol%, lacking gasoline, with a high carbon dioxide content, with no hydrogen sulphide.

The preparation of samples involved the cutting of cylindrical core plugs of a diameter of 2.54 cm and a length of approx. 5 cm. Core plugs were cut by means of a diamond core bit with a diameter of 2.54 cm. Core plugs were dried in a temperature of 105° C for 24 hours. After drying and cooling the cores, the gas permeability coefficient was determined for each of them using a DGP-100 apparatus, (EPS, UK), along with the effective porosity coefficient calculated by means of an HGP-100 (EPS, UK) helium porosimeter. Measurements of the rheological parameters of fracturing fluids were made using a pipe rheometer with a foam generator, and measurements of leakoff coefficients – by means of combining a pipe rheometer with a leak-off cell and an HPLC pump (Sykam, GE).

2.1. Rheoogy

A fracturing fluid (prepared according to the description in point 2. Materials and Methods) was introduced into the pipes of a pipe rheometer designed specifically to measure the rheological properties of foamed systems under extended pressure and temperature conditions, and the fluid was circulated with a speed of 300 s^{-1} in the measurement system. At the same time, the temperature and pressure were stabilised (6.89 MPa, T=23° C or T=60° C). Subsequently, in the case of measuring foamed fluids, N_2 was slowly injected into the measurement system, continuously stirring the fluid in the system with a shear velocity of 350 s^{-1}. Simultaneously, the basal fluid followed by partially foamed fluid was removed from the system, increasing the gas content of foam. This process was performed until reaching 50% foam quality, which was controlled by a densimeter. In order to examine the rheological properties of foamed fluids, the basal fluid was at first foamed with nitrogen. Upon stabilising the quality of foam, rheological properties were measured according to a predetermined test plan. The test took 27 minutes, with a pressure of 1000 psi, maintaining a shear velocity of 100 s^{-1}. The measurement of rheological properties during measurement loops (measurement result in the 9th, 18th and 27th minute) adopted the following shear velocities (shear rates): 40, 100, 200, 300, 200, 100, 40 s^{-1}. During a measurement loop, the shear velocity was maintained at each abovementioned level for 30 seconds. Between measurements, the foam was stirred with a speed of 100 s^{-1} for approximately 5 min.

2.2. Filtration measuments

Filtration tests were performed under static conditions according to a modified measurement procedure originating from quality standard API RP39 [23], involving the tests of fracturing fluids and examinations of the leakoff coefficient. The core intended for tests was seated in a measurement chamber using high-temperature silicone. Subsequently, the remaining elements of the measurement chamber were assembled and it was left for approximately 24 hours. Next, the chamber was thermostatted to a temperature of 60° C and the measurement was commenced. The core was first saturated with a 2% KCl solution with constant capacity by means of a constant metering pump. The chamber was then filled with fracturing fluids (with no foamed fluid or a fluid with a 50% N_2 content) and a pressure of 6.89 MPa (1000 psi) was applied. After opening the valve at the bottom of the chamber, the measurement was initiated by measuring the value of filtration after 1, 4, 9, 16, 25, 36, 49 minutes. With the data on the amount of filtrate as a function of time, the relationship between the amount of filtrate [cm^3] and the root of time [min ^{½}] was plotted in the Cartesian system and leakoff coefficients were calculated: C_w and Spurt Loss (figure 3, table 5).

2.3. Simulation of fracturing treatment and fracture propagation

The produced results of laboratory average measurements of the permeability of cores (0.14-0.16 mD), porosity (9-10%), parameters of filtration (table 5) and viscosity coefficients (tables 3, 4) enabled the performance of computer simulations of hydraulic fracturing process in a vertical borehole using a 3D Fracpro computer simulator (tables 6, 7). To this end, a number of data were adopted for performing the simulations of hydraulic fracturing process, such as, e.g.: lithostratigraphy, Young's modulus, Poisson's ratio, stress gradient. Table 1 presents the data used for the construction of a

 doi:10.20944/preprints201904.0310.v1

geomechanical model, assuming the thickness of the productive horizon of approximately 25 metres, with an inset of anhydrite.

Tabela 1. Resrvoir parameters

Layer number	Top of zone measured depth [m]	Lithostratigraphy	Fracture Toughness [kPa·cm$^{1/2}$]	Young's modulus [bar]	Poisson's ratio	Stress Gradient [bar/m]
1	0.0	Overburden	21 976.9	4.14E+05	0.250	0.2200
2	2 343.0	Salt	10 988.4	2.40E+05	0.440	0.2200
3	2 463.0	Anhydrite	16 482.7	5.20E+05	0.300	0.1800
4	2 479.0	Limestone	5 494.2	1.00E+05	0.300	0.1800
5	2 483.0	Rotliegend	10 988.4	2.00E+05	0.245	0.1700
6	2 501.0	Anhydrite	16 482.7	5.20E+05	0.300	0.1800
7	2 503.0	Rotliegend	10 988.4	2.00E+05	0.245	0.1700
8	2 510.0	Anhydrite	16 482.7	5.20E+05	0.300	0.1800
9	2 512.0	Sandstone	10 988.4	3.45E+05	0.200	0.1800
10	2 660.0	Lower Layers	21 976.9	4.14E+05	0.250	0.2300
11	3 000.0	Underlying rocks	21 976.9	4.14e+05	0.250	0.2300

A very important aspect of analysing treatment data using a simulator involves the selection of proper parameters of fracturing fluids. Rheological parameters of the fluid directly affect the parameters of treatment, flow resistances and pressures in the well and fracture, slurry efficiency and the geometry of the generated fracture. The composition and rheological parameters of specific fluids are presented in tables 3, 4. During the simulation, other technological fluids were also used, e.g. 15% HCl. Table 2 presents a comparison between the parameters of simulated fracturing process performed by means of a no foamed and foamed fluid.

Table 2. Basic data on simulated hydraulic fracturing operations.

	No foamed fluid	Foamed fluid
	Quantity	
15% HCl	5.0 m^3	5.0 m^3
Linear gel 3.6 g/l	743.0 m^3	473.0 m^3
N_2	-	89 244.7 sm^3
Proppant 100 mesh	4 800.0 kg	4 800.0 kg
Proppant 30/50 mesh	41 399.9 kg	41 600.0 kg
Average pumping rate	4 m^3/min	4 m^3/min
Reservoir temperature in the perforation interval	60 °C	
Reservoir pressure in the perforation interval	250 bar	

When performing the simulation, the following were assumed: a comparable volume of treatments (the amount of liquid or foam and proppant), a similar pumping plan and slurry rate.

 doi:10.20944/preprints201904.0310.v1

3. Results and Discussion

3.1. The results of rheological tests of no foamed and foamed fluids

Rheological parameters are of key significance for fracturing fluids, since they largely decide about the geometry of the created fracture and transport properties for proppant materials during fracturing process. The rheological parameters (n′ and K′) of no foamed and foamed fluids are presented in tables 3, 4, where n is the dimensionless flow index and K is the consistency factor.

Table 3. Rheological parameters of no-foamed fluids and fluids energised with N_2, foam quality of 50% at 23 °C.

Fluid type	Time [min]	n′ [-]	K′ [Pa·sn′]	Dynamic viscosity at a given shear rate [mPa·s]		
				$40 s^{-1}$	$100 s^{-1}$	$170 s^{-1}$
No foamed	9	0.6000	0.2154	49.2	34.1	27.6
	18	0.6006	0.2172	49.8	34.5	27.9
	27	0.5982	0.2224	50.5	34.9	28.2
50% N_2	9	0.4043	1.4727	163.6	94.8	69.1
	18	0.4038	1.4840	164.5	95.2	69.4
	27	0.3964	1.5414	166.2	95.6	69.4

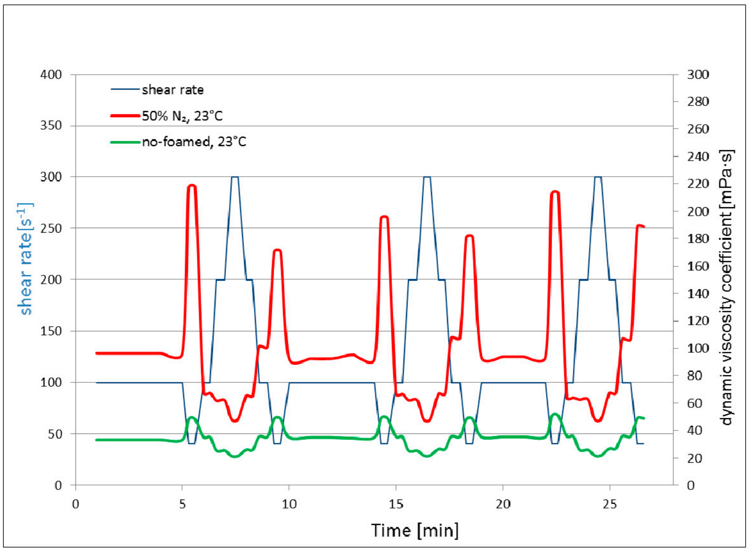


Figure 1. Viscosity of no-foamed and N_2 foamed fluid with addition of 3,6 g/l natural polymer at 23 °C.

Table 4. Rheological parameters of no-foamed fluids and energised with N_2 foam quality of 50% at 60 °C.

Fluid type	Time [min]	n′ [-]	K′ [Pa·sn′]	Dynamic viscosity at a given shear rate [mPa·s]		
				$40 s^{-1}$	$100 s^{-1}$	$170 s^{-1}$
No foamed	9	0.7674	0.0436	18.5	14.9	13.2
	18	0.7496	0.0475	18.9	15.0	13.1
	27	0.7620	0.0445	18.5	14.9	13.1

	9	0.5801	0.4111	87.3	59.4	47.6
50% N_2	18	0.5630	0.4618	92.1	61.7	48.9
	27	0.5652	0.4613	92.8	62.3	49.4

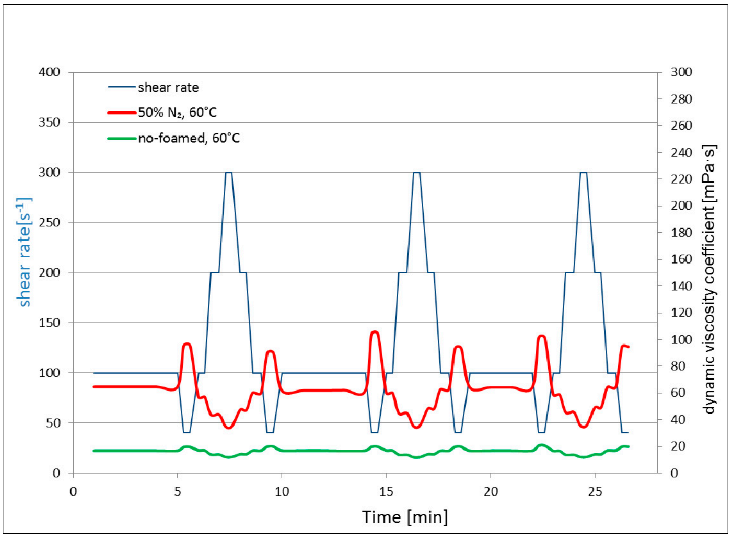
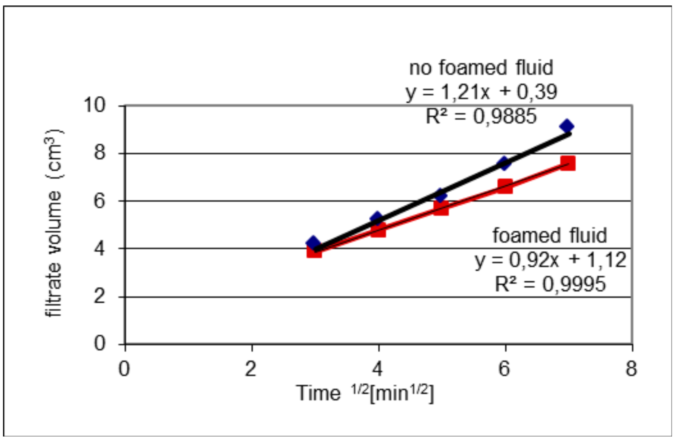


Figure 2. Viscosity of no-foamed and N_2 foamed fluid with addition of natural polymer in an amount of 3.6 g/l at 60 °C.

Tables 3 and 4 present test results for foamed fracturing fluids with foam quality of 50% and no foamed basal fluids. A drop in viscosity along with an increase in temperature is particularly visible for no foamed fluids (tables 3, 4). A no foamed fluid with quality of 50%, whose viscosity in the ambient temperature was approximately 35 cP, with a shear velocity of 100 s^{-1}, upon heating up to 60^{o} C dropped to a viscosity of 15 cP. For foamed solutions of polymer W-1, a considerably higher viscosity is observed compared to no foamed fluids. The viscosity of foamed fluids in a temperature of 23^{o} C with a shear velocity of 100 s^{-1} is approx. 3 times higher, and about 4 times higher in a temperature of 60^{o} C compared to no foamed fluids.

3.2. Filtration test results

The filtration test was performed for Rotliegend cores using a no foamed fracturing fluids and a fluid foamed by 50% of N_2 (figure 3, table 5).



(a)

Preprints (www.preprints.org) | NOT PEER-REVIEWED | Posted: 28 April 2019 doi:10.20944/preprints201904.0310.v1

Figure 3. The volumes of filtrates as a function of the root of time along with a superimposed trend line for fracturing fluids: a) no foamed – blue line, b) foamed – red line.

Table 5. A comparison of leakoff coefficients C_w and Spurt Loss of Rotliegend cores for the tested fracturing fluids.

No foamed fluid		Fluid 50% N_2	
C_w [m/min$^{1/2}$]	Spurt [m^3/m^2]	C_w [m/min$^{1/2}$]	Spurt [m^3/m^2]
$5.373 \cdot 10^{-4}$	$3.473 \cdot 10^{-4}$	$4.057 \cdot 10^{-4}$	$9.904 \cdot 10^{-4}$

The Cw coefficient is directly proportional to the speed of filtration through the generated filter cake. On the other hand, the Spurt value approximates the volume of fluid which was filtered out during the generation of the filter cake. Leakoff coefficients calculated based on the measurements (table 5) were used for simulation assumptions presented in the following part of the paper. The leakoff coefficient was lower for a foamed fluid than for a single-phase fluid. This may be caused by the penetration of gas bubbles into rock pores, which impedes the escape of liquid from a fracture. It should be mentioned that observations were performed based on relatively short filtration tests according to the guidelines of quality standard API RP39. In this case, the generation of a filtration cake is a key phenomenon at the initial stage of flow of a fluid through the core. This process is strictly associated with rock permeability, since at the beginning of the fracturing process filtration depends on the permeability of the formation. At the next stage, in the case of gelled single-phase fluids it is controlled by the filter cake formation on the walls of the fracture, whose permeability is lower than the permeability of the reservoir rock. This causes an increase in the slurry efficiency, because its smaller volume penetrates from the fracture to reservoir during the treatment. This also implies a lower invasion of liquid into the zone surrounding a hydraulically generated fracture. This enables easier clean up of the reservoir formation after the fracturing process.

It has been observed that the foam generated based on the gelled fluid also causes the creation of filter cake on the fracture walls, but its thickness is smaller than in the case of single-phase fluids; nonetheless, filtration is often lower for foam, due to the penetration of gas into the rock formation, which decreases its phase permeability. Due to this, for foams generated using linear gel, it is possible to minimize damage to formation during the fracturing process.

3.3. 3D simulation results

Figures 4 and 5 present a simulation of the fracturing process with no foamed and nitrogen- foamed fluids, along with the most important parameters of the process, such as: net pressure, bottom hole pressure, surface pressure, concentration of proppant, slurry rate and efficiency of the fracturing fluids. There are differences between pumping schedule, connected with the initial assumptions of using similar volume of fluid and proppant in both cases of the simulated treatment. Originally, the maximum pressure at the surface (at pumping units), in both cases of using foamed and no foamed fluid, amounts to 518 bar, and it equals the opening pressure of the fracture. During the treatment, it is definitely lower in the case of no foamed fluid and amounts to approximately 330-350 bar. In the case of foamed fluid, at the beginning of the procedure it amounts to approximately 350 bar, upon

Preprints (www.preprints.org) | NOT PEER-REVIEWED | Posted: 28 April 2019 doi:10.20944/preprints201904.0310.v1

which it increases to approximately 500 bar in the second part of the process. During the use of a no foamed fluid, the slurry rate is pumped at 4 m³/min. In the case of foamed fluid, a no foamed linear polymer is injected until stage 9 of pumping (table 6), while nitrogen is added from stage 10 to 18 in an amount of 50%, relative to the pumped linear gel. Figure 4 presents the pumping rate of linear gel which amounts to approximately 2 m³/min, and N_2 is introduced at the same rate. Net pressure - one of the most important parameters during the fracturing treatment, as a difference between the bottom dynamic pressure during treatment and the closing pressure of a fracture [24,25,26] behaves similarly in both simulated cases. Maximum value is reached near the end of treatments and amounts to 76.1 bar for no foamed fluid and 83.9 bar for foamed fluid, respectively. The efficiency of no foamed fluid (figure 4) increases slowly during the performed fracturing, due to a gradual stabilization of the filtration cake generated on the surface of the fracture. Close to the end of fracturing, this value amounts to 0.49. The efficiency of foamed fluid (figure 5) is constant until stage 8 of pumping; following this, in stage 9 of pumping it drops, which is caused by a decrease in the slurry rate of fluid (therefore, there is a decrease in the propagation of the fracture). When pumping a foamed fluid, its efficiency improves considerably, and near the end of treatment it reaches a value of 0.50.

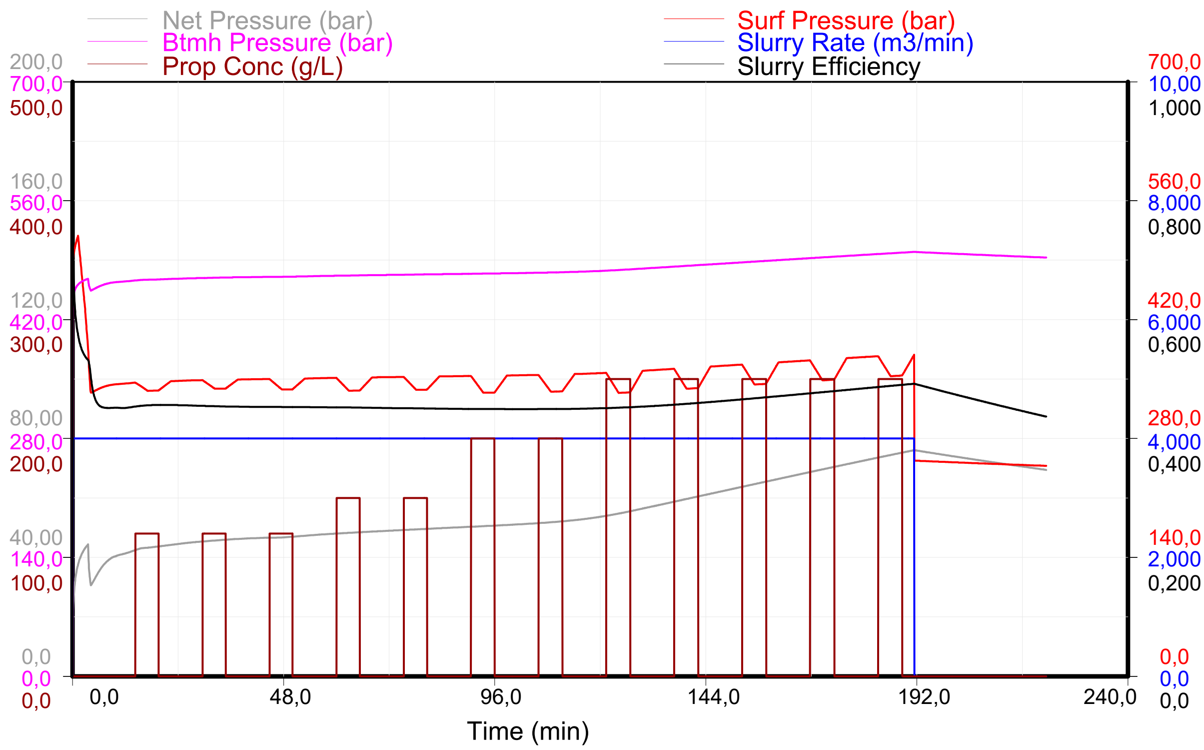
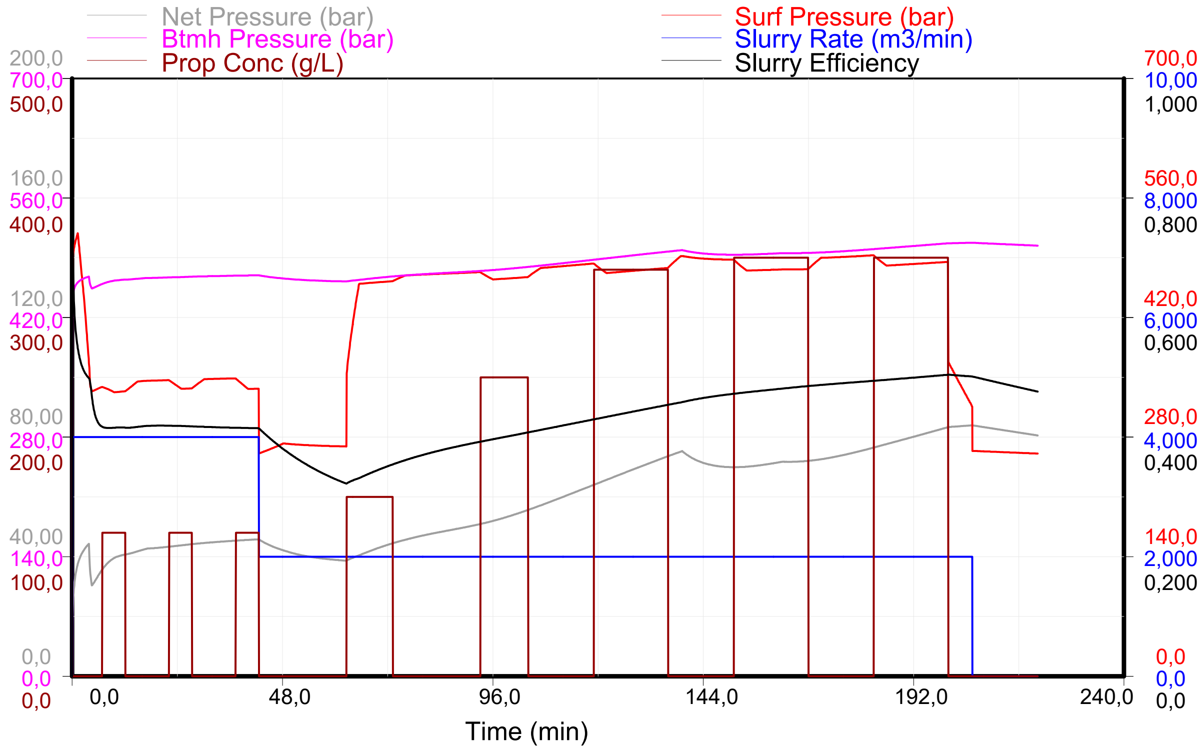


Figure 4. Treatment data for no foamed fluid.

Preprints (www.preprints.org) | NOT PEER-REVIEWED | Posted: 28 April 2019 doi:10.20944/preprints201904.0310.v1



242

243 Figure 5. Treatment data for foamed fluid.

244 Table 6. Designed treatment schedule for no foamed fluid.

Stage no.	Treatment stage type	Elapsed time min:sec	Fluid type	Volume of liquid without proppant [m³]	Proppant concetration [g/l]	Proppant per stage [kg]	Slurry rate [m³/min]	Proppant type
	Wellbore Fluid		2% KCL	11.263				
1	Main frac acid	1:14	15%HCl	5.000	0	0.0	4.00	-
2	Main frac flush	4:15	No foamed	12.000	0	0.0	4.00	-
3	Main frac pad	14:14	No foamed	40.000	0	0.0	4.00	-
4	Prop slug	19:30	No foamed	20.000	120	2 400.0	4.00	100 mesh
5	Main frac pad	29:30	No foamed	40.000	0	0.0	4.00	-
6	Prop slug	34:46	No foamed	20.000	120	2 400.0	4.00	100 mesh
7	Main frac pad	44:46	No foamed	40.000	0	0.0	4.00	-
8	Main frac slurry	49:59	No foamed	20.000	120	2 400.0	4.00	30/50

doi:10.20944/preprints201904.0310.v1

9	Main frac pad	59:59	No foamed	40.000	0	0.0	4.00	-
10	Main frac slurry	65:16	No foamed	20.000	150	3 000.0	4.00	30/50
11	Main frac pad	75:16	No foamed	40.000	0	0.0	4.00	-
12	Main frac slurry	80:33	No foamed	20.000	150	3 000.0	4.00	30/50
13	Main frac pad	90:33	No foamed	40.000	0	0.0	4.00	-
14	Main frac slurry	95:55	No foamed	20.000	200	4 000.0	4.00	30/50
15	Main frac pad	105:55	No foamed	40.000	0	0.0	4.00	-
16	Main frac slurry	111:18	No foamed	20.000	200	4 000.0	4,00	30/50
17	Main frac pad	121:18	No foamed	40.000	0	0.0	4.00	-
18	Main frac slurry	126:45	No foamed	20.000	250	5 000.0	4.00	30/50
19	Main frac pad	136:45	No foamed	40.000	0	0.0	4.00	-
20	Main frac slurry	142:13	No foamed	20.000	250	5 000.0	4.00	30/50
21	Main frac pad	152:13	No foamed	40.000	0	0.0	4.00	-
22	Main frac slurry	157:41	No foamed	20,000	250	5 000.0	4.00	30/50
23	Main frac pad	167:41	No foamed	40,000	0	0.0	4.00	-
24	Main frac slurry	173:09	No foamed	20.000	250	5 000.0	4.00	30/50
25	Main frac pad	183:09	No foamed	40.000	0	0.0	4.00	-
26	Main frac slurry	188:37	No foamed	20.000	250	5 000.0	4.00	30/50
27	Main frac flush	191:22	No foamed	11.000	0	0.0	4.00	-
28	Shut-in	221:22	SHUT-IN	0.000	0	0.0	0.00	-

doi:10.20944/preprints201904.0310.v1

Table 7. Design of the treatment schedule for foamed fluid.

Treatment stage type	Elapsed time min:sec	Fluid type	Bottom N_2 quality [%]	Bttom clean foam vol [m^3]	Bottom proppant concentration [g/L]	Proppant per stage [kg]	Bottom slurry foam rate [m^3/min]	Proppant type
1	1:14	15% HCl	0.0	5.000	0	0.0	4.00	-
2	4:14	No foamed	0.0	12.000	0	0.0	4.00	-
3	6:44	No foamed	0.0	10.000	0	0.0	4.00	-
4	12:00	No foamed	0.0	20.000	120	2 400.0	4.00	100 mesh
5	22:00	No foamed	0.0	40.000	0	0.0	4.00	-
6	27:16	No foamed	0.0	20.000	120	2 400.0	4.00	100 mesh
7	37:16	No foamed	0.0	40.000	0	0.0	4.00	-
8	42:29	No foamed	0.0	20.000	120	2 400.0	4.00	30/50
9	62:29	No foamed	0.0	40.000	0	0.0	2.00	-
10	73:03	N_2 50%	50.7	40.556	74	3 000.0	3.95	30/50
11	93:03	N_2 50%	49.3	78.936	0	0.0	3.95	-
12	103:59	N_2 50%	51.6	41.281	121	5 000.0	3.95	30/50
13	118:59	N_2 50%	49.3	59.202	0	0.0	3.95	-
14	135:53	N_2 50%	52.3	62.900	162	10 200.0	3.95	30/50
15	150:53	N_2 50%	49.3	59.202	0	0.0	3.95	-
16	167:50	N_2 50%	52.4	63.009	167	10 500.0	3.95	30/50
17	182:50	N_2 50%	49.3	59.202	0	0.0	3.95	-
18	199:47	N_2 50%	52.4	63.009	167	10 500.0	3.95	30/50
19	205:17	No foamed	0.0	11.000	0	0.0	2.00	-
20	220:17	SHUT-IN	0.0	0.000	0	0.0	0.00	-

Figures 6 and 7 present the characteristics of fractures generated in the simulation, and a summary and list of values describing the fractures are presented in table 8. When using no foamed fluid, the fracture is slightly longer and higher compared to foamed fluid, while its width is smaller. After fracturing with the foam, the placement of the proppant in the Rotliegend interval is apparent (figure 6), which is much more preferable in terms of the performance of the treatment, while high concentration of the proppant in the case of using a no foamed fluid is obtained only in the top part of the Rotliegend inset (figure 7).

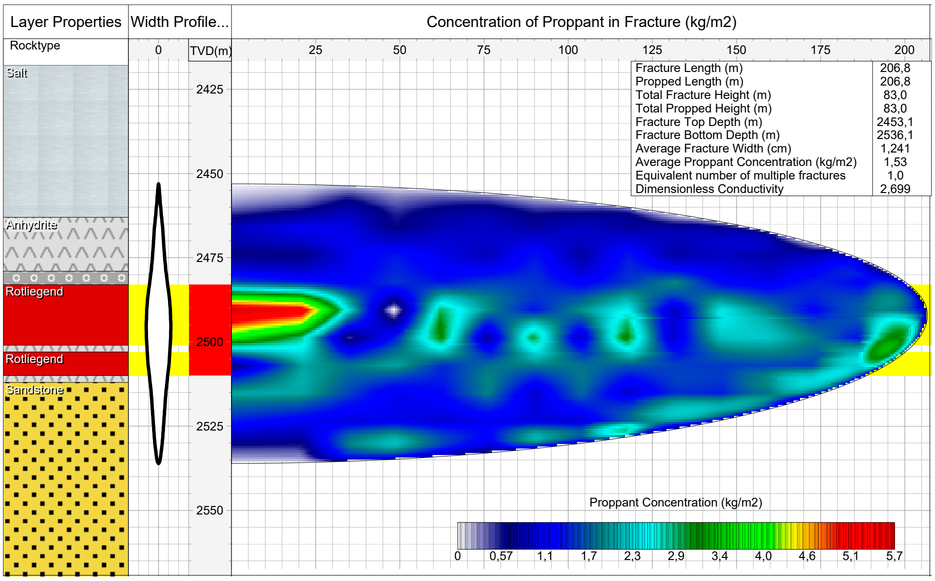


Figure 6. Fracture profile and layers for no foamed fluid.

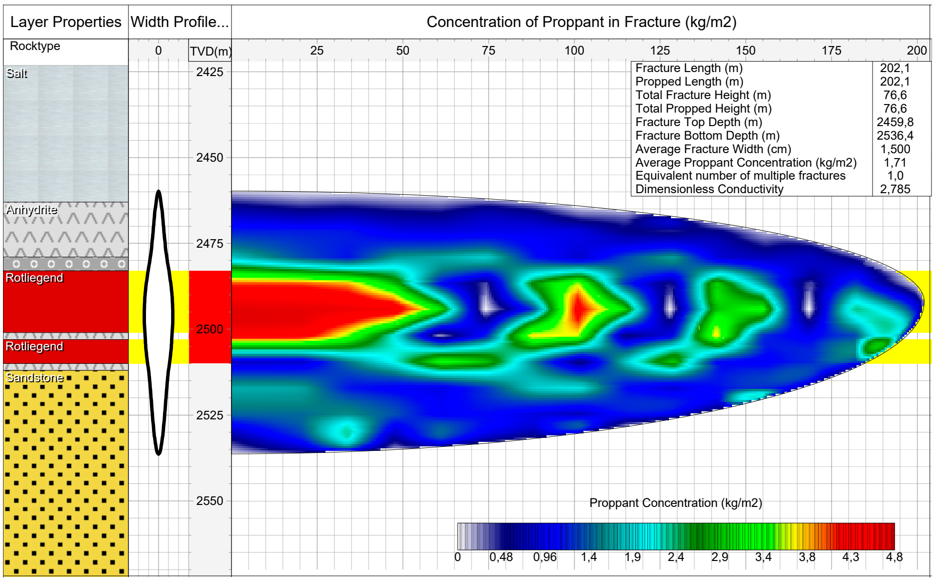


Figure 7. Fracture profile and layers for foamed fluid.

The final result of the simulation is a technical plan which describes in detail how the fracturing treatment is to be performed. One of the essential parts of this plan is the pumping schedule which includes the information on: what, when, in what amount, with what capacity and with what pressure will be pumped into the fractured deposit series (tables 7, 8; figures 4, 5). However, before a technical plan is developed and the hydraulic fracturing treatment is performed in the borehole, it is necessary to carry out tests intended to confirm or correct key borehole and reservoir data [27].

4. Conclusions

The following conclusions were drawn based on the experimental results and the findings of the study:

1. For the simulated treatments with foamed and no foamed fluid, with the same amounts of proppant and basal fluid (tables 7, 8) the resulting values of surface concentration of the proppant inside a fracture and its conductivity were similar.

2. Based on laboratory tests and simulations, it can be concluded that foamed fluids exhibit good rheological parameters and capability of opening a fracture (figures 5, 6; table 8) and transporting the proppant, which is of key significance during the fracturing treatment. In general: similar geometries of the fracture and proppant concentrations are obtained for the no foamed as well as for 50% quality - nitrogen foamed fluids. At the same time, when using a fluid with a gas additive, the saturation of the deposit with water is reduced which means the minimization of the negative results of the clay minerals swelling.

Table 8. Stimulation treatment comparision.

Parameters	No foamed fluid	Fluid 50% N_2
Fracture Length [m]	206.8	202.1
Propped Length [m]	206.8	202.1
Total Fracture Height [m]	83.0	76.6
Total Propped Height [m]	83.0	76.6
Fracture Top Depth [m]	2453.1	2459.8
Fracture Bottom Depth [m]	2536.1	2536.4
Average Fracture Width [cm]	1.2	1.5
Average Proppant Concentration [kg/m^2]	1.5	1.7
Dimensionless Conductivity	2.699	2.785
Total Clean Fluid Pumped (without proppant) [m^3]	750.8	750.1
Total Slurry Pumped (with proppant) [m^3]	766.2	765.5
Design proppant pumped [kg]	46 200	46 400

3. An analysis of laboratory data and the performed computer simulations indicated that fracturing fluids foamed by nitrogen are a good alternative for conventional fluids (no foamed), especially for the deposits of low reservoir energy and high sensitivity to contact with water.

Funding: Part of the research leading to these results was prepared on the basis of statutory study financed by Ministry of Science and Higher Education – archival no.: 0040/KS/19, order no.: DK-4100-40/19.

References

1. Sorrell S., Speirs J., Bentley R., Brandt A., Miller R. Global oil depletion: a review of the evidence. *Energy Policy* Elsevier, **2010**, 38, pp. 5290-5295.
2. Bentley R.W., Global oil & gas depletion: an overview, *Energy Policy*, **2002**, Volume 30, Issue 3, pp. 189-205.
3. Shonkoff S. B., Hays J., Finkel M. L. Environmental Public Health Dimensions of Shale and Tight Gas Development. Environ Health Perspect. **2014**, 122(8): 787–795. doi: 10.1289/ehp.1307866.
4. Rozell DJ, Reaven SJ. Water pollution risk associated with natural gas extraction from the Marcellus Shale. *Risk Anal*. **2012**;32:1382–1393.Wilk, K., Kasza, P., Czupski, M. Dodatki do spienionych płynów szczelinujących. *Przemysł chemiczny*, **2018**, 92/2, 1000-1005.
5. Wilk K., Kasza P., Labus K., Analysis of the applicability of foamed fracturing fluids. *Nafta-Gaz*, **2015**, vol. 6. pp. 425-433.

Preprints (www.preprints.org) | NOT PEER-REVIEWED | Posted: 28 April 2019 doi:10.20944/preprints201904.0310.v1

6. Hutchins R.D., Miller M.J. A Circulating Foam Loop for Evaluating Foam at Conditions of Use. SPE *Production & Facilities*, **2005**, SPE-80242-PA.
7. Gidley J.L., Holditch S.A, Nierode D.E., Veatch R.W. Recent Advances In Hydraulic Fracturing. SPE Monograph Series Vol. 12, **1990**, p.464.
8. Wanniarachchi W.A.M., Ranjith P.G., Perera M.S.A. Shale gas fracturing using foam-based fracturing fluid: a review. Environ Earth Sci, 2017, 76:91, pp.1-15.
9. Small X., T.: Water Use and Recycling in Hydraulic Fracturing: Creating a Regulatory Pilot for Smarter Water Use in the West, *Natural resources journal*, 2015, 55(2), pp. 409-440.
10. Freeman B.: Engineers improve recycling system used in fracking to save water and energy. *Membrane Technology*, Volume 2013, Issue 10, October **2013**, pp. 7.
11. Labus K.: Potential environmental problems connected with the exploitation of unconventional natural gas deposits. *Przegląd Górniczy*, **2011**, t.67 nr 1-2, pp. 12-16.
12. Tulissi M.G. May R.E. A Comparison of Results of Three Different CO_2 Energized Frac Fluids: A Case History. SPE-75681-MS. Society of Petroleum Engineers. SPE Gas Technology Symposium, 30 April-2 May, Calgary, Alberta, Canada **2002**.
13. McAndrew J.J., Fan R., Sharma M., Ribeiro L. Extending the Application of Foam Hydraulic Fracturing Fluids. Unconventional Resources Technology Conference. SPE/AAPG/SEG Unconventional Resources Technology Conference, 25-27 August, Denver, USA, **2014**.
14. Turek M., Labus K., Dydo P., Mitko K., Laskowska E., Jakóbik-Kolon A. A concept of hydraulic fracturing flowback treatment using electrodialysis reversal. *Desalination and Water Treatment*, **2017**, 64: pp. 228-232.
15. Torabzadeh J., Langnes G.L., Robertson Jr. J. O., Yen T. F., Donaldson E. C., Chilingarian G. V., Yen T. F. (eds.): Enhanced Oil Recovery, II: Processes and Operations. Elsevier Science Publishers B. V. *1989*, s. 91-106.
16. Blauer R.E., Kohlhaas C.A. Formation Fracturing with Foam, Society of Petroleum Engineers, SPE-5003-MS, Fall Meeting of the Society of Petroleum Engineers of AIME, 6-9 October, Houston, Texas, **1974**. https://doi.org/10.2118/5003-MS.
17. Cawiezel K.E., Niles T.D. Rheological Properties of Foam Fracturing Fluids Under Downhole Conditions. Society of Petroleum Engineers. SPE-16191-MS, SPE Production Operations Symposium, 8-10 March, Oklahoma **1987**.
18. Temizel C., Energy A., Betancourt D., Aktas S., Susuz O., Zhu Y., Suhag A., Ranjith R., Wang A.: Optimization of Hydraulic Fractures in Tight-Oil Reservoirs Using Different Numerical Fracture Models. SPE Asia Pacific Hydraulic Fracturing Conference held in Beijing, China, 24-26 August **2016**. SPE-181824-MS, s. 1-58.
19. Acharya R.: Hydraulic-Fracture-Treatment Design Simulation. *Journal of Petroleum Technology*, **1988**, 40(02), pp. 139–142.
20. Shahkarami A., Wang G., Belyadi H.: Horizontal Well Spacing and Hydraulic Fracturing Design Optimization: A Case Study on Utica-Point Pleasant Shale Play. This paper was prepared for presentation at the Unconventional Resources Technology Conference held in San Antonio, Texas, USA, 1-3 August **2016**, s. 1-12.
21. Wilk, K., Kasza, P., Czupski, M. Dodatki do spienionych płynów szczelinujących. *Przemysł chemiczny*, **2018**, 92/2, 1000-1005.
22. Wilk, K., Kasza, P., Czupski, M. Dobór dodatków do energetyzowanych płynów szczelinujących. *Nafta-Gaz* **2016**, 12, 1092-1100.
23. Recommended practice for standard procedure for evaluation of hydraulic fracturing fluids. American Petroleum Institute, API RP39, January 1983.
24. Kasza P.: Zabiegi hydraulicznego szczelinowania w formacjach łupkowych, *Nafta-Gaz* **2011**, 12, pp. 874-883.
25. Belyadi H., Fathi E., Belyadi F.: Hydraulic Fracturing in Unconventional Reservoirs Theories, Operations, and Economic Analysis, Chapter Nine - Fracture Pressure Analysis and Perforation Design, **2017**, pp.121-141.
26. Guo B., Liu X., Tan X.: Petroleum Production Engineering (Second Edition), Chapter 14 - *Hydraulic Fracturing*, **2017**, pp. 389-501
27. Kasza P., Zabiegi hydraulicznego szczelinowania złóż niekonwencjonalnych i metody ich analizy, *Prace Naukowe Instytutu Nafty i Gazu*, Poland, 2019, Volume 226, pp. 147.