AGH DRILLING, OIL, GAS • Vol. 34 • No. 3 • 2017

http://dx.doi.org/10.7494/drill.2017.34.3.677

**Jacek Dudek*, Damian Janiga*, Paweł Wojnarowski***

# AN ANALYSIS OF THE INFLUENCE OF FRACTURING TECHNOLOGICAL PARAMETERS ON FRACTURE PROPAGATION USING NUMERICAL MODELING

## 1. INTRODUCTION

Nowadays, hydraulic fracturing is one of the commonest treatments for both conventional and unconventional fields, a stimulation technique designed to increase well production through the reduction of flow resistance caused by the drilling process or genuine reservoir properties [17].

The process involves the injection of a high-pressure fracturing fluid, typically containing proppant particles, into the reservoir layer through the wellbore. Hydraulic fracturing starts if downhole pressure exceeds the breakdown pressure of the formation near the borehole [5]. The fracturing fluid drives the propagation of the hydraulic fracture and, in the meantime, transports proppant particles into the reservoir formation. After pumping stops and fracturing fluid flows back to the wellbore, proppant particles hold the fractures open, leaving one or multiple propped hydraulic fractures of varied length, width, and height [1]. The proppant pack within the hydraulic fracture provides a higher permeability flow path for hydrocarbon, and therefore increases well production [18].

In simulation studies of hydraulic fracture propagation, several researches have comprehensively studied fracture propagation and proppant scheduling design and thus a number of hydraulic fracturing propagations models have been developed [6]. Specifically, the PKN type fracture and KGD type fracture are well known as 2-D models because of their assumptions of constant fracture height [4, 10]. Pseudo three dimensional and 3-D fracture propagation model have also been developed to simulate the hydraulic fracturing process with variable heights [14]. In reality, geometries and conductivities of propped hydraulic fractures are non-uniform as shown in hydraulic fracture propagation models. Therefore, it is more appropriate and realistic to build reservoir models with fractures predicted by propagation simulations [17].

* AGH University of Science and Technology, Faculty of Drilling, Oil and Gas, Krakow, Poland

In this article the planar, three-dimensional numerical model of the hydraulic fracturing treatment was presented. Based on the given model, built with taking advantage of fracture simulator GOHFER 3-D, the influence analysis of the basic technological parameters of the fracturing in directional well on the fracture propagation was conducted. The consecutive parameters of hydraulic fracturing process were gradually fitted thereby considerably enhancing the probability of effective reservoir rock cracking and to maintain a permanent balance of contact and conductivity among propped fractures [11]. The proposed strategy is based on a confrontation of the most widely used materials as well as the variable parameters of using them such as, for instance, injection rate or volume of fracturing fluid, taking into consideration industrial practice. After selecting treatment parameters following the presented scheme, the fractures were constituted and propped in two different pay zones. Afterwards, the simulation of 120 days of well production was conducted, eventually proving the preservation of appropriate length, width, height and conductivity of created fractures. The example of a few steps of the following scheme are presented in the third section.

## 2. THE DESCRIPTION OF THE RESERVOIR AND WELL UNDER HYDRAULIC FRACTURING TREATMENT

### Reservoir

The Diaden tight oil field is located i the Haskell County in the U.S. state of Kansas [8] and is a part of the largest North American natural gas field, the Hugoton Gas Embayment [13]. The reservoir is built of Mississippian limestone from the first Carboniferous period. This complex geological structure is dominated by numerous interbeddings of dolomite, anhydrite and chert rocks. Due to significant heterogeneity, reservoir parameters such as porosity and permeability vary in the intervals of 2–20% and 0,01–8 mD, respectively depending on point. Therefore, it is claimed to be unconventional/semi-unconventional type of reservoir [15]. Considering the amount of hydrocarbons the field can be divided into two different regions of completely different oil and gas saturation. The crude oil from Mississippian limestone belongs to the “light sweet” category, i.e. has a very low content of carbon dioxide and hydrogen sulfide [12]. Because of an increasing amount of hydraulically fractured horizontal wells, experts forecast that oil production from the Mississippian Lime formations by 2035 will exceed 1.3 billion oil barrels [3].

In this article. the authors considering the model of hydraulic fracturing treatment performed in the St. Louis Limestone separated from the Mississippian section. This geological formation increases in thickness toward the south, moreover, there are regions crossed by faults. Generally, crude oil is produced from three different zones (A, B, C) (Fig. 1) scattered by impermeable chert beds [12]. On the basis of the implemented .LAS source files with the geophysical logs in the 560–1860 m interval, the geological structure of the zones was created. Based on the comparison of literature data [12] and the structure generated by the simulator with marked designed perforations localization (Fig. 1) it can be clearly seen that the results are analogical, therefore the created profile was used to analyze the impact of technological parameters of treatment on fracture propagation.

Because of the numerous interbeddings and considerable geological heterogeneity, it is not possible to unambiguously indicate the direction of principal stresses, thus it is impossible to determine the scale and the effect of treatment using any analytical methods.

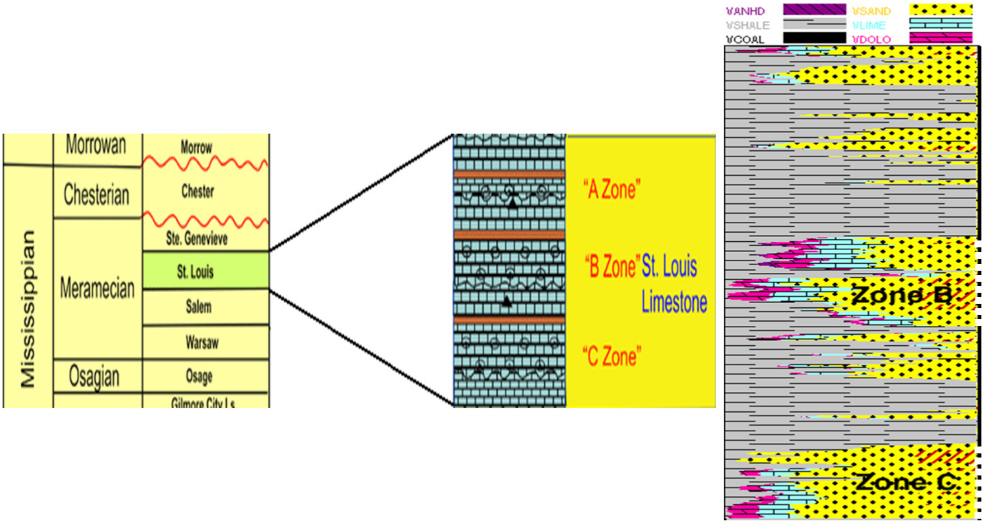


**Fig. 1.** The comparison of the literature production horizons of St. Louis Limestone formations [12] with those generated by the simulator using the implemented LAS files with well logging data

## Wellbore

Tables 1 and 2 contain the primary parameters of the stimulated well.

**Table 1**

The parameters of the stimulated, directional well Longbotham-6 [7]

| | |
|---|---|
| Name | Longbotham-6 |
| Well type | directional |
| Status | oil production |
| TVD | 1848.00 m |
| Deviated TVD | 1333.53 m |
| Deviation | 3 deg/100 m |
| Workover pipes diameter | 0.762 mm |
| Tubular space volume | 8.43 $m^3$ |
| Wellhead temperature | 21.11°C |

**Table 2**
The localizations and parameters of the created perforations in Longbotham-6 well

| Parameters | Zone B | Zone C |
|---|---|---|
| Depth | 1724–1726 m | 1754–1756 m |
| Perforation diameter | 0.1 m | 0.1 m |
| Number of perforations | 10 | 10 |

## 3. THE NUMERICAL MODELING OF HYDRAULIC FRACTURING TREATMENT

The modeling scheme depends on the multiple simulations of hydraulic fracturing treatment and consecutive results evaluation. In this article, the authors will only discuss the two main parts of the modeling scheme that allow for clearly identifying the sensitivity of the obtained fracturing effects on the change of the treatment technical parameters, with the entire flow chart of the numerical modeling presented in Figure 2.

Due to the low permeability of fractured zones of approximately 0.03–0.08 mD in most stages the main parameters according to which evaluation of the selection of particular materials and their amounts were made were the length of the propped fracture that allow oil to flow, the amount of the received fractures and then the conductivity of created cracks. Additionally, because of the probability of the distortion of the results by the liquid initially located in the wellbore, the B interval was selected as the representative value. All of the results were presented after 120 days of production simulations. This approach allows for the rational assessment of treatment effectiveness.

The simulation of the hydraulic fracturing treatment was conducted using GOHFER 3-D software created by the BARREE & ASSOCIATES LLC. GOHFER, which stands for Grid Oriented Hydraulic Fracture Extension Replicator, is a planar 3-D geometry fracture simulator with a fully coupled fluid/solid transport simulator. The fracture extension and deformation model in GOHFER is based on a formulation that expects the formation to fail in shear and essentially be decoupled. Most models assume the linear-elastic deformation of a fully coupled rock mass. A regular grid structure that was made based on the input of .LAS files containing logging data, is used to describe the entire reservoir, similar to a reservoir simulator. The grid structure allows for vertical and lateral variations, multiple perforated intervals as well as single and bi-wing asymmetric fractures to model the most complex reservoirs. GOHFER allows the modeling of multiple fracture initiation sites simultaneously and shows diversion between perforations. The grid is used for both elastic rock displacement calculations as well as a planar finite difference grid for the fluid flow solutions. Fluid composition, proppant concentration, shear, leakoff, width, pressure, viscosity and other state variables are defined at each grid block. The in-situ stress is internally calculated from pore pressure, poroelasticity, elastic modulus and geologically consistent boundary conditions. The width solution is fully 3-D, allowing shear decoupling and local displacements to be controlled by local pressures and rock properties. Screen-outs consider localized leakoff and proppant holdup and are not assumed to be caused by pad depletion or insufficient width. Fracture extension is based on a smoothly closing tip model and eliminates the fictitious singularity at the tip as well as the stress intensity factor [2].

On the basis of the available reservoir parameters, neighboring wells (Longbotham [4, 7–9]) and well production tests the following initial treatment parameters were selected (tab. 3).

**Table 3**

Initial hydraulic fracturing treatment parameters

| | |
|---|---|
| The fluid in wellbore | Slickwater 140 |
| Proppant | BradySand 16/30 |
| Proppant concentration | 60–300 kg/m$^3$ |
| Frac fluid volume | 55 m$^3$ |
| Pump rate | 4.77 m$^3$/min |
| Proppant amount | 10206 kg |

Subsequently, the initial fracture fluid pumping schedule was designed based on ball-drop system.

The ball-drop, sleeve system replaces the common “plug-and-perforate” technique, eliminating trips to prepare each zone for being hydraulically fractured. The system uses a series of balls pumped through the completion string to open valves that allow access to the formation. When the ball lands on the seat, it isolates the layers below it. Applying surface pressure activates the sleeve and opens up the fracture ports to the formation [9].

The pumping schedule consists of two main parts divided into six steps varying the intensity of proppant addiction from 60 kg/m$^3$ to 300 kg/m$^3$. The entire process begins by placing the first ball at a depth of 1756 m. Then, the pad (a fluid used to initiate hydraulic fracturing that does not contain proppant) was injected into the wellbore with an assumed rate. The first stage of the fracturing ends by locating the second ball at a depth of 1726 m, enabling the start of injecting frac fluid into subsequent interval (zone B). In order to clean the wellbore from any treatment impurities, at the end the initial fluid was injected inside. Furthermore, the process was extended by five minutes due to necessity of well pressure stabilization

Several treatment parameters are crucial in case of fracture geometry and conductivity. In Figure 2, a simulation flowchart is presented. For each single parameter (fluid, proppant volume etc.) a numerical simulation was used to determine the influence on fracture geometry. As a result, a best fracture design has been developed.

### Selection of fracturing fluid

The selection of the fracturing fluid to the first stage was made based on the parameters of the reservoir, which has a low permeability of approximately 0.03–0.08 mD. The authors chose the following fluids for the sake of their viscosity and composition – polymer type fluid Vistar with viscosity of 10 cP, Slickwater fluid having a low viscosity of about 1 cP and SlickOil, which is characterized by an average viscosity of about 5 cP.

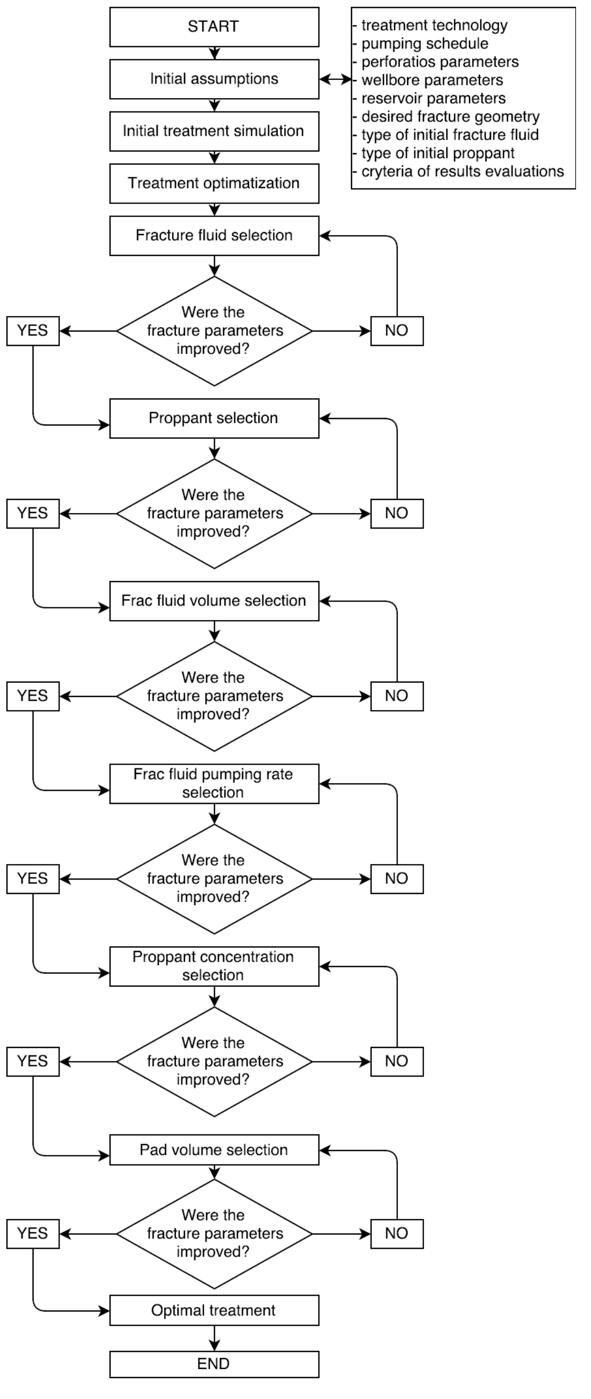


**Fig. 2.** The flow chart of numerical modeling of hydraulic fracturing treatment

The choice of the fluid is caused by the unconventional nature of the reservoir. In this case, low viscosity liquids offer more opportunities for cleaning the fracture after treatment. A typical solution in this case is the use of Slickwater, but the significant clay content in the reservoir rock can cause problems in contact with water, therefore, an alternative solution could be the use of SlickOil. The use of low viscosity fluids may cause problems with proppant transport during the treatment. Therefore, an alternative solution could be the use of a polymer – based fluid, which, however, may adversely affect the efficiency of the treatment.

The comparison of the impact of utilized fluids on created fracture parameters is presented in Table 4.

**Table 4**

The impact of the fracturing fluid on the created fracture

| | Vistar | SlickWater | SlickOil |
|---|---|---|---|
| Length of propped fracture [m] | 16.68 | 41.18 | 43.92 |
| Average height of fracture [m] | 9.14 | 4.57 | 7.62 |
| Fracture conductivity [mD ·m] | 69.07 | 98.01 | 103.20 |

According to the results obtained, a similar value is provided using SlickWater as well as SlickOil, however the average height of the fracture was greater by using SlickOil, thereby SlickOil was chosen as the fluid for the consecutive treatment modeling step.

The comparison of size of obtained, propped fracture depending on fracturing fluid type is presented in Figures 3–5.

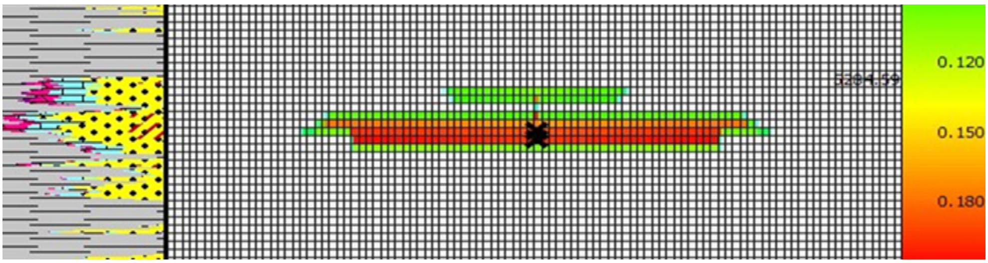


**Fig. 3.** Length of propped fracture in the [lb/ft$^2$] = 4.882 kg/m$^2$ units for the Vistar fluid

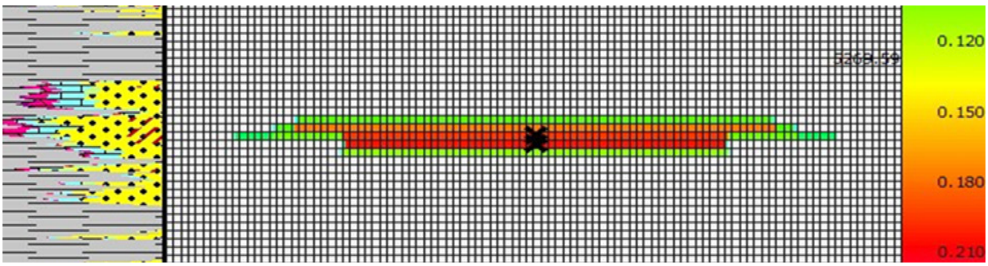


**Fig. 4.** Length of propped fracture in the [lb/ft$^2$] = 4.882 kg/m$^2$ units for the Slickwater fluid

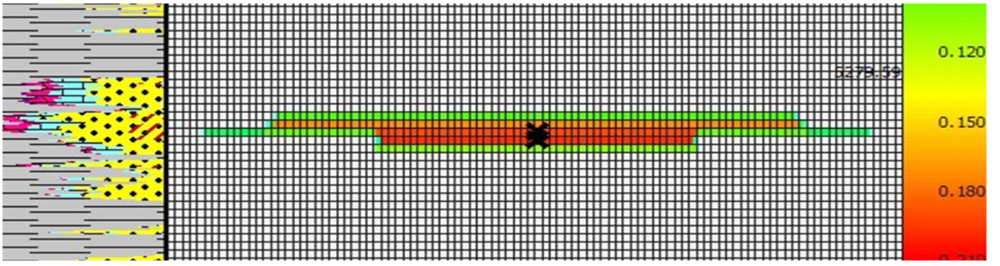


**Fig. 5.** Length of propped fracture in the [lb/ft$^2$] = 4.882 kg/m$^2$ units for SilckOil fluid

## Selection of fracture fluid injection rate

The selection of the sample volume of fracturing fluid was made based on data from previously conducted hydraulic fracturing and the standard parameters of pump units. These are the following pumping rates 4 m$^3$/min, 4.8 m$^3$/min, 5.6 m$^3$/min and 6.4 m$^3$/min. The comparison of the impact of utilized fluids injection rate on the created fracture parameters is presented on the Table 5.

**Table 5**
The impact of fracturing fluid injection on created fracture parameters

| | 4 m$^3$/min | 4.8 m$^3$/min | 5.6 m$^3$/min | 6.4 m$^3$/min |
|---|---|---|---|---|
| Length of propped fracture [m] | 55.43 | 56.93 | 61.76 | 58.25 |
| Average height of fracture [m] | 8.4 | 7.62 | 10.67 | 7.62 |
| Fracture conductivity [mD · m] | 212.17 | 233.99 | 232.23 | 229.32 |

According to the obtained data, the best result was provided using a 5.6 m$^3$/min flow pumping rate. Because of the increased pressure, a new fracture was opened. Additional increases in the pumping rate did not result in the further improvement of treatment parameters.

The comparison of the size of the obtained, propped fracture depending on fracturing fluid injection rate is presented in Figures 6–8.

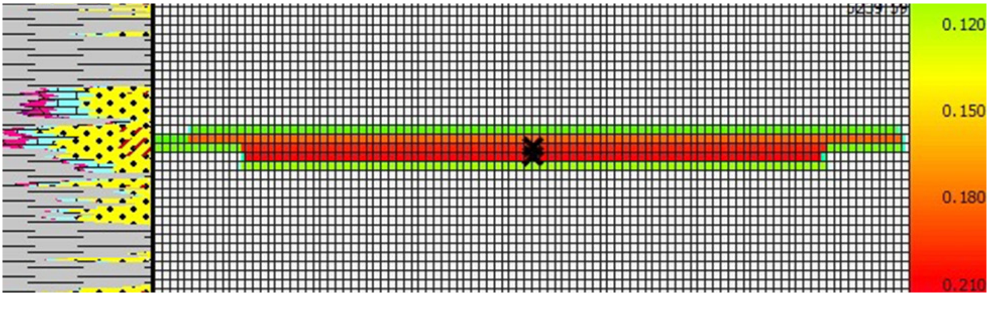


**Fig. 6.** Length of propped fracture in the [lb/ft$^2$] = 4.882 kg/m$^2$ units for rate 4.8 m$^3$/min

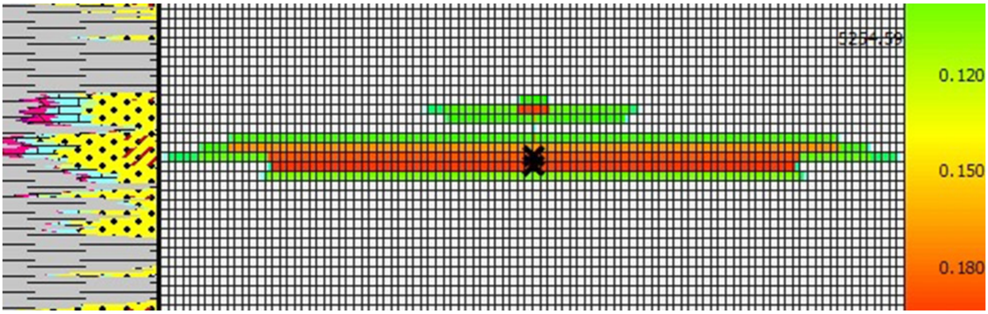


**Fig. 7.** Length of propped fracture in the [lb/ft$^2$] = 4.882 kg/m$^2$ units for rate 5.6 m$^3$/min

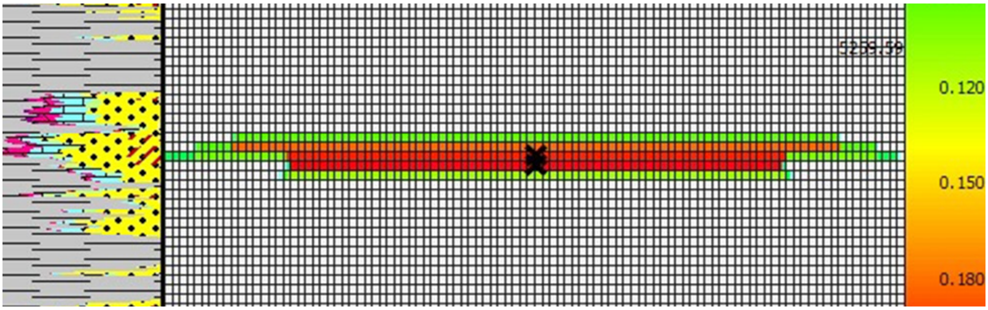


**Fig. 8.** Length of propped fracture in the [lb/ft$^2$] = 4.882 kg/m$^2$ units for rate 6.4 m$^3$/min

The opening of a new fracture does not guarantee flow rate improvement because of the high risk of a lack of conductivity and therefore no communication with the wellbore. Such phenomena could be caused by inappropriate propping. It can be clearly seen (Fig. 9) that the opened fracture was well propped and conductivity was retained.

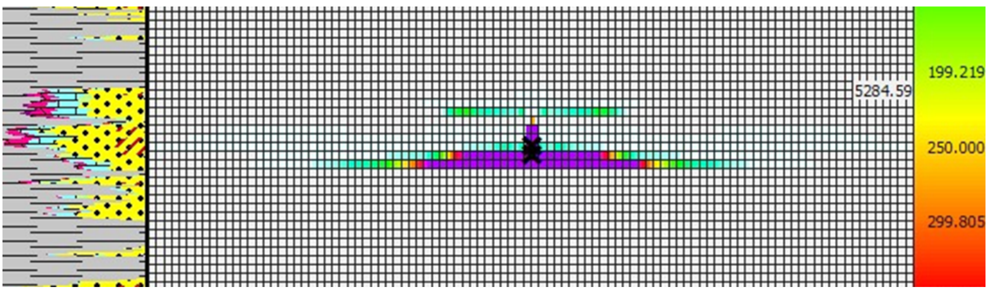


**Fig. 9.** Fracture conductivity [mD · m] for rate 5.6 m$^3$/min

### The treatment parameters after numerical modeling

The parameters of designed hydraulic fracturing treatment obtained from numerical simulation are presented in Table 6.

**Table 6**

The parameters of designed hydraulic fracturing treatment after numerical modeling

| | |
|---|---|
| Fracturing fluid type | SlickOil 180 |
| Fracturing fluid volume | 68 $m^3$ |
| Initial fluid type | SlickWater 140 |
| Volume of the wash fluid | 8 $m^3$ |
| Total volume of treatment fluid | 77 $m^3$ |
| Proppant type | Ceramic 16/30 |
| Total proppant amount | 10206 kg |
| Proppant concentration in fracturing fluid | 60–300 kg/$m^3$ |
| Number of stages | 2 |
| The length of effective propped fracture | 104 m |
| Average fracture height | 10.67 m |
| Average proppant concentration in fracture | 1.46 kg/$m^3$ |
| Average fracture height | 2.54 mm |
| Maximal fracture width | 5.08 mm |
| Treatment effectiveness | 88.91% |

**Table 7**

The schedule of fracturing fluid injection after numerical modeling

| Step | Time [min] | Fluid | Fluid vol [$m^3$] | ∑. fluid vol [$m^3$] | Proppant | Prop. conc [kg/$m^3$] | ∑.prop [kg] | Pump rate [$m^3$/min] |
|---|---|---|---|---|---|---|---|---|
| (ball) 1 | 00:00 | SlickOil | 5.68 | 5.68 | – | 0 | 0 | 5.56 |
| 2 | 01:01 | SlickOil | 5.68 | 11.36 | CarboProp | 60 | 340.69 | 5.56 |
| 3 | 02:04 | SlickOil | 5.68 | 17.03 | CarboProp | 120 | 1022.06 | 5.56 |
| 4 | 03:07 | SlickOil | 5.68 | 22.71 | CarboProp | 180 | 2044.12 | 5.56 |
| 5 | 04:12 | SlickOil | 5.68 | 28.39 | CarboProp | 240 | 3406.87 | 5.56 |
| 6 | 05:17 | SlickOil | 5.68 | 34.07 | CarboProp | 300 | 5110.31 | 5.56 |
| (ball) 7 | 06:24 | SlickOil | 5.68 | 39.75 | – | 0 | 5110.31 | 5.56 |
| 8 | 07:25 | SlickOil | 5.68 | 45.42 | CarboProp | 60 | 5450.99 | 5.56 |
| 9 | 08:28 | SlickOil | 5.68 | 51.10 | CarboProp | 120 | 6132.37 | 5.56 |
| 10 | 09:31 | SlickOil | 5.68 | 56.78 | CarboProp | 180 | 7154.43 | 5.56 |
| 11 | 10:36 | SlickOil | 5.68 | 62.46 | CarboProp | 240 | 8517.18 | 5.56 |
| 12 | 11:42 | SlickOil | 5.68 | 68.14 | CarboProp | 300 | 10220.61 | 5.56 |
| 13 | 12:48 | SlickWater | 8.43 | 76.56 | – | 0 | 10220.61 | 5.56 |
| 14 | 14:19 | SlickWater | 0 | 76.56 | – | 0 | 10220.61 | 0 |
| Sum | 19:19 | – | – | 76.56 | – | – | 10220.61 | – |

As a result of numerical modeling, the injection rate schedule was designed (Tab. 7), consisting of 14 steps divided into two main stages beginning from the put the ball into the downhole valve. The first ball thrown into the well opens the previously perforated horizon, where the hydraulic fracturing treatment is performed. After the pad injections, the concentration of the CarboProp 16/30 proppant in the fracturing fluid grew gradually from 60 mg/m$^3$ to 300 mg/m$^3$ at the constant fluid volume. Due to technological constraints, the entire treatment was conducted with the same pump units rate of 5.56 m$^3$/min. Total treatment time including the washing of the wellbore is approximately 14 min. Furthermore, the process was extended by five minutes due to the necessity of well pressure stabilization.

### The designed transverse fractures after numerical modeling

Figures 10–11 and Tables 8–9 show the geometry of transverse fractures after modeling.

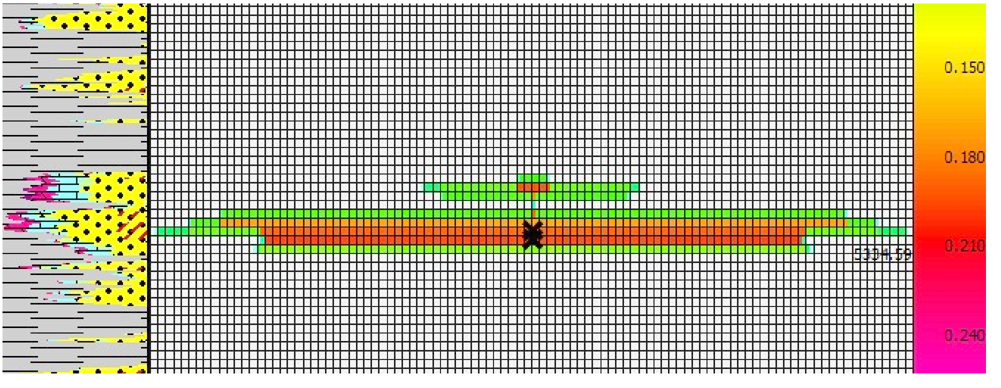


**Fig. 10.** The visualization of propped, transverse fracture in Zone B in the [lb/ft$^2$] = 4.882 kg/m$^2$ units

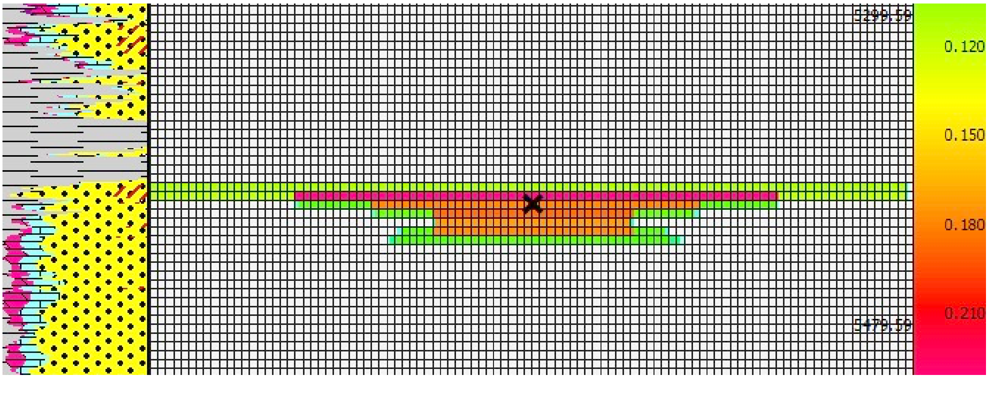


**Fig. 11.** The visualization of propped, transverse fracture in Zone C in the [lb/ft$^2$] = 4.882 kg/m$^2$ units

**Table 8**
The parameters of the designed fracture after numerical modeling in Zone B

| | |
|---|---|
| Length of well propped fracture | 61.76 m |
| Average height | 10.67 m |
| Average conductivity | 232.23 mD · m |

**Table 9**
The parameters of designed fracture after numerical modeling in Zone C

| | |
|---|---|
| Length of well propped fracture | 52.44 m |
| Average height | 10.61 m |
| Average conductivity | 240.28 mD · m |

**The designed longitudinal fractures after numerical modeling**

Figure 12 shows the geometry of longitudinal fractures after modeling.

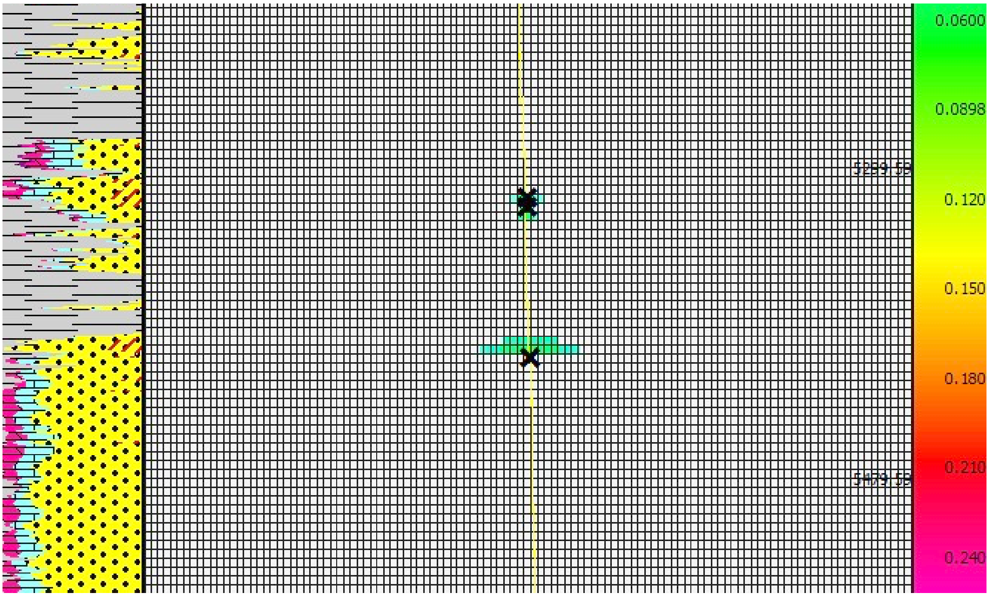


**Fig. 12.** The visualization of propped, logitudinal fracture in the [lb/ft$^2$] = 4.882 kg/m$^2$ units

The visualization of longitudinal fractures was presented for illustrative purposes only. Because of the negligible reservoir permeability, the longitudinal fractures have almost no effect on the intensification of production [16].

## 4. CONCLUSIONS

1) The obtained results indicate the immense impact of performing the numerical modeling of the hydraulic fracturing on treatment design results. Numerical modeling allows us to take into account the impact of a number of technological parameters on the effect of fracturing and rank the analyzed alternative technological options of the treatment. The principal fracture parameters such as average height and the length of propped fracture were improved by approximately 40%, moreover, the fracture conductivity was 125% greater than initial (shown in Fig. 13).

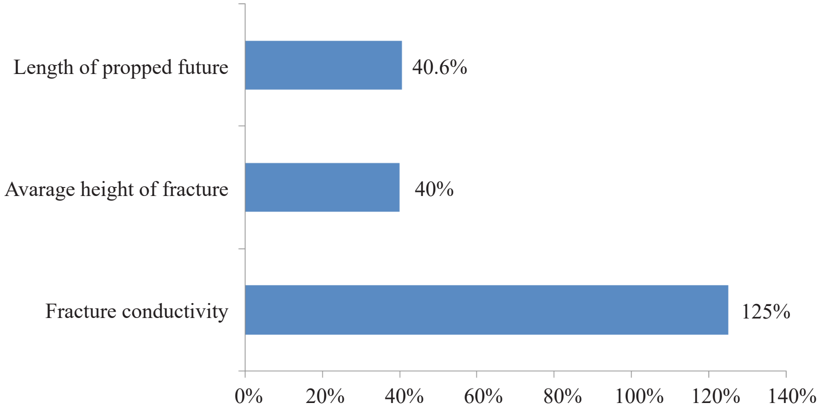


**Fig. 13.** The difference between fracture parameters before and after numerical modeling

2) Analysis of the entire numerical modeling denotes that the greatest influence on the designed treatment was the selection of fracturing fluid as well as the selection of proppant type, albeit every main factor was additionally adjusted through testing different parameters such as injection fluid rate or proppant concentration.
3) Based on one of the initial assumption concerning the evaluation of every part of numerical modeling after 120 days of production simulations, it is clear to see that the conductivity, length and width of the fracture were retained and formed at a satisfactory level, therefore the fracture propping was appropriate, and the designed hydraulic fracturing treatment was effective

## REFERENCES


[1] Barree R.D., Conway M.W.: *Experimental and Numerical Modeling of Convective Proppant Transport*. SPE-28564-P. 1995.
[2] Baree B., Svatek K.: *GOHFER User Manual*, 2015.
[3] Cross E., Trammel S., Grieser B., London S., Wilcoxson M.: *The Mississippian Lime: Not New, But Reinvented*, www.oilindependents.org/the-mississippian-lime-not-new-but-reinvented/.
[4] Daneshy A.A.: *On the Design of Vertical Hydraulic Fractures*. SPE-3654-PA, 1973.

[5] Hubbert M., Willis D.G.: *Mechanics of Hydraulic Fracturing*. In: *Petroleum Transactions*, SPE-686-G, 1957.

[6] Lei Xiao, Gang Zhao: *Study of 2-D and 3-D Hydraulic Fractures with Non-uniform Conductivity and Geometry Using Source and Sink Function Methods*. SPE 162542, 2012.

[7] LONGBOTHAM 6 API Number 15-081-21960-0100, Kansas Geologica Survey, Oil and Gas Well. http://chasm.kgs.ku.edu/ords/qualified.well_page.DisplayWell?f_kid=1043954674.

[8] Schlumberger: LONGBOTHAM 6 API Number 15-081-21960-0100, Kansas Geologica Survey, Oil and Gas Well, http://maps.kgs.ku.edu/oilgas/index.cfm?extenttype=well&extentvalue=1043954674.

[9] nZone Ball Drop Multistage stimulation system, 2012.

[10] Perkins T.K., Kern L.R.: *Widths of Hydraulic Fractures*. SPE 89- PA, 1961.

[11] Popp M.: *Completion and Stimulation Optimization of Montney Wells in the Karr Field.* University of Calgary, Calgary 2014.

[12] Qi L., *3D Reservoir Modeling of Mississippian St. Louis Carbonate Reservoir Systems*. Kansas Geological Survey, The University of Kansas, 2004.

[13] Raymond P., Sorenson A.: *Dynamic Model for the Permian Panhandle and Hugoton Fields*. Western Anadarko Basin, AAPG Bulletin 89(7), July 2005, pp. 921–938.

[14] Settari A., Cleary M.P.: *Three Dimensional Simulation of Hydraulic Fracturing*. SPE-10504-PA, 1984.

[15] Matson S.: *The Mississippian Lime: Kinematics of a Play – Structure, Reservoir Characterization and Production Performance of the Horizontal Mississippian Play*. Search and Discovery Article no. 110184, June 2015.

[16] Valko P., Economides M.J.: *Hydraulic Fracture Mechanics*. John Wiley & Sons, New York 1997.

[17] Wojnarowski P.: *Metody modelowania i oceny efektywności szczelinowania hydraulicznego skał złożowych w odwiertach naftowych*. Wydawnictwa AGH, Kraków 2013.

[18] Zhang F., Zhu H., Zhou H., Guo J., Huang B.: *Discrete-Element-Method/Computational-Fluid-Dynamics Coupling Simulation of Proppant Embedment and Fracture Conductivity After Hydraulic Fracturing*. IPTC-16444-MS, 2013.