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Fracturing Fluid Optimization in Limestone Formation Using Guar Gum Crosslinked Fluid

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Abstract

The design of the fracturing fluid is a very important aspect of the success of hydraulic fracturing. The most common fracturing fluid used in hydraulic fracturing is the cross-linked guar gum fracturing fluid. To determine the optimal fracturing fluid concentration, it is necessary to analyze the fracturing fluid optimization to obtain the best fracturing results in terms of fracturing fluid rheology, regain permeability, hydraulics, cost, fracture geometry, and FOI. From this analysis, it is expected to obtain the most optimal fracturing fluid to be applied to the JARWO Well. This research was conducted by conducting a sensitivity test method for selecting the concentration of the fracturing fluid system that affects the fracture fluid rheology, regain permeability, fracturing fluid hydraulics during injection, total material cost, fracture geometry, and the resulting FOI. The sensitivity of the fracturing fluid concentration that was tested was the system concentration of 35 pptg, 40 pptg, and 45 pptg. Each fracturing fluid is tested in the laboratory to obtain rheology which will then be simulated using MFrac software to obtain the fracture geometry formed. The results of the analysis of the concentration of each fracturing fluid showed that the fracturing fluid with a system concentration of 40 pptg was the most stable in viscosity at pumping time to produce the highest FOI. The hydraulic fracturing fluid with a concentration of 40 pptg is better than that of a concentration of 45 pptg. From the performance of regaining permeability and residue, it is quite good when compared to fracturing fluid with concentration of 45 pptg, and the cost is lower when compared to a fracturing fluid with concentration of 45 pptg. So that the fracturing fluid with a system concentration of 40 pptg is the most optimal fluid for use in hydraulic fracturing activities at the JARWO Well.

INTRODUCTION

Hydraulic fracturing at limestone formations was widely studied. This hydraulic fracturing obtains to control the heterogeneity of limestone formation due to naturally fractured. This heterogeneity affects the productivity of the formation because transmissibility difference between the matrix and fracture. The transmissibility of a naturally fractured reservoiris representeds by the interflow porosity coefficient (λ) value, the smaller the value of interflow porosity coefficient, the more dominant the fracture plays a role in flowing the fluid. In this case, the hydraulic fracturing head fixes the connectivity and permeability between matrixes and fracture in a naturally fractured reservoir, so it will increase the conductivity and productivity of the well. (Reinicke et al., 2013; Salimi & Ghalambor, 2011; Suardana et al., 2013)

One of the factors that influence the success of hydraulic fracturing is the choice of fracturing fluid and its additives. A good fracturing fluid must have a large viscosity to be able to fracture and carry the proppant. However, it must also be able to be cleaned after the fracturing process is complete so that the particles or material of the fracturing fluid does not clog the pores of the rock, which can result in a decrease in its

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permeability. The research aims to conduct fracturing fluid optimization to obtain the best fracturing results in terms of fracturing fluid rheology, return permeability, hydraulics, cost, fracture geometry, and FOI. Based on this analysis, it is expected to obtain the most optimal fracturing fluid to be applied to the JARWO Well.

LITERATURE REVIEW

In the implementation of hydraulic fracturing, fluid injection with a high viscosity (polymer) is carried out to allow for fractures to occur and be able to bring proppant into the fracture (Cramer, Woo, & Dawson, 2004). After the injection of a high-viscosity fluid (polymer), there is a possibility of formation damage due to the blockage effect of the polymer, so the expected permeability of hydraulic fracturing activities is not as expected. To deal with this, it is designed to use a breaker to break the polymer structure so that the viscosity of the injection fluid can decrease and minimize the blockage effect (Barati & Liang, 2014). The success of using a breaker needs to be evaluated on the permeability by conducting laboratory tests and simulations to obtain a return permeability that can be corrected for the blockage effect of the polymer. In this study, the fracturing fluid performance due to return permeability was observed by injectivity test using core flood apparatus. This research was also conducted by designing the optimum Base-Gel and On-Fly Fluids, testing the rheology of the Carying Fluid according to standards, and measuring the fluid-rock behavior using the injectivity test method.(Gondalia et al., 2020; Hua et al., 2016; Ming et al., 2016; Offenbacher et al., 2013; Ribeiro & Sharma, 2012; Yaritz et al., 1997)

The use of injectivity tests in observing the injection performance of hydraulic fracturing fluid designs can provide a real visual picture of how the polymer mechanism when it pushes through the pore spaces and then begins to break in the porous media. From this, it can be seen that the return permeability is whether the polymer break process is running well so that it does not leave a residue that reduces the expected permeability. This is the latest breakthrough in research in the field of hydraulic fracturing recovery. This research will be a pioneer in developing innovations in the field of hydraulic fracturing because it has never been done in Indonesia.

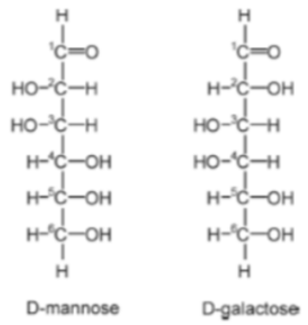

Figure 4–3a *D-mannose and D-galactose shown as mono-saccharides. Many sugars are related, differing only by the stereochemistry at one or more of the carbon atoms. D-mannose differs from D-galactose at carbon atoms 2 and 4 where the positions of hydroxyl groups are switched.*

Figure 1. Mono-Saccharides D-mannose and D-Glactose (Donaldson, Alam, & Begum, 2013)

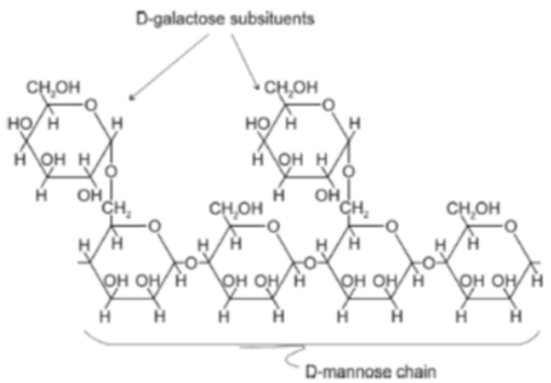

Figure 4–3b *Polymeric structure of guar gum composed of a "back-bone" chain of D-mannose with random substitutions of D-galactose in ratios of 1/6 to 1/8.*

Figure 2. Structure of Guar Polymer (Donaldson, Alam, & Begum, 2013)

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With a relatively low cost and high performance and easy handling, water-based fluid designs are the most widely used in the design of carrying fluid or frac fluid. Water-based fluid usually consists of water, a clay control agent, and a friction reducer. To reduce the relative permeability, Water Recovery Agent (WRA) is sometimes used so that the water block effect can be reduced. The biggest advantages of using this fluid design are low cost, ease to mix, and the ability to recover and reuse the water. However, the biggest drawback of this fluid is its relatively low viscosity, resulting in a relatively small fracture width. Due to the low viscosity to maintain proppant transport, a very high injection flow rate is used (60-120 bpm) (Smith & Montgomery, 2015; Tran et al., 2021; Zoveidavianpoor et al., 2013).

Water-based carrying fluids are used in two-thirds of all fracture treatments, due to the cost if it's compared to oil-based fracturing fluid, foam, or supercritical gas inert. But the disadvantage of utilizing water-based fracturing fluid is the clay issue. To control the clay issue, some clay control agent was added to the water fracturing fluid, and sometimes it was used brine with high salinity. Formation water or brine water is the best base material compared to freshwater because the content in brine water has a salinity that can handle clay/clay layers better. There are some clay-controlling agents usually used in fracturing fluid potassium-, calcium-, ammonium-, or sodium-chloride. Potassium ions form the strongest bonds with the negative part of the clay molecule, preventing hydrogen bonding with water.

Water has many advantages and flexibility, so it is widely used as a basic fluid for carrying fluid or frac fluid when compared to other basic fluids. Water is more economical and readily available, as well as more varied mixing variations because most chemical compounds can dissolve more easily in water than oil, making water easier to modify to meet various conditions needed to adapt to subsurface conditions.

Water has a viscosity of 1.0 cP at 68 ^{o}F therefore, it must be mixed with a viscosifier or thickener to be able to create new fractures and be able to bring proppant to fill the entire fracture. To make water an effective fracturing fluid, its viscosity needs to be increased to 100 times or more. Guar polymer is obtained from nuts, and when mixed with water, its viscosity increases. Guar usually forms a polymer that persists during hydration upon contact with water. With water molecules binding themselves to polymer chains, it creates a viscous fluid due to polymer bonds with each other in water-based systems (Miskimins, 2020). The viscosity of the aqueous mixture with guar ranges from 10 cP to 100 cP at 80 ^{o}F for concentrations from 20-80 lbs/1000 gal (pptg). Guar powder retains 5-10% of the plant material which is insoluble in water and causes the breakdown of formations that clog the pores of the rock matrix. As a result, chemical derivatives of guar were developed to overcome this shortcoming. Propylene oxide reacts readily with the hydroxyl groups of guars, resulting in a high molecular weight polymer [hydroxyl-propyl-guar (HPG)] which has excellent fracture propagation, proppant carrying ability, and good temperature stability. Other polymers used to make linear-polymer gels are hydroxyl-cellulose-guar (HCE), carboxyl-methyl-hydroxy-propyl-guar (CMHPG), carboxymethyl-cellulose (CEC), and xanthan gum. Linear polymer gel can be made from a mixture of fresh water with 1-2% potassium chloride (or brine water) and 2-5% HPG or HEC polymer. (Lyons, Plisga, & Lorenz, 2015).

MATERIAL AND METHOD

This study was done in three steps, first was fracturing fluid design in the laboratory including residue and core permeability damage, the second step was fracture geometry design until evaluating the productivity index using MFrac simulator and PIPESIM, and third was cost estimation. In the first stage, Guargum fracturing fluid with three different concentrations 35 pptg, 40 pptg, and 45 pptg were used and compared the rheology, residue, and permeability damage. The rheology was measured using Viscometer Chandler HTHP 5550, the residue was evaluated by mixing and filtering the guar gum as thickener and some crosslinker and breaker, and the permeability damage was determined by injectivity test using coreflood apparatus. Borate and ammonium persulfate are crosslinker and breaker used in this study. The concentration of crosslinker and breaker can be seen in Table 1.

Table 1. Fracturing Fluid Data

Additive	35 pptg Guargum	40 pptg Guargum	45 pptg Guargum
Borate crosslinker agent, mL	3	4	4
Breaker (Ammonium Persulfate), mL	2	2	6

To measure the residue take a specified amount of fracturing fluid into the thermostatic water bath of 80°C. After the fluid is broken, put it into the centrifuge at the rotation speed of 3000 r/min for 30 minutes. Remove the supernatant, place the residues in a dying oven of 150°C, and keep drying for 2 hours. Finally, weigh the residues (Hai, Liancheng, Wenhao, Tingxue, & Yiming, 2018). The permeability

damage was measured by injecting some fracturing fluid into the core which was previously saturated with water. The permeability damage was determined by comparing permeability before and after the injectivity test.(Han et al., 2005; Karaaslan et al., 2021; Zhao et al., 2015)
The second stage was fracturing geometry design, fracturing fluid hydraulic, and productivity index that evaluates using Mfrac and PIPESIM simulation. Fracturing geometry design was conducted by MFrac simulator with inputting data well hydraulic, well completion, reservoir rock properties, and treatment data. Fracturing fluid hydraulic evaluated the friction pressure loss, surface testing pressure, and HP of the pump due to the viscosity of the fracturing fluid. The increasing productivity index was performing as folds of increase (FOI) with the Cinco Ley-Samaniego method. After FOI calculation then predict the increasing rate after hydraulic fracturing using the PIPESIM simulator. The third step was cost evaluation based on the first and second steps.(Almubarak et al., 2020; Noble et al., 1997; Terracina et al., 2010; White & Daniel, 1981)

RESULT AND DISCUSSION

JARWO Well

The "JARWO" well is located in West Java is an ex-drilled well that was completed with hydraulic fracturing stimulation on Thursday, November 14, 2019. This well produces light oil in the “N” layer which is the Baturaja Formation with limestone rock lithology. This well was proposed to hydraulic fracturing due to the low permeability, around 9.8 mD, with very small production. This well is a directional well with a perforation target at 1410 – 1415 m MD with a cased hole perforated type. This well has a productive layer thickness of 7 m. To help increase production rates, this well was installed with an electrical submersible pump at a depth of 1626 m MD, with a pump intake at a depth of 1254 m MD. After well stimulation, oil production increased from 3.5 BOPD to 112.5 BOPD.
Before doing a hydraulic fracturing simulation, we need to know more about the detail of the well. From Table 2., Table 3., and Figure 3. shown the detail properties of the well that is going to be simulated using 3 type concentration guar gum fluid that is 35 pptg, 40 pptg, and 45 pptg system.

Table 2. Reservoir Data

Resrevoir data	Value	Unit
Hydrocarbon Type	Light Oil	-
Reservoir Pressure	1700	Psia
Reservoir Temperature	180	^{o}F
Lithology	Limestone	-
Permeability	9.8	mD (Horner ACA)
porosity	0.16	Fraction
Thickness	7 22.966	Meter ft
Total Depth	1978	Meter (MD)

Table 3. Well Lithology Data

Layer	Lithology	Top TVD (ft)	Bottom MD (ft)	Fracture Thoughness psi-inch$^{0.5}$
N	Shale	4174.21	4603.02	1000
	Shaly	4195.54	4625.98	1000
	Limestone	4198.82	4629.27	1000
	Limestone	4201.77	4632.55	1000
	Limestone	4205.38	4636.15	1000
	Limestone	4208.01	4639.11	1000
	Limestone	4211.29	4642.72	1000
	Limestone	4216.86	4648.62	1000
	Shaly	4223.1	4655.18	1000
	Limestone	4227.03	4659.12	1000
	Limestone	4242.13	4675.2	1000
	Shaly	4253.28	4687.01	1000
	Shale	4289.37	4725.07	1000

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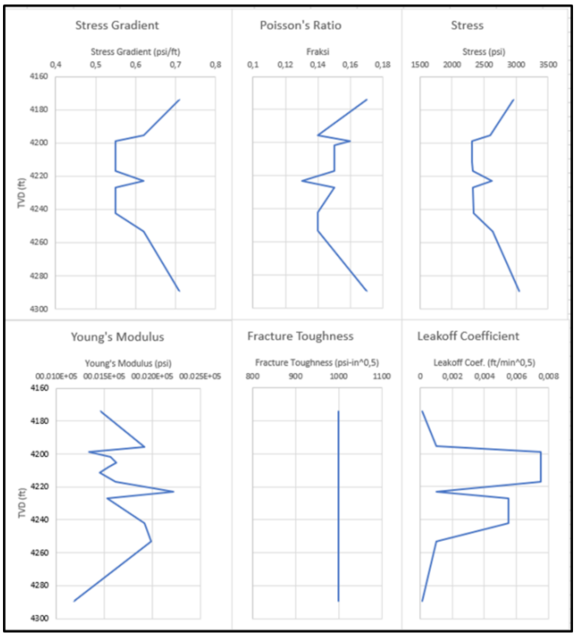


Figure 3. Well Rock Mechanics

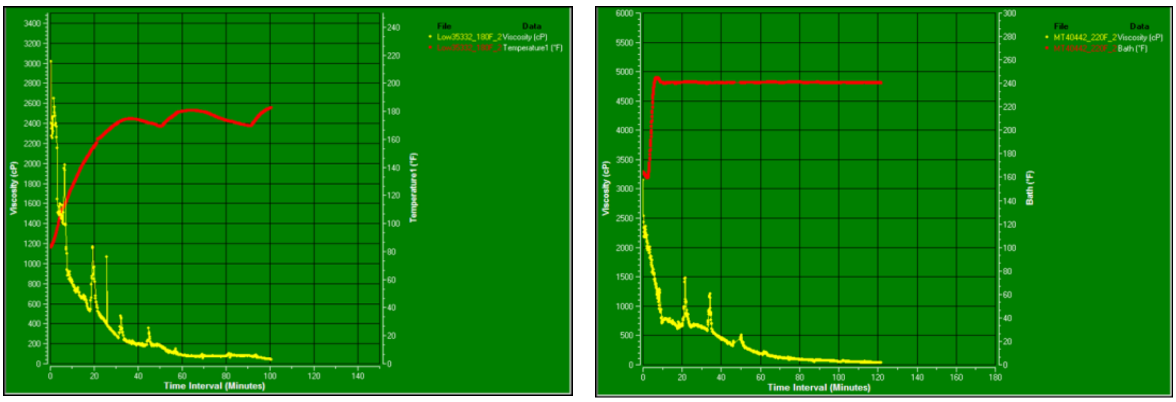
Rheological Properties

Rheology of fracturing fluids is an important criterion for evaluating fracturing fluid. It plays a crucial role in the properties of fracturing fluid. During the fracturing process, fracturing fluid injected into a formation is subjected to high temperatures and various shear stresses. With an increase in temperature and continuous shearing effect, the viscosity of polymer fracturing fluid usually decreases significantly, which makes the fracturing fluid incapable of delivering proppants into deeper formation.

Because of that reasons so fracturing fluid must meet standard viscosity. Some of these companies arrage standard viscosity of fracturing fluid of about 300-600 cp when they reach formation at reservoir temperature. The higher the fracturing fluid viscosity, the wider the fracture width so that the concentration of proppant that can be carried will also be higher, the higher the viscosity can reduce fluid loss due to filter cake formed on the fracture face so that fluid efficiency will also be better, and can reduce friction pressure (Smith & Montgomery, 2015).

We need to know the viscosity remains above 300 cp until the end of pumping to ensure the proppant transportation is leaving without a problem. In this hydraulic fracturing job, the pumping time is 44.79 minutes. Figure 4 showed the end viscosity during pumping time and the result for 40 pptg and 45 pptg system is meet the viscosity standard while the 35 pptg is below the viscosity standard. We can conclude the higher concentration system of fracturing fluid leads to more stability of fracturing fluid viscosity.

The rheological properties between three different cross-linked polymer guar gum fracturing fluid concentration systems suggest shown that the higher the concentration system, also the viscosity will be higher, and the fracturing fluid will be much more stable due to the temperature and time. For moderate temperature usage shown in this case (180 °F) 40 pptg system is capable to conduct good proppant transport since the viscosity remains above 300 cp during pumping time.



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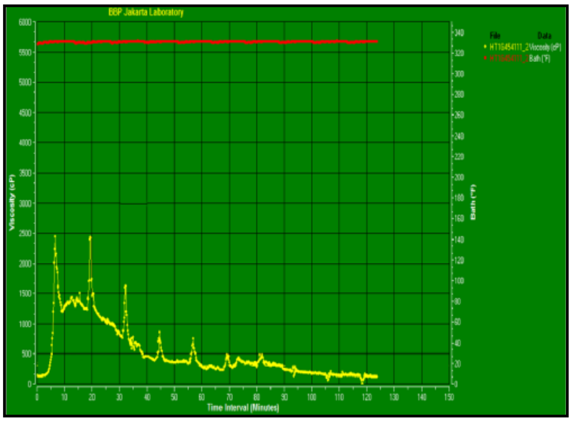

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Figure 4. Rheological Profile of (a) 35 pptg, (b) 40 pptg, and (c) 45 pptg System Fracturing Fluid

Residue

Currently, the most commonly used fracturing fluid is a guar fracturing-fluid system. However, its gel-breaking fluid can leave a high residue content and can cause obvious damage to the formation. Fracture conductivity can be compromised substantially, and the surrounding formation matrix could suffer permanent damage if the residue produced from the gel-breaking fluid cannot be evacuated from the crack on time. To reduce the damage to the fracture conductivity and matrix permeability during the fracturing process, the gel-breaking fracturing fluid should be as complete as possible, and the gel-breaking fluid should be easy to flow back (Hai, Liancheng et al 2018; Clark, 1949; De Campos et al., 2018; Howard & Fast, 1970; Jeon et al., 2016; Liu et al., 2017; Oliveira et al., 2014)
Cross-linked polymer guar gum fracturing fluid left some residue caused by the incomplete breaking process. The residue leads to permeability damage after hydraulic fracturing. The increase in system concentration leads to higher permeability damage and leaves more residues that affect the return permeability after fracturing. As shown in Table 4. the residue content is increasing with the increase of fracturing fluid concentration system, which means the higher the concentration system will damage the permeability more. Using the higher concentration system means the material that was being used also increases. Comparing those three different concentration systems we can conclude that material cost increases due to the system concentration.

Table 4. Residue content for each fluid system

Fracturing Fluid System	Residue Content
35 pptg	94 mg/L
40 pptg	306 mg/L
45 pptg	997 mg/L

Core Permeability Damage

Holditch (1979) conducted extensive research into formation-damage mechanisms and determined major factors affecting water blocking and gas flow in fractured gas wells. Generally, internal damage from the fracture and damage from the crack's penetration through the formation (fracture-face damage) are considered the two main forms of damage in hydraulic fracturing. Permeability damage in this study refers to permeability reduction or in drilling technology it's called return permeability. One factor that affect return permeability in hydraulic fracturing is compatibility between thickener which mostly cointain a polymer, crosslinker, and breaker that used to break the polymer. Unsuccess break after the fracturing fluid was injected into the reservoir can cause plugging because minerals were stuck in the pore space and reduce the permeability (Adnan & Sukowitono, 1991; ALL Consulting, 2012; Allen & Roberts, 1989; Belyadi et al., 2019; Ding et al., 2010; Driweesh et al., 2013; Economides & Nolte, 1989).
The main method used for characterizing the damage caused by the incomplete gel breaking of polymer is to determine the fracturing-fluid filtrate's damage to the core matrix. The test results on the permeability-reduction ratio are shown in Table 5. From Table 5. it is known that the damage of the higher concentration system is conduct higher permeability damage.

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Table 5. Permeabiliity Damage 35 pptg, 40 pptg, and 45 pptg System

Fracturing Fluid System	Permeability Damage
35 pptg	42.55 %
40 pptg	48.47 %
45 pptg	54.77 %

Fracture Geometry

Fracture geometry 3d model using MFrac simulation calculated on previous job scenario using the same treatment schedule and carbolite proppant 20/40 mesh. The result difference is not significant as shown in Table 6. As shown in Table 6. the highest FCD is using 45 pptg system, the higher fracture length is using 35 pptg and the higher fracture height is using 45 pptg system.

Table 6. Fracture Geometry Using Different Concenetration System Fracturing Fluid

Parameter	35 pptg System	40 pptg System	45 pptg System
xf (ft)	184.183	183.245	180.955
hf (ft)	77.777	78.339	80.334
wmax	0.52492	0.53474	0.5537
$\overline{w}$ (in)	0.1265	0.12983	0.13009
wkf (mD.ft)	5289.1	5327.2	5290
Kavg (mD)	488.75	488.75	488.75
FCD	2.9303	2.9665	2.9831

Fracturing Fluid Hydraulics

In this section, we will discuss differences in fluid performance consisting of pressure loss in tubing and perforation, surface injection pressure, hydrostatic pressure, and pump power required for each use of a fracturing fluid with concentrations of 35 pptg, 40 pptg, and 45 pptg. The difference in hydraulics fluid performance is affected by the variations of rheological behavior. The result was shown in Table 7. and Figure 5. it can conclude that the higher the guar gum concentration system, the greater the pressure loss, surface treating pressure, and also requires more pumping power.

The fracturing fluid hydraulic performance is also affected by rheological behavior. As mentioned before the higher concentration of fracturing fluid result in higher viscosity. The viscosity increment leads to higher pressure loss along the tubing that result in the higher surface injection pressure and pumping power.

Table 7. Fracturing Fluid Hydraulic Performance

Parameter	35 pptg	40 pptg	45 pptg	Unit
N_{Re}	35847.5	12090.8	7595.56	
f_f	0.00307	0.00434	0.00524	Psi
ΔP_f	2094.94	2965.38	3577.19	Psi
ΔP_{pf}	205.921	205.921	205.921	Psi
$(\Delta P_f + \Delta P_{pf})$	2300.86	3171.3	3783.11	Psi
P_h	1824.32	1824.32	1824.32	Psi
BHTP	2185.69	2185.69	2185.69	Psi
P_{surf}	3220.32	4090.76	4702.57	Psi
HHP	1499.66	1905.01	2189.92	Hp

Productivity Index Folds of Increase

The productivity increase was calculated by both Cinco-Ley and Samaniego (1981) method and also using PIPESIM simulation. The Cinco-Ley and Samaniego (1981) method uses FCD to determine rw' to calculate folds of increase (FOI). Using PIPESIM simulation to determine FOI consider the permeability damage correction to determine the regain permeability to calculate FOI. The average between the two methods is then shown in Figure 6. As shown by Figure 9. the FOI with 40 pptg system is higher than 35 pptg and 45 pptg because the permeability damage correction in 40 pptg is slightly better compared to 45 pptg system. The 40 pptg system also has a higher FCD than 35 pptg. We may then conclude the best FOI achieved by using 40 pptg systems.

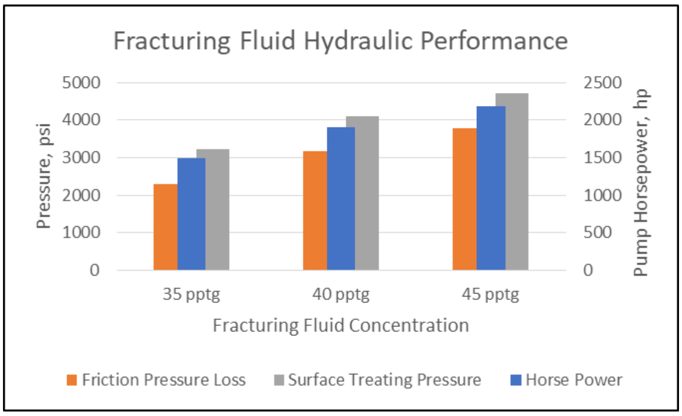

Figure 5. Fracturing Fluid Hydraulic Performance

Fracture geometry output also shows slightly different results using different concentration system. The FCD and fracture height will increase due to the higher concentration system and the fracture half-length decrease due to the higher concentration system. Based on the calculated fracture geometry then we can calculate productivity index increase called folds of increase (FOI). FOI was alculated using Cinco-Ley and Samaniego (1981) method and PIPESIM simulation. Cinco-Ley and Samaniego (1981) method calculate FOI based on FCD that will affect the rw'. The higher FCD increase the rw' that result in the higher the FOI. The highest FOI calculated using this method is 45 pptg system followed by 40 pptg and 35 pptg system. Using the PIPESIM simulation method considers the permeability damage correction to calculate the regained permeability (corrected average fracture permeability). Using this method, the highest FOI showed by 40 pptg system. Those two methods then averaged, and the higher FOI result is by using 40 pptg system.

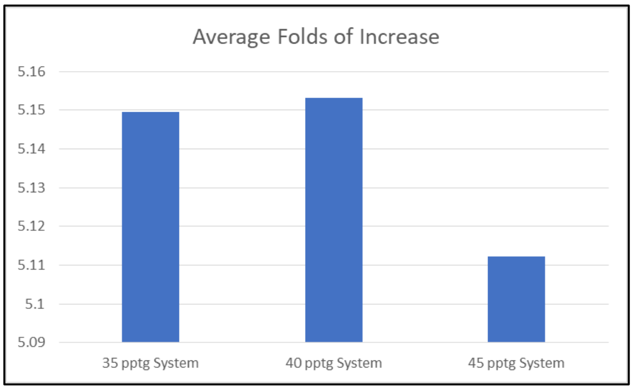

Figure 6. Average FOI Cinco-Ley Samaniego and PIPESIM Simulation

Cost

Cost estimation in this case refers to the previous job using 40 pptg system by adjusting the amount of material used based on the concentration. The higher concentration system requires more material due to the increase of gelling agents, breakers, cross-link agents, etc. As listed in Table 8. it is known that the cost would jump 3 % from 35 pptg to 40 pptg system and 1.25 % from 40 pptg to 45 pptg system.

Table 8. Fracturing Fluid Cost

Fracturing Fluid System	Cost
35 pptg	14,933.43 USD
40 pptg	15,447.41 USD
45 pptg	15,641.44 USD

CONCLUSION

Based on that analysis discuss in the previous section we can take some points listed in Table 9. It can be concluded that better performance will be gained by using 40 pptg because the viscosity is above 300 cp if

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compared to 35 pptg that could reach the viscosity stardard, residue lower than 45 pptg, permeability damage lower than 45 pptg, material cost slightly better than 45 pptg, pump power needs lower than 45 pptg, and the FOI is the highest.

Table 9. Analysis Result

Parameter	35 pptg system	40 pptg system	45 pptg system
Viscosity	170 cP	400 cP	800 cP
Residue	94 mg/L	306 mg/L	997 mg/L
Permeability damage	42.55 %	48.47 %	54.77 %
Material Cost	14,933.43 USD	15,447.41 USD	15,641.44 USD
Pump Power	1499.66 HP	1905.01 HP	2189.92 HP
Folds of Increase (FOI)	5.1497	5.1532	5.1122

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