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Effect of Pump Schedule on Fracture Geometry and Shape During Frac Packing Job

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Abstract

Recently, Frac packing was investigated to improve the economic returns of the reservoirs through the reduction of formation damage and controlling sanding from unconsolidated formation. The technique is applied for high permeability formations, in which the well production rate is affect by fracture conductivity rather than fracture length; therefore, short fat fracture with a good slurry concentration is required. The optimization of these parameters is the major factor for successful job; the optimization can be achieved through the combination of reservoir model with fracture model and tip screen-out (TSO) concept. On the basis of the formation characteristics, fracture length and conductivity with *in-situ* stress the effect of pump schedule was addressed for Tip Screen Out fracture through a well in Fula oilfield in Sudan. 3D fracture simulation software (FRACPRO PT) was used with TSO concept to address the effect of pump rate and proppant concentration on the obtained fracture. The study presented the proppant distribution is highly affected by the injection rate, and an injection rate of 3.5 was selected to avoid sanding as a result of bad proppant distribution. Also, it was observed that the fracture geometry is affected by pump rate and proppant concentration.

Keywords: Sand control; Fracturing; Proppant Concentration; Pump schedule; Tip screen-out

Abbreviations: R: local Pad Ratio; W: The Average Fracture Width According to Nordgren; C: Fluid Efficiency; L_f: Fracture Length; H_f: Fracture Height; Q_p: Pump Rate; t: Current Time; t_{SO}: The Screen-Out Time; F: Correction Factor (0.025 for Low Fluid Efficiency to 0.050 for High Fluid Efficiency Fracture)

Introduction

In poorly consolidated formations, minimizing formation sand production can be achieved by one of two categories: mechanical filtration, and reduction of matrix velocity; the mechanical control is obtained by combinations of screens and/or gravel packs. The velocity reduction will affect the economic production rate which is unacceptable for oil companies; an early effort in this area are directed at changing flow regimes from radial to bi-linear to the greatest extent possible. Frac-pack technique was appeared completion technique as well used to incorporate the stimulation potential of hydraulic fracturing with the formation sand control associated with packing the well annulus. The efficiency of the fracture depends on two steps: receiving fluids from formation and transporting the received fluid to the wellbore; the efficiency of the first step depends on fracture dimensions (length and height) while the efficiency of the second step depends on fracture permeability or conductivity. In general, low-permeability reservoirs, leading to high-conductivity fractures, which would benefit greatly from fracture length; on the other hand, high-permeability reservoirs, naturally leading to low-conductivity fractures, require good fracture permeability and width. The tip-screenout (TSO) method controls sand production both by maintaining formation stability and by bridging sand directly in the formation rather than allowing it to reach the wellbore. The key to successful frac-and-pack treatment is to maximize fracture conductivity. Such conductivity can be obtained with a tip screen-out design using fracturing fluids that do not build a fluid that do not build a particularly large filter cake. Through the Frac-pack job, the large amount of proppant packed in the fracture to ensure sufficient fracture conductivity; a short, wide fracture created for bypassing near the wellbore formation damage; the near-wellbore flow velocity and drawdown decreases. During the Frac & Pack job a fracture created by the injection of viscous fluid with pressure greater than formation break down pressure followed by the injection of slurry of fluid with proppant; when the proppant reached the tip of the created fracture (no more length can be obtained), the continuous injection of slurry causes the fracture width to increase as the pressure increases leading to balloon the fracture.

To accurately design a Frac pack job, the proppant size and type should be selected carefully; the choice of proppant size was more difficult as there were conflicting requirements; to maximize fracture conductivity the largest proppant size possible was required. Smith [1] presented statistical-based hydraulic fracturing design methodology which including constructing and calibrating a basic geological model, incorporating geo-statistics for the selection of alternate geological models, forecasting production for alternate fracturing treatments, and determining an optimum hydraulic fracturing design using all available information.

Fracture design requires a carrier fluid with a suitable leak-off coefficient which is depends on the targeting layer properties; other factors such as initial reservoir pressure and permeability, the closure-stress magnitudes in the reservoir and in the bounding formations, and rock properties (Young's modulus and the Poisson's ratio), are also required to design the fracture. When key parameters are left unknown, the hydraulic-fracture stimulation is likely to be severely suboptimal [2].

The effect of pump schedule was studied by many authors like

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GU, Dontsov and Seeyub [3-5], an old concept for typical fracturing designs include a predetermined fluid pump rate to held constant throughout the job. However, Ciezobka [6] proposed a method of pumping hydraulic fracture stages in shale formation where the fluid pump rate is rapidly changed from the predetermined maximum rate, to some significantly lower rate, and then rapidly increased back to original maximum rate. this behavior enhances micro seismicity and open additional perforations without physical flow diverters, it is also increases the production and stimulation efficiency without any additional fracture costs.

For a typical TSO job, a pump schedule is important to create the specified fracture properties; a pump schedule can be designed using analytical formulae based only on fluid efficiency. To minimize proppant pack back from the fracture tip. The slurry schedule is planned so that only low-concentration slurry is near the fracture tip during pumping; this is archived by pumping an extended low concentration stage, normally 1 lbm/gal, before the slurry concentration is increased. The front of this low-concentration stage initiates screen out, and the first part of the higher-concentration slurry stage should reach the fracture tip at the end of the pumping. The logic that this approach should minimize the aperture increase for a given pressure rise has been verified with a 3D simulator modified to model proppant transport under screen out condition.

Nolte published analytical relations based on the efficiency at screen-out for the ramp schedule and width increase for the additional injected volume after a TSO. Martins modified Nolte's concepts through the extending of the initial low-concentration proppant stage to minimize subsequent screen-out at an intermediate distance that could lead to detrimental rapid backward packing of proppant and a pressure increase, particularly for stiff fractures.

When modeling TSO, the first requirement is to estimate the desired fracture length and height needed at the start of the TSO; this step have to be done according to geological conditions, well pattern, well spacing and well density using of 3D reservoir simulation model. Secondly, fracture simulation models will be used to estimate the time required to reach a TSO and fluid efficiency at TSO need; the pad volume, the time to start the low sand concentration stage, the time to the end of the main slurry stage; the time to start the mean slurry stage and the proppant concentrations for the given time need to be calculated according to the selected model.

Work Procedure and Models

Three-dimensional fracture simulation software (FRAC PRO PT fracture design modeling) was used to calculate the fracture parameters, and to design the fracture geometry under different treatment rates and different proppant concentrations. First, using reservoir simulation and according to geological conditions, well pattern, well spacing and well density the optimal fracture half-length and fracture conductivity for the well were found 16 m and 200~300 μm^2.cm respectively; then the following steps were performed:

Determine the time required to reach a TSO (tSO) and fluid efficiency at TSO (ηSO)

$$t_{so} = \left(\frac{2\pi \cdot H_f C L_f}{Q_p} \right)^2 \tag{1}$$

$$\eta_{so} = \frac{0.01W}{0.01W + 2V_{sp} + \sqrt{8}C\sqrt{t_{SO}}} \tag{2}$$

Determine the pad volume

$$V_{pad} = R \cdot Q_P \cdot t_{SO} \tag{3}$$

Determine the time to start the low sand concentration stage, t_{IS}

$$t_{lp} = t_{SO}.R = t_{SO}((1-\eta_{So})^2 + F) \tag{4}$$

Determine the time to the end of the main slurry stage, t_{EOJ}

$$t_{EOJ} = t_{SO} + 10 \tag{5}$$

Determine the time to start the mean slurry stage, t_{MS}

$$t_{SM} = t_{EOJ}((1-\eta_{EOJ})^2 + F) \tag{6}$$

$$\eta_{EOJ} = \frac{Q_p \cdot t_{SO} \cdot \eta_{so} + \Delta V_f}{Q_p \cdot t_{EOJ}} \tag{7}$$

Determine the slurry volume; the slurry volume

Determine the Flush Volume

Flush volume=Casing Volume + Tubing Volume

The model presented above is an inverse model, iteration was used to come up with an optimal and practical design. Table 1 presented the general parameters used to design the pump schedule including the rock mechanical properties; while Table 2 presented the well completion parameters used in the model.

Results and Discussion

The simulator was run several times under constant fluid volume, pad volume and constant proppant concentration; the fluid volume was stated at 28 m^3. Low concentration slurry stage was placed during the early stage to initiate the fracture with the required length, and then continue pumping higher proppant concentration for a few minutes.

Parameters	Values
Reservoir pressure	1500 Psi
Closure stress	2000 Psi
Temperature (°C)	62
Sand permeability	305.4 md
Sand porosity	26.00%
Poisson's ratio	0.297
Young's Modulus	0.6 MM Psi
Sand thickness	13.7 m
Rock strength	0.126 MPa
Rock density	2.35 g/cm3
Internal friction angle (°)	30
Top shale thickness (m)	41
Bottom shale thickness (m)	60
Fluid compressibility: 1/MPa	0.0004

Table 1: General simulation parameters.

TD	1780 m
Perforated thickness	12.5 m
Well inside diameter	179.5 mm
Well outside Diameter	239.9 mm
Tubing diameter	89 mm
Surface casing	339.7mm × 187.37 m, ID 317.9 mm, Grade J55 61ppf
Production casing	244.5 mm × 1443.3 mKB, ID 222.4 mm, n80, 43.5ppf
The proppant size	20/40 US mesh

Table 2: Well completion parameters.

Effect of injection rates

Historically, when injecting, the range of rates is generally one to ten bbl/min for larger and moderately permeable zones and approximately one-half these values for smaller and very low permeability zones. The effect of pump rate for a constant fluid volume was studied; the fracture geometry was far affected by injection rate as can be observed from Table 3. Figures 1-3 presents the volume fraction of proppant inside the fracture for fluid volume of 28 m^3, under different injection rates. From the Figures it is clearly that a good proppant distribution can be found with an injection rate of 3.5 and 4.0 m^3/min only; for injection rate of 2.5 and 3.0 m^3/min it is clearly that the in the distribution of the proppant surrounding the fracture is not as good as that one obtained by the higher injection rate. The fracture was grown in the upper and lower shale with only 1.2 meter for injection rate of 3.5 m^3/min; while it was extended to 1.5 meter with 4.0 m^3/min injection rate. From this analysis it is clearly that an injection rate of 3.5 m^3/min is quite enough to avoid sanding with a good proppant distribution and good fracture geometry (Figure 4).

Parameters	Injection rate m^3/min			
	2.5	3.0	3.5	4.0
Fracture length (m)	18.3	18.1	17.8	17.9
Fracture propped length (m)	18.1	17.9	17.8	17.9
Fracture height (m)	16.1	16.5	16.8	17.2
Fracture propped height (m)	15.9	16.4	16.8	17.2
Width at Perfs (cm)	3.180	3.653	4.06	4.372
Max width (cm)	3.180	3.653	4.06	4.372
Average width (cm)	1.994	2.265	2.522	2.69
Average width (cm)	1.408	1.605	1.742	1.862
Average conductivity (mD m)	2503	2.931	3266	3508

Table 3: Simulation results (Constant volume different injection rate).

Effect of proppant concentration

Likewise, the simulator was run several times to obtain the desired fracture width and conductivity under different maximum proppant concentration under constant fluid volume (28 m^3) and pump rate (3.5 m^3/min). It was observed that, with a maximum proppant concentration of 13 IBm/g, the desired fracture conductivity (300 D.cm) can typically be achieved. The final pump schedule was presented through Table

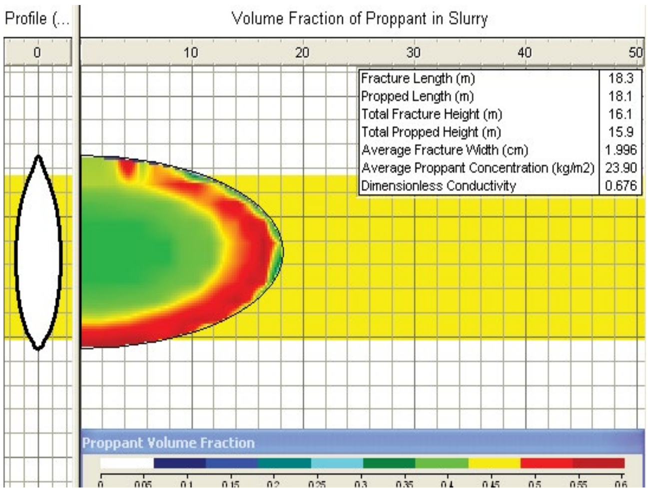

Figure 1: Proppant fraction inside the fracture (2.5 m^3/min pump rate).

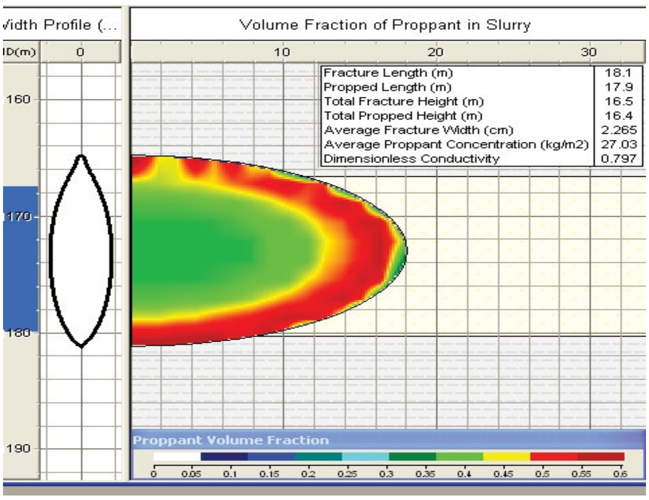

Figure 2: Proppant fraction inside the fracture (3.0 m^3/min pump rate).

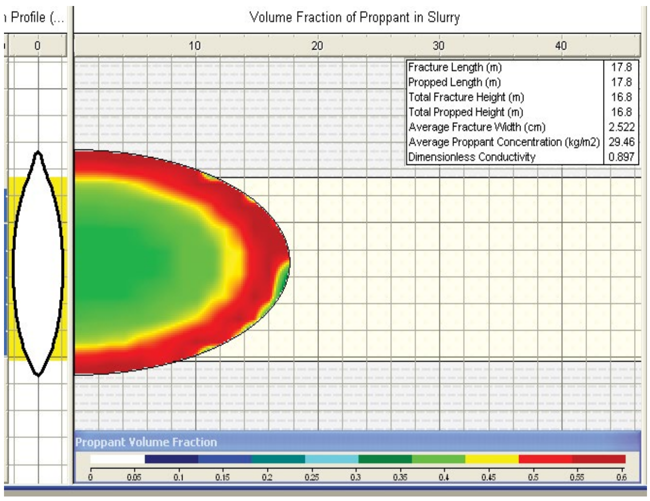

Figure 3: Proppant fraction inside the fracture (3.5 m^3/min pump rate).

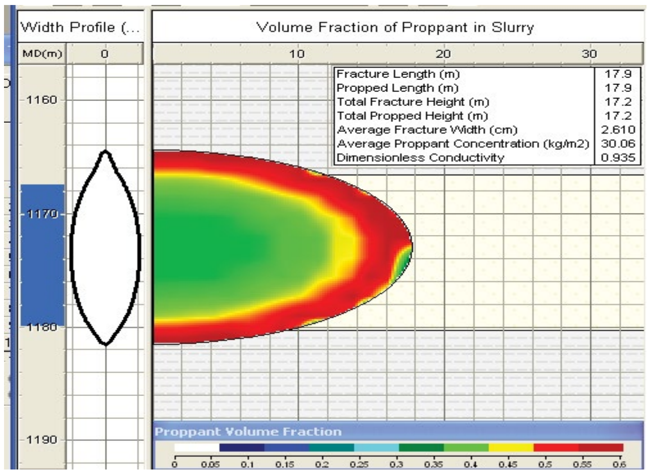

Figure 4: Proppant fraction inside the fracture (pump rate 4.0 m^3/min).

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Stage	Injection rate (m^3/min)	Clean Fluid (m^3)	Slurry Concentration Kg/m^3)	Proppant (Kg)	Cumulative Proppant (Kg)
Pad	3.5	4.9	0	0	0
Slurry	3.5	1.7	100	270	270
Slurry	3.5	2.3	970	3012	3012
Slurry	3.5	2.7	1150	3406	6417
Slurry	3.5	3.2	1170	3447	9865
Slurry	3.5	3.3	1300	3707	13572
Flush	3.5	5.6	0	0	0
Total		23.8	-	-	13572

Table 4: Pump schedule for FN-12.

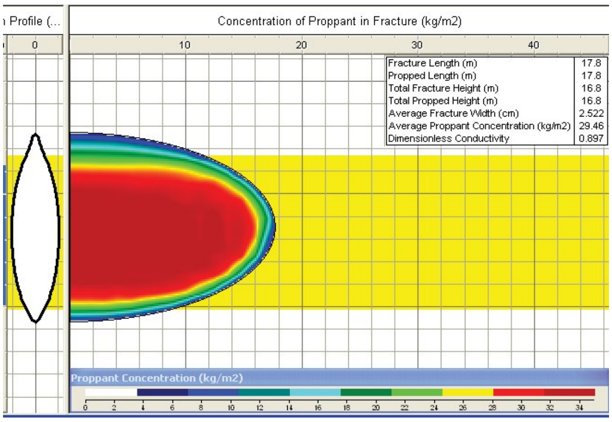

Figure 5: Sand concentration profile for pump schedule of Table 5.

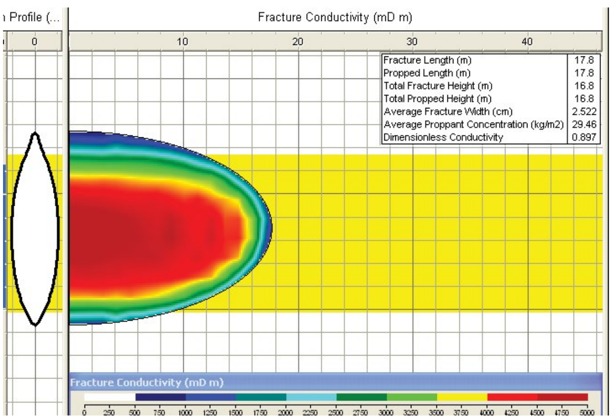

Figure 6: Conductivity profile for the pump schedule of Table 5.

Parameters	Values
Fracture length (m)	17.8
Fracture propped length (m)	17.8
Fracture height (m)	16.8
Fracture propped height (m)	16.8
Width at Perfs (cm)	4.06
Max width (cm)	4.06
Average width (cm)	2.522
Average width on proppant (cm)	1.774
Fracturing fluid volume (m^3)	28
Pumping rate (m^3/min)	3.5

Table 5: Simulation results for the pump schedule of Table 4.

4; and the proppant concentration inside the fracture, and fracture conductivity for this step are shown in Figures 5 and 6 respectively; and the simulation results parameters are presented in Table 5.

Conclusion

The effect of the different pump schedule parameters was presented through this study using data from Fula oilfield in Sudan; the effect of different pump rates and proppant concentrations on the final proppant distribution inside the fracture was addressed under constant fluid and pad volume; The proppant distribution is affected by the injection rate; and an injection rate of 3.5 be used to avoid sanding as a result of bad proppant distribution. The fracture geometry is highly affected by pump rate and proppant concentration.

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