Comparison Of Fracturing Treatment Design With An In-house Code, MFrac And FracPro

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Abstract

Hydraulic fracturing software is widely used in our industry nowadays for fracturing treatment design. Some of them are fracturing simulators that can actually mimic fracture growth while some kind is solely for treatment design. Although being different, they can provide reasonable ultimate fracture geometry and design procedure. This project aims to compare design results from three different fracturing software. Four case scenarios are studied, which involve sensitivity of consistency index of fracturing fluid, out-of-zone fluid loss multiplier, minimum horizontal stress and reservoir permeability. Each parameter is studied with individual software without interference. Results from this project can help users to understand how to cope with design changes when there is dramatic input change.

Introduction

Three software are used for this study. They are M23(a self-developed program), MFrac and FracPro. MFrac and FracPro are fracturing simulator that can provide fracture properties under every time step so that users can see how the fracture grows. Meanwhile, they also provide treatment design. Not being a simulator for M23, it will not provide how fracture grows during the treatment, but it will give the ultimate fracture geometry and treatment design.

No matter which software is used for treatment design, users must cope with different input changes. Once there are input changes, the ultimate fracture geometry and pumping sequence are likely to change. So, users have to understand the physics behind the software so that these changes can be properly treated. To achieve this, this project selects four representative parameters and investigate how they influence fracture design.

This paper is written in such a way that there is no interference between each software. All four parameters are studied by each individual software, as shown in **Figure 1**.

Input Data

The layer data are shown in **Table 1**. It is a sandstone reservoir with shale layer laminated. Data for proppant and fracturing fluid are shown in **Table 2** and **3**. **Table 4** shows reservoir property.

Study through M23

In this section, we studied the effect of consistency index, out-of-zone fluid loss multiplier, minimum horizontal stress of top layer and reservoir permeability by using M23. We first run a base case and get the results. Then we run separate case by changing one of the parameters above, and compare results with the results of the base case. For this section, the results are summarized in **Appendix A**.

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DOI:10.14800/IOGR.426

Received July 2, 2018; revised September 23, 2018; accepted October 13, 2018.

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Table 1—Reservoir layer data.

	Top ft	Thickness ft	Stess psi	KIC psi in$^{1/2}$	Perf	E 10^6psi	v	k md	Lith
1	9000	500	7585	1000	FALSE	4.28	0.3	0.001	Shale
2	9500	100	7831	1000	FALSE	4.28	0.3	0.001	Shale
3	9600	15	7110	1200	TRUE	2.80	0.26	0.5	Sand
4	9615	50	7905	1000	FALSE	4.28	0.3	0.001	Shale
5	9665	10	7156	1200	TRUE	2.80	0.26	0.5	Sand
6	9675	30	7946	1000	TRUE	4.28	0.3	0.001	Shale
7	9705	10	7158	1200	TRUE	2.80	0.26	0.5	Sand
8	9715	15	7972	1000	TRUE	4.28	0.3	0.001	Shale
9	9730	10	7204	1200	TRUE	2.80	0.26	0.5	Sand
10	9740	100	8028	1000	FALSE	4.28	0.3	0.001	Shale
11	9840	500	8274	1000	FALSE	4.28	0.3	0.001	Shale

Table 2—Proppant data.

Proppant mass	400000	lbm
Proppant permeability	50000	md
Proppant relative gravity	2.65	
Stressed proppant porosity	0.3	
Unstressed proppant porosity	0.38	

Table 3—Fracturing fluid data.

Power law fracturing fluid		
Consistency index, K	0.1	$lbf \cdot ft^{-2} \cdot s^n$
Flow behavior index, n	0.6	

Table 4—Reservoir property.

Reservoir area, Ad	40	acre
Proppant mass, M2w	400000	lbm
Proppant permeability, kf	50000	md
Reservoir permeability, k	0.5	md
Net pay, hn	45	ft

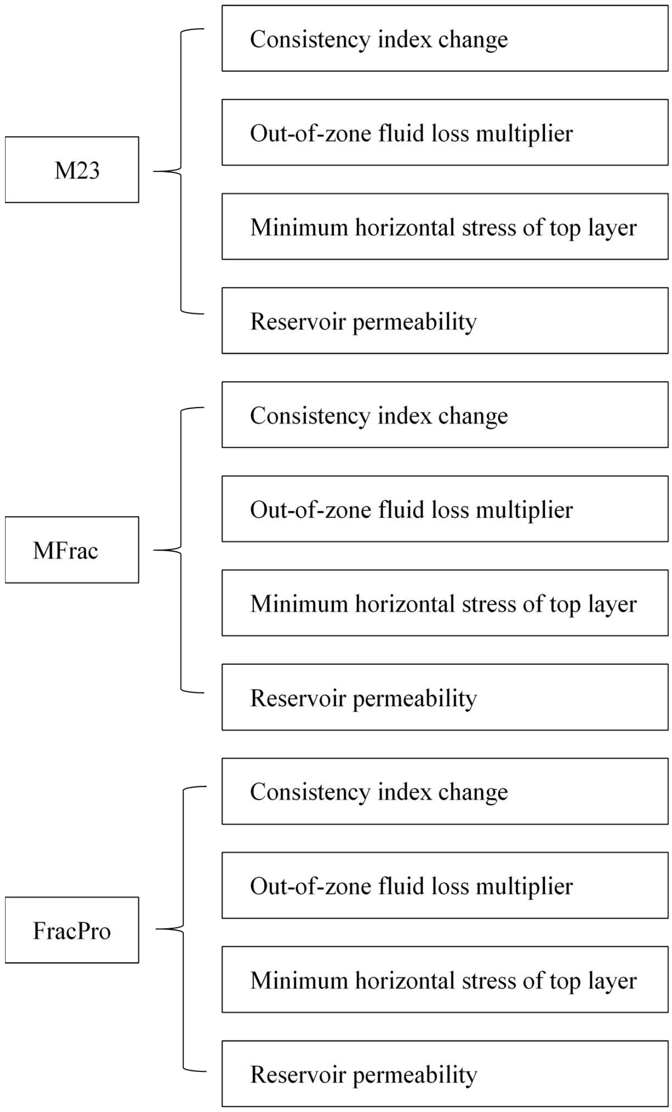

Figure 1—Project Framework.

Case 1: Consistency index of fracturing fluid decrease 10 times. Fracturing fluid is power law fluid. Based on PKN model, the fracture width of power law fluid is calculated with **Eq. 1**.

$$w_{w,0} = 9.15^{\frac{1}{2n+2}} \times 3.98^{\frac{n}{2n+2}} \left[\frac{1+2.14n}{n}\right]^{\frac{n}{2n+2}} K^{\frac{1}{2n+2}} \left[\frac{q_i^n h_f^{1-n} x_f}{E'}\right]^{\frac{1}{2n+2}}, \quad (1)$$

We can see fracture width is function of fluid rheology properties, fracture height, rock plane modulus and pumping rate. If fluid consistency index decreases by 10 times, the fracture width will become approximately 2 times smaller, as shown in **Eq. 2.**

$$\frac{w_1}{w_2} = \left(\frac{K_1}{K_2}\right)^{\frac{1}{2n+2}} = 10^{\frac{1}{2*0.6+2}} = 2.05, \quad (2)$$

In M23, the ultimate fracture length is pre-designed fracture length, which comes from UFD optimization. Fracture height is coupled with fracture width through net pressure. With the changed parameter, M23 cannot give a treatment design. It is not feasible, so we need to focus on M10.

In M10, the fracture length and height are kept the same as base case. Decreasing fracture width will decrease fracture volume. If proppant mass is kept the same, the slurry concentration in some stage will be larger than movable slurry concentration. The calculation is through **Eq. 3**.

$$c_{che} = \frac{M_{p-1wing}}{w_{ave} h_f x_f}, \quad c_{che} > c_{moveable}, \quad (3)$$

In order to solve this problem, we need to decrease slurry concentration. We can either increase fracture volume or decrease proppant mass. After calculation, the following two methods are suggested.

- Design a longer fracture with half length 670 ft
- Reduce mass of proppant to 245,000 lbm.

However, both methods produce a lower JD.

Case 2: Increase fluid loss multiplier outside pay zone from 0.25 to 0.45. In order to get the optimal JD, UFD method is used to get the optimum fracture length and conductivity. The fluid loss multiplier outside the pay zone does not affect the UFD optimization. So, the designed fracture half-length will not change. It is still 463 ft. Due to the layer data, net pressure and fluid density remain the same, the fracture height will also not change. Based on Eq. 1, the fracture width will not change either.

However, the fluid loss multiplier affects the slurry mass balance equation.

$$\frac{q_i}{h_f x_f}t - 2\kappa C_L\sqrt{t} - (\overline{w}_e + 2S_p) = 0, \quad (4)$$

$$V_{slurry} = q_i t_e , \quad (5)$$

$$V_{liquid} = V_{slurry} - V_{prop}, \quad (6)$$

$$\eta = \frac{V_{frac}}{V_{slurry}}, \quad (7)$$

$$t_{pad} = f_p t_e , \quad (8)$$

The increase of CL and Sp results in a larger pumping time. In this case, parameters that are related with pumping will change based on **Eqs. 4 to 8**. Generally, as the slurry volume, liquid volume, pumping time and pad time increase, the slurry efficiency decreases. The results can be seen in Appendix A. By comparing the results between base case and this changed case, we can see M23 can help users to decrease the negative effect of changing fluid loss multiplier and give an adjusted design.

Case 3: Increase minimum horizontal stress in Layer 1 by 1000 psi. Minimum horizontal stress is involved when calculating net pressure, and further this will affect the calculation of stress intensity factor, as shown in **Eq. 9**. The equilibrium fracture height will be affected.

$$K_{I+} = \frac{1}{\sqrt{\pi c}}\int_{-c}^{c} p_n(x)\sqrt{\frac{c+x}{c-x}}dx, \quad (9)$$

If we look at the fracture height of the base case, the upper tip is at 9,510 ft. The first layer is from 9,000 ft to 9,500 ft. That means the fracture upper tip does not penetrate into Layer 1, as shown in **Figure 2.** Therefore, before doing the design, we can guess that changes of minimum horizontal stress in Layer 1 will not affect the fracture upper tip position. And the whole fracture geometry will remain the same. Correspondingly, the treatment schedule will also be the same. This speculation is proved by running M23 with the changed parameters. The results comparison is shown in Appendix A.

Case 4: Decrease reservoir permeability by 5 times. Reservoir properties determine the fracture optimization design. Fracture needs to be designed to produce maximum productivity index for given amount of proppant. Therefore, change of reservoir properties will need a new fracture optimization. **Figure 3** describes the effect of reservoir permeability.

A new fracture optimization and treatment design is obtained by running M23 with changed reservoir permeability. The results are shown in Appendix A. We can see the new JD is larger than the base case. The comparison between this case and base case shows that M23 can give adjusted new design if reservoir permeability changes.

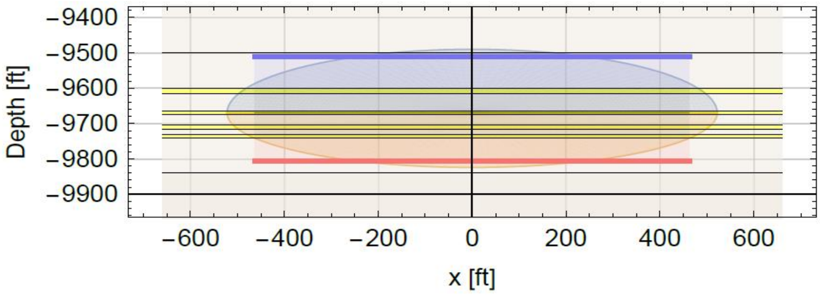

Figure 2—Fracture profile of base case.

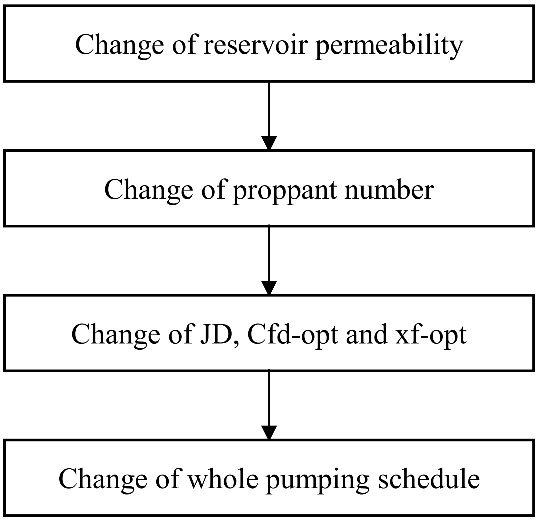

Figure 3—Effect of reservoir permeability.

Study through MFrac

In this section, we studied the effect of consistency index, out-of-zone fluid loss multiplier, minimum horizontal stress of top layer and reservoir permeability by using MFrac. Likewise, we first run a base case and get the results. Then we run separate case by changing one of the parameters above, and compare results with the results of the base case. For this section, the results are summarized in **Appendix B**.

Case 1: Consistency index of fracturing fluid decrease 10 times. In MFrac, the final proppant concentration is set to stop the simulation process. If the proppant concentration across the fracture is larger than this value, the simulated pumping continues until this concentration is reached. In this study, we set the final proppant concentration to be 10 ppga.

If we change consistency index of fracturing fluid, the fracture width during pumping becomes smaller. In order to accommodate the proppant, the fracture length has to become longer. In other words, MFrac will always produce a treatment design, with fracture geometry being very different. In this case, the fracture half-length is around 300 ft longer than base case.

Meanwhile, the fracture height in MFrac is obtained from an aspect ratio with fracture length. If the length increase due to pumping, the fracture height will also keep increasing correspondingly. The calculated results are shown in Appendix B.

We can see MFrac can provide user an adjusted design if the consistency index changes.

Case 2: Increase fluid loss multiplier outside pay zone from 0.25 to 0.45. Fluid loss data are modified layer by layer in MFrac. Modification is only applied to Shale zone. Provided the same amount of proppant, same fracturing fluid, and same final proppant concentration, the simulation process (fracture propagation process) will keep going until the final proppant concentration reaches the pre-set value. In other words, the fracture volume is the same as base case. The fracture width in MFrac is calculated through Radial Model (Eq.10)

$$w \propto \left[\frac{(1-\nu^2)}{E} K Q^n V^{\frac{2-n}{2}}\right]^{\frac{2}{3n+6}}, \qquad (10)$$

We can see the fracture width will not change due to fluid loss change. In the meanwhile, the fracture height and fracture length is coupled. So for the same fracture volume, if fracture width does not change, neither the fracture height nor length will change.

The mass balance equation in MFrac is also described with **Eqs. 4** through **8**. So larger fluid loss coefficient leads to a larger pumping time, volume pumped and pad time. The slurry efficiency will become smaller.

We can see, MFrac can adjust another design if fliud loss parameter changes. The results are shown in Appendix B.

Case 3: Increase minimum horizontal stress in Layer 1 by 1000 psi. In Base case, the fracture upper tip is at 9349 ft, which is in Layer 1. So if the minimum horizontal stress in Layer 1 increases, the fracture height will decrease according to Eq. 6. The simulation results are shown in Appendix B. We can see the fracture height decreases from 503 ft to 380 ft. In order to accommodate the proppant, the product of fracture length and width should increase.

We can see MFrac can adjust treatment design if minimum horizontal stress changes.

Case 4: Decrease reservoir permeability by 5 times. MFrac is fracture treatment design software. It cannot give fracture optimization design. If we change the reservoir permeability but keep the proppant mass, fracturing fluid the same and final proppant concentration the same, the ultimate fracture geometry will not change. In the meanwhile, the fluid loss parameters are not correlated with permeability in MFrac, so the simulated pumping parameters will also be the same. This can be seen in Appendix B.

However, as a designed, we always want to have a maximum JD. So, the user should be knowledgeable to have a rough estimation towards the fracture geometry and dimensionless conductivity. MFrac cannot substitute users at this point.

Study through FracPro

In this section, we studied the effect of consistency index, out-of-zone fluid loss multiplier, minimum horizontal stress of top layer and reservoir permeability by using FracPro. Like previous two cases, we first run a base case and get the results. Then we run separate case by changing one of the parameters above, and compare results with the results of the base case. For this section, the results are summarized in **Appendix C**.

Case 1: Consistency index of fracturing fluid decrease 10 times. In FracPro, the target Cfd is set to stop the simulation process. If the Cfd is not reached after limited number of iterations, the software will stop. Compared with base case, the Cfd is still 4.5 in this changed case. FracPro cannot give a treatment design because the calculated fracture width is small. In order to have a treatment, users need to decrease the target Cfd. In this case, the Cfd is changed to 0.2, and a treatment design is calculated, as shown in Appendix C.

We can see the proppant mass decrease around 20 times as compared with base case. The fracture geometry remain close. This means the fracture permeability becomes smaller.

In general, FracPro cannot adjust its treatment design if fracturing fluid consistency index changes. User need to make adjustments based on own knowledge.

Case 2: Increase fluid loss multiplier outside payzone from 0.25 to 0.45. Fluid loss data are correlated with formation permeability in FracPro. So, the change of fluid loss multiplier will have formation permeability changed. In this case, I changed shale layer permeability to have the fluid loss coefficient out of payzone changed. The calculated results are shown in Appendix C.

We can see the results are close to the base case, expect the slurry volume, liquid volume, injection time and pad time. The slurry efficiency is a little lower. These parameters are correlated with mass balance, as we have discussed in previous sections.

As can be seen, FracPro can adjust its treatment design if fluid loss parameters change.

Case 3: Increase minimum horizontal stress in Layer 1 by 1000 psi. In base case, the fracture upper tip is at 9,514 ft, which is in Layer 2. Therefore, if we change the minimum horizontal stress of Layer 1, the results will not be changed. The results are shown in Appendix C. We can see the results are the same as base case.

We cannot conclude FracPro can adjust its treatment if minimum horizontal stress changes by just running this case. However, M23 give correct result for this case.

Case 4: Decrease reservoir permeability by 5 times. A target CFD is set for this simulation. If reservoir permeability decreases, the product of fracture width and fracture permeability should also decrease. In this case, fracture width remains the same because we based on Eq.1, so the fracture permeability should decrease, which cause the decrease of proppant concentration inside of fracture. Also, the mass proppant concentration in injected slurry will also decrease.

In the meanwhile, the fluid loss parameters will also decrease for the pay zone. Thus, the parameters related with mass balance will change. In the results, the slurry volume, liquid volume, injection time and pad time decreases and slurry efficiency increases.

As we can see, FracPro can help to adjust the treatment design if reservoir permeability changes.

Table 5—Summary.

	M23	MFrac	FracPro
Consistency index	N	Y	N
Fluid loss parameter	Y	Y	Y
Minimum horizontal stress in top layer	Y	Y	Y
Reservoir permeability	Y	N	Y

Conclusions

We can draw the following conclusions:

1) In general, different software have different ability to cope with input changes. It can be summarized in Table 5 (Y is the software can adjust and N is not).
2) When we analyze sensitivity of parameters, first we need to know how the fracture geometry changes.
3) Based on fracture geometry, we then analyze how the pumping schedule changes.

Conflicts of Interest

The author(s) declare that they have no conflicting interests.

References

User Manual, MFrac, Meyer Associates
User Manual, FracPro, CarboCeramics

Appendix A

	Base Case	K1 10 times smaller	flmult from 0.25 to 0.45	1000Psi increase	k decrease 5 times
Mass of proppant injected, lbm	400000	400000	400000	400000	400000
Mass proppant concentration in injected slurry (ppga)	10.2	NA	10.2	10.2	5.42
Slurry volume injected (gal)	159000	NA	226000	159000	264000
Liquid volume injected (gal)	141000	NA	208000	141000	246000
Injection time (min)	108	NA	154	108	180
Pad time (min)	44.64	NA	86.8	45.1	77.8
Frac slurry efficiency	0.36	NA	0.253	0.36	0.348
Net frac pressure (psi)	312	NA	312	312	319
Half length (ft)	463	NA	463	463	618
Upper frac height (ft)	160	NA	160	159	169
Lower frac height (ft)	137	NA	137	137	152
Total frac height (ft)	296	NA	296	296	321
Max frac width (in.)	0.534	NA	0.534	0.534	0.591
Average frac width (in.)	0.336	NA	0.336	0.336	0.371
Average surface concentration (lbm/ft^2)	1.46	NA	1.46	1.46	1.01
Upper tip location (TVD) (ft)	9510	NA	9510	9510	9500
Lower tip location (TVD) (ft)	9810	NA	9810	9810	9820
Treating pressure at reference depth (psi)	7860	NA	7860	7860	7870
Base pressure to calculate net pressure (psi)	7550	NA	7550	7550	7550
Dimensionless Productivity Index	0.943	NA	0.943	0.943	1.47
Dimensionless fracture conductivity	3.02	NA	3.02	3.02	12.51

Appendix B

	Base Case	K1 10 times smaller	flmult from 0.25 to 0.45	1000Psi increase	k decrease 5 times
Mass of proppant injected, lbm	400000	400000	400000	400000	400000
Mass proppant concentration in injected slurry (ppga)	10	10	10	10	10
Slurry volume injected (gal)	188080	326410	293070	178940	188080
Liquid volume injected (gal)	169980	308310	274970	160840	169980
Injection time (min)	127.95	222.04	199.37	121.73	127.95
Pad time (min)	75.07	188.12	143.66	68.25	75.07
Frac slurry efficiency	0.32	0.188	0.206	0.332	0.32
Net frac pressure (psi)	297	186.85	295.26	402.13	297
Half length (ft)	450	742.62	451.51	517.26	450
Upper frac height (ft)	320.58	361.35	323.29	182.79	320.58
Lower frac height (ft)	182.43	146.61	182.31	197.58	182.43
Total frac height (ft)	503.01	507.96	505.6	380.37	503.01
Max frac width (in.)	0.436	0.265	0.433	0.568	0.436
Average frac width (in.)	0.268	0.162	0.267	0.3	0.268
Average surface concentration (lbm/ft^2)	1.11	0.656	1.101	1.26	1.11
Upper tip location (TVD) (ft)	9349.4	9308.7	9346.7	9487.2	9349.4
Lower tip location (TVD) (ft)	9852.4	9816.6	9852.3	9867.6	9852.4
Dimensionless fracture conductivity	2.48	0.91	2.46	2.42	2.48

Appendix C

	Base Case	K1 10 times smaller	flmult from 0.25 to 0.45	1000Psi increase	k decrease 5 times
Mass of proppant injected, lbm	469400	22000	476000	467900	112400
Mass proppant concentration in injected slurry (ppga)	14	10	14	14	2
Slurry volume injected (gal)	150528	119070	186984	149352	127596
Liquid volume injected (gal)	129301	118079	165459	128197	122514
Injection time (min)	102.2	81	126.9	101.5	86.8
Pad time (min)	50.3	36.6	75.5	49.6	26.5
Frac slurry efficiency	0.41	0.37	0.32	0.41	0.52
Net frac pressure (psi)	1131	1058	1093	1132	1147
Half length (ft)	498	482	510	497	495
Upper frac height (ft)	157	142	158	156	159
Lower frac height (ft)	140	126	141	140	145
Total frac height (ft)	297	268	299	296	304
Max frac width (in.)	0.68	0.56	0.65	0.68	0.71
Average frac width (in.)	0.43	0.35	0.4	0.43	0.44
Average surface concentration (lbm/ft^2)	2.21	0.11	2.24	2.22	0.48
Upper tip location (TVD) (ft)	9514	9528	9512	9514	9510
Lower tip location (TVD) (ft)	9810	9796	9811	9810	9815
Treating pressure at reference depth (psi)	8287	8214	8249	8288	8303
Base pressure to calculate net pressure (psi)	7156	7156	7156	7156	7156
Dimensionless fracture conductivity	4.26	0.2	4.23	4.27	4.58

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