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Lesson Learned: Fracturing Story Continues in Completely New Telisa Formation in B Structure South Sumatera

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Abstract

Telisa is a formation in South Sumatera Basin that was famous for its hydraulic fracturing success. In Pertamina, Telisa is found in TL Structure and was successfully treated with hydraulic fracturing. This year, Pertamina found Telisa as a new formation in B-Structure. It has the lowest net pressure yet highest fluid efficiency among other Telisas. Adding low permeability, low young modulus, and non-ideal reservoir behavior to that list, fracturing this formation becomes quite challenging.

The first Telisa formation in B Structure was found in well B-62. The well can only produce intermittently in a space of two months. However, its water cut was as low as 50%. In order to produce the well continuously and increase its productivity, hydraulic fracturing treatment was planned. Since Telisa is considered soft rock with young modulus around 1 million psi, the treatment was designed to use 20/40 proppant to minimize embedment effect. According to petrophysical analysis this formation has 40 mD permeability, therefore treatment design was designed to be aggressive with fracture width as priority instead of half-length.

After performing breakdown, step rate test, and data frac, treatment was redesigned. It turned out that reservoir permeability is not as high as previously estimated. Transmissibility that was acquired from breakdown test data showed that permeability is less than 10 mD, therefore the treatment was switched from aggressive to conservative with half-length as priority. Step down test, and was later confirmed by data frac, it can be inferred that this well has high entry friction at 1300 psi. Data frac also showed presence of fissures from decline curve with concave up shape. Fluid efficiency and pad ratio calculation was adjusted accordingly to handle this non-ideal reservoir behavior. Final design for fracturing treatment was with total of 65,000 lbs 20/40 proppant to target minimum 1.2 FCD, 0.3 inch fracture width, and 2 lbs/ft2 average proppant concentration. Pre-treatment of hundred mesh sand slug was pumped ahead of proppant slurry to reduce entry friction. During main frac job, sand slug failed to reduce entry friction Job was carried out to 6 ppg proppant concentration before loss prime on one of the frac pumps occurred and eventually screen out at the last proppant stage (7 ppg). Total proppant pumped into formation was 44,701 lbs.

Pumping 70% from designed proppant mass was not too bad, however opportunity for improvements was wide opened. There are three things to be considered for next treatments: perforate formation with highest entry hole size available and increase gel viscosity to handle excessive entry friction, pump more sand slug to deal with fissures, and improve pumping system reliability by installing filter to prevent unwanted solid during pumping and performing horse power test to the frac pumps.

Introduction

B Structure in Pertamina is located in South Sumatera. This structure is well known for its heavy oil properties with viscosity in range of 10 – 350 cp at reservoir condition and 15^0 - 22^0 API. This structure produces from two active formation: Talang Akar and Telisa. Figure 1 shows stratigraphy of South Sumatera Basin. It can be seen that Telisa formation is on top of Baturaja Formation.

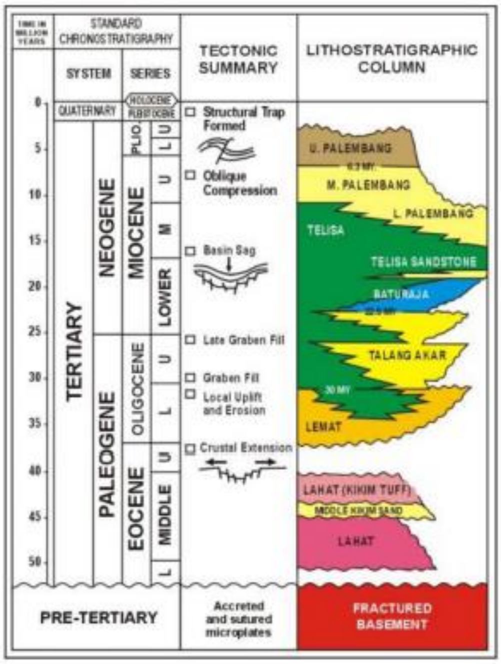

Figure 1 Stratigraphy of South Sumatera Basin (Agarkoesoemah *et al*. 2005)

Telisa formation is closely associated with hydraulic fracturing. In South Balam Field Central Sumatera, this formation has high permeability up to 100 mD. However, hydraulic fracturing is still the completion method chosen for this formation. Poerwanto *et al*. (1995) summarizes that during 1993 to 1994, out of 20 hydraulic fracturing jobs on Telisa Formation in this field, all of the wells generated more than 150 bopd initial production. It means that hydraulic fracturing completion method is suitable for this formation in high permeability Telisa Formation in South Balam Field.

Other Telisa formation with tight properties is in KS Field, Rimau Block, South Sumatera. In this field, Telisa tight sandstone is the primary target of oil production with hydraulic fracturing method as the most suitable completion method (Kamal *et al*. 2018). The results from Telisa wells in KS Field were also good, considering the wells could not flow without being hydraulically fractured.

New technology of fracturing method called pillar fracturing technique was also performed in Kaji Semoga Field (Azhari *et al*. 2017). This new technique performed in this field resulted better than conventional hydraulic fracturing method by more than ten folds of the wells' peak production.

Telisa formation in B Structure in Pertamina was first discovered in B-062 well. This well was proven in producing oil, however it can't be produced continuously. Figure 2 shows that the well needed 2 – 3 months to be reproduced. Of course operational aspects were also considered to reproduce the well, but the events were evidence that the formation contains oil and the only thing needed was suitable completion method to produce the well continuously. Hence, hydraulic fracturing was then planned and performed.

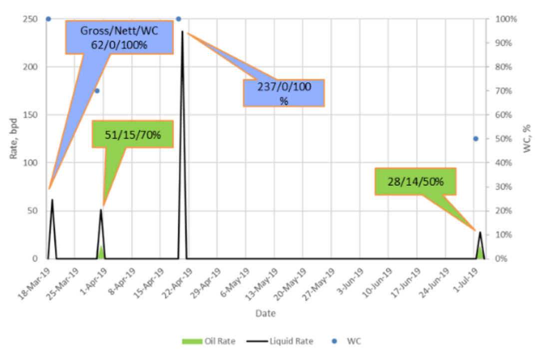

Figure 2 Well B-062 Production Performance

There are three wells that were prepared for hydraulic fracturing pilot in this structure. Two other wells were B-021 and B-020 wells, with more updip position than B-062 wells.

Data and Method

Preparation was made in Well B-062 from cleaning the well by circulation two times well volume, testing and pickling job for fracturing string, to setting and testing packer of fracturing string. Fracturing job sequence that would be performed were breakdown test, step-rate test, data frac (mini frac), and main frac after performing data frac analysis.

Petrophysicist provided permeability data of 40 mD for Telisa formation in this structure, however B-062 cyclic production behavior didn't mirror a 40 mD formation. Performing breakdown test would give transmissibility data that would indicate whether the formation has high or low permeability.

Breakdown test was performed at maximum rate of 17 bpm with maximum tubing pressure of 5200 psi using 4% KCl brine. Total volume injected was 181 bbls. Based on after closure analysis permeability was around 10 mD, tighter than what was predicted from petrophysical analysis. Fracturing design then would need to be switched from aggressive to conservative method with half-length as priority. Figure 3 and 4 show breakdown test pump chart and after closure analysis.

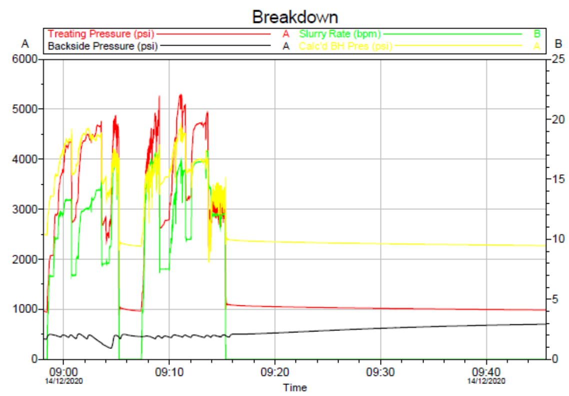

Figure 3 Breakdown Test Well B-062

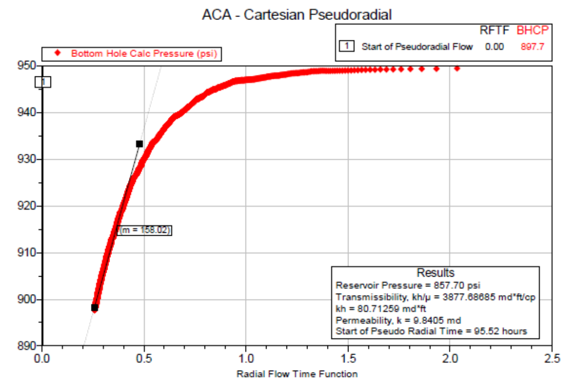

Figure 4 After Closure Analysis (ACA) Well B-062

Step rate test was then executed to know fracture extension rate and pressure and near well bore (NWB) friction. Fracture extension rate and pressure was extracted from step up test and NWB friction was analyzed from step down test. Figure 5 to 8 show step rate test pump chart and the analysis. In Figure 5 step up test started at 1 bpm to 2 bpm for low point analysis and increased per 2 bpm up to 18 bpm. For step down test, 5 points were taken.

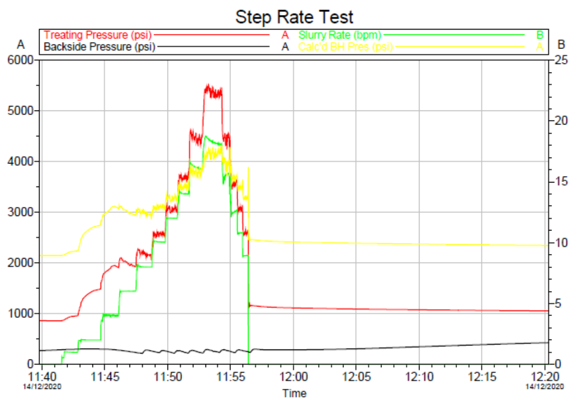

Figure 5 Step Rate Test Pump Chart

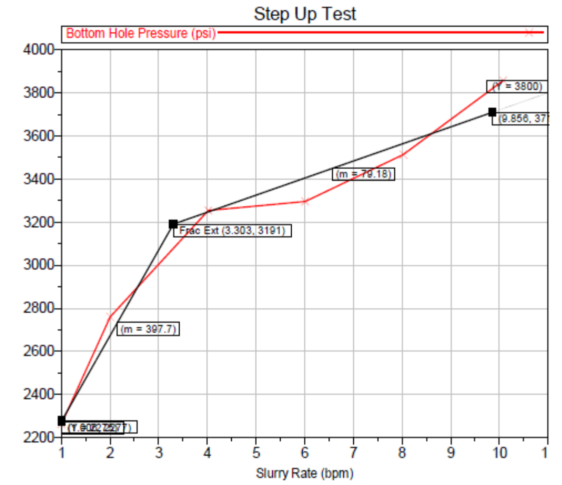

Figure 6 Fracture Extension Rate and Pressure Analysis

Step Down Analysis Input	
Surface ISIP, psi:	1165
BH Fluid Density, lb/gal:	7.17
Entry Hole Diameter, in:	0.400
Number of Perfs:	50
Discharge Coefficient:	0.90

Step Down Analysis Results			
Effective Perfs:	5.78	Beta Factor:	1.02
Pipe Friction, psi:	2477	Entry Friction, psi:	1731
Perf Friction, psi:	808	NWB Friction, psi:	923
Entry Coeff:	87.74	Perf Coeff:	2.45
NWB Coeff:	216.65		

Step	Rate (bpm)	Pressure (psi)	Pipe Frict (psi)	Entry Frict (psi)	Perf Frict (psi)	NWB Frict (psi)
1	18.15	5392	2477	1731	808	923
2	15.63	4407	1841	1456	599	857
3	12.60	3580	1205	1158	389	769
4	10.83	3056	893	1001	288	713
5	8.93	2608	615	843	196	648

Figure 7 Friction Analysis Results

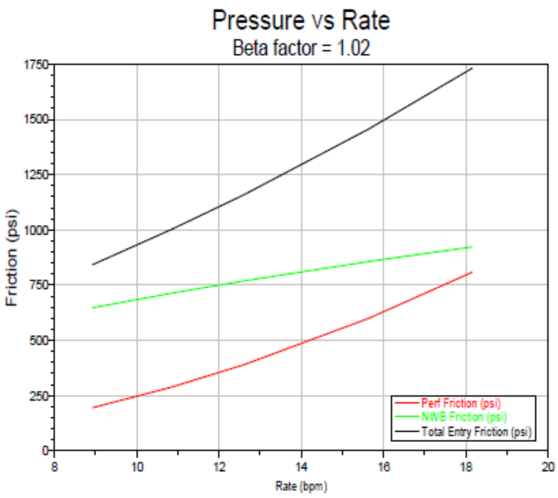

Figure 8 Pressure vs Rate in Friction Analysis

Figure 6 shows that fracture extension pressure was at 3200 psi and fracture extension rate was around 3.5 bpm. So as long as our pressure and rate are more than these numbers, our fracture will keep growing until designed length. Handicap for this well was shown in friction analysis result (Figure 7) that total entry friction for this well was more than 1700 psi. Figure 8 showed that total friction entry was in concave up shape, which means that entry friction was perforation dominated. In order to attempt to ease the NWB friction, hundred mesh (sand slug) would be pumped before pumping designed proppant slurry.

Mini frac was performed to analyze net pressure and fluid efficiency to be later used in final fracturing design. While break down test and step rate test utilized 4% KCL as the pumped fluid, data frac used frac gel. Pumping operated at 16 bpm with total of 231 bbls pumped fluid volume. Figure 9 shows that the gap between pressure before the pump was shut in (around 4200 psi) and the Bottom hole Instantaneous Shut in Pressure (ISIP) (2855) psi was the total NWB friction. It means there are still around 1400 psi NWB friction handicap to handle in this well.

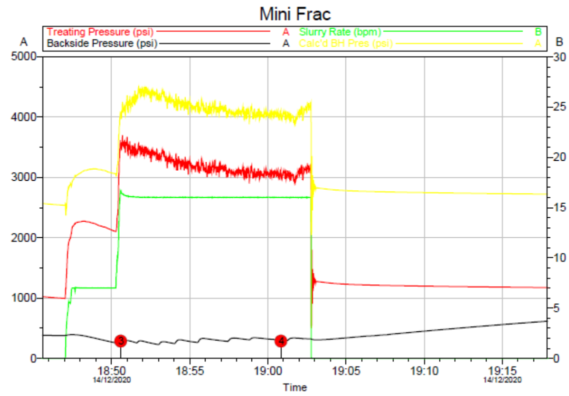

Figure 9 Data Frac Pump Chart

Figure 10 shows mini frac G function analysis. From the chart it can be seen that decline curve shows concave up shape, which indicated presence of fissures in the reservoir. Because of this irregularities, instead of taking G closure from dP/dG or G dP/dG, G time was taken from the interception of the line from bottom hole ISIP to the ¾ point between bottom hole ISIP and closure pressure and the closure pressure line from G dP/dG or dP/dG. This G time was called G*. From G* calculation of fluid efficiency was 27%. Fluid efficiency calculation from G closure on G dP/dG curve was 61%. Since this is the first fracturing in Telisa formation B Structure and no previous reference, fluid efficiency for design was the average between G* calculation and G closure calculation, which was 44%. Pad ratio was then calculated to be 39%. From minifrac data, final design for main frac was laid out as shown in Figure 11 and 12.

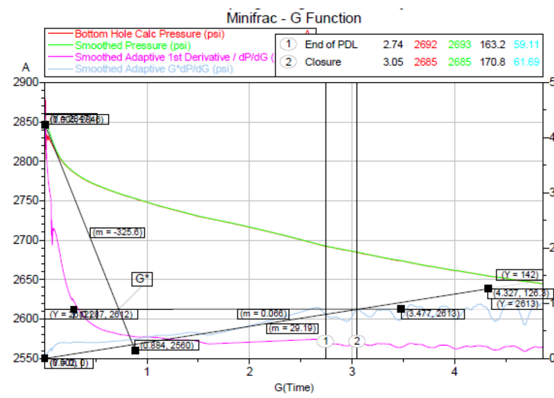

Figure 10 Minifrac G Function Analysis

	Stage Type	Flow Rate 1 (bpm)	Flow Rate 2 (bpm)	Prop Conc 1 (ppg)	Prop Conc 2 (ppg)	Clean Vol (gal)	Stage Length (min)	Cumul Time (min:sec)	Fluid Type	Proppant Type
1	Main frac pad	15.00	15.00	0.00	0.00	14,000	22.22	35:27	HH35G2K	
2	Prop slug	15.00	15.00	0.50	0.50	4,400	7.17	42:37	HH35G2K	100 mesh
3	Main frac slurry	15.00	15.00	0.50	1.00	3,000	4.92	47:32	HH35G2K	bauxite 20/40
4	Main frac slurry	15.00	15.00	1.00	3.00	3,000	5.18	52:42	HH35G2K	bauxite 20/40
5	Main frac slurry	15.00	15.00	3.00	4.00	3,000	5.49	58:12	HH35G2K	bauxite 20/40
6	Main frac slurry	15.00	15.00	4.00	6.00	2,800	5.41	63:37	HH35G2K	bauxite 20/40
7	Main frac slurry	15.00	15.00	6.00	7.00	3,100	6.32	69:56	HH35G2K	bauxite 20/40
8	Main frac slurry	15.00	15.00	7.00	7.00	3,250	6.74	76:40	HH35G2K	bauxite 20/40
9	Main frac flush	15.00	15.00	0.00	0.00	1,180	1.87	78:32	WG1113cP	

Figure 11 Main Frac Pump Schedule

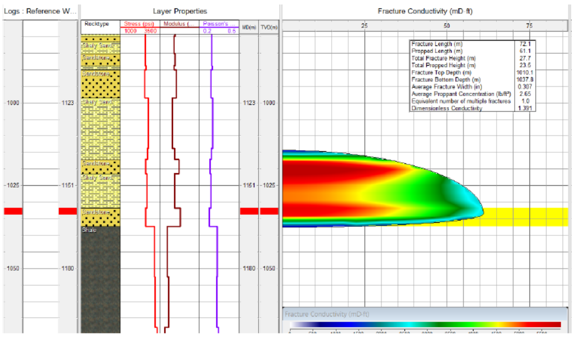

Figure 12 Fracture Geometry Design for B-062

Total proppant that would be pumped was 65 klbs 20/40 proppant preceded by 100 mesh sand slug. From fracture geometry design in Figure 12 showed that dimensionless fracture conductivity (FCD) was more than 1.2, fracture width was more than 0.2 inch, and average proppant concentration was more than 2 lbs/ft^2. These three parameters showed that this design was quite good and ready to be executed.

Result and Discussion

Main frac was then executed with pump chart and event log shown in Figure 13 and 14.

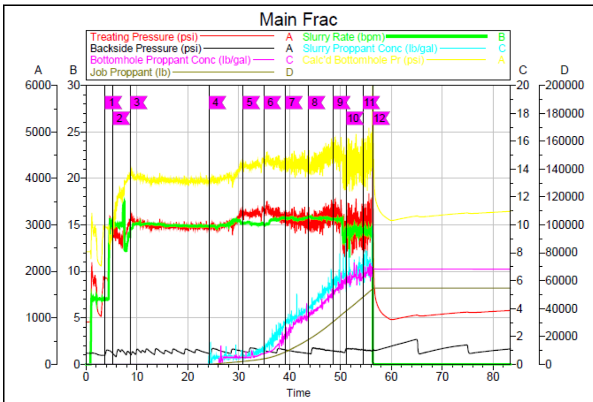

Figure 13 Main Frac Pump Chart

Local Event Log

	Intersection		TP	SR	BP	SPC	BPC	CBP
1	Crosslink Test	3.73	1871	6.993	199.6	0.000	0.000	2967
2	PAD	5.29	3045	15.02	229.9	0.000	0.000	3110
3	Rate adjustment	8.69	3096	14.56	227.4	0.000	0.000	4075
4	0.5 ppg Sand slug	24.17	2937	14.86	233.7	0.309	0.000	3923
5	0.5 - 1 ppg Proppant	30.82	3296	15.16	280.9	0.610	0.486	4327
6	1 - 3 ppg Proppant	34.96	3361	15.01	297.4	1.097	0.769	4421
7	3 - 4 ppg Proppant	39.20	3146	15.70	306.5	2.946	1.769	4302
8	4 - 6 ppg proppant	43.65	3285	15.84	234.6	4.047	3.455	4509
9	6-7 ppg Proppant	48.61	3353	15.65	291.7	5.802	5.268	4678
10	Rate Decreased	51.19	3133	14.21	330.4	6.134	5.926	4542
11	7 ppg Proppant	54.39	3236	14.32	314.2	6.907	6.301	4643
12	Screen Out	56.34	4976	5.243	307.5	7.864	6.897	6781

Figure 14 Main Frac Event Log

Figure 13 and 14 show that erratic treating pressure started from 3-4 ppg slurry stage that forced a decrease in pumping rate in 6-7 slurry stage, and the pumping ultimately ended because of early screen out at 7 ppg slurry stage on minute 56th. The erratic treating pressure was suspected either due to pump problem or because outside material was accidentally pumped into the fracturing system. Investigation was carried out in order to know the root cause of early screen out as well as erratic treating pressure behavior that preceded the screen out. Figure 15 shows summary of the main treatment.

Main Treatment

Parameter	Value	
Average Rate	15	bpm
Maximum Tubing Pressure	4877	psi
Maximum Annulus Pressure	355	psi
Type of Fluid	**Hybor H3.5411**	
Type of Proppant	**Bauxlite 20/40**	
Fluid Pumped (Clean)	749	bbl
Slurry Pumped	807.00	bbl
Proppant Summary		
Design	65000	lbs
Sand Slug (100 Mesh) pumped	2200	lbs
Proppant pumped	52451	lbs
Proppant in wellbore	7750	lbs
Proppant in formation	44701	lbs

Figure 15 Main Frac Treatment Summary

Figure 15 show that 44,701 lbs proppant was successfully pumped into formation (69% of 65,000 lbs design). After performing investigation, improper suction frac valve condition was found. The root cause for this was solid material that was accidentally pumped during the frac job and stuck inside frac valve (Figure 16). All of the equipment was checked prior to the job and in a good condition. Due to alien material that was found in the investigation, precautions were planned to prevent this to happen in the future by installing screens / filters on the fresh water tank and on suction blender.

Figure 16 Investigation Result Showed Improper Suction Frac Valve Condition due to Unwanted Pumped Solid Material

This early screen out really affected the fracturing result. Well B-062 can only produce half of total fluid pumped during fracturing sequence and then was back to low influx. During unloading, the well's fluid sample indicated fines migration occurred because there was 0.35% basic sediment number (Figure 17).

Figure 17 Fines Migration Occurred After Frac Job

Lesson learned from this first hydraulic fracturing in B Structure Telisa Formation was as follow:

- There was indication of non-ideal reservoir behavior in the presence of fissures.
- High NWB friction (around 1400 psi total NWB friction).
- Fines migration occurred after the job, which means next job clay stabilizer material needs to be evaluated.
- There was so many room of improvement in the operational aspects to make next job better.
    - There was doubt on reliability of frac pumps. Prior to the job, inspection was performed to all the equipment, however for the pumps, hydraulic horse power (HHP) test was not performed. Pump condition was checked by the report of last preventive maintenance. HHP should be performed for the future job.
    - Screens / filters were needed in some locations to prevent outside material to intrude fracturing system.
    - Evaluation on the number of personnels on site for performing fracturing job need to be evaluated to ensure smooth operation for the next job.

Figure 18 shows production performance of Well B-062 after fracturing job. Production under orange shade the well's performance after fracturing job. It can be seen that the well was still in unloading pumped fluid/gel phase. Total fluid recovered was only 564 bbls from total 1408 bbls fluid (980 bbls frac gel) pumped during the job. The well could not be produced anymore due to fines migration combined with the failure in meeting the fracturing design.

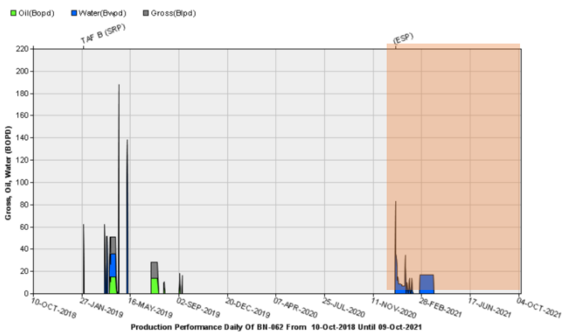

Figure 18 Production performance of Well B-062 after fracturing job

For the next job several mitigations was taken to attempt for a better job execution:

- In order to try to reduce NWB friction, aside from using hundred mesh sand slug during the job, perforation shape charge selection would be taken with more attention. The selection would be more on the hole diameter rather than penetration. The size of 0.4" minimum hole diameter was required, and it can fulfilled because 0.43" diameter was available in B Structure.
- Performing Hydraulic Horse Power (HHP) test for all the frac pump would increase the belief on the reliability of the pump.
- Instead of using 4% KCl brine as clay stabilizer, 7% KCl brine was used to attempt preventing fines migration. The increase of in KCl concentration was decided after the occurrence of fines migration after fracturing job. Laboratory test was needed to confirm the effectiveness of increasing this clay stabilizer.
- Screens / filters were installed when receiving fresh water from vacuum truck and on suction blender to prevent solid material from outside entering fracturing system.
- Additional frac crew would be available for the next job.

With all the lesson learned above, a better job on the operational aspect was expected. This job showed that no matter how good a fracturing design is, proper materials, equipment, personnels, and preparation needs to be paid attention too. If both design and operational aspects of hydraulic fracturing job have already been taken care meticulously, then the result will follow.

Conclusions

Development of Telisa Formation in B Structure is still not conclusive. Further evaluation on subsurface and completion aspect need to be paid more attention. In the completion part for hydraulic fracturing, operational aspects need to be paid attention in the same amount if not more than the design. No matter how good the design is, if operational is a disaster, bad results will follow. However, when unwanted outcome occurred, lesson learned from that experience need to be paid attention to for better jobs in the future.

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