EVALUATING OF FRACTURING RESULTS USING GELLED OIL IN OFFSHORE NORTHWEST PERU

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ABSTRACT

This paper summarizes the practical experiences and results obtained in offshore operations when a gelled crude oil fluid has been used to perform hydraulic fracturing in low permeability formations sensitive or non-compatible with water base fluids. The first studies to see the feasibility to use crude oil as fracturing fluid in offshore operations were made in 1983 and abandoned due to operational problems, but in 1995 the project was re-opened to find an economical fracturing fluid system to replace the gelled diesel that had been used for many years. In particular this paper discusses the 1) reservoir characteristics 2) core analysis 3) fracturing fluid 4) perforations diameter and phasing 5) fracturing design gelled oil 6) operational job description and 7) well response to the treatments.

INTRODUCTION

As part of its completion most of the wells drilled in offshore Northwest Peru are stimulated using the hydraulic fracturing to improve flow capacity(0.002 - 0.3 md). Another problem to resolve was the high volume of the fracturing fluid needed in our operations, making the gelled Diesel system non-economical due to its price. This new system has to be more readily available, economical, and compatible with the productive formations to be treated. After several laboratory tests a gelled crude oil fluid system was chosen as the new fracturing system. In this study are presented the history cases, where new drilled wells and workover jobs have carried out using gelled crude having as main objective the upper Mogollon formation in Lobitos offshore area, and how the operation facilities were prepared to handle this process according to the safety and environmental regulations.

RESERVOIR CHARACTERISTICS

Despite, to its low matrix permeability, the existence of natural fractures in Mogollon reservoir can explain the well productivity after fraccing. In this type of reservoir the target will be known the orientation and distribution of the natural fractures and intercepted most part of them with the induced fracture and also created secundary fractures to the system. Another way to improve Mogollon formation productivity is drilling a well that run perpendicular to the direction of the natural fractures trend to intercept them, but in this case the hydraulic fracturing is the method that is actually applied in this field.

The Mogollon reservoir in Lobitos offshore area has been divided in four (4) blocks due to the faults system presented, given 10 reservoirs, but their common characteristics according to the geology deposition time are presented in Table 1:

Reservoir Characteristics

TABLE 1

Datum ,ft-ss 5000' – 5300'	Permeability from Cores 0.002 – 0.03 md
Average Thickness, vertical ft. 300 – 400	Original Reservoir Pressure 3100 psi
Average Porosity (logs) 8.5% - 9.5%	Initial Oil FVF 1.31, bbl/STB
Avg. Water Saturation (logs) 38.9% - 40.1%	Reservoir Temperature 115 °F – 120 °F
Average Grain Density 2.676 gr/cc	

CORE ANALYSIS.

Solubility test analysis in 15% HCl

TABLE 2

HCl Solubility	24%

Data from qualitative X-ray diffraction in (%) from sample taken in Mogollon formation.

X-ray Diffraction (%)
TABLE 3

QUARTZ	41
FELDSPAR	9
CALCITE	5
PYRITE	1
KAOLINITE	3
CHLORITE	7
ILLITE/MICA	12
MIXED LAYER	21
GYPSUM	1

The analysis results showed that reservoir rock is a sandstone with 21% of mixed layer clays. It is well-known that this type of material swells in contact with aqueous fluids.

THE FRACTURING FLUID AND BREAKER SELECTION.

Having the formation characteristics and the fluid available selected, tests were made with the lease crude oil from offshore production platforms and onshore stock oil tanks. After the test were completed, and for operation facility, the crude oil (Table 4) was taken from offshore production platforms to the storage barge.

Crude Oil Properties
TABLE 4

Apparent viscosity	10 cp @ 100 RPM
N'	0.83
K'	5E-04 lb sec ft^{-2}
BSW	0.2%
API	36.7 @ 60° F
Flash Point	15° F

To have an initial rheological data, some test were carried out with the gelled oil using the Fann Model 50 viscosimeter.

Fann Model 50 Rheological Data
TABLE 5

Time (min)	Time @ Temp (min)	Temp (ºF)	N'	K'	App Visc. 170/sec
87	62	128	0.11	0.20	95

Knowing that the crude oil could be gelled, several test were done after two hours of gelling up the lease oil using a model 35 Fann V-G meter, the rheology of the samples at 75º F were recorded giving the following values:

Gelled Crude Oil Properties
TABLE 6

Apparent viscosity	45 cp @ 100 RPM
N'	0.69
K'	5E-02 lb sec ft^{-2}

Using different concentrations of the chemical products it was determined that the optimum gel viscosity to perform the job was reached two hours after that it had been mixed. For the following hours the gel viscosity was increased slowly.

For field purposes Marsh flow tests were made mixing 500 ml of crude oil. After 60 min it was transferred to the Marsh Funnel to take the time to drain 250 ml from the Marsh Funnel. This data was obtained at 80º F and used to know the quality of gel in the frac tanks before the treatment.

Marsh Flow Testing
TABLE 7

Time After Mixing	Time to drain 250 ml.
60(min)	180 (sec) or more
Crude Oil	9 (sec)

The selection of the amount of breaker to be added was choosen in order to reduce the gel viscosity to values less than 50 seconds Marsh Funnel measured two hours after it has been added on fly to the gelled oil. This test allows to know if we have enough time to pump and displace the sand slurry into the formation to complete the job. After the job the well was shut-in for six hours to allow gel break and the fracture close, then the well was opened to return it to production.

PERFORATIONS DIAMETER AND PHASING.

All wells are completed with 5 ½", 17 ppf, N-80 casing, being most of them deviated wells (30º – 50º). According to this the perforations were made using 4" OD hollow steel carrier guns with 3 spf , 120º phasing, having an theorical entry hole of 0.43 in. It is demostrated that for deviated wells with less than 50º the hole efficiency is 2/3 (67%), this means that 2 out of 3 perforations will have communication with the created fracture. The calculations of the pressure losses by perforations were minimum due to the high number of perforations in the interval to be treated.

FRACTURING DESIGN.

WELL A. LOBITOS AREA

In July 1996 the well "A" was fracced in two stages using the new fluid system according to the fracturing schedule showed in the table 8, it has been drilled with 52 acres spacing, and the propped fracture length designed to 365 ft.The fracturing design was made using a 3D fracturing model for well A, where the formation layer properties (in-situ stresses) and permeability, were estimated according to the logs and using values taken from the literature. They were adjusted matching the pressure in real time and the analysis of the pressure decline of the minifrac performed before the main treatment. Starting each stage, before fracturing the pay zone a ballout with hydrochloric acid was performed to open the perforations.

Fracture Design
Table 8

FLUID	STAGE	VOLUME (GAL)	PROPPANT CONC.	MESH
	I - II	I - II	PPG	
GELLED OIL	PAD	20,000 – 10,000		
GELLED OIL	CARRYING	2,000 - 2,000	2	20/40
GELLED OIL	CARRYING	10,000 – 4,000	3	20/40
GELLED OIL	CARRYING	9,700 - 6,000	4	20/40
GELLED OIL	CARRYING	12,200 – 5,000	5	20/40
CRUDE OIL	DISPLACEMENT	4900 - 4600		

WELL "B" LOBITOS AREA

The second case presented is the job done in the well "B" formation Mogollon that belongs to Lobitos area. This well was fracced in three stages from 7012' MD to 6152' MD using gelled oil. As the well "A" the fracturing design was made using a 3D fracturing model. It has been drilled with 52 acres spacing, the propped fracture length was designed for 380 ft. The fracturing schedule is shown in the table 9 below. After perforate the first stage the well head pressure was 200 psi (5560' VD), the stimulation program was carried-out according to table 9.

WELL B. LOBITOS AREA

Fracture Design
Table 9

FLUID	STAGE III	VOLUME (GAL) Prog. - Job	PROPPANT CONC. (PPG)	MESH
GELLED Oil	PAD	14,000 – 18,000		
GELLED Oil	CARRYING	2,000 – 0	1	20/40
GELLED Oil	CARRYING	4,000 – 2,000	2	20/40
GELLED Oil	CARRYING	10,000 – 9,000	3	20/40
GELLED Oil	CARRYING	5,000 – 11,000	4	20/40
GELLED Oil	CARRYING	5,000 – 1,000	5	20/40
Crude Oil	Displacement	5,900		

OPERATIONAL JOB DESCRIPTION.

In order to handle this oil base frac fluid in a bigger amounts than gelled diesel and for safety conditions, a barge was fitted out as frac fluid supply, with capacity to store below deck 4000 barrels of crude oil to be pumped to three frac tanks of 500 barrels each one installed onto the barge deck. The crude oil stored in the barge was circulated thru the special circuit designed to eliminate the possible residual gas in solution. After 3 or 4 days the fluid had the condition to be used in the fracturing jobs. This fluid volume available made it possible to perform fracturing jobs of four or five stages per day without moving the barge and frac vessel from the location.

The volume necessary for each stage was batch mixed in the frac tanks installed onto the barge deck using an pre-gelliing blender, then the fluid was tested to determinate its viscosity before being pumped to the well, as part of the logistic the pre-gelling blender also was used as booster, to pump the gelled crude oil from the barge to the sand proportioner blender installed in the fracturing marine vessel, where the proppant and other additives were added on fly. During the job the barge with the frac fluid was located between the platform and the fracturing ship, and the ship along side of the barge.

After the operation and before the break down all high pressure pumping lines that had been in contact with crude oil during the job, were cleaned, pumping water through system. The water mixed with crude oil has to be stored in a special tank prepared for this purpose, to separate the fluids later.

RESPONSE TO THE TREATMENTS.

Well "A"

The well "A" was fracced on July 1996 in two stages,(Table 10) 2170 bbl of gelled crude oil with 199,000 pounds of 20/40 sand were pumped. According to the design the propped length was 350 ft with an areal sand concentration of 1 Lb/ft2. After frac the well was opened and its initial production was 850 BOPD casing flow. After one year the frac sand was cleaned out and the well equipped with continous gas lift. Until February 1999, this well had accumulated 360,000 BO. The total investments including drilling and completion for well "A" was $ 670,000. The results from an economic evaluation, using the well production obtained during the first 2.5 years are showed in the Table 11:

Fracturing Job
Table 10

Stage	**I**	**II**
Interval	5374'-5094'	4978' – 4713'
Casing	5 ½" 17 ppf, N-80	5 ½" 17 ppf, N-80
Well TD	5596'	5596'
Crude Oil Used (bbl)	1410	760
Formation - Shots	Mogollon - 318	Mogollon - 138
VNS	157'	82'
Break Down Pressure	3200* psi	4200* psi
Maximun Pressure	3600 psi	3600 psi
Average Pressure	3200 psi	3000 psi
ISIP	2200 psi	2700 psi
Rate	26 BPM	26 BPM
Sand 20/40	1340 Sx	650 sx
Sx/Vns	8.5	8
Fracture Gradient	0.80 psi/ft	0.95 psi/ft

* Break down pressure data taken from the Acid Ballout.

Economic Evaluation Well "A"
TABLE 11

Oil Reserves (MBO)	430
Total Investment ($M)	670
Rate of Return (%)	>100
Pay-Out, (Years)	0.42
Operation Cost ($M/year)	100
Crude Oil ($/bbl)	16
P/I Ration (discounted), $/$	2.9

Well "B"

This well "B" was drilled to 7,300 ft MD having as main objective Mogollon formation with 280' of vertical net sand that was opened and fracced on June 1996 in three stages, (Table 12). In this job 3,000 bbl of gelled crude oil with 185,000 pounds of 20/40 sand were pumped. According to the design the propped length was 300 ft with an areal sand concentration of 0.74 Lb/ft2. After frac the well was opened and its initial production was 236 BOPD casing flow, then the frac sand was cleaned out and the well equipped with gas lift installation. Until February 1999, this well had an accumulated production of 116,000 BO. The expenses for stimulation the well "B" (cased log, perforating and frac) were $ 130,000 and for all project including the drilling job were $1,300,000 the results from an economic evaluation, using the well production obtained during the first 2.5 years showed that the project is still paying, but the stimulation job had been paid 3.6 months after the job.

Fracturing Job
Table 12

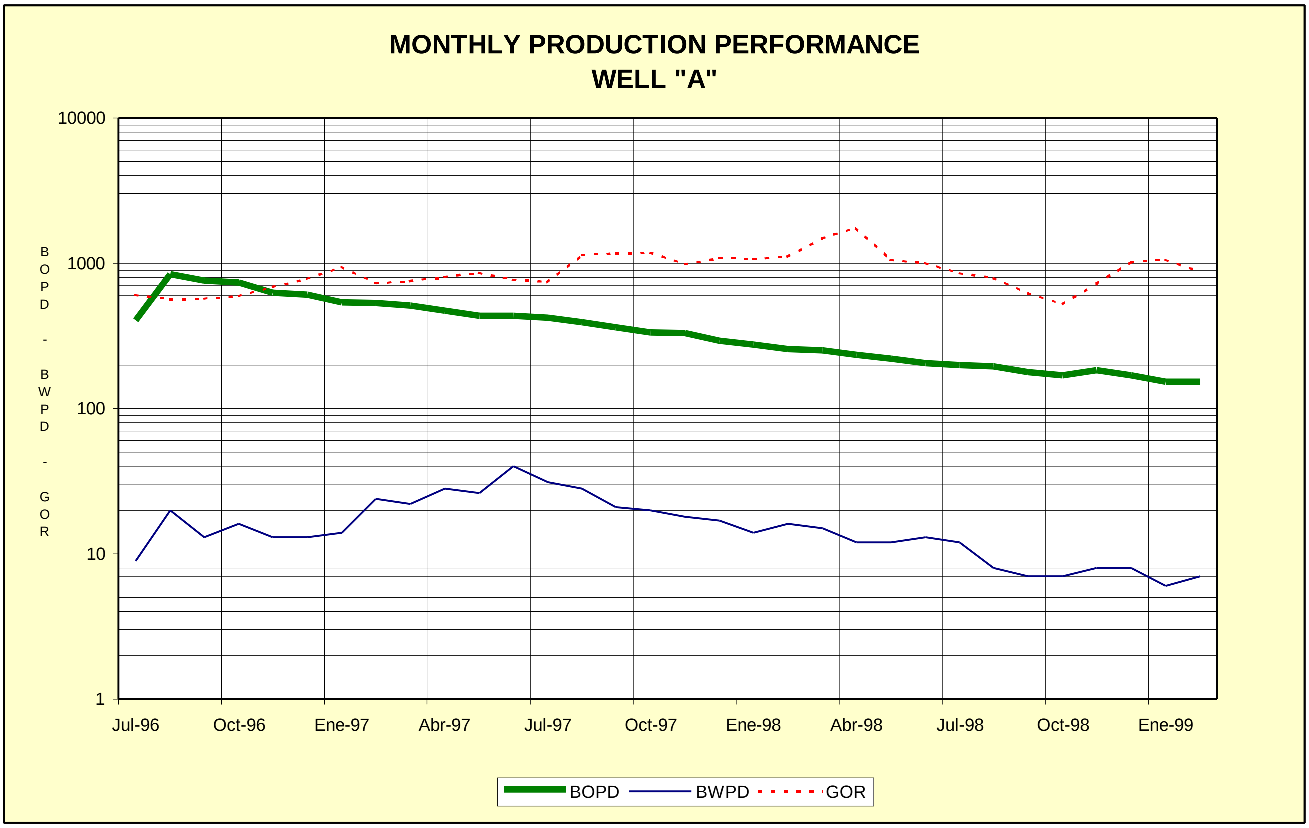
Stage	I
Interval	7012'-6834'
Casing	5 ½" 17 ppf, N-80
Well TD	7300'
Crude Oil Used (bbl)	850
Formation - Shots	Mogollon - 120
VNS	63'
Break Down Pressure	3200 psi
Maximun Pressure	3700 psi
Average Pressure	3400 psi
ISIP	2800 psi
Rate	28 BPM
Sand 20/40	450 Sx
Sx/VNS	7.1
Fracture Gradient	0.84 psi/ft

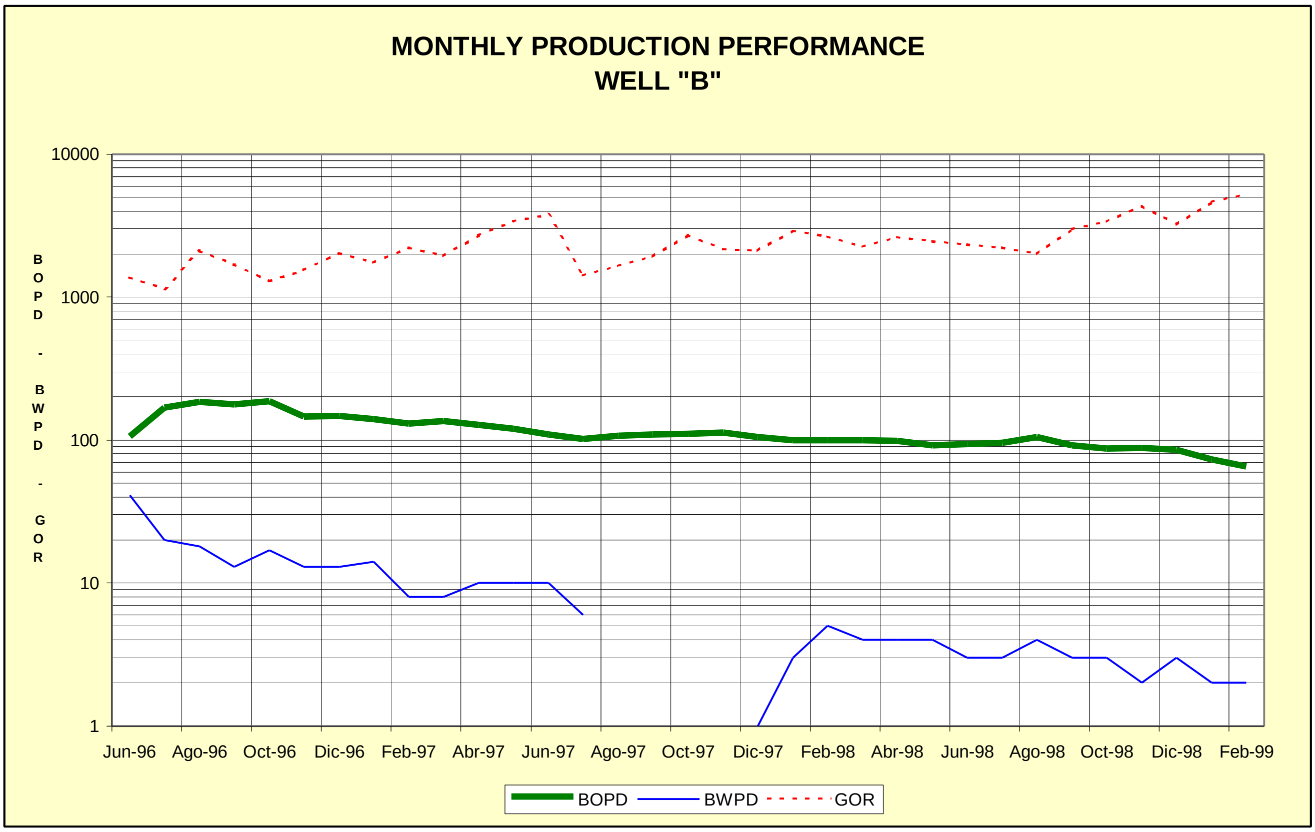
An economic evaluation taking the production for the first 2.5 years only for the stimulation job.

Economic Evaluation Well "B"
TABLE 13

Oil Reserves (MBO)	120
Total Investment ($M)	130
Rate of Return (%)	>100
Pay-Out, (Years)	0.3
Operation Cost ($M/year)	100
Crude Oil ($/bbl)	16
P/I Ration (discounted), $/$	4.3

PRODUCTION CURVES





CONCLUSIONS.

It was demonstrated that the gelled oil fluid can be used as fracturing fluid in Offshore operations when reservoir, well geometry, operation facilities, environmental control and safety are taken in account. New parameters in the frac design were introduced to have a cheaper fracturing fluid than gelled diesel. This allowed pumping more sand into the formation getting better areal sand concentration into the fracture. In the economic aspect the savings for the two wells presented in this paper only due to the fracturing fluid change were $167,000 otherwise, will be necessary to buy diesel for $ 243,000 (out of pocket). Analyzing the production results, it was found that the investments for the fracturing jobs were paid in 3.5 months.

In our operations from september 1995 to December 1998, 108 jobs were performed using this new fracturing system between new wells and workovers, and 116 Mbbl of gelled crude oil with 5,250 MetricTons of proppant were pumped.

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