TITLE: ECONOMIC RECOVERY OF OIL TRAPPED AT FAN MARGINS USING HIGH ANGLE WELLS AND MULTIPLE HYDRAULIC FRACTURES

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Objective

This project attempts to demonstrate the effectiveness of exploiting thin-layered, low-energy deposits at the distal margin of a prograding turbidite complex through the use of hydraulically-fractured horizontal or high-angle wells. The combination of a horizontal or high-angle well and hydraulic fracturing will allow greater pay exposure than can be achieved with conventional vertical wells while maintaining vertical communication between thin interbedded layers and the wellbore.

A high-angle well will be drilled in the fan-margin portion of a slope-basin clastic reservoir and will be completed with multiple hydraulic-fracture treatments. Geologic modeling, reservoir characterization, and fine-grid reservoir simulation will be used to

select the well location and orientation. Design parameters for the hydraulic-fracture treatments will be determined, in part, by fracturing an existing test well. Fracture azimuth will be predicted by passive seismic monitoring of a fracture-stimulation treatment in the test well using logging tools in an offset well.

Summary of Technical Progress

The long radius, near-horizontal well has been drilled and completion operations are in progress. Upon initial review of log data, two hydraulic fracture treatments were planned. However, the probability of the lower frac growing into thick sands previously swept by waterflood has called for additional information to be obtained prior to proceeding with hydraulic fracture treatments. Should permeabilities prove to be as favorable as some data indicate, produced water volumes could be excessively high. Prior to pumping the first frac, the well will be perforated and produced from lower pay intervals. These perfs will not impact future frac work. Rate data and pressure transient analysis will dictate the need for the lower frac.

Completion Design

Log Analysis

Preliminary log-derived rock properties for each sand interval are shown in Tables 1 and 2. To be consistent with other wells in the field, porosities were calculated using sonic data. The porosity values were then reduced for shaliness using gamma ray and neutron porosity data.

The average net sand rock properties for well 91X-3 are shown in Table 1 and are based upon shale volumes (V_{sh}) < 30%, and effective porosities (ϕ_{eff}) > 8%. All net sand with water saturations less than 40% was considered net pay. Average net pay rock properties are shown in Table 2.

Net sand and net pay cutoffs were derived from geologic and reservoir modeling during Budget Period One (BP1). Permeabilities were calculated based upon a log porosity-core permeability relationship established during BP1 and were found to be lower than expected.

Permeability values from the magnetic resonance log (CMR) tended to be in line with those values used in the BP1 geologic and reservoir modeling. The impact of the CMR permeabilities vs. the porosity log-derived permeabilities will be addressed in the following section.

Hydraulic Fracture Treatments

Log analysis showed that some intervals had been swept by the waterflood (as expected). Consequently, no more than two hydraulic fracture treatments were planned.

Fracture treatment designs were based upon the expectation that the fracs will tend to orient in the direction of the wellbore. Relatively short fracture half-lengths of 150 to 200

ft are planned because of the possibility that the fracs will instead orient orthogonal to the wellbore. This should minimize undesirable changes in areal sweep.

The fracture treatment intervals were selected to minimize frac'ing into the high water saturation D and E sands shown in Tables 1 and 2. These sands would be expected to produce at 100% water cut. Despite the location of the lower frac interval, the frac can extend into Sand D with minimal downward growth (Fig. 1).

An analytical technique was used to predict the impact of frac'ing into these high water saturation sands. Joshi's constant boundary solution for a horizontal well^{1,2} was used in combination with Darcy's Law to predict the production rates of each major sand interval. The Joshi equation was used to predict the performance of a horizontal well without fracs.

The fracs were considered to be stimulated vertical wells tied into the horizontal well and were represented by Darcy's Law including a productivity improvement ratio (J/J_o) of 1.78. The J/J_o ratio was based upon a fracture treatment in offset well 57X-34 ($x_f = 200$ ft.). The lower frac was assumed to penetrate the productive B and C sands, as well as the 100% water cut D sand. The upper frac was assumed to also penetrate the B and C sands, plus the productive A sand. Figure 1 depicts the locations of the two fracs.

Since it is planned to produce the well with an electric submersible pump (ESP), the expected producing bottomhole pressure of 1600 psi will be lower than the bubble point pressure of 2200 psi. Therefore, Vogel inflow performance relationships (IPR) were established by sand interval.

Figures 2 and 3 show IPR curves for each sand interval based on the rock properties shown in Tables 1 and 2. As previously mentioned, the permeabilities shown in these tables were calculated from a log porosity-core permeability relationship established during BP1 and were lower than expected (0.5-1.5 md., 1.2 md. avg.). Figures 2 and 3 indicate that the well could produce at a rate of 445 BOPD and 1245 BLPD. Although Sand D is predicted to produce 685 BWPD with no oil, the water volume is not excessively high.

The CMR log indicated that permeabilities were more in line with those used in the geologic and reservoir modeling during BP1 (1.0-4.8 md., 4.3 md. avg.). If these permeabilities are in fact representative, the IPR curves shown in Figs. 4 and 5 predict that the well would be capable of 1165 BOPD and 2950 BLPD (1480 BWPD from Sand D). This water rate is considered excessive. Although an ESP is capable of producing 3000 BPD from 10,000 ft., operating costs would be needlessly high.

Adjustment to Plans

The completion design has been changed to collect additional data prior to proceeding with the hydraulic fracture treatments. Three net pay intervals totaling 160 ft. will be perforated below the lower planned frac interval (Fig. 1) and produced. These "pre-frac test perms" are not expected to hamper future frac work. Production tests and pressure transient analysis will determine productivity and permeability. The proper decision regarding the need for the lower frac can then be made.

Completion Operations

Progress

A completion rig was moved in and the well was being prepared to add the pre-frac test perfs. Drilling mud was cleaned out of the 9-5/8" intermediate casing and 7" production liner.

References

1. Joshi, S.D., *Augmentation of Well Productivity Using Slant and Horizontal Wells*, Journal of Petroleum Technology, pp. 729-739, June 1988.
2. Joshi, S.D., *A Review of Horizontal Well and Drainhole Technology*, paper SPE 16868 presented at the 62th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, Texas, September 27-30, 1987.

Table 1

* Net Sand Properties

Sand	Gross Sand, ft	Net Sand, ft	Net-to-Gross, %	Porosity, %	Wat. Sat., %	Perm., md	Water Cut, %
A	110	86	78.2	11.3	44.9	0.5	67
B	367	300	81.7	11.6	37.7	0.9	38
C	303	241	79.5	11.3	40.1	1.3	53
D	389	364	93.6	11.7	65.4	1.5	100
** E	105	95	90.5	12.3	75.9	1.3	100
Tot. / Avg.	1274	1085	85.2	11.6	51.4	1.2	92

* Footages represent measured depths.

** Sand E not fully penetrated.

Table 2

* Net Pay Properties

Sand	Gross Sand, ft	Net Sand, ft	Net Pay, ft	Porosity, %	Wat. Sat., %	Perm., md	Water Cut, %
A	110	86	24	12.8	36.7	1.3	25
B	367	300	188	12.3	33.1	1.2	15
C	303	241	125	12.6	33.5	2.3	15
D	389	364	38	12.8	34.6	1.8	15
** E	105	95	0	-	-	-	-
Tot. / Avg.	1274	1085	374	12.5	33.6	1.7	15

* Footages represent measured depths.

** Sand E not fully penetrated.

Figure 1. Actual well path relative to major Yowlumne sand intervals. Also shown are the planned pre-frac test perfs and the planned frac intervals.

Figure 2. Predicted total liquid inflow performance by interval based on two fracs and log-derived permeabilities.

Figure 3. Predicted oil inflow performance by interval based on two fracs and log-derived permeabilities.

Figure 4. Predicted total liquid inflow performance by interval based on two fracs and model permeabilities.

Figure 5. Predicted oil inflow performance by interval based on two fracs and model permeabilities.