Title Page

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

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Abstract

The Yowlumne field is a giant field in the southern San Joaquin basin, Kern County, California. It is a deep (13,000 ft) waterflood operation that produces from the Miocene-aged Stevens Sand. The reservoir is interpreted as a layered, fan-shaped, prograding turbidite complex containing several lobe-shaped sand bodies that represent distinct flow units.

A high ultimate recovery factor is expected, yet significant quantities of undrained oil remain at the fan margins. The fan margins are not economic to develop using vertical wells because of thinning pay, deteriorating rock quality, and depth.

This project attempts to demonstrate the effectiveness of exploiting the northeast distal fan margin through the use of a high-angle well completed with multiple hydraulic-fracture treatments. A high-angle well offers greater pay exposure than can be achieved with a vertical well. Hydraulic-fracture treatments will establish vertical communication between thin interbedded layers and the wellbore. The equivalent production rate and reserves of three vertical wells are anticipated at a cost of approximately two vertical wells.

The near-horizontal well penetrated the Yowlumne sand; a Stevens sand equivalent, in the distal fan margin in the northeast area of the field. The well was drilled in a predominately westerly direction towards the interior of the field, in the direction of improving rock quality.

Drilling and completion operations proved to be very challenging, leading to a number of adjustments to original plans. Hole conditions resulted in obtaining less core material than desired and setting intermediate casing 1200 ft too high. The 7 in. production liner stuck 1000 ft off bottom, requiring a 5 in. liner to be run the rest of the way. The cement job on the 5 in. liner resulted in a very poor bond, which precluded one of three hydraulic fracture treatments originally planned for the well.

Openhole logs confirmed most expectations going into the project about basic rock properties: the formation was shaly with low porosities, and water saturations were in line with expectations, including the presence of some intervals swept out by the waterflood. High water saturations at the bottom of the well eliminated one of the originally planned hydraulic fracture treatments.

Although porosities proved to be low, they were more uniform across the formation than expected. Permeabilities of the various intervals continue to be evaluated, but appear to be better than expected from the porosity log model derived in Budget Period One.

The well was perforated in all pay sections behind the 5 in. liner. Production rates and phases agree nicely with log calculations, fractional flow calculations, and an analytical technique used to predict the rate performance of the well.

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Introduction

The Yowlumne field is a giant field in the southern San Joaquin basin, Kern County, California. It is a deep (13,000 ft) waterflood operation that produces from the Miocene-aged Stevens Sand. The reservoir is interpreted as a layered, fan-shaped, prograding turbidite complex containing several lobe-shaped sand bodies that represent distinct flow units.

A high ultimate recovery factor is expected, yet significant quantities of undrained oil remain at the fan margins. The fan margins are not economic to develop using vertical wells because of thinning pay, deteriorating rock quality, and depth.

This project attempts to demonstrate the effectiveness of exploiting the northeast distal fan margin through the use of a high-angle well completed with multiple hydraulic-fracture treatments. A high-angle well offers greater pay exposure than can be achieved with a vertical well. Hydraulic-fracture treatments will establish vertical communication between thin interbedded layers and the wellbore. The equivalent production rate and reserves of three vertical wells are anticipated at a cost of approximately two vertical wells.

This report covers the progress of the project over a one-year period of time ending September 27, 1997. It primarily focuses on drilling and completion activities of the project well, and production history to date.

Results and Discussion

Project Location

The project well, Unit B well no. 91X-3, is located in the Yowlumne Field in the southern San Joaquin Basin, Kern Co., California, 25 miles south of Bakersfield (Fig. 1).

The objective of the new well was the Yowlumne sand; an Upper Miocene Stevens sand equivalent, in the distal fan margin in the northeast area of the field (Fig 2). Well no. 91X-3 was drilled as a long-radius, near horizontal well in a predominately westerly direction towards the interior of the field, in the direction of improving rock quality.

Drilling Operations

Well no. 91X-3 was spud on December 4, 1996; 60 ft east of well no. 81X-3, a dry hole drilled in 1980 (Figs. 2 and 3). Re-entry of well 81X-3 was considered but dismissed because of pipe-size limitations imposed by the existing 10-3/4 in. surface casing. However, the pad for well no. 81X-3 was reused for the new well, reducing costs and making use of fallow land.

Drilling Rig

A top-drive-drilling rig was selected to drill the well. This permitted rotation and circulation while pulling pipe out of the hole, thereby minimizing the risk of sticking. In addition, greater rates of penetration were expected because of increased rotary torque at the drill bit and the ability to drill with longer stands of pipe.

Vertical Hole

A 17-1/2 in. hole was drilled to 2522 ft where surface casing was cemented in place. Drilling of the vertical hole continued to a depth of 11,471 ft using 12-1/4 in. tricone insert and polycrystalline diamond compact (PDC) bits. Despite mud weights of 12.6 pounds per gallon (PPG), drilling operations were severely hampered by sloughing shales, requiring intermediate casing to be set 1200 ft higher than desired.

Directional Hole

Kick-off point was at 11,471 ft. A steerable drilling assembly consisting of bent subs and mud motors was used to build angle at approximately 7° per 100 ft while drilling an 8-1/2 in. hole. The top of the Yowlumne sand was encountered at 12,959 ft, or 12,329 ft true vertical depth (TVD). The well penetrated 1341 ft of the target formation at an average angle of 84°, reaching a total depth (TD) of 14,300 ft, or 12,515 ft TVD. The bottomhole location is 253 ft north and 2237 ft west of the surface location (2248 ft of closure). Figures 3 and 4 show the well path in map view and in cross section.

Coring Operations

Thirty ft of 4-1/2 in. core was cut and recovered from 12,991 to 13,021 ft. The core was taken near the top of the Yolwumne sand in near-horizontal hole (83°). Coring operations were precarious in the high angle hole because of sloughing formation. Therefore, no additional core was taken, although two more 20-ft cores were planned.

Logging Operations

The vertical hole section was logged with resistivity and porosity tools on wireline prior to setting intermediate casing.

Drillpipe-conveyed logs were run in the 2858 ft open hole section below the 9-5/8 in. intermediate casing. Conventional logging tools were run consisting of litho-density (LDL) and compensated neutron logs (CNL) to obtain porosity data, and a dual induction log (IDPH) to obtain resistivity data.

Three advanced logging tools were also run. A high-resolution magnetic resonance tool (CMR) was run to infer permeability. A dipole shear sonic imaging tool (DSI) was run to obtain mechanical properties to be used for designing hydraulic fracture treatments, such as stress values, Young's Modulus, and Poisson's Ratio. In addition, the travel time data were used to compute sonic porosities. Finally, a full bore formation micro imaging tool (FMI) was run to obtain a "visual image" of the formation face, which could be used to identify natural fractures and/or faults. Unfortunately, the FMI tool failed, and because of hole conditions, the wait time for a backup tool was prohibitive. Thus, an FMI log was not obtained.

Casing

Thirteen and three-eighths in. surface casing was cemented in place at a depth of 2522 ft.

The 12-1/4 in. vertical hole section was cased with 9-5/8 in., 43.5, 47, and 53.5 lbs/ft, P-110 intermediate casing and cemented in place at 11,442 ft. It had been planned to set the intermediate string near the top of the Yowlumne sand in a tangent section of the high-angle hole to maximize pump-setting depth. However, sloughing shales required setting the intermediate casing approximately 1200 ft short of plans. The casing is large enough to produce the well with an electric submersible pump (ESP) hung off a "Y" offset tool. The "Y" offset tool will permit production logging.

A 7 in., 32 lbs/ft., P-110 production liner had been planned to case the target formation. However, the liner became stuck at 13,424 ft and was cemented in place. The remaining open hole section was cased with a 5 in., 23.2 lbs/ft., P-110 liner and cemented in place. As a result, the target formation was cased with 465 ft of 7 in. liner and 876 ft of 5 in. liner.

The intermediate casing and production liners were designed to withstand bottomhole pressures in excess of 16,000 psi during hydraulic-fracture treatments.

Log and Core Analysis

Log Analysis

The Yowlumne sand penetrated by the project well was confirmed as shaly, evidenced by a crossplot of density porosity vs. neutron porosity (Fig. 5). To be consistent with other wells in the field, log-derived porosities were based upon sonic data. Sonic porosities were reduced for shaliness using gamma ray and neutron porosity data in calculating effective porosities.

In general, porosity values were low but more uniform than expected. There were few surprises with calculated water saturations, some intervals appearing to be swept by waterflood as expected.

Average rock properties for each sand interval are shown in Tables 1 and 2. Table 1 gives average properties for net sand based upon the following cutoffs: 1) shale volume (V_{sh}) < 30%, and 2) effective porosity (ϕ_{eff}) > 8%.

All net sand with water saturations less than 40% were considered net pay. Average properties for net pay are shown in Table 2.

Net sand and net pay cutoffs were derived from geologic and reservoir modeling during Budget Period One (BP1). Permeability calculations were based upon a log porosity-core permeability relationship established during BP1.

Permeability values from the magnetic resonance log (CMR) are not shown in the tables. They tended to be high compared to those calculated from porosity logs, and more in line with the geologic and reservoir modeling of BP1. The impact of CMR permeabilities vs. those derived from porosity logs is discussed in the completion operations section.

Producing water cuts were predicted from log analysis and fractional flow calculations from core relative permeability data.

Core Analysis

Routine and special core analysis was performed on samples from the 30-ft core consisting of porosity, saturation, and permeability measurements. Preliminary results have been received from relative permeability, capillary pressure, and mechanical properties tests.

Many of the samples used in the stressed mechanical properties test indicate a general east-west maximum principal stress orientation. This is in agreement with microseismic logging results of the hydraulic fracture treatment on the test well (Yowlumne Unit B 84-32) during BP1. It also agrees with borehole breakout data from Yowlumne Unit B 57X-34, a north offset well to the project well. Therefore, vertical fractures established during hydraulic fracture treatments in the project well are expected to propagate in the

same general direction as the azimuth of the well. This is the preferred frac azimuth because of proximity to offset wells and existing waterflood fronts.

Results of core analyses are being reconciled with log data from the project well and with log-core relationships established during BP1. In addition, extensive thin-section work is in progress.

Completion Operations

Hydraulic Fracture Treatment Design Considerations

Original completion plans were to stimulate the horizontal pay section with three hydraulic fracture treatments spaced 200-300 ft apart (Fig. 6). Each frac would be a “point-source” frac, pumped through “clustered” perforations. Clustered perfs, a four to five interval of high-shot density, would enhance the probability that each frac would create a single vertical fracture plane intersecting the horizontal wellbore. The remaining pay along the wellbore would then be perforated after all fracs had been pumped.

Preliminary design work for the hydraulic fracture treatments was based upon the expectation that the vertical fracs would tend to orient in the direction of the wellbore. However, as a precaution, short fracture half-lengths (x_f) of 150 to 200 ft were designed because of the possibility that the fracs would instead orient orthogonal to the wellbore. Short x_f would lessen the possibility of undesirable changes in areal sweep.

Log analysis indicated that the mature waterflood project had swept some intervals very thoroughly, particularly Sands D and E (Tables 1 and 2). Consequently, the lowermost of the planned hydraulic fracture treatments was eliminated.

There was still concern that the lowest, if not both, of the two remaining fracs would break into Sands D and E with only minimal downward growth. These sands would produce at 100% water cut, possibly at high volume.

An analytical technique was used to assess 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 conjunction with Darcy's Law to determine the production rate of each major sand interval. The Joshi equation was used to predict the performance of a horizontal well without fracs. The fracs were considered as stimulated vertical wells tied into a horizontal well and were represented by Darcy's Law with a productivity improvement ratio (J/J_o) of 1.78. The J/J_o ratio was taken from a fracture treatment in offset well 57X-34 ($x_f = 200$ ft.). The lower of the two fracs was treated as penetrating the oil productive B and C sands, as well as the 100% water productive D sand. The upper frac was also assumed to penetrate the B and C sands, plus the oil productive A sand.

Vogel inflow performance relationship (IPR) curves were derived from this analytical technique for each sand interval based on the rock properties shown in Tables 1 and 2. The permeabilities shown in these tables were calculated from a log porosity-core permeability relationship established during BP1 and were fairly low (0.5-1.5 md., 1.2 md. avg.). Figures 7 and 8 indicate that the well could produce at a rate of 191 BOPD and 477 BWPD.

Although Sand D is predicted to produce 380 BWPD with no oil, the water volume is not excessively high.

Permeabilities from the CMR log appear to be more in line with the geologic and reservoir modeling of BP1 (4.0-5.0 md., 4.8 md. avg.). The IPR curves shown in Figs. 9 and 10, with these higher permeabilities, predict that the well would be capable of 729 BOPD and 1621 BWPD (1271 BWPD from Sand D). Although an electric submersible pump (ESP) would be capable of producing 2400 BPD from 10,000 ft., the additional lifting costs would be excessive.

Modification of Completion Program

Because of the risk of fracturing into excessive water, the completion program was modified to collect additional data prior to pumping any fracs. Three net pay intervals totaling 160 ft would be perforated below the lowermost of the two-frac intervals (Fig. 11). These "pre-frac test perfs" could provide the additional information without hampering future frac work. Production data and pressure transient analysis would be used to determine productivity and permeability of the Yowlumne sand near Sands D and E, the zones of high water saturation. The proper decision regarding the lower of the two remaining fracs could then be made.

Completion Results

A completion rig was moved in to prepare the well for the pre-frac test perfs. After cleaning out mud and loading the hole with water, tubing-conveyed cement bond logs were run in the 5 in. and 7 in. production liners and a short interval of the 9-5/8 in. intermediate casing. The 9-5/8 in. casing and the 7 in. liner were well bonded to the formation. The 5 in. production liner was found to have a very poor cement bond. Without a good bond, there would be no control of a hydraulic fracture treatment. Plans were then altered to forego the lower frac and perforate all pay behind the 5 in. liner. Only the pay behind the 7 in. liner would be hydraulically fractured (Fig. 12).

While tripping in the hole to circulate out heavy load water, the casing was discovered to be losing fluid at an unknown depth. A 5 bbl cement plug consisting of Class G plus additives was spotted at the bottom of the 5 in. liner. This plug successfully shut off the fluid loss.

Prior to perforating pay behind the 5 in. liner, a remedial cement squeeze treatment was designed to establish isolation from high water saturations in Sands D and E. After perforating four squeeze holes at 13,752 ft (12,394 ft TVD), a cement retainer was set at 13,746 ft. The 5 in. liner was then squeezed with 15 bbls of Class G cement plus additives in two stages.

Cement was drilled out to the top of the retainer, and 2% KCl water was spotted across the interval to be perforated. Tubing-conveyed perforating guns were assembled and loaded to perforate all pay behind the 5 in. liner with 4 shots per ft and 90° phasing at the following depths: 13,320-13,362 ft; 13,371-13,394; 13,405-13,482; 13,499-13,520; 13,546-

13,556; 13,568-13,620; and 13,673-13,730 ft. The true vertical depth of this interval ranged from 12,360-12,403 ft.

The guns were run in the hole on 2-7/8 in. tubing. A 6800 ft cushion of 2% KCl water was established to perforate approximately 2000 psi underbalanced. After setting a retrievable packer at 11,895 ft, the guns were fired by applying 1500 psi pressure to the casing.

The well was swabbed for two days, recovering load water plus formation water at low entry rates. The oil cut was approximately 15% at the end of swabbing. The tubing, packer, and perforating guns were pulled out of the hole. All guns had fired, and drilling mud or contaminated, unset cement was observed on the perforating guns. A retrievable packer and hydraulic jet pump bottom hole assembly (BHA) were run in the hole to lift the well. The packer was set at 11,702 ft, placing the top of the BHA at 11,636 ft (11,621 ft TVD). The well was placed on hydraulic lift.

The production rate after several days had stabilized at approximately 40 BWPD and a trace of oil. The expected rate was at least 200 BPD liquid with minimal water. The perforations were believed to be damaged as evidenced by the low production rate and either mud or cement observed on the perforating guns. To remove the damage, the perforations were stimulated with a non-acid reactive fluid consisting of a blend of KCl water, iron chelating agents, mutual solvents, and surfactants. This formulation was preferred over mud acid due to the high clay and feldspar content of the Yowlumne sand. The perforated interval was treated with a volume of one-half barrel per ft of perforations. After pumping a nitrogen preflush, the treatment fluid was nitrified with 500 SCF per bbl to assist flowback and cleanup. The treatment was pumped through 1-1/4 in. coiled tubing below fracture pressure while slowly reciprocating the coiled tubing tail across the perforated interval.

The well was returned to production, initially making approximately 220 BOPD and 20 BWPD (Fig. 13). The low water cut was in line with log analysis and fractional flow calculations (Table 2). A producing bottom hole pressure measurement was obtained and found to be 850 psi, corrected to the perforations. The previously mentioned analytical technique was used to calculate an unfrac'd production rate from the existing perforations (Fig. 14). This technique matched the initial production rate of the well very nicely.

Conclusion

The phase of this project representing the drilling and completion of the high-angle well is nearing an end. Drilling and completion operations proved to be very challenging, leading to a number of adjustments to original plans.

Hole conditions resulted in obtaining less core material than desired and setting intermediate casing 1200 ft too high. The 7 in. production liner stuck 1000 ft off bottom, requiring a 5 in. liner to be run the rest of the way. The cement job on the 5 in. liner resulted in a very poor bond, which precluded one of three hydraulic fracture treatments originally planned for the well.

Openhole logs confirmed most expectations going into the project about basic rock properties: the formation was shaly with low porosities, and water saturations were in line with expectations, including the presence of some intervals swept out by the waterflood. High water saturations at the bottom of the well eliminated one of the originally planned hydraulic fracture treatments.

Although porosities proved to be low, they were more uniform across the formation than expected. Permeabilities of the various intervals continue to be evaluated, but appear to be better than expected from the porosity log model derived in Budget Period One.

The well was perforated in all pay sections behind the 5 in. liner. Production rates and phases agree nicely with log calculations, fractional flow calculations, and an analytical technique used to predict the rate performance of the well.

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.

Technology Transfer

Open File

An “open file” for this project has been established with the California Division of Oil, Gas, and Geothermal Resources (DOGGR) and is updated periodically. The open file is available to the public, and should be useful to operators of slope-basin clastic reservoirs, particularly in California.

Technical Papers, Presentations, Workshops

February 4, 1997: Dr. Mike Clark conducted a field trip to observe drilling operations for the project well. A petroleum geology class (instructor Dr. James Boles) from the University of California, Santa Barbara participated in the field trip.

March 2, 1997: Dr. Clark gave a presentation and hosted a poster session at the Department of Energy Class Program Workshop, Fourth International Reservoir Characterization Technical Conference, Houston, Texas. His paper was published in softbound notes handed out at the workshop (pp.49-63). In addition, this paper will be published by the AAPG in hardbound symposium proceedings.

April 17, 1997: Dr. Mike Clark gave a talk with abstract on the reservoir characterization study to the PTTC Focused Technology Workshop, University of Southern California. The abstract was published in softbound notes handed out at the workshop, page 122. The paper was published by PTTC in softbound workshop proceedings.

May 8, 1997: Dr. Mike Clark gave a talk on the reservoir characterization study to the petroleum geology class of Dr. Jan Gillespie at California State University, Bakersfield, California.

May 15, 1997: Dr. Mike Clark gave a talk with abstract on the reservoir characterization study at the Pacific Section Convention of the American Association of Petroleum Geologists (AAPG) in Bakersfield, California. The abstract was published in the AAPG bulletin, v.81, p.681. A complimentary poster presentation was made the next day.

June 10, 1997: Dr. Mike Clark presented a poster on the reservoir characterization study at the monthly dinner meeting of the San Joaquin Geological Society.

June 17, 1997: Dr. Mike Clark gave a talk with abstract on the reservoir characterization study at the DOE Petroleum Technology Review, Houston Texas.

September 24, 1997: Dr. Mike Clark presented the reservoir characterization aspect of this project at the ARCO Geoscience Conference in Plano, Texas.

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. Net sand based on shale volumes (V_{sh}) < 30%, and effective porosities (ϕ_{eff}) > 8%.

** 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. Net sand based on shale volumes (V_{sh}) < 30%, and effective porosities (ϕ_{eff}) > 8%. Net pay based on net sand with water saturations less than 40%.

** Sand E not fully penetrated.

Figure 1: Map of California showing location of the San Joaquin Basin and the Yowlumne field.

Figure 2: Bottomhole locations of wells in the Yowlumne field and planned well path for well no. 91X-3.

Figure 3: Plan view of 91X-3 well path.

Figure 4: Cross-sectional view of 91X-3 well path.

Figure 5: Crossplot of density porosity vs. neutron porosity indicating a shaly Yowlumne sand.

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Figure 7: Predicted total liquid inflow performance relationship by interval based on two fracs and low permeabilities.

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Figure 11. Actual well path relative to major Yowlumne sand intervals with planned pre-frac test perfs and two planned frac intervals.

Figure 12. Actual well path relative to major Yowlumne sand intervals with actual perfs behind 5 in. liner and planned frac interval.

Figure 2. Well tests for Yowlumne Unit B 91X-3.

Figure 14: Inflow performance relationship for actual perfs behind 5 in. liner.