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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 by fracturing an existing test well. Fracture azimuth will be predicted, in part, by passive seismic monitoring from an offset well during fracture stimulation of the test well.

Summary of Technical Progress

The fine-grid reservoir simulation of the northeast fan-margin region of the Yowlumne field was completed during third quarter 1996. A variety of development alternatives were investigated aimed at optimizing project economics. Model forecasts compared slant well performance to more conventional development options and quantified rate impacts due to changes in well location, orientation, and completion technique. Project economics were then updated with the production forecasts from the simulation model.

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Model Production Forecasts

The fine-grid, partial-field reservoir-simulation model of the northeast fan-margin region was used to test a variety of development alternatives aimed at optimizing project economics. Model forecasts compared slant well performance to more conventional development options and quantified rate impacts of changes in well location, orientation, and completion technique. Model results are reported in terms of incremental rates and reserves in order to eliminate interference effects.

Continued Operations

All model forecasts were compared against a base prediction to determine incremental performance. The base prediction assumed water injection would replace reservoir voidage through year end 1999. Waterflood operations were then limited to re-injection of produced water only. Each producing well was placed on bottomhole pressure control for the entire predictive period and allowed to decline to an abandonment rate of 12 BOPD. The model forecast was extended for the expected field life which ends in 2005.

Results from the continued operations forecast demonstrated the effectiveness of the Yowlumne Unit B waterflood. Ultimate recovery from the model area, accounting for fluid flux, was 38.2 MMBO, or 48.5% OOIP.

North-South Fractured Slant Well

The model was initially used to predict the performance of a slant well drilled along the south-to-north well path described in the project proposal. The well was expected to penetrate the reservoir interval at a 55° angle entering from an updip position (25° dip). This provided 1100 ft of pay exposure within approximately 180 ft of stratigraphic thickness. The well was also assumed to be fractured at three locations spaced 250 ft apart along the well path.

Based on results from the stimulation treatment in well 84-32, fractures were assumed to propagate along a northwest-southeast trend. Results from microseismic monitoring of the 84-32 treatment also indicated that fractures would probably not be confined by internal shales and would tend to be asymmetric with the longer fracture wing extending to the interior of the field.

For modeling purposes, fracture height was defined as equal to fracture length and was set at approximately 175 ft. Roughly 70% of total fracture length was allocated to the interior fracture wing, leaving 30% of total length to extend toward the sand margin.

Within the model, each fracture was represented as a separate deviated wellbore which was defined to traverse the entire fracture plane numerous times. This treatment created an infinite conductivity pathway. Rates from each fracture were constrained based upon analogy to a successful frac in offset well 57X-34 and to predictions from commercial fracture-stimulation software.

Model results indicated the well would initially produce 1252 BOPD if drawn down to a producing bottomhole pressure of 1200 psi. Despite the high initial rate, incremental reserves attributed to the slant well were only 465 MBO.

East-West Fractured Slant Well

Saturation and pressure distributions estimated for the partial-field model of the fan margin differed from results generated by the full-field model. Better representation of reservoir heterogeneity and a change in flow unit correlations resulted in a significant portion of the original bypassed oil target being swept. Fine-grid modeling suggested that an alternate east-to-west well path would be superior to the south-to-north orientation. An area of higher oil saturations appeared to be trapped between two east-west rows of producers immediately adjacent to the original slant well location.

A second slant well location was therefore tested with an approximate 1000 ft east-to-west well path. The well is expected to penetrate the formation approximately along strike at a 75° angle from vertical. The well was assumed to be fractured at three points 250 ft apart. The approach used to represent each fracture plane was identical to the methodology described for the north-south well. This required that the nested grid be re-oriented to accommodate the east-west well path.

Model results indicated the well could initially produce 2180 BOPD and provide 724 MBO of incremental reserves. Improved well performance for the east-west orientation was attributed to higher oil saturations and better reservoir quality. The well also produces an incremental 8% of OOIP from the distal fan margin. The east-to-west slant well orientation was selected for this project.

Vertical Wells

In order to evaluate other development options, the model was next used to predict performance of three vertical wells placed equidistant along the east-west slant well path. The wells were assumed to be unstimulated with 0.25 ft wellbore radii and skin factors of 3.

On a development cost basis, the three wells were virtually identical to the east-west slant well. Model projections, however, indicated that rates and reserves were much lower for vertical wells. The forecast estimated the combined initial rate of all three wells to be 679 BOPD, while incremental reserves were projected to be only 223 MBO.

Increased pay exposure along the deviated well path and fracture planes accounted for most of the variance in rates between the slant well and vertical wells. However, operational differences in the two sets of forecasts also contributed to the rate difference. The slant well was assumed to be equipped with an electrical submersible pump to minimize producing bottomhole pressure. The vertical wells were assumed to be lifted using hydraulic jet pumps operating at 500 psi higher bottomhole pressure. The reason for the difference in lift equipment was that the incremental rate from any one of the vertical wells due to greater drawdown could not justify the higher operating cost associated with the ESP.

Horizontal Well

The east-west slant well was also compared to a horizontal well. The horizontal well was assumed to be drilled and completed entirely within Sands E1 and E2 (model layers 8 and 9), which appeared to be relatively unswept. The well would follow the same lateral east-west path as the slant well.

The model forecast suggested the horizontal well would initially produce 404 BOPD and provide only 74 MBO of incremental reserves. These results confirmed the obvious need to establish communication between the wellbore and each productive flow unit.

Number of Fractures

A sensitivity study was conducted to examine the impact of reducing the number of fracture treatments pumped in the slant well. Model results are summarized in the table below.

<i>Number of Fracs</i>	<i>0</i>	<i>1</i>	<i>2</i>	<i>3</i>
Incremental Rate, BOPD	684	1267	1638	1980
Incremental Recovery, MBO	296	527	622	734
Total Well Recovery, MBO	691	1215	1388	1547

Model results clearly demonstrated the importance of establishing vertical communication at multiple points along the well path.

Analytical Estimates of Reserves and Initial Rates

Analytical methods were used to confirm model predictions of reserves and initial rates. Although there are many uncertainties, particularly with reserve estimates, model results appeared to be reasonable. Because of the detailed geology and reservoir characterization in the fine-grid model, and the difficulty with analytical methods of accounting for fluid flux in a small volumetric region, the results from the reservoir simulation model are felt to be much more reliable.

Conclusions

Results from the fine-grid model confirm using the east-to-west slant well with multiple vertical fractures to develop the fan-margin region. The well clearly outperforms other development options in thinning highly stratified intervals (Figs. 1 and 2).

The detailed description used in the fine-grid, partial-field model also provided a much improved representation of static and dynamic reservoir conditions.

Project Economics

A discounted cash flow model was used to update the original economics of drilling the slant well and completing with as many as three hydraulic-fracture treatments.

Decision Tree Analysis

Decision tree analysis was applied to production and costs in the economic evaluation to account for the numerous outcomes that are possible (Fig. 3). There is mechanical risk involved in drilling the well and successfully pumping up to three fracs. In addition, successfully pumping three fracs does not guarantee desired frac results such as height, length, width, conductivity, azimuth, etc. There is also geologic risk pertaining to rock quality and reservoir risk regarding saturations.

Costs to Drill, Complete, and Operate

The estimated investment outlays to drill, complete, and equip the slant well are shown in Table 1. There are several activities associated with the proposed slant well that add to the costs to drill, complete, and equip a "typical" vertical well in the Yowlumne field:

- (1) Directional work.
- (2) Cut and analyze whole core.
- (3) Drillpipe-conveyed logging.
- (4) Process FMI log data.
- (5) Perforate long intervals.
- (6) Three large hydraulic-fracture treatments.
- (7) Microseismic logging in an offset well for each of the three fracs.
- (8) Production testing, pressure transient testing, and production logging of each fractured interval.
- (9) Electric submersible pump (ESP) lift.

Expected operating expenses for the slant well are also higher than the cost to produce a typical well in the field. Table 2 lists the annual operating expenses used in the economic evaluations for the 8.5 yr life of the well. All expenses are inflated 5% annually.

Operations surveillance costs represent lifting costs for a well equipped with an ESP sized for 3000 - 3500 BPD, including provisions for one ESP replacement each year. The production string will be equipped with a "Y" offset tool to permit production logging and pressure transient testing while the well is producing. In addition, costs are included for remedial water shut-off workovers.

The economics also include contract and company labor costs for frac and microseismic logging design, five years of technology transfer, overhead, and burden.

Production

The production streams for each scenario consisting of a slant well with no fracs up to a slant well with three fracs were input into the economic evaluation (Fig. 4). Each stream was factored based upon decision tree analysis. The expected-value incremental production stream (Fig. 5) consists of a starting rate of 967 BOPD and reserves of 407 MBO. Expected-value reserves are 55% of the three-frac success case reserves.

Gas and NGL sales were also included in the economics and were based upon a GOR of 489 SCF/STB, gas shrinkage of 22%, and 5.1 GPM yield.

Product Prices

Pricing is based upon 1996 postings for the Yowlumne Field (31° API). The starting prices were \$18.00 per BO, \$18.15 per BNGL, and \$1.45 per MCF. Prices were escalated at 5% per year, consistent with escalation of operating expenses.

Tax Rates

Income tax rates used in the economics were 35% for federal and 5.4% for California state. Severance tax rates were 2.2% for oil and 0.22% for gas. The ad valorem tax rate was 1.61%.

Results

Using commercial economic analysis software, expected-value, incremental economics were calculated for the project based upon working and revenue interests of 100%. The following table lists the present worth figures, BFIT and AFIT, for a range of discount rates:

<i>Discount Rate, %</i>	<i>BFIT Present Worth, M\$</i>	<i>AFIT Present Worth, M\$</i>
0	629	387
5	865	471
10	969	487
15	992	463
20	967	416

The economics are less favorable at lower discount rates due to rate acceleration effects. Although the well has full incremental operating expenses for 8.5 years, there is virtually no incremental production after five years. Higher discount rates increase the present values of the negative cash flows after year 5, thereby improving project economics.

Project Evaluation Report and Continuation Application

After updating project economics with the reservoir simulation production forecasts, a project evaluation report was prepared for budget period one. A continuation application to implement budget period two was also prepared. These documents were shipped to the DOE on September 27, 1996.

Technology Transfer

Mr. Jim Davis, President, ARCO Western Energy, discussed this project in a presentation to the Bakersfield chapter of the American Association of Drilling Engineers on September 26, 1996.

An abstract entitled **Characterization of the Distal Margin of a Basin-Slope (Class III) Reservoir, ARCO-DOE Slant Well, Yowlumne Field, California** was

submitted for presentation at the Fourth International Reservoir Characterization Conference workshop on March 2, 1997.

Table 1

Outlays to Drill, Complete, and Equip Slant Well (M\$)

	<u>3 Fracs</u>	<u>2 Fracs</u>	<u>1 Frac</u>	<u>0 Fracs</u>	<u>Mechanical Failure</u>
Drill	2193	2193	2193	2193	2078
Complete	1085	776	309	157	35
Equip	291	291	291	291	0
Microseismic Logging	196	130	65	0	0
Total Outlays	3765	3390	2858	2641	2113

Table 2

Slant Well Operating Expenses (M\$)

	<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>	<u>Year 6</u>	<u>Year 7</u>	<u>Year 8</u>	<u>Year 9</u>	<u>Total</u>
Operations surveillance	269	471	480	429	423	439	456	478	335	3780
3rd party consulting and technology transfer	177	104	29	64	25	0	0	0	0	399
Company labor, burden, and overhead	263	167	163	124	172	180	189	199	104	1561
Total Project Costs	709	742	672	617	620	619	645	677	439	5740

Fig. 1 Comparison of model production forecasts for EW slant well and NS slant well.

Fig. 2 Comparison of model production forecasts for EW slant well with fracs, 3 vertical wells, and EW horizontal well.

Fig. 3 Decision tree for determining expected value production and costs.

Fig. 4 Sensitivities of EW slant well model production forecasts to number of fracs.

Fig. 5 Expected value rate and reserves for EW slant well based upon decision tree analysis of model production forecasts.