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 United States Department of Energy (DOE) granted approval of the continuation application to implement Budget Period Two (BP2) effective November 21, 1996. The only Budget Period One (BP1) activities for the quarter involved project administration.

Budget Period Two activities were initiated with the development of a drilling program for the high-angle slant well. The well was spud on December 4, 1996 and was drilling at 10,830 ft in the vertical section of the hole as of the end of the month.

Drilling Program

Location

Yowlumne Unit B well no. 91X-3 is located in Kern Co., California, 25 miles south of Bakersfield (Fig. 1). The surface location is 60 ft east of well no. 81X-3, a dry hole drilled in 1980 (Fig. 2). The pad for well no. 81X-3 was reused for well no. 91X-3, reducing costs and making use of fallow land. 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.

Directional Plan

Well no. 91X-3 was planned as a long-radius, near-horizontal well. It was targeted to reach a total depth (TD) of 13,941 ft, a true vertical depth (TVD) of 12,453 ft. After drilling 11,458 ft of vertical hole, the well was scheduled to build angle at 7° per 100 ft. The maximum hole angle of 85° would be reached at TD, 1996 ft west and 114 ft north of the surface location. The top of the Yowlumne sand, a Stevens sand equivalent, was expected to be encountered at 12,701 ft (12,294 ft TVD). The wellbore would be exposed to 1140 ft of formation. Figures 3 and 4 depict the directional plan.

Drilling Procedure

A top-drive drilling rig was selected to drill the well, which would permit rotation and circulation while pulling pipe out of the hole, thus minimizing the risk of becoming stuck. In addition, rates of penetration would be greater due to the ability to drill down with longer stands of pipe and an increase in the available rotary torque to the drill bit.

The procedure called for drilling a 17-1/2 in. hole to 2500 ft, where 13-3/8 in. surface casing would be cemented in place. A 12-1/4 in. vertical hole would then be drilled to 11,400 ft primarily using tricone insert bits and polycrystalline diamond compact (PDC) bits as necessary. While drilling the Etchegoen formation at 7000 to 9000 ft, the water-based mud would be weighted up as high as 13.0 pounds per gallon (PPG) to control sloughing shales.

Conventional resistivity, lithology, and porosity logs would then be run on wireline. After logging, the open hole would be cased with 9-5/8 in., 43.5 and 47 lbs per ft pipe and cemented in place. Confinement of the sloughing shales would allow mud weights to be reduced to a range of 10.5 to 11 PPG in the directional hole.

The remainder of the hole would be drilled primarily with 8-1/2" tricone insert bits, using PDC bits as necessary. Kick-off point for the directional hole was planned for 11,458 ft. A steerable drilling assembly consisting of bent subs and mud motors would be used to drill the 2483 ft of directional hole.

Three 20 ft cores were planned in the productive reservoir, dependent upon hole conditions. These cores would be cut at strategic intervals in the 1140 ft of penetrated formation. Rock property measurements such as porosity, saturation, permeability, capillary pressure, etc. were scheduled to validate the refined log model from BP1. Mechanical properties would also be determined to better design the hydraulic-fracture treatments planned for the well.

Drillpipe-conveyed logs were planned for the 2483 ft of high-angle hole below the intermediate casing. Compensated density and neutron logs would be run to obtain porosity data, and an array induction log would be run to obtain resistivity data. Three advanced logs were planned to obtain additional data. A high-resolution magnetic resonance tool would be run to infer producibility, phases, permeability, and water cut. A formation micro imaging log would provide a "visual image" and supplement core data. In addition, natural fractures, if any, could be identified and taken into account in the design of the hydraulic-fracture treatments. Finally, a dipole sonic log was planned which would permit the inference of mechanical properties to be used in the frac designs, such as stress values, Young's Modulus, and Poisson's Ratio.

After logging, a 7 in., 32 lbs per ft, P-110 production liner would be run from 11,200 ft to TD and cemented with Class G cement, silica flour, and other additives. The liner was designed to withstand bottomhole pressures higher than 16,000 psi during hydraulic-fracture treatments. Seven inch pipe was required to accommodate the expected production equipment consisting of an electric submersible pump (ESP) with a "Y" offset tool.

Drilling Progress

Well no. 91X-3 was spud on December 4, 1996. A 17-1/2 in. hole was drilled to 2522 ft, where 13-5/8", 54 and 61.5 lbs per ft surface casing was cemented in place. As of December 31, the rig was drilling the 12-1/4 in. vertical hole at 10,830 ft.

Figure 1: Map of California showing location of the Yowlumne field and the San Joaquin Basin in relation to other oil-producing basins in the state.

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

Figure 3: Plan view of directional plan for Yowlumne Unit B well no. 91X-3

Figure 4: Cross-sectional view of directional plan for Yowlumne Unit B well no. 91X-3