FRACTURING POORLY CONSOLIDATED SANDSTONE FORMATIONS

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ABSTRACT

The A & B zones of the Trading Bay Oil Field, Cook Inlet, Alaska are a series of heterogeneous, largely unconsolidated sandstones. These sands contain several million barrels of reserves. Although numerous attempts had been made to produce these zones since 1967, less than 1% of the oil-in-place had been produced by January, 1980. Wells which were completed in the A & B intervals typically tested at non-commercial producing rates or declined to uneconomic rates within a year. Reperforating, acidizing and various flushes with oil, all proved unsuccessful.

Extensive analysis and studies of reservoir fluids, core material and production characteristics resulted in isolating the cause of the producing problems as a formation fines movement problem. Use of various clay stabilizing chemicals met with no success. Conventional formation fracturing to stimulate production appeared to be out of the question because of the problems of proppant imbedment in the soft, dirty sandstones.

However, a concept to fully pack created hydraulic fractures with high concentrations of proppant and modifications of conventional fracturing procedures to achieve it, appeared promising, was pursued, and found to be successful.

This paper describes a fracturing technique including procedures and materials for poorly consolidated sandstones. The stimulation technique has resulted in successful completions in the A & B zones and made possible economic recovery of a significant and heretofore essentially non-producible resource.

It is expected that the technique may be applicable in many other areas where economical drainage of oil deposits from poorly consolidated sandstones is presently not possible.

INTRODUCTION

The Trading Bay Field is a complexly faulted, anticlinal structure located in the Upper Cook Inlet Basin of Alaska (Figure 1). The A & B zones are the shallowest productive zones in the Trading Bay Field. These sands occur at a depth of approximately 1800'subsea. As presently mapped, the A zone consists of ten sand members with 1300' of gross interval and the B zone consists of ten sands with a gross thickness of 1500'. Some or all of these sand members are present in each of the major fault blocks within the Trading Bay Field (Figures 2 and 3).

HISTORY

Twelve wells had been tested or were completed in the A and B zones prior to

1980. Only three wells were productive for more than two years. All other wells tested at non-commercial rates or declined to uneconomic rates within a years time. Well A-27, the most prolific A & B zone producer, was completed in April 1973 at 1350 BOPD. The production rate declined to essentially zero in six weeks. Productivity problems were originally believed to have been caused by wax precipitation in the formation. Seven treatments with organic solvents were performed over the life of the well in an attempt to eliminate suspected wax plugging. These well treatments resulted in limited success. The well was also reperforated twice and two diesel backflushes were performed in an attempt to alleviate any near-wellbore plugging caused by wax or fines migration. Nothing was successful in maintaining commercial production. The well was shut-in in 1978 with sand covering the B zone and the A zone non-productive.

STUDIES

Analysis of production curves for the A & B reservoirs showed that production decline occurred rather consistently in a manner typified by Figure 4. Because of this observation and the poor production history of well A-27, an intensive effort was made to study the cause or causes of the poor productivity from this reservoir. Major areas of investigation included log analyses, petrographic studies, formation brine and flood water compatibility, fluid cross-flow and wettability aspects. The results of these investigations at this point strongly indicated that either wax precipitation or formation fines movement in the pore space caused the producing difficulties and that additional work was required to pinpoint the exact cause, i.e., determine which one of the two probable causes (wax or particle movement) represented the actual problem. Therefore, bottom hole reservoir oil samples were recovered under bottom hole pressure and shipped to the laboratory. Core flow tests were designed and completed to show if, or at what temperatures the wax component of the oil will produce permeability decreases. The core sample and the reservoir oil were first heated to well above reservoir temperature before flow through the core was begun. Flow was then continued at progressively lower temperatures - as permeability was continuously measured - and the test was terminated at a temperature $\sim 30^{\circ}F$ below bottom hole temperature.

This experiment clearly established that wax solidification did not cause the production problem being experienced. No permeability decrease was measured at or above bottom hole temperature. It was thus clearly established that mobile formation fines were to be combatted to effectively overcome the production problem.

As use in the past of some of practically all of the available clay stabilizing chemicals had met with no success, a well treatment not relying upon clay stabilization by chemical means was considered to offer promise for the solution of the major production difficulties encountered.

TREATMENT CONCEPT

With the fact established that the production failures experienced in A & B zone wells were caused by pore plugging with mobile formation fines, it was possible to concentrate on a solution.

The poor results from previous reperforations, acid jobs, and diesel backflushes and the use of clay stabilizing chemicals precluded these treatments from being considered as completion techniques. Gravel packing was considered but its effectiveness over extended intervals and the fact that formation fluid velocities would not be sufficiently minimized left it out of consideration.

Successful reduction of fluid flow velocity at and within the rock face - through effective wellbore enlargement by formation fracturing - clearly held promise. Unfortunately, conventional fracturing in the soft formation rock with a monolayer of proppant obviously would fail, as virtually immediate and total proppant imbedment would result in fracture closure or "healing" upon fluid pressure release after fracturing.

However, a concept was considered and pursued of depositing a deliberately large, multi-layer of propping agent in a hydraulic fracture created in the "dirty," soft sandstone (Figure 5). Although closure of the fracture and the deformation of the sandstone over the multi-layer would, of course, still occur, it was reasoned that a high permeability flow channel, nevertheless, would remain within the proppant pack itself. Arguments and objections concerning the belief that soft or unconsolidated sands cannot be adequately fractured could be met with literature reference[1] where it had been shown in the laboratory that even jello could be hydraulically fractured. It has also been found by experience that in the Santa Barbara Channel, for example, hundreds of barrels of whole drilling mud frequently are lost in unconsolidated sands indicating that the solids laden drilling fluid is being lost to fractures. Hence, hydraulic fracturing is actually routinely being experienced in unconsolidated sands.

Finally, the use of highly gelled, polymeric, fracturing fluids was expected to permit the placement of the maximum amount of proppant in the fractures created. Forming a fully-packed fracture, of course, would be the best method of minimizing fluid velocity, hence, pore plugging by mobile formation fines. The problem now was to design an effective fracturing technique for these shallow, unconsolidated sandstone formations.

TREATMENT DESIGN

Table 1 shows a typical treatment design. One primary consideration in fracture design was the location of the job site. The treatments were performed on an offshore platform with limited space and load carrying capacity. Treatments could not be performed from work boats due to the 30 foot tidal fluctuations and the presence of floating ice. These restrictions limited the treatment size to 1700 HHP (two turbines), 100,000 pounds of sand, and 42,000 gallons of gelled water.

The three major factors in treatment design were the treatment placement, selection of the proper fracturing fluid, and the proper fluid loss agent. The sandstone intervals were grouped into three sizes for design: 20 - 30 feet thick; 50 - 75 feet thick; and 100 - 125 feet thick. Multiple computer runs showed that perforating only one-third of the zone would be the most effective method of limiting fracture growth. It was necessary to limit fracture growth in order to maximize the sand concentration within the fractures created. It was believed that fractures would grow up (as was subsequently confirmed by post-frac temperature logs). Therefore, the lower portion of each interval was perforated.

In order to obtain a highly conductive fracture, it was necessary to maximize the sand concentration and minimize the pad size. Due to the water sensitivity of the formation it was necessary to use non-damaging fluids. A cross-linked polysaccharide derivative (PSD) was selected as the most effective fracturing fluid. Because of the high viscosity of this fluid, excellent prop suspension was obtained and it was possible to use very high concentrations of sand with relatively small pad volumes. The PSD fluids are relatively clean (cleaner than, for example, guar gum based gels). They leave little residue thus permitting improved well clean-up. Initial treatments were performed using YF4PSD (40 pounds gel/1000 gallons) and subsequent treatments used YF3PSD (30 pounds gel/1000 gallons) and YF2PSD (20 pounds gel/1000 gallons). Because no reduction in treatment performance was observed the more economical YF2PSD was used.

Another major consideration was, the type of fluid loss agent. It was decided that 70-140 mesh sand would be employed as this sand represents a highly conductive means of tip packing in secondary hair line fractures which would not accept proppant of larger size. This "tip packing" prevented excessive loss of high viscosity fluid to the hair line fractures. The 70-140 mesh sand, acting as a secondary proppant, has a measured permeability of 4000 MD at 8000 PSI closure pressure.

The principal proppant used was 20-40 sand at concentrations up to 10 PPG. In the initial treatments a small amount of 8-16 mesh sand was added at the "tail end" of the treatment, hopefully, to improve conductivity near the wellbore. This small amount of large proppant proved to be essentially wasted as the bulk of the 8-16 mesh sand was left in the casing. Later treatments were tailed in with larger volumes of 10-20 mesh sand in an effort to increase prop pack conductivity.

After all the fractures had been performed, each fractured interval was acidized with 120 gallons/foot of Clay Acid to help control production declines through clay stabilization and immobility of fine material near the wellbore. Because of the time required to individually treat each sand, this part of the treatment was omitted in some of the well treatments.

RESULTS

Well A-22, the first A & B zone well to be fracture stimulated, was completed in November 1979. The well was completed in three B-zone sands and each sand was fractured. Following fracturing, each sand was treated with Clay Acid. The well was opened up slowly and within four months production peaked at 200 BOPD. The well has been on production for three years and is currently producing 110 BOPD. Well A-21 was completed immediately after well A-22. This well was completed in five A-zone sands. As in well A-22 each sand was fractured and treated with Clay Acid. Production from the well peaked at 440 BOPD and is currently averaging 230 BOPD. Well A-30 was completed and fractured in four B zone sands in August 1981. This well peaked at 240 BOPD and is currently producing 190 BOPD. Three additional wells have been completed in the A & B zones with limited success. All three are producing 60 BOPD or less. One of the wells was treated through tubing into perforations which had already been opened therefore there was no control over fracture placement.

CONCLUSIONS

1. A technique of fracturing in poorly consolidated sandstone reservoirs and of filling the fracture with a thick multi-layer of proppant has proven successful in stimulating sustained production in wells in the Cook Inlet of Alaska.

2. Fracturing these weak zones has provided sustained production from zones which previously could not be produced and recovery of a major resource heretofore not producible was made possible.

3. There was no significant difference in results when fluids of varying polymer concentrations were used. Therefore, the least expensive fluid was applied.

4. The 70-140 mesh sand utilized as a fluid loss additive apparently was effective and possibly less damaging than a silica flour.

5. Larger sized sand pumped at the end of the treatments did not have a discernible effect on production rate.

6. Wells treated with Clay Acid apparently produced at higher rates than wells not so treated.

7. The well stimulation method described for poorly consolidated sandstone reservoirs may be expected to be effective in areas other than the Cook Inlet of Alaska, i.e., in areas where conventional fracture stimulation in relatively soft formations had not been successful.

REFERENCES

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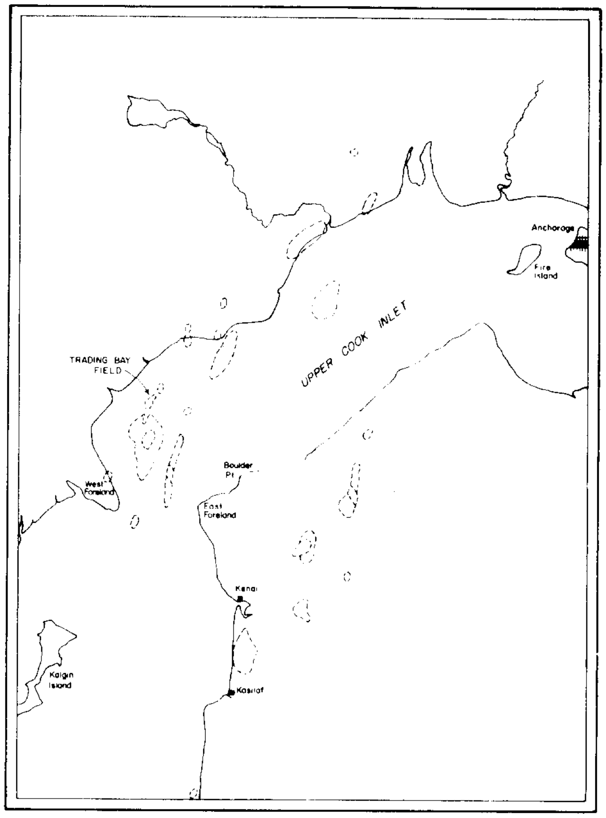

FIGURE 1 OIL AND GAS FIELDS OF UPPER COOK INLET, ALASKA

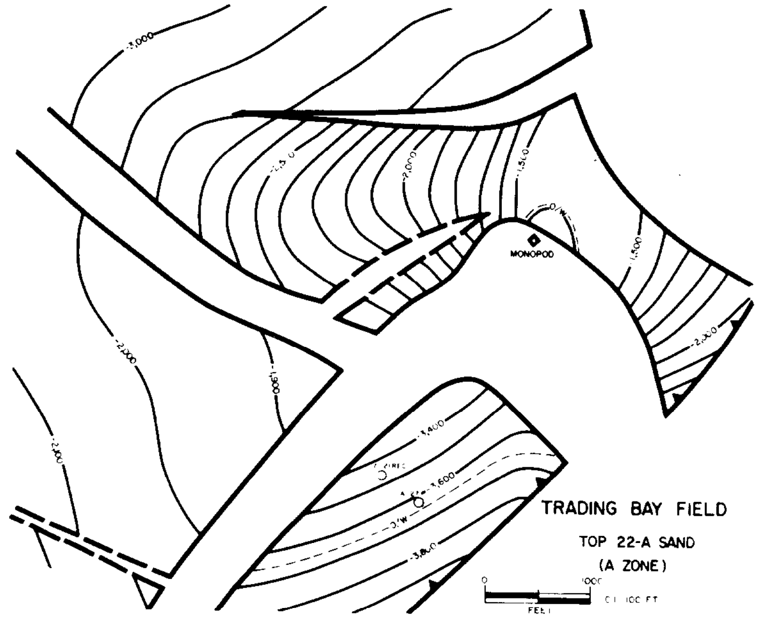

FIGURE 2 TRADING BAY FIELD, A ZONE STRUCTURE MAP

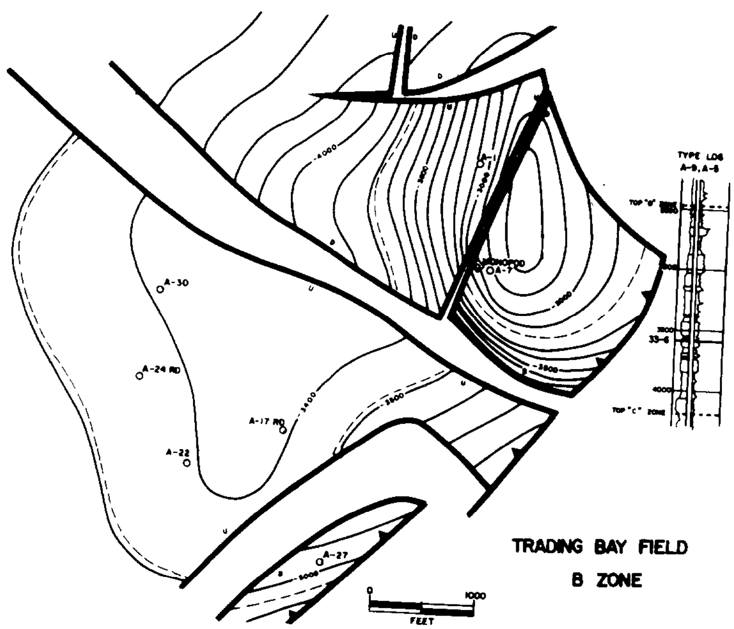

FIGURE 3 -- TRADING BAY FIELD, B ZONE STRUCTURE MAP

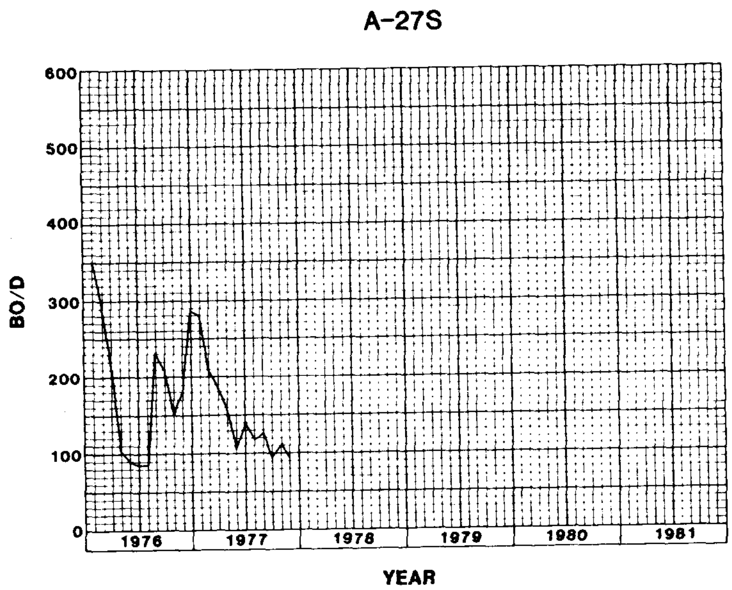

FIGURE 4 — TYPICAL PRODUCTION DECLINE OF A & B ZONE WELLS

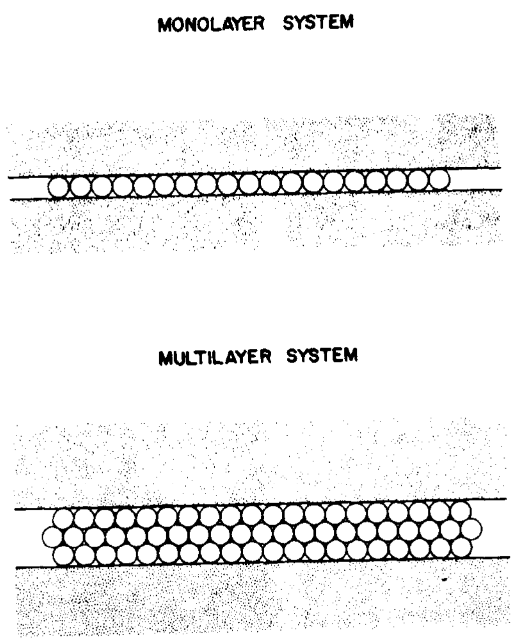

FIGURE 5 — MULTILAYER VS. MONOLAYER FRACTURE

TABLE 1
FRACTURING TREATMENT FOR A - B SAND (50 - 70 FEET)

Procedure:

STAGE VOL BBLS	CUMM VOL BBLS	STAGE VOL GALS	COMM VOL GALS	SAND	SAND PPG	SAND STAGE LBS	SAND CUMM LBS	FLUID STAGE
24	---	1000	---	---	---	---	---	12-3 Mud Acid - Spearhead
120	24	5000	1000	---	---	---	---	Clay Acid - Pre Pad
94	144	4000	6000	---	---	---	---	WF20J347 - Pad
36	238	1500	10000	70-140	2	3000	---	WF20J347 - Frac
60	274	2500	11500	70-140	4	10000	3000	WF20J347 - Frac
120	334	5000	14000	---	---	---	13000	YF2PSD - Crosslink Pad
72	454	3000	19000	20-40	4	12000	---	YF2PSD - Frac Pack
72	526	3000	22000	20-40	6	18000	12000	YF2PSD - Frac Pack
72	598	3000	25000	20-40	8	24000	30000	YF2PSD - Frac Pack
72	670	3000	28000	20-40	10	30000	54000	YF2PSD - Frac Pack
---	742	---	31000	---	---	---	84000	Workover Fluid-Flush

Rate: 15 BPM

WF20J347 - 20 lbs. PSD gelling agent/1000 gals.

YF2PSD - 20 lbs. PSD gelling agent/1000 gals. - crosslinked