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HEAVY OIL RECOVERY USING SOLVENTS AND EXPLOSIVES

By

L. J. Heath, F. S. Johnson,
J. S. Miller, R. A. Jones, and W. D. McMurtrie

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Bartlesville Energy Research Center
Department of Energy
Bartlesville, Oklahoma

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by

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ABSTRACT

The Bartlesville (Okla.) Energy Research Center, U. S. Department of Energy, is developing petroleum-recovery techniques for the many shallow, low-productivity, heavy-oil sand deposits in southeastern Kansas, southwestern Missouri, and northeastern Oklahoma.

In 1971, laboratory flooding experiments were conducted to determine optimum field operating conditions for recovery of heavy oil. Concurrently the Research Center began a field experiment in Labette County, Kans., using a recovery method (SolFrac) that combines chemical-explosive fracturing, to create communication with solvent injection, to improve mobility.

The general boundaries of heavy-oil deposits are reported, and the areal extent and general characteristics of the reservoir in Labette County are described.

The fracturing, injection, and production techniques and the production results from the field experiment are described. About 14 percent of the solvent injected was not recovered and thus was lost to the formation. Roughly 27 percent of the oil-in-place within the five-spot interwell zone was recovered.

Reinjection of the produced solvent-oil mixture was done on a limited basis. Not enough additional oil was picked up during recycling of the solvent to justify this procedure.

An economic analysis was not prepared primarily because of (1) the small size at the test site, (2) the greatly increased cost of the aromatic solvent, and (3) inadequate rubblelization at normal well spacing conditions.

1 Project Leader.

2 Petroleum Engineer.

3 Petroleum Engineering Technician.

INTRODUCTION

There is a widespread interest within the petroleum industry and State and Federal Governments concerning the large heavy-crude oil resource in the United States. This interest has been stimulated by a decrease in the rate of growth of the nation's proved crude oil reserve; a forecast of increasing demand for domestic crude oil; and recent advancements in technology, particularly thermal methods of oil recovery. According to the American Petroleum Institute (API), the nation's proved crude oil reserve increased from about 13 billion bbl in the mid-1930's to a peak of almost 31.8 billion bbl by the end of 1961. Since that date, however, the yearly additions to reserves, excluding the North Slope, has declined.

A Department of the Interior report (4)⁴ indicates a probable demand for domestic liquid hydrocarbons from 1964 through 1980 almost equal to the domestic cumulative oil production since 1859. Because of the expected large demand and increased exploration costs, the known United States petroleum sources have been re-evaluated. The heavy-oil reservoirs have received much attention lately because of (1) recent increases in heavy-oil production from thermal-recovery operations, (2) the existence of more than 2,000 known heavy-oil reservoirs, and (3) the fact that these reservoirs contain a high percentage of the oil originally in place.

Petroleum-impregnated formations have been termed at various times as tar sands; oil-, bitumen-, or asphalt-impregnated rock; and heavy oil formations. The most widely misused term is "tar sands." Several rock types as well as petroleum materials are included in the term "tar sands" (12). In this report, the term heavy oil will be used instead of tar sand and is defined as oil having a gravity of 25° API or lower. Conventional secondary-recovery methods used to recover heavy oil are often impaired by the unfavorable mobility ratio between the driving and driven fluids. To develop methods of producing heavy oil economically, much research has been done by the industry including numerous field tests of thermal-recovery methods.

The technology for greatly increasing the recovery of viscous crude oil by raising its temperature through steam injection is presently available. However, economics has limited general use of thermal methods of recovery to reservoirs having characteristics considered to be most favorable. Significant improvements in technology or economic conditions could result in increased profitability and use of not only thermal methods but also other methods to recover crude oil.

⁴ Underlined numbers in parentheses refer to items listed in the references at the end of this report.

Many heavy oil sands are incompetent; that is, they tend to slump or cave into any voids created when the oil becomes mobile because the sand grains are not cemented to one another. Thus, when a fracture is created and heat is applied to the formation through the fracture, the incompetent formation will slump into the fracture and reduce the permeability, even when the fracture contains a conventional propping agent. Slumping can sometimes be prevented by maintaining sufficient pressure in the fracture and by regulating the fluid composition and flow rate.

Although natural fractures may exist in some heavy oil sandstones, improved fluid injectivity probably could be created by hydraulically fracturing the formation. However, if the fracture were created in a vertical plane the fracturing would not necessarily result in a connection between wells.

The only solvents of much use in dissolving the complex hydrocarbons comprising the heavy asphaltic oils are the relatively expensive naphthenic and aromatic substances. Solvent stimulation of oilfields producing heavy oils has been practiced in California since the mid sixties. This method has been limited to injecting a given solvent into the zone around the wellbore and then placing the well back on production (3,6,8). The resultant stimulation is caused by cleaning up the formation and dissolving the asphaltenes, etc., adjacent to the wellbore.

The production potential for oil from U.S. heavy-oil deposits is poorly defined; neither industry nor government has made a comprehensive and conclusive examination of the physical extent and economic possibilities of such deposits. Bureau of Mines Monograph 12, (1) describes 546 occurrences of tar sands and 383 shallow heavy oil fields. Reserve figures, however, are available for only a few deposits. Only a few of the large deposits in California and Utah have been surveyed carefully enough so that the reserve figures are meaningful; accurate volume figures for the remaining deposits are not available. Forty-two counties in Kansas, Missouri, and Oklahoma contain 40 percent of the recognized heavy oil deposits. Much of this is fairly shallow, less than 500 feet, and could be mined; however, because of costs and environmental considerations research should be initiated for the economical recovery of this crude by in situ methods.

Statistics on cumulative oil production are available on most of the heavy oil productive reservoirs. A breakdown of heavy-crude oil resources in the United States (13) indicates a proved reserve of 5.2 billion bbl with an oil resource of 106.8 billion bbl; this resource being classified at 51.3 billion bbl of 20° to 25° API gravity and 55.5 billion bbl of lower than 20° API gravity crude. This resource is also classified as to depth

at 21.3 billion bbl in reservoirs to 1,500 feet deep, 38.1 billion bbl in reservoirs from 1,500 to 3,000 feet, and 47.4 billion bbl in reservoirs deeper than 3,000 feet. These figures do not include those oil-impregnated rocks which are known but from which no crude has been recovered. It is estimated that the total amount of heavy oil in the United States would be in excess of 150 billion bbl of oil in place if deposits were included such as those in western Missouri, eastern Kansas, northeastern Oklahoma, and other reservoirs which have no reported individual oil-production statistics. Considering the low primary recovery from these accumulations, the potential recovery is tremendous. The geographical location of U.S. heavy-oil accumulations (5) is shown in figure 1.

FIGURE 1. - Major areas of heavy oil deposits in the United States (adapted from Dietzman, Carrales, and Jirik, 1965).

THE RESEARCH PROGRAM

This research was designed to provide technical support to the nation's energy program, supplement industry's petroleum and natural gas research, and more specifically develop useable means for adding the billions of barrels of currently known, but non-producible, petroleum resources to this country's storehouse of energy. Prime sources that have not been economical in the past, using known technology, are tar sands and heavy oil. Review of current technical literature reveals a poverty of information about the areal limits or the geological depth of known deposits of heavy oil. This research has as its objective the solution to the mechanical and engineering problem of producing heavy, viscous crude oil from consolidated sandstone reservoirs.

Crude oil of 15° (and under) API gravity will not flow readily at ambient temperature; therefore, heat or dilution with a suitable solvent is required to produce such a crude oil. Many sands containing these oils occur at shallow depths and are not responsive to standard fracturing or stimulating techniques.

In order to solve such production problems, BERC engineers investigated the location of shallow, high-viscosity oilfields as a possible site for a field test. The proposed test would involve two or more wells, either in or capable of being arranged in a definite pattern. The wells would be shot with high explosives in an attempt to rubblize the interwell formation and would be cleaned out. Then an aromatic type solvent would be circulated between the wells with varying soak periods being tested.

REGIONAL DISTRIBUTION OF HEAVY OIL

In western Missouri, eastern Kansas, and northeastern Oklahoma, heavy-oil deposits occur over an area of roughly 8,000 square miles. This area extends for about 250 miles, roughly along the Kansas-Missouri border, and reaches a width of about 80 miles, as shown in figure 2. Heavy-oil deposits are found throughout the region although some lighter oil deposits also occur. Oil saturation and viscosity vary from one reservoir to another and from one depth to another in the same well. Formations of particular interest are the Wayside, the Bartlesville, and the Burgess.

HEAVY-OIL RECOVERY TEST SITE

Engineers at the Bartlesville Energy Research Center investigated several possible sites and finally selected a lease in Labette County, Kansas, that would be satisfactory for a research project. This lease, in the Bartlett oilfield, is the Energy Recovery Corp. H. H. Leap lease in SE 1/4 sec. 16, T. 34 S., R.

FIGURE 2. - Heavy oil deposits in the tri-state area of Oklahoma, Kansas, and Missouri.

HISTORY OF THE LEASE

Prior to 1960 several wells had been drilled on the Leap lease. One well was drilled by Apache Uranium and Oil Corp., and one was drilled by Oceanic Oil Co. Other test holes and small gas wells had been drilled on the lease.

Williams Brothers Oil Co. acquired the lease, and in November and December 1961 drilled two wells. These two wells penetrated over 100 feet of Bartlesville sand with good oil saturation, but the oil was too viscous to produce.

Collins Oil Co. acquired the lease from a broker in the first part of 1963. Reliable core reports had shown 50,000 bbl of oil per acre in place under this quarter section. The top of the Bartlesville sand is at approximately 250 feet, and the sand is up to 120 feet thick. The lower 60 feet is more uniform than the upper part.

20 E. (See figure 3.) Eleven wells had been drilled on this property before this research was begun. Total production was about 25 bbl, mostly from steam injection. In addition to the wells drilled on this lease, wells were drilled in each of several quarter sections in the area as a result of an intensive joint formation-testing program by several oil companies during the mid-1960's. Well-log information indicated the existence of a large heavy-oil reservoir extending over an area of about four townships. Figure 4 is an isopachous map of this Bartlesville oil sand. A cross-section (A-A'), drawn through the Leap lease in an almost west-east direction, is shown in figure 5.

FIGURE 3. - Location of lease and simplified schematic of wells and tank battery, heavy oil recovery test site.

FIGURE 5. - Cross section A-A', Bartlett area.

FIGURE 4. - Isopachous map of Bartlesville oil sand, Bartlett area.

Collins decided to initiate a field research venture to recover this heavy crude oil. The Oceanic well and one of the Williams Brothers wells had been cored. The Oceanic well had been plugged and abandoned. Collins planned for a 5-spot pattern covering about 1 1/4 acres. They used the two Williams Brothers wells which they redesignated wells 1A and 2A. In November 1963, they drilled well 3A and two months later drilled 4A. The Old Apache well was cleaned out and renumbered 5A. Although the pattern was essentially a 5-spot, it was rather irregular, with 3A being the center well and the distance from wells varying from 130 to 240 feet.

Laboratory tests showed the advantages of using solvents and heat in lowering the viscosity of the crude. Collins planned to use a combination of these. A central plant composed of solvent tank, oil tank, discharge header, heater, etc., was installed. The heater was rated at 315,000 Btu/hr, 302 gph at a rise of 100° F. Each well was equipped with a macaroni string and a return line. A Wheatley simplex pump was used to inject the solvent (and other liquids) at a pressure of 400 to 450 psig.

The first part of the project was to test the formation pressure gradient, the effect of dilution, the percentage of solvent to use, the effect of heat on straight injection, and the effect of a heated circulated solution in the pumping well. In addition, it was planned to use steam and also a bottom-hole electric heater.

During 1964, Collins intermittently circulated, injected, and/or treated the 5-spot with hot water, kerosene, cold water, isopropanol-white gasoline mixture, and steam. The only well equipped to pump was 3A, the center well. Around the middle of November the pump was pulled, and a bottom-hole electric heater was run, and the rods and pump were rerun. Much difficulty was encountered with the heater (blown fuses, etc.), and by the end of 1964 the bottom-hole heater had been pulled and the entire operation temporarily shutdown. In December, 6A was drilled, 30 feet west of 3A, shot with 60 quarts of nitro, and cleaned out. There was no further activity on this lease from February through October 1965.

On November 9, 1965, a TRW bottom-hole heater was run in 3A and tested for about 2 months. During this 2-month period, the bottom-hole heater was inoperative on several occasions, and steam was injected for several days. Water was being injected into 1A, 2A, and 5A at the rate of 5 bbl/day, and steam into 6A at 5 bbl/day. The bottom-hole heater was pulled on Jan. 6 and the cable was found to be eroded at the top of the pump. That night, fire destroyed the pump house and its contents, including the water heater, the bottom-hole heater, header, and control equipment. The property was then placed in the hands of a broker.

Johnson-Fagg acquired this property and in August 1966 drilled Well 0 located about 750 feet northwest of the 3A well. Well 0, with a 6 3/4-inch borehole, was cased to bottom with 4 1/2-inch casing and perforated with 26 holes from 334 feet to 360 feet using Schlumberger crack-jet charges. A steam-injection pilot project was begun on the lease to ascertain the following:

1. Steam injection rates and pressures to determine feasibility of steamflooding.
2. Possible oil production stimulation by "huff and puff" method of recovery.
3. Mechanical problems associated with steam injection.

Johnson-Fagg, Inc. began steam injection into the Leap 0 at 5:00 p.m., Sept. 26, 1966, and stopped at 4:00 p.m., Oct. 2, 1966. During this 143 hours of operation, 2,670 bbl of water was injected as steam at an average generator pressure of 885 psig and temperature of 532° F. This well was placed on pump on Oct. 12 and over the next 2 to 3 weeks averaged about 1 bbl of oil and 11 bbl of water per day.

The day after cessation of injection into Leap 0, Johnson-Fagg, Inc. started steam into the Leap 6A well and continued the injection for 54 hours. During this period, they injected 481 bbl of water (probably as water since the injection line from the generator was rather long) at an average generator pressure of 880 psig and temperature of 530° F. Wells 3A, 4A, and 5A flowed water beginning 12 hours after injection was started. Well 2A flowed kerosene beginning 24 hours after the start of "steam" injection. Well 3A flowed water for 5 days after injection was stopped.

In August 1967, perforations in the Leap 0 were squeeze cemented, and the casing was jet notched in two places, at 305 feet and 335 feet. Each notch was individually fracture treated with 35,000 gallons of water containing 1 pound of sand per gallon. The well was placed on pump, but production was too small to be economical.

Total production from this lease was only about 25 bbl of oil.

The lease is now held by Energy Recovery Corp.

SITE PREPARATION

Drilling

Two drilling programs were initiated to complete the 50-ft five-spot pattern required for the solvent recovery experiment (11).

The first drilling program was started in April 1971, and wells 7, 8, and 9 (figure 3) were drilled. Well 7 was drilled with a 13 1/2-inch bit to 260 ft and cored to 375 ft. After the cores were examined the well was reamed with a 13 1/2-inch bit to 375 ft, and plugged back to 360 ft. Wells 8 and 9 were drilled with a 13 1/2-inch bit to 360 ft and all three wells were completed with 7-inch casing to 295 ft, and cemented to the surface. A solvent-injection test was performed in these wells after they were explosively fractured and before the well pattern was expanded.

The second drilling program was started in September 1972, and wells 10, 11, 12, 13, and 14 (figure 3) were drilled. Wells 13 and 14 were located 75 ft apart on diagonals from wells 7 and 8 for explosive fracturing wells. The wells were drilled with a 13 1/2-inch bit to a depth of 360 ft. After the explosive shots were detonated, these wells were plugged in accordance with Kansas State Corporation Commission rules and regulations. Well 12, an observation well located midway between wells 13 and 14, was drilled with a 7 7/8-inch bit to 290 ft; a 6-inch core was obtained between 290 and 360 ft, and the well was plugged back to a casing depth of 290 ft. Five-inch casing was set to 290 ft and cemented to the surface, and the well was cleaned out to a total depth of 360 ft. Wells 10 and 11 were located on 50-ft spacing from wells 7 and 8 to complete the five-spot pattern. The wells were drilled with a 9-inch bit to 290 ft, and 7-inch casing was set and cemented to the surface. The wells were drilled to a total depth of 360 ft with a 6 1/4-inch bit.

Formation Properties

Two wells were cored. Well 7 was cored prior to explosive fracturing to obtain formation properties such as permeability, porosity, and oil and water saturation. Well 12 was cored after explosively fracturing to determine postshot fragmentation of the explosively shot interval.

Well 7 was cored over the interval from 260 to 375 ft with 100-percent recovery. Core plugs were taken at 71 locations (273 to 375 ft) along the core and analyzed for porosity, permeability, and oil and water saturation. Information obtained from core plugs and visual observation of the core from 260 to 295 ft and 360 to 375 ft indicated little or no oil saturation in these intervals.

Fifty-five core plugs were analyzed in the zone of interest from 295 to 360 ft. Porosity ranged from 10.7 to 26.0 percent with a weighted average of 20.0 percent, permeability ranged from 0.2 to 654.6 md with a weighted average of 152.5 md, oil saturation

ranged from 0 to 75.8 percent with a weighted average of 36.4 percent, and water saturation ranged from 0 to 8.4 percent with a weighted average of 2.1 percent.

The interval of time from when the cores were obtained to when the core plugs were analyzed was of sufficient duration to have decreased the oil and water saturation values of the samples by evaporation. The gas saturation in this formation is negligible and was not considered in the analysis; therefore, the total fluid saturation (oil and water) should be approximately 100 percent. The analysis of the Leap cores indicated a weighted average fluid saturation of 38.9 percent. The remaining 61.1 percent of fluid saturation is felt to be mostly a loss of water saturation with some slight loss of oil saturation due to evaporation of fluids from the cores during the time delay.

The oil in place determined through the zone of interest (295 to 360 ft) was calculated to be 37,000 bbl/acre. The cored interval was divided into four sections: from 273 to 295 ft, from the casing set point to the cleanout point (295 to 330 ft), from the cleanout point to the final total depth (330 to 360 ft), and the bottom 15-ft interval which was cored in well 7 (360 to 375 ft). Well 7 was plugged back to 360 ft, and the other two wells were drilled to only 360 ft. The results of weighted-average calculations are shown in table 1.

TABLE 1. - Core analysis

Depth, feet	Permeability, millidarcies	Porosity, percent	Oil saturation percent	Oil in place, bbl/acre	Oil in place, bbl/acre- ft
273-295	147.1	21.9	6.6	2,464	112
295-330	132.6	18.4	33.9	16,937	484.
330-360	175.6	21.9	39.4	20,069	669
360-375	13.3	15.8	4.7	868	58

Well 12 was cored through the interval 290 to 357 ft with 99 percent recovery. Four core plugs, taken at 295, 315, 337, and 354 ft, indicated that the permeability, porosity, oil saturation, and water saturation were within the values obtained from plugs cut from the core on well 7. Visual observation of the cores indicated that the formation characteristics correlated between the core taken in well 7 to that in well 12.

The preshot core, obtained from well 7, was competent through the entire cored interval indicating that no fractures existed prior to explosive fracturing. The postshot core, obtained from well 12, indicated that fracture patterns existed in the explosively shot zone between wells 13 and 14. Near-vertical to vertical-type fractures were noticed between 306 to 342 ft.

Electric Logs

An electric log was run on well 7 using spontaneous-potential and resistivity logs. The logs were run from the surface to a depth of 360 ft in a 13 1/2-inch hole and from 360 to 375 ft in a 6 3/8-inch hole, as shown in figure 6. The logs indicated the top of the Bartlesville sand at approximately 246 ft, with no indication that the bottom of the formation had been reached. The well was plugged back to 360 ft, and all subsequent wells were bottomed at 360 ft, all within the Bartlesville sand.

Test For Oil Oxidation

On Oct. 28, 1971, samples were taken of the effluent gas from wells 8 and 9.

The purpose of taking these samples was to ascertain if the air that had been injected into well 8 in July had oxidized the oil in the formation to any extent. The air had been injected to a pressure of 200 psi to determine if communication existed between the other two experimental wells. The pressure in well 9 had begun to increase within a few minutes. These two wells had remained shut in at approximately 110 psi since that time. Well 7, the other well in the three well pattern, showed no pressure increase. The gas samples were taken as the wells, No. 9 first and then No. 8, were blown down. These samples were taken through the 1/4-inch pressure gage fitting below the master valve on each well which was purged thoroughly before each evacuated bag was filled.

FIGURE 6. - Induction electrical log, well 7, showing interval of Bartlesville sand.

The sample bags were marked according to the well and sample number. The pressure at which each sample was taken was also noted.

The results of the analysis of the samples are shown in table 2.

TABLE 2. - Analysis of effluent gas from wells 8 and 9.

Sample No.	Pressure, psig	Percent CO	Percent CO ₂	Percent O ₂
8-1	100	0.52	2.11	8.5
8-2	55	.572	2.345	7.6
8-3	10	.629	2.78	6.5
9-1	90	1.37	2.625	4.6
9-2	55	1.36	2.96	4.1
9-3	10	1.36	3.21	3.7
air ¹	atmos	.0005	.03 to .04	20.9

1 Not a sample. Estimated normal content of air.

The increase in CO and CO₂ in the effluent gas indicates the possibility that some oxidation of the oil in the formation occurred. Because of the presence of oxygen still in the gas, the oxidation was considered to be incomplete. Two factors that confuse the picture is the possibility that these might be residual gases from the TNT detonation or lack of gas diffusion.

Explosive Fracturing

Two explosive fracturing experiments, using a total of 15,000 lb of pelletized TNT (3000 lb/well), were performed in five wells on the Leap lease as part of this research program. The experiments were performed to create fragmentation and paths of communication between wells so that the heavy, high-viscosity oil could be produced by the experimental solvent application.

The first explosive shot was performed in three wells (7, 8, and 9) that formed part of the 50- by 50-ft five-spot pattern. The second explosive shot was performed in two wells (13 and 14) that were drilled outside the pattern for explosive wells exclusively (figure 3).

In both tests, all wells were bailed to total depth to gage the rate of water influx and to determine if excess water was

invading the wellbores. Each well could be bailed down, some more rapidly than others, indicating a variance in water intrusion. With excessive water influx, the explosive could bridge at a height in the wellbore so as not to accommodate the explosive charge. This would cause damage to the casing from the explosive detonation.

The priming device for both tests consisted of a weight, 50 ft of detonating cord, two 1-lb primers, and two No. 8 electric caps on 400-ft leads. The weights, tied to the detonating cord, were used to sink the priming device to the bottom through any oil interface and water remaining in the wellbore. Two 1-lb primers with caps were taped to the detonating cord approximately 5 ft and 25 ft above the weight. After each well was bailed, the priming device was lowered to total depth and tied in place to the casing. The pelletized TNT was poured at a moderate rate into a galvanized funnel until the TNT overcame the influx of water (figure 7). After approximately half the TNT was poured, the explosive height was measured to assure that the explosive had not bridged. If the wellbore was clear, the remaining TNT was poured at a fairly rapid rate until 3,000 lb of TNT was loaded in each well. In the first explosive shot, a wireline measurement was taken to determine if a safe interval existed between the explosive and casing bottom to prevent casing damage. No wireline measurement was necessary in the second explosive shot because the shot wells did not contain casing.

FIGURE 7. - Pouring pelletized TNT into the well.

Tests have indicated that with water in the 27 percent void space in prilled TNT, the available energy is 17 percent greater and the explosion pressure is 57 percent greater than that for the corresponding dry prilled TNT (2). Approximately 2 bbl of water was added to the shot wells in explosive shot No. 1 to fill the void space of the explosive. No water was added to fill the void space of the explosive in explosive shot No. 2 because of excessive water influx.

Each cap was tested with a blasting galvanometer to determine whether or not the blasting circuit was closed and in proper condition for firing. Sand was

added to each well to an approximate height of 150 ft. This procedure was followed to contain the explosion in all wells and protect casing in the cased wells.

The shooting line and all caps were again tested with a blasting galvanometer for continuity. The cap wires were tied into a parallel circuit and connected to the 500-ft shooting line. After the shunt was removed from the end of the 500-ft shooting line, the circuit was tested for continuity and connected to a condenser discharge blasting machine.

After clearance of the site (in both explosive shots), the wells were simultaneously shot. A strong shock wave was felt in both explosive shots. Figure 8 indicates the typical ground disturbance and elevation rise associated with contained wellbore explosive shots.

In explosive shot No. 1, well 7 blew the sand tamp to the atmosphere, and black smoke billowed for several hundred feet into the air and gradually changed to a clear gas. The wells were shut in, and after about 30 minutes the wellhead pressure had built up to 80 psig. In explosive shot No. 2, the expanding explosive gases fractured through the formation to wells 7, 8, and 9, blowing the water tamp to the surface. About 10 minutes after the shot, explosive well 13 blew its sand tamp several hundred feet into the atmosphere and continued blowing explosive gas into the air for about 45 minutes.

FIGURE 8. - Visual indication of ground disturbance and elevation rise from explosive detonation.

Wireline measurements were made in wells 7, 8, 9, 13, and 14 before and after the second explosive shot. These measurements, shown in table 3, indicated little or no sand fillup in wells 7, 8, and 9 from the shock wave or gas expansion caused by the explosive shot. The measurements in wells 13 and 14 indicated the sand tamp heights, which proved valuable in plugging these wells.

Sand Removal

Three attempts were made to remove 30 ft of pulverized sand from the wellbores of wells 7, 8, and 9. The sand was extremely fine, probably 90 percent of the grains being 200 mesh or finer. In the first two

TABLE 3. - Preshot and postshot wireline measurements of drilled wells

Well No.	First shot		Second shot	
	Preshot measurement, feet	Postshot measurement, feet	Preshot measurement, feet	Postshot measurement, feet
7	359	301	329	327
8	362	229	333	334
9	355	182	331	330
13	(1)	(1)	349	297
14	(1)	(1)	354	187

1 Wells not drilled at this time.

attempts, a contract rig, by lowering and raising the drill stem through the 30 ft of sand column, ejected sand up the annulus with a water-foam-air mixture. About 90 hours of rig time was used to eject 50 cu yd of sand from each well. The average measurements of total depth after cleanout of each well was about 360 ft. After several weeks, the wells were remeasured; the formation had sloughed and the total depth measured about 330 ft.

The third attempt to clean out the 30-ft column of sand from the wells was made using a pulling unit to run a string of 1-in. pipe and a string of 2-in. pipe to the top of the sand. Air and foam under high pressure were injected down the 1-in. string of pipe to stir the sand and rock mixture. The lightened mixture was foamed out the 2-in. string of pipe to the surface. Rocks were also ejected from the 2-in. production string. Occasionally some rocks, approximately the size of the diameter of the pipe, became wedged in the pipe and stopped the return flow of the mixture. Difficulty in lowering the pipe strings indicated the existence of larger rocks in the cavings. Occasionally air and foam were injected through the 7-in. casing, and the sand mixture was foamed out the 2-in. string. The preferred method was to move the 2-in. pipe up and down into the sand column until little or no sand or rock was produced. Pipe was added to both strings and the process was repeated until total depth was reached. After raising the injection and production string, sand again sloughed in, and the process was repeated. Cleanout operations were stopped after an additional 25 cu yd per well of formation material was recovered. Water-injection and water-withdrawal tests indicated a cavity between 295 and 330 ft with an average diameter of about 6 ft and a void volume of 1,067 cu ft.

Airflow Tests

Preshot and postshot airflow tests were made to ascertain possible increased flow capacities between wells which would indicate greater fracture paths and fragmentation through the shot zone.

Prior to the preshot flow test, all wells were bailed to total depth. Air was injected into well 8 to a pressure of 100 psi with the other wells shut in. Wellhead pressure gages were observed on wells 7 and 9 to determine if fractures or paths of communication were evident between wells. Little pressure falloff was noted on the injection well, and no pressure buildup was noted on the production wells which indicated negligible communication between wells.

A postshot flow test was run on wells 7, 8, and 9 after the cleanout was stopped. The flow tests were run to determine the extent of communication between wells, the flow capacities between wells, and which well to use as the solvent-injection well.

Before testing, water was removed from the wells by pressuring up the annulus and flowing water from the 1-in. string of pipe set at 330 ft. Air was injected into all three wells to a pressure of about 300 psi to keep the water influx at a minimum during the airflow tests.

FIGURE 9. - Flow tests of well pairs with well 9 as the production well.

Three tests were made by injecting air into wells 7, 8, and 9 in turn, with the other wells shut in until pressures in the pattern stabilized. Each of the paired wells for each test was produced at three rates through a critical flow prover for a 1-hour test period while injecting into the remaining well. The production rates were calculated by the standard critical flow prover flow equation using a 24-hour flow basis. The stabilized injection pressure (P_i) and flowing pressures (P_f) for each rate Q were recorded. Backpressure curves, plotting $P_i^2 - P_f^2$ versus Q , using well 9 as an injection and production well, are shown in figures 9 and 10. Figure 9 shows wells

FIGURE 10. - Flow tests of well pairs with well 9 as the injection well.

7 and 8 as injection wells and well 9 as the production well. Figure 10 shows well 9 as the injection well and wells 7 and 8 as production wells. Values of rate Q_{10} , (determined for the wells at a $P_i^2 - P_f^2$ of 10,000) are compared in table 4. The Q_{10} values listed in table 4 indicate that well 9 had better injection-production relationship to the other wells, with the exception of well 7 to well 9, and consequently, it was picked as the injection well.

Water-Injectivity Tests

Airflow tests were not run on wells 10 and 11, after the second explosive fracturing test, because of the unavailability of a compressor. Water-injectivity tests were run using wells 7, 8,

TABLE 4. - Q_{10} values obtained from backpressure curves

Injection well	Production well	Q_{10} Value, Mcfd
7	8	53.800
7	9	188.300
8	7	38.700
8	9	63.700
9	7	149.200
9	8	98.500

10, and 11 as injection wells and well 9 as the production well to determine the degree of fracture communication between wells in the five-spot pattern. Two types of tests were made: testing the four injection wells individually, and testing the four wells simultaneously.

In the individual well tests, water was injected into each well with a piston-type pump for a given time. The flow rate on each well was measured by a water meter, and the pressures were obtained from pressure gages on the wellhead. Four flow rates and corresponding pressures were recorded.

The flow data for each test are given in table 5 and the plotted data points are illustrated in figure 11.

TABLE 5. - Q_{50} values obtained from water-injectivity curves

Injection well	Production well	Q_{50} Value, bbl/day	
		Single well test	Combined well test
7	9	72.0	39.0
8	9	71.0	53.0
10	9	17.0	13.0
11	9	5.0	31.0

The plotted curves of the data points from the individual well tests (fig. 11) show that two of the original wells (7 and 8) have nearly identical injection profiles and that the injection profiles of the two new wells (10 and 11) are nearly identical. Figure 5 shows that the Q_{50} rates (rate Q at 50 psia) for wells 7, 8, 10, and 11 were 72, 71, 17 and 5 bbl/day, respectively. These tests indicate that water can be injected from 4 to 12 times as fast through fracture systems in wells 7 and 8 as through fractures created in wells 10 and 11.

A combined well test was performed by injecting water simultaneously into wells 7, 8, 10, and 11. Flow rates and corresponding wellhead pressures were recorded for the four flow periods. The flow data for the test are given in table 5 and the plotted data points are shown in figure 12.

FIGURE 11. - Water injectivity tests, single well.

FIGURE 12. - Water injectivity tests, combined wells.

To illustrate, a Q_{50} value was determined for the wells to indicate the position difference of the four curves from the previous test. The corresponding injection rates on wells 7, 8, 10, and 11 are 39, 53, 13, and 31 bbl/day, respectively.

The flow rates from this test differ from the flow rates of the previous test. The effects of simultaneous injection in the four wells are indicated in the comparison of the test results. The added injection capacity in the simultaneous test from wells 10 and 11 reduced the injection capacity of wells 7 and 8. The injection capacity of well 10 was not affected appreciably, but the injection rate of well 11 was increased. The increase of rate from well 11 can be attributed to flow of fluid through additional fracture systems within the pattern or leakoff of fluid through fractures off the pattern.

Impression Packer Survey

To determine the extent of formation fracturing caused by explosive detonations in wells 13 and 14, downhole packer impressions were obtained in well 10. Well 10 was completed with 7-in. casing and drilled to 360 ft with a 6 1/4-inch bit to accommodate the impression-packer tool.

The impression sleeve was made of a special 4-in ID shrinkable polyolefin tubing. The 3 7/8-in. packer element accommodated approximately 5 ft of the tubing. The tubing was pulled over the full length of the element and the tubing was shrunk to a tight fit by applying heat with a heat gun.

The packer assembly was run on 2-in. tubing to the required depth and hydraulically inflated in the wellbore to approximately 1,400 psi. The packer was set for a 30-minute time interval to obtain imprints in the plastic sleeve of irregularities that occurred in the wellbore surface. To retrieve the packer, the hydraulic pressure was increased to 1,500 psi to shear a pin holding a ball and seat assembly in place for seating the packer. The packer was pulled, a new sleeve installed, and the packer assembly run to the next required depth interval. Twelve such surveys were run at 46-in. intervals from 300 to 346 ft.

Irregularities were obtained on the sleeves at depths corresponding to the fractured intervals in the core obtained from well 12 indicating fractures or fracture patterns resulting from explosive fracturing.

LABORATORY INVESTIGATION

Laboratory experiments were begun concurrently with site preparation. First the solvent was selected, then four different types of core tests were run using the solvent (9).

Selection of Solvent

A solvent or mixture of solvents was required that would lower the viscosity of the Bartlett oil and still retain the asphaltenes in solution. The solvent was to have an initial boiling point higher than 300° F because of plans to inject a hot solvent. An end boiling point lower than 425° F was required so that the solvent could be distilled from the oil after production.

A sample of oil from a stock tank was routinely distilled. The results are shown in table 6. The oil sample contained approximately 10 percent water, which caused considerable trouble when running the analysis. It was necessary to centrifuge the sample before the distillation could be completed.

TABLE 6. - Crude petroleum analysis

6-485 b
(April 1958)Bureau of Mines Bartlesville Laboratory
Sample 70101

IDENTIFICATION

Bartlett field
Bartlesville, Pennsylvanian
300 feetKansas
Labette County

GENERAL CHARACTERISTICS

Gravity, specific, 0.966 Gravity, ° API, 15.0 Pour point, ° F., 55
Sulfur, percent, 0.71 Color, brownish black
Viscosity, Saybolt Universal at 100°F., 13.466sec. at 130°F., 3.872sec. Nitrogen, percent, 0.317

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 745 mm. Hg
First drop, 446 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122									
2	167									
3	212									
4	257									
5	302									
6	347									
7	392									
8	437									
9	482	1.8	1.8	0.846	35.8	-	1.46244	143.8		
10	527	5.3	7.1	.859	33.2	42	1.47350	153.5		

STAGE 2—Distillation continued at 40 mm. Hg

11	392	6.3	13.4	0.878	29.7	47	1.48047	159.5	39	Below 5
12	437	6.9	20.3	.895	26.6	51	1.49632	169.3	51	20
13	482	8.5	28.8	.916	23.0	58	1.51034	170.1	75	50
14	527	8.6	37.4	.927	21.1	60	1.52024	171.7	131	60
15	572	10.5	47.9	.934	20.0	60	1.52300	182.9	275	65
Residuum.		51.5	99.4	1.020	7.2					

Carbon residue, Conradson: Residuum, 4.9 percent; crude, 2.7 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline				
Total gasoline and naphtha				
Kerosine distillate				
Gas oil	16.3	0.870	31.1	
Nonviscous lubricating distillate	12.1	.894-.921	26.9-22.2	50-100
Medium lubricating distillate	9.3	.921-.930	22.2-20.6	100-200
Viscous lubricating distillate	10.2	.930-.938	20.6-19.4	Above 200
Residuum	51.5	1.020	7.2	
Distillation loss	.6			

The test used to determine the amount of precipitation was modified from ASTM D2042-66, Standard Method of Test for Solubility of Bituminous Materials in Organic Solvents. Briefly, the test consists of filtering 1 g of oil diluted with 100 ml of solvent solution through an asbestos fiber mat and determining the percentage of residual left on the mat after boiling off the solvent in an oven. The only modification was that of increasing the oven temperature to evaporate the different solvents used. In these tests, no differentiation was made between the asphaltenes and other insoluble matter. The results are shown in table 7 as percent precipitates.

TABLE 7. - Summary of solvents tested

Solvent	Aromatic content, percent	Viscosity of mixture, centipoise ¹	ASTM test, precipitate, percent
Diesel fuel	32.5	183	ND
Benzene	99.0	36	1.11
2-Nitropropane.	0	58	15.68
Decalin	0	148	ND
Styrene	99.9	45	.73
n-Pentane	0	72	12.70
Kerosine.	0	235	7.19
Carbon disulfide.	0	17	2.16
Stoddard solvent.	4.6	127	6.57
Commercial mix 1.	38.1	103	4.15
Commercial mix 2.	55.5	93	2.55
Commercial mix 3.	72.9	85	1.65
Commercial mix 4.	98.6	68	.94
Commercial mix 5.	74.2	77	1.97
Commercial mix 6.	73.6	97	1.87
Commercial mix 7.	97.9	89	1.05
Commercial mix 8.	18.6	130	6.91
Commercial mix 8 w/5 pct pine oil.	22.7	117	4.55
Commercial mix 8 w/10 pct pine oil	26.7	104	3.05
Commercial mix 8 w/15 pct pine oil	30.8	118	2.15
Commercial mix 1 w/5 pct pine oil.	41.2	101	1.57
Commercial mix 9.	98.0	78	ND
Commercial mix 10	74.0	73	2.17
Commercial mix 11	0	49	12.26
Gasoline.	25.0	130	4.32

ND Not determined

1 75 percent crude oil, 27 percent solvent.

To determine the viscosity-lowering effect of each solvent on the crude oil, viscosities were determined for mixtures of 25 percent solvent and 75 percent oil at room temperature (table 7).

Figure 13 shows the percent precipitate plotted against the percent aromatic content for the solvents listed in table 7. The curve of solvents without pine oil shows that percent precipitate decreases as aromatic content of the solvent increases. Only two of the solvents tested were considerably off the curve, and these were pure compounds with no aromatic content. Note that at 70 percent aromatics, the percent precipitate decreased below 2 percent. Below this percentage of precipitate, the effect of plugging by the precipitate should be negligible.

The literature on solvents shows that pine oil has a high Kauri butanol value, greater than 500. As this value is indicative of a solvent's power to dissolve organic matter, it was decided to see if small quantities of pine oil would accomplish the same low percentage of precipitates as did large amounts of aromatics in the solvent. Precipitate tests were run using commercial mix 8 with 5, 10, and 15 percent pine oil added, and on one mixture with 5 percent pine oil added to commercial mix 1. The results of these tests are also shown in figure 13. The curve shows that the pine oil content would have to be greater than 15 percent if mixed with commercial mix 8 before the precipitates would be lowered below 2 percent. Only 5 percent pine oil

in commercial mix 1 was needed to prevent precipitation greater than 2 percent. However, the total cost of the mixture with even this small percentage of pine oil would exceed the cost of a higher aromatic solvent.

FIGURE 13. - Results of ASTM precipitate test.

Both the aromatic and paraffinic solvent significantly lowered the viscosity of the oil. The aromatic solvents such as benzene, styrene, and the commercial mixes with higher than 70 percent aromatics gave low percent precipitates and significant viscosity reduction. The solvent shown as commercial mix 10 in table 6 was selected for the field test. This solvent, supplied by Charter Chemicals⁵ as Espesol 1300, has a boiling range of 324 to 373° F,

⁵ Reference to specific trade names or manufacturers does not imply endorsement by the Department of Energy.

a gravity of 35° API, and a composition of 74.3 percent aromatics, 13.1 percent naphthenes, 12.3 percent paraffins, and 0.3 percent olefins.

Core-Solvent Investigation

Fifteen experiments were conducted on cores from the lease using the solvent selected to determine the optimum operating conditions for the reservoir. Soak time, temperature, pressure, flow direction, influence of water, recycling solvent, and surface area exposed to solvent were investigated.

The core experiments were classified as follows:

1. Solvent soak--the core was loosely placed in a core holder in which solvent flows around the core but was not driven through the core.
2. Solvent flood--the core was placed in a Hassler sleeve type core holder and solvent was driven through the core.
3. Solvent-water flood--both water and solvent were driven through the core at various times.
4. Recirculated solvent and water--similar to solvent soak experiments, but solvent was recirculated around core.

General Experimental Procedure

Horizontal core samples were cut from the cores taken from the lease. Most of these oil-saturated core samples were 2 in. in diameter and about 3 in. in length. Some of the cores were randomly cut at different angles to represent or simulate a fractured condition of the interwell zone expected after explosively fracturing the formation. The core samples were measured and weighed before being placed in the core holder.

During the different tests, the fluid that was produced was a mixture of solvent, oil, and sometimes water. There was no emulsion formed; separation of the water was by gravity. The percent of oil in the solvent was determined with a colorimeter. The solvent-oil mixture was diluted with pure solvent until light transmittance could be read on the colorimeter scale. The oil in the solvent was determined from a calibration chart constructed from prepared samples of known percent of oil in the solvent and the known dilution. Accuracy of this method is estimated to be within 2 percent.

At the end of each test, the core was placed in a Soxhlet extractor and boiled from 12 to 20 days using first the aromatic solvent, then toluene, isopropal alcohol, and water. After drying, the core was weighed. Final determination of oil recovered from the core in each test was based on the difference between the initial and dry weight.

Table 8 shows the physical characteristics of the cores, the test conditions, and the final recoveries from each experiment at the indicated pore volume of fluid produced. Plots of cumulative oil recovery versus pore volumes of produced fluids for each experiment are given later in this paper. These plots show only the recoveries to 15 pore volumes even though some experiments extended farther than this. High injected fluid volumes would be impractical in field operation.

TABLE 8. - Results of solvent-core experiments

Experiment	Porosity, percent	Permeability, millidarcies	Oil saturation, percent	Pore volume, cm ³	Solvent injected, PV	Water injected, PV	Fluid produced, PV	Oil produced, percent	Injection pressure, psig	Total time, days
SOLVENT SOAK EXPERIMENTS										
1	20.9	48	27.8	52.8	NA	0	37.2	63.5	NA	106
2	21.4	202	58.0	52.7	NA	0	46.4	82.9	11-60	33
3	22.0	87	31.8	48.9	NA	0	38.3	88.6	NA	100
4	21.8	73	33.0	31.7	28.4	0	27.5	82.5	NA	67
SOLVENT-FLOOD EXPERIMENTS										
5	21.8	NA	45.9	25.4	NA	0	6.4	19.9	11-40	14
6	20.9	179	54.5	17.9	8.0	22.1	24.5	19.6	5-115	20
7	21.4	202	52.7	23.0	NA	0	7.5	45.6	11-40	14
8	21.1	149	36.7	28.0	NA	0	15.4	96.4	40	6
9	22.9	217	35.0	33.6	12.5	0	11.6	93.7	5-18	2
SOLVENT-WATER FLOOD EXPERIMENTS										
10	20.9	179	53.7	18.5	2.9	11.0	9.6	9.7	5-111	26
11	24.3	481	28.4	20.6	2.8	9.5	10.9	41.2	2-3	41
12	21.9	199	55.5	26.4	5.9	5.9	10.1	57.6	9-65	3
13	23.8	285	51.9	31.4	24.5	24.9	49.0	91.0	6-26	5
14	22.8	279	50.2	60.6	10.8	8.4	17.3	85.1	NA	84
RECIRCULATED SOLVENT AND WATER EXPERIMENT										
15	21.5	194	49.6	57.6	7.8	2.6	10.6	93.5	NA	94

NA - Not available.

Solvent Soak Tests

In experiments 1, 2, and 3, the 2-in. cores were cut to simulate fractures. They were placed in a holder consisting of a 2 1/16-in. pipe nipple, capped on both ends. The caps were tapped to accommodate 1/4-in. valves. The core was maintained in a vertical position during the test. First, the solvent was pumped into the core holder from the bottom to purge any air that might be in the core. During the first cycle, 100 ml of solvent was pumped through the core at a slow rate. Direction of flow was then reversed by inverting the core holder and pumping 100 ml of solvent through the core in the opposite direction. The core

was allowed to soak in the solvent for at least 16 hours. The cycle was repeated until it was determined that hardly any crude oil was being recovered. The length of the soak time was varied from 1 to 4 days.

In experiment 1, the core holder was placed in a 300° F oil bath after 7.58 pore volumes had been produced. In experiment 2, the core holder was placed in the oil bath after 38 pore volumes of fluid had been produced. Solvent was injected through a coil of copper tubing in the bath to preheat it to 300° F before entering the holder. Experiments 3 and 4 were run entirely at room temperature (74°F).

Experiment 4 consisted of placing a whole core in a beaker of slightly larger diameter than the core. The core was covered with solvent and allowed to stand with the beaker covered. The solvent surrounding the core was replaced after each soak period.

Additional experiments similar to experiment 4 were performed to obtain information on optimum soaking time. The information on these experiments is not shown in table 8 because they were not performed on Bartlett cores. Berea sandstone cores were cut 1 1/4 in. in diameter and 1 1/4 in. long and saturated with Bartlett oil by heating the cores in the oil to 300° F. The average properties of the seven cores were as follows: permeability, 267 md; porosity, 19.7 percent; initial oil saturation, 94.3 percent; and initial water saturation, 0 percent. These saturated cores were placed in beakers and soaked in solvent for different periods of time. The solvent was then drawn off and tested for oil content. Care was taken not to disturb core or solvent during the soaking period.

Results

FIGURE 14. - Oil recovery from solvent-soak experiments.

Figure 14 shows the results of the solvent-soak experiments. Heat did not affect the solvent-soak experiments appreciably. Experiment 1 showed no increase in recovery rate when placed in the 300° F oil bath at 7.58 pore volumes of fluid produced. Experiment 2 did show an increase when heated, but only about 10 percent of the overall recovery (table 8) could be attributed to the temperature increase. The viscosity change of the oil due to heating was from 2,820 cp at 100° F to 16 cp at 300° F, almost

a 200-fold decrease. Viscosity is a very important consideration in oil flow rate. However, in these experiments, the solvent injected did not push the oil out, but dissolved and diluted the oil inward from the surface of the rock.

The amount of surface area of the core exposed to the solvent was expected to affect the rate of oil recovery. Experiment 4, using the whole core, shows a higher rate of oil recovery than that with the simulated fractured cores. The fractures in the cores were cut on a diamond saw. They were not propped in any way during the experiment. Consequently, the artificial fractures must have closed because of the small pressure of the confining spring placed in the core holder and free passage of solvent was blocked. This, and the fact that the core used in experiment 4 was shorter and the surface-to-volume ratio was larger, could account for its higher recovery rate.

The core used in experiment 2 has the highest permeability and oil saturation of the solvent-soak experiments (table 8). However, this experiment had the lowest recovery at 15 pore volumes of fluid produced. Higher oil saturation, even though combined with higher permeability, could mean less penetration into the core by the solvent, thus less oil recovery during soaking.

In experiments 1, 2, and 3, (fig. 14) the slope at approximately 4 pore volumes increased sharply. Another increase is detected for experiments 2 and 3 around 7 pore volumes. The first two points were run on the same day. Then the core was

soaked in solvent overnight. The same thing happened after the third and fourth point for these experiments. This indicates that the amount of time spent soaking is significant.

FIGURE 15. - Oil content of first solvent removed versus time soaked in Berea core tests.

Experiment 4 was run allowing three to four soak days between each point on the curve. The much higher rate of recovery in this experiment indicates the importance of soaking. Additional experiments of this type were run on Berea cores to obtain information on optimum soaking time. The results of the initial soaking period for these experiments are shown in figure 15. Each of the points represents the oil content acquired by fresh solvent on separate cores when soaked the indicated number of

days. The solvent on the outside of the core rapidly dissolves oil from the core for the first several days; however, after 3 to 5 days, the rate of oil dissolving in the solvent decreases.

These data were confirmed by results obtained in the earlier portion of the field test (10). Soaking periods of 2 to 3 weeks seemed to result in oil recoveries little different from those obtained with soaking periods of 1 week. Soaking periods of 2 to 3 days resulted in maintaining oil contents in the solvent of 6 to 8 percent. Soaking times of only 1 day lowered the oil content to 5 percent.

Solvent Flood Test

After cutting and weighing, solid cores were placed in a Hassler core holder, and tests were run similar to normal water-flood tests. All of the cores were 2 in. in diameter except core 6 which was 1 1/2 in., and the length of the cores varied. The solvent was injected with a diaphragm-type metering pump from a graduated cylinder and produced from the core into a graduated cylinder at atmospheric pressure. The core and end pieces were wrapped tightly with Saran Wrap to prevent contact between the solvent and the rubber sleeve. However, some of the tests ended sooner than planned because the rubber sleeve ruptured due to solvent contact.

Reversing the core, as discussed in Results, simply meant turning the core holder around and making the injection end the production end. Care was taken to drain the production end of oil-solvent mix and refill with solvent to prevent air from being pumped through the core.

FIGURE 16. - Oil recovery from solvent-flood experiments.

Results

A flooding-type experiment might be expected to recover more oil than the soaking-type experiment described previously. Figure 16 shows the percent oil produced plotted versus the produced fluids for the solvent-flood experiments. In experiments 5 and 6, the solvent bypassed much of the oil; thus, recoveries were low.

The time and pressure it took to displace the oil from the cores indicates the difficulty in pushing the solvent

FIGURE 17. - Time required to perform solvent-flood experiments.

through the cores. Figure 17 is a plot of recovery versus time. The range of pressure used in each experiment is shown in table 8. Experiment 5, for example took 14 days to run. After 6 days, only 1 pore volume of fluid had been recovered. The pressure on the inlet had been increased from 11 to 40 psig by the fourth day. Also, experiment 6 took 20 days to perform and 6 days to recover 1 pore volume of fluid. The pressure in this experiment had been increased gradually until 95 psig was on the core inlet by the sixth day.

In experiment 7, the core was reversed after 3 1/2 days. The inlet pressure lowered causing the rest of the fluid to be produced that same day. Since this reversing seemed to make a difference, we reversed the core in experiment 8 after each 0.4 pore volume was produced. Oil recovery and rate were much higher in addition to the experiment being completed in only a little more than 1 day. Since reversing the flow direction aided the oil recovery in the laboratory, plans were made to reverse the flow of solvent in the field experiment to ascertain its importance there.

Experiment 9, which shows the highest recovery rate of all the experiments, was not reversed until approximately 3 pore volumes were produced from the core. At that time, over 90 percent of the oil had already been produced. One explanation for the difference in this experiment is that this particular core had the highest porosity and permeability and the lowest oil saturation of the cores used in this series. Logically, this combination would produce the most oil because the solvent could penetrate farther into the core before forming a heavy oil bank that would hinder flow.

Solvent-Water Flood Test

These tests were run using the Hassler type core holder and solid cores as were the solvent flood tests; the only difference being that water and solvent were alternately injected into the core instead of just solvent.

Experiment 14 was the exception. This experiment was run similar to the solvent-soak experiments except that water and solvent were alternately placed next to the core.

Results

The experiments using both solvent and water were run to answer three questions. First, would the water influx in the wells affect the oil production? Water fills each well from a source which is suspected to be separate and above the oil producing zone. The wells will fill up with water to within 35 ft of the surface at a rate of 2 to 5 bbl/hr. Secondly, if solvent and water were alternately injected would this cut down on the amount of solvent needed without affecting the oil production? Thirdly, could we use water at the end of the field experiment to flush out most of the solvent left in the formation?

The first question was answered from observations of the experiments. No emulsions were observed in the effluent through the clear plastic tubing emerging from the core holder or in the oil-solvent-water mixture found in the receiving graduate cylinder. The water separated immediately from the oil-solvent mixture. The only problem became one of measuring the percentage of oil in the solvent. The presence of water diffused in the oil-solvent mixture, even though probably less than 1 mole percent, caused high readings of oil content which had to be corrected.

There seems to be no problem of emulsions forming in the cores. However, we did notice the same difficulty of pushing the solvent through the core as we did in the solvent-flood experiment (see figures 18 and 19). Note the contrast in permeability and oil saturation between experiments 10 and 11 in table 8. Experiment 10 which has a lower permeability but higher saturation than experiment 11 went slower when injecting solvent first. It took 4 days for the solvent to break through. The solvent broke through in experiment 11 the first day of injection. Experiments 12, 13, and 14 were reversed more often than experiments 10 and 11, possibly producing more fluids in a shorter period of time.

FIGURE 18. - Oil recovery from solvent-water flood experiments.

The second question was answered by comparing the average cumulative crude oil produced by the solvent flood experiments with that of the solvent-water flood experiments, as shown in figure 20. Approximately one-half as much solvent was used in the solvent-flood experiments.

FIGURE 19. - Time required to perform solvent-water flood experiments.

FIGURE 20. - Comparison of averaged laboratory data with field results.

Scarcely any difference was noted in the amount of solvent injected compared to the amount of oil produced in any of the solvent-water experiments. The pore volume of the cores was small compared to the volumes of fluids used. Some solvent could have been bypassed and not been detected. Otherwise, in answer to the third question it can be said that most of the solvent was displaced from the core by water. Even in the soaking situation, as seen in experiment 14 where solvent and water were used alternately, the oil recovery was high (2 to 3 days of soaking time between points), and 94.5 percent of the solvent injected was recovered.

Recirculated Solvent and Water Test

Experiment 15 was run to determine whether the solvent could be recirculated continuously around the core as in a solvent-soak experiment and still recover significant oil. In the beginning of this experiment, 2.6 pore volumes of solvent were injected at a slow rate into a core. Small samples of the solvent-oil mix were taken daily to determine the percentage of oil in the mix. Periodically, additional solvent had to be added to the circulating solvent to replace the volume of samples taken.

Results

A total of 7.8 pore volumes of solvent was used during 65 days of recirculating (table 8).

During this time, 90.5 percent of the oil in the core had been recovered. The solvent surrounding the core was displaced with deionized water and the core was allowed to soak for 8 days. An additional 1.5 percent of the oil was produced when more water was injected into the core holder. A total of 2.6 pore volumes of water was used in this displacement.

Finally, the core holder was heated to 424° F and the fluids which boiled off were trapped. An additional 1.5 percent of oil was produced in this manner making the total oil produced to be 93.5 percent of the original oil in place. Also, almost all of the solvent and water remaining in the core was produced by evaporation.

This experiment was important for three reasons. First, it showed that continuously recirculating the solvent could recover similar amounts of oil with less solvent being used than in the solvent-soak experiments described previously. Secondly, it showed that water could recover additional oil even when the use of solvent had almost depleted the core. Thirdly, the application of heat to a temperature above the boiling range of the solvent could boil most of the solvent and water from the core.

Comparison of Results

The average results of the three groups of core tests (fig. 20) show that solvent flooding gave a higher recovery per pore volume produced than did solvent-water flooding during the first few pore volumes. However, as the pore volumes produced increased beyond 10, the gap between these two cores and those represented by the solvent-soak curve began to decrease. The solvent-soak experiments eventually obtained more oil than the other experiments. Based on the average ultimate recovery data (table 8), solvent soak obtained 79.4 percent, solvent flood 55.0 percent, and solvent-water flood 56.9 percent recovery of the oil originally in the cores. Also, in many of the solvent flood and solvent-water flooding experiments, the early production rate of oil was low because of the long time required to flow the solvent through the core, thus making the two recovery processes more nearly comparable on a time basis.

PRODUCTION

The first drilling, shooting, and producing program (Phase I) involved three wells, part of a five-spot having a distance of 50 feet between outside wells (7). All three wells were completed similarly. Two strings of 1-in. pipe were installed through a dual-string tubing head. One string was set at 330 ft, the other at 220 ft. Well 9 was the injection well, and wells 7 and 8 were the producing wells.

The injection well was initially filled with solvent from a depth of 330 ft. Subsequent solvent injection was through the 220-ft tubing. Production was accomplished by directing compressed air down the annulus of the production well to clean out all liquids above the 220-ft level. For the first 3 days, solvent injection was continuous. After that a normal injection-production day consisted of producing wells 7 and 8 in the morning, injecting solvent into well 9 for about 12 hours, and again producing wells 7 and 8 at the end of the injection period. This production phase was terminated on Oct. 4, 1972.

The five-spot pattern was completed, and communication tests were made during the next few months.

The difficulties and costs encountered in cleaning out the first three wells after they were shot, compared with the cost of drilling a well to 360 ft, prompted the decision not to use explosives in the two additional corner wells needed to complete a five-spot pattern. There was also a need to see whether fracture communication could be established between wells farther apart than 50 ft. Consequently, the two wells to be fractured were drilled 75 ft apart and diagonally from the two planned corner locations. These are wells 13 and 14 as shown in figure 3.

During the winter of 1972-73, a flash distillation unit was constructed to separate the produced oil from the solvent. Oil and solvent mix are pumped through a 15-kilowatt heater that heats the mixture to 360° F. A control valve next to the 5-ft long, 8-in. diameter flash chamber reduces the pressure from 50 psi to atmospheric pressure. Vaporized solvent is produced through the top of the flash chamber and condensed. Oil, containing some solvent, is removed from the bottom of the flash chamber. The distillation unit will process 18 bbl of solvent-oil mix in 24 hours.

Injection-production operations (Phase II) were resumed on July 10, 1973, using wells 7, 8, 10, and 11 as injection wells and well 9 as the production well. Wells 10 and 11 were completed with dual 1-in. tubing strings similar to the completion of the other three wells. Solvent was injected down the 220-ft string, and well 9 was produced by compressing air down the annulus and displacing well fluids up the 220-ft string. A normal injection-production day consisted of producing well 9 in the morning, injecting solvent for about 3 hours, and producing well 9 at the end of the injection period.

In January 1975, after a soak period of 29 weeks, Phase III was begun. Very little solvent was injected during this period. Previously, production of fluid was limited to removing only the oil from the well cavity. During Phase III, all fluids were

removed from the center well; water production varied from about 60 to 95 percent. Fluid removal was accomplished with a sucker-rod pump installed on the production (center) well. Solvent-oil production remained about the same but the percent of oil in the oil-solvent mix increased to threefold.

Phase IV (waterflood) was begun July 22, 1975, after the completion of eight water-injection wells drilled along the perimeter of a circle having an approximate 75-ft radius from the center well of the five-spot pattern. The drill bit encountered solvent that had migrated outside the pattern in several of the wells. Water rates were determined and set to predetermined rates twice a week by use of turbine meters. Waterflooding was discontinued in November 1975 after more than 30,000 bbl of water had been injected.

The production history is shown in table 9. Soaking time, amount of daily solvent injection, and production techniques have been varied to establish the optimum ratio of oil produced to solvent injected. Soaking periods that have been tried include 1-, 2-, and 3-week periods; soaking only on weekends; and soaking on Tuesdays and Thursdays in addition to the weekends. The latter soaking period would probably give the highest percentage of oil in the solvent produced, but would give less total oil produced over a given period than soaking only on weekends. The average amount of daily solvent injection was 28, 10, 4.5, and 2.5 bbl/day during different periods. Daily production results indicate that the injection rate of 28 bbl/day caused over-flushing of the fracture system between the injection wells and the producing wells and that an injection rate of 4.5 bbl/day did not displace all of the solvent in the formation each day.

The calculated pore volume of the five-spot is 2,868 bbl with an oil content of 972 bbl. This is based on an interwell area of 0.0574 acre and includes the interval from 295 to 330 ft. Cumulative fluid produced from the zone is 2,538 bbl or 0.88 pore volume. Net crude oil production is 263 bbl, or 27 percent of the oil in place.

RESIDUAL OIL

After the waterflood operations were terminated, well 23 was drilled and cored within the five-spot between wells 9 and 10. (See figure 3.) One hundred and forty-one core plugs were cut from the cored interval 258 to 358 ft. Fluids in these core plugs were extracted with toluene; the toluene was then evaporated leaving a residue of crude oil and/or solvent. Percent crude oil was determined by gas-liquid chromatography, and the percent solvent was determined as the difference between 100 percent and the percent crude oil. An examination of the core data indicates an

TABLE 9. - Injection and production data

Injection period	Solvent injected		Solvent-oil mixture produced		Crude oil produced		Water produced, barrels	Oil in mixture, percent	Oil in injected solvent, percent
	Barrels	Barrels per day	Barrels	Barrels per day	Barrels	Barrels per day			
1972 - Phase I									
Fill up	205.62	-	-	-	-	-	-	-	-
May 9-10	80.42	40.21	46.39	23.20	5.78	2.89	1.17	12.46	0
May 15-19	121.66	24.33	108.00	21.60	6.79	1.36	10.00	6.29	0
May 22-26	110.71	22.14	103.73	20.75	5.84	1.17	1.75	5.63	0
May 29-June 2 (Soaked 3 weeks)	0	0	33.82	11.82	3.76	1.25	.58	11.11	0
June 26-30	91.46	18.29	82.56	16.51	6.85	1.37	16.48	8.30	0
July 5-6 (Soaked 3 weeks)	0	0	8.46	4.23	.58	.29	1.73	6.86	0
July 31-Aug. 4	86.61	17.32	73.67	14.73	6.03	1.21	11.60	8.19	0
Sept. 27-29 ¹	0	0	² 70.60	-	³ 1.0	-	ND	-	0
Oct. 2-4 ¹	0	0	² 149.90	-	³ 3.92	-	ND	-	0
1973 - Phase II									
Fill up	403.59	-	-	-	-	-	-	-	-
July 10-13	113.74	28.44	30.61	7.65	2.90	0.73	22.11	9.47	0.04
July 16-20	133.76	26.75	79.06	15.81	5.34	1.07	12.97	6.75	.10
July 23-25 (Soaked 2 weeks)	0	0	21.16	7.05	1.83	.61	8.64	8.65	0
Aug. 6-10	49.26	9.85	30.80	6.18	3.21	.64	32.97	10.39	.97
Aug. 13-17 (Soaked 2 weeks)	35.88	7.18	27.07	5.41	2.54	.51	20.17	9.38	.50
Sept. 4-7	34.79	8.70	25.49	6.37	2.90	.73	17.86	11.38	.40
Sept. 10-14 (Soaked 3 weeks)	48.34	9.67	40.04	8.01	2.75	.55	22.75	6.87	.35
Oct. 8-12 (Soaked 3 weeks)	54.15	10.83	33.70	6.74	2.55	.51	25.77	7.57	1.05
Nov. 5-9	22.61	4.52	22.47	4.49	1.99	.40	22.75	8.86	3.49
Nov. 12-16 ⁴ (Soaked 7 weeks)	12.36	2.37	15.42	3.08	1.48	.30	25.06	9.60	1.78
1974									
Jan. 28-Feb. 1	44.28	8.86	23.37	4.67	2.10	0.42	4.50	8.99	0.61
Feb. 4-8 ⁶	55.25	11.05	21.33	4.27	1.58	.32	7.55	7.41	.58
Feb. 11-15	50.46	10.09	41.22	8.24	2.75	.55	.15	6.67	.46
Feb. 18-22	48.01	9.68	37.59	7.52	2.36	.47	0	6.28	.23
Feb. 25-Mar. 1	47.49	9.50	38.31	7.66	2.04	.41	0	5.32	.06
Mar. 4-8	45.48	9.10	36.86	7.37	2.07	.41	0	5.62	.18

See footnotes at end of table.

TABLE 9. - Injection and production data--Continued

Injection period	Solvent injected		Solvent-oil mixture produced		Crude oil produced		Water produced, barrels	Oil in mixture, percent	Oil in injected solvent, percent
	Barrels	Barrels per day	Barrels	Barrels per day	Barrels	Barrels per day			
1974, Cont'd.									
Mar. 11, 13, 15 ⁸	28.25	9.42	20.75	6.92	1.08	0.36	0	5.20	0.21
Mar. 18, 20, 22	26.57	8.86	18.29	6.10	1.07	.36	0	5.85	.41
Mar. 25, 27, 29 ⁷	28.16	9.39	22.71	7.57	1.41	.47	0	6.21	13.24
April 1, 3, 5	33.82	11.27	20.46	6.82	1.66	.55	0	8.11	8.26
April 8, 10, 12	31.64	10.55	24.38	8.13	1.93	.64	0	7.92	6.23
April 15, 17, 19	31.20	10.40	22.20	7.40	1.66	.55	0	7.48	6.59
April 22, 24, 26	31.06	10.35	22.06	7.35	1.67	.56	0	7.57	6.92
April 29-May 3	32.65	10.88	21.48	7.16	1.64	.55	0	7.62	6.89
May 6-10	34.10	11.37	25.11	8.37	1.90	.63	0	7.56	7.33
May 13-17	30.04	10.01	21.62	7.21	1.73	.58	0	7.99	7.62
May 20-24	29.90	9.97	19.16	6.39	1.68	.56	0	8.79	7.66
May 27-31	26.85	8.95	16.40	5.47	1.51	.50	0	9.20	7.49
June 3-7	30.04	10.01	18.58	6.19	1.62	.54	0	8.74	7.92
June 10-14	40.20	13.40	27.86	9.29	2.32	.77	0	8.33	7.99
June 17-21	30.77	10.26	23.80	7.93	2.20	.73	0	9.23	8.38
June 24-28	35.12	11.71	25.69	8.56	2.28	.76	0	8.87	8.60
(Soaked 29 weeks)									
1975 - Phase III									
Jan. 20-24 ⁸	0	0	57.41	14.35	14.26	3.57	243.93	24.84	-
Jan. 27-31	35.93	11.98	17.25	3.45	4.08	.82	128.43	23.65	12.58
Feb. 3-7	107.94	21.59	99.19	19.83	17.37	1.47	157.89	17.51	12.35
Feb. 10-14	0	0	54.41	18.14	11.99	4.00	144.76	22.04	-
Feb. 19-21	0	0	28.70	14.35	5.54	2.77	114.79	19.30	-
Feb. 25-28	0	0	20.62	6.87	4.38	1.46	95.57	21.24	-
Mar. 3-7	0	0	28.55	7.14	6.65	1.66	69.54	23.29	-
Mar. 10-14	0	0	3.21	1.07	.87	.29	63.25	27.10	-
Mar. 17-21	0	0	21.32	7.11	4.27	1.42	97.11	20.03	-
Mar. 24-28	0	0	6.09	2.03	1.60	.53	69.78	26.27	-
Mar. 31-April 4	0	0	8.27	4.14	1.57	.79	40.74	18.98	-
April 7-11	0	0	10.88	3.63	2.12	.71	57.55	19.49	-
April 14-18	51.60	10.32	13.77	2.75	3.16	.63	57.14	22.95	18.52
April 21-25	0	0	11.73	2.35	3.06	.61	55.02	26.05	-
April 28-May 2	54.62	10.92	15.50	3.10	4.85	.97	47.27	31.59	18.52
May 5 ⁹	0	0	15.89	15.89	4.49	4.49	9.93	28.25	-
July 21 ¹	0	0	222.49	-	67.49	-	-	30.34	-

See footnotes at end of table.

TABLE 9. - Injection and production data--Continued

Injection period	Solvent injected		Solvent-oil mixture produced		Crude oil produced		Water produced, barrels	Oil in mixture, percent	Oil in injected solvent, percent
	Barrels	Barrels per day	Barrels	Barrels per day	Barrels	Barrels per day			
1975, Cont'd. - Phase IV									
July 22-25 ¹⁰	0	0	2.32	0.58	1.22	0.31	0	52.59	-
July 26-Aug. 1	0	0	1.30	.18	.60	.09	2.05	46.15	-
Aug. 2-8	0	0	5.94	.85	2.17	.31	4.58	36.53	-
Aug. 9-15	0	0	2.32	.33	1.01	.14	5.27	43.53	-
Aug. 15-22 ¹¹	0	0	51.29	7.37	10.07	1.44	82.92	19.63	-
Aug. 23-29	0	0	67.37	9.62	13.60	1.94	327.11	20.18	-
Aug. 30-Sept. 5	0	0	29.41	4.20	7.81	.76	476.51	17.99	-
Sept. 6-12	0	0	5.80	.83	.76	.11	474.55	13.15	-
Sept. 13-19	0	0	20.14	2.88	2.92	.42	509.27	14.50	-
Sept. 20-26	0	0	25.21	3.60	3.68	.53	383.73	14.60	-
Sept. 27-Oct. 3	0	0	28.26	4.04	4.01	.57	814.09	14.19	-
Oct. 4-10	0	0	22.46	3.21	2.96	.42	489.58	13.10	-
Oct. 11-17	0	0	33.32	4.76	4.95	.71	420.46	14.86	-
Oct. 18-24	0	0	11.73	1.68	2.97	.42	950.31	25.32	-
Oct. 25-31	0	0	.28	.04	.10	.01	768.61	35.71	-
Nov. 1-7	0	0	.87	.12	.28	.04	789.59	32.18	-
Nov. 8-14 ¹²	0	0	1.59	.23	.61	.09	582.94	40.67	-
Nov. 15-Mar. 9 ¹³	0	0	40.80	-	13.42	-	898.05	32.89	-
Total or average	2646.39	-	2537.87	-	¹⁴ 339.19	-	-	13.36	-

ND - Not determined.

- ¹ Emptied wells to prepare for next phase.
- ² Includes wellbore, fill-up volume.
- ³ Includes oil from wellbore, fill-up volume.
- ⁴ Injection into only one well each day for a 2-week period.
- ⁵ Started flowing production well.
- ⁶ Started injecting only 3 days per week.
- ⁷ Started recycling solvent.
- ⁸ Installed sucker-rod pump on center (production) well, Jan. 6, 1975.
- ⁹ Perforated center well from casing seat to top of formation, May 2.
- ¹⁰ Waterflood begun, July 22.
- ¹¹ Cleared solvent from outside four wells, Aug. 20.
- ¹² Water injection stopped, Nov. 14.
- ¹³ Clearing fluids from wells to March 9, 1976.
- ¹⁴ Re-injected 76.63 bbl.

absence of solvent over the interval 258 to 294 ft. Also, there were two 5-foot intervals, at 303 to 308 ft. and 321 to 326 ft., in which the solvent saturation was 100 percent. These two intervals were located just below the casing point and the bottom of the 1-in. production string. An examination of the core data reveals that the permeability over these intervals is extremely low, most values being less than 1 md.

Percent solvent is plotted against depth in figure 21. Line A-A' was drawn based on the equation $y = 243.88 - 0.628x$ calculated by the method of least squares over the interval 294-359 ft. This line indicates a decrease in solvent content as the depth increases.

SUMMARY AND CONCLUSIONS

There are many heavy oil deposits in the United States; much of this heavy oil is in the mid-continent area. DOE engineers investigated one such reservoir containing 15° API gravity crude and located in southeastern Kansas to determine whether a method could be developed for economic production. The method involves the use of explosives to rubblize the formation followed by the injection of a solvent (SolFrac process.)

The solvent selected for use in this particular field experiment lowered the viscosity of the reservoir oil significantly, prevented appreciable precipitation of asphaltenes, and was relatively easily separated from the oil at the surface.

In the solvent-soak experiments, an increase in the soaking time, the surface-to-volume ratio, and the temperature resulted in an increase in the amount of oil recovered per pore volume produced. Soaking time appeared to be the major influence while the application of heat was not as important a factor in oil recovery as expected.

FIGURE 21. - Percent solvent remaining in cores at end of field test.

In the flow-through experiments, reversing the flow increased the rate of oil recovery, and in some cases higher recovery rates were obtained from the cores with lower oil saturations.

In the experiments where solvent and water were used, the amount of solvent required to produce the oil was much less than using solvent only, but the average recovery was lowered by about 10 percent. These experiments also showed that most of the solvent could be recovered by water injection.

Pelletized TNT, used in wellbore shots, fragmented the oil sand and created communication channels between wells of the 50-by 50-ft five-spot pattern.

In considering the three-well pattern (wells 7, 8, and 9), the airflow tests showed that well 9 had the better injection-production relationship and was selected as the injection well.

In considering the five-well pattern (wells 7, 8, 9, 10, and 11), the water injectivity tests show that wells 7 and 8 have better fracture communication to the system than wells 10 and 11, using well 9 as a production well.

The evaluation techniques did not indicate the extent of the fracture system or the size of rock fragmentation.

The results of the field experiments, even though less than 1 pore volume of oil-solvent mix was produced, showed more oil recovered per pore volume of solvent mixture produced than did the laboratory experiments.

Intermittent injection of about 10 bbl of solvent every other day seems to be the most effective quantity to inject.

Reinjection of the produced solvent-oil mixture was done on a limited basis. Not enough additional oil was picked up during recycling of the solvent to justify this procedure.

During Phase III, the path for the flow of fluids was lowered to the depth of the pump setting. This helped remove some of the heavy oil from the lower fracture system, and the net result was an increase in the percent of crude oil in the oil-solvent mix.

Net crude oil production was 263 bbl or 27 percent of the 972 bbl in place. Some of this oil could have been leached from the formation outside of the five-spot pattern.

The total net injection of solvent was 2,570 bbl, whereas the net solvent produced was only 2,199 bbl. The difference of 371 bbl (14 percent of the injected solvent) represents the amount of solvent lost to the formation.

An economic analysis was not prepared, primarily because of the small size of the experimental test site. The rubblization of the formation in a normal well spacing was not considered feasible because of the present state-of-the-art of fracturing with chemical explosives. In addition, the cost of the aromatic solvent has tripled since initiation of the solvent injection operations.

Use of explosives and solvents to stimulate shallow, low-gravity, high-viscosity oil reservoirs is technically feasible. Additional field testing using larger well spacing should be considered. In the final analysis, economics will govern the application of this technique.

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