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EVALUATION OF THE COALINGA POLYMER DEMONSTRATION PROJECT

Work Performed for the Department of Energy
Under Contract No. DE-AC19-80BC10033

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UNITED STATES DEPARTMENT OF ENERGY

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SUMMARY

The Coalinga Polymer Demonstration Project was designed by the Shell Oil Company to show the relative merits of water and polymer flooding in a reservoir with medium viscosity oil. Located in the East Coalinga Field, Fresno County, California, the 149-acre project area contained four ±22-acre inverted five-spot injection patterns. The target reservoir was a 350 foot thick, unconsolidated sandstone formation at about 2,000 feet. Following nearly two years of water injection and an extensive field polymer injectivity and filtration study, polymer injection into four injection wells began in May 1978. The production response to polymer injection was less than expected and the project was terminated early. Two major contributing factors that resulted in the poor performance were:

1. A loss of polymer injectivity and

2. A lack of movable oil in the project area.

The loss of polymer injectivity was thought to be caused by near wellbore plugging by unhydrated biopolymer and bacterial debris. After polymer injection had begun, a subsequent petrophysical study indicated that little movable oil remained in the project area after primary production.

The project was designed and operated in an expert manner. However, recommendations are made on how the project could have been improved if initiated today. These include: (1) Appropriate petrophysical studies, conducted prior to project initiation, should be conducted to guide the selection of the most suitable area within the field. (2) Polymer injectivity could be improved by completing wells in unconsolidated formations with a screen and liner/gravel pack and by using currently available biopolymers which contain less bacterial debris. These practices will minimize the amount of filtration that is required on location.

INTRODUCTION

The purpose of this report is to provide an appraisal of the Coalinga Polymer Demonstration Project. This appraisal suggests ways which could have improved project performance and emphasizes areas needing additional research. This work is performed for the U. S. Department of Energy under Contract No. DE-AC19-80-BC10033.

The Coalinga Polymer Demonstration Project was initiated as a jointly funded venture by the Shell Oil Company and the Energy Research and Development Administration (later the U. S. Department of Energy) under Contract Nos. E(04-5)-1004 and EF-77-C-03-1556 on June 26, 1975. The objective of this field project was to demonstrate the relative merits of waterflooding and polymer flooding in a reservoir containing medium viscosity oil which has an unfavorable water displacement mobility ratio. To do this, Shell dedicated 149 acres in a representative area of the reservoir as the project area. This area contained four ±22-acre inverted five-spot patterns with the remaining offset 61 acres included as observation acreage updip of the flood patterns. Plans were to inject fresh water at a rate of 5,400 barrels per day into the project's four injection wells long enough to establish a waterflood performance trend, followed by a 1.5 year polymer injection period. After the polymer injection, water injection would resume. The results of the project would indicate whether waterflooding or polymer flooding was feasible for a full-scale supplemental recovery project in the Temblor Zone II reservoir of the East Coalinga Field, Fresno County, California.

This report is divided into three sections. The first section provides background information and includes a discussion on project area geology and general reservoir conditions. The second section is an evaluation of the project's design and implementation and their possible effect on project performance. The third section is an overview of the project performance. Throughout the discussion, suggestions are offered that might have improved the ultimate project performance. These suggestions are simply made in an effort to aid in any future endeavor of this type. All data used in this report have been previously published in U. S. Department of Energy Annual Reports or in geologic and petroleum related publications.

SECTION I

BACKGROUND

GENERAL FIELD BACKGROUND

The East Coalinga Field is located in Fresno County on the northern end of the San Joaquin Valley in central California. A map showing the general field locations is shown on Figure 1.[1] The field has been under primary production since 1901. During the early productive life of the field, little emphasis was put on conservation of reservoir energy. As a result, much of the solution gas was lost, leaving a medium (25 cp) viscosity oil-in-place. Some limited attempts at waterflooding in the East Coalinga Field have been made in spite of the obvious adverse water displacement mobility ratio of 1.46.[2] The results of these attempts are not well documented and discussions as to their success or failure cannot be supported. The field continues to produce primarily by gravity drainage. In the immediate project area, however, there is some evidence that significant dump flooding of water from upper zones into the Temblor Zone II may have also contributed to the reservoir producing mechanism.

PROJECT AREA GEOLOGY

Structurally, the 149-acre project area is located near the crest of a southeasterly plunging asymmetrical anticline, shown on the contour map of the Top Black Shale in Figure 2.[1] The top of the Temblor Zone II, designated as the Top Black Shale on the type log of the East Coalinga Field in Figure 3,[1] occurs at depths of 1,900 to 2,400 feet and dips at between 13 and 14 degrees to the southeast over the project area. The Temblor Zone II, of Middle Miocene age and the main producing formation in the project area, is approximately 350 feet thick. Shell geologists have defined ten separate sand members in Zone II and have divided the reservoir into two distinct depositional environments, marine and non-marine. The "E" and "F" sands at the top of Zone II are marine fine-grained, silty sands interbedded with low energy marine shales. These two sand members are not considered to have a significant influence on field wide performance. However, these sand members are well developed in the project area and are considered in the project evaluation. The ±260-foot interval from the "G" marker down to the top of the Kreyenhagen shale is described as non-marine and contains eight major unconsolidated sand members. These channel sand members are generally correlative across the project area and are considered as separate and non-communicating units.

PROJECT AREA RESERVOIR DATA

There has been much discussion as to the actual reservoir conditions in the project area prior to water and polymer injection.[3] Based upon the available data in 1975, an assessment of pore volume and oil-in-place was made. As additional data became available through the drilling of project wells, a re-assessment of the project area pore volume and oil-in-place was provided by Shell petrophysicists in 1979. Table 1 shows the comparison of the reservoir parameters used to estimate the oil-in-place for each of the two studies, along with other pertinent reservoir data.

It is interesting to note that the project area, shown at an enlarged scale on Figure 4,[1] was initially thought to contain 132 acres. But after planimetering the acreage represented by the boundaries in the 1979 study, the project area included 149 acres.[3] This acreage adjustment, however, was consistent with the simulation grid used in 1975 for the initial project performance prediction work.

As of July 1, 1976, there was a significant difference in the average oil saturation used in each of the studies. In the 1975 study the average oil saturation was estimated at 54 percent. In the 1979 study, the average oil saturation as of July 1, 1976, was calculated to be 39 percent. The differences resulted when the well logs were re-analyzed to account for areal water salinity variations caused by dump-flooding in the project area. Also, an 8 percent reduction in the porosity was used to calculate the pore volume in the 1979 study. Again, this was a result of in-depth well log evaluation. Table 2 shows the comparative results of the two studies and their effect on pore volume and oil-in-place calculations. The important aspect of this comparison is the marked reduction in movable oil-in-place as of July 1, 1976. The 1979 study showed only 3,859 MSTB as compared to the initial (1975) estimate of 10,295 MSTB. This was considered by Shell to be one of the major pitfalls that led to the poor demonstration of water and polymer injection in the project area.[3] There was not a significant amount of movable oil-in-place at the start of the project.

SECTION II

PROJECT DESIGN AND IMPLEMENTATION

INITIAL PILOT PERFORMANCE PREDICTIONS

The demonstration project was designed to make a direct comparison between waterflooding and polymer flooding in a single, representative portion of the field. It was anticipated that the water injection phase would last approximately one year with a total injection rate of 5,400 barrels per day into the four injection wells. A polymer injection phase lasting approximately one and one half years would follow the water injection with an injection rate of about 4,000 barrels per day. It was estimated that a 5.9 percent incremental recovery of the movable oil-in-place would be obtained from water-polymer injection over waterflooding. Incremental oil recovery was projected to be 605,000 STB over a 16-year period.[1] The original projections, using a reservoir simulator, are shown on Figure 5. These projections also show the expected injectivity drop, due to polymer injection, to be about 25 percent. Actual field injectivity tests, to be discussed later, observed a 40 to 80 percent drop. The simulation projections were based on geological and petrophysical data available at the initiation of the project in 1975. Clay sensitivity effects, which reduce fresh water injectivity, were included in the simulator's numeric formulation. The simulation also accounted for areal and vertical distribution of net pay, flow capacity, and fluid saturations. No documented attempts to validate or calibrate the simulation input parameters through the use of history-matching techniques[4] were put forth, nor is there any discussion supporting the size and configuration of the flood patterns. These additional uses of the computer simulation beyond the performance projection, particularly in attempting a performance history match, could have provided insight into input parameter validation and project site suitability. The initial performance predictions were overly optimistic and did not account for the severe polymer injectivity loss and the lower-than-anticipated movable oil saturation.

PRE-PROJECT POLYMER INJECTION TESTS

Between December 1970 and February 1972, an initial series of extensive field tests was conducted to determine the most suitable polymer product for the Coalinga Polymer Demonstration Project. The comparative testing of both polyacrylamide polymer and biopolymer products was to determine the degree of <u>in situ</u> mobility control and possible wellbore impairment. These tests were performed in the project area's polymer injection test well, 9-7-27. The test well is located in the up-dip, extreme western portion of the project area shown in Figure 4.[1] The tests consisted of injecting different polymer solutions (Pusher 700 - Polyacrylamide, Enjay 9700 - Biopolymer, Kelzan MF - Biopolymer) and water only at different times into two sand members of the Temblor Zone II formation. A detailed discussion of this testing can be found in Reference 5 by Tinker, Bowman and Pope. It is interesting to note that during each of the biopolymer tests (Enjay 9700 and Kelzan MF), roughly an 80 percent decrease in injectivity - barrels per day per psi - occurred as compared with pre-polymer fresh water injection rate. The 80 percent decrease in injectivity was "believed to be caused by undispersed or unhydrated polymer and/or bacterial debris left in the polymer from the manufacturing process".[5] It was thought that the injectivity drop could be controlled by proper filtration. Injectivity during the Pusher 700 - Polyacrylamide test decreased roughly 40 percent, but the polymer was considered to be highly susceptible to shear degradation, reducing the effective in situ mobility control. From the results of the initial testing, it was decided that the Kelzan MF would be satisfactory for use in the demonstration project if suitable filtration of the biopolymer was maintained.

Beginning in January 1975, a second series of injectivity tests was initiated to further evaluate the in situ mobility control and potential plugging properties of Kelzan MF. Four separate tests were conducted. The February 1975, Kelzan MF test was very short with polymer injection lasting for only eight days. The test was too short to furnish conclusive data on mobility control. However, about a 50 percent decline in injectivity - barrels per day per psi - was observed over pre-polymer injection rates. A Bacteria Destruct treatment described in Reference 3 was performed using a suction wash technique to remove a suspected bacterial debris impairment. Water injectivity was restored to near pre-polymer injection rates after the treatment, indicating that the bacterial debris impairment was a near-wellbore plugging problem.

Another short test in September 1975 also had similar injectivity reduction problems. The test was complicated, however, by a reduced pre-polymer injection water rate indicating wellbore impairment of an unknown origin.

In September 1976, just after initiation of water injection into the project area injectors, a longer polymer injectivity test was also characterized by a rapid loss of injectivity. This performance was not expected because good quality polymer solutions were maintained throughout the test. Again, quantities of bacteria sufficient to cause wellbore impairment were found during a suction wash treatment.

The final polymer test was started in January 1978, just prior to full pilot polymer injection startup. Injectivity was again significantly reduced with the introduction of polymer into the JV sand. Calculations from a pre-polymer pressure falloff test resulted in a permeability thickness product, kh, of 236.5 millidarcy-feet, md-ft.[3] A pressure falloff test run during polymer injection showed a transmissibility, kh/ , calculation of 26.5 md-ft/cp. This shows an apparent viscosity of 8.9 cp compared to pre-polymer injection and was in good agreement with design specifications. However, actual transient data were not published and no assessment of skin damage was made.

POLYMER FILTRATION

It is obvious that the one underlying similarity for all the injectivity tests was near-wellbore plugging. Data indicating the exact cause of plugging were not available, but it was suspected that the unhydrated polymer and bacterial debris were major contributors. Some filtration tests were conducted by Shell and reported in Reference 5. These tests demonstrated the effect of diatomaceous earth (DE) filtration and various types of filter aids on the filterability of 300 ppm Kelzan MF solution. The tests indicated that a 50 square foot DE filter with a STD Supercel filter aid required a twelve-hour cycle time when it was subjected to a 35 psi differential pressure restriction and a flow of 300 barrels per day of 300 ppm Kelzan MF. This filtration scheme was the basis for the project area filtration system. This particular filtration scheme could remove particles, 0.4 microns in size or greater, without a loss of viscosity. This filtration scheme could not remove bacteria debris but resulted in a threefold increase in filterability over non-filtered fluids.

Two other filter aids were also tested with improved filtering capability. They were Celite 577 and Fibracel-IF. When applied to the test conditions, each filtration scheme showed a significant improvement over the STD Supercel filter aid by removing particles 0.2 and 0.3 microns in size or greater, respectively. The Fibracel-IF removed all of the bacteria but provided only a one-hour cycle time. It was concluded that, if future injection tests required finer filtration than that provided by the STD Supercel, either larger DE filters or alternative methods would be required because cycle times of less than twelve hours were not considered feasible when applied to field applications.

Although never stated in any of Shell Oil Company's annual reports,[1,3,6,7,8] it is presumed that the DE filter and an STD Supercel filter aid used for actual pilot injection were also used for the last field injectivity test in Well 9-7-27. If this were the case, stricter filtration requirements should have been imposed on the actual project polymer injection system. This would have required a larger filtration system because of filter cycle regeneration time. Polymer filtration, or methods to improve the manufacturing process of biopolymers, might be areas where additional research could be justified.

PROJECT WELL DEVELOPMENT

Injection Wells:

Prior to the 1975 contract date, two of the four injectors in the four 22-acre inverted five-spot patterns were drilled and completed through the Temblor II pay with seven-inch casing. Well 15-6-27 was drilled in 1968 and Well 2-7-26 was drilled in 1969. See Figure 4[1] for actual well locations. Well 15-9-27 and Well 2-9-26 were drilled after the contract date. These wells were also completed through the pay with seven-inch casing. All of the injection wells were perforated at selected intervals with four jet shots per foot, suction washed, and selectively stimulated with hydrochloric and hydrofluoric acids (mud-acid). The wells were then selectively Darley treated[9] to stabilize interstitial clays that have a tendency to swell and disperse in fresh waters[10] causing a 20-fold decrease in permeability.[8]

Jennings[11] suggests, and we agree, that injection wells completed in unconsolidated formations such as at Coalinga could have been completed by under-reaming and gravel packing behind a screen or slotted liner. This completion technique, employing a high permeability gravel pack, closely corresponds to an open-hole completion having an 18-inch under-reamed diameter. This offers a surface area for flow that is 860 times larger than that presented by four collapsed perforations per foot.

Producing Wells:

Just after 1975, remedial work was initiated on project area producing wells. Some form of sand control was employed on all of the producing wells. Specific details are outlined in Reference 1. Most, but not all, of these wells were also Darley treated. It is interesting to note that some of the older wells that were not Darley treated did see some oil production increase during the waterflood phase of the project. Those wells that were Darley treated, particularly the center producing Well 1-8-26, experienced a disappointing oil response during both the water and polymer injection phase. Although there is some evidence that the Darley treatments proved to be detrimental, it appears that additional research in the area of clay stabilization and sand control should be considered.

Observation Wells:

Five observation wells were drilled in 1975. Four of these wells were sampling wells selectively completed and isolated in only three of the ten sand members present in each of the wells. The completion intervals for each of the sampling wells are shown below. The other well, 16-2-27, was a logging observation well completed with a non-perforated fiberglass liner through the entire pay interval. Its main function was to furnish saturation change data during the project by monitoring changes in the logging device response.

Sampling Observation Wells	Zones Completed
1-7-26	F, Gc, Hu
1-9-26	F, Gc, Gd
15-8-27	Gc, Gd, Hw
16-7-27	Gd, Hw, Hx

Sampling information, as well as log response interpretation, is well documented in Reference 3. One of the benefits of sampling the observation wells was a better assessment of water salinity in various areas in the reservoir. As stated earlier, much of the pilot area was subject to dump flooding from the Temblor Zone I formation, and the Zone II formation water salinities varied between 4,000 ppm and 9,000 ppm equivalent NaCl. With a quantitative assessment of the water salinity, petrophysical interpretation of the log data was greatly improved. The results of Shell's subsequent petrophysical work, as discussed earlier, indicated that a substantially lower oil saturation existed in the project area than was calculated prior to project implementation.

SECTION III

PROJECT AREA PERFORMANCE OVERVIEW

PRIMARY PERFORMANCE

The 149-acre project area in the East Coalinga Field, prior to the initiation of water and polymer injection, was produced primarily from 63 wells. A project area production performance histogram, beginning in January 1961 and continuing until the initiation of water injection in June 1976, is shown in Figure 6.[1] Cumulative oil recovery from the project area, as of July 1, 1976, is estimated to be between 1.8 and 1.64 MMSTB.[3] In January 1961, the oil production rate was 650 STB per day with about a 13 percent water cut. In June 1976, fifteen and one-half years later, the oil production rate declined to 250 STB per day with about an 80 percent water cut. Total fluid production increased from about 800 barrels per day to nearly 1,600 barrels per day over the fifteen and one-half year period. This performance is not consistent with production characteristics of a reservoir influenced only by a gravity drainage producing mechanism. Generally, a gravity drainage producing mechanism is characterized by little or no water production.[12]

An explanation of the increased water production from the project area is the possibility of dump flooding into mechanically defective wells from the Temblor Zone I formation just above Zone II. Produced water analyses, performed after project initiation, support this idea. The water analyses are presented in the Second Annual Report.[6] Normal water salinities from the Temblor Zone II formation range between 4,000 ppm and 9,000 ppm equivalent NaCl. Salinities as low as 2,000 ppm equivalent NaCl were found in the project area, indicative of Zone I formation water.

There is, however, evidence that the project area's primary production performance is due to gravity drainage. Tinker[13] discussed the existence of desaturated zones found in the gas tracer injection Well 12-7 just west of the inverted five-spot injection patterns in the project area (see Figure 4). These zones were detected using an excellent suite of well logs and were further delineated by actual gas tracer injection. The desaturated zones, indicative of a gravity drainage producing mechanism, may have acted as high conductivity pathways for the dump-flooded water and later for the actual injected water and polymer. This, of course, further complicated the project waterflood and polymer design, from the standpoint of displacement mobility control, to include a possible adverse vertical sweep efficiency effect.

With the combination of a gravity drainage producing mechanism and a possible waterflood producing mechanism due to dump flooding, a relationship between actual project area performance and areal fluid saturation distribution would have been difficult to quantify. But, a program of individual well performance analysis, along with radioactive tracer production profiles, temperature surveys, noise logs, water analysis, and petrophysical work on existing well logs and core data, may have suggested that this project area may have been significantly influenced by dump flooding and, thus, not suitable to demonstrate the relative merits of water and polymer flooding. This same study would have suggested other areas in the East Coalinga Field where a demonstration pilot could have been implemented with a greater degree of interpretability control. The likelihood of finding such an area is remote, however, considering the general age and early completion techniques used in the majority of the primary producing wells in the East Coalinga Field. Dump flooding is probably widespread, making the choice of the project area location reasonably representative of field-wide conditions.

Prior to water and polymer injection, four injection wells, five producing wells, and five observation wells were drilled and/or completed. Four old wells were reconditioned or treated. Of the original 63 producing wells, 39 were abandoned so as not to interfere with the four flood patterns. The current well configuration, without the abandoned wells in the project area, is shown on Figure 4.[1]

Production performance of the project area under water and polymer injection was significantly lower than was originally predicted. A ten-year project performance curve is shown on Figure 7.[3] The performance curve includes gross production rates, oil rates, water cut, and both water and polymer injection rates with a projection of primary performance based on the five and one-half years of pre-injection oil rates.

WATER INJECTION

Waterflooding began in late June 1976, with a water injection rate of approximately 5,400 barrels per day. Water injection at this rate lasted for nearly 22 months. During this period, gross production rates nearly doubled from 1,200 to 2,300 barrels per day with oil production increasing slightly and remaining steady at about 400 barrels per day. Most of the oil response can be attributed to an up-dip, non-pattern Well 275-27 which was one of the few wells not Darley treated. A tracer survey conducted during this time was rather inconclusive; showing, if anything, poor areal sweep.

POLYMER INJECTION

Polymer injection into the four project injection wells began in May 1978. The initial injection rate was 1,600 barrels per day and was increased to 1,800 barrels per day in mid-May. In about 45 days, three of the four injectors reached their maximum wellhead pressure constraints of 600 psig. At that time, total polymer injection dropped to about 1,000 barrels per day. The fourth injector experienced a more gradual injectivity decline. In six months, polymer injection for all four injectors dropped to about 500 barrels per day. This injectivity drop affected oil production rates which fell below the projected primary performance prediction, in June 1978 (Figure 7). Polymer injection was terminated in October 1979. Water injection was resumed in November 1979 at about 1,500 barrels per day.

CONCLUSIONS

1. The project was not a successful demonstration of polymer flooding in the East Coalinga Field. Little or no incremental oil was recovered.

2. One major factor affecting performance was severe polymer injectivity loss. This resulted in reduced oil production and early termination of the project. The injectivity loss was caused by wellbore plugging of unhydrated polymer and bacterial debris. This problem could have been minimized by improved completion techniques and/or more extensive polymer filtration. It is recognized that improved filtration may not have been practical.

3. Another factor affecting performance was the lower than expected movable oil in the project area. An in-depth petrophysical study of the area prior to the start of the project might have suggested that an alternate project location be found.

4. Darley treatments, designed to stabilize clays, may have adversely affected performance of producing wells. Some production performance records tend to support this conclusion.

RECOMMENDATIONS FOR PROJECT IMPROVEMENT

Our evaluation of this project showed that it was well conducted, and utilized state-of-the-art technology. The following are recommendations on how the project could have been improved if initiated today. These are made with the advantage of viewing the project in hindsight and considering improvements in technology.

1. Prior to a major commitment to project surface facilities and water/polymer injection, a petrophysical study of the project area should have been completed. This study would have shown, as Shell's 1979 study indicated, that there was little mobile oil in the project area at the start of water and polymer injection. This study could have also suggested areas where a pilot project might have been better suited to demonstrate the relative merits of both water and polymer injection in the East Coalinga Field.

2. Biopolymers available at that time were in dry form. Such polymers contain some bacterial debris and were also difficult to completely hydrate. Injectivity into low permeability reservoirs can be difficult unless the polymer is extensively filtered. Manufacturers have placed a major emphasis on producing a cleaner product. Consequently, the currently available biopolymers have less bacterial debris, especially those available in liquid broth form. Projects initiated today could utilize the improved products, thereby reducing the need for costly, extensive filtration.

3. To improve polymer injectivity in unconsolidated formations, injection wells should have been completed with a screen and liner/gravel pack. This should provide a significant increase in cross sectional area available to injection and resulted in less near wellbore plugging.

RESEARCH AREAS

1. Continued attention is needed in the manufacturing process of biopolymers to reduce the amount of bacterial debris that occurs with the polymer product.

2. Clay stabilization and reduction of clay swelling by using the Darley treatment and other techniques could be further evaluated.

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TABLE 1

PROJECT PARAMETERS

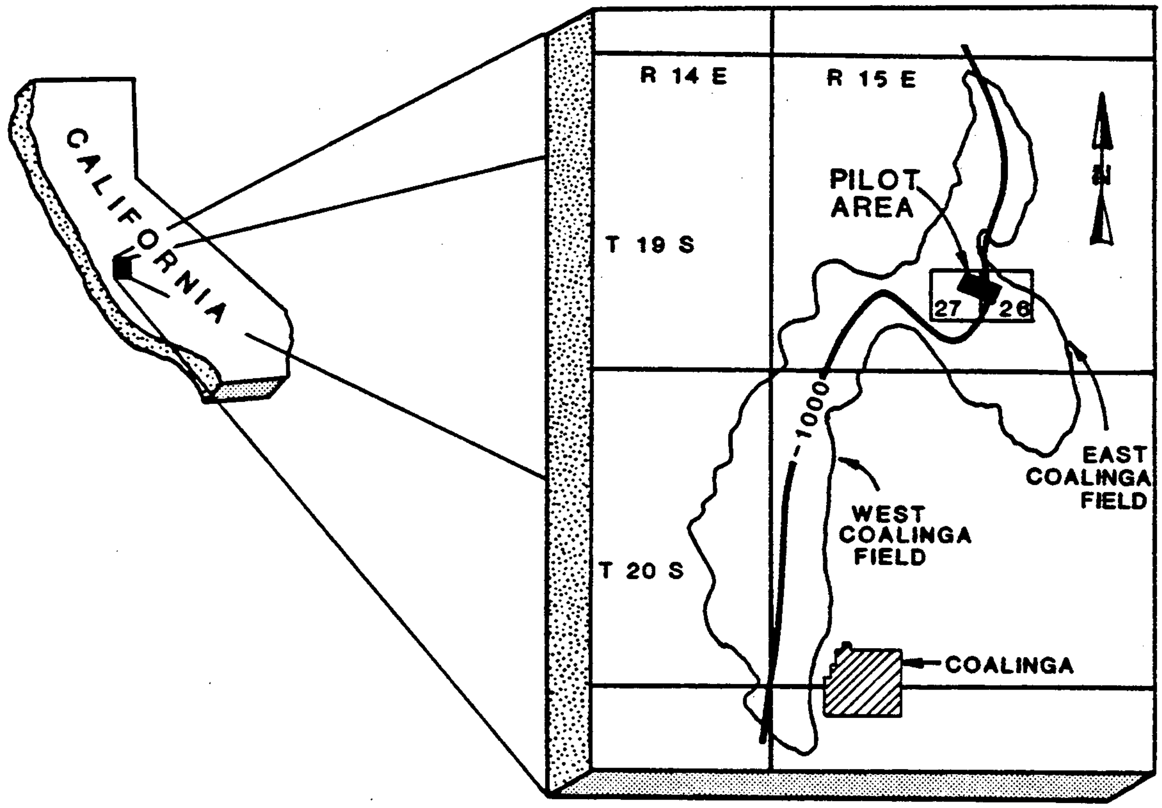
	1975 Estimate	1979 Estimate
Project Area, Acres	132	149
Average Thickness, Feet	125	129
Porosity, Fraction	0.265	0.243
Initial Average Oil Saturation, Fraction	0.650	0.660
July 1976 Average Oil Saturation, Fraction	0.540 (1)	0.390 (2)
July 1976 Average Water Saturation, Fraction	0.330 (1)	0.490 (2)
July 1976 Average Gas Saturation, Fraction	0.130 (1)	0.120 (2)
Waterflood Residual Oil Saturation, Fraction	0.235 (1)	0.28 ± .04 (2)
Permeability Range, md	50-480	50-480
Reservoir Temperature, °F	100	100
Oil Viscosity at Reservoir Temperature, cp	25.	25.

(1) Initial Simulation Study
(2) Petrophysical Reassessment

TABLE 2

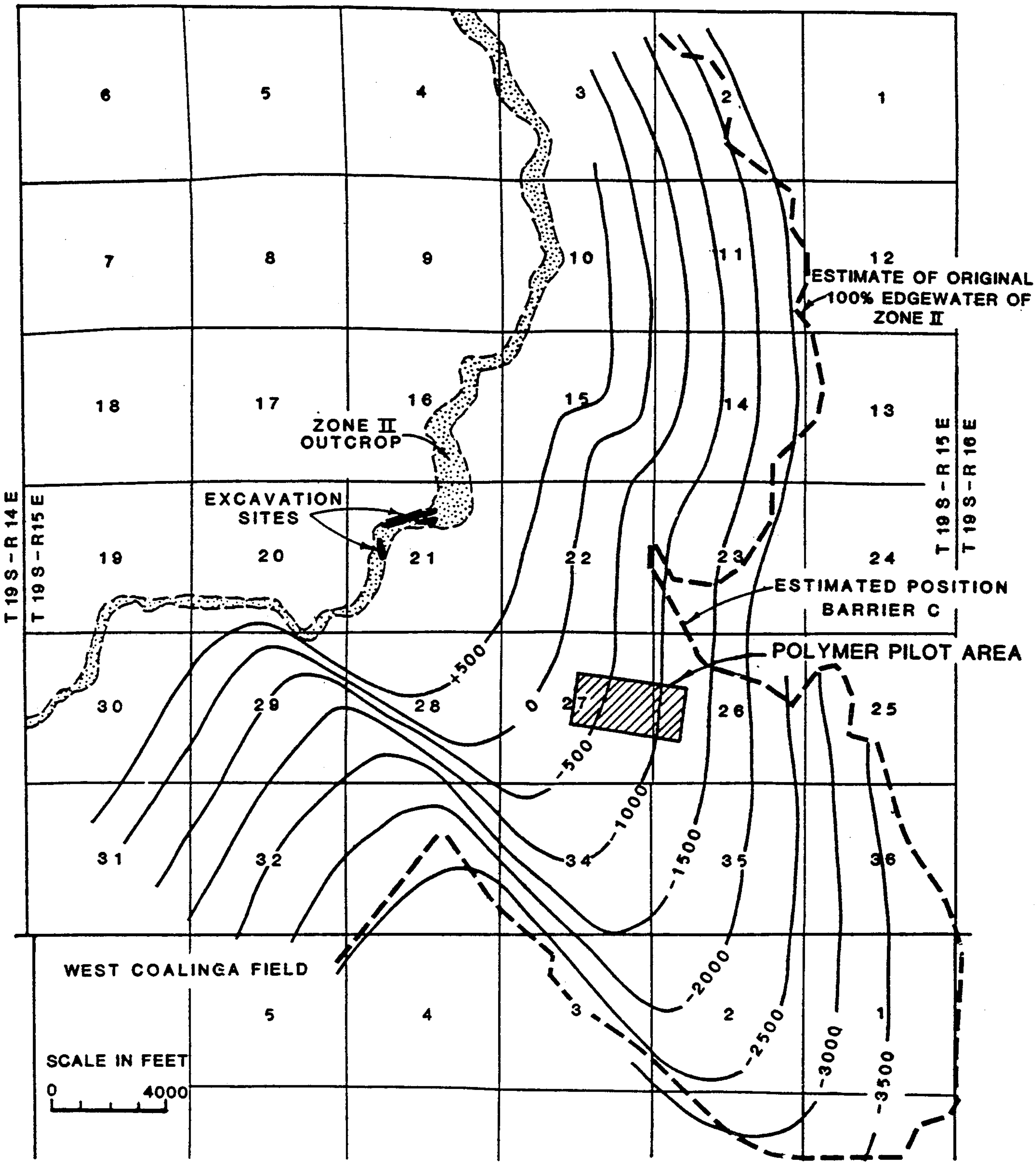
PROJECT VOLUMES

	1975 Estimate	1979 Estimate
Pore Volume	33,922 MB	36,130 MB
Original Oil-In-Place	20,607 MSTB	22,286 MSTB
Zone II Production to July 1976	18,000 MSTB	16,424 MSTB
July 1976 Oil-In-Place	17,780 MSTB	13,680 MSTB
July 1976 Movable Oil-In-Place	10,295 MSTB	3,859 ± 1,403 MSTB
Continued Primary	710 MSTB	710 MSTB
Differential Waterflood	2,040 MSTB	
Differential Polymer Flood	605 MSTB	



COALINGA FIELD INDEX MAP
POLYMER DEMONSTRATION PROJECT

FIGURE 2



EAST COALINGA FIELD
FRESNO COUNTY, CALIFORNIA
CONTOUR TOP BLACK SHALE
C. I. = 500'

FIGURE 3

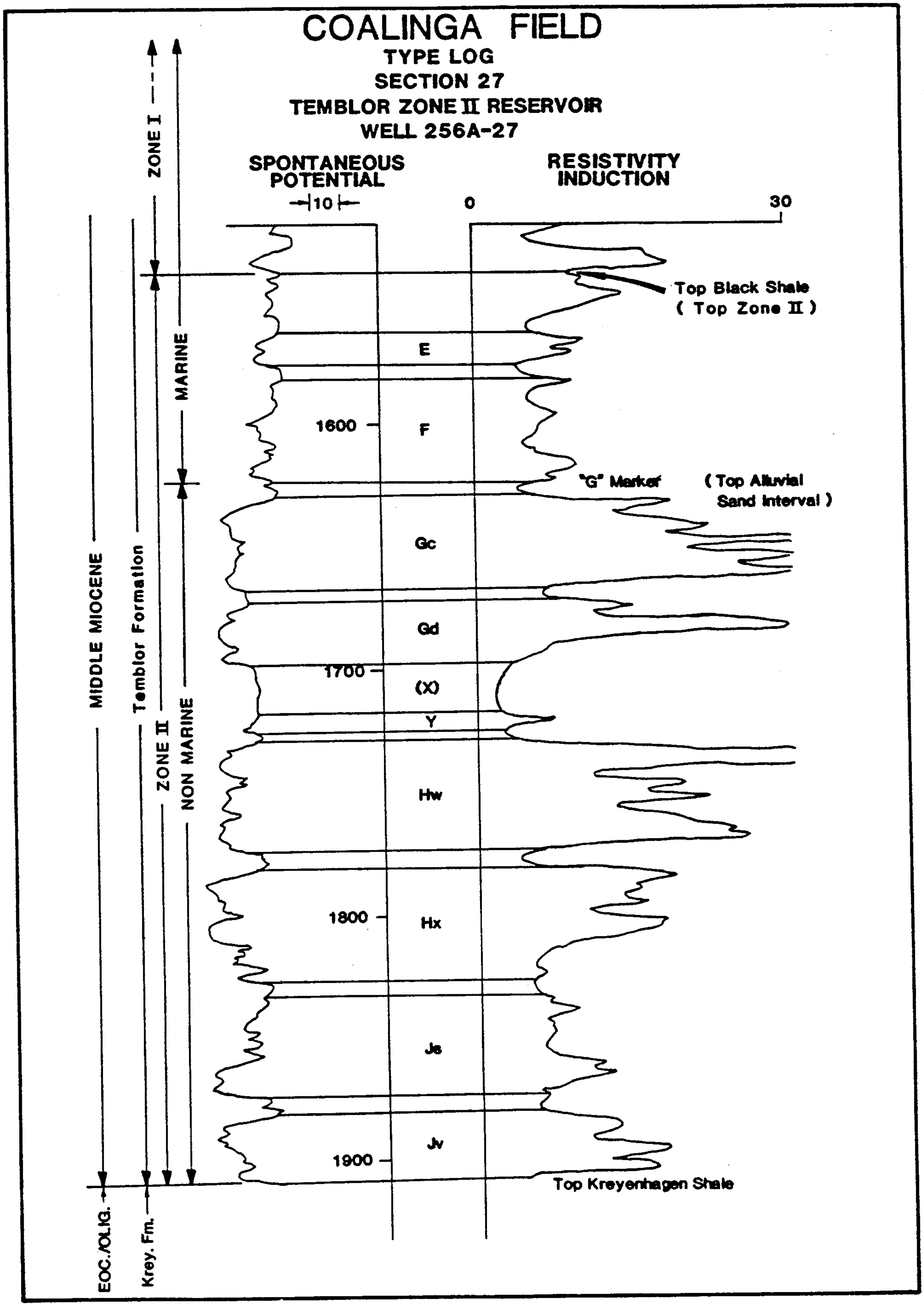
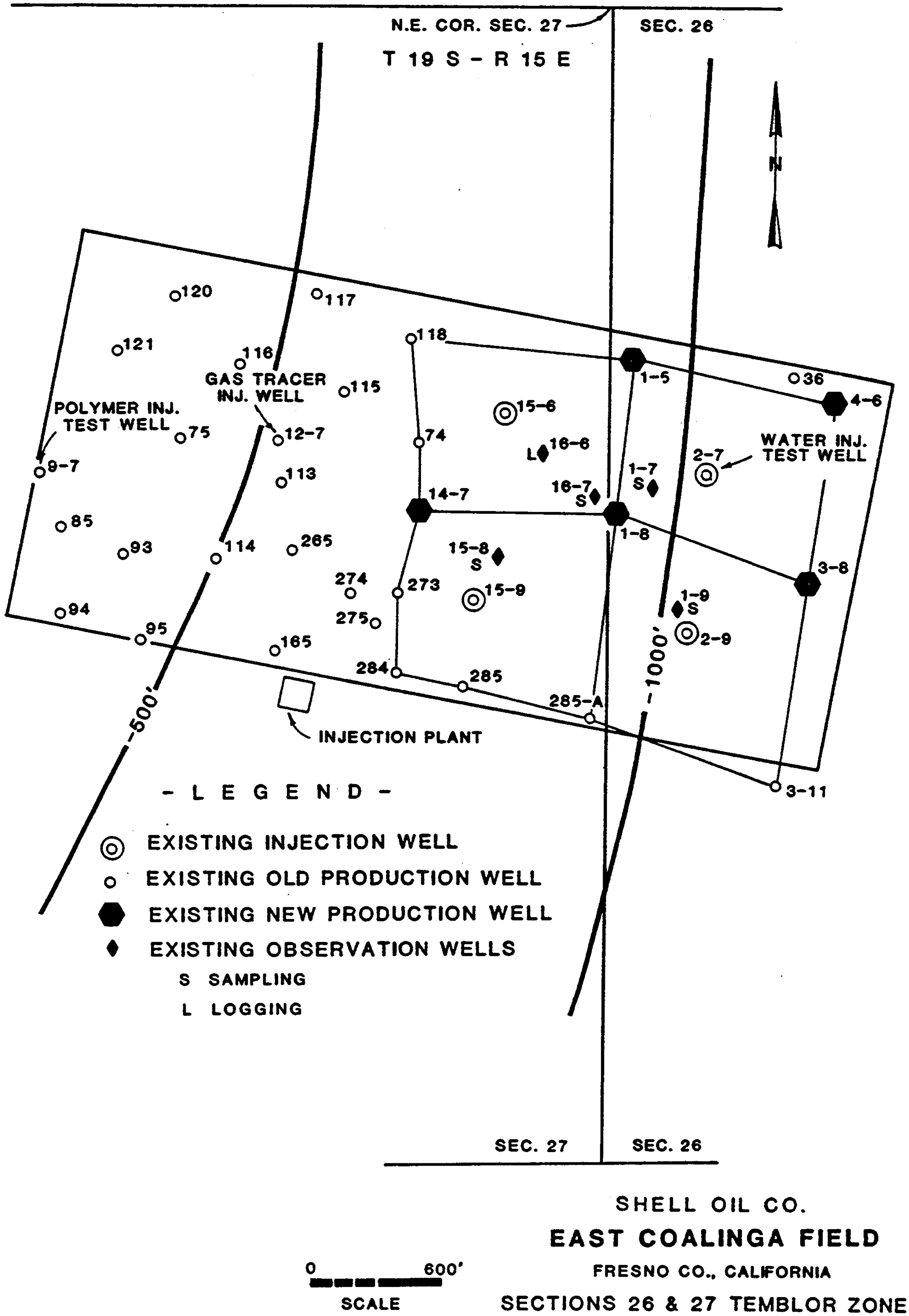

COALINGA FIELD
TYPE LOG
SECTION 27
TEMBLOR ZONE II RESERVOIR
WELL 256A-27
SPONTANEOUS POTENTIAL
10
RESISTIVITY INDUCTION
0
30
Top Black Shale
(Top Zone II)
E
1600
F
"G" Marker
(Top Alluvial Sand Interval)
Gc
Gd
1700
(X)
Y
Hw
1800
Hx
Js
Jv
1900
Top Kreyenhagen Shale
ZONE I
MARINE
MIDDLE MIOCENE
Temblor Formation
ZONE II
NON MARINE
EOC./OLIG.
Krey. Fm.

FIGURE 4



SHELL OIL CO.

EAST COALINGA FIELD

FRESNO CO., CALIFORNIA

SECTIONS 26 & 27 TEMBLOR ZONE II

POLYMER PILOT AREA

CONTOURS ON TOP BLACK SHALE

FIGURE 5

RESERVOIR SIMULATION STUDY
EAST COALINGA FIELD
PROCESS COMPARISON
OIL PRODUCTION AND WATER INJECTION

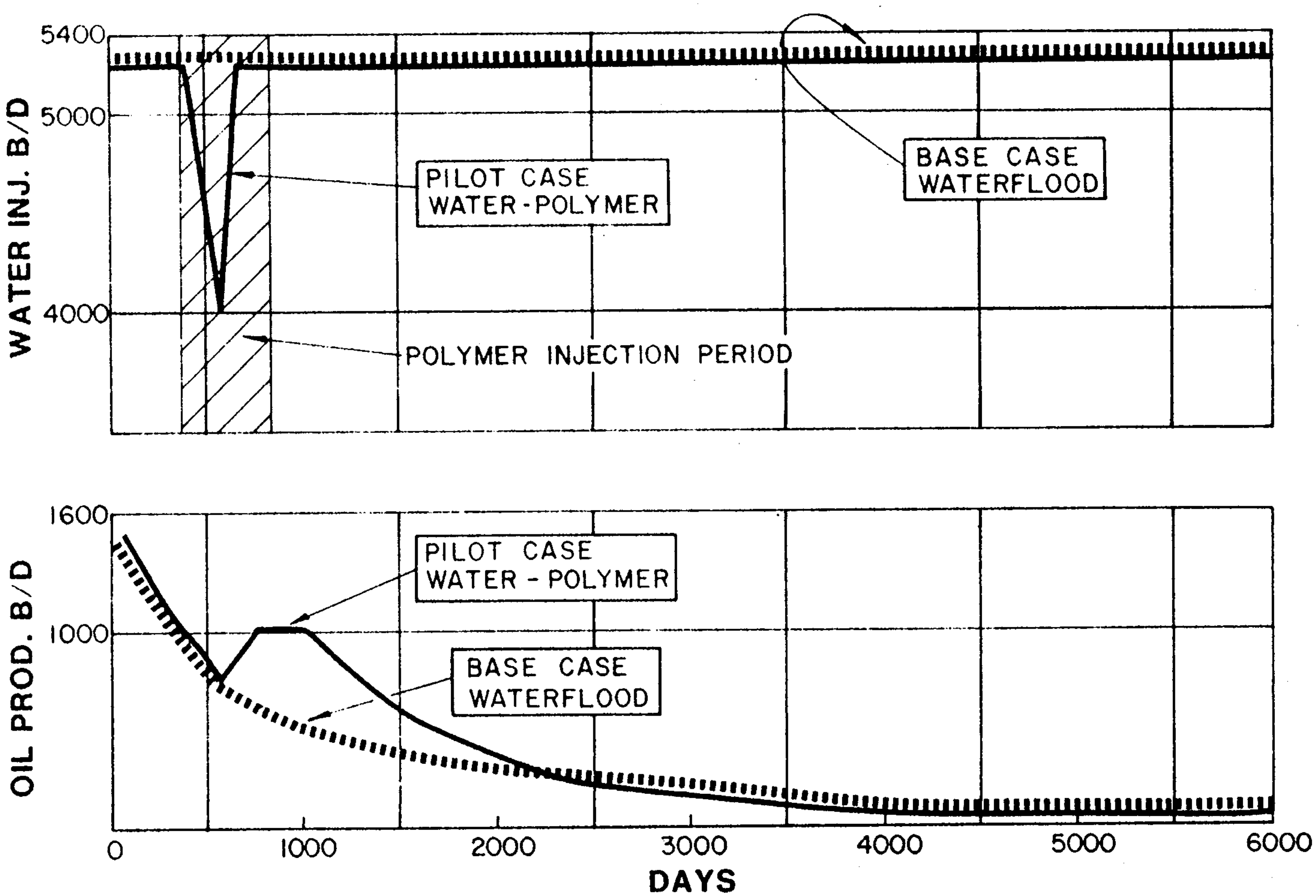
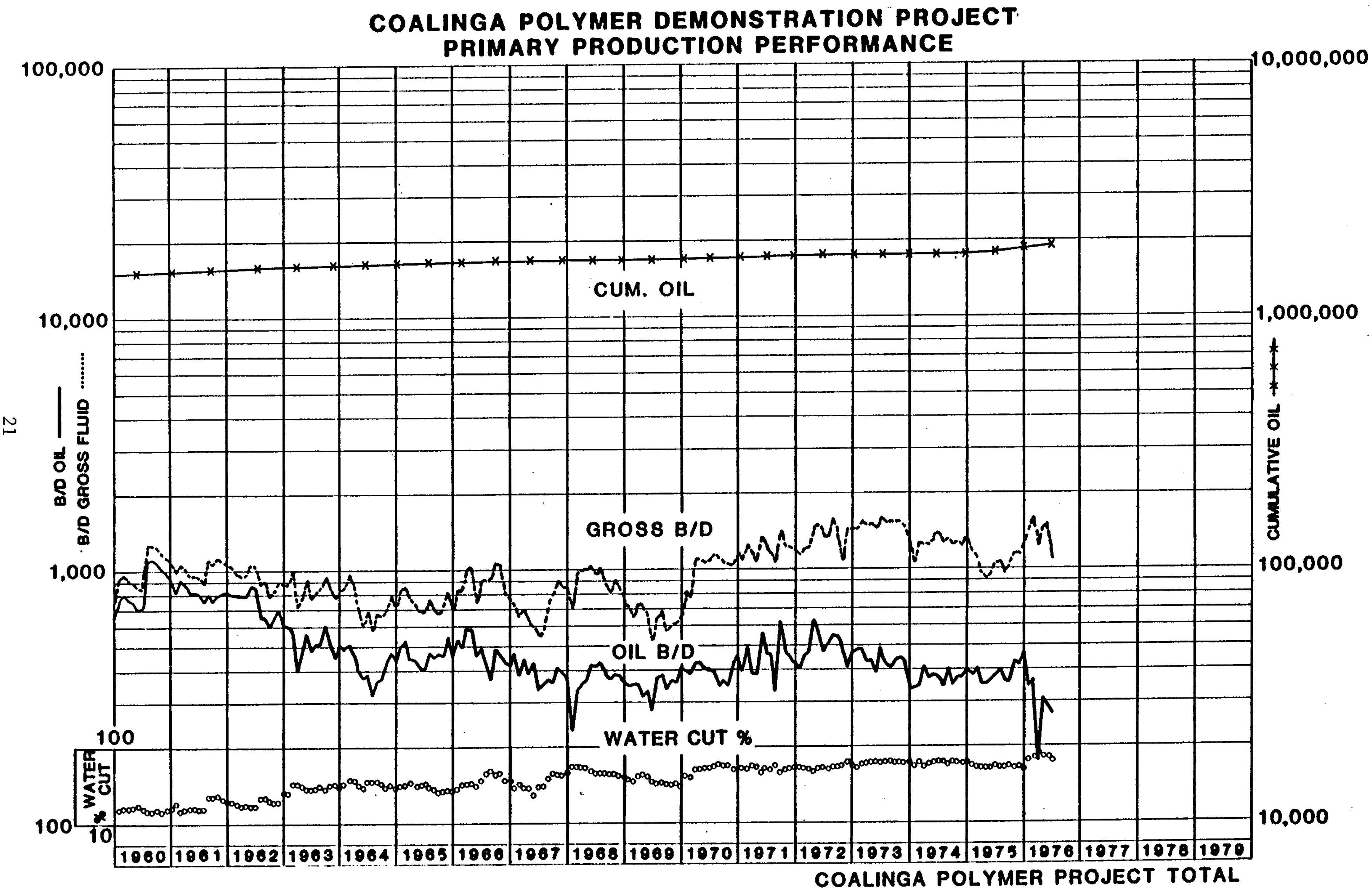


FIGURE 6



COALINGA POLYMER DEMONSTRATION PROJECT
PRIMARY PRODUCTION PERFORMANCE
100,000
10,000
1,000
100
100
10
B/D OIL
B/D GROSS FLUID
% WATER CUT
10,000,000
1,000,000
100,000
10,000
CUMULATIVE OIL
CUM. OIL
GROSS B/D
OIL B/D
WATER CUT %
1960
1961
1962
1963
1964
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
COALINGA POLYMER PROJECT TOTAL

FIGURE 7

COALINGA POLYMER
PILOT PERFORMANCE CURVE
IMMEDIATE PILOT AREA