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IMPROVED OIL RECOVERY BY ALKALINE FLOODING IN THE HUNTINGTON BEACH FIELD

Final Report

Work Performed for the Department of Energy
Under Contract No. DE-AC03-79ET12053

Date Published—October 1982

Aminoil USA, Inc.
Huntington Beach, California

National Petroleum Technology Office
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Final Report

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TABLE OF CONTENTS

LIST OF ILLUSTRATIONS

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ABSTRACT

A pilot test of an alkaline flooding process for improved oil recovery is being conducted by Aminoil USA in the Lower Main Zone of the Huntington Beach Field. This field was developed in 1940 with primary production continuing through 1969. At that time, a pilot waterflood was initiated in Fault Blocks 22/23 using a 5-spot pattern with four injection wells. Approximately two pore volumes of water had been injected into this area prior to initiation of the alkaline flooding pilot.

A softened water preflush was started in June, 1978 in the same pattern used for the waterflood pilot following redrilling of two injection wells and workover of several production wells in the pilot area. The softening plant was designed for an injection rate of 10,000 B/D. Soft water preflush injection continued through March, 1980. A series of organic, inorganic and radioactive tracers were injected in October, 1979 to monitor fluid movement in the pilot area. In March, 1980, alkaline injection at a concentration of 0.2% by weight of sodium orthosilicate solution was begun. The concentration of alkali was increased to 1.0% by weight in October, 1980 and has been continued at this level to the present time. Alkaline injection will be continued through 1984. A short postflush with softened water will be injected prior to continued injection with field produced water to the economic limit of the pilot area.

Preflush breakthrough has occurred in three of the production wells, as measured by reductions in salinity and water hardness. The tracers have not been detected at any significant levels, except for tritium. Oil production has followed a typical waterflood decline over the period of pilot operation. There has been no significant response to the alkaline injection, but there has been an indication of decreases in the water/oil ratio in the central producer in the inverted 5-spot pattern area.

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HISTORY OF PROJECT

This project was initiated July 1, 1977 with a completion date of December 31, 1980. The total cost under the project was $2,289,997, with DOE funding $531,374. During the first year, laboratory studies were conducted to develop an improved alkaline waterflooding process. A comprehensive coring and logging program was run during redrilling of one of the pilot injectors. The softening and injection facilities were constructed during this period. During the second year, laboratory studies and the preflush were continued. In the third year, tracer injection occurred in September-October, 1979, to establish flow patterns and the preflush was completed in March, 1980. Injection of alkali was started in March, 1980 and will continue through 1984.

GENERAL PROJECT DESCRIPTION

INTRODUCTION

The Huntington Beach Field is a major oil accumulation lying on the California coastline approximately 20 miles southeast of Los Angeles. Figure 1 shows the location of the Huntington Beach Field in the Los Angeles Basin with the offshore area of the field cross-hatched.

The field has a length of seven miles along the Newport-Inglewood Fault Zone and a maximum width of three miles. The trapping of oil is controlled by a complex combination of structural, fault, and stratigraphic mechanisms. Production from the offshore area is from five major zones with the upper zone assisted by steam injection while three of the lower zones are under waterflood. One of the lower zones has not yet been waterflooded and is producing on primary. The current water injection rate of 450,000 B/D ranks the Huntington Beach Field as the third largest waterflood in the U.S.

An example of one of the major producing zones in the offshore area of the Huntington Beach Field is shown in Figure 2. Note the change in orientation of this figure. All maps of the offshore area are oriented with the shoreline at the bottom, looking offshore. The contour lines are for the top of the Lower Main Zone, with the alkaline flood project area outlined near the center of the map.

The cross section A-B indicated on the Huntington Beach Offshore Area map (Fig. 2) is shown in Fig. 3. This cross section is just offshore from the project area and shows the five major productive zones. The Lower Main Zone is the subject of this evaluation and it is the zone where the alkaline flood is being pilot tested.

A map of the alkaline flood project area is shown in Fig. 4. The area was originally drilled in 1940 and produced by primary means until 1969, at which time a pilot waterflood was initiated in Fault Block 22 using a single 5-spot pattern. The pilot flood was expanded to the entire Lower Main Zone in the period from 1971 to 1972. The same fault block and pattern used for the waterflood pilot is being used for the alkaline flood pilot with the area in Fault Block 23 also included as part of the response pattern.

Since all the wells shown in Fig. 4 have been directionally drilled from onshore locations, the completion intervals penetrate the zone at an average angle of 20^{o}. In Fig. 4, the small circle shows where the well penetrates the top of the zone while the large circle indicates the bottom of the completion interval. The wells are completed with gravel packed slotted liners except for four older producers in the project area which are completed with slotted liners but not gravel packed. Production rates are limited to 1000 B/D in these older producers to prevent sand problems.

Approximately two pore volumes of water had been injected into the project area prior to the start of preflush injection. It is currently producing at a water-oil ratio of over 35. Remaining economic life of the project area was estimated to be one year without the enhanced recovery project. Original oil-in-place was estimated to be 1300 STB/AF, of which approximately 700 STB/AF remain in place.

The purpose of conducting the alkaline flood pilot test is to establish the oil recovery effectiveness of the tertiary process utilizing the waterflood's existing 5-spot injection pattern in Fault Blocks 22 and 23. In order to allow a more thorough evaluation of the project, a contract was entered into with the Department of Energy to provide partial funding for two aspects of the alkaline pilot project. The objectives of this contract were as follows:

(1) To determine the residual oil saturation distribution in the watered-out pilot area through a comprehensive coring, logging and core evaluation program; and

(2) To establish a basis for evaluation of the pilot process using reservoir tracer tests, laboratory core flood tests and reservoir simulation.

DETERMINATION OF RESIDUAL OIL SATURATION

Redrilling of Well S-55A

One of the injectors being used in the alkaline flood pilot, Well S-55A, was redrilled due to poor mechanical condition. This well is shown as the redrilled Well S-55B on Fig. 4. S-55A had been in use since 1969 with a cumulative injection of over 20 million barrels of water at an average rate of approximately 7000 B/D.

A program was formulated to log and continuously core the entire productive section of the Lower Main Zone to determine the oil remaining in place at a location which had been extensively waterflooded.

A comprehensive group of logs were run after the coring was completed. The group consisted of three resistivity tools (a shallow focused log, a medium induction log, and a deep induction log), SP, gamma ray, compensated neutron, compensated density, and a proximity log-mini-log. Computer assisted calculations were completed on the logs.

Coring Operations

At the top of the zone, the mud system was changed over to a specifically formulated coring fluid and the well was continuously cored to the water-oil contact using both plastic sleeve and pressure core barrels. A total of 535' were cored using a 3-1/2" diameter plastic sleeve core barrel while 78 feet were cored with a 2-1/2" diameter pressure core barrel.

The Lower Main Zone of the Huntington Beach Field is split into three major subzones by shale breaks which are correlatable across large areas of the field. These divisions are the LM_{2-3}, the LM_{3-4}, and the LM_{4-5}. The coring was planned so that pressure cores would be obtained both in the LM_{2-3} and in the LM_{3-4} zones.

Recovery with the plastic sleeve barrel was 73.5% while recovery with the pressure barrel was 36%, which was primarily due to the smaller diameter of the core that the pressure barrel cut. The overall recovery was 69%. This recovery percentage is excellent considering that the reservoir is a slightly consolidated sand, interbedded with shale and clay, and that the well is directionally drilled with a maximum deviation of 45 degrees from the vertical. Deviation through the zone was 28° from vertical.

The core material was described at the well site and then frozen in dry ice before transportation to a local core lab for analysis. The core material which was not used for analysis has been kept in continuous frozen storage.

Determination of Current Oil-in-Place

Determination of reservoir porosity and oil saturation at an extensively waterflooded location in the reservoir were the primary objectives of the test well. In a poorly consolidated reservoir such as the Lower Main Zone at Huntington Beach, it is essential to determine both in situ porosity and saturation due to the stress sensitivity of the reservoir rock.

The depositional environment of the reservoir plays a major role in the distribution of porosity and oil saturation and in understanding current reservoir performance. The turbidite deposition of the Lower Main Zone in a marine environment has created a reservoir in which the rock properties can vary extensively in a short vertical interval. Lithology can vary from shale through sand to conglomerate in a three foot interval. The variation in rock type translates into extremely wide ranges for porosity, permeability and saturations. The routine core analysis data which are shown in Table 1 give an indication of these ranges. Helium porosity at zero confining pressure varied by over a factor of two from 19.7% to 43.4%. Air permeability ranged from 2 to 8650 md while the range in oil saturation was 0 to 45.8% PV.

Porosity Under Confining Pressure

Porosities in the range of 30% are typically determined from routine core analysis of poorly consolidated samples. The average porosity from routine core analysis of 133 core plugs from Well S-55BZ was 29.7%. The effect of triaxial confining pressure on routine core analysis porosity is shown in Fig. 5 for 14 samples distributed throughout the productive interval of the Lower Main Zone. The average of these samples is shown as the dashed line in Fig. 5.

Since the exact state of stress in the reservoir is uncertain, the confining pressure is calculated to be the overburden pressure of one psi/foot less the reservoir pressure.

At the time of discovery, reservoir pressure was 1800 psi at the datum depth of 4100 feet subsea, giving an effective confining pressure of 2300 psi. As the reservoir was produced under primary, the pressure declined to approximately 100 psi for an effective confining pressure of 4000 psi. Waterflooding has increased the reservoir pressure back to the initial pressure of 1800 psi and decreased the effective confining pressure to 2300 psi.

The 14 sample average curve shown in Fig. 5 had an initial unconfined porosity of 28.9% which decreased by 20% or 5.7 porosity units to 23.2% at a confining pressure of 2300 psi. At the confining pressure of 2300 psi, the sample porosity ranged from 20.6% to 25.4%.

Since the average unconfined porosity of 28.9% for the 14 core samples on which confining pressure data was obtained was slightly below the total zone average of 29.7%, the 20% decrease in porosity due to confining pressure was applied to each of the subzones and the porosities reported in Table 2. Application of the 20% porosity reduction resulted in a total zone average porosity under 2300 psi confining pressure of 23.8%.

Due to the stress history of the reservoir, a hysteresis or inelastic effect on porosity could possibly occur. This potential influence was investigated in the lab by determining porosities of all core plugs on the decreasing pressure cycle. Although the meaning of the decreasing pressure data from a reservoir viewpoint is uncertain, in this case there was less than one porosity unit difference over the pressure range of interest and therefore no correction was applied for this possible effect.

Porosity from Pressure Core Analysis

A special lab technique was developed to obtain porosity measurements on plugs cut from the pressure cores. These cores had been recovered under reservoir pressure and frozen at the surface. The plugs were thawed under a triaxial confining pressure of 2300 psi and the reservoir fluids removed using sequential flushing with methanol and toluene. Toluene filled pore volume and bulk volume were determined under confining pressure and the porosity calculated.

The average porosity of seven pressure core plugs from the LM_{2-3} subzone was 23.2%. In the LM_{2-3} subzone the average porosity of the conventional cores under a 2300 psi confining pressure with helium filling the pore space was 23.6%, indicating good agreement between the porosity of the pressure cores and the porosity of the conventional cores under confining pressure. Pressure core recovery in the LM_{3-4} subzone was insufficient to present meaningful data for this subzone.

Porosity from Logs

FDC and CNL Logs, using lab measurements of grain density, were used with a computerized cross plotting technique to calculate porosity. Average log porosities of 24.2% and the average core porosities under confining pressure of 23.8% are in good agreement. The log and core porosity comparison for each subzone are listed in Table 2.

Results of Saturation Determination By Routine Core Analysis

Routine core analysis was performed on 133 plugs from Well S-55BZ and this data is summarized in Table 1. Oil saturation determined by routine core analysis at zero confining pressure varied significantly from zone to zone. Average oil saturation in the LM_{2-3} interval was 22%, while the LM_{3-4} had an average oil saturation of 18.9% and the LM_{4-5} had an average oil saturation of 11.9%. These routine core analysis oil saturations were corrected back to reservoir conditions using the following equation

$$S_{or} = S_{o\,RCA} \times B_o \times \frac{\emptyset_{RCA}}{\emptyset_R}$$

Where

S_{or} = residual oil saturation in the core at reservoir condition

$S_{o\,RCA}$ = oil saturation determined by routine core analysis

B_o = oil formation volume factor

$\emptyset_{RCA}$ = porosity determined by routine core analysis at zero confining pressure

$\emptyset_R$ = reservoir porosity

to account for the formation volume factor and the change in pore volume due to confining pressure. The corrected oil saturations were 30.9% in the LM_{2-3}, 26.5% in the LM_{3-4}, and 16.7% in the LM_{4-5}.

Since both oil and water contents are determined directly in routine core analysis and free gas is not present in the reservoir, the corrected sum of the oil and water saturations should completely fill the reservoir pore space. Over the entire interval cored, the sum of the oil and water saturations was 98.2% which fills the reservoir pore space within experimental error.

Saturations from Pressure Core Analysis

The advantage of pressure cores over conventional cores is that they are recovered and frozen under reservoir pressure which prevents saturation changes due to loss of reservoir pressure.

A special laboratory technique was developed to obtain saturations under conditions of continuous confining pressure.

The average corrected reservoir oil saturation of seven pressure core plugs from the LM_{2-3} subzone was 32%. The average corrected reservoir oil saturation from conventional core plugs in the LM_{2-3} subzone was 30.9%.

The fluid saturations obtained from analysis of the pressure cores confirmed that significant bleeding did not occur in the conventional cores and the conventional core saturations could be adjusted to reservoir saturations through a porosity and a formation volume factor correction as noted above.

Saturations from Logs

Reservoir saturations were computed from digitized electric log data using lab measurements of formation factor and cation exchange capacity. The formation factors and cation exchange capacities were low, indicating a relatively clean sand.

The determination of formation water salinity in each of the subzones required considerable effort due to change in injection water salinity during the waterflood. The TDS in the formation water prior to waterflood was 25,600 ppm. Sea water, with a TDS of 33,000 ppm, was injected for the first four years of the waterflood. The amount of sea water in the injection stream decreased over the next 1-1/2 years as produced water reinjection increased. A small fraction of brackish water was used as make-up for the next 1-1/2 years until sufficient produced water was available to inject all produced water.

Use of the salinity history of the injection water with injection profile data showed that only sea water had been injected below the LM_3 marker. A production profile while the well was backflowing showed that 30% of the flow was from below the LM_3. This data allowed the salinity in the LM_{2-3} zone to be calculated at 29,400 ppm compared to the salinity of 33,000 ppm in the LM_{3-4} and LM_{4-5} and these salinities were used in the log calculations.

The log derived saturations in general agree well with the core derived saturations. The average oil saturation was 30.2% in the LM_{2-3} interval where the conventional core analysis oil saturation corrected to reservoir conditions was 29.3% and the pressure core oil saturation was 32%.

The average oil saturation in the LM_{3-4} interval was 28.3% which compares with a value of 25.3% from the core analysis data corrected to reservoir conditions.

The average oil saturation in the LM_{4-5} interval was much lower due to the occurrence of original water tables in several of the sand bodies. The average oil saturation calculated from the logs in the LM_{4-5} interval was 11.7% while the average oil saturation from the core analysis data corrected to reservoir conditions was 16.0%.

For the entire interval cored, the log oil saturation averaged 24.7% while the oil saturation from core analysis data corrected to reservoir conditions averaged 25.4%. Log and core oil saturations are compared for each subzone in Table 2.

SOFTENING AND INJECTION FACILITIES

Preliminary laboratory screening studies had indicated that softened water with a salinity of 7500 ppm as NaCl would be the appropriate choice for the alkaline waterflooding project injection water. This water would be used for the preflush to condition the reservoir and as a carrier for the alkaline chemicals added during the main chemical slug injection. Following an extensive review of the environmental constraints, water requirements of the Huntington Beach Field, chemical requirements and water disposal requirements, a blend of produced water and brackish water available from shallow aquifers was chosen as the raw water stream for the injection plant. The chemical composition of the available waters and the blend of 25% produced water with 75% brackish water are given in Table 3.

Several softening alternatives were evaluated. Those choices included lime softening; series softening with a strong acid, gel-type resin; series softening with a strong acid, gel-type resin in the primary and a weak acid, gel-type resin as a polish; series softening with a weak acid, gel-type resin; and series softening with a weak acid, macroreticular type resin. The final system chosen was series softening with a weak acid, macroreticular type resin.

A great deal of time was devoted to the optimization of the regeneration efficiency and reduction of the associated operating cost. The two key elements which came out of the evaluation work were: (1) the improvement of resin/acid contact by regeneration in the upflow direction with air to agitate the resin bed; and (2) the recirculation of acid in the downflow direction during the latter portion of the regeneration cycle.

Evaluation of the resin bed neutralization performance resulted in essentially the same conclusions as those drawn from the acid regeneration performance evaluation. The conclusion was to start the neutralization in the upflow direction with air and finish with a recirculation of the sodium hydroxide at the end of the cycle.

Effects of osmotic pressure on the regeneration efficiency of the macroreticular resins appear to be of no consequence.

The surface facilities were designed using the parameters established during the resin evaluation, which are shown in Table 4.

The flow diagram of the softening and injection facilities is given in Fig. 6. The produced water and brackish water are blended in a 1500-bbl. raw water surge tank (T-1). The blended water is then pumped (P-1) to the primary softener and then to the polish softener. From the polish softener the softened water flows into a 1500-bbl. soft water surge tank (T-2). The soft water is then pumped (P-3) to the injection pump (P-9).

The softeners are backwashed and regenerated using soft water from the soft water surge tank (T-3) using pump (P-2). A pump (P-4) provides standby capability for pumps (P-1), (P-2), or (P-3).

The alkaline chemicals are added downstream of the injection pump (P-9) by pumps (P-8a and P-8b). Pump (P-8c) is a standby alkaline injection pump. The acid pump (P-6) is used for the acid regeneration of the softeners. The sodium hydroxide pump (P-7) is used for the neutralization of the softeners.

The hydrochloric acid used for the acid regeneration of the softeners is stored in tank (T-3). The sodium hydroxide used for the neutralization of the softeners and for the alkaline flood is stored in tank (T-4). The sodium silicate for the alkaline flood is stored in tank (T-5).

The blended water flows through two vessels in series: a primary and a polish. The total hardness of the blended water (25:75) is 650 mg/l. as $CaCO_3$. The total hardness effluent from the primary is less than 5 mg/l. as $CaCO_3$ and less than 1 mg/l. as $CaCO_3$ from the polish vessel.

The softening cycle is determined by a cycle timer with a high hardness alarm/override. If the primary softener breaks before the cycle timer times out, the vessel cycle will be advanced.

When the cycle is terminated by either the cycle timer or the hardness detector, the primary vessel goes into the backwash-regeneration cycle and the polish goes into the primary cycle. The vessel which has been backwashed and regenerated then comes in as the polish vessel. A fourth vessel (V-4) serves as a standby for vessels V-1, V-2, or V-3.

The cycle time for the primary is 6 hours. The backwash/regeneration requires 2-3/4 hours. There is, therefore, a 3-hour time period provided for manual backwashing or regeneration of the vessels if required.

TRACER INJECTION AND MONITORING

As a part of the original proposal for support by DOE for additional testing to provide better reservoir definition in the alkaline pilot area, an extensive tracer injection and monitoring program was designed. The purpose of the tracer test was to empirically establish injector-producer flow patterns in the Fault Block 22 area of the Lower Main Zone caustic pilot flow and to determine reservoir properties within the area. The results of the test were to be used in conjunction with earlier waterflood data to adjust production and injection rates in the Fault Block 22 area of the pilot flood in order to maximize sweep efficiency and oil recovery.

Tracer material was injected into four injection wells in Fault Block 22 in the Lower Main Zone on the 392.1 Lease. Tracer response is monitored at S-47A, a central producer which forms a five-spot pattern with the four injectors, and seven other producing wells surrounding the pattern.

The wells involved in the test were:

Inj. Wells: S-168, S-66A, S-50A, S-55B

Prod. Wells: S-47A,S-12A,S-72A,S-73, S-86A,S-100, C-30, S-88

The amounts and type of tracer added to each injection well are listed in Table 5. In addition, the soft water being injected as a preflush, which started in June, 1978, is of sufficient difference in composition to act as an injection front tracer system. Reductions in total dissolved solids and hardness ion levels indicate the degree of preflush breakthrough to the production wells.

Water samples were taken from the eight production wells listed above at three week intervals until the tracer injection was initiated. Since that time samples have been taken from the production wells at one-week intervals. Complete water analyses for the constituent cation and ion content have been performed on samples taken every third week. The weekly samples have been analyzed by gas chromatography for the presence of the alcohol tracers. Analysis for radioactivity in the water samples was performed by an outside testing laboratory. In the two year period since injection of the tracer no alcohols have been detected at the production wells. The analytical procedures used for the detection of low levels of nitrate and thiocyanate ions were not sensitive enough to detect low levels of these ions (10 ppm or less), so there is a high degree of uncertainty in the results. Fortunately, there are small retained samples of water from the production wells which will be reanalyzed by ion chromatography within the next few months. These data will not be available for this report.

Tritium breakthrough was detected in May, 1980 at Well S-72A, which is the closest high-volume production well to Well S-168 into which the tritiated water had been injected. The initial tracer count was 17 dpm/ml, which increased to a maximum of 35 dpm/ml in August, 1980. Since that time, the tracer level has declined at a fairly constant rate to a level of 10 dpm/ml early in 1982. In October, 1981, a tritium level of 2-3 dpm/ml was detected in water samples from Well S-73, which is the closest well to S-168 by distance, but the well has a much lower production rate than S-72A. Also, tritium levels of 2-3 dpm/ml have been detected in Well S-47A. None of the cobalt radioactive tracers have been detected in any of the produced water samples. The limits of detection for the cobalt activity is 25 dpm/l and 1.0 dpm/ml for the tritium activity.

Preflush breakthrough has been observed in three production wells, S-12A, S-47A, and S-72A, as a gradual reduction in total dissolved solids, chloride level and hardness ion levels. The chloride levels in the produced water from these three wells is plotted in Figure 7. Extrapolation of the decline in the various constituents in the produced water, compared to the normal average levels shown for the first few months after preflush injection started, allows an estimate of preflush breakthrough to be made. For Wells S-12A and S-47A, preflush breakthrough apparently occurred during the period of November-December, 1979, or about 17-18 months after preflush injection started. For Well S-72A, preflush breakthrough is more difficult to estimate due to the influx of water from outside injection wells, which may contribute two-thirds or more of the water produced by S-72A. The decline in salinity and hardness has been much less than was observed for the other wells which are fed almost entirely by the pilot injectors; but breakthrough probably occurred during the period of July to September, 1979 or 13-15 months after the start of preflush. This agrees reasonably well with the radioactive tracer breakthrough which started about nine months after injection.

LABORATORY CORE FLOOD STUDIES AND PILOT DESIGN PARAMETERS

Laboratory core flood studies have been run on unconsolidated sand-packs prepared from preserved samples of core material from Wells S-12A and S-55B. The core test procedure is outlined in Appendix 1. The results from a typical core flood run, using crude oil from Well S-47A and core material from Well S-55B, are shown in Fig. 8. On an average, alkaline injection after waterflooding the core to residual oil saturation will produce about 0.05 pore volumes of additional oil. The early laboratory core flood studies, using core material from Well S-12A and results from earlier field trials performed by other oil companies, were used to define the operational parameters of the alkaline flood pilot. Based on these studies, the pilot injection sequence was originally designed as follows:

1. Preflush: 0.40 pore volume of softened water with a total salinity of 7500 ppm as NaCl
2. Alkaline Slug: 0.40 pore volume of 0.2% by weight sodium orthosilicate solution in softened water of the same salinity
3. Postflush: 0.20 pore volume of softened water

Later work, using core material from Well S-55B, indicated that higher concentrations of alkaline chemical should be more effective in promoting an earlier formation of the oil bank and in improving the areal sweep efficiency because of a better mobility ratio. In addition, outside studies had determined that reactivity of the alkaline chemicals with the reservoir rock would reduce the effectiveness over time to the extent that there would be insufficient alkali present to mobilize the crude oil if the injection concentration were too low (0.2% or less). Based on these findings, the alkaline chemical concentration was increased from the original design rate of 0.2% to 1.0% by weight, sodium orthosilicate.

COMPUTER SIMULATION STUDIES

A reservoir simulation computer model is being developed to attempt to predict the performance of the alkaline pilot. Modeling the pilot area is a complicated process due to the differences in completion depths of the injection and production wells. The productive intervals of the Lower Main Zone are divided into several subzones by thin shale sections, as mentioned earlier in the section on core analysis. Not all of the wells in the pilot area were completed to the maximum depth of the Lower Main Zone when they were redrilled, mainly because the sands were considered to be too depleted for economic waterflooding. Figure 9 shows the average cross-sectional depths of the net sands in the various subzones and the completion depths of the injection and production wells in the pilot area. This Figure shows that fluid injected into the LM_{3-4} and LM_{4-5} subzones will be produced only in short intervals at Wells C-30, S-72A, S-86A, and S-88. The only deep production wells are S-12A and S-73. Production Well S-47A was not completed below the LM_3 marker when it was redrilled in 1972. This well is the central well of the inverted 5-spot injection pattern. Studies made prior to the start of the project had indicated that there would be no problem in interpreting the results of the pilot project even though all the wells were not completed in all the Lower Main Zone sand intervals.

A streamline flow pattern plot based on average injection and production rates for the period of June, 1978 to March, 1982 is given in Fig. 10. This plot shows the flow in the LM_{1-3} subzones in the pilot area. Each streamtube represents 50 B/D of fluid flow at a mobility ratio of 3. The well locations are set based on the center point of penetration through the LM_{1-3} subzones. No layering effects were included in the model as the entire subzone was assumed to be homogeneous to horizontal flow. Based on breakthrough times of each streamline, an approximate prediction can be made for reduction in salinity levels at Well S-47A for comparison to the observed analysis data. This comparison is shown in Fig. 11 along with a prediction for salinity reduction which was derived from the streamline program by application of a dispersion equation. This modified prediction shows a reasonable match with historical data on salinity at this well.

PILOT AREA INJECTION AND PRODUCTION DATA

In the alkaline pilot area four injection wells, S-50A, S-55B, S-66A, and S-168, have been used since June, 1978 to inject the softened water preflush and the alkaline slug. The average daily injection rates for the total pilot area are shown on Figures 13 and 14. The cumulative total injection volumes and the individual injection well contributions are shown in Fig. 12. The softening and injection plant was designed for an injection rate of 10,000 B/D. This rate was attained during the first year of operation, but plant operational problems with the water softening system reduced the average injection rate to about 7,000 B/D in the second half of 1979. The injection rate averaged about 8,300 B/D in 1980 and 7,200 B/D in 1981. Operational improvements are being made to attempt to maintain an average daily injection rate of 9,000 B/D to the end of the project.

Historical production data, giving net oil and gross fluid production for the alkaline pilot area, are given in Fig. 13, starting in 1973. The detailed data for the pilot are given in Fig. 14, starting in 1979. This figure presents the combined net oil, gross production, injection rate and the water/oil ratio for all the pilot production wells. The same combined data for the three wells that have shown preflush response, S-12A, S-47A, and S-72A, are shown in Fig. 15. The individual production data for wells S-12A, S-47A, and S-72A are given in Figures 16, 17, and 18, respectively.

To date, there has been no significant indication of response in the pilot area to the injection of alkaline chemicals. The preflush has appeared at three of the eight production wells, but no increase in pH or silica levels have been detected by analysis of the produced water. A positive response to alkaline injection should result in a lowered water/oil ratio and an increase in the oil production at the production wells. Based on streamline breakthrough predictions from the computer model, significant response to the alkaline chemicals would be anticipated to occur during the second half of 1982 or early in 1983 at wells S-12A, S-47A, and S-72A. These predictions are based solely on plug flow breakthrough and are not adjusted for the effects of dispersion and alkaline consumption.

The preflush injection volume was 5.9 million bbls. of softened water, which was equivalent to 19% of the total project area pore volume, or 33% of the interior 5-spot pattern pore volume. The total volume of 0.2% alkali, followed by 1.0% alkali, injected through March, 1982, was 6.5 million bbls. This volume is equivalent to 21% of the total pattern pore volume and 36% of the interior pattern pore volume. Alkaline injection will continue into 1984 to achieve a total pattern injection volume of 0.40 pore volumes and an interior pattern volume of 0.7 pore volumes. A soft water postflush will continue into 1985, followed by normal field injection water to the economic limit of the project.

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APPENDIX I

LABORATORY CORE FLOODING PROCEDURE

Preserved core material from Well S-55B is extracted with toluene to remove oil and methanol to remove water. The extracted sand is dried at 150^{o} C for 24 hours and screened through a 10-mesh screen to remove coarse rock particles. Normally, sufficient dried core material is composited to provide sufficient material for 10 to 12 core flood runs. The dry core material is packed into plastic core holders with inner dimensions of 11 inches (27.5 cm) in length by 1.5 inches (3.8 cm) inner diameter. These core holders are fitted with end caps sealed with rubber O-rings. About 500 g of dry material is required to fill the holder and a typical void volume (pore volume) is about 110-120 ml.

The dry core material is saturated with filtered produced water obtained from Aminoil's filter plant and the pore volume is calculated from the weight difference. The permeability of the core to water is measured at this time. The core is then saturated at reservoir temperature with crude oil from Well S-47A, which had been obtained using a special separator. (All chemical treatment of the producing well had been halted for a week prior to sampling.) The permeability to oil at irreducible water saturation is measured and the initial oil saturation is calculated.

The core is then waterflooded with 1.5 to 2.0 pore volumes of produced water at a flow rate of one foot per day, and the permeability to water at irreducible oil saturation is measured. The alkaline flood test is started at this point at a flow rate of one-third foot per day to simulate typical Huntington Beach reservoir flow rates. The desired preflush, alkaline slug and postflush volumes are injected, followed by produced water to the end of the run. The produced fluids are analyzed for pH, total dissolved solids, chloride level, hardness level, and silica level. The results are tabulated and plotted as shown in Figure 8.

TABLE 1

CORE ANALYSIS DATA - WELL S-55B

Zone	Routine Core Analysis: Average Helium Porosity %	Average Air Permeability md	Average Oil Saturation % PV	Average Oil Saturation Corrected to Reservoir Conditions % PV
LM_{2-3}	29.5	641	22.0	30.9
LM_{3-4}	29.7	784	18.9	26.5
LM_{4-5}	29.8	763	11.9	16.7
ZONE TOTAL	29.7	725	18.1	25.4
Range	19.7 - 43.4	2 - 8650	0 - 45.8	

TABLE 2

COMPARISON OF LOG AND CORE ANALYSIS DATA FROM WELL S-55B

Zone	Avg. Helium Porosity of Conventional Core Plugs Under 2300 ps Confining Pressure %	Avg. Toluene Porosity of Pressure Core Plugs Under 2300 psi Confining Pressure %	Avg. Log Porosity %	Avg. Oil Saturation From Conventional Cores Corrected to Reservoir Conditions % PV	Avg. Oil Saturation From Pressure Cores Corrected to Reservoir Conditions % PV	Avg. Oil Saturation From Log % PV
LM_{2-3}	23.6	23.2	24.5	30.9	32.0	30.2
LM_{3-4}	23.8		23.9	26.5		28.3
LM_{4-5}	23.8		24.2	16.7		11.7
ZONE TOTAL	23.8		24.2	25.4		24.7

TABLE 3

CHEMICAL COMPOSITION OF PRODUCED WATER AND SOURCE WELL WATER

	mg/l								
	Sodium	Calcium	Magnesium	Barium	Iron	Bicarbonate	Sulfate	Chloride	Iodide
Produced Water	9,340	200	234	17		1,000	200	14,000	31
Source Well Water	280	60	22	0	1.0	360	0	1,000	1
50% Produced Water/ 50% Source Well Water	5,150	140	150	10		930	110	8,000	
25% Produced Water/ 75% Source Well Water	3,190	104	86	5		910	22	4,800	

TABLE 4

ALKALINE PILOT SOFTENING DESIGN PARAMETERS

OPERATING PARAMETERS

Linear flow rate	10 gpm/ft^2
Kinetic flow rate	2 gpm/ft^3
Bed depth	6 ft
Resin capacity	30 kgr/ft^3
Vessel operating time	6 hr
Hardness leakage	1 ppm
Pressure drop at 10 gm/ft^2	2 psig

BACKWASH AND REGENERATION PARAMETERS

Low scrub rate	5 gpm/ft^2
Gas scrub rate	10 $scfm/ft^2$
High rate rinse	10 gpm/ft^2
Acid regeneration (5% HCl)	0.33 gpm/ft^3
Recirculation rate	5 gpm/ft^2
Rinse rate	7 gpm/ft^2
Neutralization (4% NaOH)	0.33 gpm/ft^3
Recirculation rate	5 gpm/ft^2
Rinse rate	7 gpm/ft^2

REGENERATION CHEMICAL REQUIREMENTS

HCl (37%)	4.0 lb/ft^3
NaOH (50%)	5.0 lb/ft^3

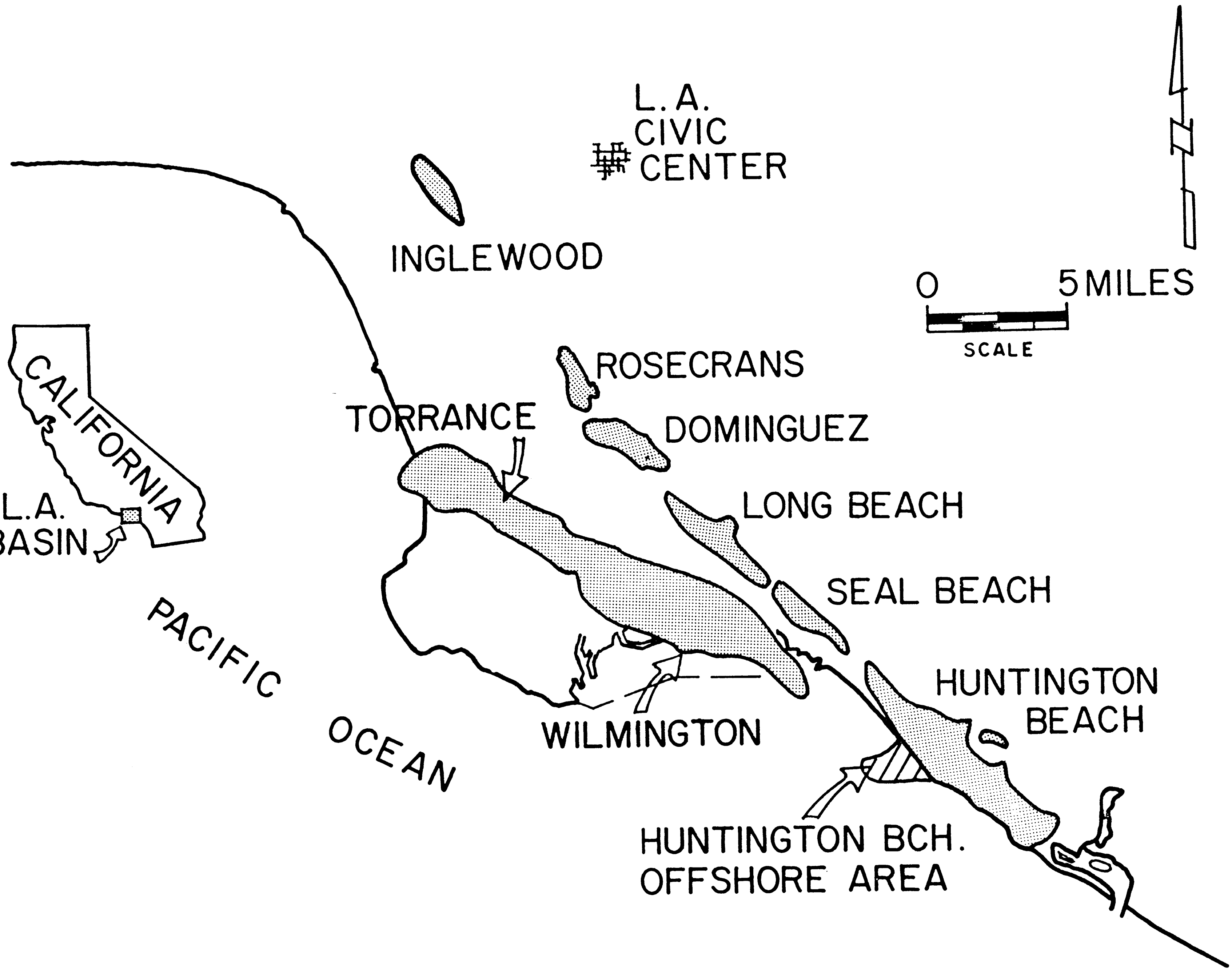
TABLE 5

TRACER INJECTION INTO FB 22 ALKALINE PILOT WELLS

Tracer	Injection Well	Injection Volume	Conc., % Wt. or Vol.	Injected Radioactivity Level, DPM/ML 10/79	3/82
$NaNO_3$	S-168	5913 Bbl	1.29% (Wt.)		
NH_4SCN	S-55B	1970 Bbl	1.68% (Wt.)		
Methanol	S-50A	669 Bbl	10.8% (Vol.)		
Ethanol	S-168	2007 Bbl	3.65% (Vol.)		
2-Propanol	S-66A	260 Bbl	5.92% (Vol.)		
			Total Activity		
Tritiated Water (t 1/2 = 12.26 yr)	S-168	1900 Bbl (3.02×10^8 ml)	40 Ci (0.13 u Ci/ml)	2.9×10^5	2.4×10^5
Co^{60} (t 1/2 = 5.26 yr)	S-55B	204 Bbl (3.24×10^7 ml)	40 mCi (1.23×10^{-3} u Ci/ml)	2.7×10^3	2.2×10^3
Co^{58} (t 1/2 = 71 days)	S-66A	42 Bbl	40 m Ci (5.00×10^{-3} u Ci/ml)	1.1×10^4	10
Co^{57} (t 1/2 = 270 days)	S-50A	104 Bbl	40 m Ci (2.41×10^{-3} u Ci/ml)	5.3×10^3	850

Detection Limits in Produced Water: Tritium = 2 dpm/ml
Cobalt = 0.025 dpm/ml

The above tracer materials were injected during the period of September 17, 1979 to October 19, 1979.

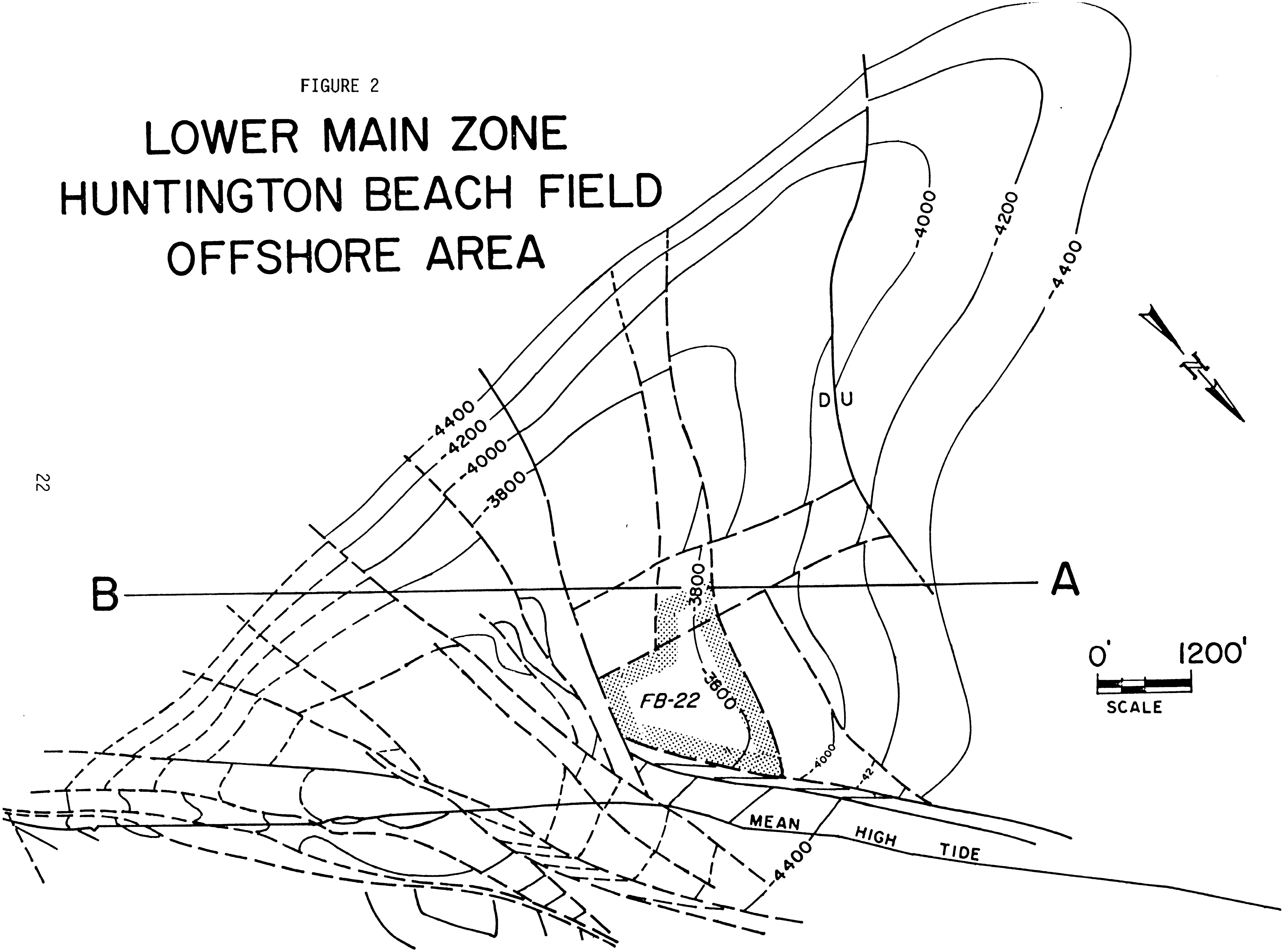


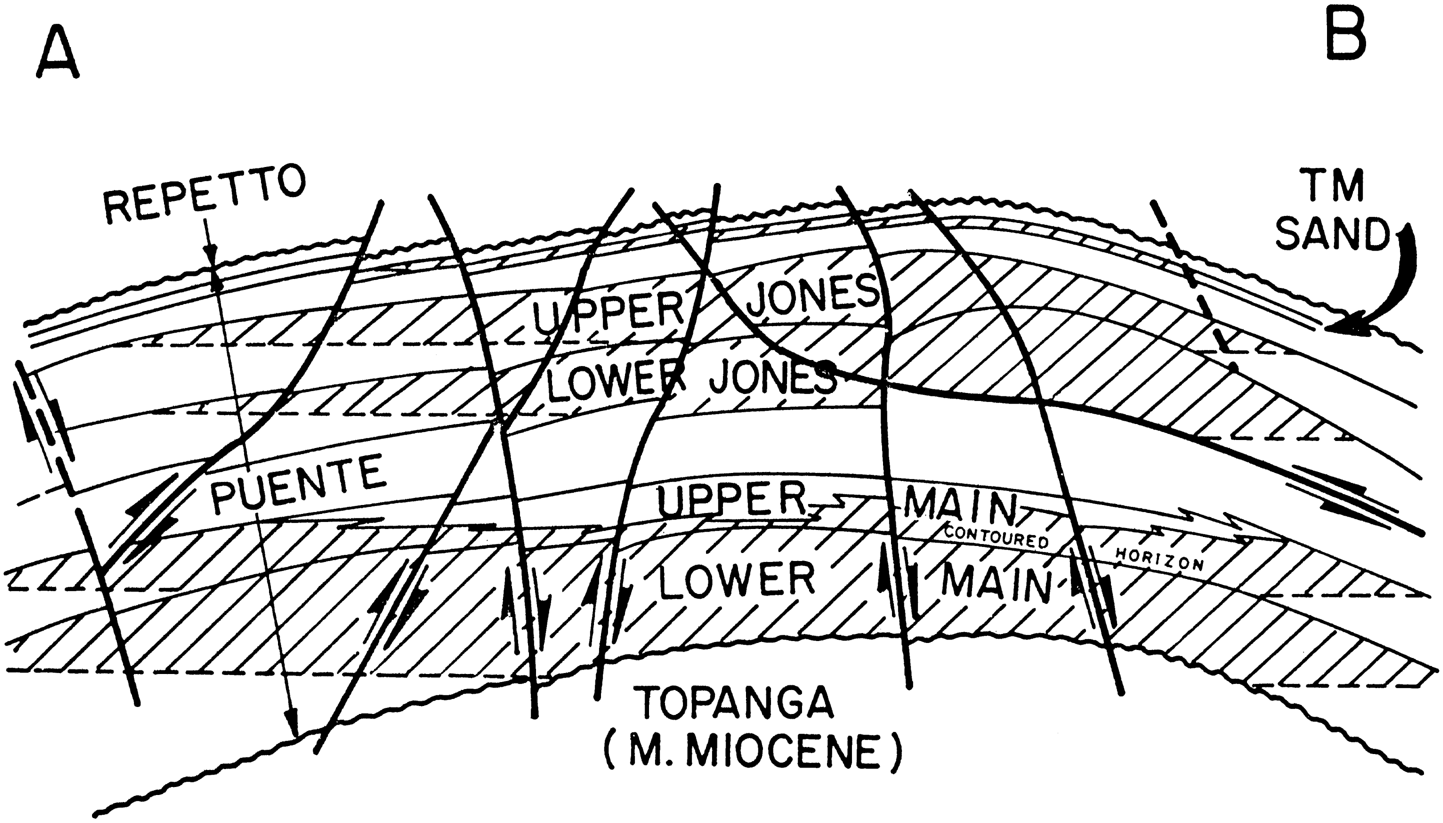
LOS ANGELES BASIN OIL FIELDS

FIGURE 1

FIGURE 2

LOWER MAIN ZONE HUNTINGTON BEACH FIELD OFFSHORE AREA





CROSS-SECTION HUNTINGTON BEACH FIELD OFFSHORE AREA

FIGURE 3

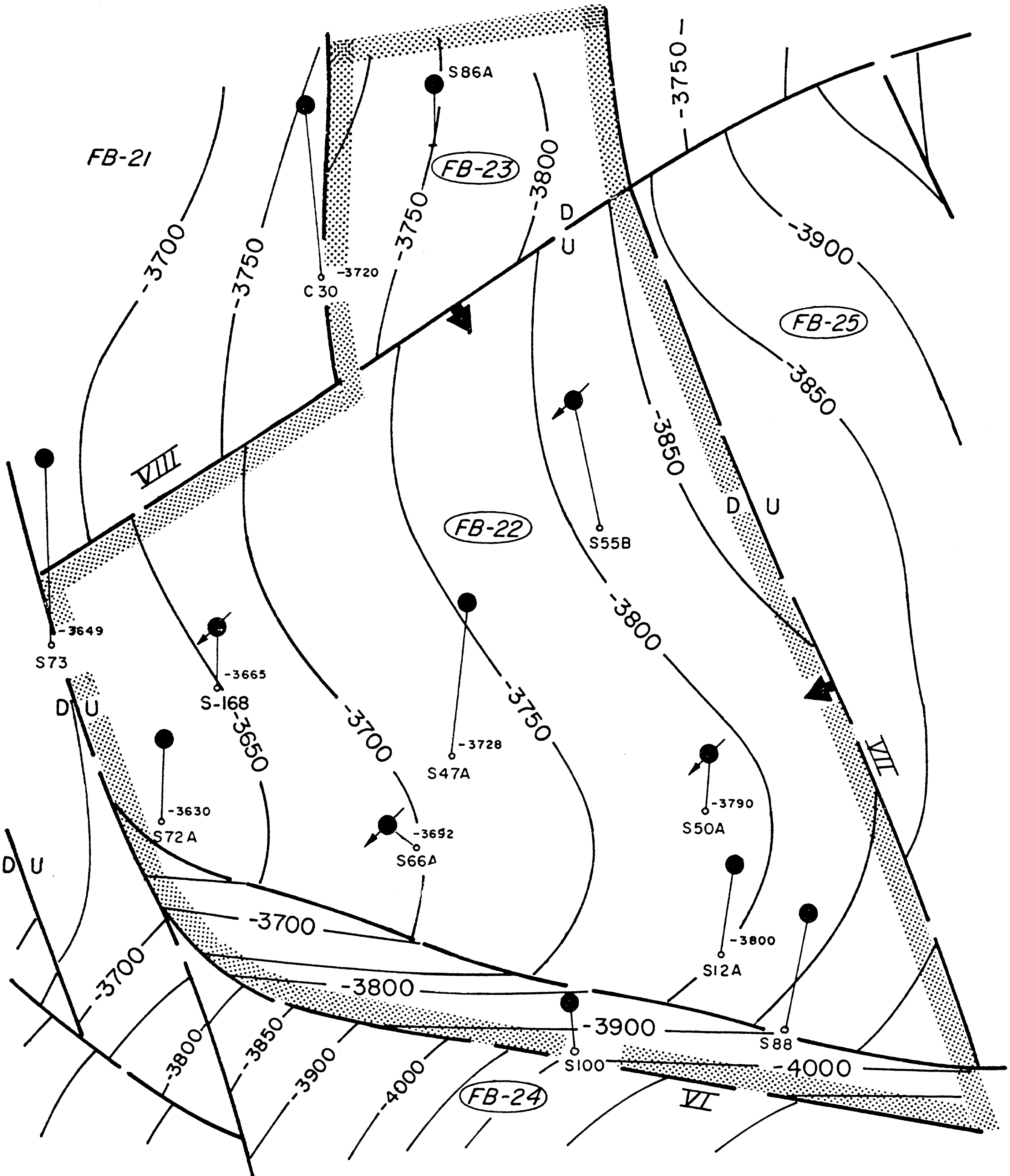


FIGURE 4

LOWER MAIN ZONE
FB–22/23 ALKALINE
PILOT FLOOD AREA

FIGURE 5

EFFECT OF TRIAXIAL CONFINING PRESSURE ON POROSITY OF CORE PLUGS FROM WELL S-55B

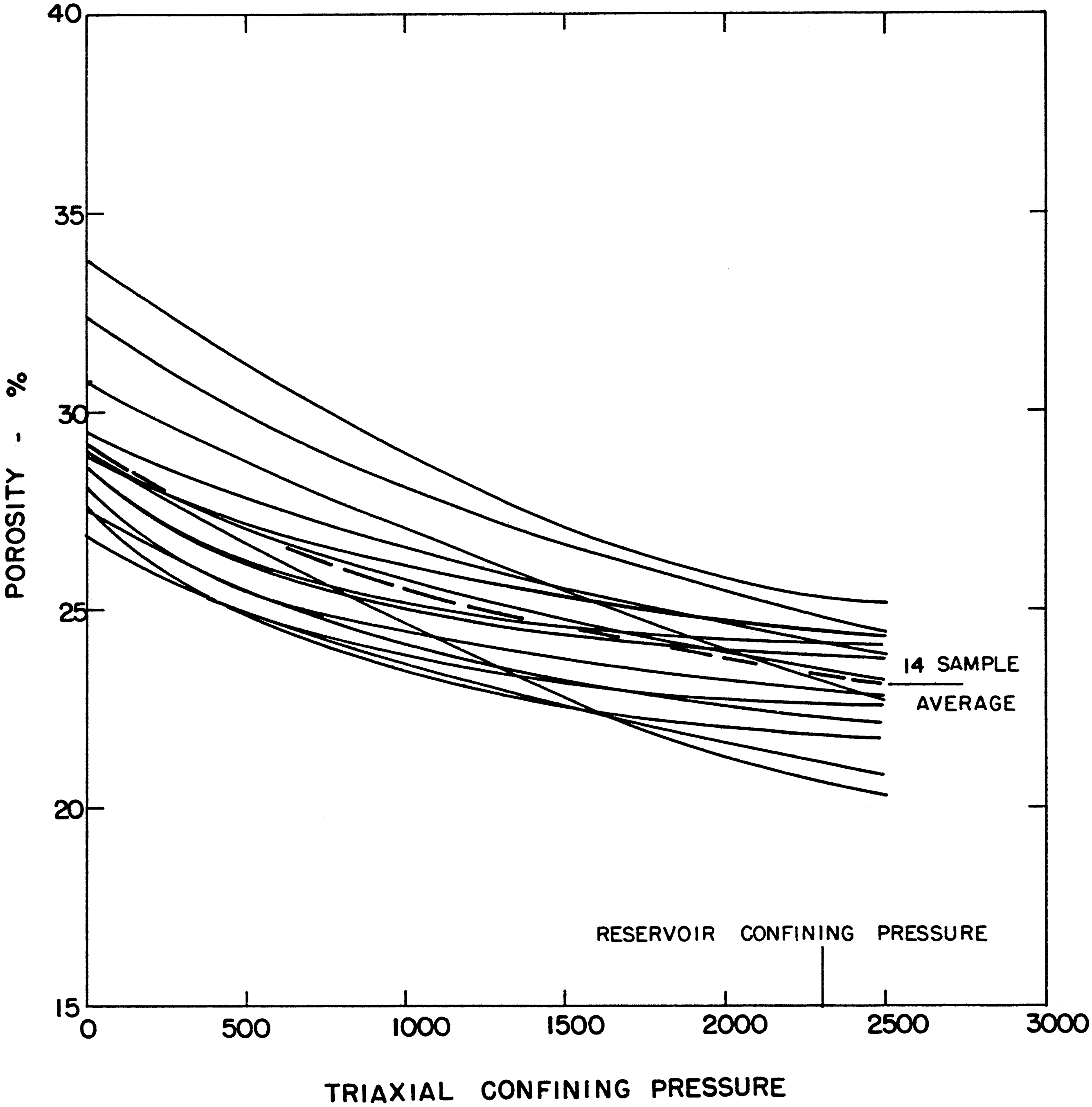


FIGURE 6

SURFACE FACILITIES FLOW DIAGRAM

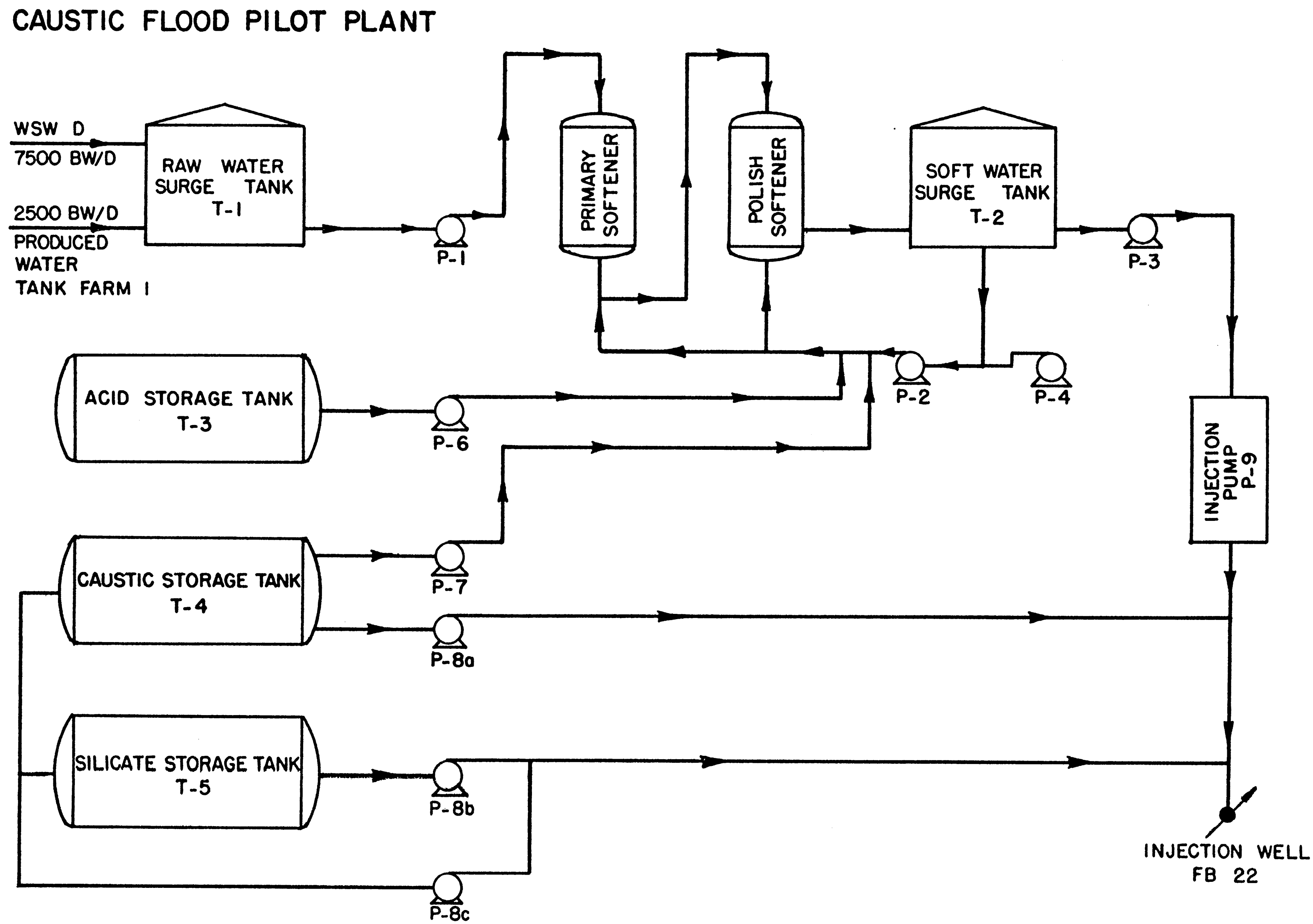


Figure 7

Chloride Levels in Alkaline Pilot Production Wells: S-12A, S-47A, and S-72A

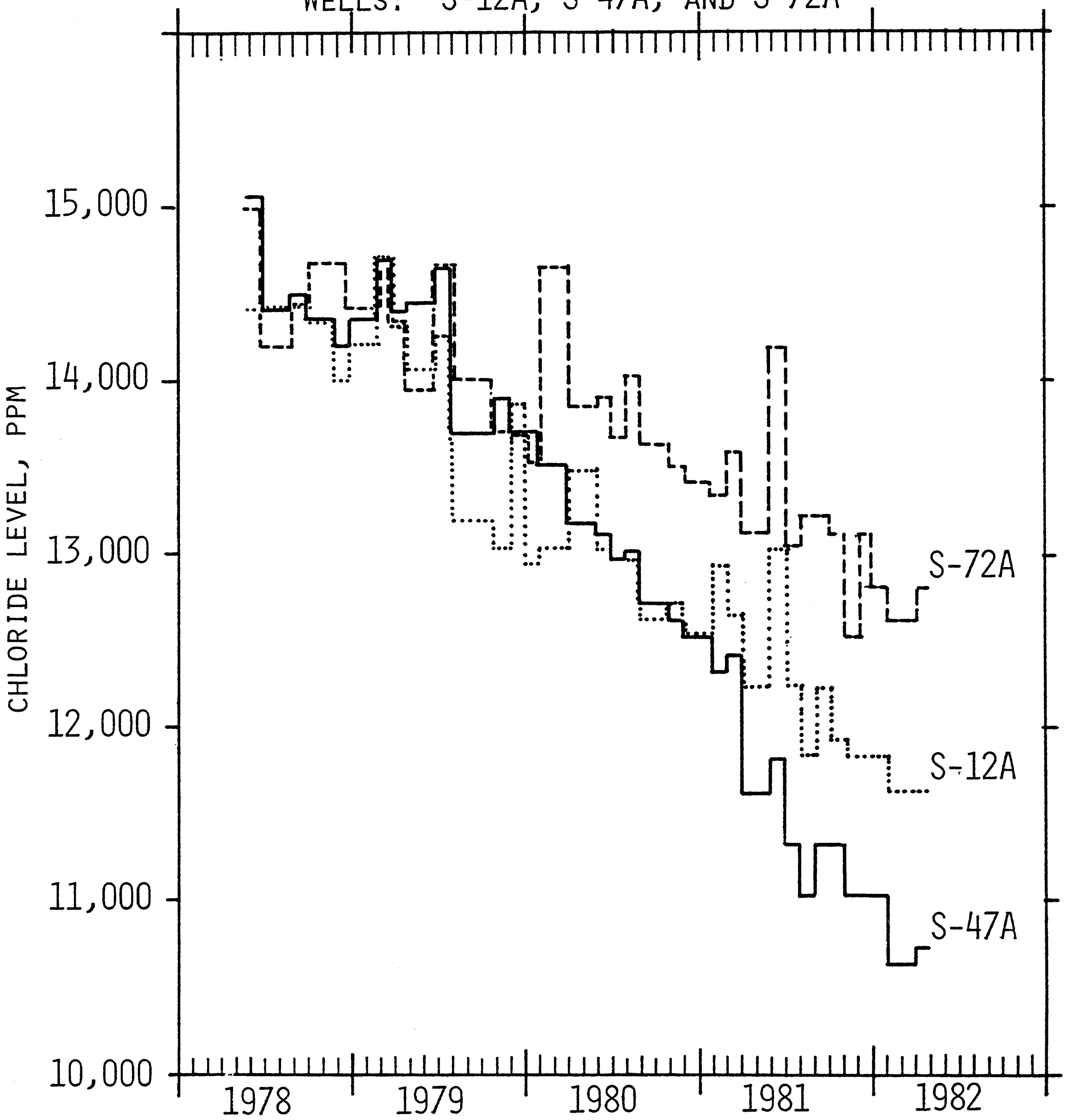
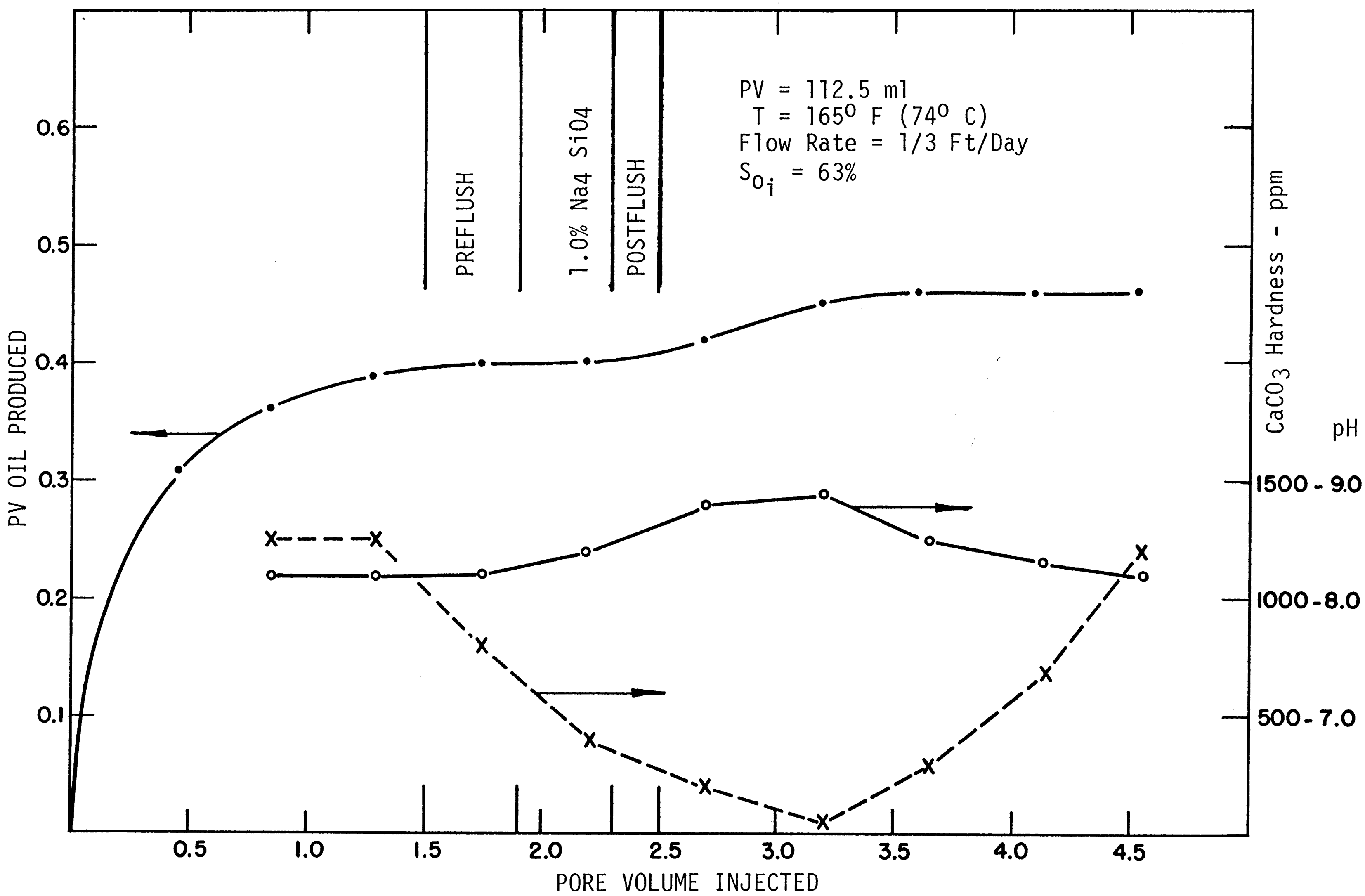


FIGURE 8

LABORATORY CORE FLOOD USING PRESERVED CORE MATERIAL FROM WELL S-55B AND CRUDE OIL FROM WELL S-47A



COMPLETION INTERVAL
LMZ FB 22/23 ALKALINE PILOT PROJECT

FIGURE 9

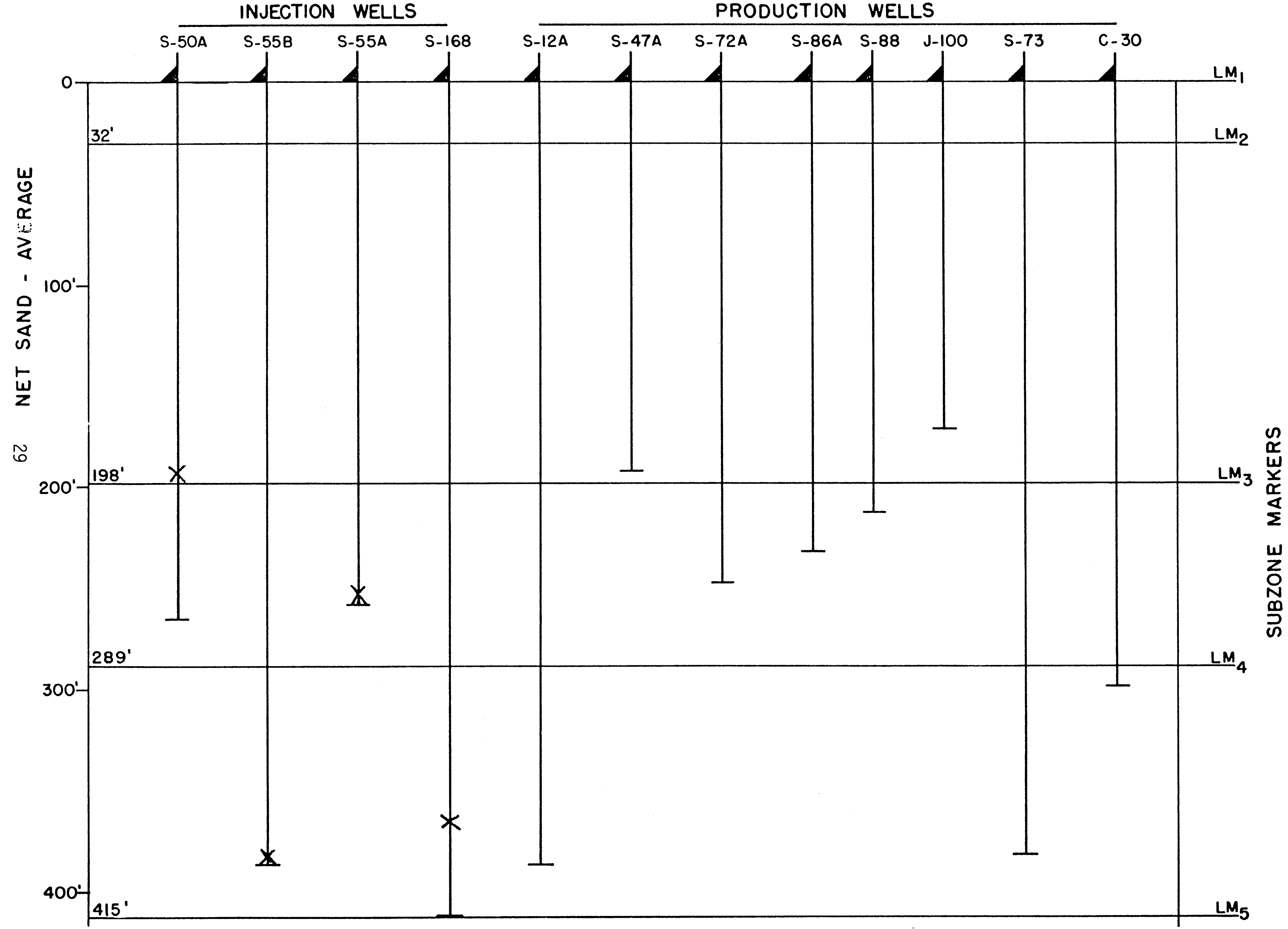
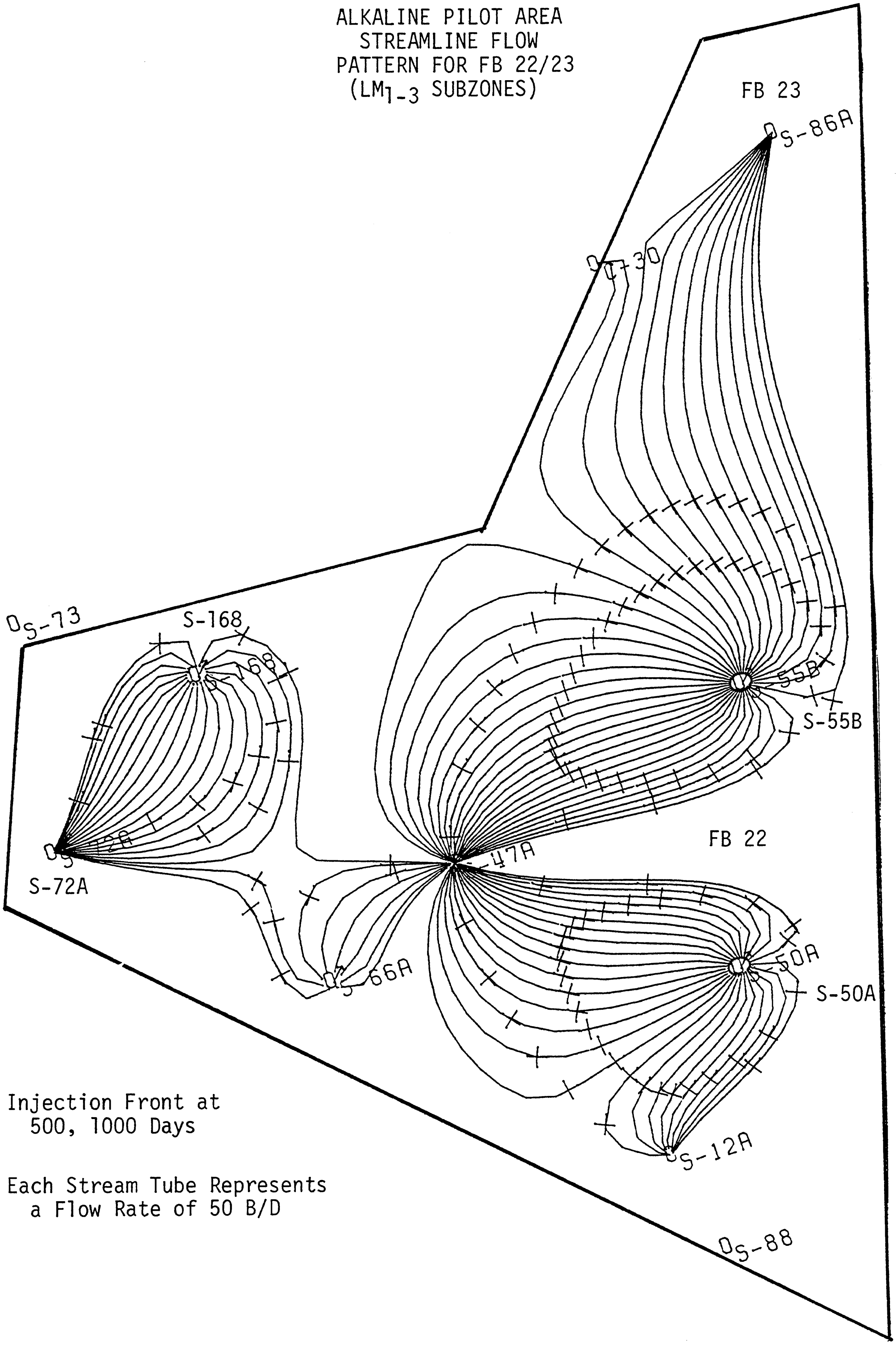


FIGURE 10

ALKALINE PILOT AREA
STREAMLINE FLOW
PATTERN FOR FB 22/23
(LM_{1-3} SUBZONES)



+ Injection Front at
500, 1000 Days

Each Stream Tube Represents
a Flow Rate of 50 B/D

FIGURE 11

ACTUAL AND PREDICTED CHLORIDE LEVELS IN PRODUCED WATER FROM WELL S-47A

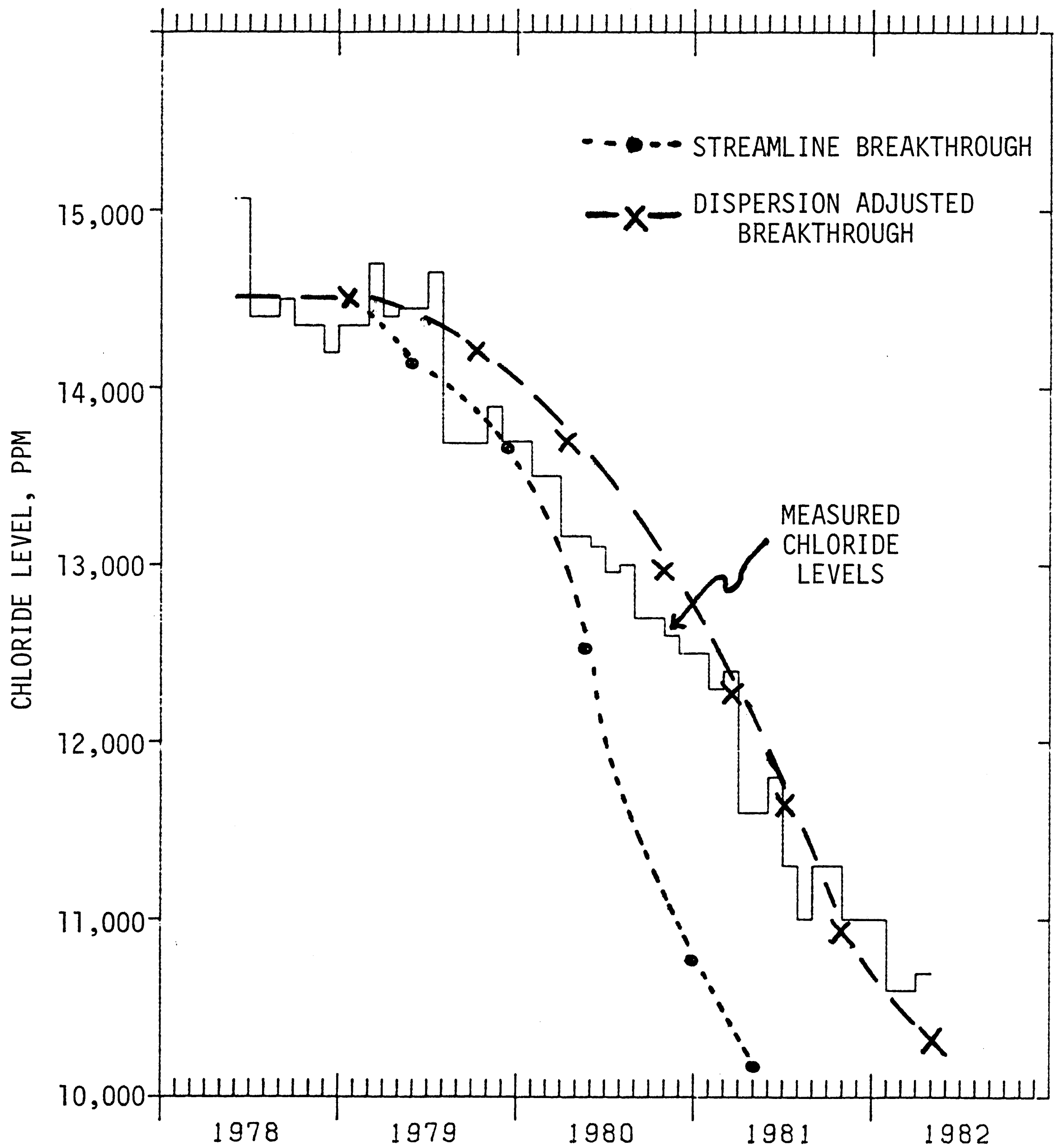


FIGURE 12

TOTAL CUMULATIVE INJECTION
IN FB 22/23 ALKALINE PILOT
AND INDIVIDUAL WELL CUMULATIVE TOTAL

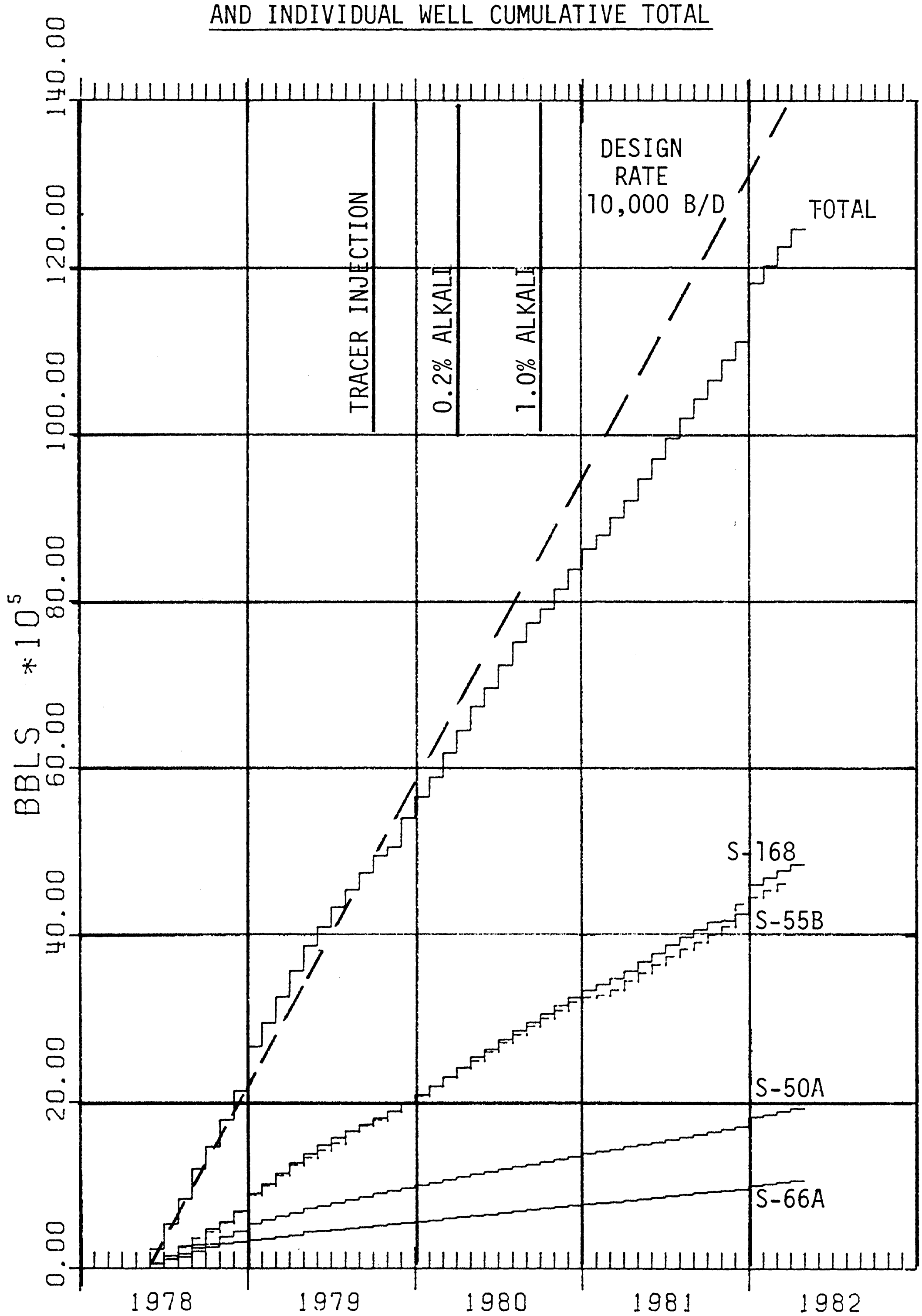


Figure 13

Lower Main Zone, FB 22/23 Historical Production Data, 1973 - 1982

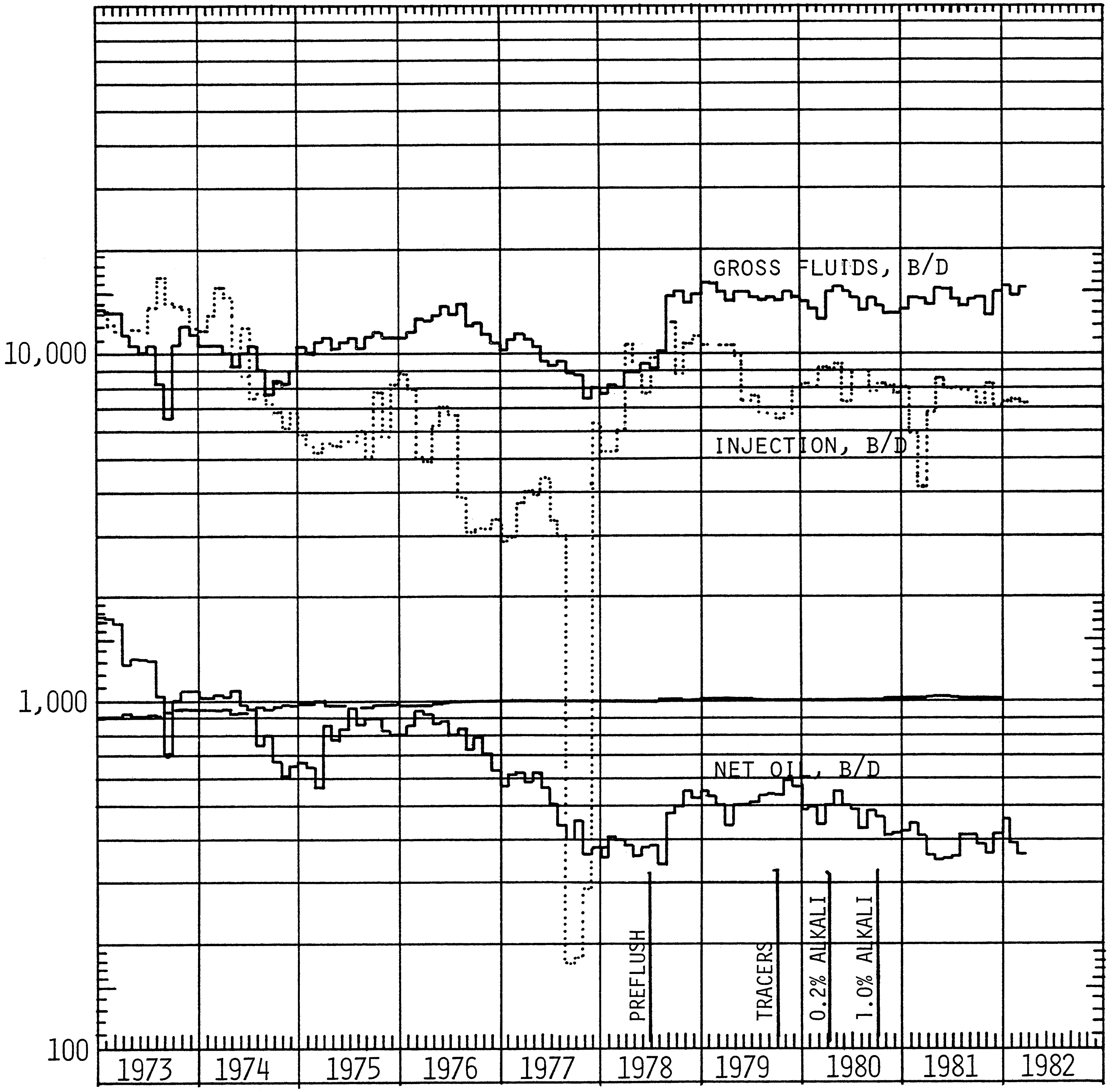


FIGURE 14
FB 22/23 ALKALINE PILOT AREA PRODUCTION DATA

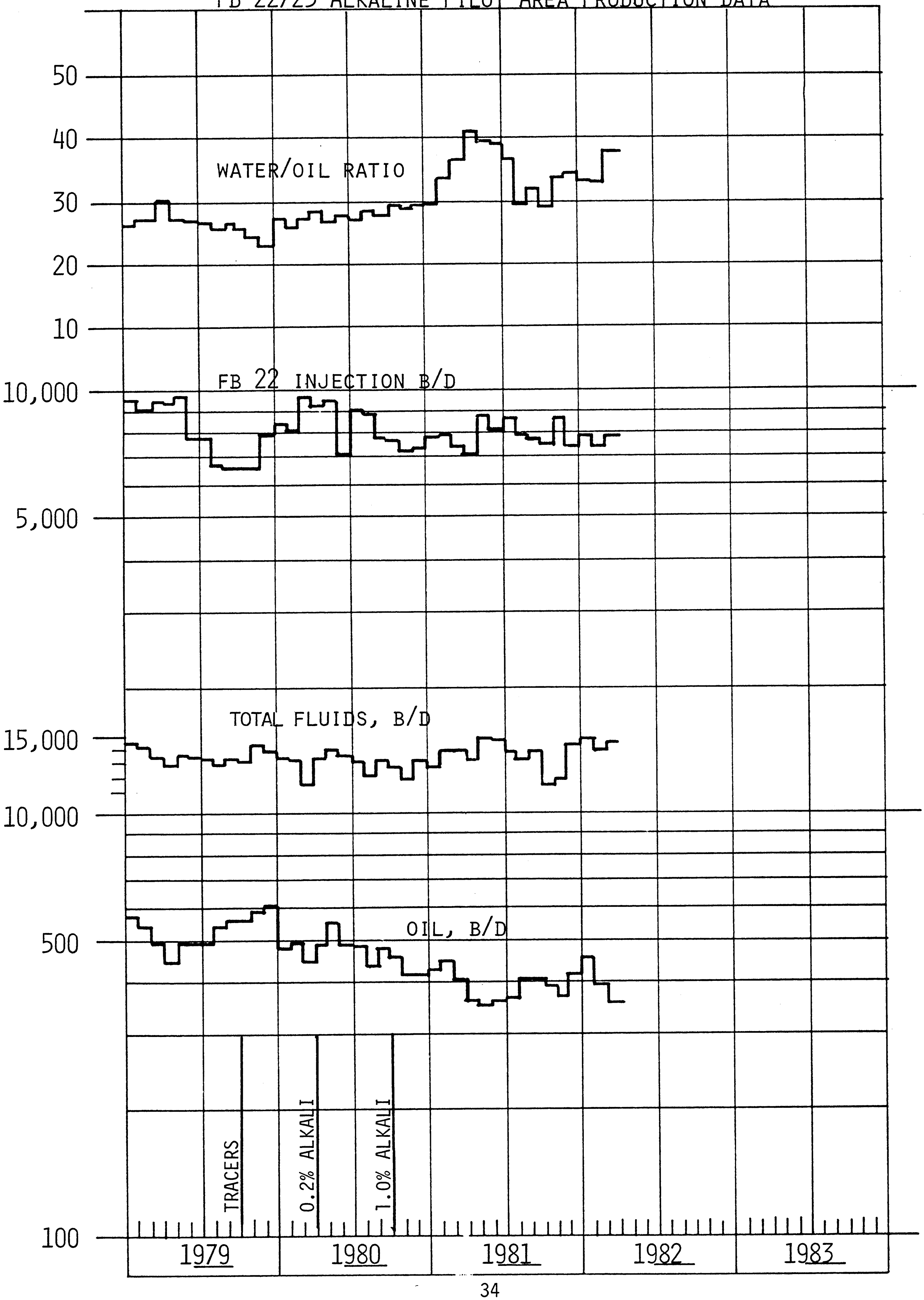


FIGURE 15

COMBINED PRODUCTION DATA FOR
WELLS: S-12A, S-47A, AND S-72A

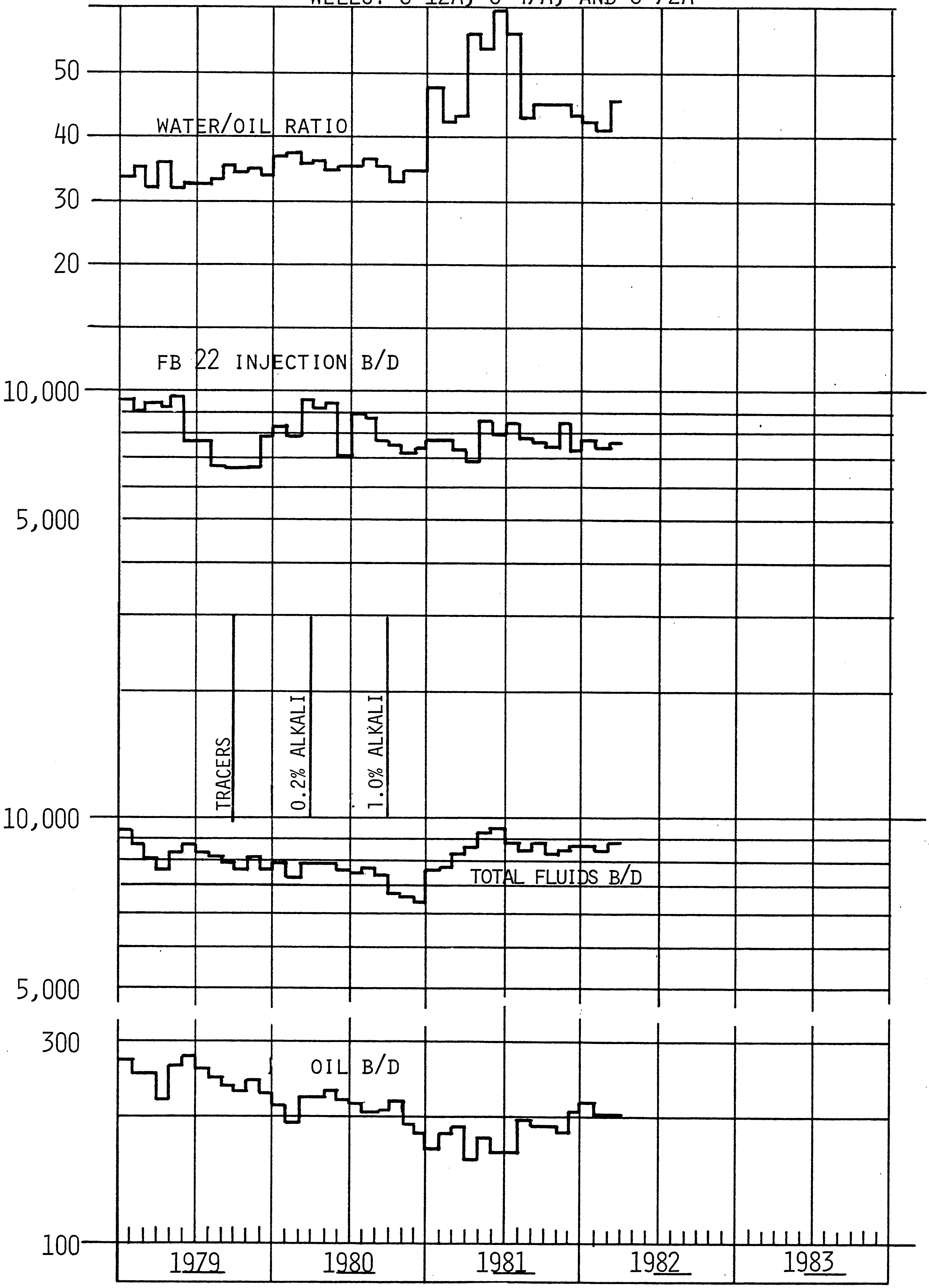
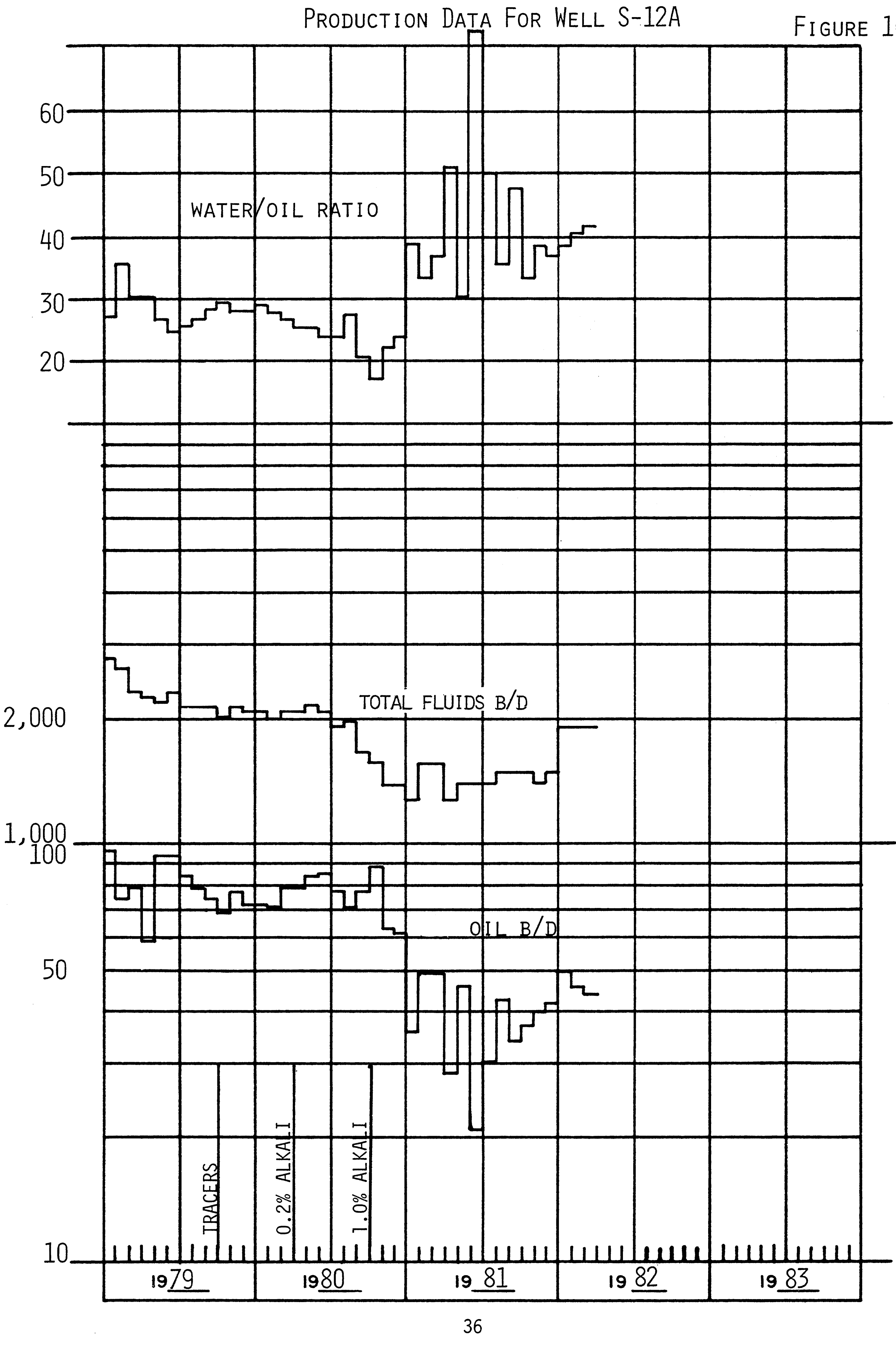


Figure 16



Production Data For Well S-12A
60
50
40
30
20
WATER/OIL RATIO
2,000
1,000
TOTAL FLUIDS B/D
100
50
10
OIL B/D
TRACERS
0.2% ALKALI
1.0% ALKALI
1979
1980
19 81
19 82
19 83

FIGURE 17

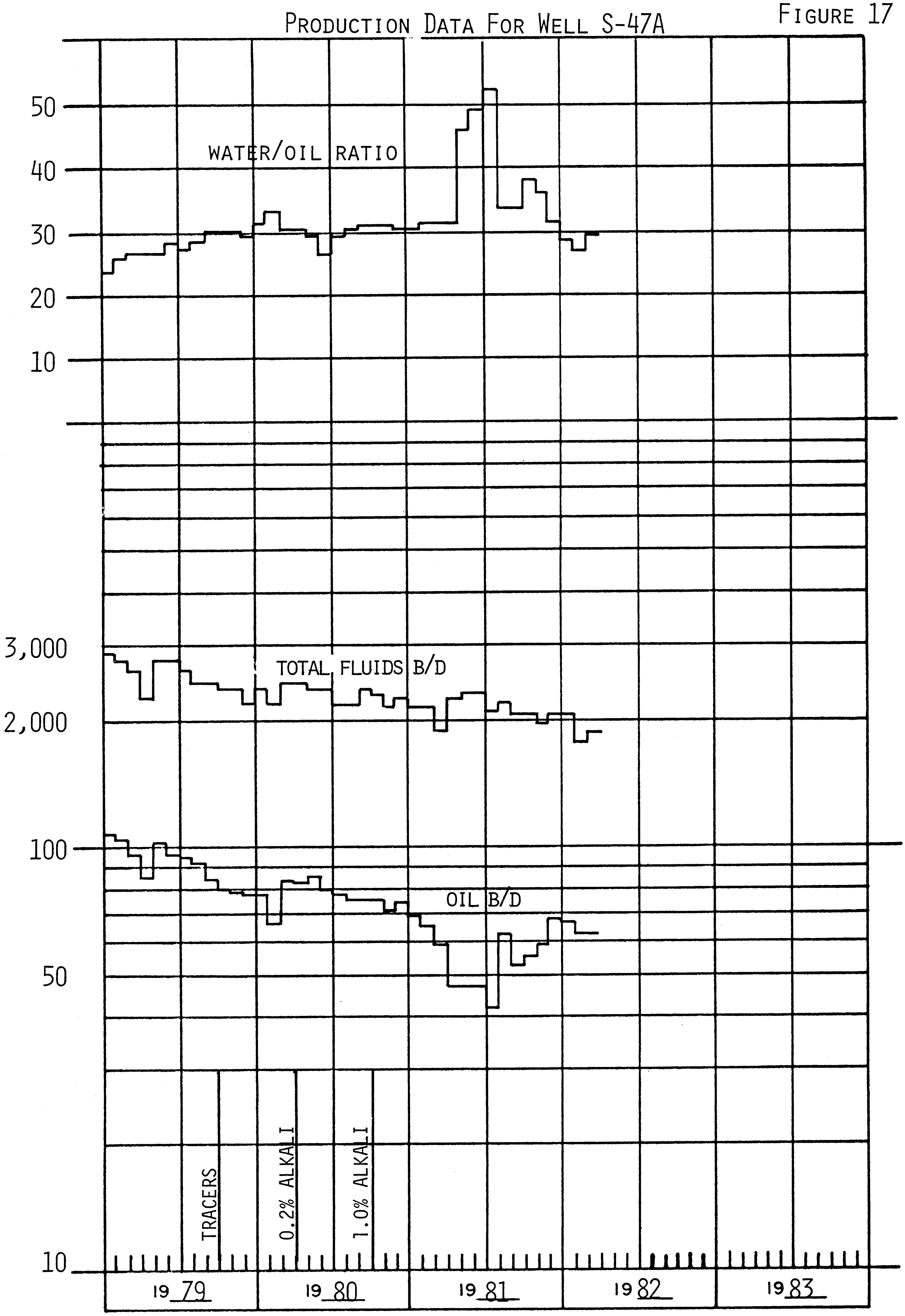
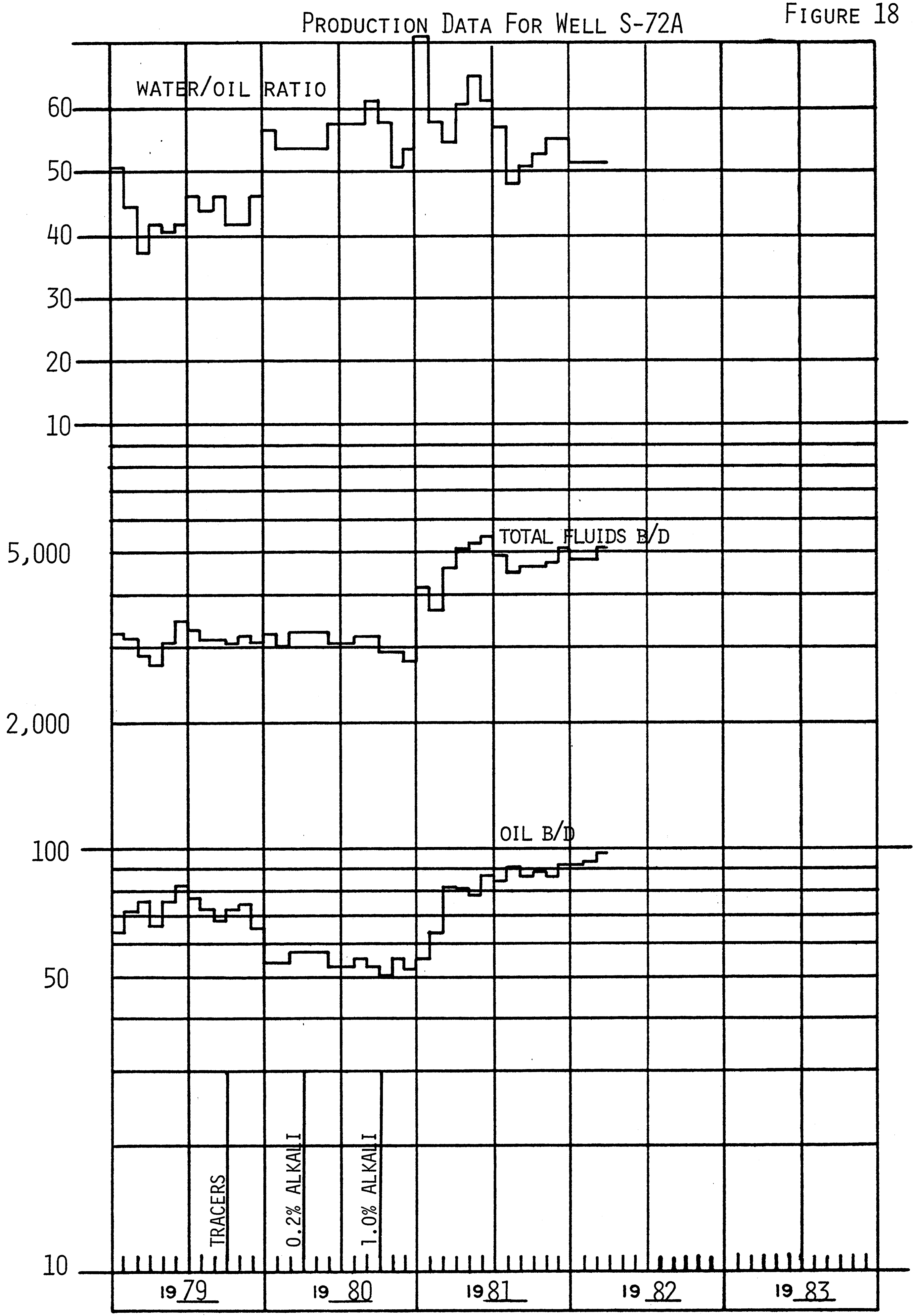

PRODUCTION DATA FOR WELL S-47A
50
40
30
20
10
WATER/OIL RATIO
3,000
2,000
TOTAL FLUIDS B/D
100
50
10
OIL B/D
TRACERS
0.2% ALKALI
1.0% ALKALI
19 79
19 80
19 81
19 82
19 83

FIGURE 18



GPO 569-028/62 1982