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Effect Of Secondary Recovery And Pressure Maintenance On Value Of Oil Properties

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INTRODUCTION

The wide spread application of fluid injection processes apparent in today's oil production picture confirms the confidence of the oil producer in these processes as a means of increasing value of oil properties. Since the producer is motivated by his interest in conservation and profit to install these types of operations, it is reasonable to presume that the average oil operator recognizes the engineer's ability to accurately predict their outcome and is willing to invest substantial capital in a field project in order to accomplish the predicted gains. Not only is the industry's confidence reflected by the capital invested in injection projects, but also by the substantial efforts put forth in unitization and other negotiations among operators in order to facilitate this type of operation. In transactions involving the purchase or sale of oil properties, it is becoming increasingly common to find that the potential value of properties susceptible to these operations is taken into account in arriving at the total consideration paid or received.

Early applications of fluid injection were restricted to shallow, depleted oil reservoirs and were, in a true sense, secondary recovery operations. The primary reserves of the field had been recovered and a stripper stage of production existed at the outset of the fluid injection. Because of the age of the fields, little or no data associated with the modern science of petroleum engineering were available on the reservoirs to be treated. Lack of confidence in fluid injection potentialities on the part of the operators made them reluctant to spend money to obtain data for proper engineering valuation.

Frequently, the cumulative oil recovery from the properties was known only as to order of magnitude. Reservoir volumes could only be crudely estimated from driller's logs. Basic characteristics of the reservoir rock and the fluids contained therein were virtually unknown. It is small wonder, therefore, that many projects of water and gas injection instituted during the formulative period of the science were failures. It is probably more remarkable to consider the relatively high success ratio in these projects realizing that this testifies to the general susceptibility of oil reservoirs to fluid injection. If this were not true, many more failures would have been experienced during this hit-or-miss period.

Let us digress for a moment and consider the causes for failure in some of the early fluid injection projects. Foremost of these causes was timing. Many of the reservoirs processed would have been prime prospects for injection in the early stages of depletion. However, the rapid primary depletion, followed by a long period of stripper production, led to gravity segregation and the formation of a secondary gas cap. This gas cap became a high capacity flow channel during injection, resulting in rapid movement of the injected fluids to the producing wells without significant displacement of the remaining oil in the reservoir. The existence of exceptionally high primary oil recovery per acre may have been the major incentive to the operator to institute injection when, in fact, this circumstance was due, in part, to gravity segregation. This condition is readily determinate today by modern core analysis techniques.

A second cause of failure may have been due to inherently poor permeability distribution in the reservoir. This condition could not be detected from the primary depletion history. The problem would arise from a relatively high permeability section being stratified rather continuously throughout the reservoir in association with a remaining section of low permeability. Here again, the injected fluids course through the high permeability streak without significantly displacing oil from the lower permeability section which contributed the major portion of the primary oil recovery. This condition is also detectible by modern core analyses techniques.

Some failures may have been caused by multiple reservoirs being exposed in common openhole completions. Perhaps only a single reservoir of high permeability was ultimately swept, leaving large quantities of oil in the reservoirs of lesser quality. Cases are also on record wherein multiple reservoir exposure in common completions has led to inadvertent water flooding when water from one zone invades another zone through the common well bore.

WATER ENCROACH

Time has simply run out on many fields which in earlier stages of depletion would have been excellent prospects for fluid injection. Progressive operators are rapidly recognizing this fact and the trend is becoming established toward early evaluation and application of fluid injection prior to primary depletion. Much effort is being expended during the development drilling to obtain adequate data for this evaluation in the form of cores, logs, fluid analysis, and research testing in the laboratory. Even in considering secondary recovery in a depleted field, test wells and core holes are drilled to evaluate the formation characteristics and saturation conditions.

All of this, coupled with the project installation, requires large investments. In spite of the widespread application of secondary recovery and pressure maintenance processes and the impressive record of successful evaluation when adequate data are available, financial institutions involved in oil investments still consider the increased values which can be generated in oil properties by these applications to be somewhat speculative. Much of this attitude is derived from the knowledge of failures in secondary recovery projects instituted many years ago, which failures are understood by the petroleum engineer and, in the light of present knowledge of the mechanics of secondary recovery, would have been predictable. If sufficient data of the particular type needed are available to the petroleum engineer today, he can predict the reserves and the performance of the average oil field under secondary recovery or pressure maintenance operation with a degree of accuracy approaching that experienced in predicting primary reserves and performance.

It may be well then to review the basic data which are essential to a successful prediction of recovery and performance under these types of operation. The most important source of information is derived from cores taken from the producing formation and properly analyzed. The fundamental core properties of porosity and permeability are essential to the determination of the volume of oil in-place and the producing and injection characteristics of the wells involved in the project. The residual oil saturation observed in cores which are preserved prior to laboratory analysis is a significant indication of the total amount of oil which will be mobile in a water-flood operation. All of these data are available from routine core analysis.

At the time routine core analyses are made, it is desirable to request the testing laboratory to retain the permeability plugs in order that they will be available for future special tests which may be required to properly define the water-flood potentiality of the reservoir. These special tests would include porous plate connate water determinations and flushing tests. The latter tests are designed to determine the susceptibility of the reservoir rock to waterflooding and to confirm the quantities of mobile oil which may be displaced from the rock by waterflooding. Another measurement which is made during the course of the flushing test is the permeability of the rock to water at residual oil saturation which is applied in the computation of water cuts in producing wells and injection capacity of injection wells.

In addition to the above data obtained from cores, it is essential to develop a knowledge of the type of oil to be displaced. In the case of a totally depleted reservoir which may be a candidate for secondary recovery, a sample of oil taken from the stock tank and checked for viscosity characteristics at various elevated temperatures will generally suffice for the determination of the fluid characteristics. In the case of a new reservoir or partially depleted reservoir a bottom hole sample should be obtained for complete analyses of the reservoir fluids.

A complete and accurate well testing program in the field is as essential to accurate prediction of water-flood performance as the laboratory tests outlined above. Supplementing these well tests, a bottom hole pressure survey adequate to define the average pressure conditions in the reservoir should be made. If the field exhibits any water production, samples of the produced water should be obtained and analyzed and, if possible, a sample of the potential water supply source should be taken and analyzed.

With the above data in hand, the petroleum engineer may proceed to analyze the performance and reserve potentialities of a field under water-flooding operations. The degree of accuracy of this prediction will increase with the increasing quantity of core analysis and other data which he has available. To emphasize the statement that performance and reserves under secondary recovery and pressure maintenance operations can be reliably predicted, attention is now called to three field histories wherein studies were conducted from data similar to that outlined above prior to instituting a water flood, and wherein sufficient history has been accumulated to demonstrate the degree of agreement between these predictions and actual observed production characteristics in the field.

FIELD "A"

Field "A" as shown in Fig. 1, is producing from a small sand lens of the Travis Peak formation in East Texas. Oil was discovered in October, 1950 at an approximate depth of 6050 feet subsurface. Of the nine wells that penetrated the lens, eight wells were completed as oil producers. Development defined a reservoir having an areal extent of 199 acres and a productive sand volume of 1609 acre-ft, the sand was cored in eight of the nine penetrations, defining the following average characteristics:

Porosity, Per Cent	14.7
Permeability to Air, Md.	26.1
Residual Saturations:	
Oil, Per Cent	18.6
Water, Per Cent	26.4

A fluid analysis of the reservoir crude was made to determine the pressure-volume-temperature relationships. At original pressure, the formation volume factor of the crude was measured to be 1.318 bbl of saturated fluid per bbl of residual oil. Original gas content of the crude amounted to 538 cu ft/bbl of stock tank oil. Viscosity of the oil varied from 0.615 cp at original pressure to 1.39 cp at zero pressure.

Laboratory tests for determination of water-flood characteristics provided the following data:

Permeability, Md.	
To Air	21.6
To Brine	14.8
To Fresh Water	14.5
Relative Permeability, Per Cent of Specific Permeability to Brine	9.2
Residual Oil Saturation, Per Cent	23.5

Capillary pressure measurements indicated a connate water value of 25 per cent. Original oil content of the reservoir was calculated to be 649 STB/acre-ft.

Ultimate primary recovery, calculated by the Muskat equation, amounted to 275,000 bbl of oil to economic limit. An analysis of the water-flood recovery possibilities was undertaken in October, 1952. During the two year period from time of discovery to initiation of the study, 177,496 bbl of oil had been produced from the reservoir. Reservoir pressure in October, 1952 was approximately 1600 psig and the daily producing rate was 279 bbl of oil at a gas-oil ratio of 2000:1. Predicted and actual primary recovery performance after Nov. 1, 1952, are presented on Fig. 2.

Water is injected into a single well centrally located in the reservoir. Position of this well together with the area affected by the water-flood program is shown in Fig. 1. Ultimate recovery by water injection was calculated to be 442,000 bbl of oil, representing a gain of 167,000 bbl over primary producing operations. Calculated and actual water injection performance are presented on Fig. 2.

A tabular economic comparison of the predicted primary performance and the water-flood performance from the time of the study is presented below:

	Primary Performance	Water-Flood Performance
Future Life, Years	2.75	5.25

	Primary Performance	Water-Flood Performance
Working Interest		
Gross Income/bbl	$2.38	$2.38
Taxes and Operating Expenses/bbl	$ .43	$ .56
Water-Flood Investment/bbl		$ .06
Pumping Equipment Cost/bbl	$ .44	$ .14
Net Income/bbl	$1.51	$1.62
Present Net Worth/bbl @ 5%	$1.47	$1.46
Payout Time on Flood Investments		2 months

FIELD "B":

Field "B" is producing from a sand bar-type formation of Cretaceous age in Arkansas and is shown in Fig. 3. The discovery of oil in this field was made in March, 1946. Rapid development of the field substantially defined the productive extent of the reservoir by July, 1948 and the drilling program had been completed by July, 1949.

Reservoir fluid data obtained from bottom-hole sampling indicated a highly undersaturated crude. Reservoir pressure measurements showed rapidly declining pressures and immediate attention was given the problem of increasing the oil recovery. The indicated primary recovery was a relatively low fraction of the oil in place due to the low solution gas saturation and consequent low reservoir energy.

Core analysis showed an average porosity for this reservoir of 32 per cent, and average permeability of 2800 md. Laboratory tests of core samples indicated an average reservoir connate water of 10.6 per cent of pore space and the average residual oil saturation after water flooding, as determined from routine core analyses was 28.7 per cent.

The reservoir fluid analysis showed a formation volume factor of 1.06 reservoir bbl/STB at saturation pressure and viscosity ranging from 3.5 cp at saturation pressure to 5.0 cp at atmospheric pressure. Saturation pressure was found to be 364 psig while the original pressure in the reservoir was estimated to be 1280 psig. Original gas in solution was 65 cu ft/bbl.

The ultimate primary recovery calculated for this reservoir amounted to 9,826,000 gross bbl of oil to the economic limit of operations. During the second half of 1947, a study of the producing mechanism of the field was undertaken with the express purpose of defining the advantages of instituting injection operations to sustain reservoir pressure and producing rates and increase ultimate recovery.

At the conclusion of this study in December 1947, the reservoir pressure had declined to 650 psig and production had amounted to approximately 780,000 bbl.

The results of the study indicated that the ultimate recovery by water injection would be about three times the primary recovery if the injection program could be initiated prior to the reservoir pressure decline to saturation pressure.

The field was unitized on July 1, 1948, for the purpose of installing the water-flood and injection was commenced in September, 1948. The reservoir pressure at this time was 415 psig and the cumulative production was 2,058,000 gross bbl.

Response to the injection program was immediate in that the pressure trend was reversed as soon as injection rates exceeded withdrawals and the subsequent history has been substantially as calculated. The production, injection and pressure history of this field is shown on Fig. 4. Cumulative production from the reservoir to Jan. 1, 1956, had amounted to 18,354,000 bbl of oil.

A summary of the comparative economics of this field under calculated primary performance and water flood performance since unitization shows that:

	Primary Production	Water-Flood Program
Future Life, Years	5-1/2	18-1/2
Working Interest		
Gross Income/bbl	$2.470	$2.565*
Operating Exp./bbl	$0.124	0.208
Water Flood Investment/bbl		0.040
Net Income/bbl	$2.345	$2.317
Present Net Worth @ 5%/bbl	$2.111	$1.700
Payout Time on Flood Investments		2 months

*Reflects price increase not applicable to primary life.

FIELD "C"

Field "C", shown in Fig. 5, is producing from a Waltersburg Sand reservoir located in Henderson County, Kentucky. The discovery well in this field was drilled in November, 1949, encountering the Waltersburg sand at a depth of 1200 ft subsurface. Initial potential on the discovery well was 108 BOPD and 34 BWPD. Through the month of August, 1950, a total of 32 wells were drilled and completed as producers, with their initial potentials ranging from 10 to 480 BOPD and with varying amounts of water. This development defined a reservoir having an areal extent of 400 surface acres and a productive sand volume of 3634 acre-ft. During the development of this field a minimum amount of coring was performed with the result that analysis data were available for this study from only 18 core samples. These determinations showed the following average sand properties:

Porosity	17.2 per cent
Permeability	165 md.
Residual Oil Saturation	20 per cent

In addition to these data, a connate water saturation of 25 per cent was used and a formation volume factor of 1.05 was estimated. The oil produced has an average gravity of 34.5° API at 60° F and a viscosity of 8.8 cps. at 74° F, the estimated reservoir temperature. Original oil content of the reservoir was calculated to be 950 STB/bbl per acre-ft.

On December 1, 1952, the cumulative oil production from the field had amounted to 510,059 bbl. This was equivalent to 140.4 bbl per acre-ft. for the entire reservoir. However, by individual leases recoveries varied from 83.3 bbl/acre-ft. to 234.2 bbl/acre-ft. The oil in this field is an accumulation near the crest of a large anti-clinal structure, and a detailed study of the area indicated that the entire productive area was underlain by water. As a result of the underlying water, it was evident that a natural water drive had played an important part in the recovery of oil to the December 1952 date. At this time, an analysis of the water flood possibilities for the field were undertaken and in the course of this study it was estimated that an ultimate primary recovery of 1,165,989 bbl of oil would be realized. The expected ultimate primary recovery from the above analysis would result in a recovery of 320.9 bbl oil/acre-ft.

Peak oil production under primary producing methods occurred in July of 1950 when the average for the field was 1285 B/D, and in December of 1952, at the time that the reservoir study was initiated, production had declined to an average rate of 300 BOPD.

Ultimate recovery by water injection was calculated to be 1,840,350 bbl or an additional oil recovery of 674,361 bbl over that estimated by primary means. This total recovery is equivalent to 53.1 per cent of the oil originally in place as compared to 33.6 per cent by primary means. The calculated and actual water injection performance are presented in Fig. 5. For the purpose of this calculation, it was assumed that water injection would commence on July 1, 1953, whereas injection was actually started in December, 1953. The predicted cumulative recovery to Jan. 1, 1956, was 1,232,200 BO and actual cumulative recovery to that date has been 1,255,172 BO.

One of the most interesting aspects of this field is the fact that, at the time the reservoir study was initiated, average produced water cuts were slightly in excess of 50 per cent and, under normal circumstances, this volume of water production would seriously affect the performance and economics of a water-flood program since the oil is accumulated in an anti-clinal structure and underlain by a basal aquifer. A peripheral type injection pattern was selected utilizing wells which penetrated the underlying water sand thereby effecting complete water drive of the reservoir. These features are shown in Fig. 6.

A very quick reaction was obtained from the water injection program and within a period of 5 months the oil rate had increased from an average of 259 B/D to a maximum of 1119 B/D with no increase in field water cut. The calculated performance for the reservoir was based on an average injection rate of 3500 B/D being maintained. However, actual injection volumes have been substantially above this rate. The rate of injection has consistently exceeded fluid withdrawals by an average amount of from 75,000 to 80,000 bbl per month, and this excess injection has resulted in a continual increase in bottom-hole pressure. As the bottom-hole pressure increased, the producing wells were progressively converted to a flowing status and at the present time, 26 wells are flowing and 3 are being pumped. The increased injected volume allows the production by flowing of the same quantities of fluid which could be pumped under the lower injection rate. The ability to flow the equivalent production has substantially decreased the cost of operation of the flood while maintaining the calculated flood producing rates.

A tabular economic comparison of the predicted primary performance and the water-flood performance is presented below:

	Primary Performance	Water-Flood Performance
Future Life, Years	14	9
Working Interest		
Gross Income/bbl.	$2.54	$2.54
Taxes and Operating Expense/bbl.	$1.25	$ .54
Water-Flood Investment/bbl.		$ .09
Net Income/bbl.	$1.29	$1.93
PNW @ 5%/bbl.	$1.10	$1.63

Payout time on Flood Investment 7 months

CONCLUSION:

In conslusion, the accuracy that performance and reserves can be predicted in a secondary recovery or pressure maintenance operation is dependent upon the adequacy of the basic data required to describe reservoir rock and the characteristics of the contained fluids. The three fields cited demonstrate the predictability of performance where sufficient basic data are available. In most cases, a properly coordinated program for accumulation of the basic data necessary to predict the primary producing performance will be adequate also to define the water injection potentialities.

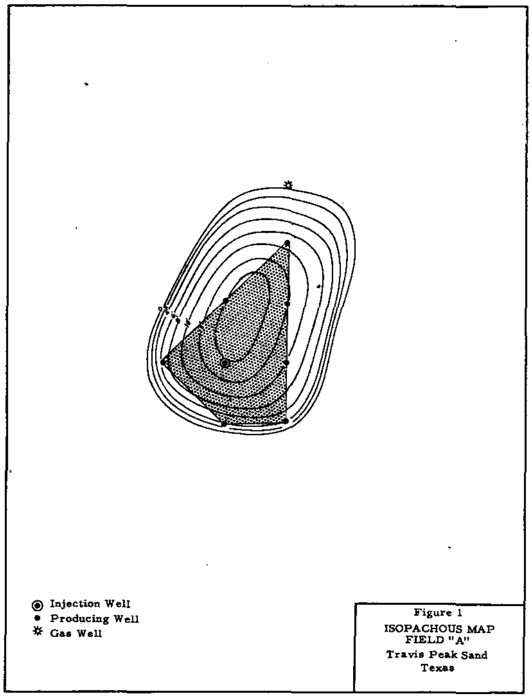

Figure 1
ISOPACHOUS MAP
FIELD "A"
Travis Peak Sand
Texas

6-630

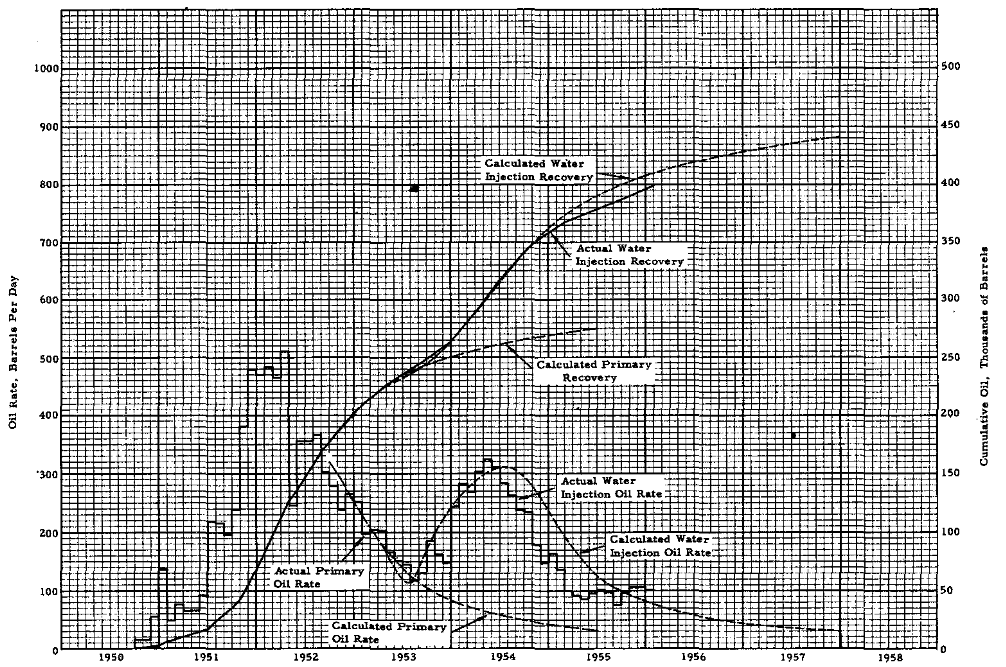

Figure 2
RESERVOIR PERFORMANCE
FIELD "A"
TRAVIS PEAK SAND
TEXAS

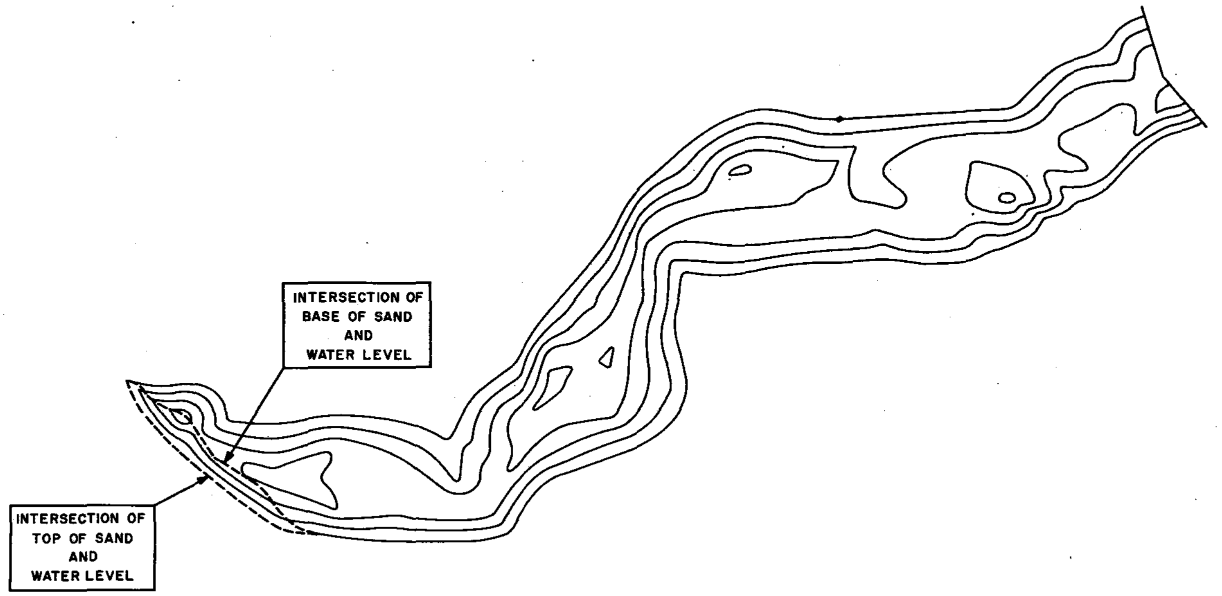

FIGURE 3
FIELD "B"
CRETACEOUS SAND
ARKANSAS

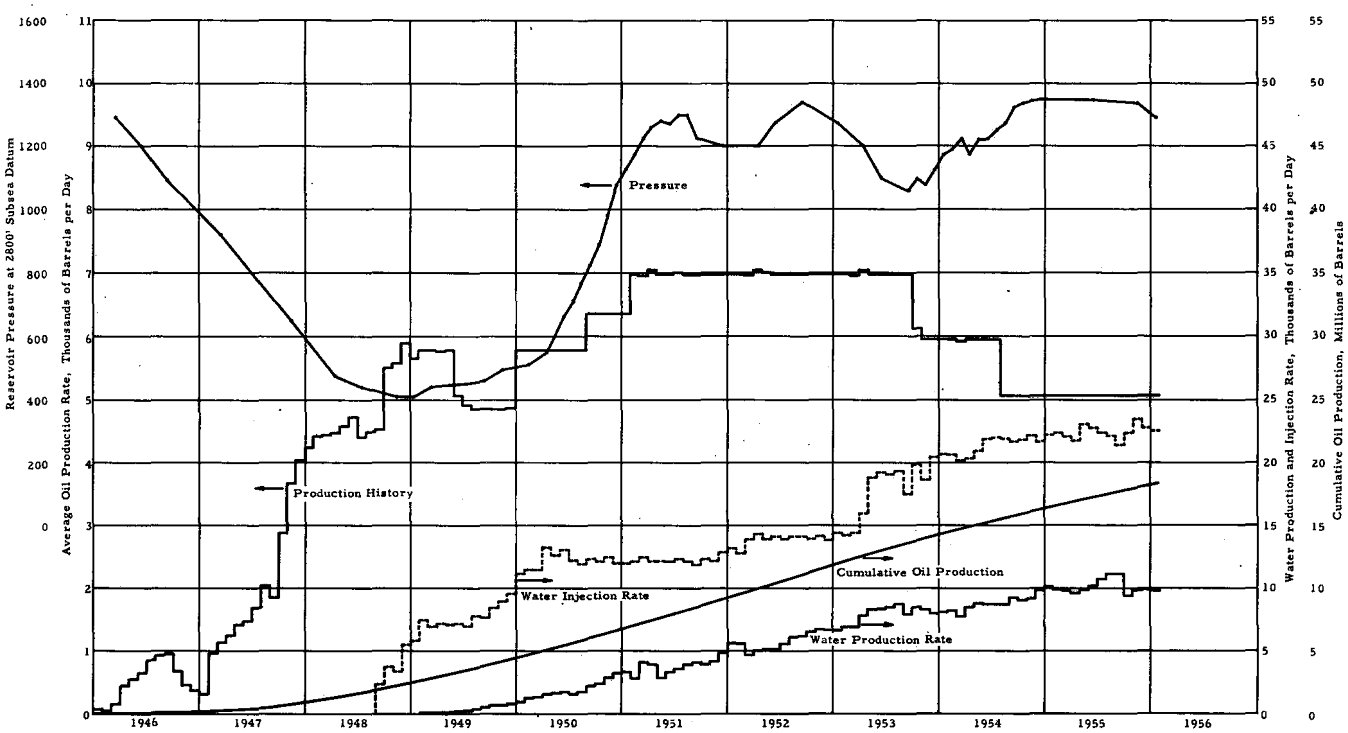

FIGURE 4
PRODUCTION HISTORY
FIELD "B"
ARKANSAS

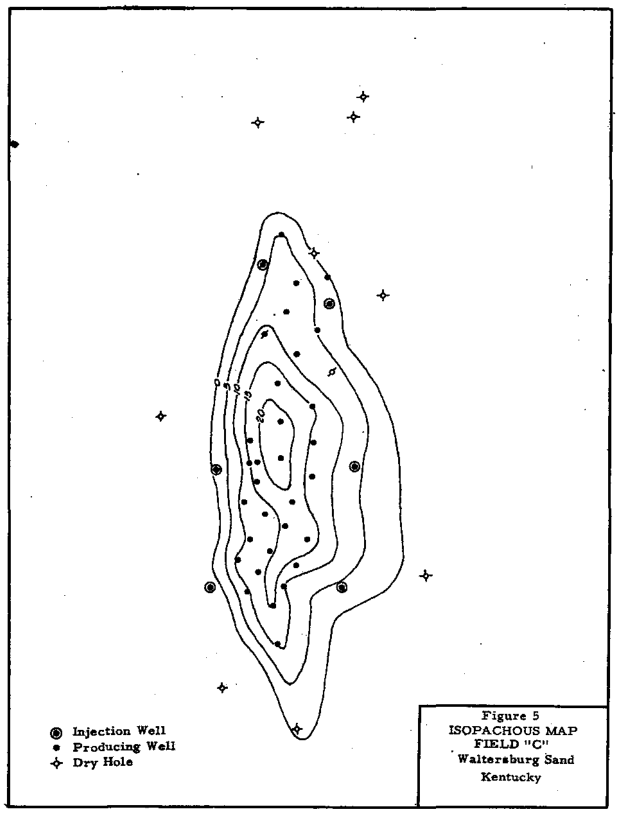

Figure 5
ISOPACHOUS MAP
FIELD "C"
Waltersburg Sand
Kentucky

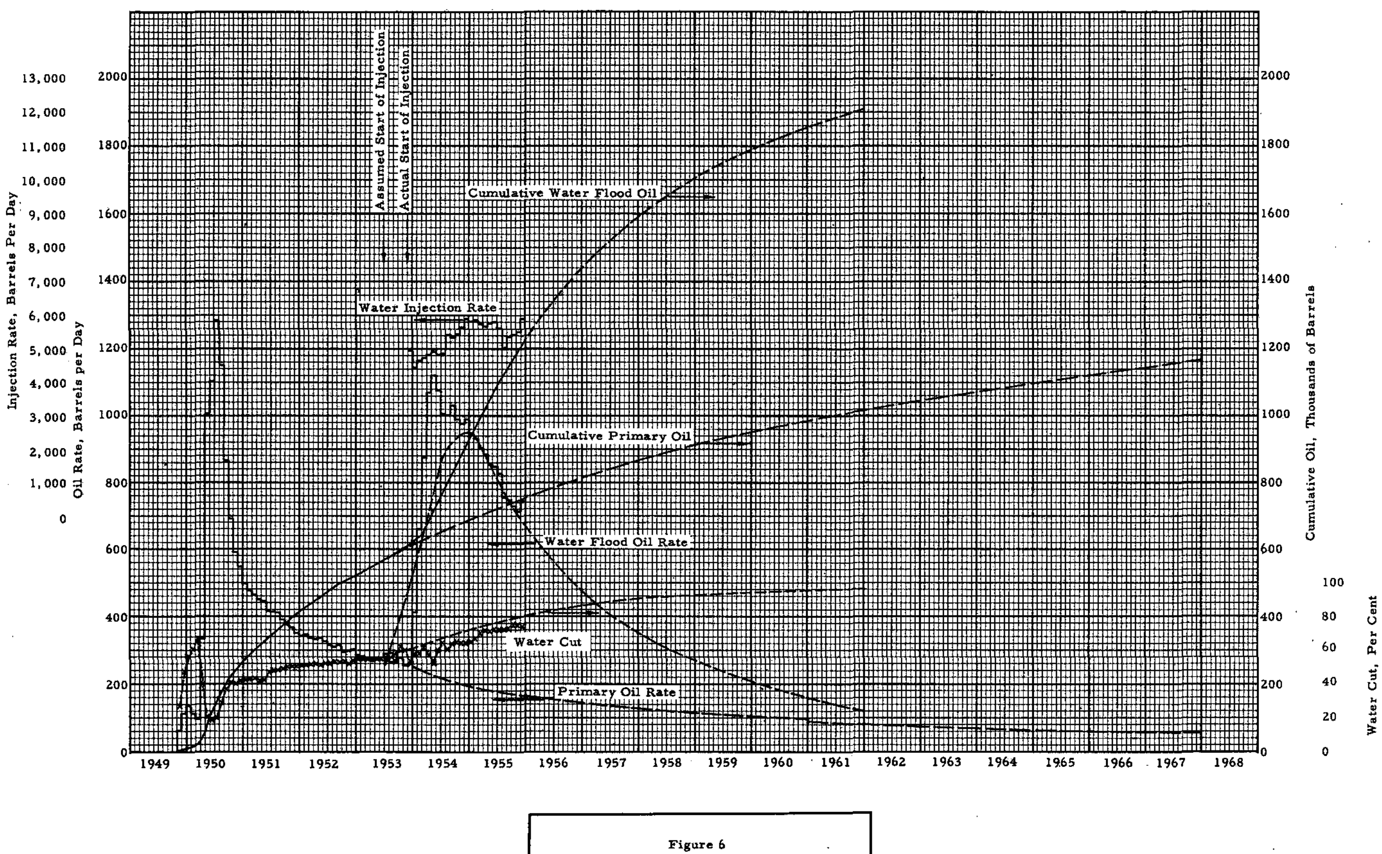

Figure 6

RESERVOIR PERFORMANCE
FIELD "C"
WALTERSBURG SAND

KENTUCKY