MISCIBLE CO_2 INJECTION PROJECT IN A WEST TEXAS CARBONATE REEF

by Richard B. Nagai, Scientific Software Corp.
and Glenn W. Redmond, Union Texas Petroleum

ABSTRACT

Performance predictions of the proposed miscible CO_2 injection project for the Wellman Field, Terry County, Texas were made using an enhanced oil recovery process numerical simulator. The study investigated the potential of injecting a relatively small, gravity stable CO_2 slug with nitrogen as the drive gas into the crest of the cone-shaped reservoir. The effects of slug size, injection rate and reservoir pressure were evaluated for an optimum future operating plan.

The differences in fluid densities at reservoir conditions were conducive to gravity segregation of the nitrogen, CO_2 and miscible oil bank. Assuming that most of the produced CO_2 would be reinjected, a CO_2 slug as small as 15% of the initial hydrocarbon pore volume appeared to be sufficient to mobilize the remaining recoverable oil in-place. Oil production performance during the early years of the project was similar for CO_2 injection rates of 10 MMSCF/D and 20 MMSCF/D so the lower rate case appeared economically more attractive. Since the massive carbonate reef, having a vertical oil column of over 800 feet, exhibited no major barriers to impede horizontal or vertical fluid flow, an excellent sweep of the reservoir was predicted in all cases.

The results of this study indicated that the concept of the proposed CO_2 flood was reasonable and could provide an economic tertiary oil recovery process for the Wellman Field.

INTRODUCTION

The objective of the study was to analyze the historical behavior of the Wellman Field and predict future performance by both continued waterflood and by gravity-stable, miscible CO_2 injection. The complete study included analysis of the geology, the well logs, and the production and injection history of the 39 wells in the Field. The contents of this paper emphasize the engineering aspects of the study and in particular the results of the CO_2 prediction cases. The effects of slug size, injection rate and reservoir pressure were evaluated to determine an optimum future operating plan.

The numerical simulation phases of the project involved the construction of a representative model of the reservoir which would be capable of meeting the objectives of the study. A three-dimensional, full field model with 1,320 cells was determined to be adequate for the conditions expected in the reservoir. The history matching process that is typically a part of the simulation study such as this was performed with a multi-phase, IMPES, black oil simulator, which was also used for the waterflood predictions. The CO_2 flood predictions utilized an enhanced oil recovery, mixing rule, miscible simulator also employing an IMPES solution technique.

DISCUSSION

Geological Setting

The Wellman Field, located in Terry County, Texas (Fig. 1), is part of the reef complex referred to as the "Horseshoe Atoll" that developed on a shallow platform in the north central part of the Midland Basin during Pennylvanian and Early Permian time. The thick limestone accumulation, known as the reef complex, developed along the eastern, southern and western edges of this ancestral platform and the geometric configuration resembles a horseshoe-shaped atoll. Wellman is a Permian (Wolfcamp) Limestone reef field located at the western end of the Horseshoe Atoll in the western part of the Midland, Basin.

STRUCTURE

The structural configuration on top of the Wolfcamp Reef is illustrated by the structure contour map, Fig. 2. The map portrays two small local highs on a general cone-shaped reef. The cone is oval-shaped in plan view with the long axis trending about N 20° E.

The Wolfcamp shale is draped over the top of the reef with a onlapping relationship as it climbed the flanks of the reef and finally buried it. The upper surface of the reef is, therefore, an unconformity and the structure map represents the attitudes of that uncomformity and the shale beds immediately overlying the reef. The dip on this unconformity ranges from about 10° to 15°.

Figure 3 depicts a geologic cross-sectional view of the reef and adjacent stratigraphic units along the line shown in Fig. 2. The horizontal and vertical scales are the same so that the structural configuration of the reservoir can be appreciated without distortion.

SIMULATION MODEL STUDY

A three-dimensional numerical simulation model that could be used to evaluate future performance of the Wellman Field under various operating schemes was constructed and calibrated by matching the historical performance of the reservoir.

The areal grid that was used for each layer of the full field model is shown in Fig. 4. The interior cells were 660 feet square or ten acres in area each. The outward dimensions of the outer row of cells was 660 feet in the upper layers, but increased as the width of the reef increased in the lower layers.

One of the conclusions of the geological analysis of the reef was that there were no reservoir features that could be correlated across the entire field. Since the model layers could not be based on stratigraphic boundaries, a horizontal layering scheme was devised which would provide the best simulation results within the scope of the project. The model layers are shown on the schematic cross-section in Fig. 5.

FLUID PROPERTIES

The oil PVT properties used in the full field model were based on the available laboratory reports and the actual field performance data.

The reservoir temperature was constant at 151° F, the oil density was 43.5° API and the undersaturated compressiblity, though variable with pressure, remained constant between the different sets of data. The gas and water PVT properties [3,4] were derived from standard correlations. A summary of the fluid and rock data is given in Table 2.

HISTORY MATCH

The observed data that was to be matched by the model was, in order, of priority: 1) average reservoir pressure, 2) movement of the oil-water and gas-oil contacts, and 3) individual water cuts. As expected, the initial attempts to match the historical performance of the reservoir indicated a need to modify the input data.

Several parameters were considered "keys" to the reservoir performance and more important than the others in obtaining the final history match. They were relative permeability, absolute permeability, vertical transmissiblity and the aquifer response. Adjustments to other parameters were to "fine-tune" the model.

RELATIVE PERMEABILITY

Several adjustments to the curve shapes and the end point values of relative permeability at the critical saturations were made during the course of the study. The initial and final sets of oil and water curves appear in Fig. 6. The straight-line relative permeability curve were a result of a very segregated type of fluid flow within the reservoir. The model was actually not very sensitive to the shapes of the curves, and the final set was probably an average of a range of possibilities.

The final gas relative permeability curve shown in Fig 7 was based on the concept of a strongly segregated flow regime similar to the water-oil system. The lowered end point value was found necessary to reduce the production of gas in several wells at certain times during the history matching process. There was less confidence in the gas-oil performance of the model since the observed gas production data were not reliable and near-solution gas-oil ratios have been reported through the life of the field.

ABSOLUTE PERMEABILITY

It was quite evident in the early history match runs that the absolute permeability (average 10 md) in the model had to be increased. Extremely large pressure gradients were created across the reservoir areally and vertically with the initial data. Most of the observed pressure data indicated excellent communication within the reservoir, since variations from well to well of 50 psi or smaller were often measured at any one time.

The average vertical permeablility through the reservoir remained approximately equal to the horizontal permeability, except in the lower layers near or in the aquifer where the KZ's were often much lower.

AQUIFER

The final aquifer to hydrocarbon pore volume ratio was 34:1 on a reservoir volume basis. The size of the aquifer was adjusted mainly by changing the lateral dimensions of the outer rows of cells in Layer 12. The large volume was needed to provide a source of energy to the reservoir, especially during the latter portion of the historical period.

HISTORY MATCH RESULTS

The calculated pressure performance and fluid contact movements assured a reasonably accurate description of the reservoir system. The Wellman Field was discovered and placed on production in late 1950, but most of the early years exhibited relatively low production rates. Thus, the historical period simulated was from January 1, 1972 to July 31, 1981.

The full field model matched the average reservoir pressure observed in the field very well, as illustrated in Fig. 8 of the Total Field Performance Versus Time.

SIMULATION MODEL PERFORMANCE PREDICTIONS

The full field simulation model was used to determine the future performance of the reservoir under two basic operating schemes, continued waterflood and CO_2 injection. Two waterflood cases were run to a minimum oil rate to obtain an estimate of the remaining reserves for a waterflood. Four other prediction cases were run with CO_2 injection under miscible reservoir conditions to examine the benefits of this tertiary recovery method.

BASE CASE PREDICTION OF CONTINUED WATERFLOOD

The ultimate oil recovery was 71.5 MMSTBO, or 56.7% of the original oil-in-place (OOIP=126 MMSTB). It was interesting to note how the production dropped off dramatically in 1986, with essentially all of the oil having been obtained by 1991.

The reservoir was virtually swept of mobile oil by the end of the prediction period.

CONTINUED WATERFLOOD WITH ACCELERATED OIL PRODUCTION RATES

A modified version of the previous Base Case was run with the objective of accelerating production. It was assumed that at April 1, 1983, the maximum oil rate would be allowed to reach 11,500 STBO/D and be maintained as long as possible with the aid of five new producers. The higher rate of Base Case II resulted in a short-term incremental gain during the 2.25 years that the 11,500 STBO/D plateau was sustained. That advantage diminished after a similar period of time until the resulting reservoir performance became almost exactly as calculated in the Base Case run. The field shut-in at about the same time in 1999 with a 56.7% recovery and only 84.0 MSTBO less recovered.

CO_2 INJECTION PREDICTIONS

Four cases were run for the purpose of determining the optimum CO_2 slug size, injection rate, sweep efficiency and operating procedure.

Laboratory studies[5] indicated that the CO_2 minimum miscibility pressure (MMP) was at about 1,950 psi. CO_2 was allowed to dissolve in the oil from the bubble point pressure, 1,375 psi, up to the MMP, at which point the oil contained 535 SCF/STB of CO_2 and had swelled to about 1.4 times its non-CO_2 volume.

An important parameter in a study such as this is the residual oil saturation after miscible flooding. Since there was a lack of data directly from the Wellman Field, a value was selected by relating the type of reservoir and displacement process to other similar projects from which more information was known. A Sorm of 0.10, at swelled reservoir conditions, was selected since it was within the range of values observed in other west Texas projects and was considered on the conservative side for Wellman.

OMEGA AND SCALING

A calculation option available in the EOR simulator used is the ability for the user to specify the value of the mixing paramter, omega. It is used in the mixing rule model to calculate effective fluid properties in the gas-oil miscible phase, and thereby take into account the imperfect mixing and consequent unstable advance that are characteristic of miscible floods.

A series of one-dimensional large cell and small cell model runs was done to test the sensitivity of omega in the horizontal and vertical directions. Since laboratory data were not available and extensive theoretical research was considered beyond the scope of the project, this work was performed to evaluate the omega of 0.67 that was selected on an experience basis. The effects of scaling, or grid cell size, were also investigated with one-dimensional large cell versus small cell models.

CO_2 PREDICTION CASE 1

The first CO_2 injection case involved the relatively high primary injection rate of 20 MMSCF/D to be started on October 1, 1982, and continued for a period of about five years. The CO_2 was injected into Well 8-4 and a well to be drilled, 4-8, in model location I-6, J-4 at 10 MMSCF/D each. Well 8-4 was open to model Layers 1 and 2; Well 4-8 was open to Layer 2 only. The assumptions concerning well and field limits that applied in the Base Case were also used in Case 1.

Unlike the Base Case, the reservoir pressure in Case 1 had to be monitored and kept at a specific level for the reservoir processes involved. The MMP of 1,950 psi had to be maintained in order to achieve miscibility and mobilize the oil down to the S_{orm} of 0.10. The top end of the range was limited by the pressure at which the CO_2 became heavier than the miscible oil. Thus, an important constraint for the prediction run was to try to maintain a reservoir pressure of about 2,300 psi.

After about two years of CO_2 injection, an appreciable amount of the producing gas stream was CO_2. To prevent depletion of the CO_2 slug, it was considered necessary to assume that gas plant facilities would become available to extract the CO_2 and that the recovered CO_2 would then be reinjected into the reservoir. Using an estimate 80% gas plant efficiency for extracting CO_2, 40% of the produced gas stream was automatically reinjected starting on July 1, 1984. The CO_2 fraction of the produced gas continued to increase, requiring a change to the maximum recycling rate of 80% on January 1, 1986. By the end of 1987, an amount equal to about 16% of the original hydrocarbon pore volume

(160 MM reservoir barrels) was in-place. An incremental gain of 2.06 MMSTB of oil over the Base Case was recovered as shown in Figure 9.

Case 1 was not run beyond 1987 after comparison with Case 2 at 1992 revealed a slightly better sweep efficiency at a lower injection rate for the same CO_2 volume in-place.

CO_2 PREDICTION CASE 2

The second CO_2 injection prediction run involved the same conditions described for Case 1 with two basic differences: 1) total CO_2 injection rate was 10 MMSCF/D and 2) average reservoir pressure was to be maintained at 2,000 psi. The lower reservoir pressure was considered more desirable since it should have increased the difference in reservoir densities between the CO_2 and oil, thus creating a more gravity stable condition. Case 2 was run through 1992 and then compared to the conditions calculated in Case 1 at the end of 1986, a time when approximately the same CO_2 in-place volumes existed. Comparisons were made at other intermediate times, also, to evaluate sweep efficiency and the integrity of the CO_2 slug. In general the CO_2 slug appeared similar in both cases with a slightly better flood front profile in Case 2. Both cases maintained a high oil production rate at or near the 9,000 STB/D limit through 1987 as can be seen in Figure 10. Since the performance of the reservoir was about the same with half as much CO_2 required, the decision was made to halt Case 1 at 1987 and continue only with Case 2.

CO_2 injection and recycling continued until a 30% hydrocarbon pore volume (HCPV) was in-place at January 31, 2007. At that time, primary CO_2 injection ceased and nitrogen (N_2) commenced at a 10 MMSCF/D rate into the same crestal wells and layer completions. Continued recycling of the produced CO_2 was accomplished via a new well drilled at model location I=6, J=6 in the center of the field. The new well, Well 4-9, was completed in Layers 5 and 6 to reinject the CO_2 at the flood front and below the nitrogen chase gas. Well 4-9 was set up to recycle 80% (estimated gas plant efficiency) of the produced gas stream which was essentially all CO_2 at that time.

Case 2 was run through the year 2030 at which time about 80% of the original oil-in-place had been recovered and the oil rate showed no signs of slackening from its 1,000-1,500 STB/D rate. An extrapolation of the recovery curve indicated an excellent sweep of the reservoir could be possible with the remaining CO_2 in-place.

CO_2 PREDICTION CASE 3

The third CO_2 injection prediction case investigated the performance potential of a smaller CO_2 slug size. Case 3 was restarted from a Case 2 run at January 1, 1994, when the CO_2 in-place was approximately 15% of the HCPV.

N_2 injection and recycled CO_2 injection commenced at January 1, 1994 with the same well set-up as in Case 2. However, recycled CO_2 was injected into Layer 4 only, since the flood front was not at the same depth that it was when N_2 injection started in Case 2. All other well and field constraints remained basically the same. This case was terminated at the end of 2006, since an oil recovery trend had been established by that time and the CO_2 slug was getting difficult to track.

Nitrogen production was more severe in this case since the CO_2 slug was only one-half the size used in Case 2. Therefore, reinjection of N_2 as well as CO_2 was performed to maintain reservoir pressure and, as importantly, to keep the gas front moving downward. Minimizing the total gas in-place loses by recycling both N_2 and CO_2 resulted in a faster mobilization of oil and buildup on an oil bank which permitted higher oil rates by 50%-100% over those in Case 2.

The oil recovery at the end of 2006 was about 89.58 MMSTB or 71.1% of the OOIP. The incremental oil recovery was 18.07 MMSTB over the Base Case runs as shown in Figure 9.

CO_2 PREDICTION CASE 4

This CO_2 injection case was similar to Case 3 in that it involved the relatively low primary injection rate of 10 MMSCF/D of CO_2 starting on October 1, 1982, until a 15% HCPV slug (33.7 BSCF) existed in the reservoir. As a Base Case II, the maximum oil rate limit was raised to 11,500 STBO/D to investigate the effects of acceleration on the reservoir. The increased rate started at the same time that five new producers were activated, April 1, 1983.

The overall performance of this run was similar to that of Case 3, with reductions in free gas production and high water cuts due to more stringent well controls. The higher oil rate (11,500 STBO/D) was calculated to be possible for three years and nine months with no apparent problems. The mobile oil in the upper layer depleted faster than in Case 3, causing a more severe decline in oil rate through 1991, until the amount of mobile oil available and the oil rate began to stabilize. Even so, the cumulative oil versus time plot, Figure 9, shows that the oil recovery could be accelerated by simply raising the rate and adding five infill wells. The total oil recovery at December 31, 2006 was 92.97 MMSTB or 73.8% of the OOIP. The incremental oil recovery was about 21.5 MMSTB over the waterflood cases.

Extrapolating the Oil Recovery Versus Pore Volumes of Injected Gas In Place curves of Figure 13, indicates that an excellent recovery may be possible under the conditions applied in these prediction cases.

It had been observed during the CO_2 injection runs that the location of the pressure sinks across the reservoir played a significant role in determining the shape of the CO_2 slug. Attempts to direct the CO_2 to some areas involved deepening several high water cut wells active, even though their oil rates may have fallen below the economic limit. Another well problem involved keeping high gas-oil ratio wells open in many upstructure completion layers in order to maintain as high an oil rate as possible.

It is conceivable that a better well management scheme might have produced a better CO_2 flood front with less N_2 breakthrough. Although careful analysis of each segment of the runs was made and innumerable adjustments to well completions were performed, the results only demonstrated and reinforced the importance of careful reservoir management during the proposed CO_2 project. Of primary concern will be monitoring the reservoir pressure and tracking the CO_2 slug and chase gas by careful observation of each well's production stream.

ECONOMICS

Five economic cases were evaluated to help determine the best approach to the CO_2 project. The first case involved a comparison between the two waterflood predictions. Since the economics of the Base Case II were substantially the same, the Base Case was used because of its low initial investment for incremental evaluations of the four other economic cases involving CO_2.

Three versions of Prediction Case 4 were investigated with different combinations of starting dates for acceleration and CO_2 injection, and also the type of CO_2 separation process to be used. The most favorable of these versions and of all the evaluations occurs when five producing wells are drilled immediately with CO_2 injection as soon as possible.

CONCLUSIONS

1. The basic concept of the proposed CO_2 injection scheme appears to be a good reservoir process with which to obtain a significant incremental gain (approximately 18 MMSTBO) over the waterflood. The CO_2 slug should remain gravity stable and nitrogen chase gas should provide an adequate driving fluid for the CO_2.

2. The potential to contact and sweep practically all of the remaining mobile oil is indicated with a CO_2 slug as small as 15% of a HCPV (approximately 33.7 BSCF of CO^2).

3. Much of the injected CO_2 will be produced early in the operation, so gas plant facilities will be necessary to separate the produced CO_2 for reinjection into reservoir.

4. Maintaining gas production at a reasonable level and oil production at its maximum potential were operating constraints that indicated that workovers and recompletions will become routine in the field as the gas front and oil bank move steadily downstructure. Careful production monitoring will become esential to have even a moderately successful project.

5. A continued waterflood under current conditions would result in a excellent sweep of the reservoir, leaving only a few minor pockets of potentially mobile oil along some flank area. The estimated ultimate oil recovery was 71.5 MMSTBO or 56.7% of the original oil-in-place.

6. The importance of having CO_2 removal facilities available early with sufficient capacity to process large volumes of CO_2 production must be emphasized.

7. Methods for monitoring the movement of the CO_2-oil interface need to be investigated. The use of TDT logs may be of value in this regard.

8. Economic analyses of various scenarios based on the results of this study are favorable.

ACKNOWLEDGEMENTS

The authors wish to expess their appreciation to Union Texas Petroleum for permission to publish this paper. We also appreciate the assistance of Drs. Dennis Graue and Linus R. Litsey, and Mr. Joseph A. Dozzo of SSC and Mr. Van R. Temple of UTP during the project.

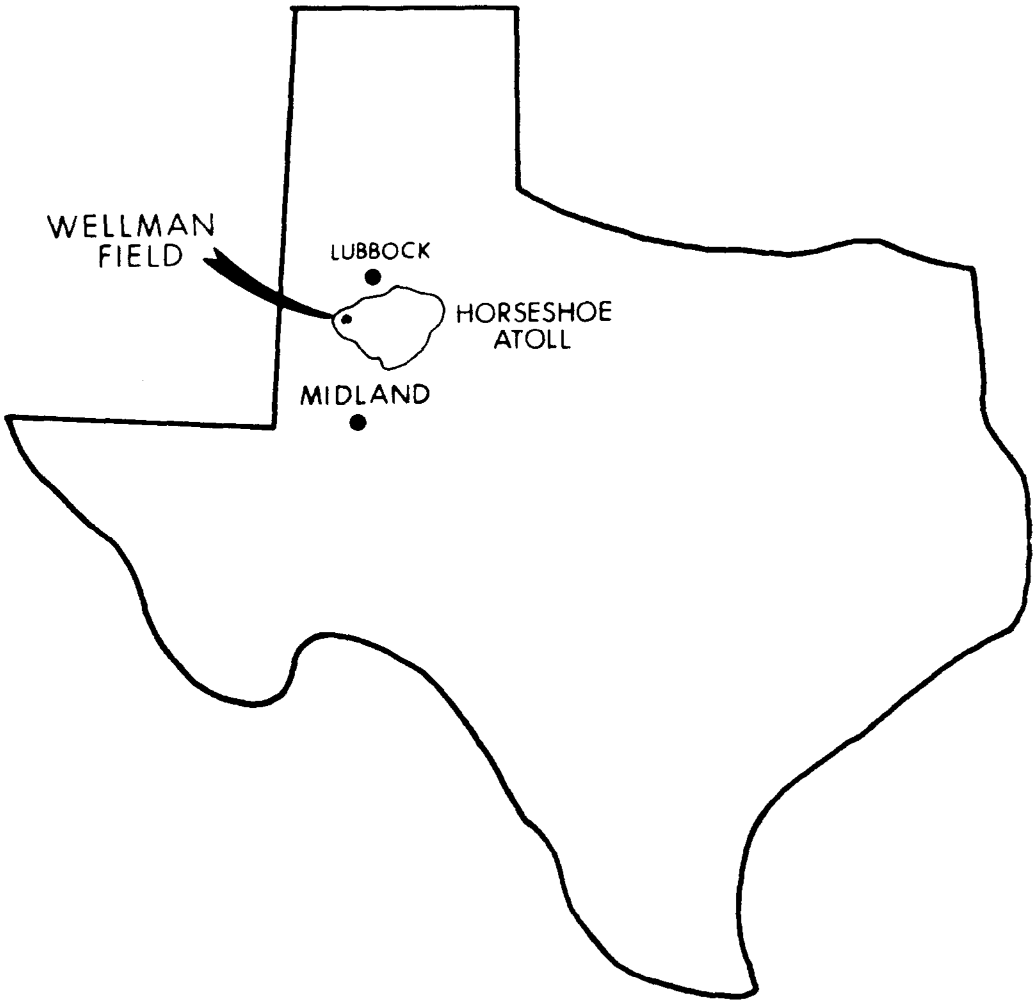

FIGURE 1 — STATE OF TEXAS—LOCATION OF WELLMAN FIELD AND THE HORSESHOE ATOLL.

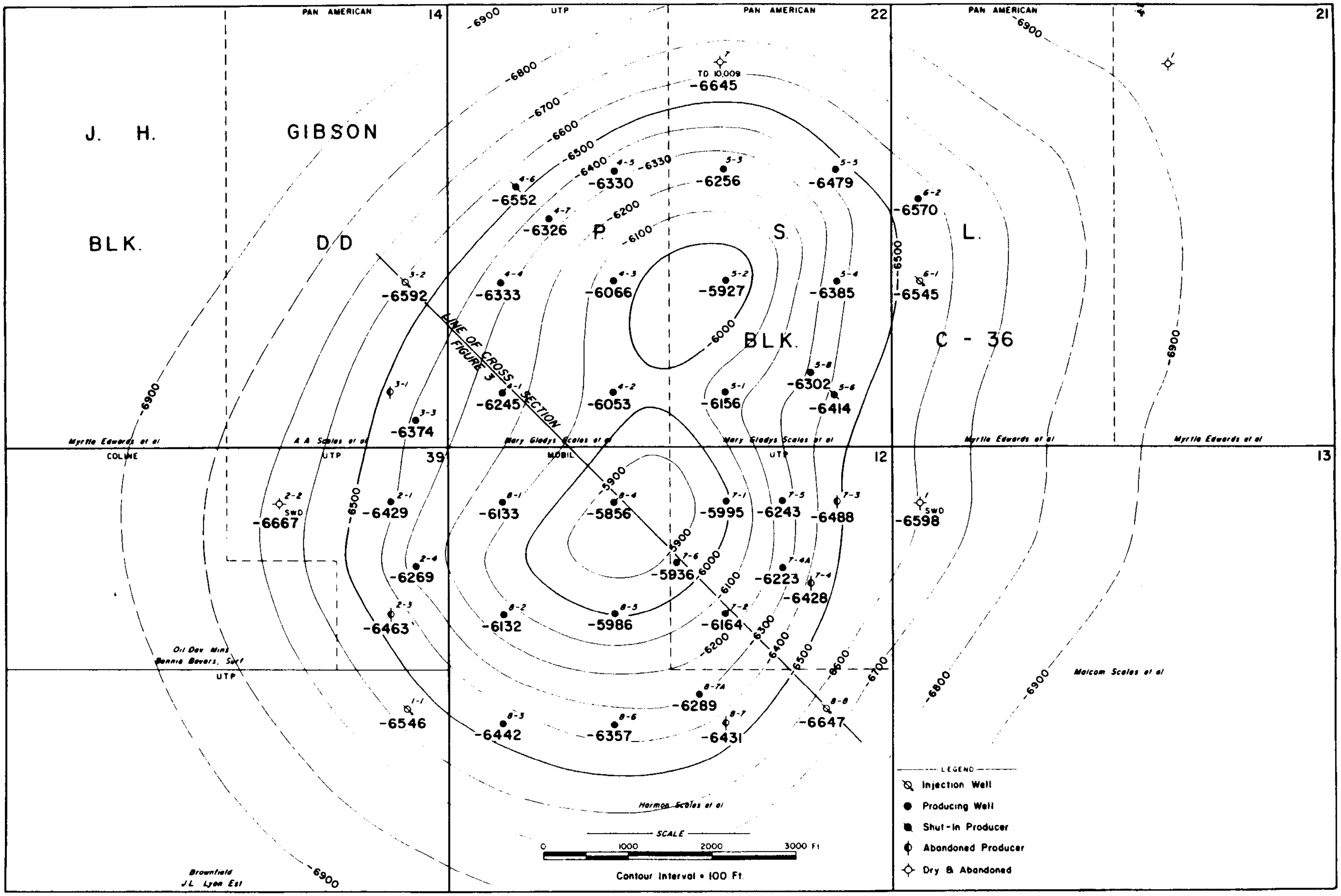

FIGURE 2 — STRUCTURE TOP OF WOLTCAMP REEF.

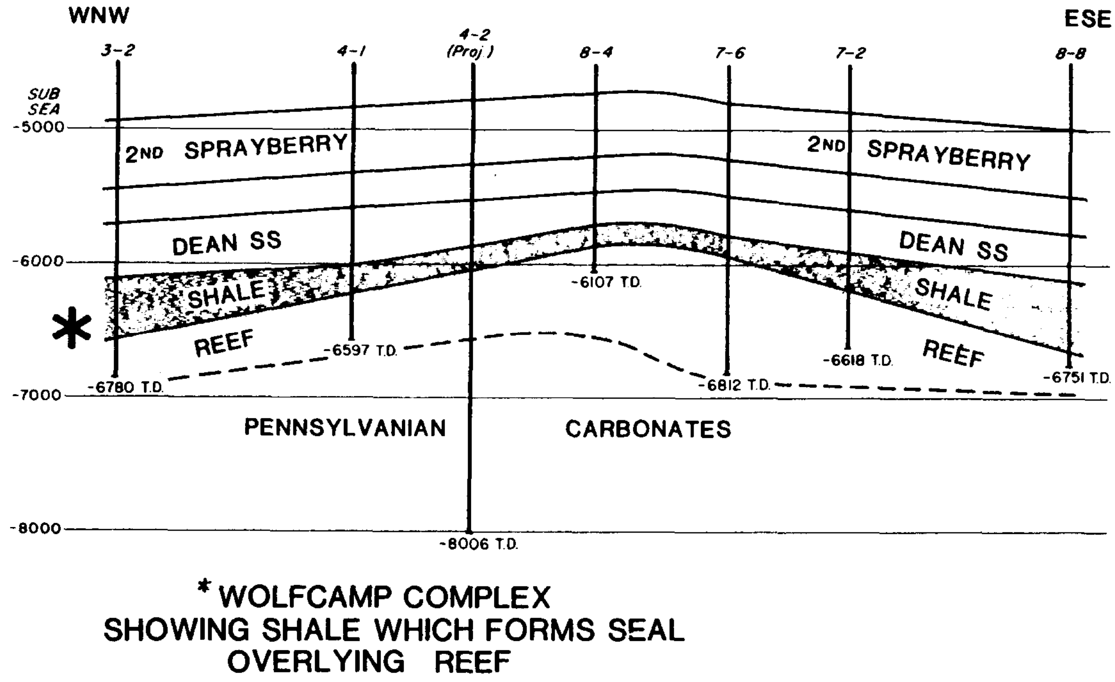

FIGURE 3 — CROSS SECTION ESE-WNW.

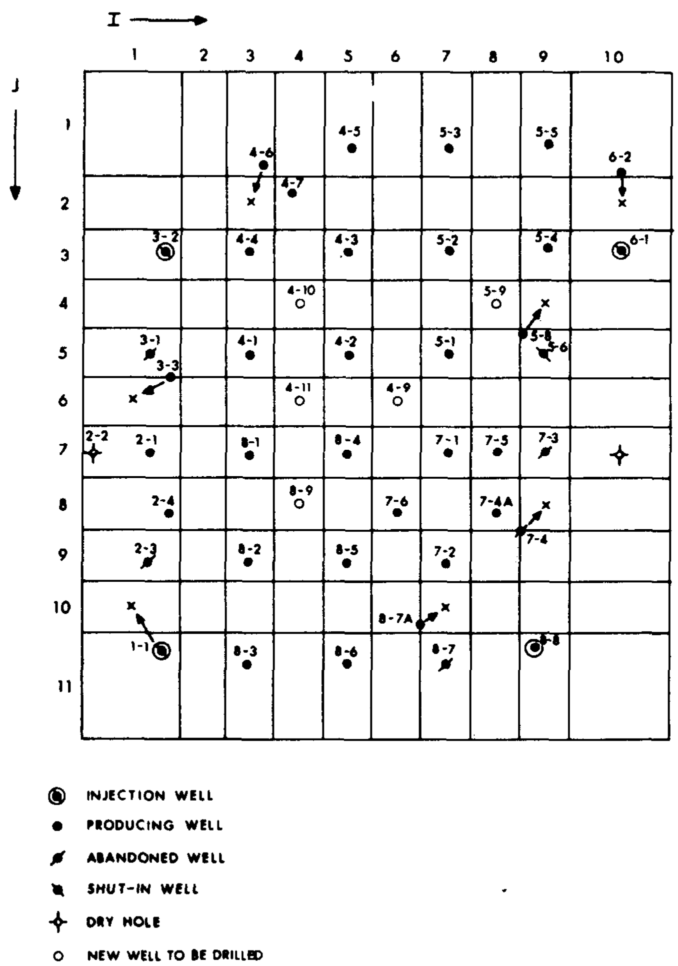

FIGURE 4 — AREAL GRID USED IN THE SIMULATION MODEL.

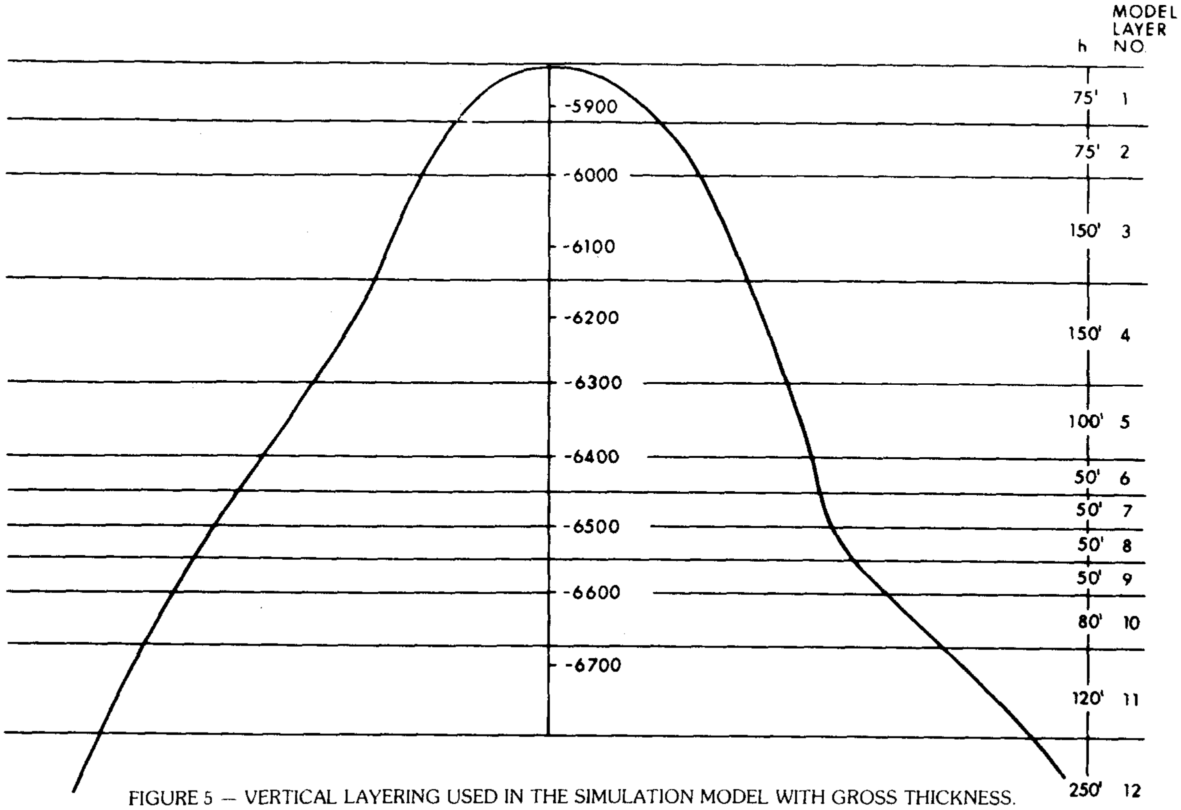

FIGURE 5 — VERTICAL LAYERING USED IN THE SIMULATION MODEL WITH GROSS THICKNESS.

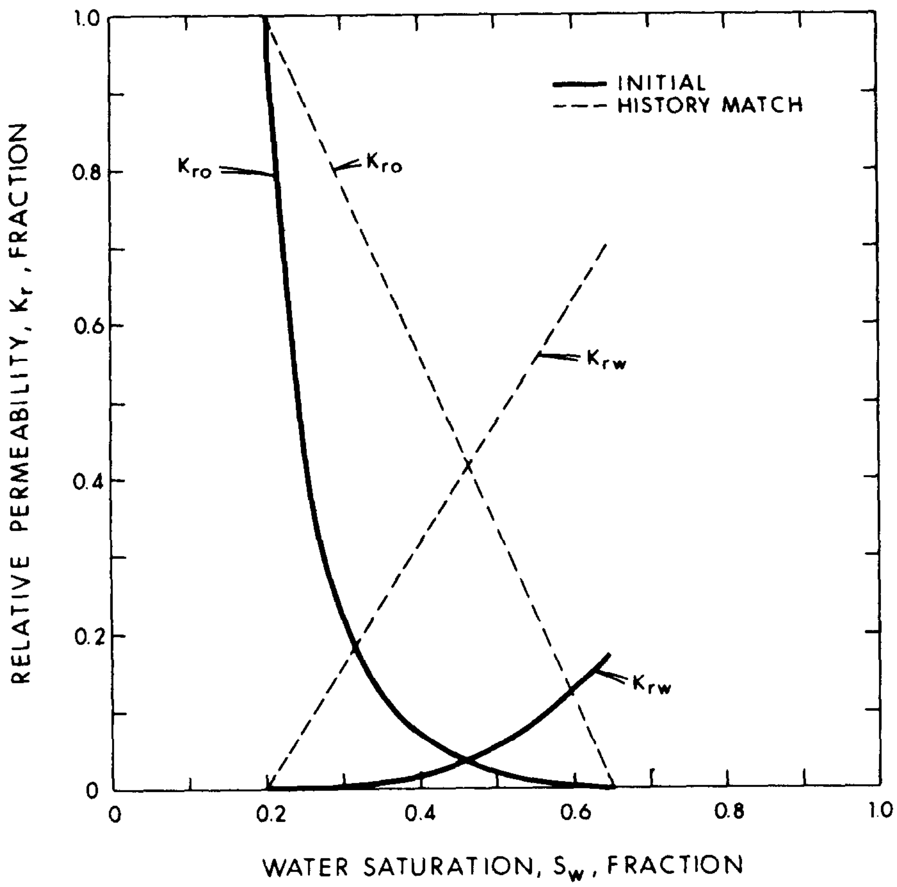

FIGURE 6 — INITIAL AND FINAL OIL-WATER RELATIVE PERMEABILITY CURVES.

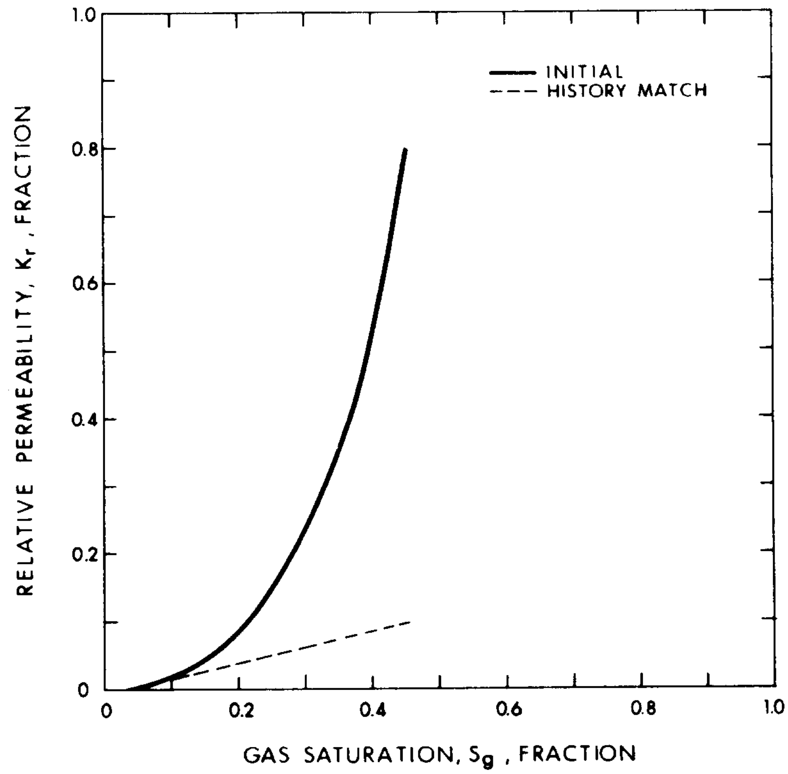

FIGURE 7 INITIAL AND FINAL GAS RELATIVE PERMEABILITY CURVES.

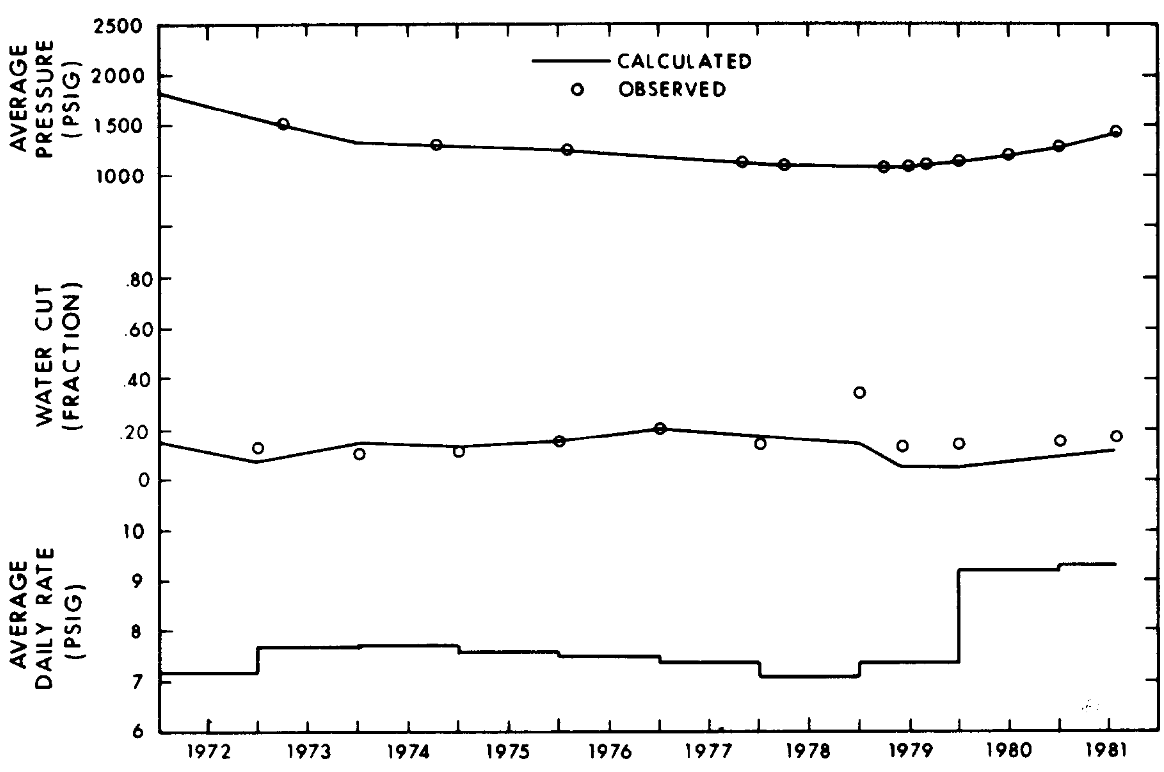

FIGURE 8 — TOTAL FIELD PERFORMANCE OF THE FINAL HISTORY MATCH RUN.

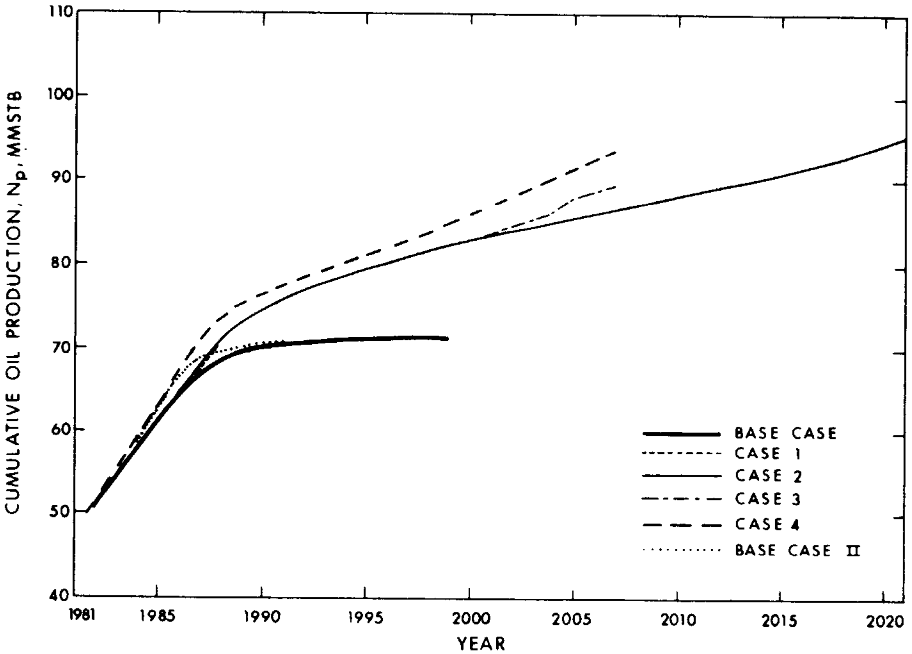

FIGURE 9 — COMPARISON OF CASES—CUMULATIVE OIL PRODUCTION VS. TIME.

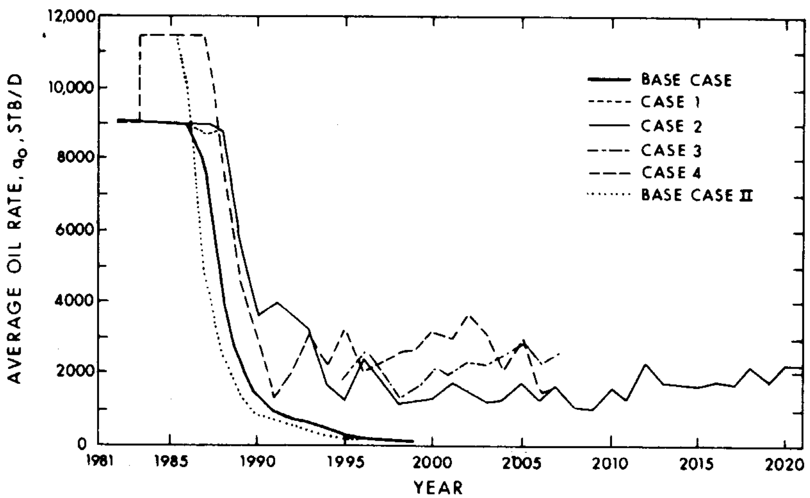

FIGURE 10 — COMPARISON OF CASES—AVERAGE OIL RATE VS. TIME.

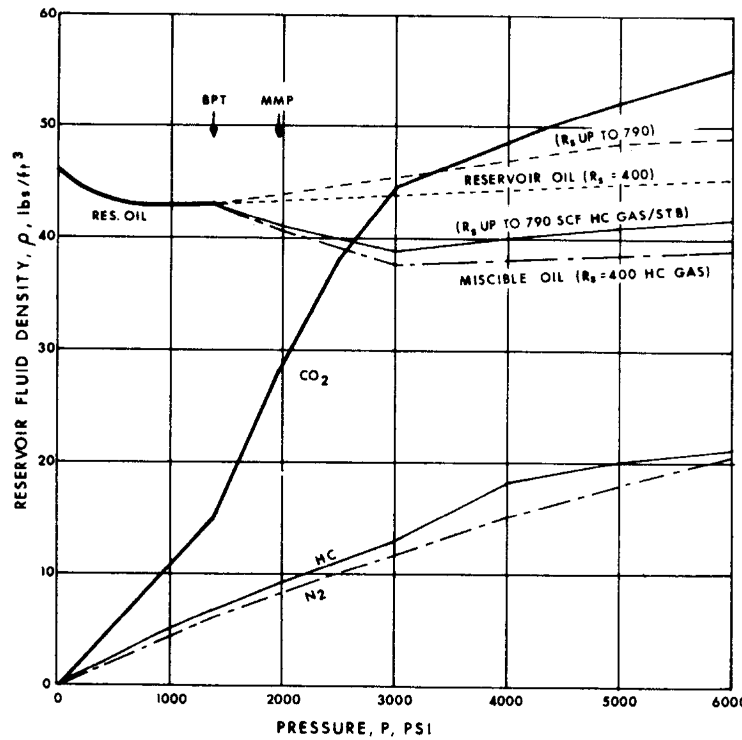

FIGURE 11 — RESERVOIR FLUID DENSITIES VS. PRESSURE.

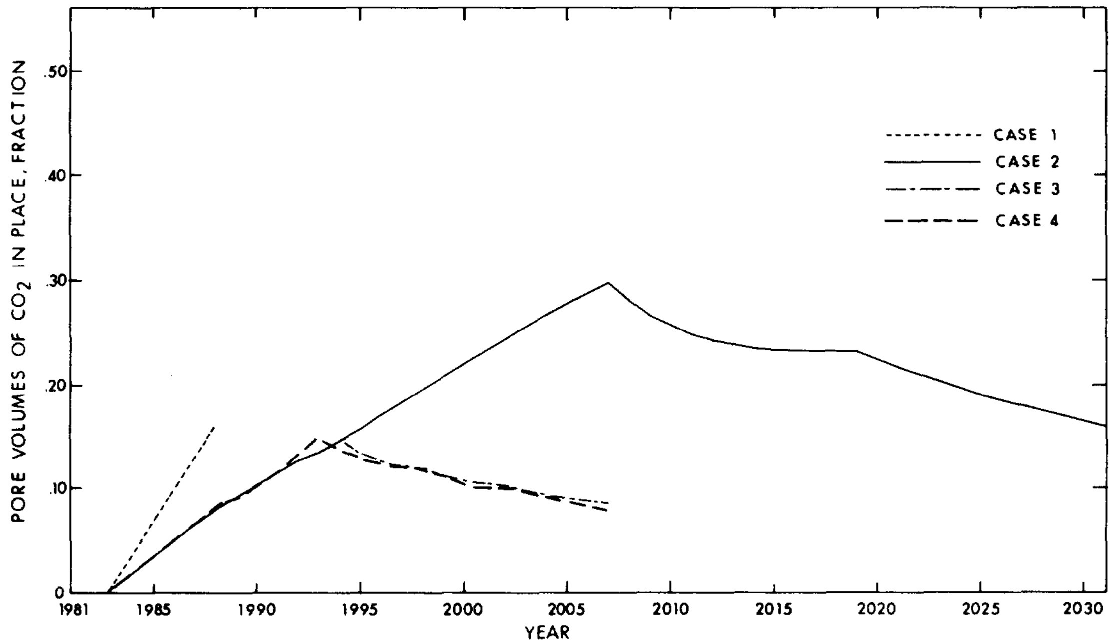

FIGURE 12 — COMPARSION OF CASES—PORE VOLUMES OF CO^2 IN-PLACE VS. TIME.

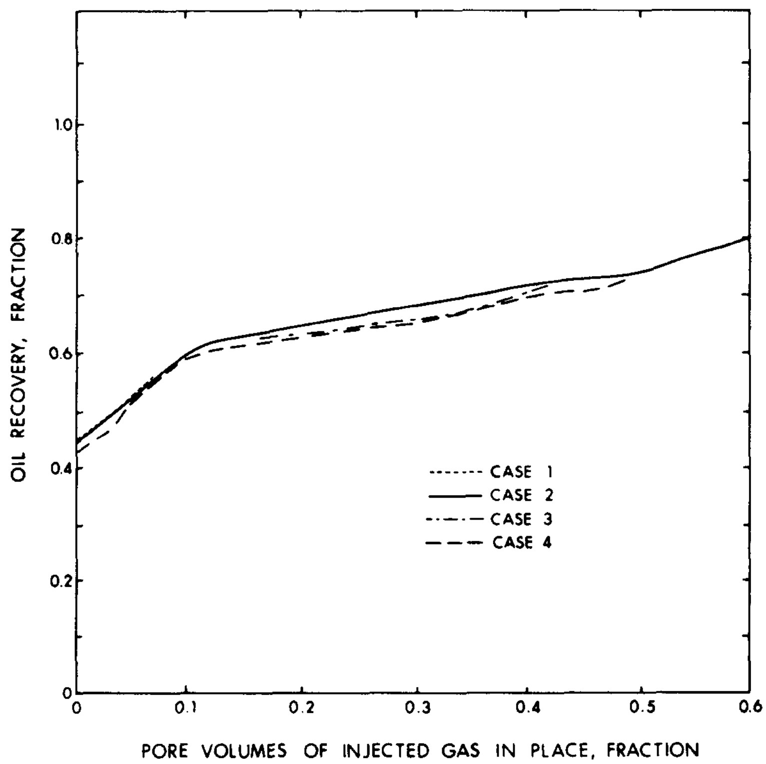

FIGURE 13 — COMPARSION OF CASES—OIL RECOVERY VS. PORE VOLUMES OF INJECTED GAS IN-PLACE.