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TARGET RESERVOIRS FOR CO_2 MISCIBLE FLOODING—FINAL REPORT

Volume I: Discussion of CO_2 Injection Process
Volume II: Full Scale and Pilot Field Tests

By
John H. Goodrich

October 1980
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TARGET RESERVOIRS FOR CO_2 MISCIBLE FLOODING – FINAL REPORT

Volume I: Discussion of CO_2 Injection Process
Volume II: Full Scale and Pilot Field Tests

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U.S. DEPARTMENT OF ENERGY

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Note: For all the reports in this volume, tables and figures are grouped together at the end of each report.

TARGET RESERVOIRS FOR CO_2 MISCIBLE FLOODING

TASK ONE REPORT

REVIEW AND ANALYSIS OF PAST AND ONGOING CARBON DIOXIDE INJECTION FIELD TESTS

I. INTRODUCTION

The technical potential for increasing recovery from underground accumulations of crude oil by injection of carbon dioxide has long been recognized [1]. Early work using CO_2 as a means of enhancing recovery considered two technically different processes:

(1) Injection of CO_2 dissolved in water--so-called "carbonated water flooding" [2].

(2) Injection of CO_2 as a solvent for the crude oil in place in the pores--analogous to LPG injection--as a variation of "miscible" displacement [3,4].

Carbonated waterflooding, a technique known as the "Orco Process" [5], was introduced in 1951 [6]. Considerable laboratory research [3,7-10] and a number of field trials [11-14] were reported in the literature of the time. This process was shown to be capable of recovering oil unrecoverable by conventional waterflooding. Carbonated waterflooding was generally conducted at pressures below CO_2 miscibility pressure and the benefits were derived from:

(1) Swelling of the oil by solution of CO_2, which reduces the stock tank equivalent of the oil volume contained by the reservoir residual oil saturation.

(2) Reduction of reservoir oil viscosity by solution of CO_2, which improves the mobility ratio for viscous oils and thus enhances waterflooding efficiency.

Residual oil saturation of swelled oil left in the reservoir rock was the same as that for conventional waterflooding, about 20 to 40 percent of pore space. Benefits [15] from the process were therefore inherently limited to the relatively minor recovery improvements that result from the mechanisms listed above.

The Orco process proved uneconomic and is not currently used as an enhanced oil recovery technique. Hence, this report will not consider carbonated-water flooding to be within the scope of CO_2 miscible flooding field application.

General Background Of This Study

By contrast with carbonated-water flooding, displacement of oil by CO_2 at pressures above "miscibility" pressure appears to be a very promising technique for substantially increasing oil recovery in both secondary and tertiary recovery applications [16,17]. This is true because at pressures greater than "miscibility" pressure, CO_2 can extract a substantial portion of the oil contacted, leaving a residual saturation of only 3-5 percent of pore space. A study of field applications of this technique as related to basic CO_2 displacement technology is the subject of this report.

Technological development was sufficiently advanced and the economic benefits of the CO_2 displacement process were sufficiently known by the late 1960's and early 1970's to provide industry with justification for installing two pilot tertiary recovery projects [18,19] and two field-scale CO_2 injection secondary recovery projects [20,21]. These projects are discussed in detail later in this report. The Arab oil embargo of 1973 and the consequent dramatic increase in world oil prices provided incentives both to private industry and to government to accelerate application of enhanced oil recovery techniques to increase production and recovery from domestic oil reservoirs.

Private industry clearly recognized the potential for CO_2 displacement projects in the large carbonate reservoirs of the Permian Basin in West Texas and eastern New Mexico [22]. This recognition resulted in increased research in industrial laboratories, some of which (as discussed in a later section) is now being published, and in a competitive search for sources of CO_2 supply [23,24].

Government efforts to accelerate application of enhanced oil recovery techniques began in 1974 when the U.S. Bureau of Mines entered into cost-sharing contracts with industry to support field demonstrations of enhanced oil recovery (EOR) techniques [25]. These efforts were subsequently expanded (by ERDA and DOE as successors to the USBM in administering the program) to include several studies of the enhanced oil recovery "resource base" [25-30]. These studies led to a comprehensive five-year enhanced oil recovery management plan published in January 1977 [31]. The work published in the present report is an outgrowth of this management plan as specifically applied to plans for CO_2 flooding programs.

Purpose and Scope Of This Report

This report is part of the work required to fulfill a contract [32,33] awarded to Gruy Federal, Inc. by the Department of Energy (DOE) on February 12, 1979. The requirements of the contract are summarized in Enclosure I-1 (pages 4-6). The contract, originally awarded by DOE's Oak Ridge Operations Office [34], is now administered by the Morgantown Energy Technology Center, Morgantown, W. Va. [35]

Specifically, this report is directed toward fulfilling the work requirement of Task One, which states:

"2.1 Summary of Available CO_2 Field Test Data

"Data will be collected, categorized, and interpreted from all significant past and on-going CO_2 field operations in order to evaluate the relative success of each test. This information will include oil gravity, reservoir pressure, depth, temperature, porosity, permeability, and net/gross pay. Also, these data must include pattern size, estimated incremental oil production due to CO_2 injection, CO_2 concentration and slug size, CO_2 injection rates and sequencing, CO_2 breakthrough and production rates, and any indications of formation damage or corrosion." [32]

To accomplish this, information from published geological and engineering literature sources, raw data from public records (Texas Railroad Commission, Arkansas Oil and Gas Commission, etc.), and other available information were used to compile comprehensive field reports following the format given in Enclosure I-2 (page 8). These reports were prepared for each of the projects listed in Enclosure I-3 and are included in the Appendix (Volume 2) to this report.

Data for many of these projects have been published in summary form [17,36]. However, no comprehensive treatment of both the geological and engineering aspects of these projects is believed to be available in any public literature. This report relates data from these field studies to existing CO_2 flooding theory and technology and correlates the various projects.

ENCLOSURE I - 1

"TARGET RESERVOIRS FOR
CARBON DIOXIDE MISCIBLE FLOODING"

Contract No. DE-AC21-79MC08341

APPENDIX A
STATEMENT OF WORK

1.0 OBJECTIVE

1.1 The objective is to build a solid engineering foundation upon which field mini and pilot tests may be conducted in both high and low oil saturation carbonate reservoirs for the purpose of extending the technology base in carbon dioxide miscible flooding.

2.0 SCOPE OF WORK

2.1 Summary of Available CO_2 Field Test Data

Data will be collected categorized, and interpreted from all significant past and on-going CO_2 field operations in order to evaluate the relative success of each test. This information will include oil gravity, reservoir pressure, depth, temperature, porosity, permeability, and net/gross pay. Also, these data must include pattern size, estimated incremental oil production due to CO_2 injection, CO_2 concentration and slug size, CO_2 injection rates and sequencing, CO_2 breakthrough and production rates, and any indications of formation damage or corrosion.

2.2 Summary of Existing Reservoir and Geological Data

The following reservoir geology will be determined on carbonate reservoirs located in west Texas, southeast New Mexico, and the Rocky Mountain states: stratigraphy, structure, mineralogy, porosity, permeability, gross and net thickness, and any other geological properties deemed significant regarding CO_2 injection. Reservoir data will be collected on hydrocarbon content, composition and distribution; connate water content and composition; pressure and production data from primary and/or secondary recovery operations; PVT analysis; and well test data and analysis. Guidelines for selecting reservoirs to be included are as follows:

average formation permeability -	5 md
average current oil saturation -	38%
oil gravity - - - - - - - - - - -	36 deg API
oil viscosity - - - - - - - - - -	10 cp

In addition, no extremely high-permeability, stratigraphic, thief zones should exist. However, no consideration should be given to the proximity of CO_2 sources at this point. The objective here is to "characterize the resource" for possible future CO_2 injection.

2.3 Selection of Target Reservoirs

By analyzing available reservoir and geological data, and comparing the results of various CO_2 field tests, a priority list will be developed based primarily on potential incremental oil recovery and the projected CO_2 requirements and availability. CO_2 requirements can be based on estimates from data collected in Task 1 and CO_2 supply data can be obtained from existing public documents on the subject (e.g. "The Supply of Carbon Dioxide for Enhanced Oil Recovery" by Pullman Kellogg, September, 1977).

2.4 Selection of Specific Reservoirs for CO_2 Injection Tests

A selection will be made from the priority list based on demonstrating the technology in those reservoirs with the greatest potential influence toward stimulating new projects capable of meeting the 1985 incremental oil production of 124,000 barrels per day stated in the Technical Implementation Plan for reservoirs in these target areas. For the reservoirs selected, the owners and operators will be identified. Also company officials who have the authority or influence to bring about commercialization of CO_2 recovery processes will be contacted. This is absolutely necessary since it is these companies which must eventually initiate and carry out commercial demonstrations of CO_2 injection if the full potential of the target reservoirs is realized.

2.5 Selection of Specific Sites for Test Wells (carbonate reservoirs)

Using all useful available knowledge from previous CO_2 field tests, reservoir and geological compilations, conventional production data, PVT analysis, log analysis, core analysis, and well test analysis, specific sites will be selected for drilling test wells for further delineation and substantiation of the reservoir properties prior to conducting CO_2 injection tests. These sites must be in the Rocky Mountain and west Texas-southeast New Mexico areas. A minimum of eight and a maximum of twelve sites are to be selected.

2.6 Drilling and Coring Activities

Depending on the availability of data at each site selected, test wells will be drilled, cored, logged, tested and analyzed to confirm initial oil saturation parameters and to design mini-test CO_2 injection programs. It is expected that one test well will be drilled at each site selected. However, the exact number and location of wells to be drilled will be negotiated to be consistent with the amount of additional engineering and geological information required, drilling costs in the area at the time of execution, and any other economic and engineering factors that may arise.

ENCLOSURE I - 2

FORMAT FOR PREPARATION AND PRESENTATION OF CO_2 INJECTION FIELD PROJECT REPORTS

Standard Outline

Location and General History

Geologic and Petrophysical Data

Reservoir Performance Data

CO_2 Project Data

- Size and Type of Project
- Operating Plan and CO_2 Source
- Injection and Production Performance
- Interpretation of Project Data

Conclusions

References

Standard Enclosures

Data Form

Geographic Location Map

Geologic Structure Map

Type Log (Geologic Column and Pay Section)

Isopach Map

Project Area Map

Field Performance Graph

Project Performance Graph

Plus special enclosures as appropriate

ENCLOSURE I - 3

CO_2 FIELD INJECTION PROJECTS STUDIED IN THIS REPORT

FULL-SCALE (COMMERCIAL INTENT) PROJECTS

Field	Operator(s)	Reservoir Lithology	Region or State
Kelly-Snyder (SACROC)	Chevron	Carbonate	West Texas
Crossett (North Cross)	Shell	Carbonate	West Texas
Lick Creek	Phillips	Sandstone	Arkansas
Ritchie	U.S. Oil, Phillips	Sandstone	Arkansas
Twofreds	H.N.G.	Sandstone	West Texas
South Gillock	Amoco	Sand	Texas Gulf Coast
Weeks Island	Shell	Sand	Louisiana Gulf Coast

"FIELD SCALE" PILOT PROJECTS

Field	Operator(s)	Reservoir Lithology	Region or State
Wasson	Arco, Shell	Carbonate	West Texas
Mead (Strawn)	Union of Calif.	Sandstone	West Texas
Slaughter	Amoco	Carbonate	West Texas
Levelland	Amoco	Carbonate	West Texas
North Cowden	Amoco	Carbonate	West Texas
Little Creek	Shell	Sandstone	Mississippi
Granny's Creek	Columbia Gas	Sandstone	West Virginia
Griffithsville	Guyan Oil Co.	Sandstone	West Virginia
Rock Creek	Pennzoil	Sandstone	West Virginia

II. REVIEW OF CARBON DIOXIDE DISPLACEMENT THEORY AND PROCESSES

A number of reviews describing the CO_2 miscible flooding process are available in the literature [16,17,26,36-38]. This chapter draws freely on this source material and on other published studies with the intent of providing a comprehensive reference to both theory and technology. This will provide the framework needed to evaluate the field test results reported in a later chapter.

Carbon dioxide as an injection fluid has the following effects during removal of oil from porous rock:

"1. It promotes swelling.
2. It reduces oil viscosity.
3. It increases oil density.
4. It is highly soluble in water.
5. It exerts an acidic effect on the rock.
6. It can vaporize and extract portions of crude oil.
7. It is transported chromatographically through porous rock" [39].

These phenomenological observations are supported by experimental data that will be discussed in this section. This discussion will synthesize available reference material to provide an understanding of (1) the basic physical behavior of carbon dioxide, (2) the behavior of mixtures of CO_2 and crude oils, and (3) present knowledge about the displacement/extraction process that occurs when CO_2 contacts and moves oil in a porous medium.

Physical Properties And Behavior Of Carbon Dioxide

Carbon dioxide is a stable molecule containing one atom of carbon bonded to two atoms of oxygen, as indicated by the chemical notation CO_2. Over the range of pressures and temperatures available to technology, it can exist as a solid (Dry Ice), a liquid, or a vapor. Basic physical constants are:

Molecular weight: 44.010
Critical temperature: 87.8°F (547.8°R)
Critical pressure: 1069.4 psia

Carbon dioxide is a gas at ambient conditions and is relatively dense, approximately 50 percent heavier than air at atmospheric conditions.

Phase Behavior. Phase behavior of pure carbon dioxide as a function of pressure and temperature is shown in Fig. 1.* It is evident from this figure that for the practical range of temperatures that may be encountered in oil field practice--say, 0°F or higher--only the liquid and vapor phases and their behavior will be of consequence. Figure 2 shows in more detail

*Figures 1 through 10 appear on pages 12 through 22.

the vapor-liquid phase relationship for CO_2 over the temperature range from 0°F to the critical temperature, 87.8°F. The physical significance of this curve below critical temperature is that CO_2 condenses to liquid when compressed to pressures above the vapor pressure.

Above critical temperature, CO_2 behaves as a vapor whose density increases as pressure increases. Data illustrating this are shown in Fig. 3 [40,41], which shows that fluid density is a continuous function of pressure at temperatures above critical but that abrupt discontinuities appear at the vapor pressure for the subcritical temperatures of 60°F and 80°F.

Volumetric Behavior. Volumetric behavior of liquid carbon dioxide can be derived from density data of the type portrayed in Fig. 3. To illustrate the volumetric changes that occur in the liquid phase as pressure is increased isothermally, data taken from Fig. 3 are plotted on Fig. 4 in the form of:

$$\text{Relative volume of liquid } CO_2 = \frac{\rho \text{ at vapor pressure}}{\rho \text{ at } p > \text{vapor pressure}}$$

These data show that liquid CO_2 is compressible and hence shrinks in volume as pressure increases. Average compressibility, defined as

$$c = \frac{1}{\bar{\rho}} \frac{\Delta\rho}{\Delta p}$$

for the density and pressure ranges shown in Figs. 3 and 4, is calculated to be:

Temperature	Pressure Range	Compressibility
60°F	750-4,250 psi	5.9×10^{-5} vol/vol/psi.
80°F	1,000-5,750 psi	7×10^{-5} vol/vol/psi.

These data indicate that liquid CO_2 is some 20 times more compressible than water at comparable temperatures and pressures and that liquid volume shrinkage and compressibility increase as temperature increases.

The volumetric behavior of vapor phase CO_2 could similarly be derived from the data given in Fig. 3. However, it is simpler to study vapor phase volumetric behavior in terms of the gas laws:

$$\frac{p_1V_1}{z_1T_1} = \frac{p_2V_2}{z_2T_2} = \text{constant.} \quad (1)$$

The deviation of CO_2 from ideal gas behavior is expressed by the gas deviation factor (z) or "supercompressibility". Published data showing the variation of the CO_2 gas deviation factor as a function of pressure and temperature are shown in Fig. 5 [41,42].

The conventional reservoir engineering technique for representing volume changes with pressure and temperature is based on the concept of formation volume factor [8], defined as:

$$B = \frac{\text{volume at reservoir pressure and temperature}}{\text{volume at surface or standard pressure and temperature}}$$

For vapor-phase materials, the gas laws (Eq. 1) are used to develop the needed mathematical expression:

$$B_g(p,T) = \frac{p_{sc}zT}{pT_{sc}} \tag{2}$$

where the gas deviation factor (z) is evaluated at reservoir pressure (p) and temperature (T). Formation volume factors for CO_2 at various pressures and temperatures, calculated from Eq. 2 using data from Fig. 5, are shown in Fig. 6.

The barrels of reservoir pore space that will be occupied by a given standard volume of CO_2 is another concept useful in CO_2 flooding technology. For a volume of 1,000 standard cubic feet (1 Mscf) of CO_2, the necessary equation is:

$$\text{Res. bbl. at } p,T = \frac{(1.0 \text{ Mscf})(B \text{ at } p,T)}{0.005614} \tag{3}$$

Data from Fig. 6, converted to equivalent reservoir barrels per Mscf using Eq. 3, are plotted in Fig. 7.

Other numbers useful in CO_2 flooding arise from the fact that CO_2 is often measured and reported by weight (pounds or 2,000-lb tons) rather than volume. The conversion factors are:

1 ton CO_2 = 17.2 Mscf
1 lb CO_2 = 8.6 scf

at a pressure of 14.696 psia and a temperature of 60°F.

<u>Viscosity Changes with Pressure and Temperature</u>. The viscosity of carbon dioxide vapor is strongly dependent on pressure and temperature, increasing as the density of the vapor increases. Figure 8 shows CO_2 viscosity as a

function of pressure for several temperatures. These data were obtained from a cross-plot [40] of published experimental data [43].

Solubility of Carbon Dioxide in Water. Carbon dioxide is soluble in water, as any user of carbonated beverages knows. Its solubility is a function of pressure, temperature, and water salinity. Reasonably typical data [36] are plotted in Fig. 9. Additional data from published sources [44,45] are shown in Figs. 10A and 10B. These graphs can be used to estimate the solubility of CO_2 in a given oilfield water.

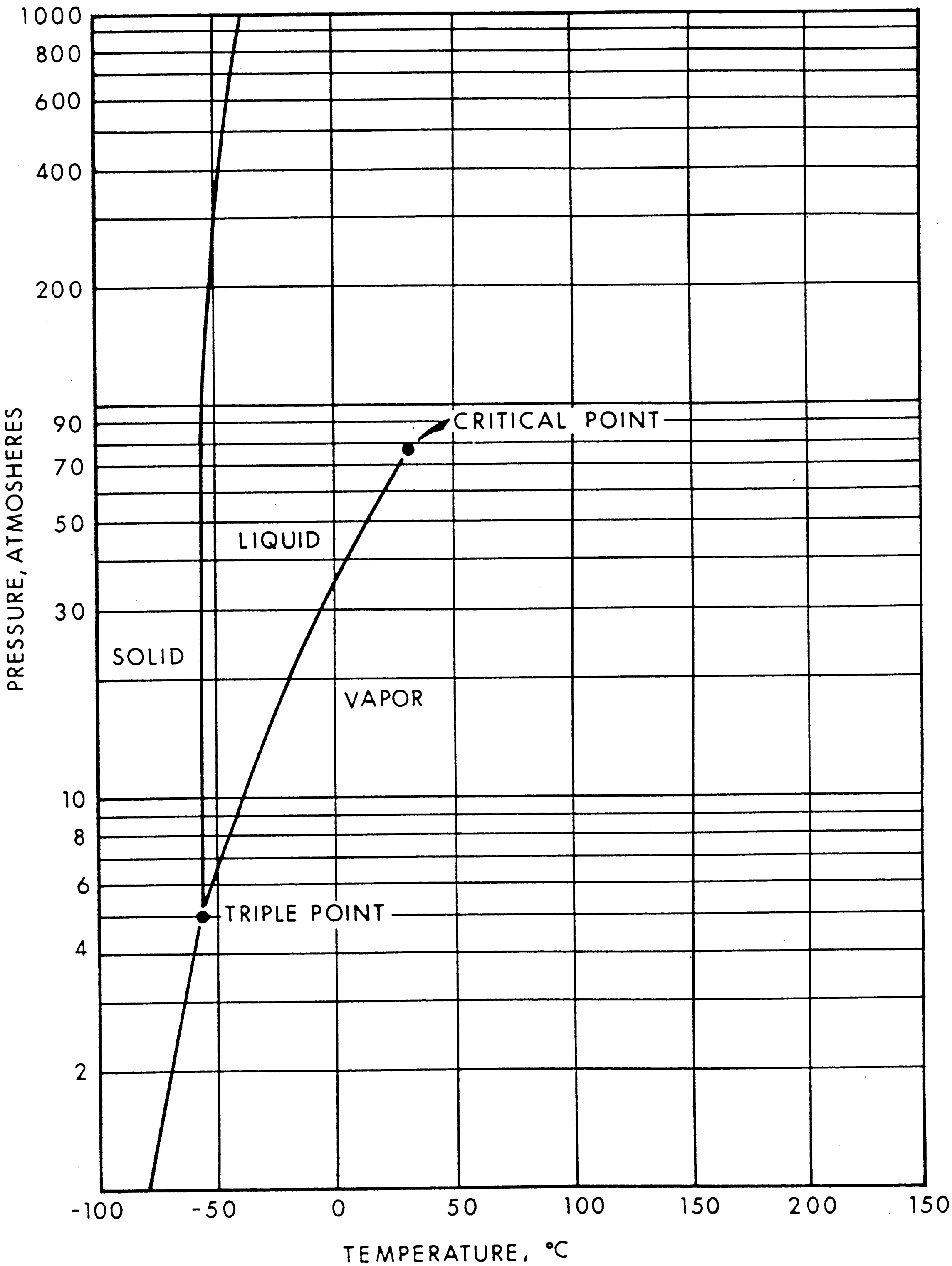


Figure 1.--Phase diagram for carbon dioxide (from Vukalovich, M. P., and Altunin, V. V., *Thermodynamic Properties of Carbon Dioxide*, Collet's Publishers, London, 1968).

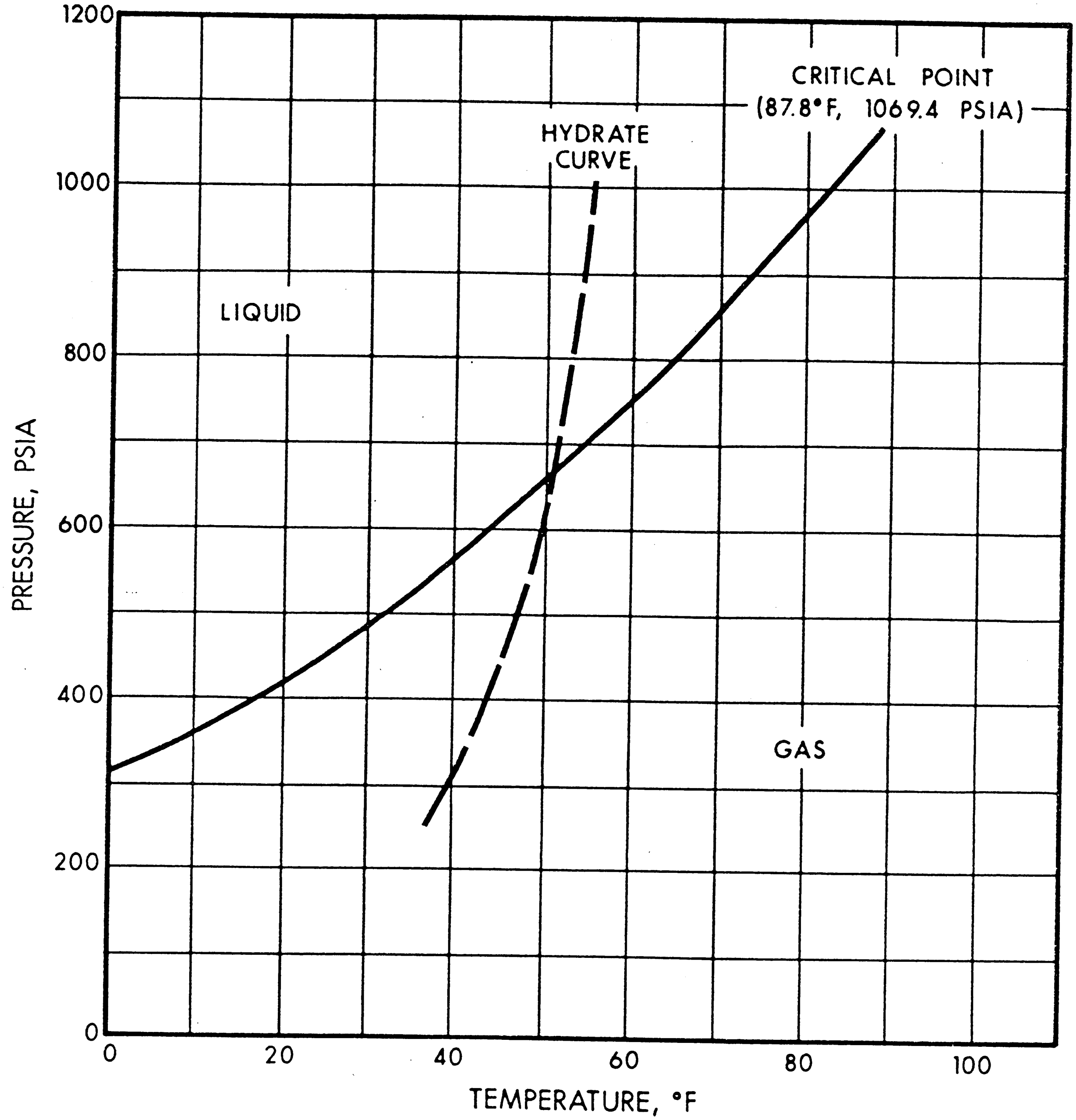


Figure 2.—Vapor-liquid relationship for carbon dioxide.

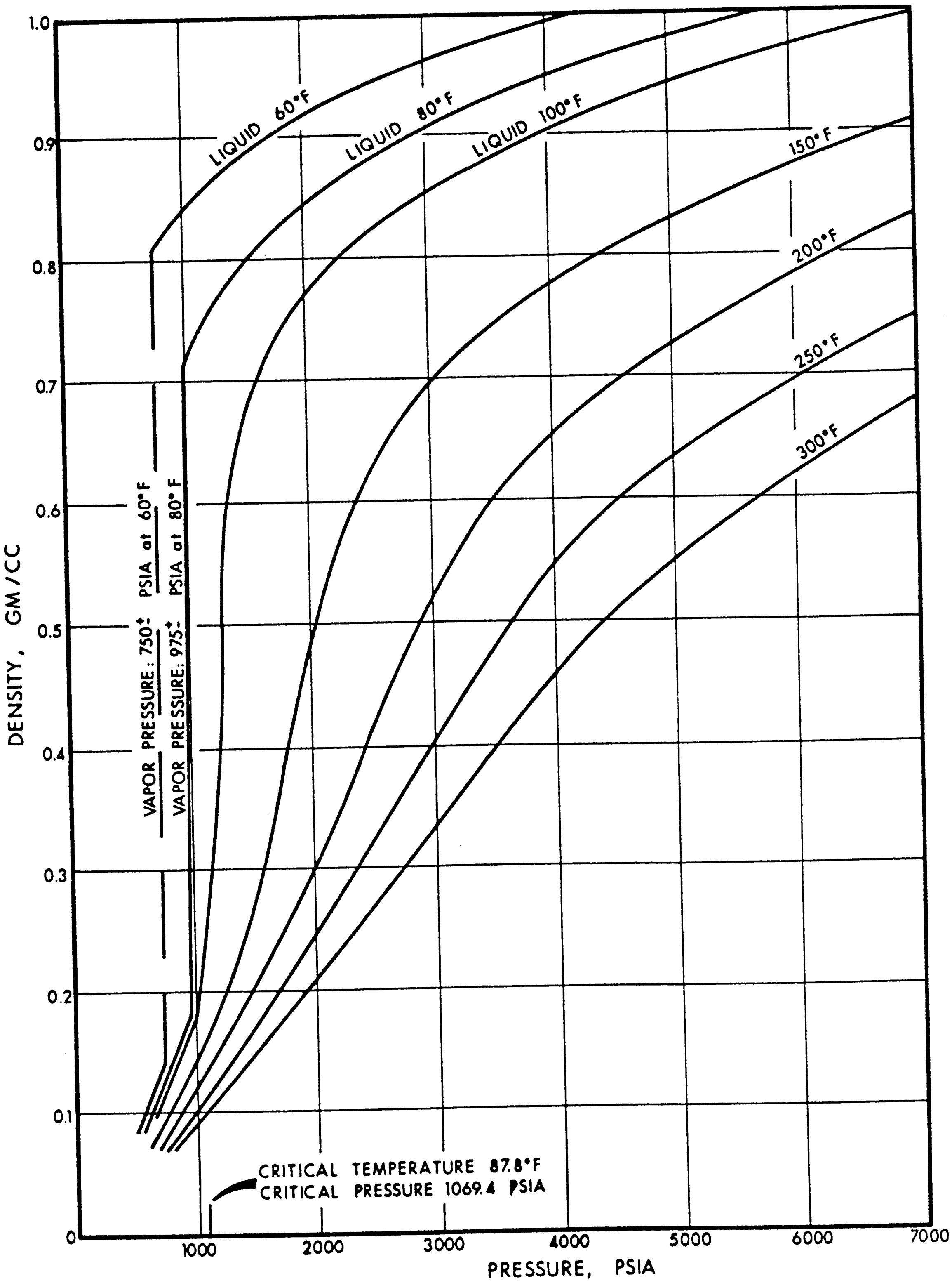


Figure 3.--Density of carbon dioxide as a function of pressure at various temperatures.

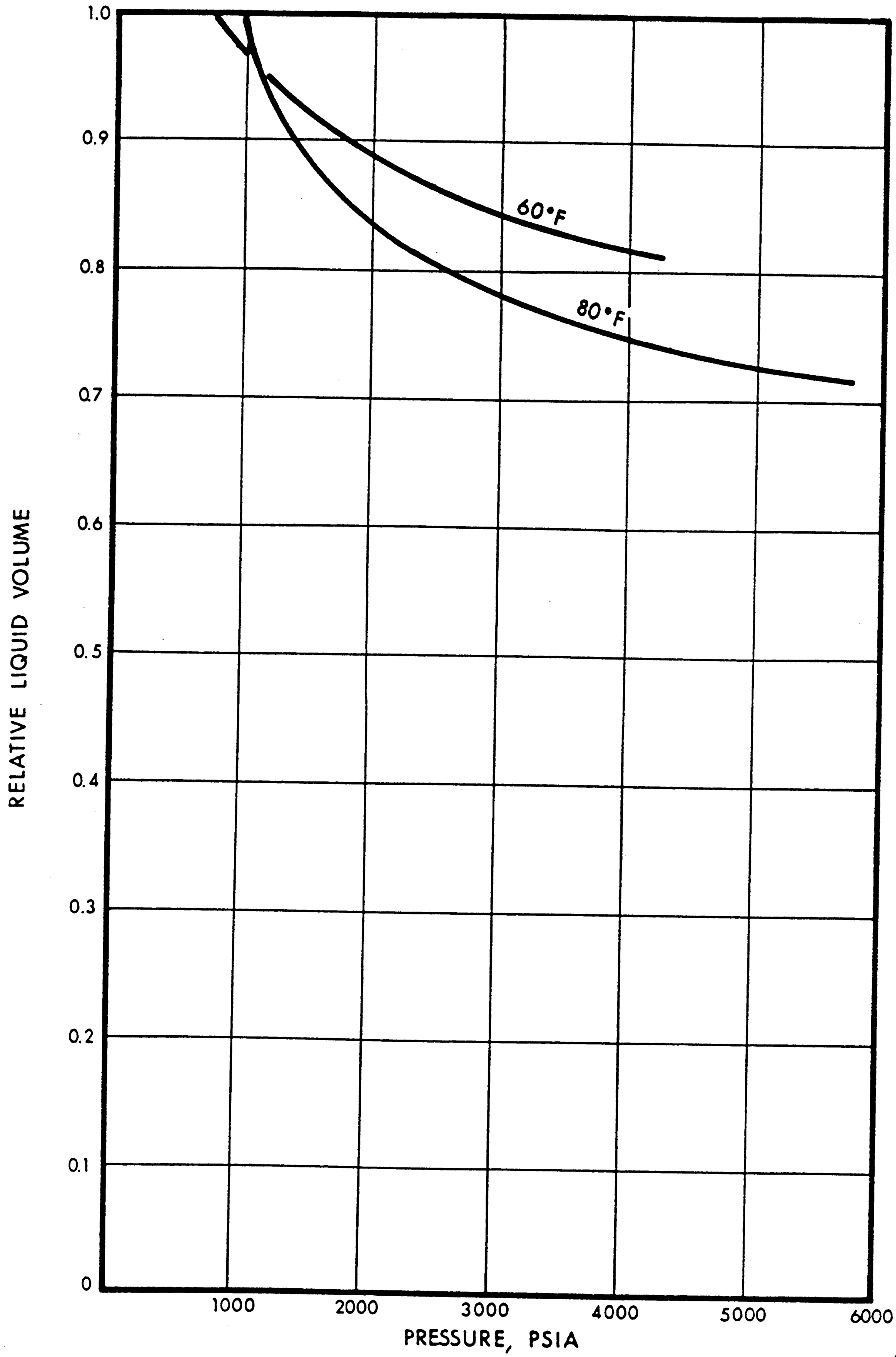


Figure 4.--Relative liquid volume (volume at vapor pressure = 1.0) of carbon dioxide as a function of pressure at 60° and 80°F.

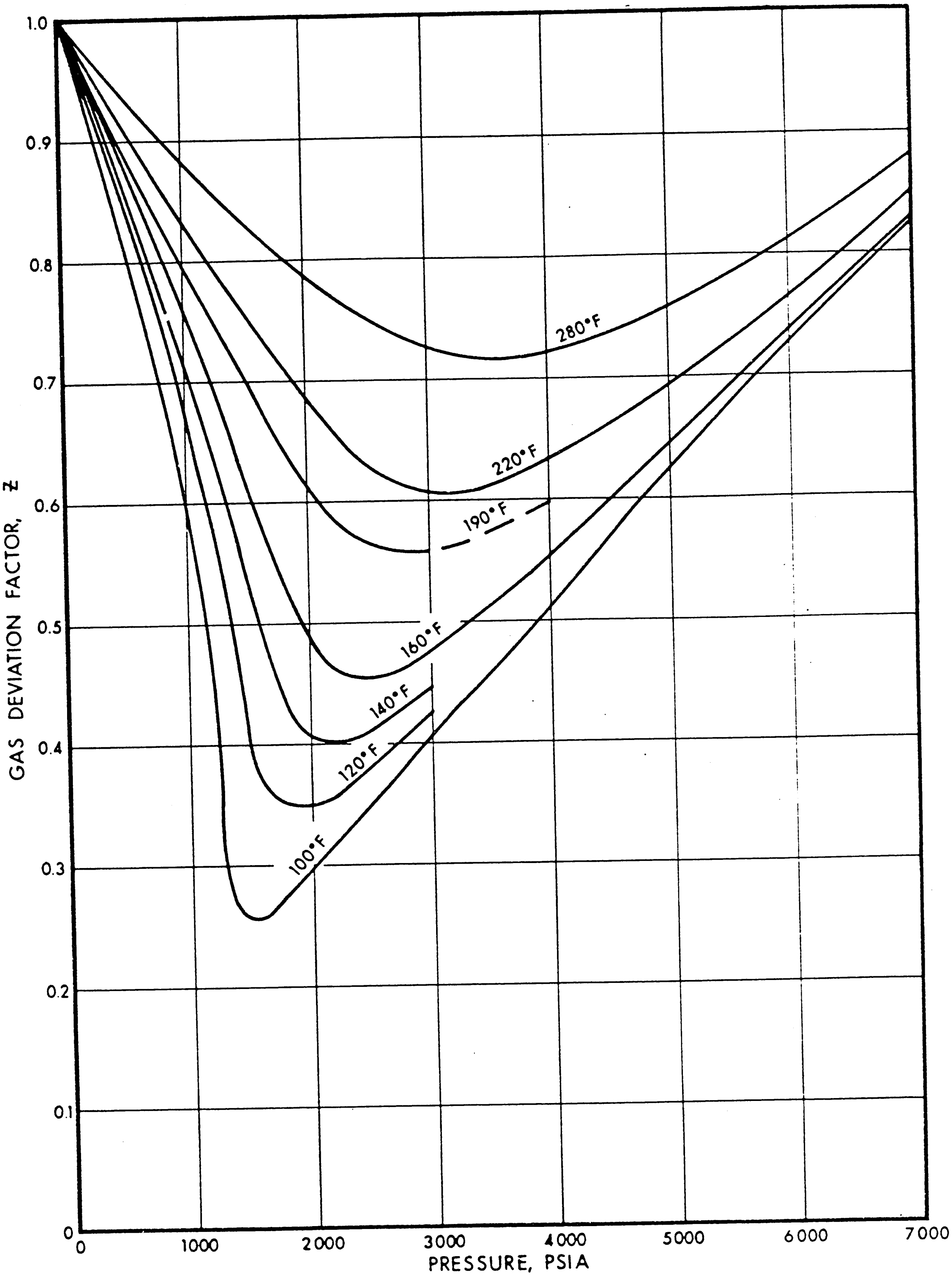


Figure 5.--Gas deviation factor (supercompressibility) for carbon dioxide as a function of pressure at various temperatures.

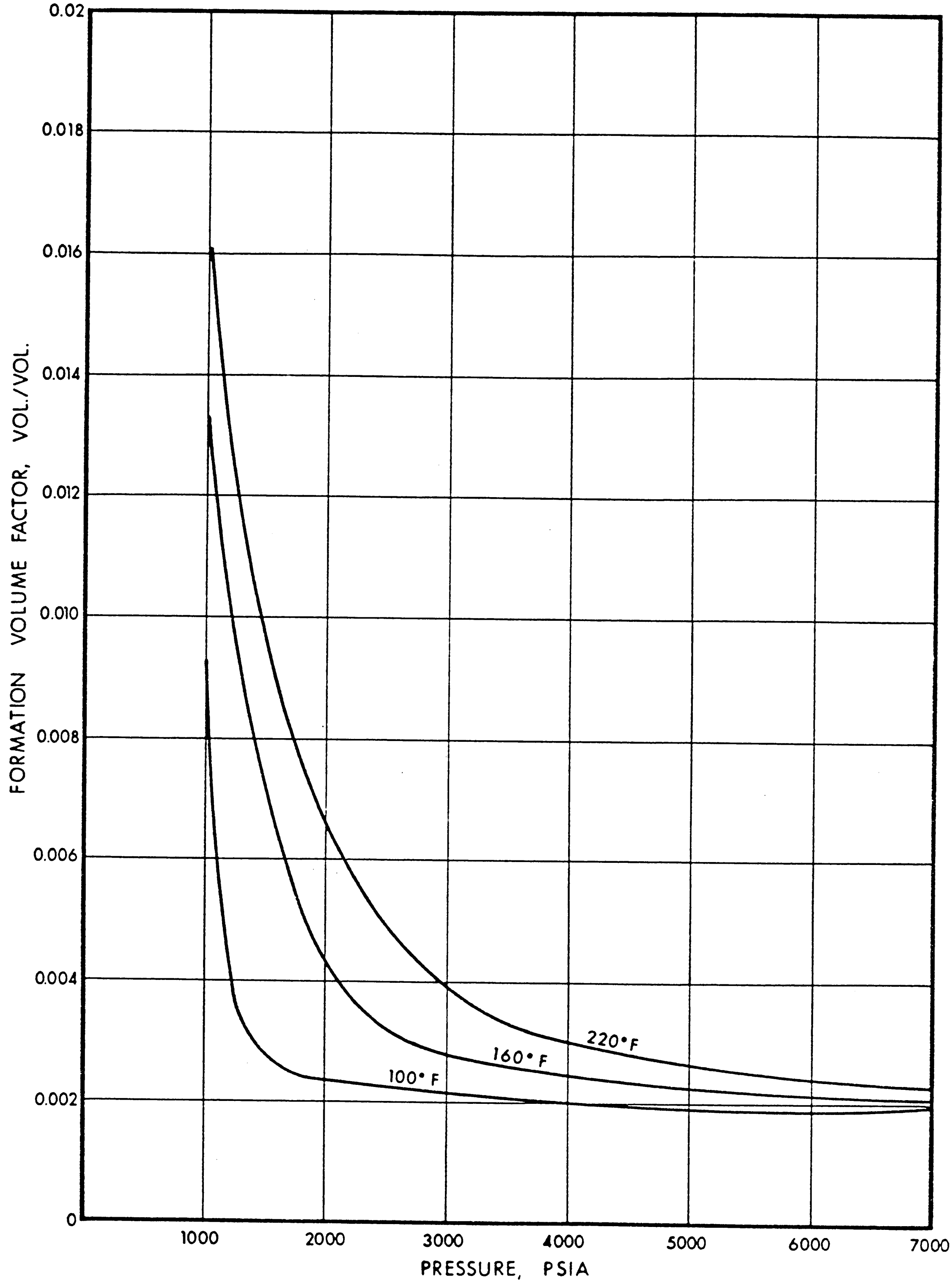


Figure 6.--Formation volume factors for carbon dioxide as a function of pressure at various temperatures.

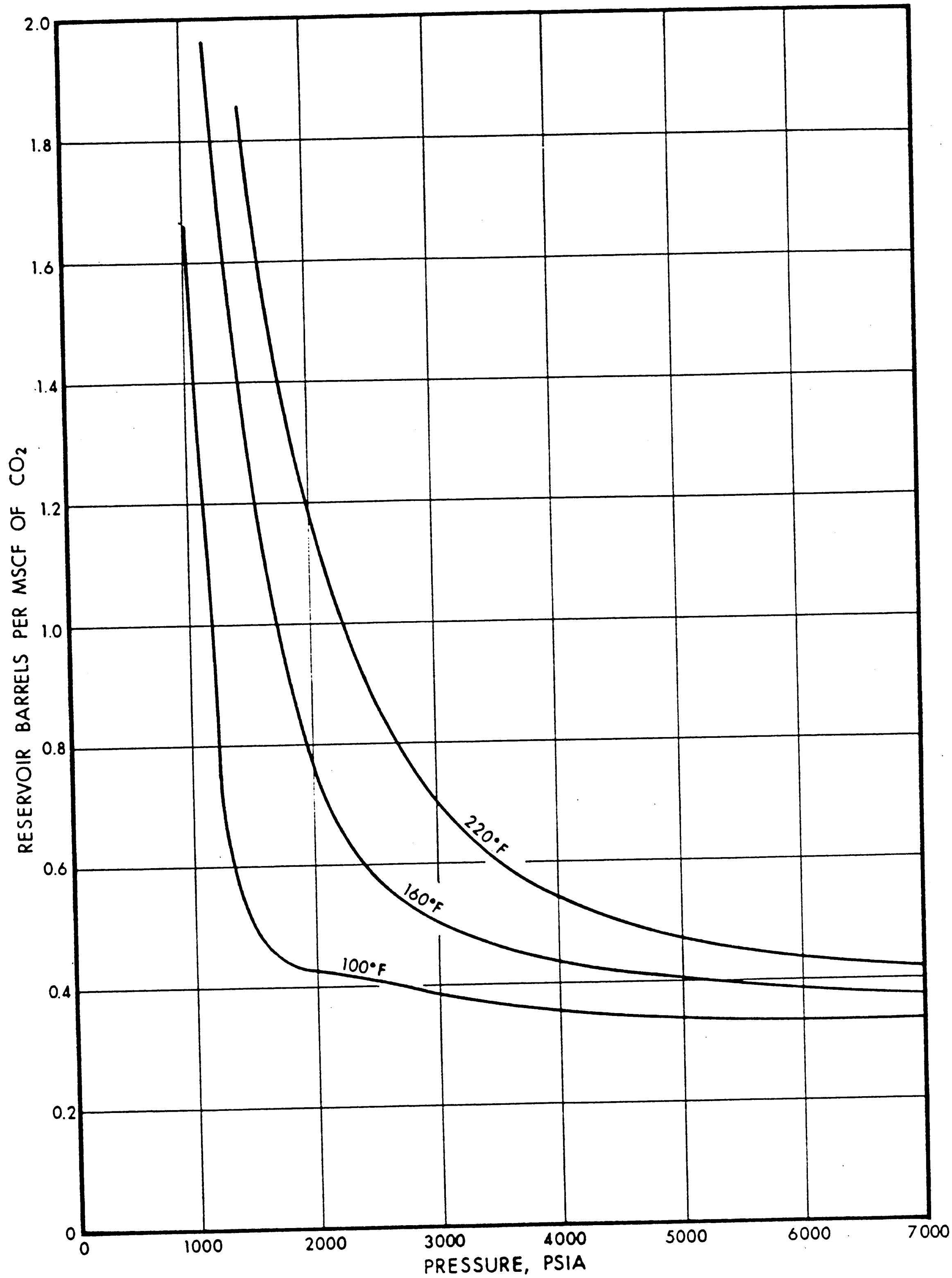


Figure 7.--Reservoir barrel volumes of carbon dioxide at various pressures and temperatures.

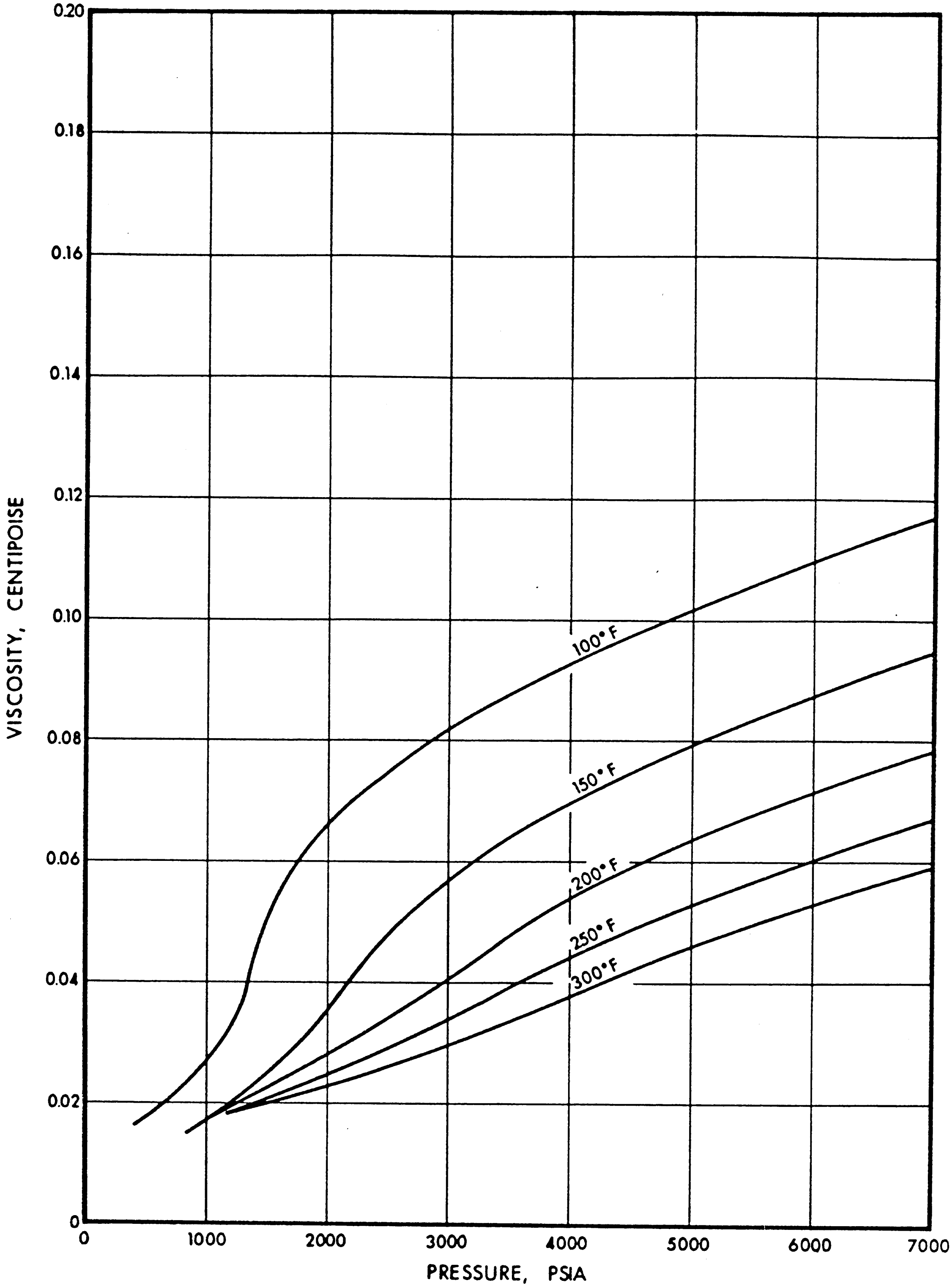


Figure 8.--Viscosity of carbon dioxide as a function of pressure at various temperatures.

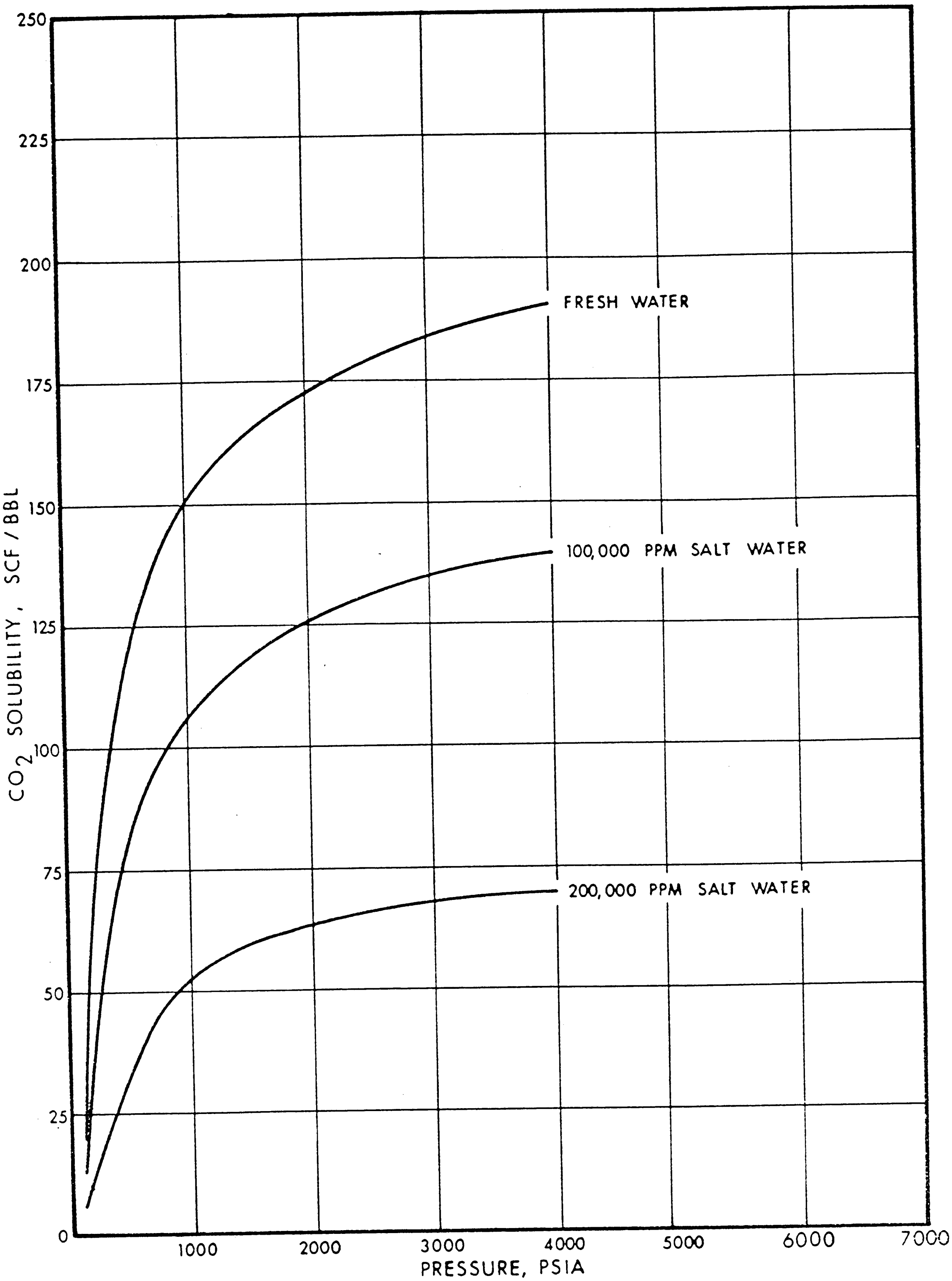


Figure 9.--Solubility of carbon dioxide in water at 100°F (data from McRee [46]).

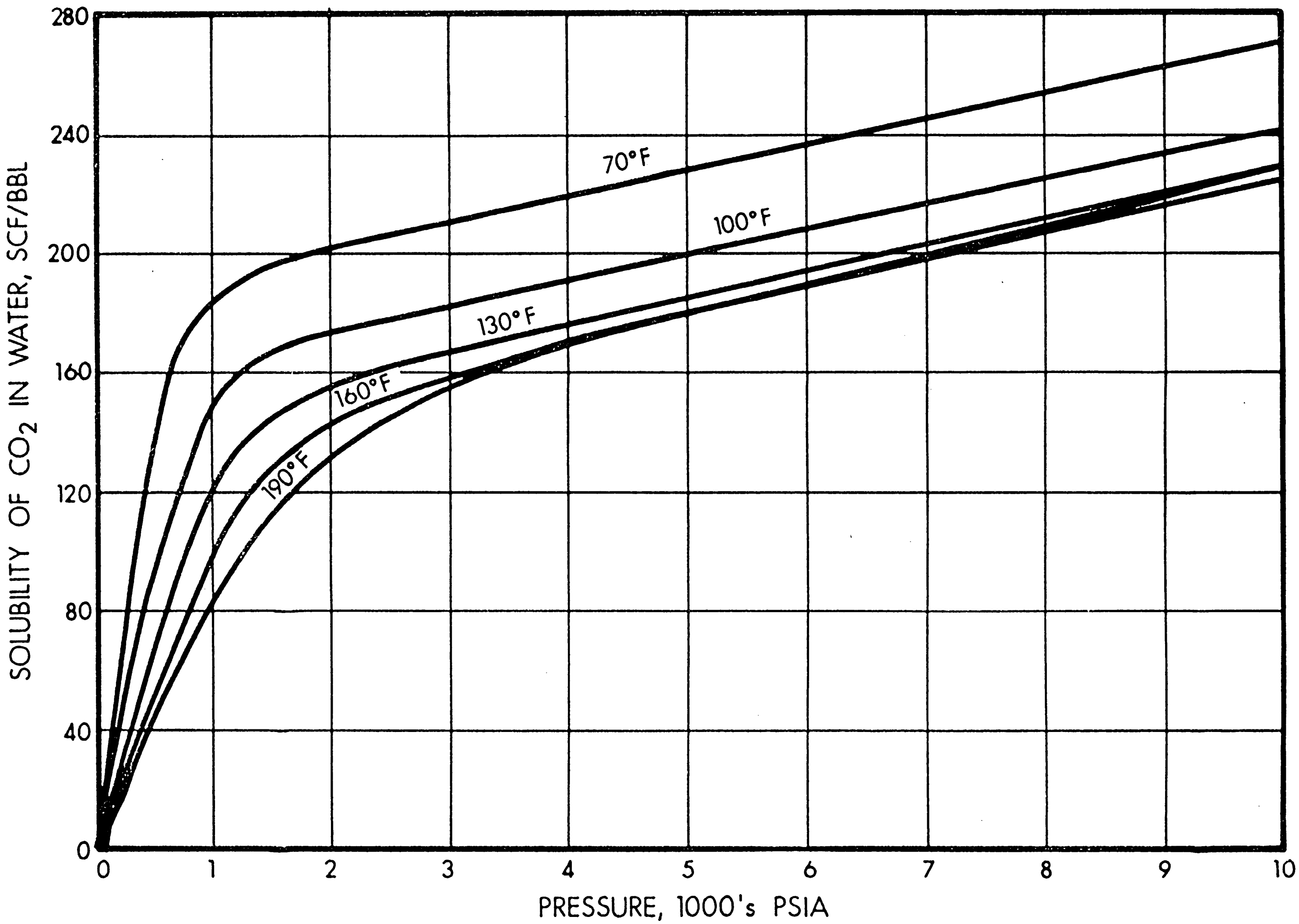


Figure 10A.--Solubility of carbon dioxide in water as a function of pressure at various temperatures (from Crawford *et al.* [44]).

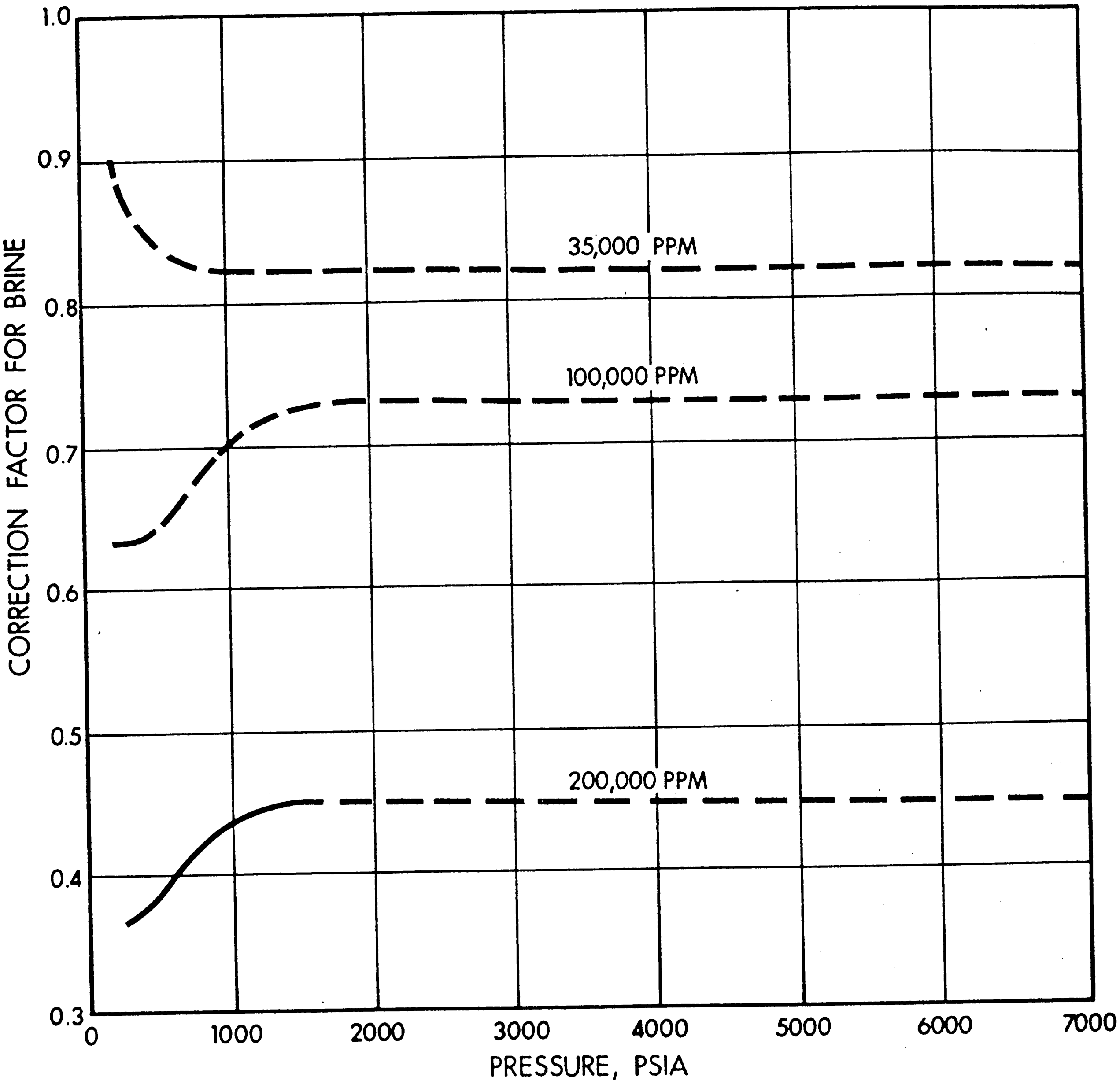


Figure 10B.--Correction factor for solubility of carbon dioxide in brine (from Crawford *et al.* [44]).

Behavior of Mixtures of CO_2 and Crude Oil.

The quantitative behavior of any given mixture of CO_2 with a specific crude oil cannot be predicted theoretically but must be determined experimentally. Sufficient experimental data have been published to permit a general description of the processes and physical changes that take place when CO_2 is mixed with crude oil. This description is intended to provide qualitative insights into the phenomena that can occur under various reservoir conditions of oil composition, pressure, and temperature.

Liquid Phase Behavior of Hydrocarbon/CO_2 Mixtures. Two aspects of liquid phase behavior of hydrocarbon-CO_2 mixtures are important to an understanding of CO_2 flooding processes:

a. CO_2 solubility in crude oil and resultant swelling;
b. Viscosity reduction with addition of CO_2.

Data drawn from various sources will be presented in this section to illustrate and quantify (as much as possible) these phenomena.

CO_2 Solubility and Swelling of Crude Oil. Published data illustrating the solubility of CO_2 in various hydrocarbons, including a "west Texas crude oil" (otherwise unidentified), are given as a function of pressure in Fig. 11A* [3,10]. These data were obtained by adding CO_2 to measured amounts of oil at constant pressure and temperature (125°F) until equilibrium conditions were reached, at which point the volume of CO_2 dissolved in the oil was measured. The investigator noted that "with the crude . . . used in this study, the CO_2 solubility showed a sharp increase with pressure up to about 1600 psi and then a constant value as pressure was increased. . . ." (see Fig. 11A). The related swelling of the crude oil as CO_2 dissolves is shown in Fig. 11B. It can be noted that volumetric expansion is a maximum (approximately 35 percent) at 1,600 psi. It was at this pressure that the crude-oil-rich liquid phase "began to shrink due to the extraction or retrograde vaporization of lighter hydrocarbons into the CO_2-rich vapor phase" [3] present in the P-V cell.

Other investigators' data for Ada crude are shown in Fig. 12 [7]. These data were obtained at two different temperatures, one below (70°F) and one above (120°F) the 87.8°F critical temperature of CO_2. Figure 2 shows that the vapor pressure of CO_2 at 70°F is about 860 psi; hence most of the data shown in Figs. 12A and 12B for the 70°F experiments were obtained with CO_2 vapor at pressures below the vapor pressure. All of the 120°F experimental data are for CO_2 vapor by definition. These data show the same phenomena:

(1) Constant solubility of CO_2 above a recognizable pressure value --again, probably coincidentally, approximately 1,600 psi at 120°F;

*Figures 11 through 23 appear on pages 26 through 38.

(2) Shrinkage of the liquid phase at pressures higher than the pressure at which solubility becomes constant.

Ada crude is described as "an aromatic base crude, . . . low in gasoline content and high in asphaltenes" [7]. Viscosity of the crude was reported as 400 cp at 70°F and 180 cp at 100°F.

Data for another crude oil, described as a "viscous, low-gravity San Joaquin Valley" crude (otherwise unidentified--no detailed data) [15], are shown in Fig. 13. These data end at 2,000 psi and do not show the high-pressure shrinkage effects observed in Figs. 11 and 12. Volumetric data for Mead Strawn and Bandini stock tank crudes are shown in Fig. 14A. Equivalent solubility data were not reported [39].

Further data showing volumetric behavior of Mead-Strawn crude at three different temperatures are illustrated in Fig. 14B. These experimental data all show the characteristic shrinkage of crude volume above a maximum solubility pressure. On the basis of these data, the maximum solubility pressure at a given temperature (cf. Fig. 14A) seems to be function of crude oil gravity, and for a given crude, the pressure and presumed upper limit of solubility seem to be functions of temperature.

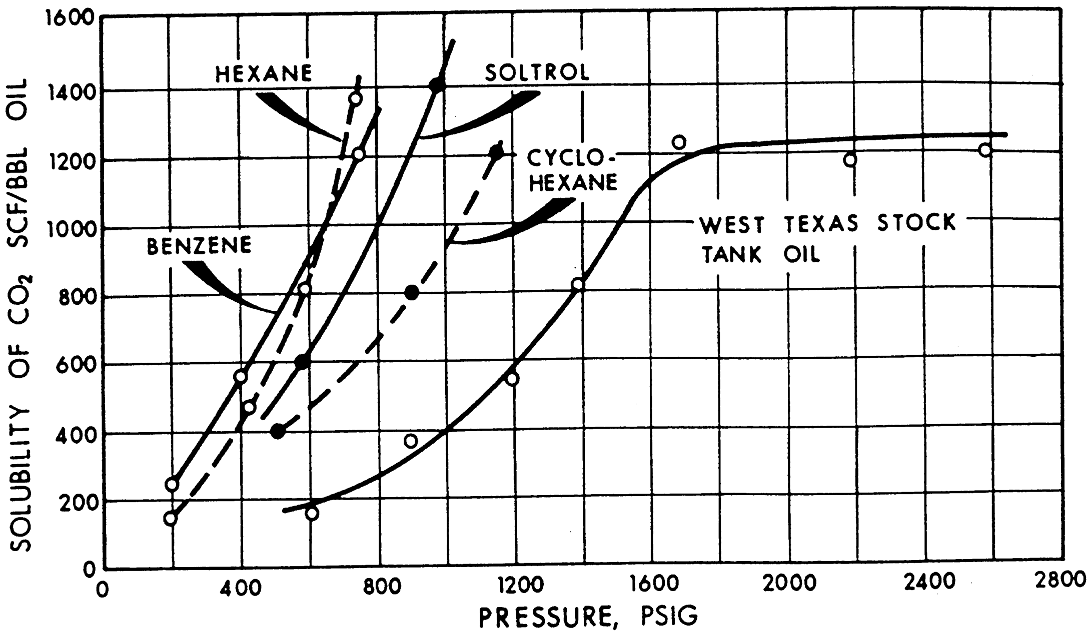
Behavior of Mixtures. Data more general than those shown by these specific examples are provided by the results of experimental studies in which the investigators made measurements for 40 different CO_2-oil mixtures [46]. Correlations of solubility and swelling data, obtained by combining known amounts of pure CO_2 and crude oil in a windowed cell at a fixed temperature and measuring the bubble point and swelling of the mixture, are presented in Figs. 15 and 16. These data were developed in terms of the Universal Oil Products (UOP) characterization factor, an empirical parameter defined as the ratio of the cube root of the average boiling point in degrees Rankine (°F + 460) to the specific gravity at 60°F [47]. The UOP characterization factor for a given oil can be determined from correlation charts presented in reference 47 if the API gravity and viscosity of the oil are known. A sample correlation chart for viscosity data at 122°F versus API gravity, with the characterization factor plotted as a parameter, is given in Fig. 17.

Other experimental data show the same phenomena [48]. Solubility of CO_2 and related swelling of Day crude oil (21.8°API) from the Moran field, Allen County, Kansas, are shown in Fig. 18. These data indicate that CO_2 solubility and related swelling for a given oil are reduced as temperature increases. The data shown are for a maximum pressure of 800 psia; a more general plot showing CO_2 solubility at 80°F as a function of saturation ("carbonation") pressure and API gravity is given in Fig. 19. The investigators who published these data indicate that the related swelling can be calculated from a linear correlation of the data:

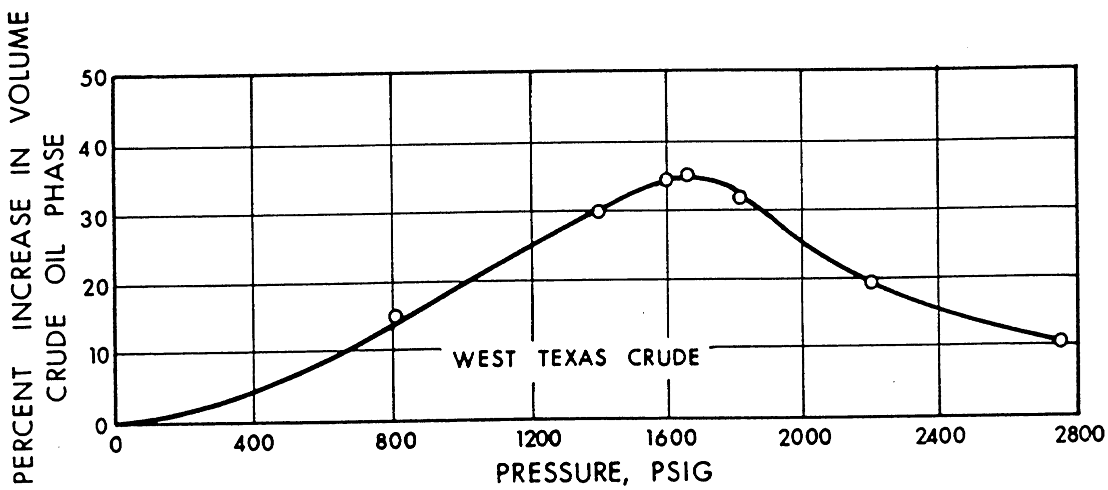
$$\text{Swelling factor} = 1.0 + \frac{0.35(R_{sc})}{1000} ,$$

where R_{sc} is dissolved CO_2 expressed in cubic feet per barrel [48].

Viscosity Reduction of Crude Oil Mixed with CO_2. The viscosity of solutions of CO_2 in crude oil is markedly lower than that of the crude. Experimental data for the Ada [7] and San Joaquin Valley [15] crude oils previously discussed are shown in Fig. 20. Data for Mead-Strawn crude oil [39] are shown in Fig. 21, which also shows that the density of the mixture increases as CO_2 is dissolved in the oil. Generalized correlations (Fig. 22) developed by Simon and Graue indicate that the viscosity of heavier, more viscous crude is reduced to a much lower fraction of the original viscosity than is the viscosity of lighter, less viscous crude oil [46]. These observations are supported by published data [48] obtained at 80°F for several crude oils, as shown in Fig. 23.

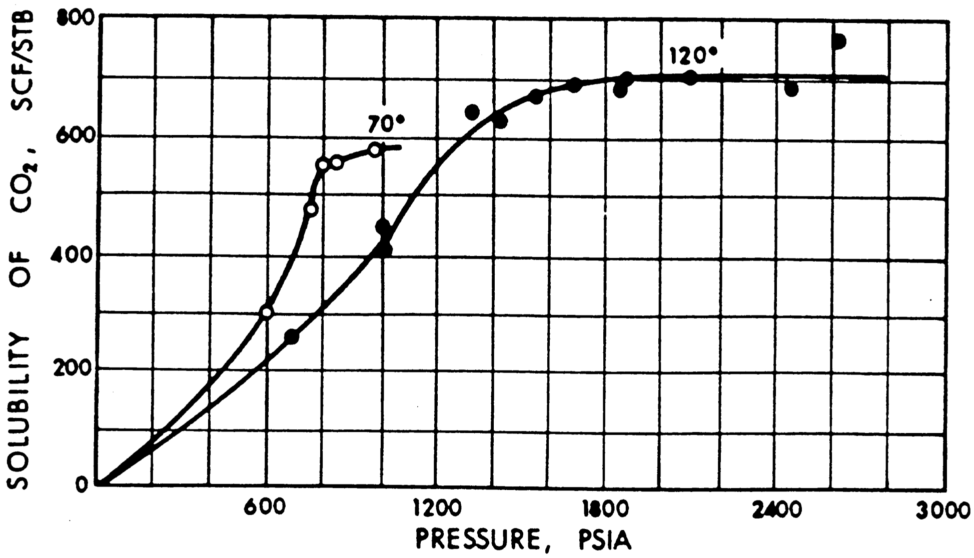


A. Solubility of carbon dioxide in various hydrocarbons at 125°F.

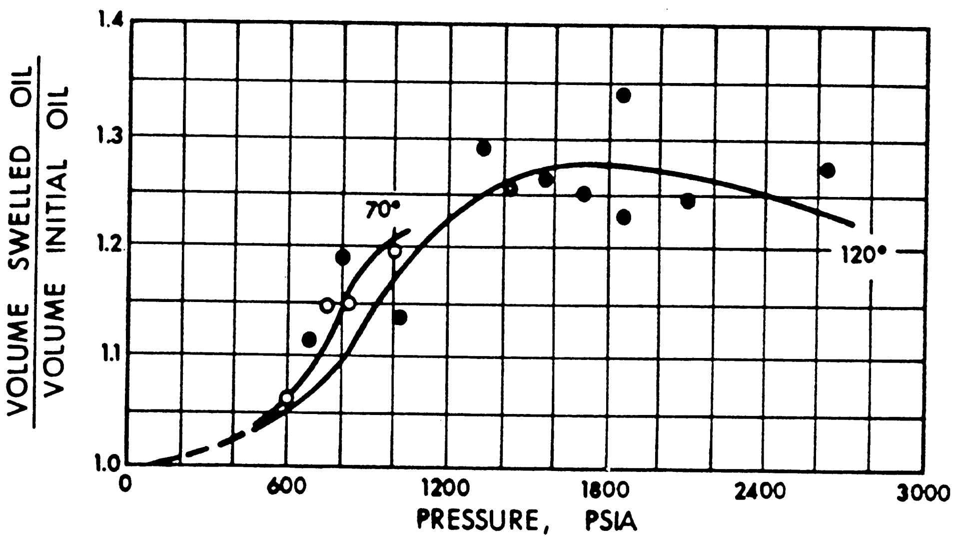


B. Volumetric expansion of crude oil saturated with carbon dioxide at 125°F.

Figure 11.--Solubility of carbon dioxide in hydrocarbons and related swelling of crude oil (from Holm [3,10]).



A. Solubility of carbon dioxide in Ada crude.



B. Volumetric behavior of Ada crude oil saturated with carbon dioxide.

Figure 12.--Solubility of carbon dioxide and related volumetric behavior of Ada crude (from Beeson and Ortloff [7]).

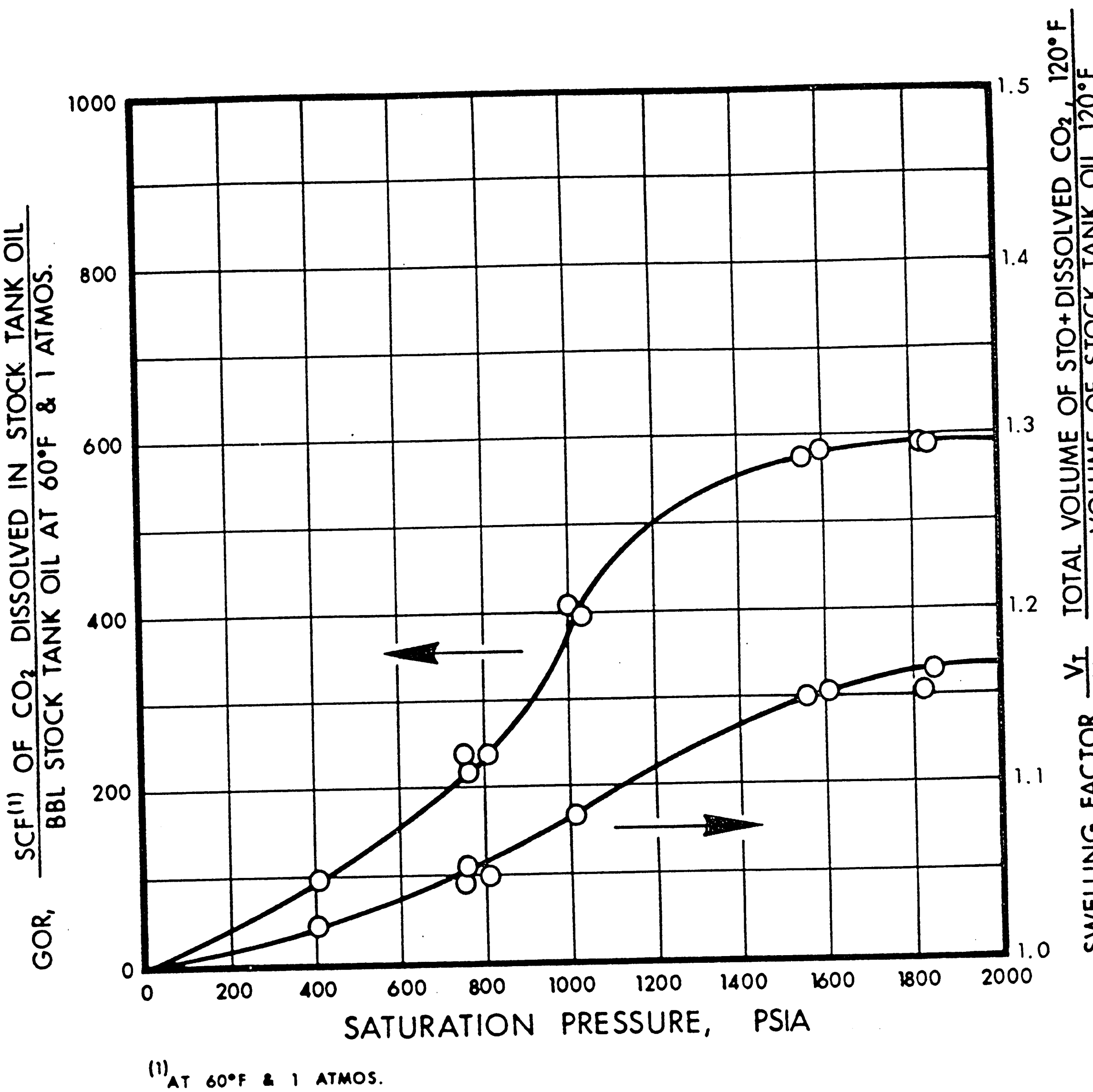
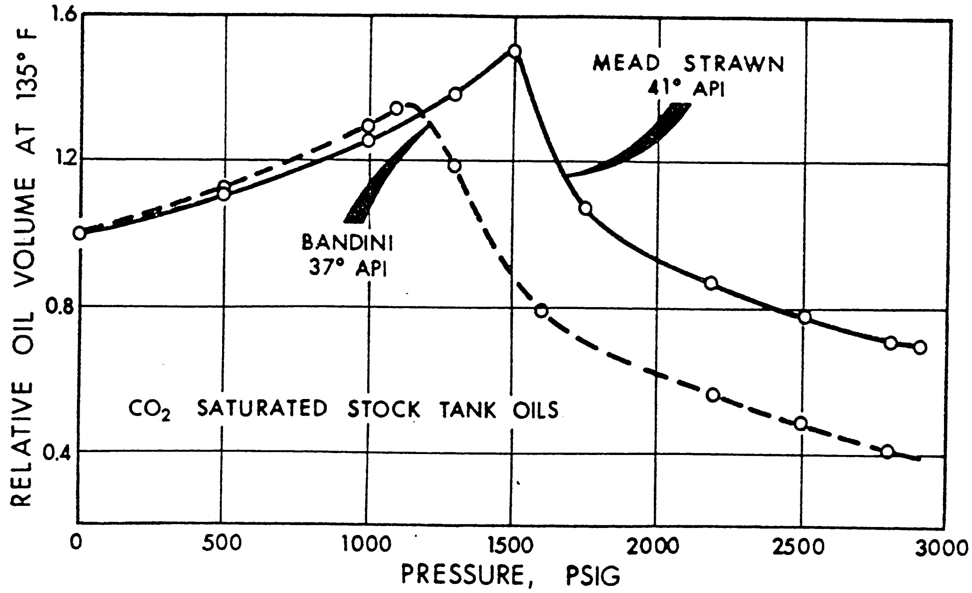
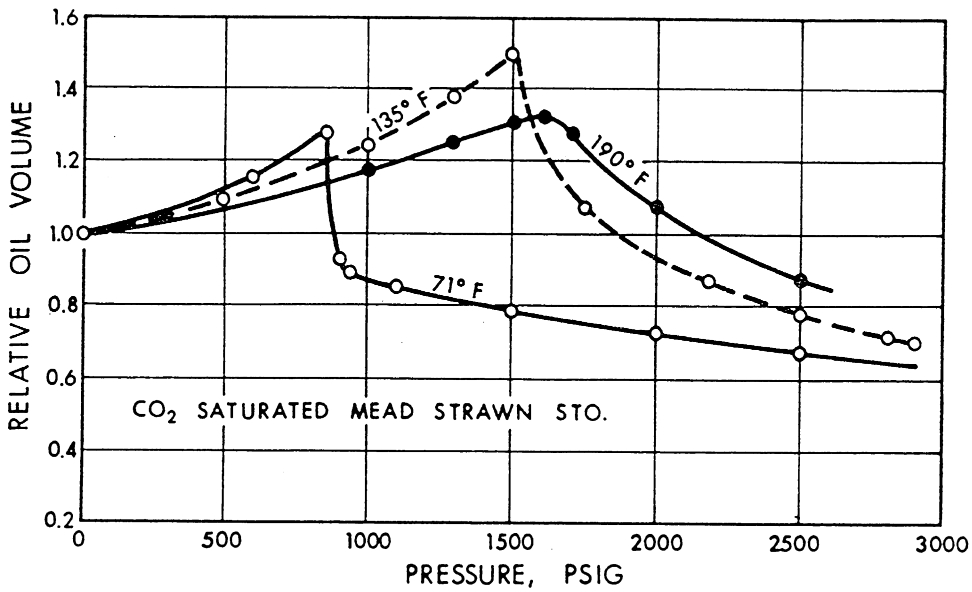


Figure 13.--San Joaquin Valley crude GOR and swelling factor vs. saturation pressure (from de Nevers [15]).



A. Change in oil volume on addition of carbon dioxide at 135°F and various pressures.



B. Change in volume of Mead-Strawn stock tank oil on addition of carbon dioxide at various temperatures and pressures.

Figure 14.--Volumetric behavior of crude oils containing dissolved carbon dioxide (from Holm and Josendal [39]).

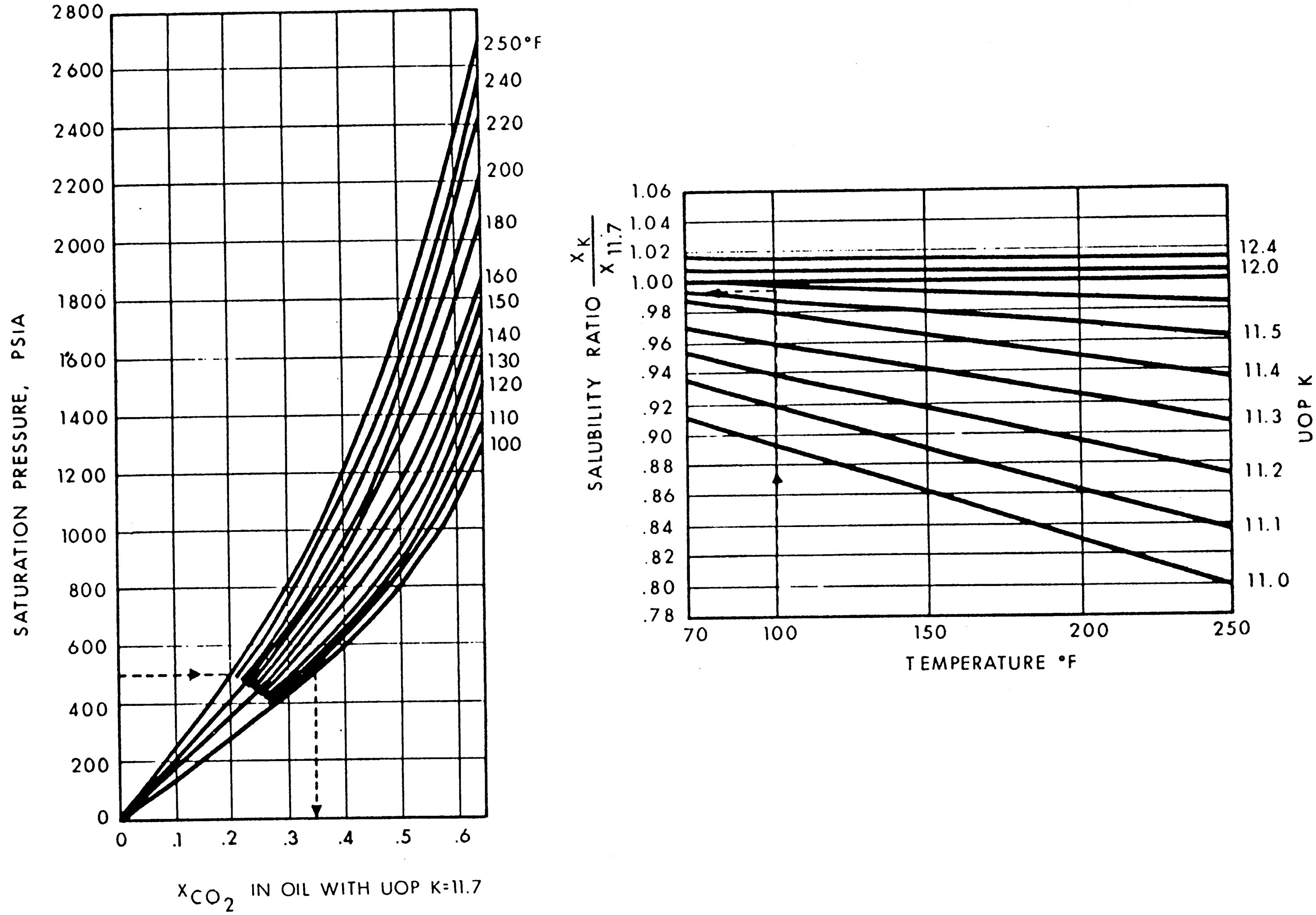


Figure 15.--Solubility (mol fraction) of carbon dioxide in oils as a function of UOP number (from Simon and Graue [46]).

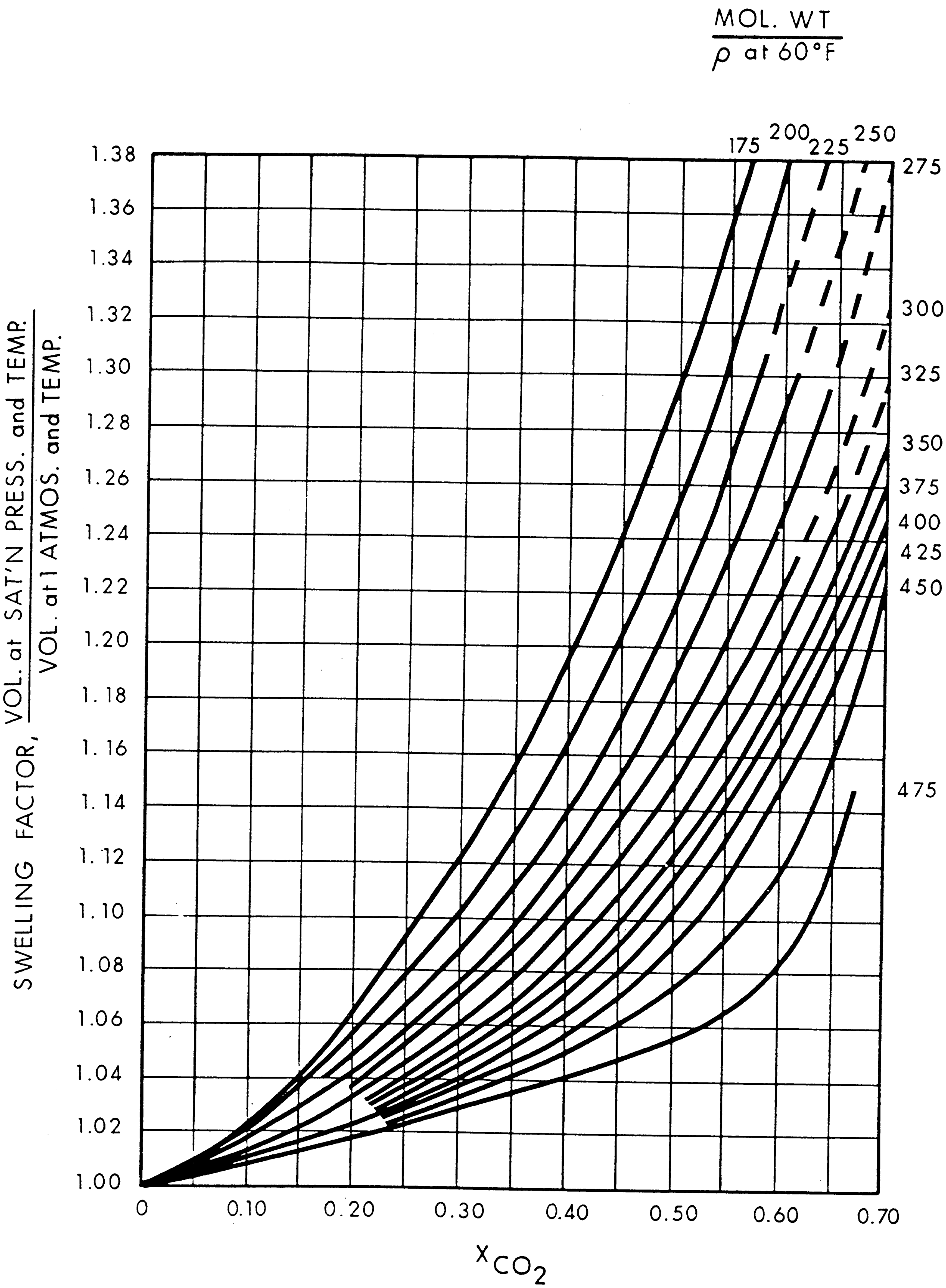


Figure 16.--Swelling of oil as a function of mol fraction of dissolved carbon dioxide (from Simon and Graue [46]).

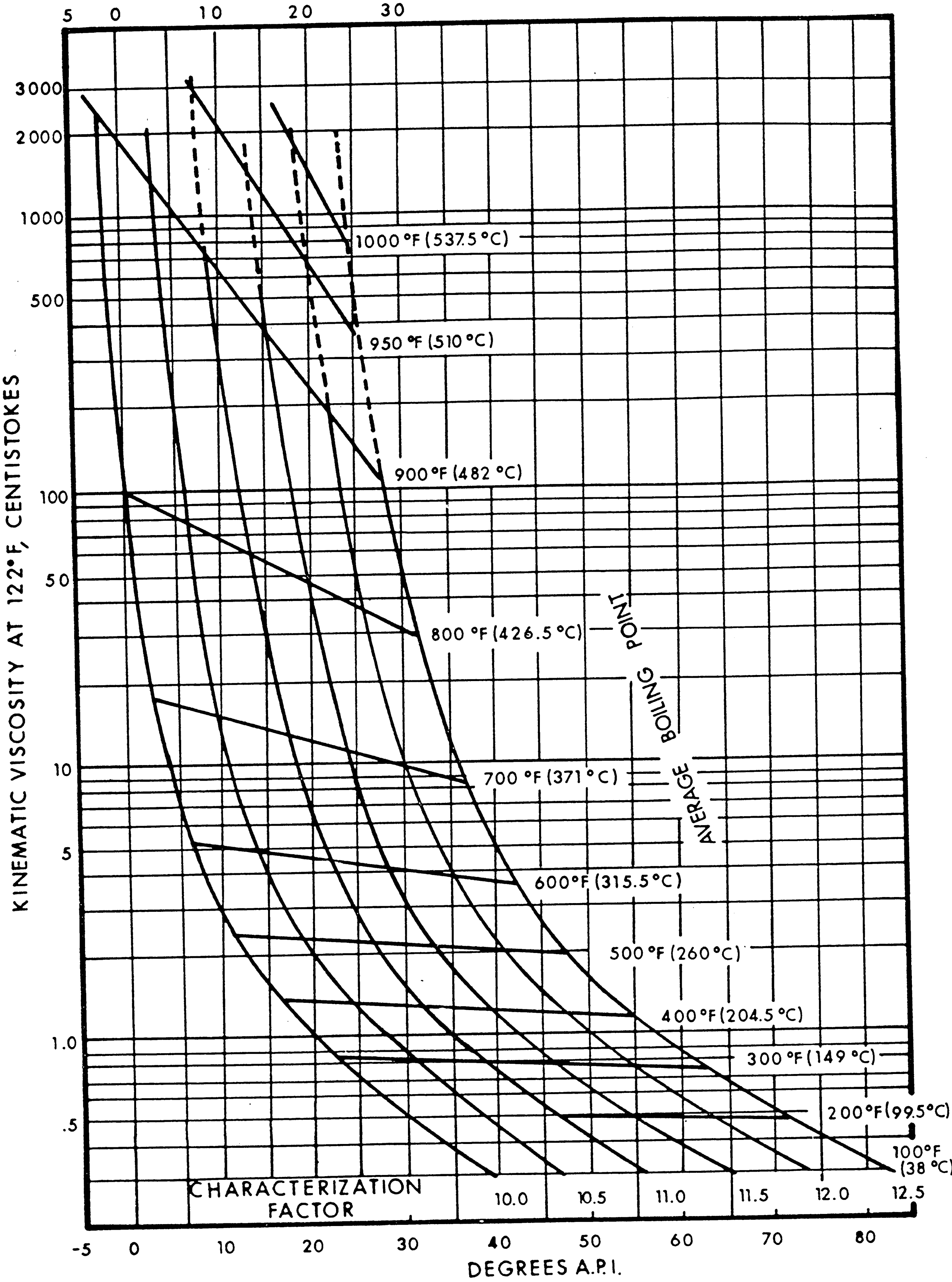
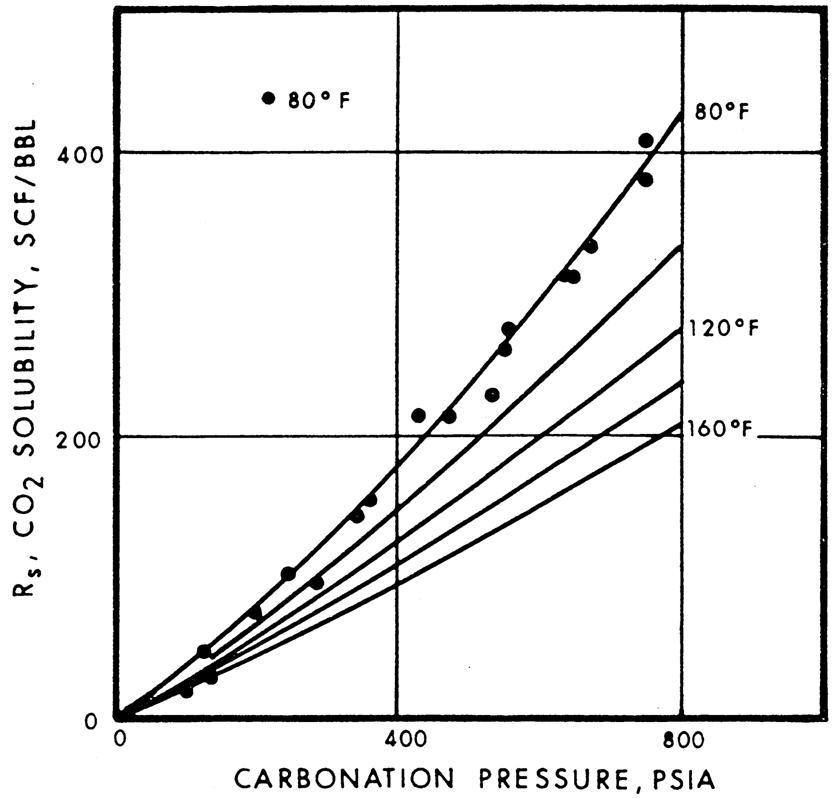


Figure 17.--UOP characterization factor for viscosities at 122°F (from Watson *et al.* [47]).



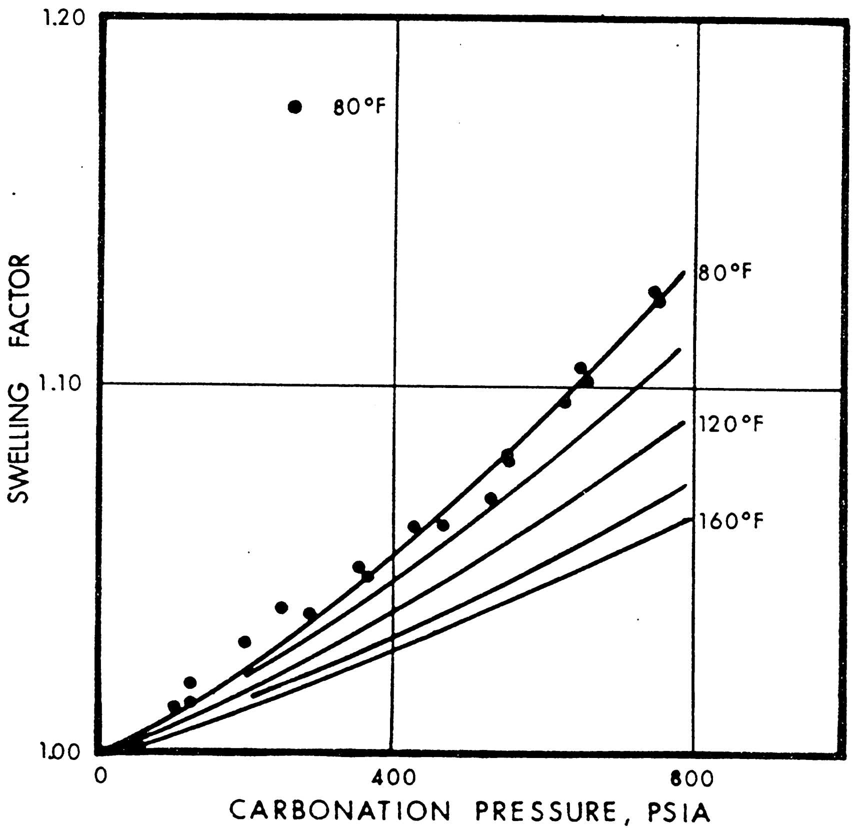


Figure 18.--Solubility of carbon dioxide and related volumetric behavior of Day crude, Moran field, Allen County, Kansas (from Welker and Dunlop [48]).

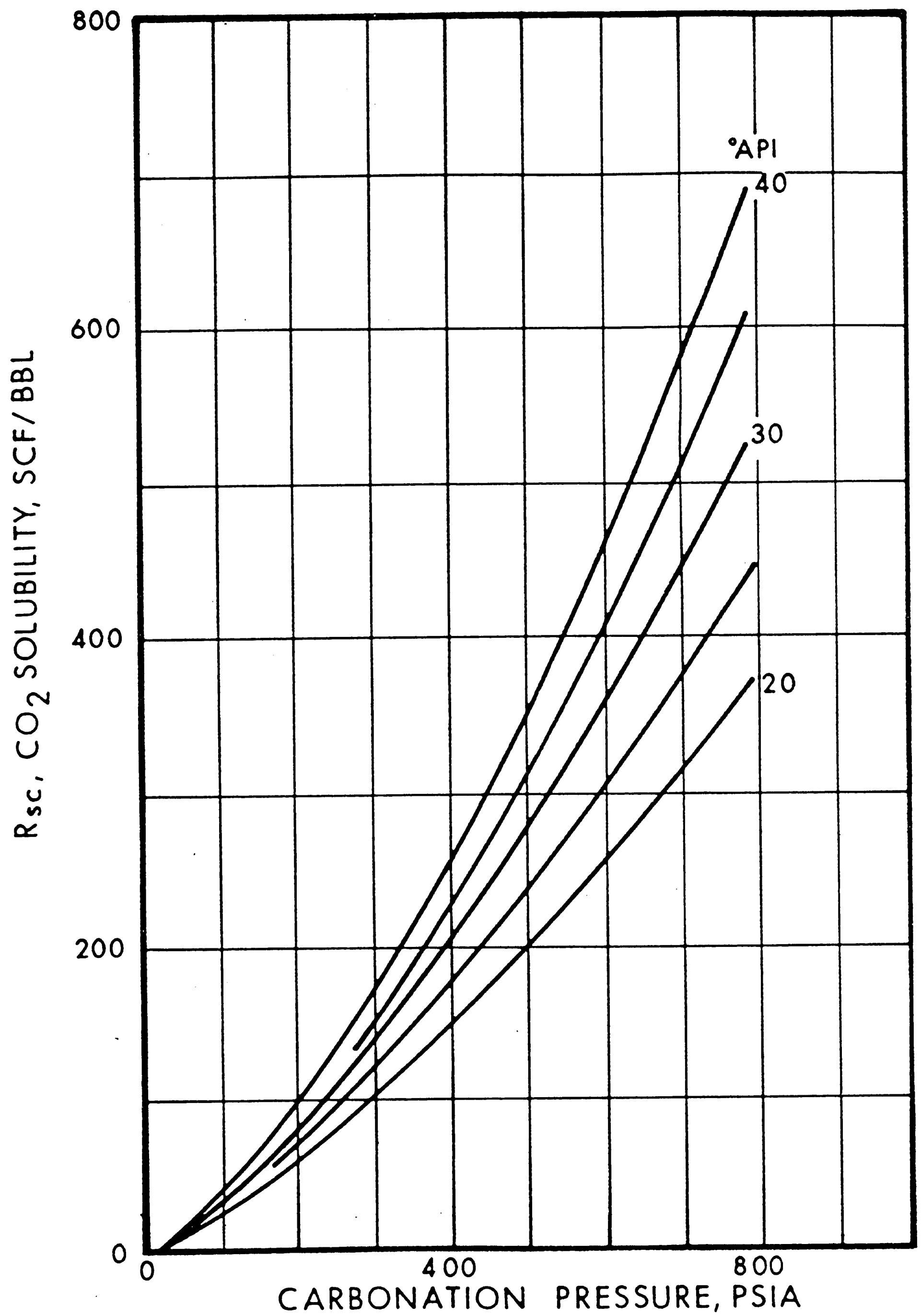
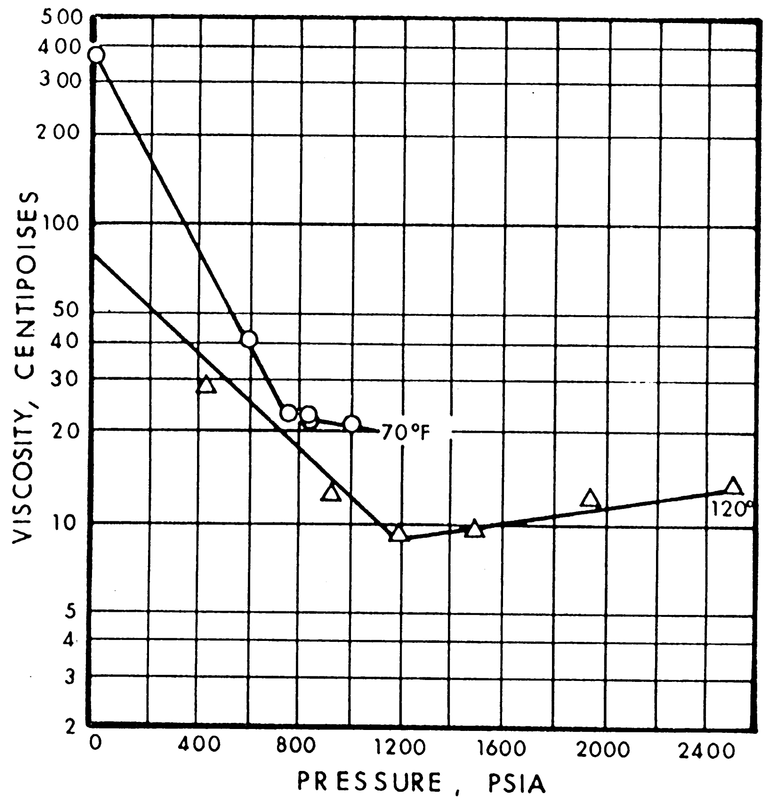
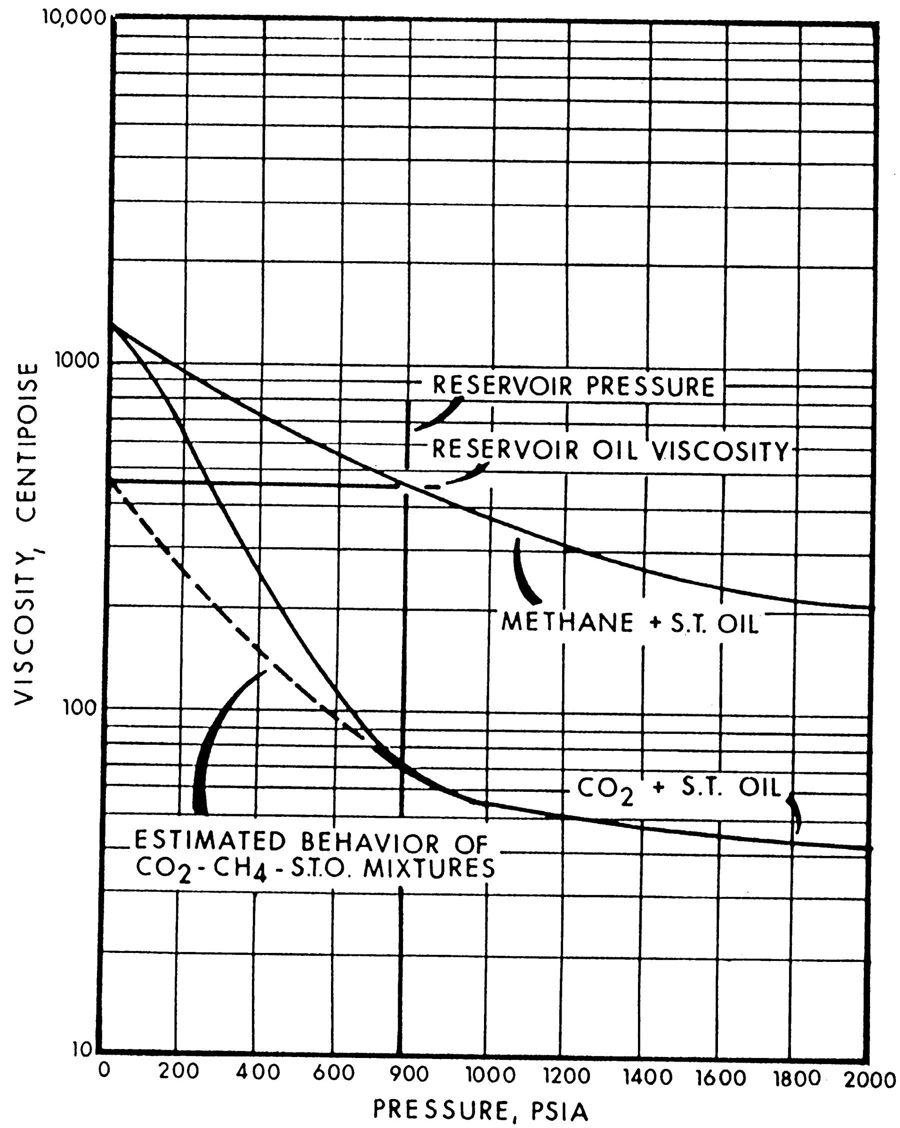


Figure 19.--Solubility of carbon dioxide in crude oils at 80°F (from Welker and Dunlop [48]).



A. Viscosity of Ada crude oil saturated with CO_2 (from Beeson and Ortloff [7]).



B. Viscosity of San Joaquin Valley crude and CH_4 or CO_2 (from de Nevers [15]).

Figure 20.--Viscosity of Ada and San Joaquin Valley crude oils as functions of carbon dioxide saturation pressure.

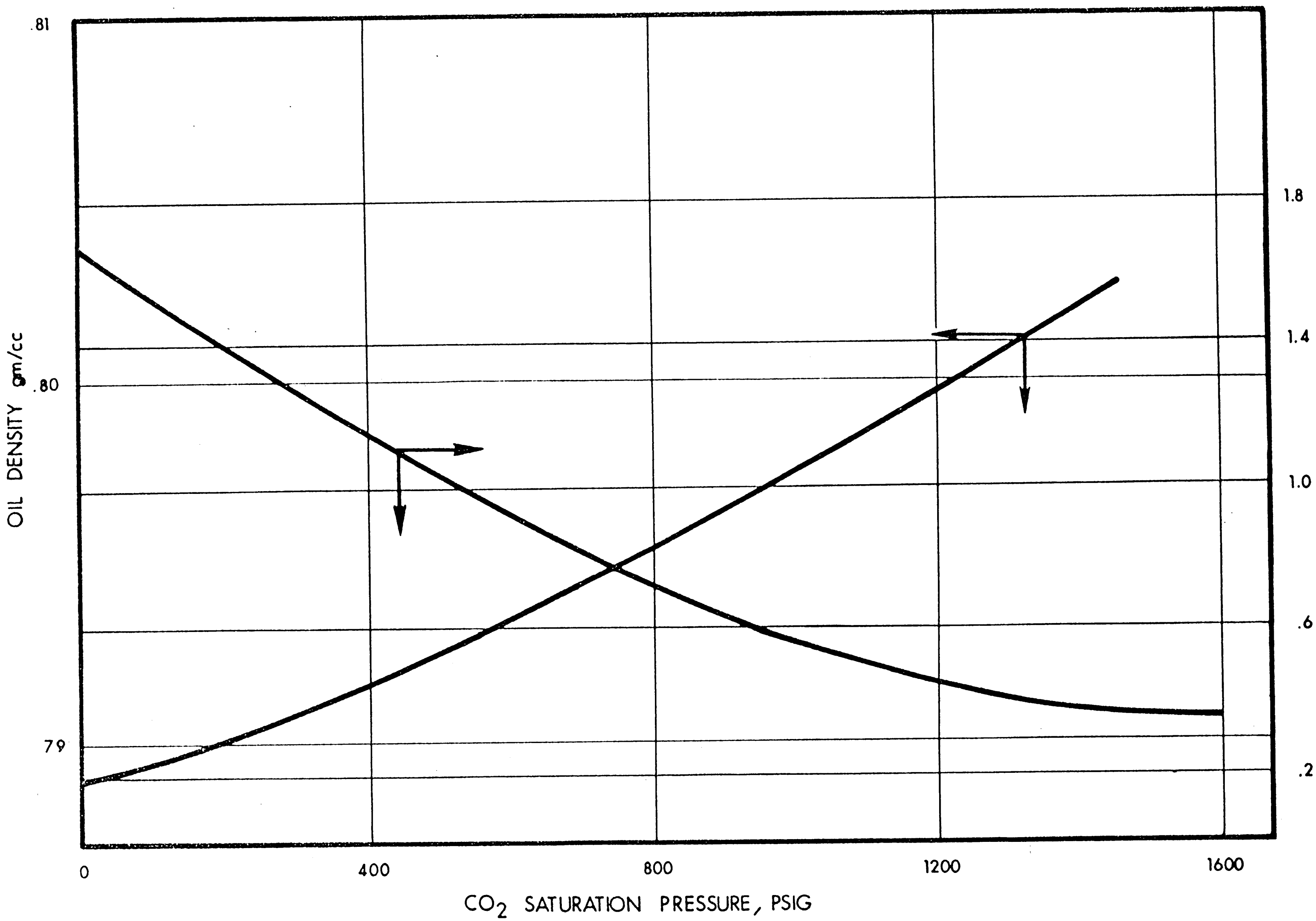
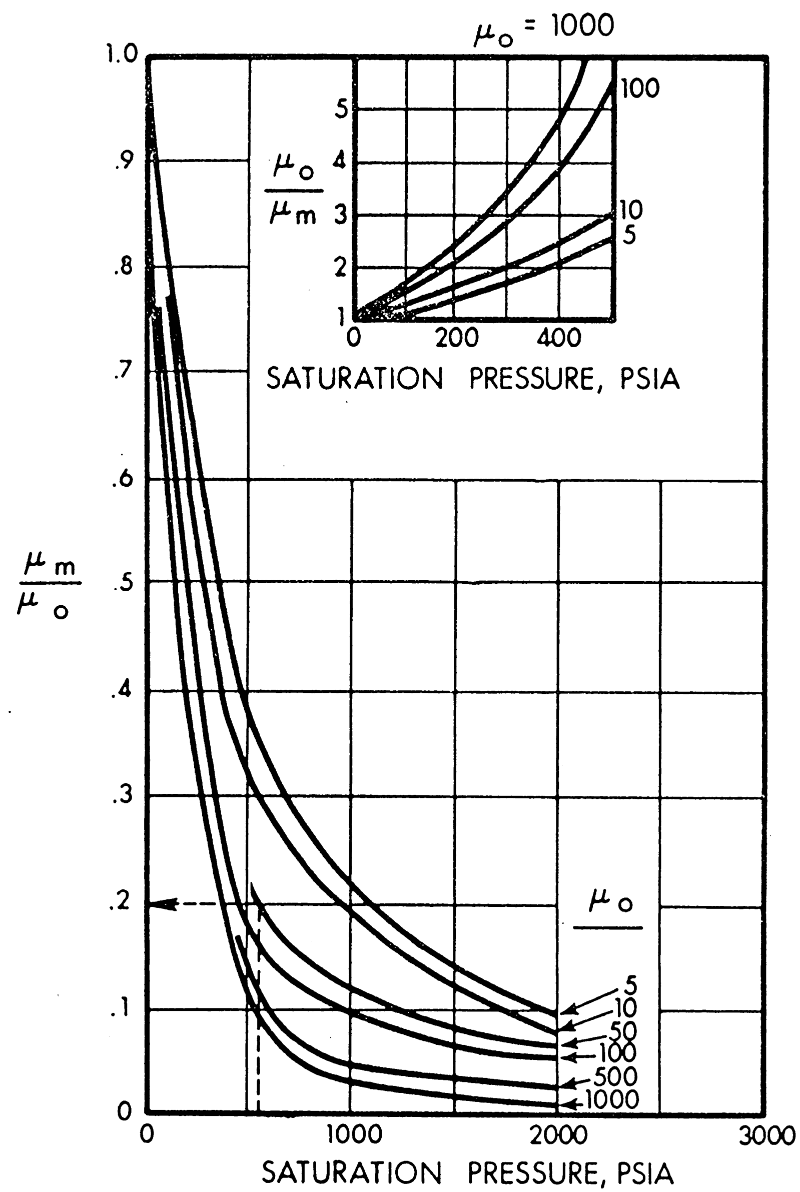
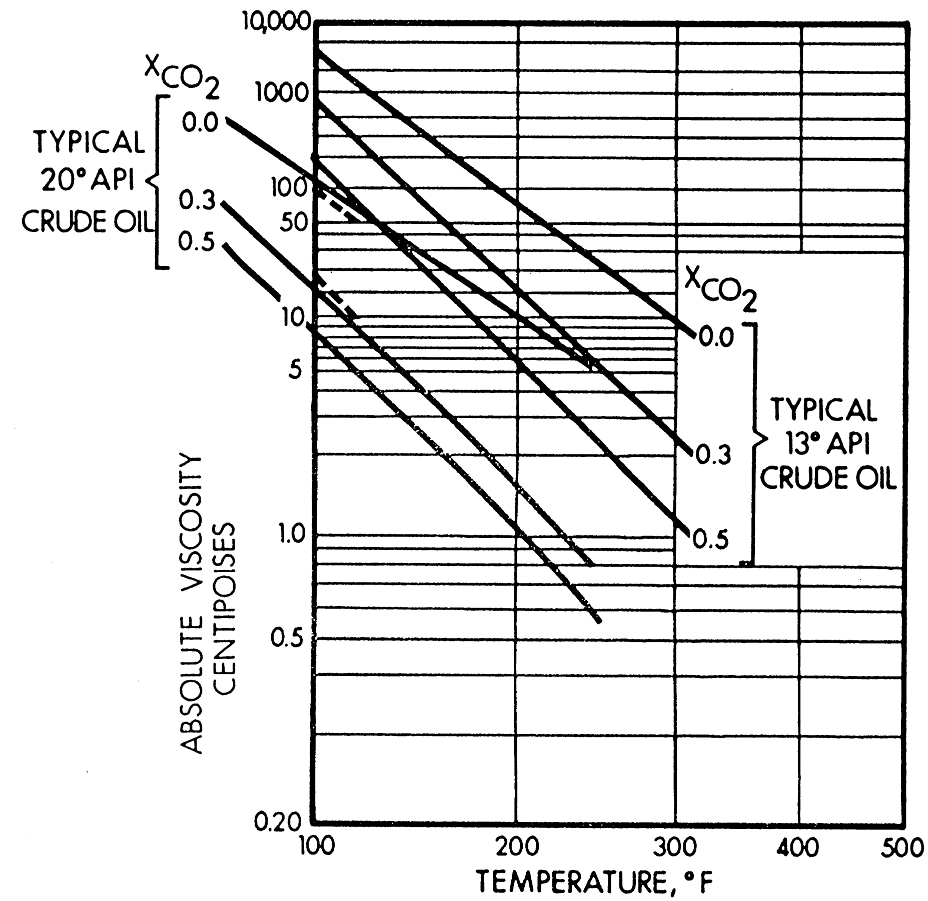


Figure 21.--Viscosity and density of Mead-Strawn stock tank oil as a function of carbon dioxide saturation pressure at 135°F (from Holm and Josendal [39]).



A. Viscosity of CO_2-crude oil mixtures at 120°F.



B. Viscosity-temperature chart.

Figure 22.--Viscosity correlation charts for carbon dioxide-oil mixtures (from Simon and Graue [46]).

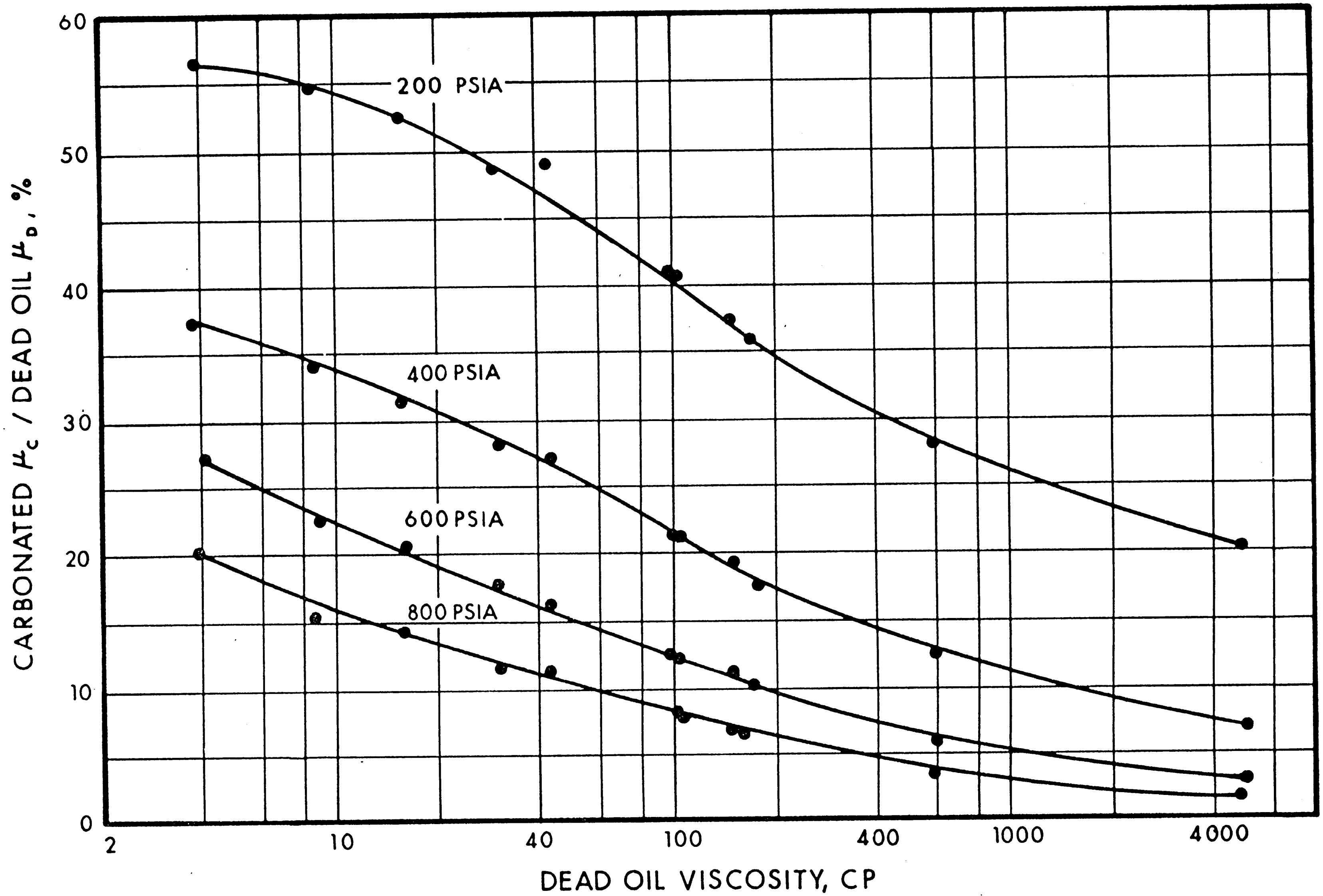


Figure 23.--Reduction of viscosity in carbonated oils at 80°F (from Welker and Dunlop [48]).

Vapor/Liquid and Liquid/Liquid Phase Behavior

Published studies of phase behavior of mixtures of carbon dioxide and crude oil are generally based on "single-contact" experiments using windowed equilibrium cells that permit observations of phase distribution within the cell as a function of pressure at constant temperature. The data from experimental work by different investigators on several oils show extremely complex phase behavior, as discussed below.

In experiments conducted at higher temperatures, the mixture at high pressure goes from a liquid phase to a vapor phase as CO_2 concentration increases. Behavior of this type is shown in Fig. 24*, where data for the Weeks Island (South Louisiana) "S" sand reservoir crude are shown for experiments conducted at the reservoir temperature (225°F) [49]. Compositions of the reservoir oil and the injected gas (95 percent CO_2) are shown in Table II-1. Experimental data for behavior of this type have been reported in detail [50], as discussed below.

On the other hand, in experiments conducted at lower temperatures (90-110°F), formation of multiple liquid phases or liquids plus a solid phase is frequently observed at high pressure with high concentrations of CO_2. This behavior, in which the liquid phases have different colors and densities and segregate because of gravity, has been reported by a number of investigators [17,51,52]. Similar phenomena have also been reported when light hydrocarbons are mixed with reservoir oils at relatively low temperatures [53,54]. An example of this type of phase behavior is shown in Fig. 25 for a low-temperature West Texas reservoir oil [17].

The following sections present detailed data drawn from laboratory studies of phase behavior of both types.

Vapor/Liquid Phase Behavior. Data have been published for detailed studies of two reservoir fluids in which a vapor phase is formed at high concentrations of CO_2 in the mixture. Data from one set of experiments are shown in Fig. 26. The experimental procedure was described by Simon, Rosman, and Zana [50] as follows:

> "Ten mixtures of CO_2 and Reservoir Oil A were prepared. These mixtures contained CO_2 concentrations of 0, 20, 40, 55, 60, 65, 70, 75, 80, and 90 mol percent. At 130°F, pressure traverses were made with each mixture. These traverses started in the single-phase region at a pressure above the bubble (or dew) points and lowered the pressure in discrete steps, passing from the single-phase into the two-phase region.
>
> "At each step, the vapor and liquid volumes were measured. . . . At 130°F, the critical point of the CO_2-Reservoir Oil A system (where intensive properties of the gas and liquid phases were equal) is 2,570 psia and 60 mol percent CO_2."

---

*Figure 24 through 37 appear on pages 52 through 65.

TABLE II-1

COMPOSITION OF WEEKS ISLAND "S" SAND RESERVOIR FLUID AND INJECTION GAS

Component	Mol Fractions Reservoir Oil	Mol Fractions Injection Gas
CO_2	0.0083	0.9505
C_1	0.5677	0.0481
C_2	0.0322	0.0014
C_3	0.0181	
C_4	0.0106	
C_5	0.0111	
C_6	0.0117	
C_{7+}	0.3404	
Total	1.0000	1.0000

Reservoir temperature 225°F

Bubble-point pressure 5,100 psia

Composition of the unidentified reservoir oil A is given in Table II-2. A similar suite of experimental data, obtained at a higher temperature (255°F) using an oil of different composition (see Table II-2, reservoir oil B), is shown in Fig. 27. It may be noted that each figure shows a critical point at CO_2 concentrations and pressures as follows:

Oil	CO_2 Concentration Mol percent	Critical Pressure psia
A	60	2,570
B	74	4,890

At this critical point the intensive properties of the liquid and vapor phases became identical. At CO_2 concentrations higher than critical, the cell was predominantly occupied by a vapor phase.

Simon et al. also studied compositions of the coexisting phases in both of these reservoir oil-CO_2 systems and reported the data in detail. For reservoir oil A, which is discussed below, 6 two-phase mixtures were studied:

Mixture	Mol Percent CO_2	Pressure @ 130°F psia
1	0	1,660
2	55	2,000
3	55	2,420
4	80	2,020
5	80	2,410
6	80	2,920

The composition of Mixture 1, the bubble-point reservoir crude without CO_2, is given in Table II-2. The relationship of the other experimental points to the two-phase reservoir oil/CO_2 system is shown in Fig. 26.

The mixtures containing 55 mol percent CO_2 contained less CO_2 than the critical mixture and showed a bubble-point pressure of 2,420 psia. The cell contained a single liquid phase above this pressure. The mixtures containing 80 mol percent CO_2 were beyond the critical point and were predominantly vapor-phase with some liquid condensate.

The distribution of components of the equilibrium vapors of the 55 mol percent CO_2 - 45 mol percent reservoir oil mixtures is plotted against cell pressure in Fig. 28. The figure also shows the component distribution of the bubble-point vapor from the reservoir oil alone. The CO_2-mixture vapor phase contained approximately 90 mol percent CO_2 and was relatively leaner in C_1-C_3 components and richer in C_4-C_{7+} components than the original vapor from the reservoir oil at the bubble point. Component data for the equilibrium liquids of the CO_2-oil mixtures are shown in Fig. 29 as a function of cell pressure. The liquid phases are seen to contain 50 to 55 mol percent CO_2 and are leaner in C_1-C_6 components but

TABLE II-2

COMPOSITION DATA FOR RESERVOIR OILS A AND B STUDIED BY SIMON ET AL. [50]

Component	Oil A Mol Fractions	Oil B Mol Fractions
N_2	0.0000	0.0027
CO_2	0.0001	0.0133
C_1	0.3100	0.3870
C_2	0.1041	0.0431
C_3	0.1187	0.0315
C_4	0.0732	0.0295
C_5	0.0441	0.0269
C_6	0.0255	0.0271
C_7^+	0.3243	0.4389
Total	1.0000	1.0000

Reservoir temperature	130°F	255°F
Bubble-point pressure	1,660 psia	2,554 psia
Molecular weight	87.51	120.3
Density at bubble point	0.685 gm/cc	0.648 gm/cc
Viscosity at bubble point	0.345 cp	Not reported

richer in C_{7+} components than the original reservoir oil at the bubble point. Thus, mass transfer takes place whereby the vapor phase of the CO_2-oil mixture strips middle components from the oil and CO_2 condenses into the liquid phase.

Component distributions of the vapor phases present in the 80 mol percent CO_2 - 20 mol percent reservoir oil mixtures are plotted in Fig. 30 as a function of pressure. These vapors contain approximately 90 mol percent CO_2 and are relatively richer in C_5-C_{7+} components than the bubble-point vapor from the reservoir crude. Component distribution of the liquid (condensate) phase shows relatively complex behavior as a function of pressure, as shown in Fig. 31. At 2,920 psia, where some 15 percent of the cell volume was occupied by liquid (Fig. 26), the mixture was relatively lean (23 mol percent) in CO_2 and rich (59 mol percent) in C_{7+} components. At lower pressures, where liquid volume increased, more CO_2 condensed into the liquid phase.

Liquid/Liquid Phase Behavior. Published data from two studies of liquid/liquid phase behavior by different investigators will be discussed in detail below.

The first published study, by Huang and Tracht, used a reconstituted reservoir fluid, made by combining appropriate amounts of hydrocarbons (methane through n-hexane) with a West Texas stock tank oil [55]. The composition of the reconstituted reservoir fluid and related stock tank oil and separator gas are given in Table II-3. CO_2 solubility and oil swelling tests were conducted in a high-pressure windowed cell at 90°F. Results of these tests are shown as a function of CO_2 saturation pressure in Fig. 32. These data are obviously qualitatively similar to those obtained by other investigators whose data were presented and discussed earlier.

Huang and Tracht reported that a single liquid phase was present in the cell at pressures greater than CO_2 saturation pressure, up to and including the experimental point where the mixture contained 68.2 mole percent CO_2 at a saturation pressure of 1,185 psia. In the next step of the experimental work, at a CO_2 content of 77.8 mole percent, two liquid phases occupied the cell at pressures higher than 1,090 psia. These two liquids were described as a hydrocarbon-rich liquid (termed L_1) and a CO_2-rich liquid (termed L_2). At pressures below 1,090 psia, a vapor phase began to evolve from the CO_2-rich liquid phase. The hydrocarbon-rich liquid phase showed greatly reduced swelling at high CO_2 concentrations in the mixture, as shown in Fig. 33.

The complicated phase behavior observed at CO_2 content greater than 68.2 mol percent is further illustrated in Fig. 34. The investigators reported that for the mixture labeled M (77.8 mole percent CO_2) on the figure, the volume ratio of the CO_2-rich liquid to the hydrocarbon-rich liquid was 0.51 and that this ratio remained essentially constant as cell pressure was increased to 1,800 psia. At pressures below 1,090 psia, the CO_2-rich liquid began vaporizing and had vaporized completely at a pressure of 965 psia (point Q on Fig. 34). In the pressure region between 1,090 and 965 psia the two liquids L_1 and L_2 and a vapor (V) occupied the cell.

TABLE II-3

FLUID ANALYSES AND PROPERTIES OF WEST TEXAS OIL STUDIED BY HUANG AND TRACHT [55]

	Composition, Mol percent		
	Separator Gas	W. Texas S.T. Oil (STO)	Reconstituted W. Texas Oil (RRF)
CO_2	---	---	---
C_1	56.00	0.00	13.00
C_2	18.58	0.07	5.25
C_3	13.69	2.53	6.35
C_4*	7.52	5.15	5.26
C_5*	3.11	6.95	6.26
C_6*	0.88	7.54	5.96
C_{7+}	0.22	77.76	57.92

Sp. gr. C_{7+}	0.865
Mol. wt. C_{7+}	232
Solution gas/oil ratio	180 scf/bbl
Formation volume factor	1.09
Bubble-point pressure (BPP)	475 psia
Viscosity at BPP & 90°F	2.17 cp
Reservoir pressure	1265 psia
Reservoir temperature	90°F

*Normal and iso components are not segregated.

Below 965 psia, only a single liquid (L_1) plus vapor occupied the cell. Similar phenomena were observed for point N (83.5 mole percent CO_2) commencing below a pressure of 1,065 psia.

As part of this suite of experiments, a mixture of composition M was prepared and a sample of the CO_2-rich liquid phase at a pressure of 1,265 psia was withdrawn from the cell and analyzed. The analytical data given in Table II-4 show that 10.3 mol percent of the mixture comprised hydrocarbons "extracted" from the reconstituted reservoir fluid. The hydrocarbon mixture is apparently richer in C_1-C_5 components and leaner in C_6 and C_{7+} than was the reconstituted reservoir fluid (Table II-3). No data were given for the composition of the coexisting hydrocarbon-rich liquid phase.

On the basis of the ternary phase diagram shown in Fig. 35, "true" miscibility between CO_2 and the reconstituted reservoir fluid cannot be attained at the reservoir pressure of 1,265 psia and reservoir temperature of 90°F. However, as will be discussed in the next section, the hydrocarbon extraction mechanism apparently resulted in high recovery of residual oil in core displacement tests.

Phenomena similar to those described above were reported in a study by Shelton and Yarborough [54]. This work was also performed in a windowed cell held at reservoir temperature, using both rich gas and CO_2 with reservoir oils. However, the discussion that follows will deal only with the experiments using CO_2.

In the experiment the cell was filled with pure CO_2, which was then combined with a known amount of recombined reservoir oil having the composition given in Table II-5. A phase-distribution test starting at high pressure (4,000 to 8,000 psi) was performed on the mixture by a constant-composition expansion in which the volume of the cell and of the phases observed in the cell were measured at a series of pressures. Additional oil was then added to the cell and the phase-distribution test procedure was repeated. This sequence of procedures was repeated until sufficient oil had been added to dissolve all of the CO_2 in the cell. Eight oil-CO_2 mixtures, covering the composition range from 59 to 95 mole percent CO_2, were used in this phase of the work. All tests were run at reservoir temperature, 94°F.

The results of the phase distribution tests on the original eight mixtures (plus a ninth, discussed further below) are shown in Fig. 36. The left portion of the diagram shows that only a single liquid phase (L) existed in the cell at pressures above the CO_2 saturation pressure for CO_2 concentrations less than 56 mol percent. At higher CO_2 concentrations and a high pressure (greater than 1,200 to 1,400 psi) the upper right portion of the diagram shows two liquid phases plus a solid phase (S), which was not measurable volumetrically and was described as a tar-like resinous precipitate that clouded the window of the cell. The two liquid phases were a hydrocarbon-rich liquid (L_1) and a CO_2-rich liquid (L_2). Finally, the diagram indicates a four-phase region over a narrow range of pressures

TABLE II-4

COMPOSITION OF CO_2-RICH PHASE OF A MIXTURE OF CO_2 AND RECONSTITUTED RESERVOIR FLUID [55]

	CO_2-rich Liquid Phase Withdrawn from a Mixture at 90°F and 1,265 psia (77.8 CO_2-22.2 Mol % RRF)	Hydrocarbon Fractions Normalized to 10.3 Mol %
CO_2	89.7	---
C_1	2.4	23.2
C_2	1.2	11.6
C_3	1.5	14.6
C_4*	1.1	10.7
C_5*	1.3	12.6
C_6*	0.3	2.9
C_7*	2.5	24.4
	100.0	100.0

*Normal and iso components not segregated.

TABLE II-5

COMPOSITION OF RESERVOIR OIL USED IN CO_2 EXPERIMENTS OF SHELTON AND YARBOROUGH [54]

Component	Mol percent in Recombined Reservoir Oil B
Nitrogen	0.48
Carbon Dioxide	0.11
Methane	16.30
Ethane	4.03
Propane	2.97
Butanes	3.65
Pentanes	3.73
Hexanes	3.32
Heptanes plus	65.41
Total	100.00
Heptanes plus:	
Molecular weight	227
Specific gravity	0.8553
API gravity	33.9
Temperature, °F	94
Bubble-point pressure, psia	798

at CO_2 concentrations greater than 56 mol percent. These phases were the resinous precipitate (S), the hydrocarbon-rich liquid (L_1), the CO_2-rich liquid (L_2), and a vapor (V).

To investigate these multiple-phase phenomena further, the behavior of a ninth oil-CO_2 mixture containing 78.93 mol percent CO_2 was examined in detail. The results of a phase distribution test on this mixture are shown in Fig. 37. In the narrow pressure region in which four phases existed in the cell, the hydrocarbon-rich liquid and the CO_2-rich liquid each occupied about 50 percent of the cell volume. At higher pressures, the volume of the CO_2-rich phase increased to approximately 60 percent while that of the hydrocarbon-rich phase decreased to about 40 percent. This change is attributable to increased extraction of hydrocarbons from the hydrocarbon-rich liquid by the CO_2-rich liquid at higher pressures.

The investigators described in detail the behavior of the mixture at pressures traversing the four-phase region. They noted that as cell pressure was decreased, the volume of the CO_2-rich liquid phase decreased abruptly at a pressure slightly greater than 1,200 psi with a corresponding increase in the volume of the hydrocarbon-rich liquid. At 1,200 psi a vapor phase formed whose volume increased rapidly at the expense of the CO_2-rich liquid as pressure was lowered. At 1,125 psi, the CO_2-rich liquid had completely vaporized, leaving the cell occupied by oil, gas, and a small amount of precipitate. Data on composition of the fluids (liquid and vapor) in the cell at pressures where four phases were present were obtained by analyzing samples taken from the cell after equilibrating at 1,184 psi. These data are shown in Table II-6. It is notable that the less volatile liquid phase termed "oil-rich" contains a relatively high concentration (59.45 mol percent) of carbon dioxide.

Synthesis of Observed Phase Behaviors

From the published data discussed above, it appears possible to construct a qualitative synthesis of these seemingly dissimilar phase behavior observations. In each of the three studies, the mixtures of CO_2 and reservoir oil had two fluid phases present at high pressure and high CO_2 concentration. These fluid phases were shown to be a "more volatile" CO_2-rich phase and a "less volatile" hydrocarbon-rich phase. In the study by Simon et al., the more volatile phase (derived from 80 mol percent CO_2 mixed with the reservoir oil) was a vapor at 130°F. In the studies by Huang and Tracht and by Shelton and Yarborough, the more volatile phase, at CO_2 concentrations of 77.8 mol percent and 78.93 mol percent respectively, was a CO_2-rich liquid at high pressures with temperatures of 90°F and 94°F respectively.

Comparative composition data for the three more volatile fluids observed in these studies are listed in Table II-7 along with composition data for the reservoir oils used. These data indicate that the CO_2-rich volatile phases present in all three studies were of similar composition. This observation further suggests that the presence of a predominantly vapor

TABLE II-6

EQUILIBRIUM PHASE COMPOSITIONS FOR A MIXTURE OF CO_2 WITH A RECOMBINED RESERVOIR AT 94°F AND 1,184 PSIA [54]

Component	Mol Percent				
	Overall Mixture	Oil-Rich Liquid	CO_2-Rich Liquid	Gas Sample 1	Gas Sample 2
Nitrogen	0.10	-	0.10	0.24	0.25
Carbon dioxide	78.95	59.45	87.97	89.72	89.87
Methane	3.44	3.01	3.82	6.93	6.98
Ethane	0.85	1.46	1.25	1.29	1.19
Propane	0.63	0.96	0.66	0.51	0.42
Butanes	0.77	1.18	0.70	0.36	0.35
Pentanes	0.78	1.06	0.58	0.25	0.23
Hexanes	0.70	0.44	0.87	0.23	0.23
Heptanes plus	13.78	32.46	4.05	0.47	0.48
Total	100.00	100.00	100.00	100.00	100.00
Heptanes plus:					
Molecular weight		227	240		
Specific gravity		0.8553	0.8952		
API gravity		33.9°	26.5°		
Phase density at 94°F and 1,240 psia, gm/cc		0.8361	0.7091		

TABLE II-7

COMPARATIVE COMPOSITION DATA FROM PHASE BEHAVIOR STUDIES
"VOLATILE PHASE" DATA

	Mol Fractions					
	Simon et al 80 Mol % CO_2		Huang & Tracht 77.8 Mol % CO_2		Shelton & Yarborough 78.93 Mol % CO_2	
Component	Res. Oil	Vapor (2020 psia 130°F)	Res. Oil	CO_2-rich Liquid (1265 psia, 90°F)	Res. Oil	CO_2-rich Liquid (1184 psia, 94°F)
CO_2	0.0001	0.87740	-	0.8970	0.0011	0.8797
C_1	0.3100	0.06306	0.1300	0.0240	0.1630	0.0382
C_2	0.1041	0.01913	0.0525	0.0120	0.0403	0.0125
C_3	0.1187	0.01877	0.0635	0.0150	0.0297	0.0066
C_4	0.0732	0.01000	0.0526	0.0110	0.0365	0.0070
C_5	0.0441	0.00422	0.0626	0.0130	0.0373	0.0058
C_6	0.0255	0.00222	0.0596	0.0030	0.0332	0.0087
C_{7+}	0.3243	0.00520	0.5792	0.0250	0.6541	0.0405
TOTAL	1.0000	1.00000	1.0000	1.0000	1.0000	1.0000

phase at higher temperatures in contrast to two liquid phases at lower temperatures may be related to the critical temperature of the CO_2-rich phase. Huang and Tracht reported that the critical temperature of the CO_2-rich phase of their study was measured experimentally to lie between 111°F and 121°F. At temperatures above critical, the CO_2-rich fluid is a vapor regardless of pressure. Below critical temperature, the CO_2-rich fluid may be either liquid or vapor, depending upon pressure.

As discussed in more detail in the section entitled "Miscible Behavior" (below), recently published research indicates that the mechanism by which miscibility is attained can be expected to depend on the phase equilibria behavior of the CO_2/reservoir oil mixture, which varies depending upon temperature [56]. Hence, while it is not a controllable variable in a field project, reservoir temperature and related phase behavior are key design and evaluation parameters when considering CO_2 flood behavior.

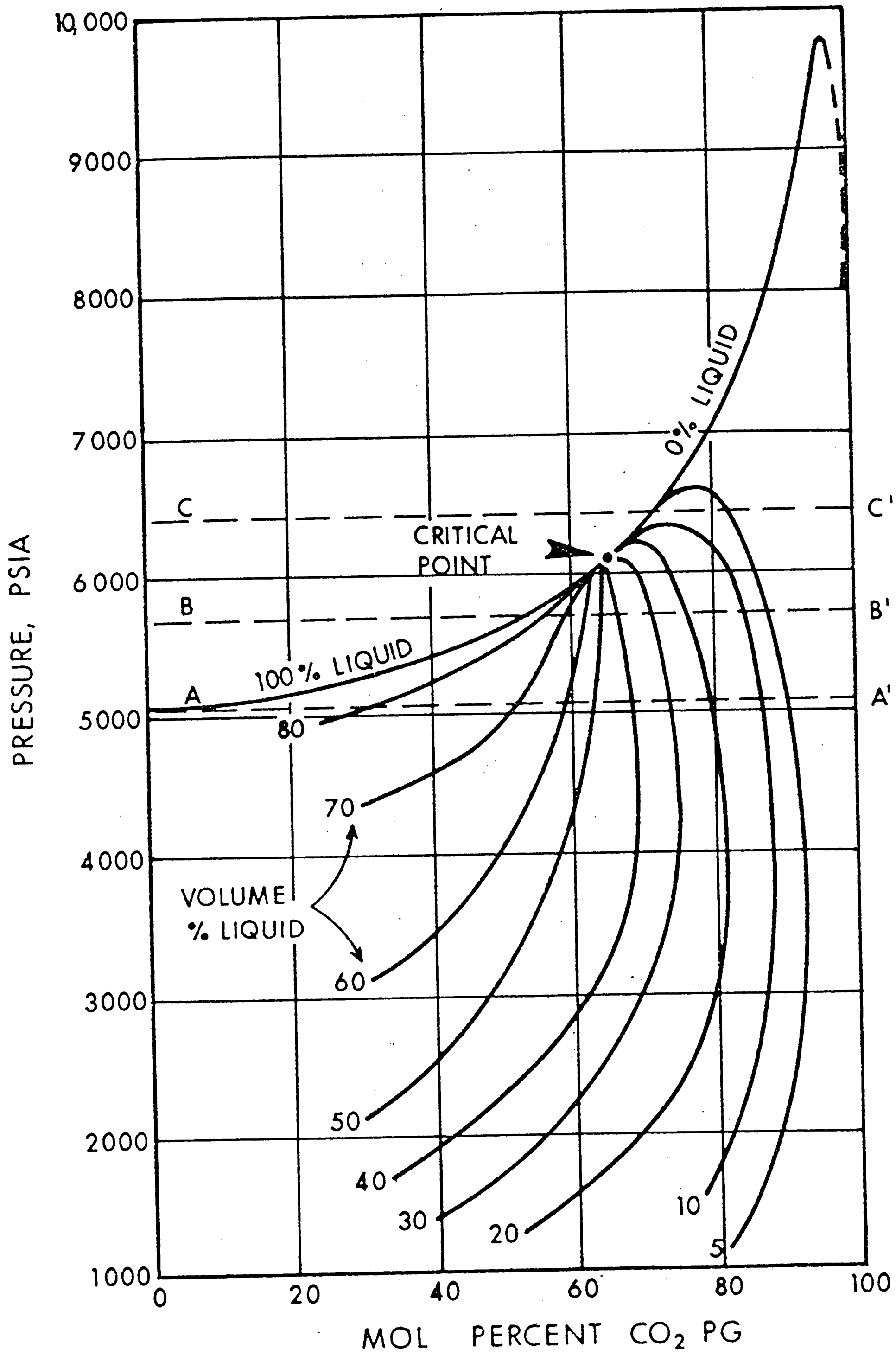


Figure 24.--Phase envelope for Weeks Island "S" Sand crude and 95% CO_2-5% plant gas at 225°F (from Perry [49]).

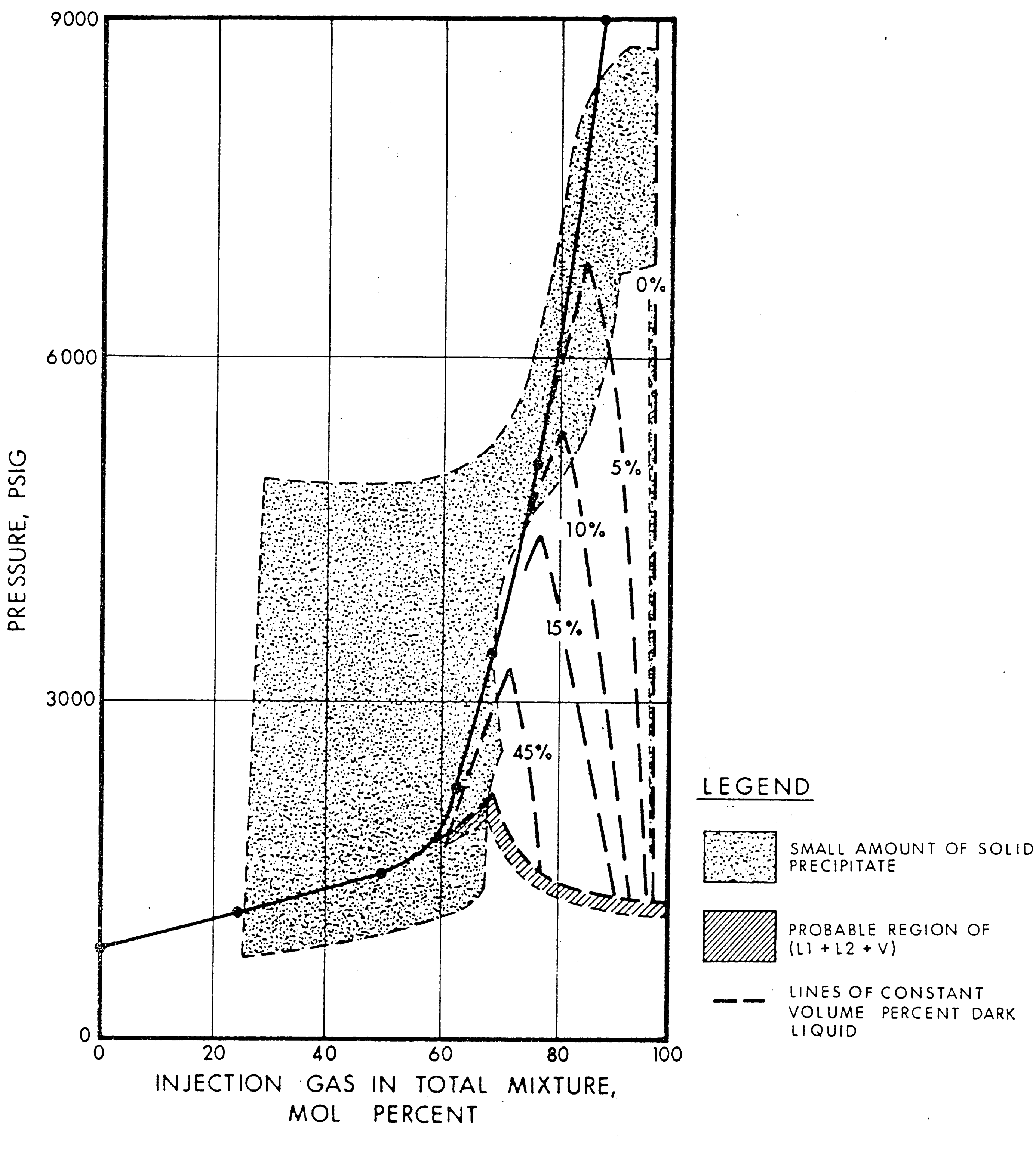


Figure 25.--Phase diagram for a west Texas reservoir oil and a 95% CO_2 injection gas (from Stalkup [17]).

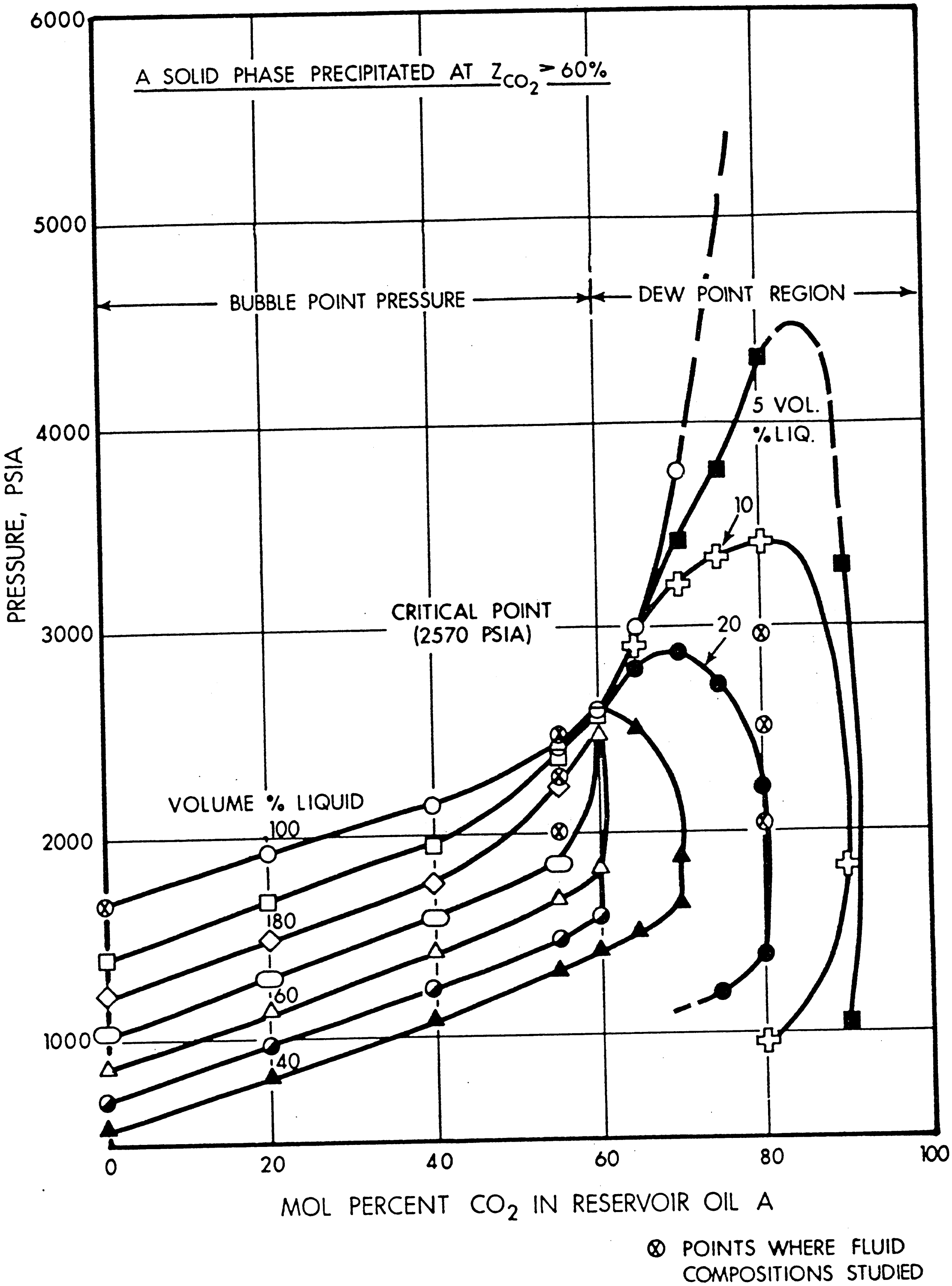


Figure 26.--Phase diagram of reservoir oil A mixed with carbon dioxide at 130°F (from Simon *et al.* [50]).

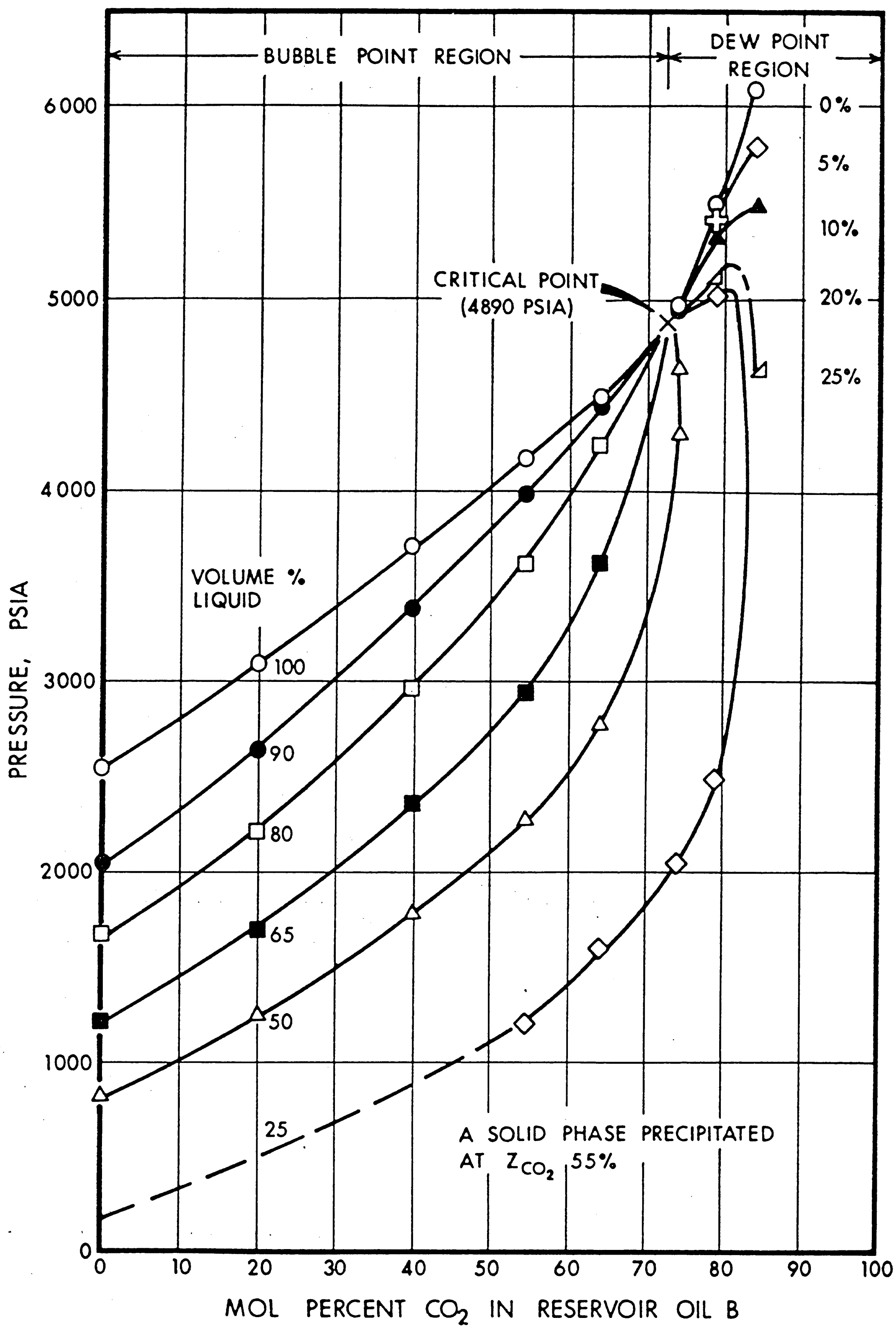


Figure 27.--Phase diagram of reservoir oil B mixed with carbon dioxide at 255°F (from Simon *et al.* [50]).

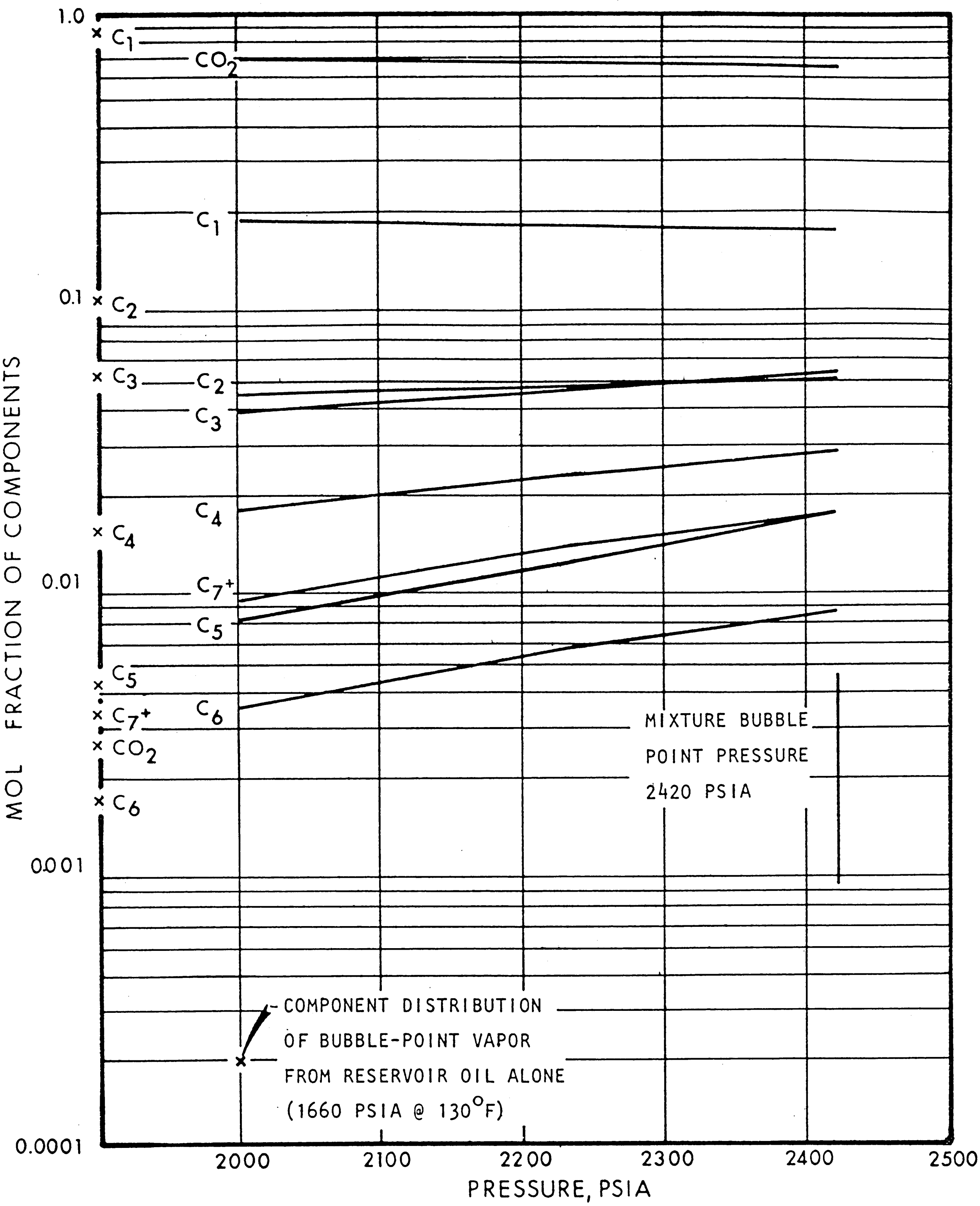


Figure 28.--Effect of pressure on composition of equilibrium vapor from a mixture of 55 mol percent carbon dioxide with 45 mol percent reservoir oil A at 130°F (data from Simon *et al.* [50]).

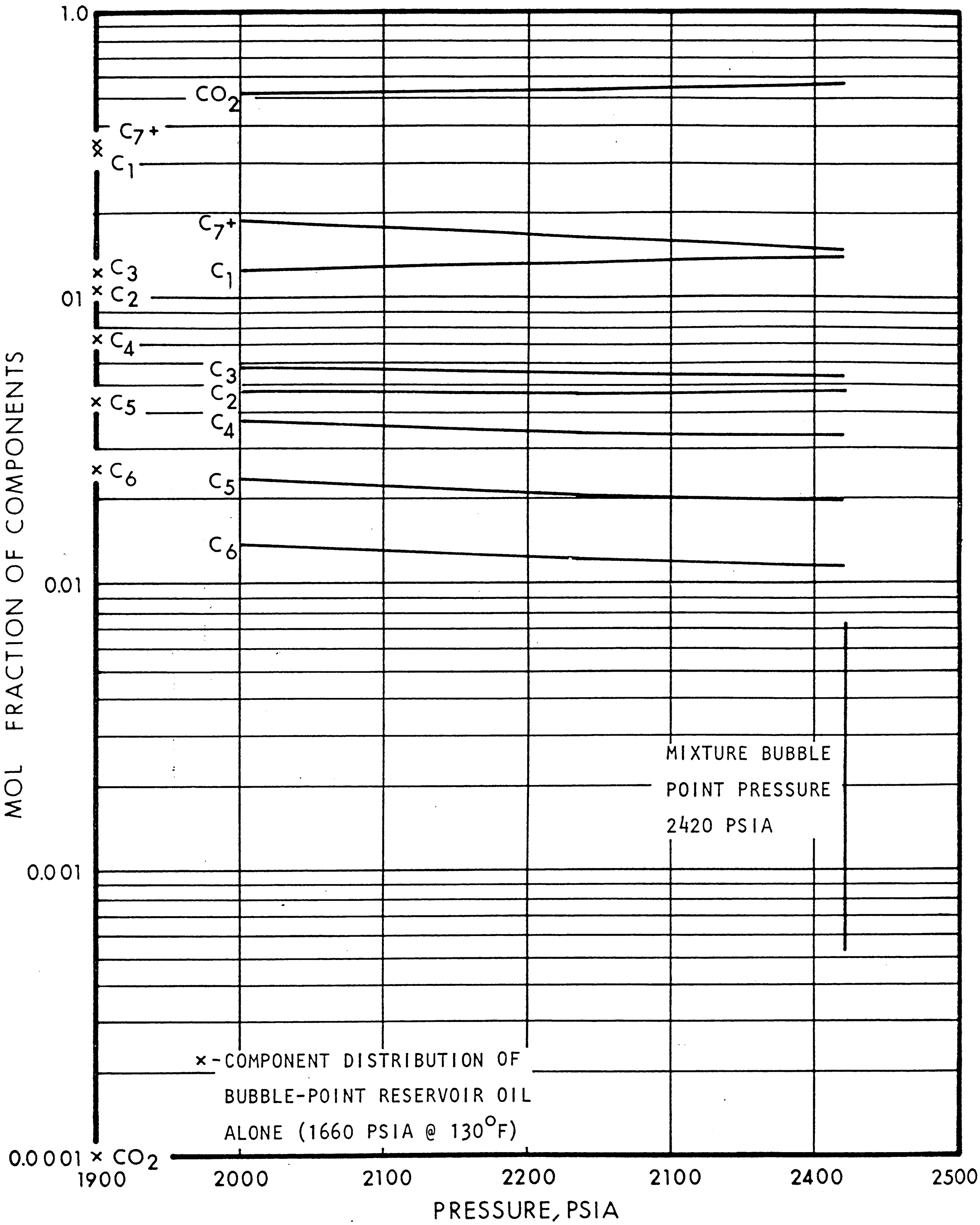


Figure 29.--Effect of pressure on composition of equilibrium liquid from a mixture of 55 mol percent carbon dioxide with 45 mol percent reservoir oil A at 130°F (data from Simon *et al.* [50]).

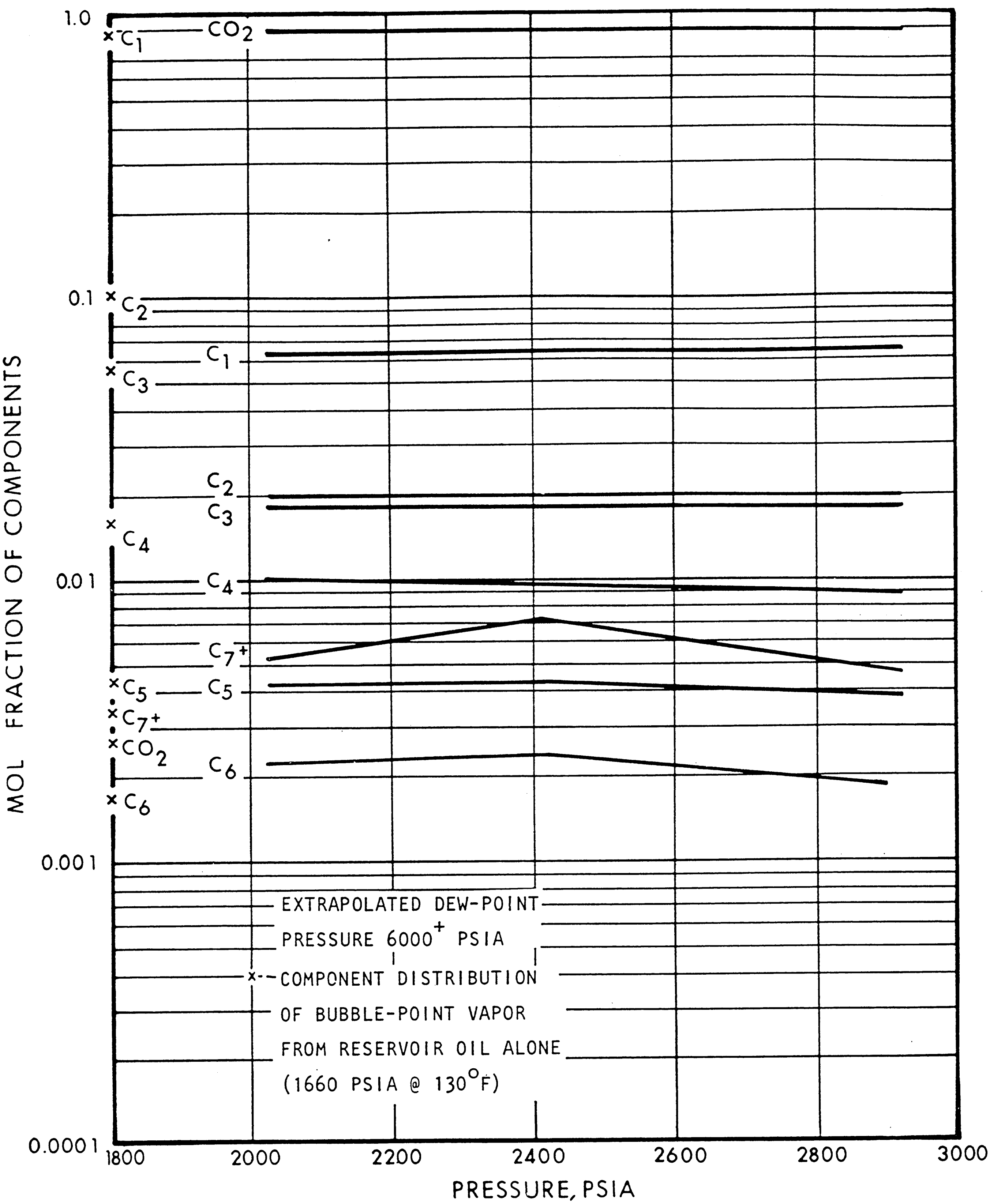


Figure 30.--Effect of pressure on composition of equilibrium vapor from a mixture of 80 mol percent carbon dioxide with 20 mol percent reservoir oil A at 130°F (data from Simon *et al.* [50]).

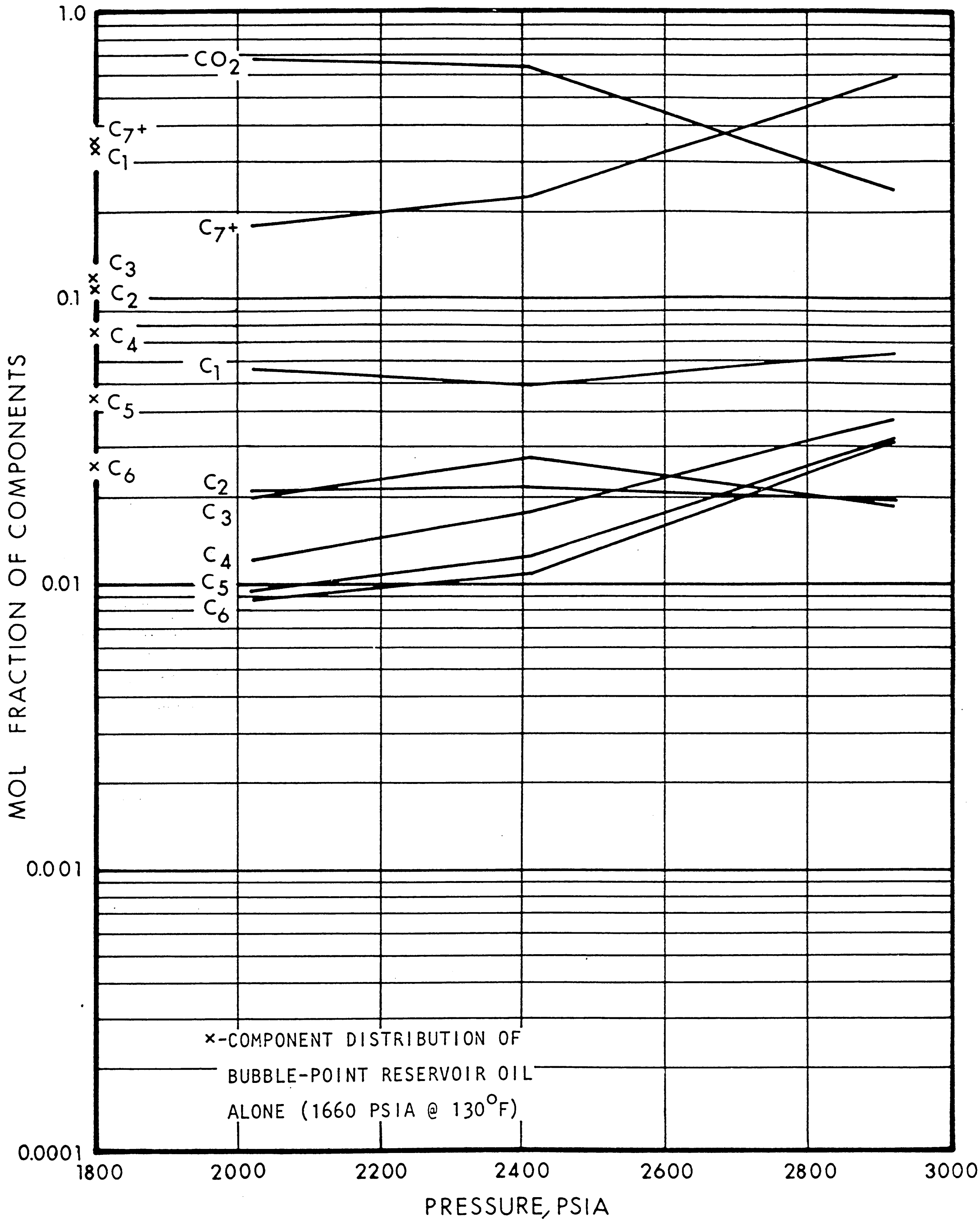


Figure 31.--Effect of pressure on composition of equilibrium liquid from a mixture of 80 mol percent carbon dioxide with 20 mol percent reservoir oil A at 130°F (data from Simon *et al.* [50]).

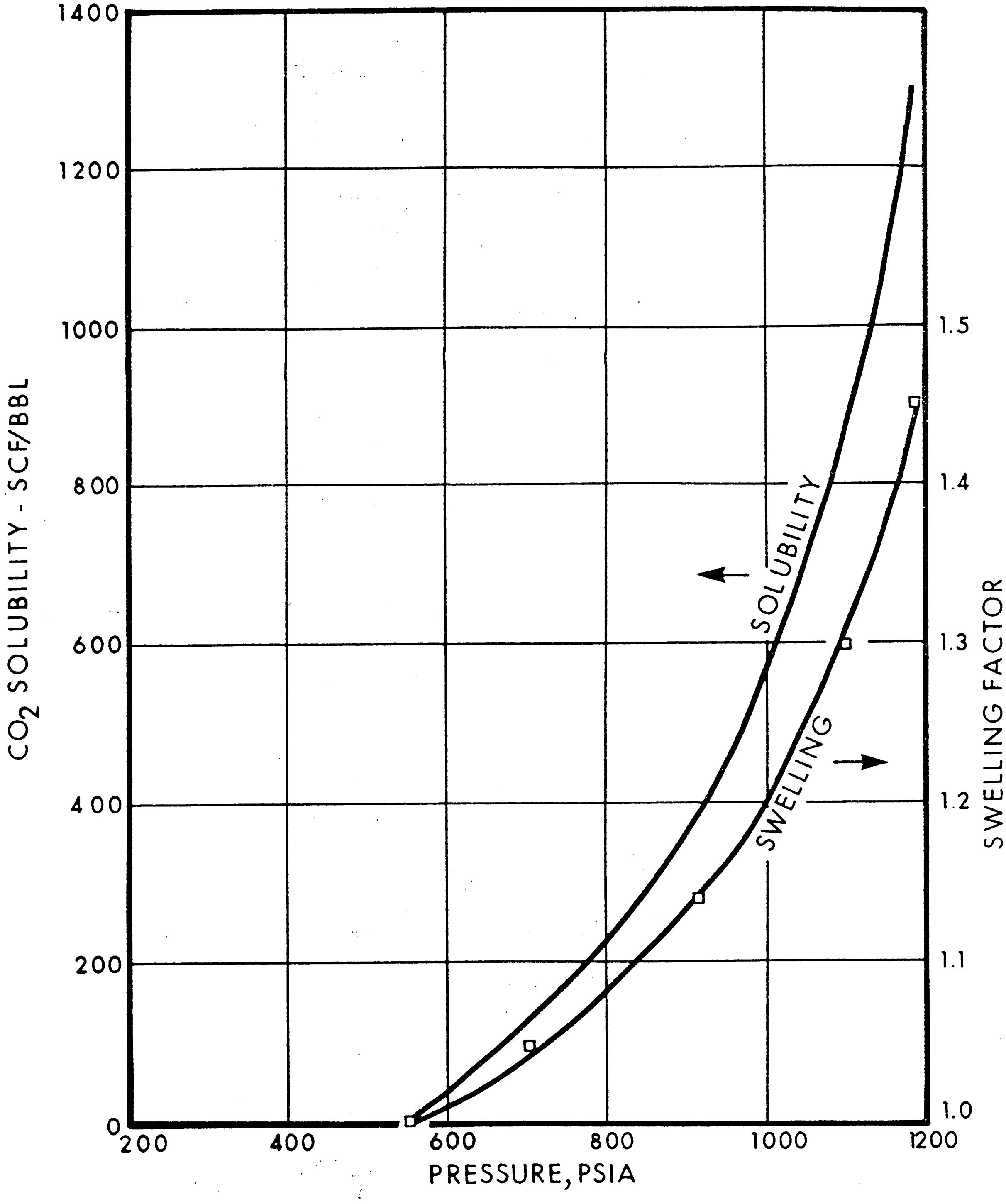


Figure 32.--Carbon dioxide solubility and swelling data for reconstituted west Texas reservoir fluid at 90°F as a function of carbon dioxide saturation pressure (data from Huang and Tracht [55]).

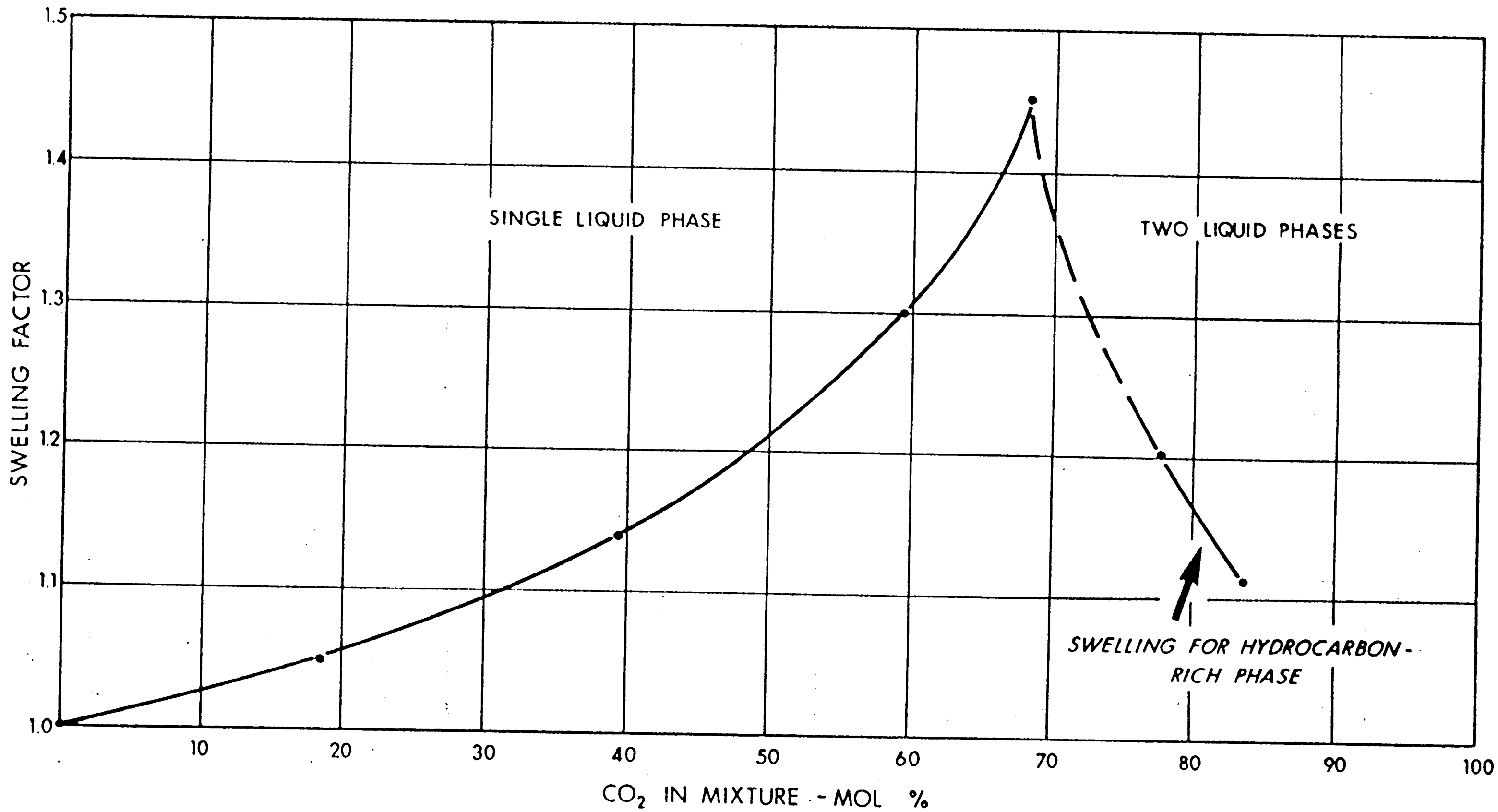


Figure 33.--Swelling factor vs. content of mixture for reconstituted west Texas reservoir fluid at 90°F (from Huang and Tracht [55]).

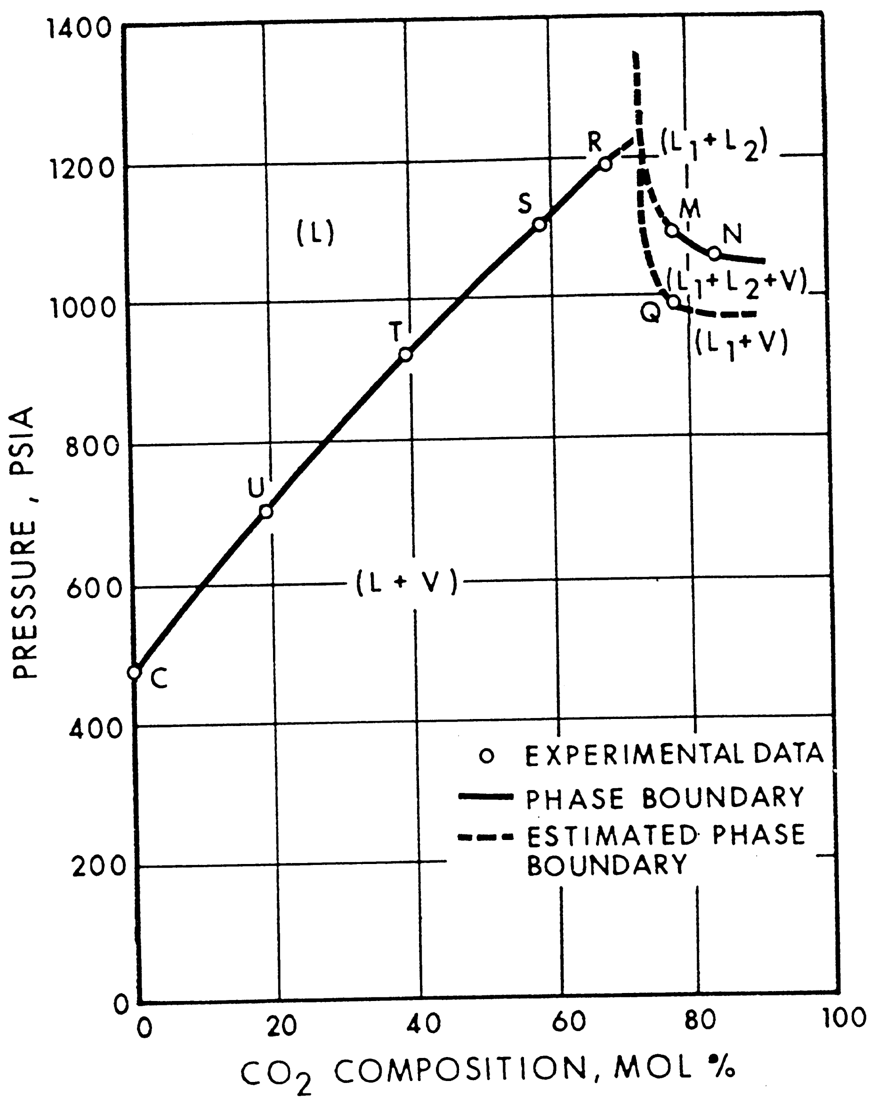


Figure 34.--Pressure-composition diagram for the carbon dioxide-reconstituted reservoir fluid system (from Huang and Tracht [55]).

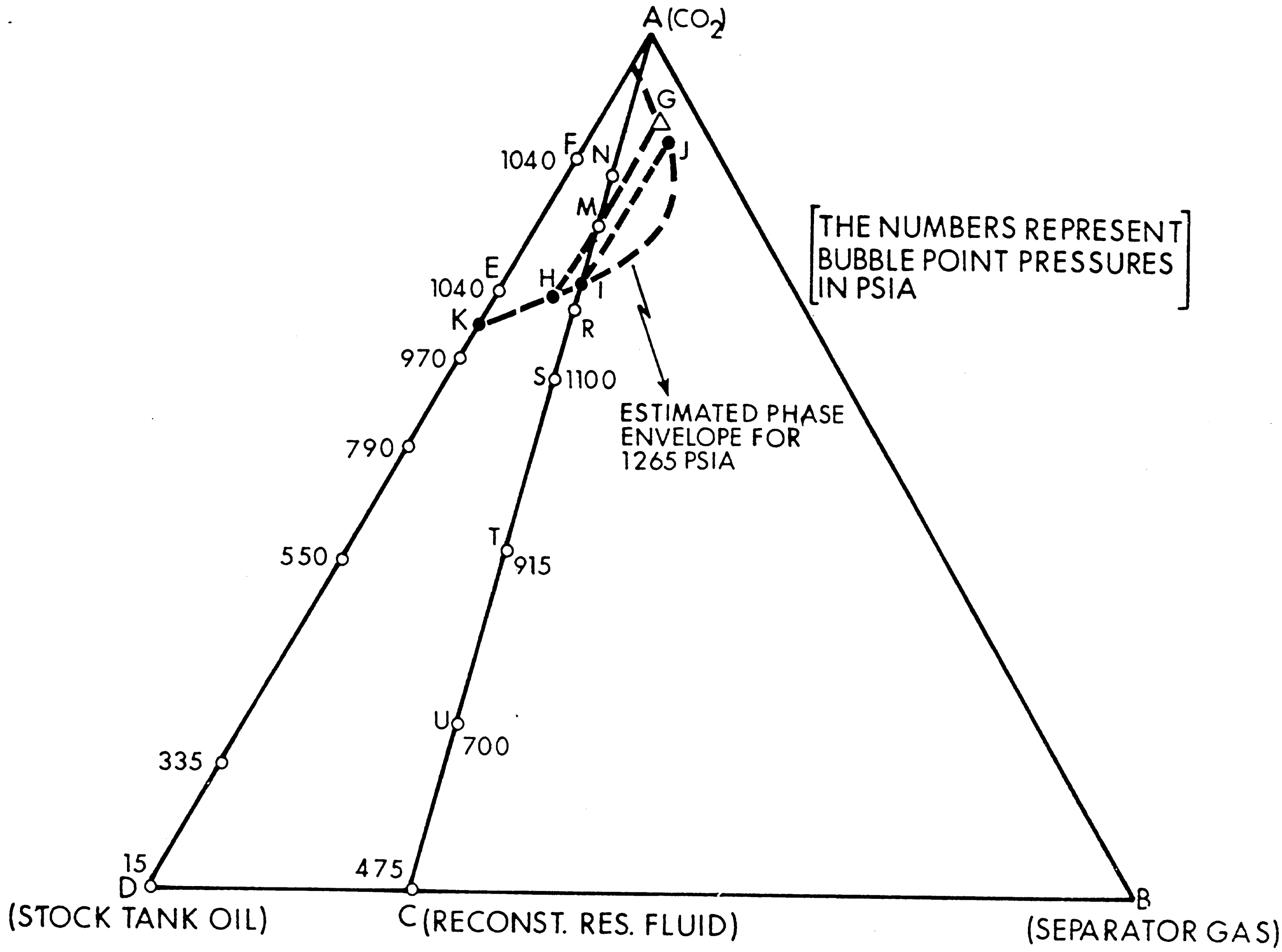


Figure 35.--Ternary phase diagram for the carbon dioxide-separator gas-stock tank oil system at 90°F (from Huang and Tracht [55]).

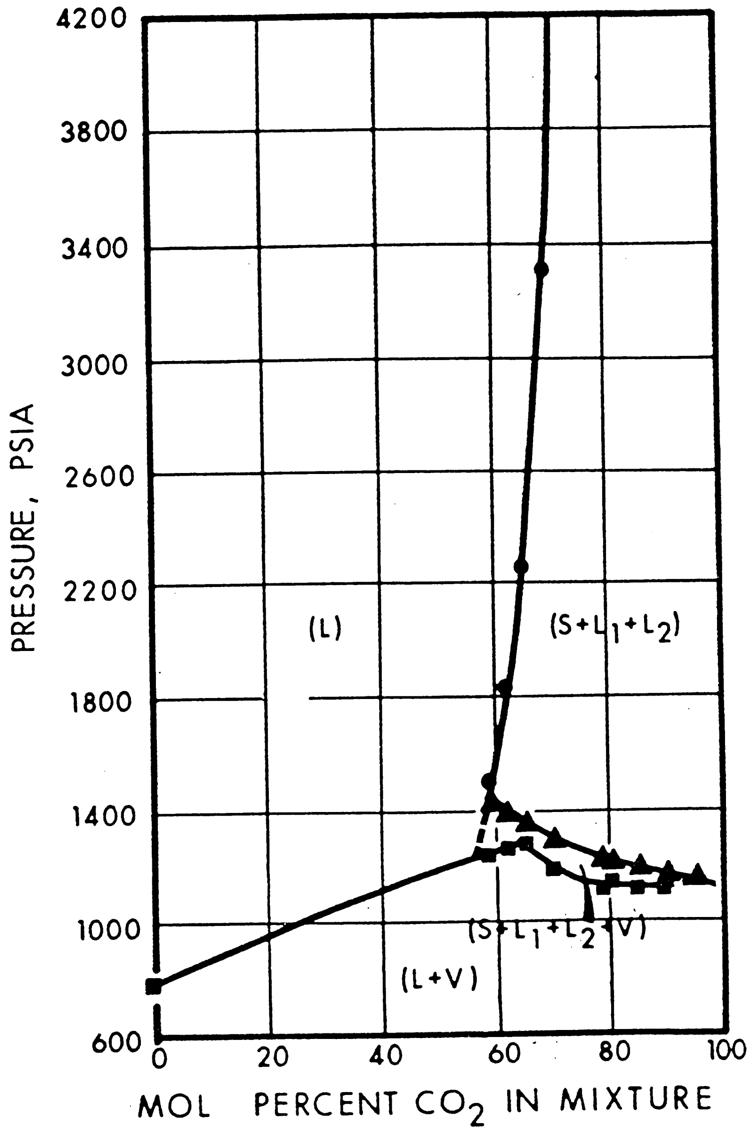


Figure 36.--Phase diagram for mixtures of recombined reservoir oil B with CO_2 at 94°F (from Shelton and Yarborough [54]).

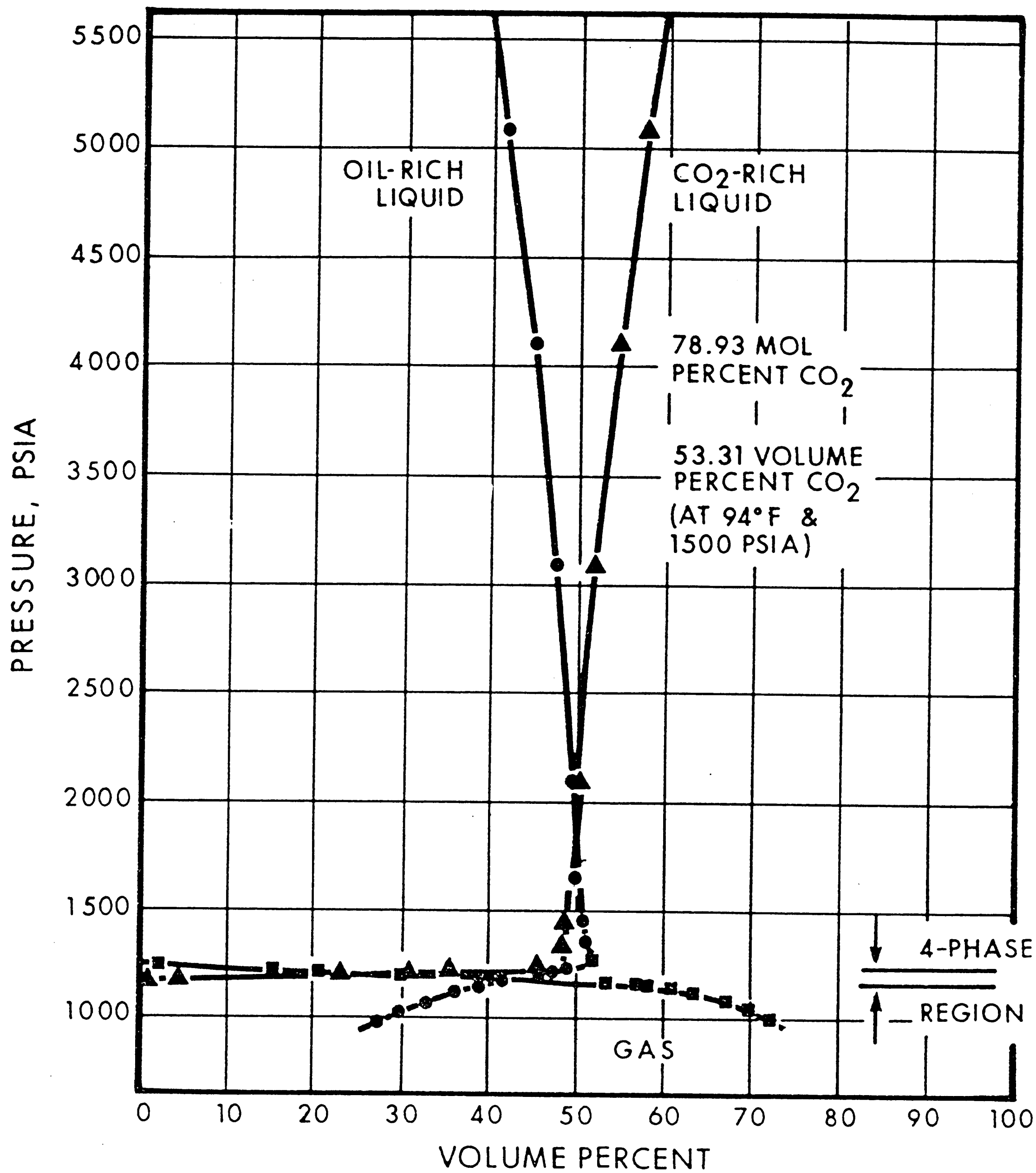


Figure 37.--Distribution of phases for recombined reservoir oil B-carbon dioxide Mixture 9 at 94°F (from Shelton and Yarborough [54]).

Miscible Behavior

A miscible displacement of fluid from porous media occurs when no interface exists between the driving fluid and the driven fluid because of the miscibility, or mutual solubility, of the two fluids. Dry gas displacing "wet" gas in a cycling project, or toluene flushing oil from a core, are obvious examples. This is in contrast to immiscible displacements, such as water or low-pressure gas driving oil. In the miscible displacement of oil by another fluid, interfacial and related capillary forces between the two fluids are absent and the driving fluid will totally displace oil in place in the rock entered by the driving fluid, leaving no residual oil. Because of this, miscible displacement has obvious technical potential for enhanced oil recovery.

As mentioned in the introduction to this report, CO_2 flooding began as a variation of solvent-type miscible flooding [3,4]. Hence, while more recent work summarized in the preceding sections has shown that "miscibility" between CO_2 and reservoir oils is an elusive and complex subject, the literature to date reflects the conceptual heritage and hence is written using the methodology and terminology of hydrocarbon-miscible flooding. For completeness, this background is summarized in the next few paragraphs. This is followed by a discussion of "miscible" behavior of CO_2/reservoir oil systems.

Hydrocarbon Miscible Flooding Concepts. For practical oilfield applications, three technically different miscible displacement processes using hydrocarbon driving fluids have been conceived and applied:

(1) LPG or LPG-slug process [57,58]
(2) High-pressure dry gas process [59]
(3) Enriched-gas process [60].

The first of these processes, in which propane was generally used as the solvent or miscible agent, is a "first contact" miscible process. "First contact" miscibility means that the fluids are mutually soluble without any compositional alterations. The other two, in general, require multiple contacts between the driving fluid and the reservoir oil before miscibility is achieved. Because of the conceptual applicability to CO_2 flooding, the concept of "multiple-contact" miscibility requires more discussion. This is presented in the following paragraphs.

The process by which a lean or dry gas (generally methane but sometimes flue gas or nitrogen) can develop miscibility by multiple contacts with a rich oil was studied by Hutchinson and Braun [61]. Miscibility is achieved in this process because intermediate hydrocarbon components (C_2-C_6) are vaporized into the gas phase from the liquid oil until the gas composition is sufficiently enriched to be miscible with the oil. The mechanism of the process can be qualitatively illustrated by the ternary phase diagram shown in Fig. 38.* This diagram shows a two-phase region in the upper left that

*Figures 38 through 47 appear on pages 71 through 80.

is larger or smaller depending on system temperature and pressure. Methane (at the apex) is not directly miscible with the reservoir oil, shown lower center, because of the intervening two-phase region. Increasing the pressure to shrink the two-phase region so that a line between the reservoir oil and methane does not cross the two-phase region would result in first-contact miscibility. For the two-phase region shown, miscibility must be achieved by multiple contacts which successively enrich the methane by vaporization of C_2-C_6 components from the oil. The gas composition path follows the dew-point curve until line of sight with the reservoir oil composition can be attained. If line of sight cannot be achieved without passing the critical point and its tangential tieline, miscibility will not be attained. This multiple-contact process has been termed vaporizing miscible displacement or vaporizing gas drive. In other words, miscibility is achieved by mass transfer of components from the oil to the gas through vaporization.

In the enriched-gas process, multiple-contact miscibility is achieved by mass transfer of components in the opposite direction, that is, by condensation from the vapor phase into the liquid phase. As shown in Fig. 39, this is achieved by injecting a gas rich in middle (C_2-C_6) components. Through multiple contacts, these components condense into the oil (liquid) phase, progressively enriching it in middle components. The oil, originally poor in middle components, follows the compositional path shown by the bubble-point curve. Miscibility is achieved when the enriched oil has a composition that provides line of sight with the injected gas without traversing the two-phase region or crossing the critical point. This process has been termed condensing gas drive. First-contact miscibility would occur in this system if the injected gas were sufficiently enriched in middle components so that a line connecting oil and injected gas composition would not traverse the two-phase region initially.

Miscibility of CO_2 with Reservoir Oils. Early work with CO_2 flooding, published in 1959, indicated that the high recovery of oil in place typical of miscible displacements could be attained in the laboratory with Soltrol-saturated Berea cores when flooded at 1,700 psi with a CO_2 slug followed by carbonated water [3]. Results of a CO_2-slug/carbonated-water field test, which began in 1964, also indicated that a partial miscible displacement could occur with a 41°API reservoir oil at 135°F flooded at pressures averaging 2,200 psig [18]. Later research demonstrated that miscible-type displacements could be verified, and provided a rationale for the attainment of miscibility with CO_2 at pressures substantially lower than those usually required when methane or flue gas was used as the miscible agent [51]. More recent studies, presented in detail in the preceding section, have illustrated the complexities involved in the miscible behavior of CO_2/reservoir oil systems [50,54,55]. A recent paper reporting on the results of research done "to increase our understanding of the multiple-contact miscible displacement mechanism for CO_2 flooding" takes full cognizance of these complexities and the authors propose that:

TABLE II-8

NPC METHOD FOR ESTIMATING MISCIBILITY PRESSURE [26]

Miscibility Pressure Versus Oil Gravity

Gravity, °API	Miscibility pressure, psi
27	4,000
27-30	3,000
30	1,200

Correction for Reservoir Temperature

Temperature (°F)	Additional pressure required, psi
120	None
120-150	200
150-200	350
200-250	500

> The mechanism of miscibility development is related directly to the phase equilibria of the CO_2/reservoir-fluid system. When temperatures and pressures are high, the mechanism is one of vaporization. . . . If, at the same pressure level, the temperatures are relatively low, the mechanism is described more correctly by condensation . . . of CO_2 into the oil phase [56].

The authors conclude that more research is needed before a better understanding of the CO_2 multiple-contact miscible process can be formulated.

Work designed to identify on a more pragmatic basis the conditions under which miscibility between CO_2 and reservoir oil could be attained has proceeded in parallel with the efforts, discussed above, to understand CO_2 miscible displacement from first principles. This work generally allowed prediction of the pressure required to achieve miscibility of CO_2 with oil when certain other data were available. A correlation presented by Holm and Josendal [39,62] is shown in Fig. 40. To use this correlation, the molecular weight of the C_{5+} fraction of the reservoir oil and reservoir temperature must be known. It can be seen that, for any given molecular weight C_{5+} fraction, miscibility pressure increases at higher temperatures. The correlation also indicates that higher pressures are required to attain miscibility with heavier oils at any given temperature. A second method of estimating miscibility pressure was used in a study published by the National Petroleum Council [26]. This method appeared in tabular form and is reproduced as Table II-8. Yellig and Metcalfe have recently published a correlation that, on the basis of their comparative data, seems to predict miscibility pressure with more statistical accuracy than the two earlier methods [63]. This correlation and the methods by which it was developed are discussed in more detail in the following paragraphs.

In common with other investigators [17,39,51,54,55], Yellig and Metcalfe observed that recovery of in-place oil by CO_2 displacement from an experimental sand pack was a function of pressure until an observable "high" pressure level was reached, at which point recovery approached 100 percent of oil in place. Typical experimental data are shown in Fig. 41. The pressure at which the recovery versus pressure curve breaks over (1350± psi, Fig. 41) is the CO_2 "minimum miscibility pressure" (MMP) as defined by the authors.

The effect of temperature on experimental determinations of MMP is illustrated in Fig. 42. It can be seen that for oil of a given composition MMP increases as system temperature increases. This effect was also shown by Holm and Josendal (see Fig. 40) [39]. Experiments conducted with a variety of oils ranging from "heavy" to "light" indicated that minimum miscibility pressure was only slightly dependent on composition. The experimental data supporting this observation are shown in Fig. 43. The authors observed that "considering the temperature and compositional variations in this study, it is likely that both condensation and vaporization displacement mechanisms were encountered in these tests" [39].

From these data a correlation was developed that can be used to predict minimum miscibility pressure for CO_2 displacement. This correlation, given in Fig. 44, indicates that MMP is a quasi-linear function of reservoir temperature. The authors noted that the correlation was reasonably accurate when applied to oils having saturation (bubble-point) pressures lower than MMP but was less accurate when the saturation pressure of the oil was greater than predicted MMP, which may reflect compositional effects not present in the synthetic experimental oils. Hence, the recommended procedure for using Fig. 44 is:

(1) Determine MMP as a function of temperature alone;
(2) If MMP is less than the bubble-point pressure of the oil, take MMP to be equal to bubble-point pressure.

This procedure helped to eliminate inaccuracies in comparing data from the correlation with experimental miscibility pressure data. Data comparing the predictive accuracy of this correlation with similar determinations using earlier methods [26,39] are shown in Figs. 45 through 47.

This correlation can be used for a screening-type estimate of minimum miscibility pressure. However, for serious project planning, experimental determinations of miscibility using actual recombined reservoir oil and actual injection gas (which may contain small fractions of methane, nitrogen, etc.) are prudent engineering practice. Investigations have shown that higher pressure is required to achieve miscible recovery when the injected CO_2 is contaminated with methane or nitrogen [17,39] but may decrease if the contaminants are hydrogen sulfide or hydrocarbons in the C_2 to C_{6+} range [26]. Field-source CO_2 gas commonly contains small amounts of contaminants that cannot be economically separated. Hence, laboratory results using reagent-grade CO_2 may be misleading, even if actual recombined reservoir oil is used to determine miscible displacement behavior.

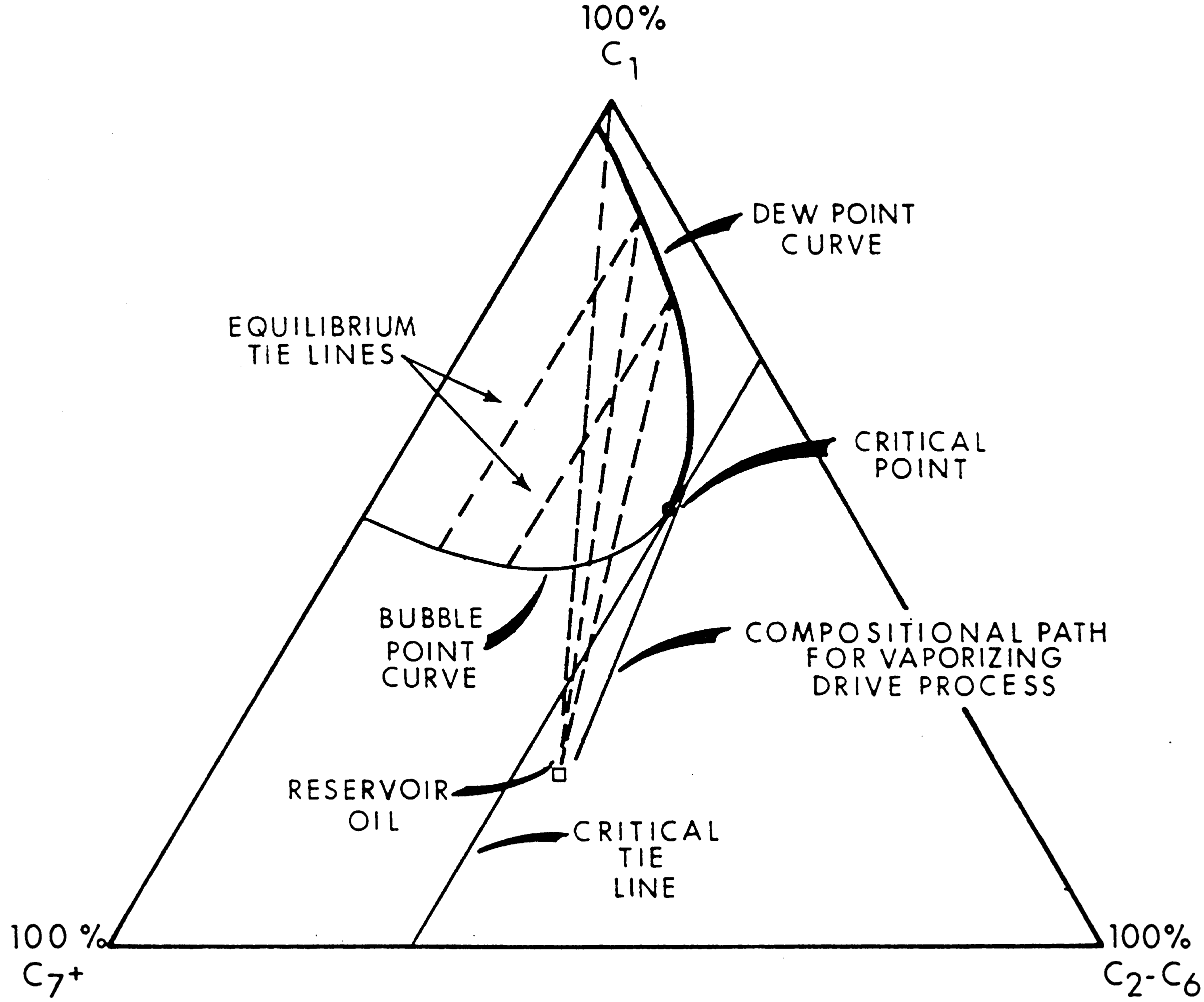


Figure 38.--Ternary phase diagram illustrating multiple-contact miscibility by vaporization.

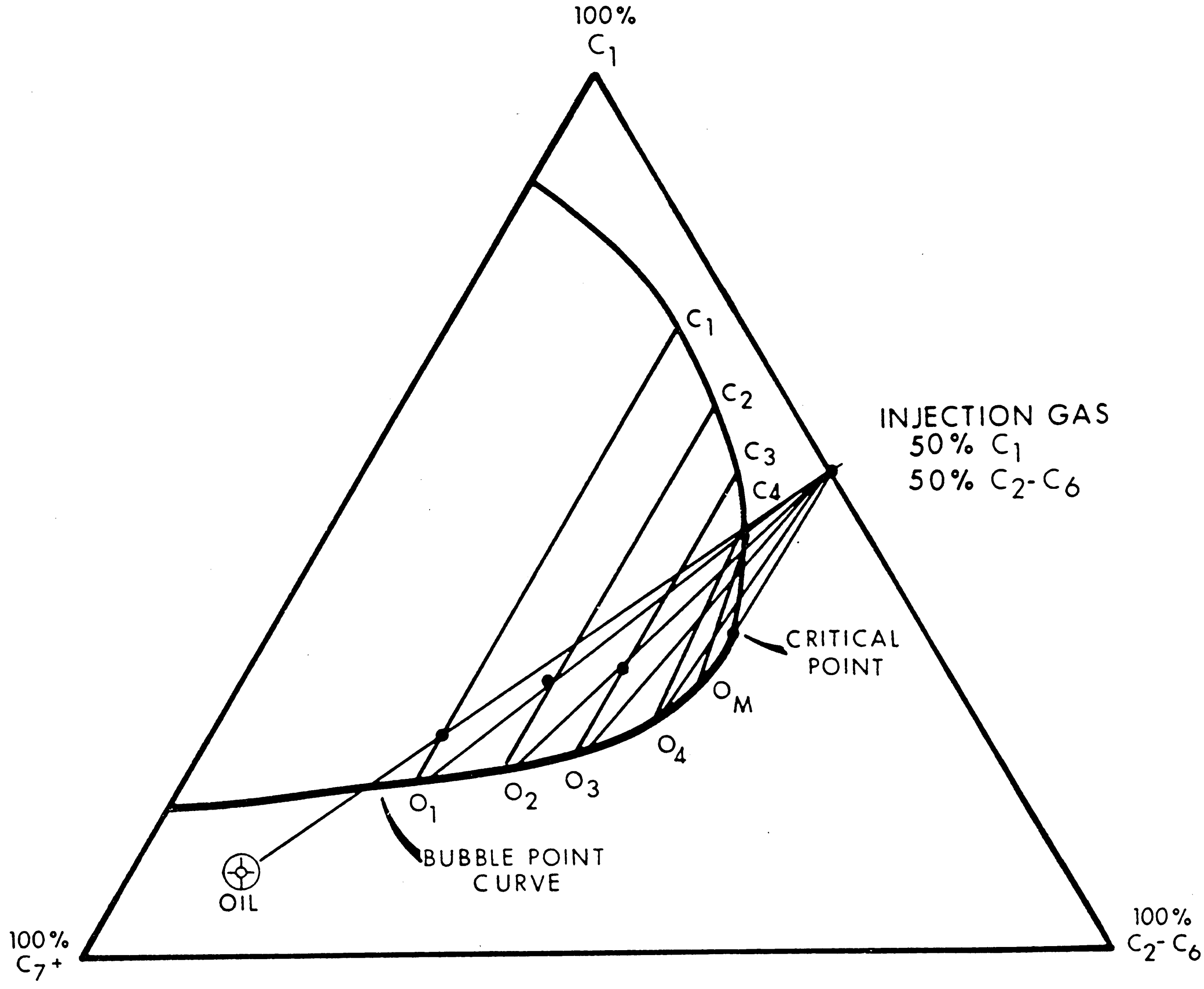


Figure 39.--Ternary phase diagram illustrating multiple-contact miscibility by condensation.

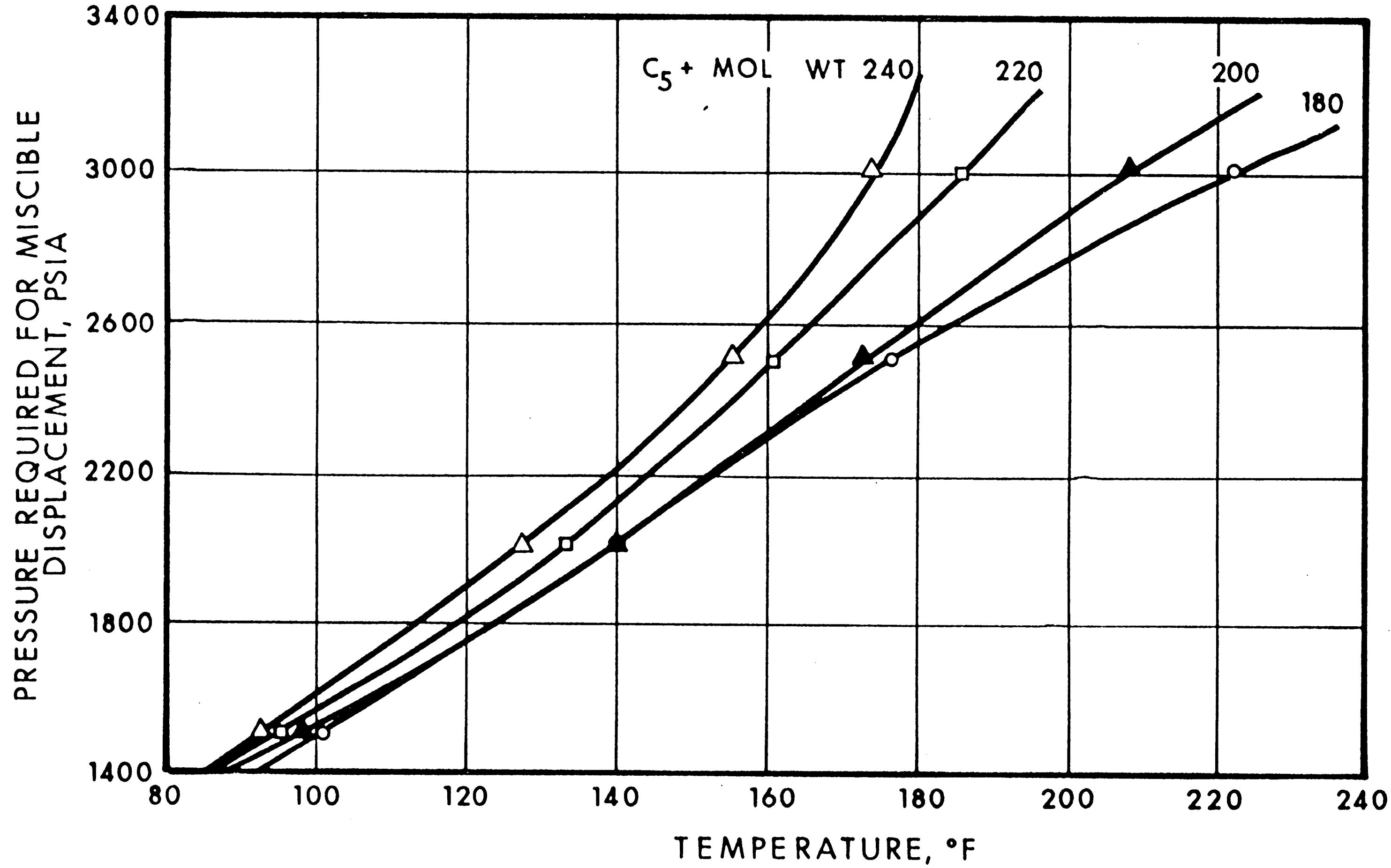
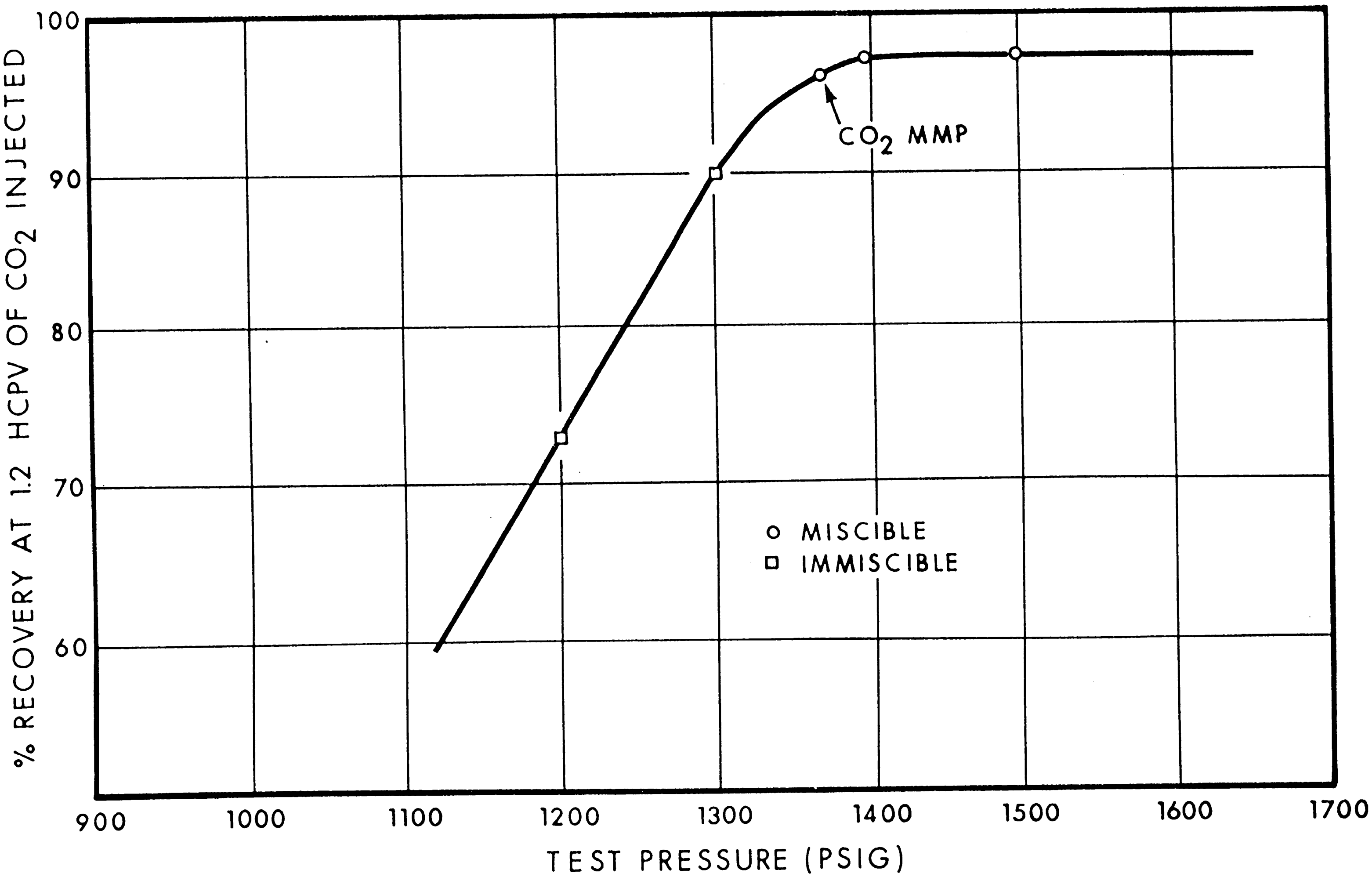


Figure 40.--Correlation for predicting pressure required for miscibile displacement in carbon dioxide flooding for a 59% methane-41% propane displacing fluid (from Holm and Josendal [39]).



TEST RESULTS FOR FIXED OIL COMPOSTION AND FIXED TEMPERATURE.

Figure 41.--Experimental data illustrating concept of CO_2 minimum miscibility pressure (MMP) (from Yellig and Metcalfe [63]).

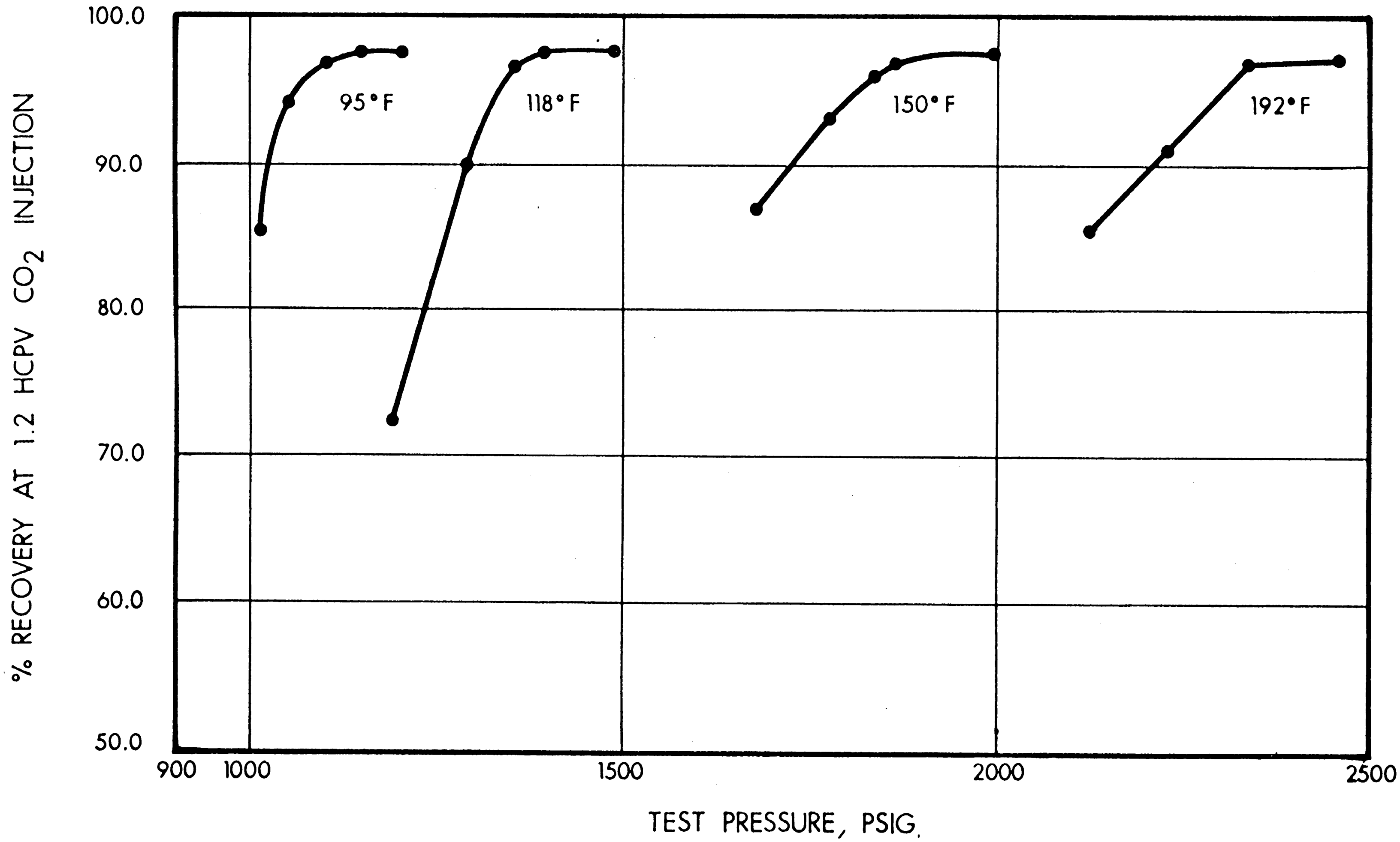


Figure 42.--Effect of temperature on CO_2 minimum miscibility pressure for oil of fixed composition (from Yellig and Metcalfe [63]).

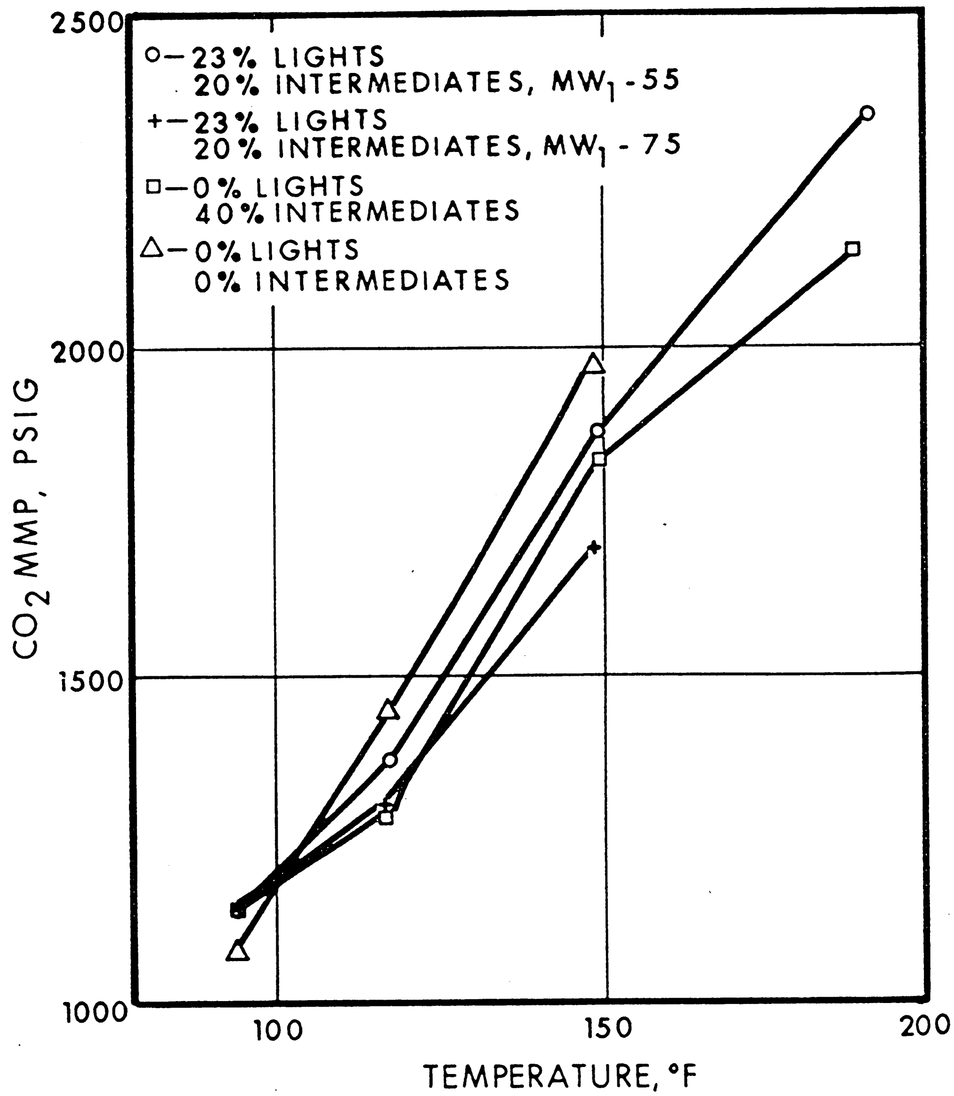


Figure 43.--Effects of oil composition and temperature on CO_2 minimum miscibility pressure (from Yellig and Metcalfe [63]).

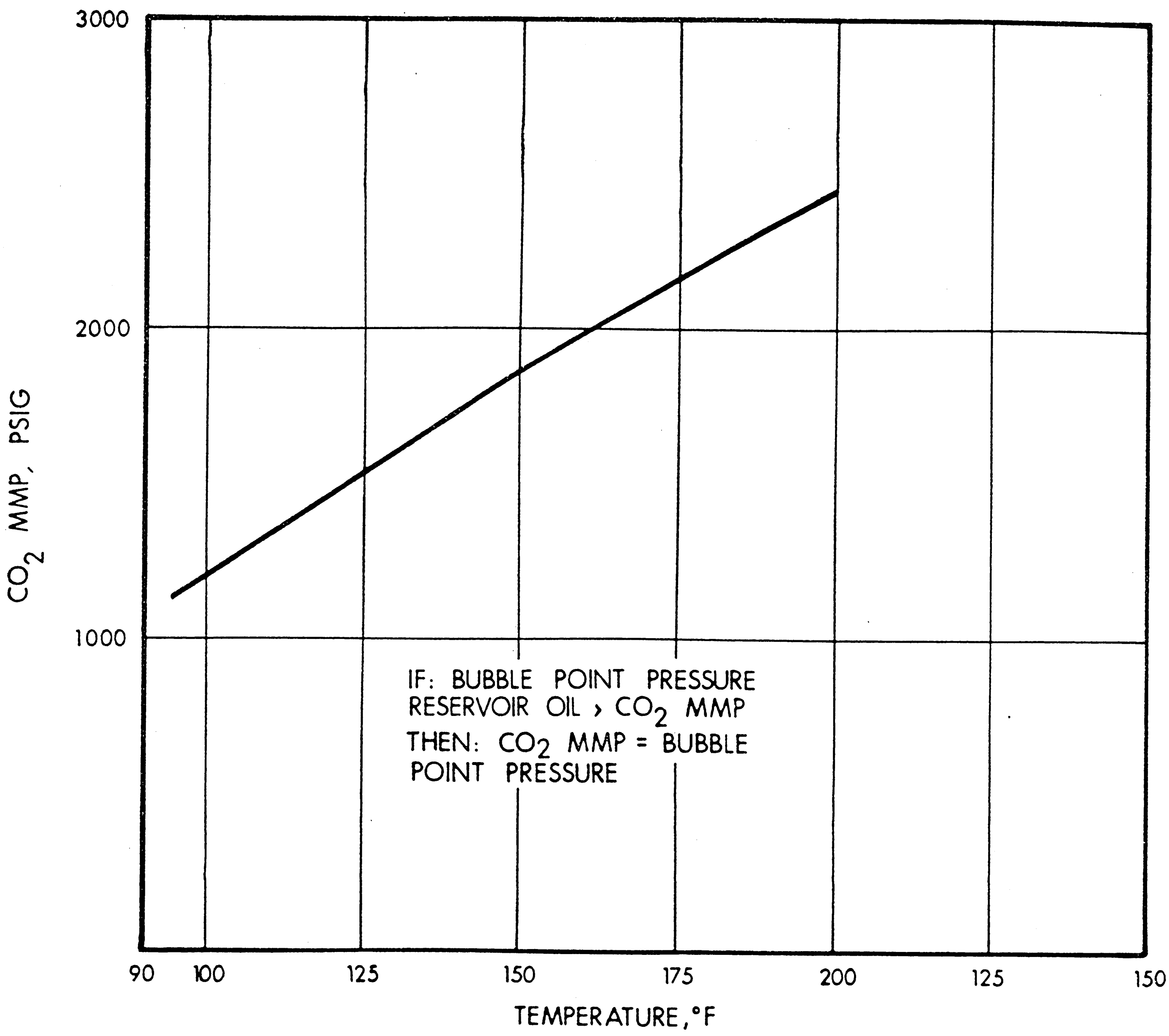


Figure 44.--Temperature-bubble-point pressure correlation for predicting CO_2 minimum miscibility pressure (from Yellig and Metcalfe [63]).

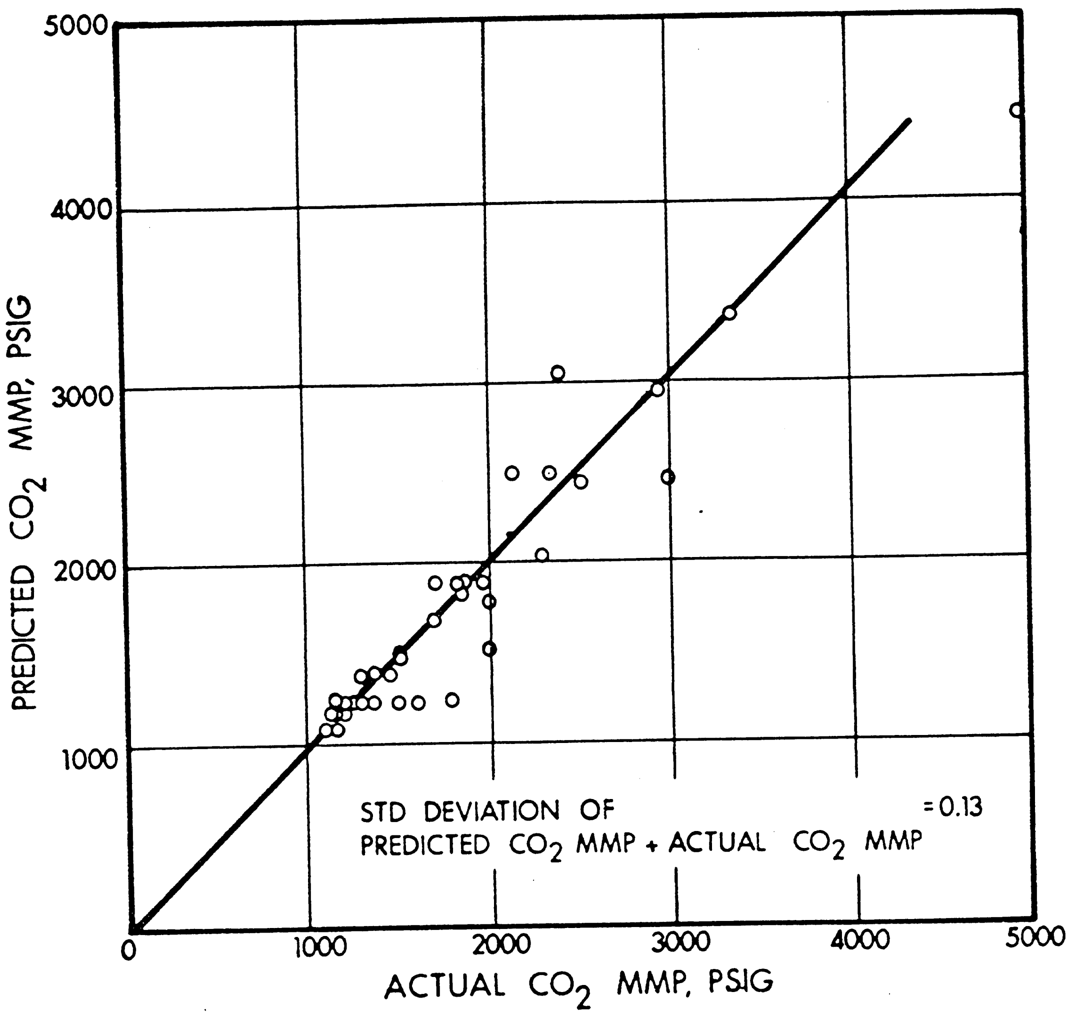


Figure 45.--Accuracy of temperature-bubble-point pressure correlation for predicting CO_2 minimum miscibility pressure (from Yellig and Metcalfe [63]).

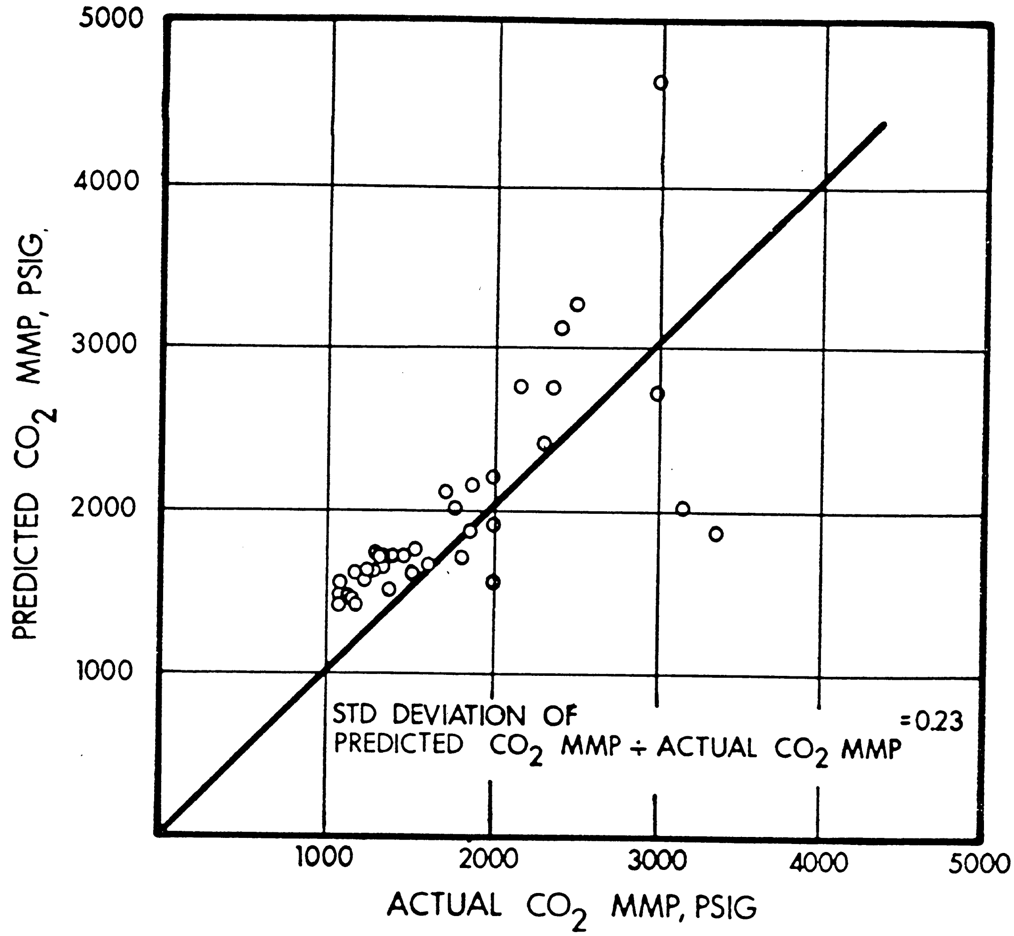


Figure 46.--Accuracy of Holm and Josendal correlation for predicting CO_2 minimum miscibility pressure (from Yellig and Metcalfe [63]).

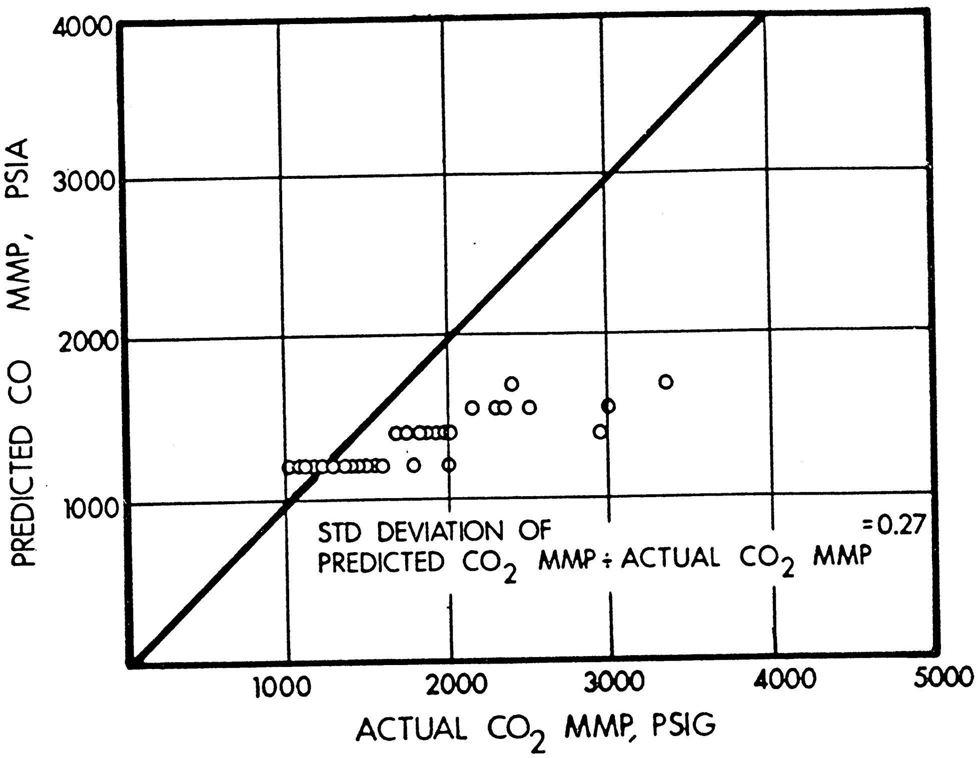


Figure 47.--Accuracy of NPC correlation for predicting CO_2 minimum miscibility pressure (from Yellig and Metcalfe [63]).

Displacement/Extraction Processes in Porous Materials

A number of studies have been published reporting experimental data from displacements of various oils through porous materials by CO_2. Some studies using core material containing 100 percent oil saturation provide insights into the miscible displacement mechanisms involved and suggest such conclusions as:

> "1. The use of CO_2 in displacements of reservoirs where miscibility may be developed by the high-pressure gas process offers the advantage of much lower displacement pressure than with methane.
>
> "2. Immiscible displacements by CO_2 may yield very efficient recovery of oil by vaporization and swelling of the heavy ends. . . ." [51]

Later work, discussed in the preceding section, concluded that:

> "1. More than one mechanism is possible for miscible CO_2 displacement of hydrocarbon systems.
>
> "2. Reservoir temperature and displacement pressure (insofar as they fix CO_2-oil phase equilibria) determine which mechanism will control the displacement." [56]

Other displacement experiments, in which immobile or mobile water saturations were present, are discussed in the following paragraphs.

Experimental data published by Holm clearly show the efficacy of CO_2 as an enhanced oil recovery agent [3]. Typical results of a displacement in a Berea sandstone core by injecting a CO_2 slug followed by carbonated water are shown in Fig. 48.* Data from a similar experiment conducted in McCook dolomite are shown in Fig. 49.

In these experiments, the cores were first saturated with water and then flooded with oil at the desired pressure and temperature. This procedure resulted in oil saturations ranging from 53 to 57 percent of pore space. CO_2-slug/carbonated-water floods conducted at 1,700 psi at temperatures of 95°F and 130°F showed the high oil recoveries (96 and 92 percent of oil in place respectively) typical of miscible displacements. Floods conducted at lower pressures (1,000 to 1,370 psi) resulted in recoveries ranging from 78 to 89 percent of oil in place. Typical waterflood recoveries in these cores ranged from 33 to 41 percent of oil in place. These high recoveries indicated that considerable extraction of oil by CO_2 had taken place even though truly "miscible" conditions were not attained. Extraction of oil was confirmed by compositional observations in an experiment conducted at 1,300 psig and 125°F, which indicated that a bank of light hydrocarbons was formed between the driven oil and the injected carbon dioxide. Holm

*Figures 48 through 55 appear on pages 85 through 92.

characterized this phenomenon as "a retrograde vaporization of the lighter hydrocarbons into the CO_2 rich phase" [3]. Similar results were later reported for a series of CO_2 displacement experiments in slim-tube sand packs [39]. Results of these experiments are shown in Fig. 50, which also shows that high recoveries were attained from a CO_2 displacement conducted at 71°F and 1,250 psig. Data given earlier in Fig. 14B indicate that substantial extraction of the oil would occur at this temperature with pressures in excess of about 900 psig.

Results of a CO_2 displacement in a Berea core were reported by Shelton and Yarborough [54]. In this experiment, the core was saturated with recombined reservoir oil "B" (Table II-5, Fig. 36) and an immobile connate water phase. The experiment was conducted at 94°F and 1,450 psig and achieved 91 percent recovery of the oil in place. Sight-glass observations indicated that a CO_2-rich liquid phase and an oil-rich liquid phase formed in the core. A solid precipitate of black asphaltic material also formed. This experiment apparently confirmed that the phase behavior observed in equilibrium cell studies (discussed above) also occurs during displacement through porous material when water is present in the system.

These experimental data and other reports all indicate that CO_2 is an efficient agent for recovery of oil under "secondary" conditions of high oil saturation and immobile water saturation whether or not true miscibility is attained [16,17,64].

Experimental data have also been published in which CO_2 was used to displace residual oil left by waterflooding of cores, a "tertiary" recovery process. An example of the data from this type of core experiment is shown in Fig. 51 [17]. In this experiment, continuous injection of 0.75 pore volume of CO_2 resulted in 90 percent recovery of residual oil.

Figure 52 shows data presented by Huang and Tracht for a continuous CO_2 drive of a Berea core that had been waterflooded to immobile residual oil saturation [55]. This experiment was performed for reservoir conditions of 90°F and 1,250 psig with a waterflood-residual oil saturation of 38.5 percent. Oil production began after injection of 0.23 pore volume of CO_2 and CO_2 production started at an injection of 0.35 pore volume. After CO_2 breakthrough, the produced oil changed from dark brown (35°API) to light yellow (40°API) near the end of injection. Oil recovery was 68.9 percent of in-place residual oil saturation. Data from a suite of similar experiments are shown in Fig. 53; the experimental results are listed in Table II-9. These data also illustrate the effect of the size of a water-driven CO_2 slug on ultimate recovery. In this core, optimum slug size was indicated to be 0.42 pore volume. Smaller slugs gave lower recovery, as shown in Fig. 53. On the basis of equilibrium cell studies, CO_2 was immiscible with the residual oil at the pressure and temperature of the experiments. Despite this, considerable recovery of waterflood-residual oil was achieved by swelling and extraction of hydrocarbons in place and possibly by the effects of low interfacial tension between equilibrium phases of the CO_2-hydrocarbon mixtures [64]. Similar results were reported by Kumar and Von Gonten for a series of experiments in Berea cores, in which CO_2 was also immiscible at experimental conditions [65].

TABLE II-9

CO_2 DISPLACEMENT TESTS IN WATERFLOODED BEREA SANDSTONE CORES

(From Huang and Tracht, reference 55)

Run No.	Solvent	Solvent Slug Size, % PV	Driving Fluid	Residual Water Sat., % PV	Residual Oil Sat. (S_{or}), % PV	Ultimate Oil Rec., % of S_{or}	Oil Rec. at 1 PV Inj., % of S_{or}
(I) Berea Cores:							
1-2	CO_2	74.0	None	39.4	38.6	69.4	-
1-9	CO_2	81.5	None	39.8	38.5	68.9	-
1-4	CO_2	40.0	H_2O	39.2	38.6	67.0	-
1-5	CO_2	33.0	H_2O	39.7	38.5	59.4	-
1-1	CO_2	25.4	H_2O	41.3	34.8	48.8	-

Properties of Berea Core No. 1:

Length	6 ft
Diameter	2 in.
Porosity	23.6%
Permeability	470 md

Laboratory studies have shown that oil may be isolated from contact with a displacing "solvent" like CO_2 by the presence of mobile water; thus it may remain trapped during a tertiary displacement [66-68]. Studies using cores have shown that most of the residual oil left by waterflood can be initially isolated or trapped. Typical data demonstrating this are shown in Figs. 54 and 55. The effect is more pronounced in rocks strongly wet by water. The trapped oil can eventually be displaced by molecular diffusion between CO_2 and the oil after passage of the displacing fluid front. However, both mathematical [67] and experimental [68] data suggest that the phenomenon is probably significant only in laboratory core experiments, where contact time between fluids is generally small compared to field-scale displacement rates and contact times. Hence, trapping may not be significant in field projects.

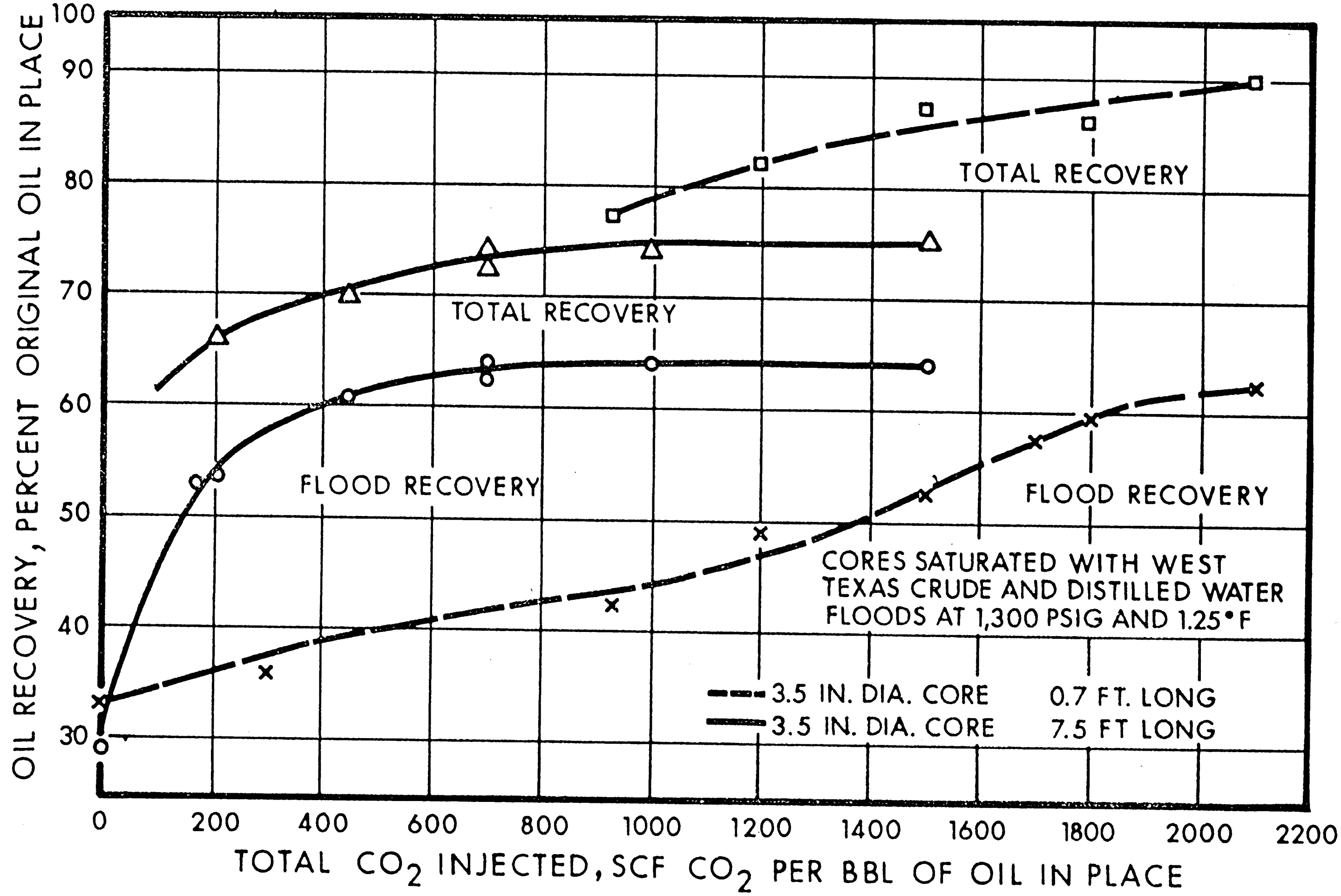


Figure 48.--Oil recovery vs. total CO_2 injection using CO_2 slug-carbonated water floods in Berea sandstone (from Holm [3]).

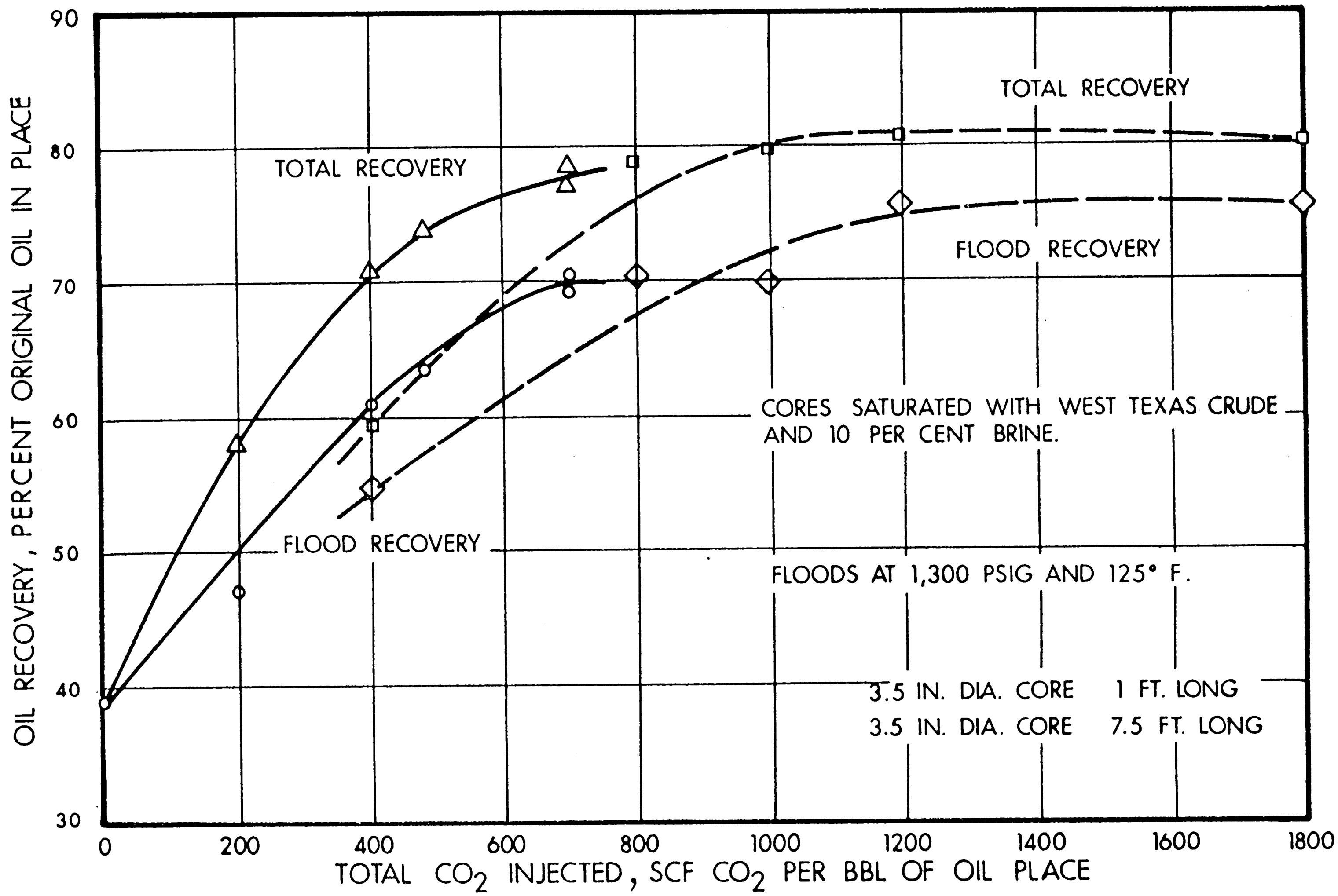


Figure 49.--Oil recovery vs. total CO_2 injection using CO_2 slug-carbonated water floods in vugular dolomite (from Holm [3]).

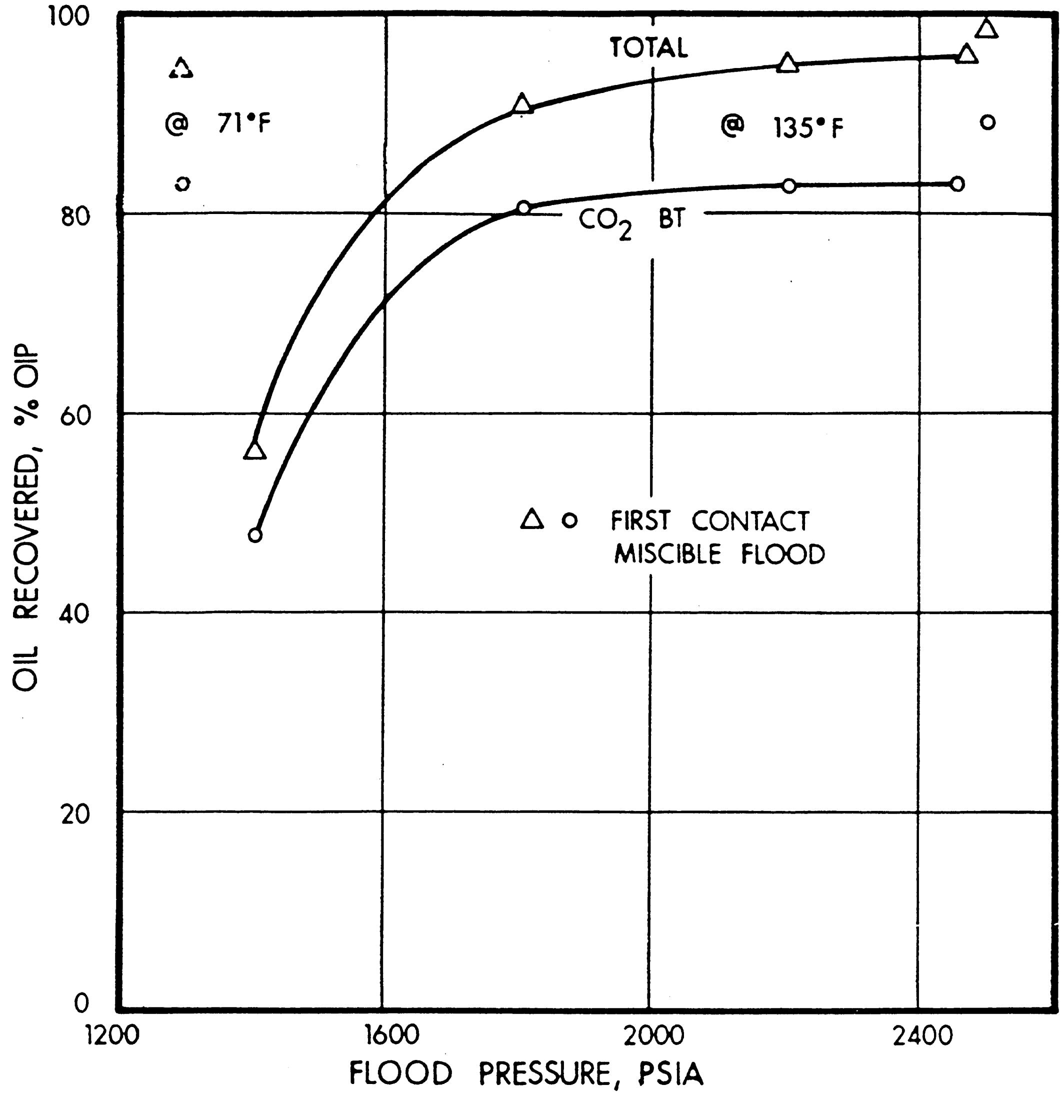


Figure 50.--Oil recovered from CO_2 floods of 48-ft sand pack containing Mead-Strawn stock tank oil (from Holm and Josendal [39]).

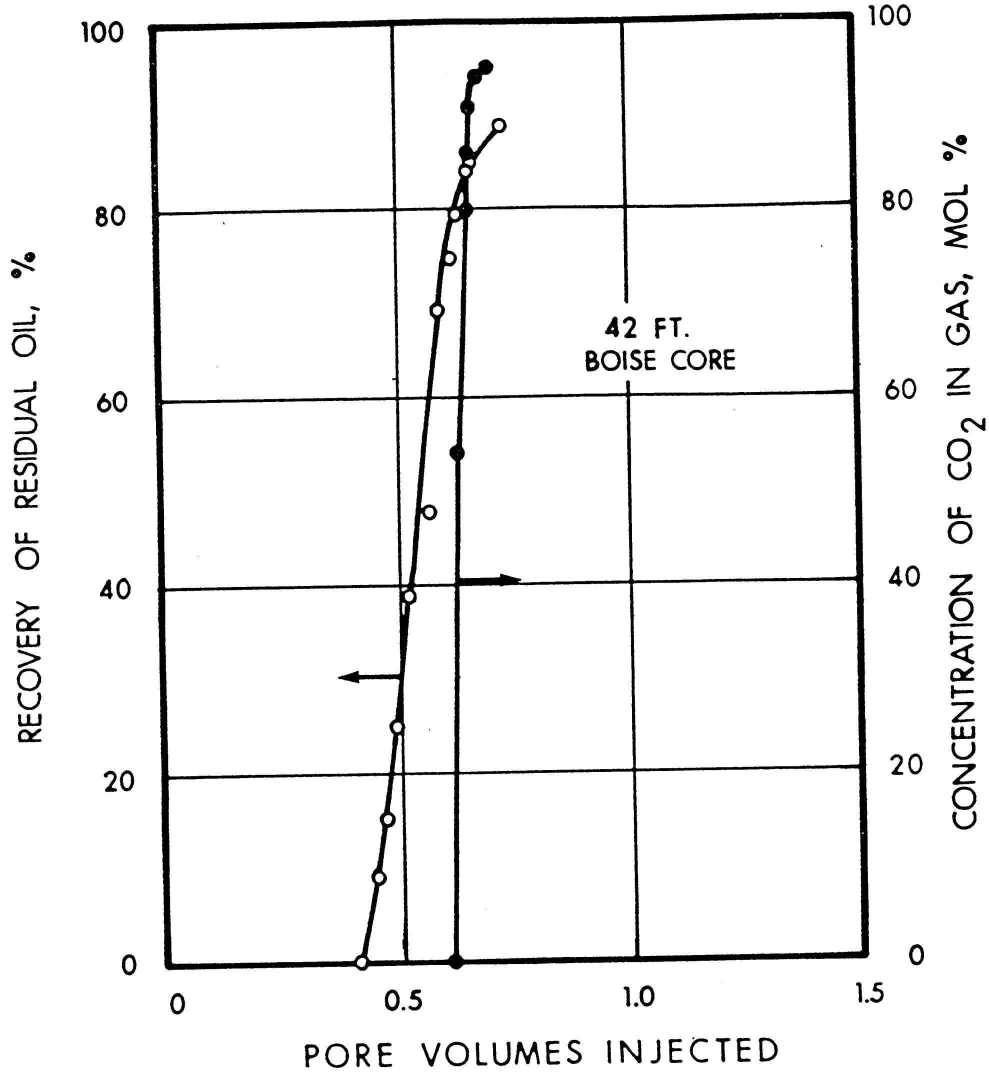


Figure 51.--Recovery of residual oil by continuous injection of CO_2 (from Stalkup [17]).

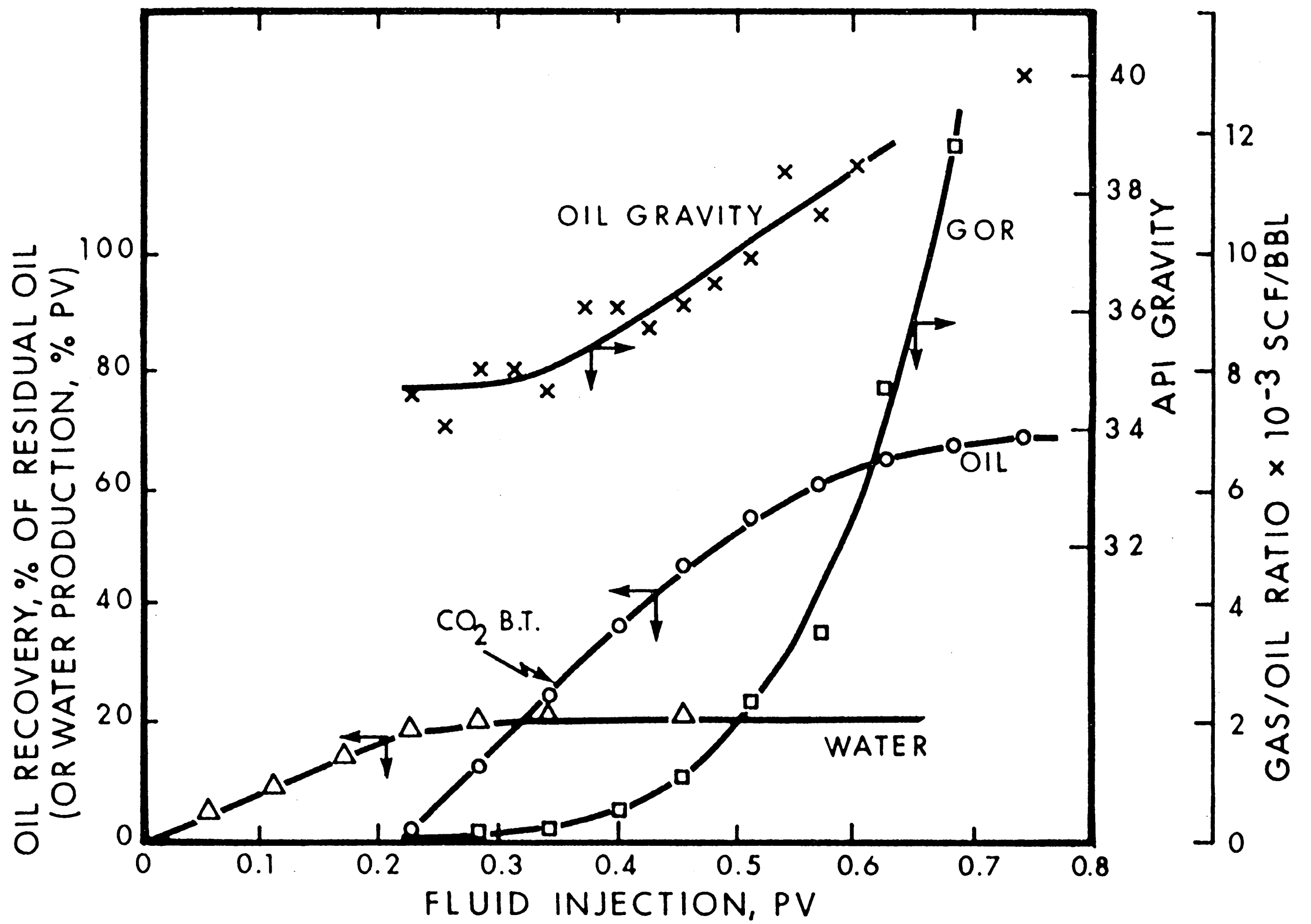


Figure 52.--Production history for a continuous CO_2 drive in a waterflooded Berea core (from Huang and Tracht [55]).

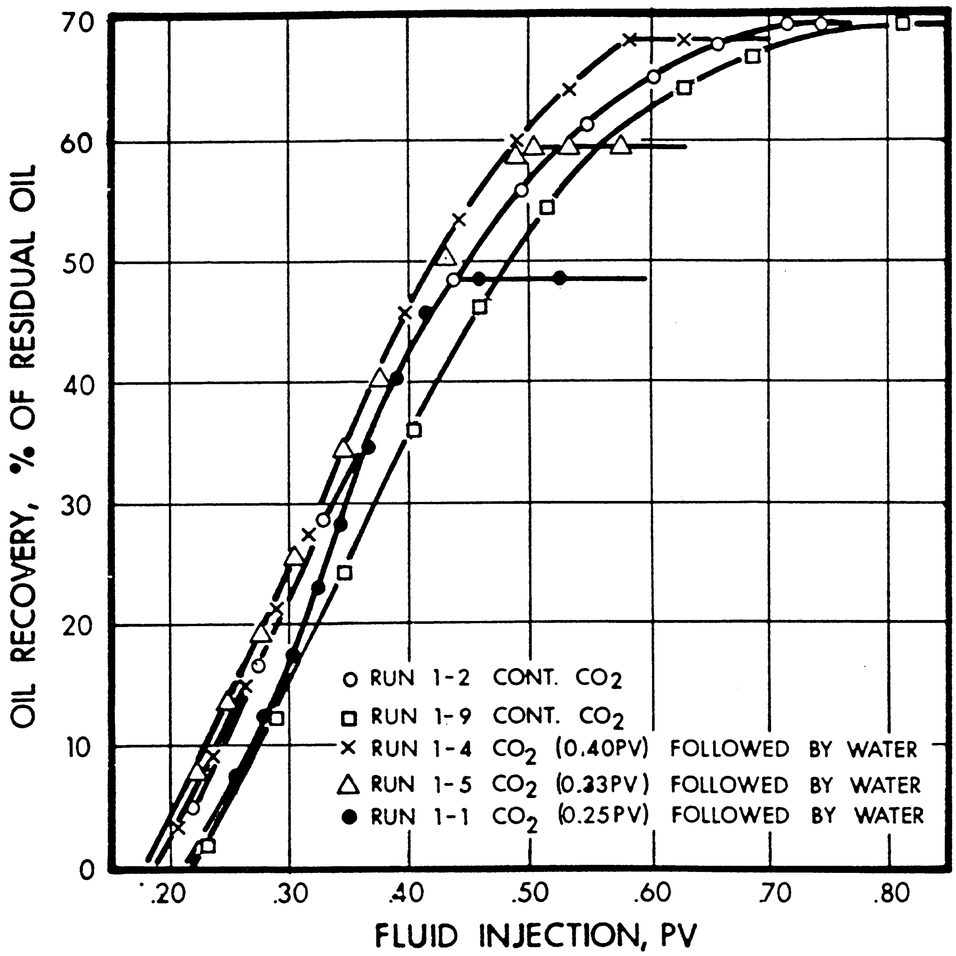


Figure 53.--CO_2 flooding of waterflooded Berea cores (from Huang and Tracht [55]).

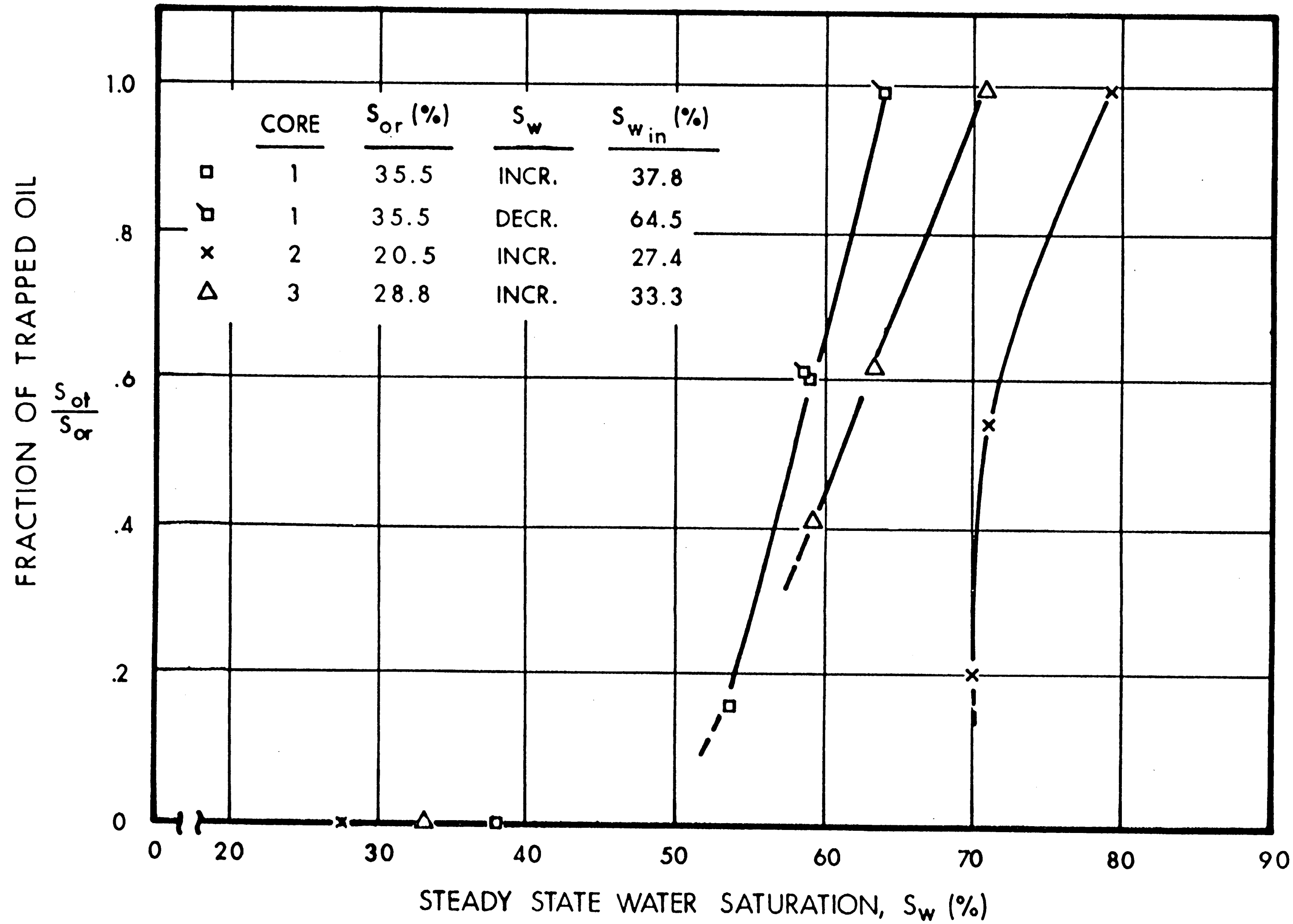


Figure 54.--Oil trapped on imbibition as a function of water saturation (from Raimondi and Torcaso [66]).

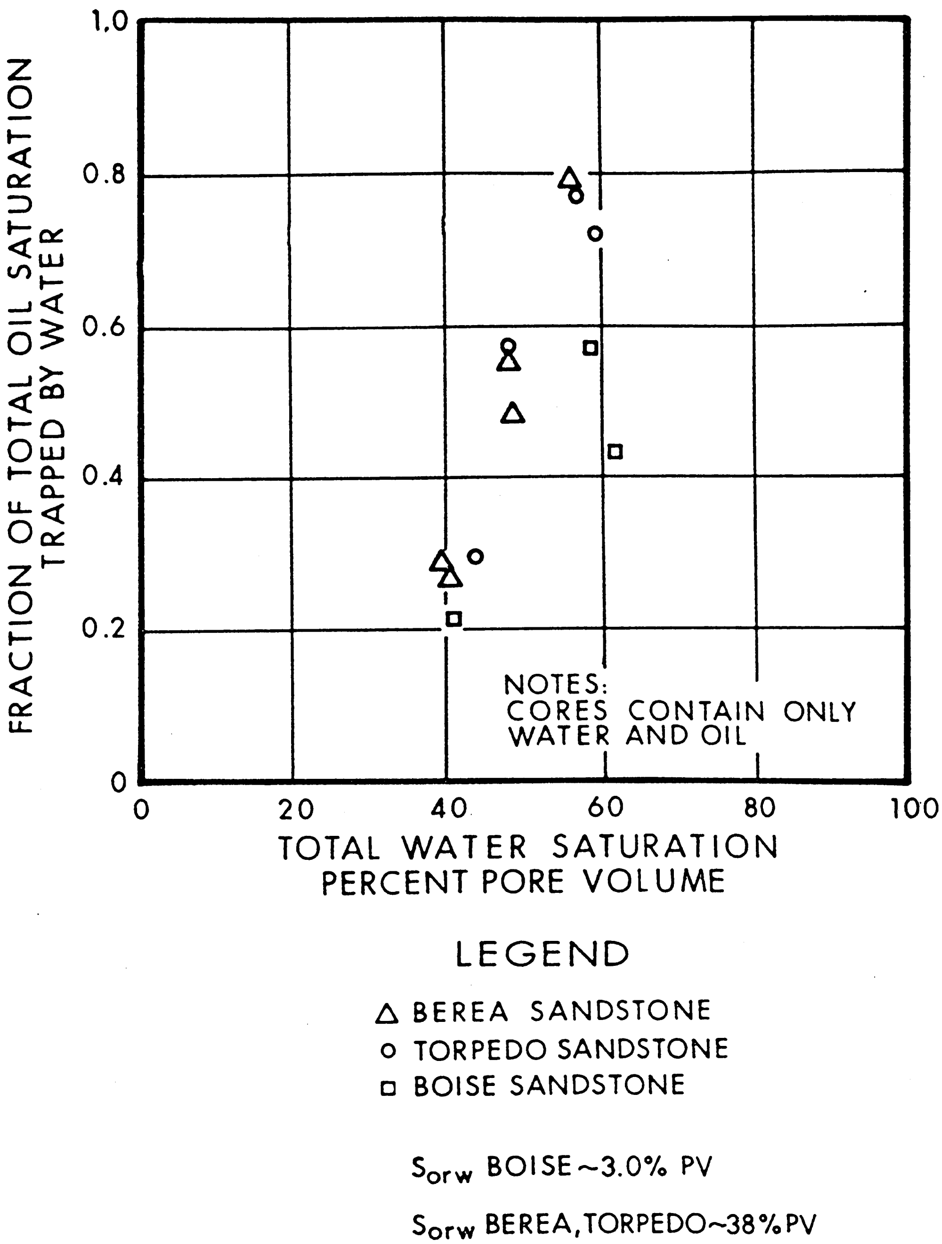


Figure 55.--Trapping of oil by mobile water (from Stalkup [17]).

III. APPLICATION OF THEORY TO FIELD PROJECT DESIGN

The previous chapter dealt in detail with the aspects of CO_2 flooding that seem unique to that process and need to be considered in field project design. These considerations need to be integrated with the other aspects of displacement project design that are common to most or all processes. Hence, a design model should provide for evaluating the effects of such factors as:

(1) Well configurations or patterns,
(2) Geologic and petrophysical data,
(3) Reservoir fluid properties,
(4) Viscous and gravitational instabilities, and
(5) Operating strategies

on the expected performance of the project.

Basic Considerations

The effects on project performance of well configuration, geologic and petrophysical data, and fluid properties have been studied in detail by many investigators for application in conventional waterflooding or gas injection. It is presumed that the reader is familiar with or has access to some of the standard works dealing with these subjects [69,70]. Since these contain extensive references for further study, this report will not discuss these aspects of field project design further.

Viscous instabilities may occur in a displacement process when the displacing fluid is more mobile than the displaced fluid. This has been demonstrated experimentally [71,72] and studied theoretically [73,74] for unfavorable mobility (immiscible) displacement of oil by water. The instability is manifested by "fingers" of displacing fluid which advance ahead of the displacing fluid front. This results in early breakthrough of the displacing fluid, with attendant lower sweep efficiency. The tendency to develop viscous fingers during displacement and the relative growth rate of the fingers compared to the main displacing fluid front increase as the mobility contrast increases [75]. The same phenomenon occurs in miscible displacements [76], although finger growth may be somewhat dampened by dispersion between the miscible phases [77,78].

Viscous fingering is clearly shown in laboratory model experiments, as illustrated in Fig. 56.* This series of miscible experiments was run in a parallel-plate model representing a symmetry element of a five-spot pattern and containing porous material [79]. The effect of increased displacing fluid mobility ratio (M) on the intensity of finger growth is evident. The impact of this on breakthrough sweep efficiency is shown in Fig. 57.

*Figures 56 and 57 appear on pages 96 and 97.

Gravitational instabilities are also possible in displacements where the displacing and displaced fluids have different densities. If the displacing fluid is lighter, it tends to unstably override the system, resulting in early breakthrough and low sweep efficiencies. The reverse phenomenon, gravity underrunning, occurs when the displacing fluid is heavier. Studies of these gravitational instabilities indicate that adverse effects in dipping reservoirs can be minimized if a critical balance of viscous to gravitational forces is not exceeded [80-82]. This has application to miscible displacements in reservoirs with sufficient dip to permit injection at practical rates that do not exceed the critical rate needed to maintain stability.

Design Models

(Note: The following paragraph is, by intent, a superficial summary of design models. It is intended to provide the uninitiated reader with a starting place to obtain further information from the voluminous reference material available.)

A variety of mathematical models for predicting the performance of miscible floods has been developed. The simplest of these [83,84] provide a relatively quick hand-calculation means of appraising the impact of process variables, such as mobility ratio, on expected performance. However, they are confined to simple geometries and can be related to time only by assumptions regarding injection rates and the tacit assumption of incompressible or steady-state flow. In general, reservoir simulation studies using special computer programs are necessary to obtain more comprehensive predictions and evaluations [85,86]. A recent paper reviews the requirements a simulator model of the CO_2 flooding process must satisfy if the important complexities of the process are to be considered, and concludes that none of the models known to be currently in use entirely satisfies these requirements [87].

Application in Project Design

The North Cross (Devonian) Unit CO_2 injection project in the Crossett field of West Texas provides a well documented example of the use of simulation model studies in field project design [88,89]. These studies used a miscible version of a black-oil simulator to design an optimum injection well pattern and operating strategy [90]. Later studies, conducted after the project had been operating for four years, indicated that CO_2 project performance could be history-matched by using appropriate simulator revisions and techniques [91,92].

A similar black-oil simulator has been used to evaluate the potential for full-scale CO_2 flooding of the Willard unit of the Wasson field in west Texas [93]. This was done by history-matching the data from a CO_2 injection mini-test and projecting these results to full scale using a representative average symmetry element to describe the reservoir.

Incompressible-fluid simulation model studies using layered symmetry elements were used to design and evaluate alternatives to improving recovery of the SACROC unit in the Kelly-Snyder field in west Texas [94]. These studies indicated that an inverted nine-spot pattern into which alternating slugs of CO_2 and water were injected would be the most effective method of improving recovery. After project implementation in 1972, studies using a compositional simulator were useful in adjusting operating practices to improve flood performance [95,96].

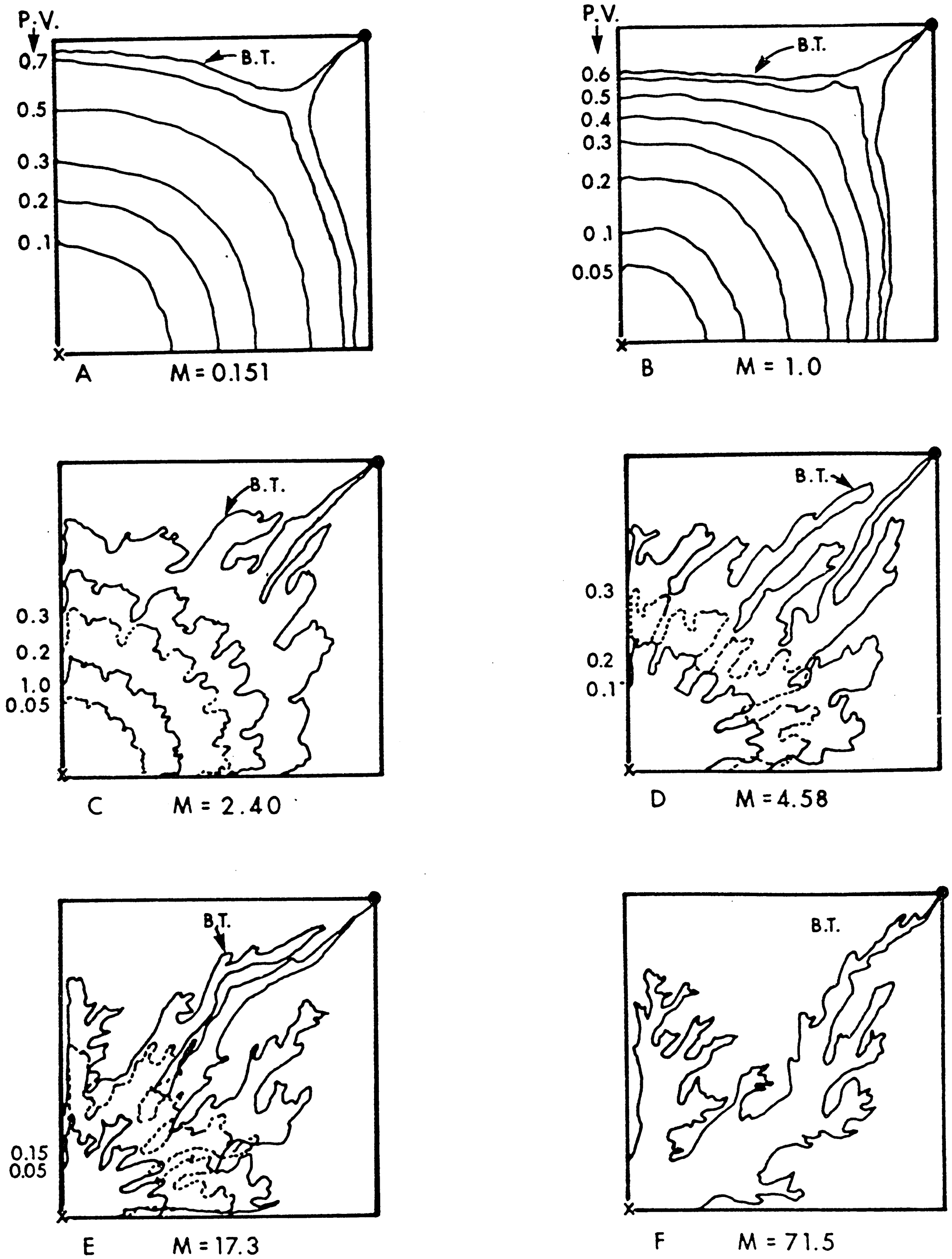


Figure 56.--Displacement fronts for different mobility ratios and injected pore volumes until breakthrough. Each figure is one quarter of a five-spot (from Habermann [79]).

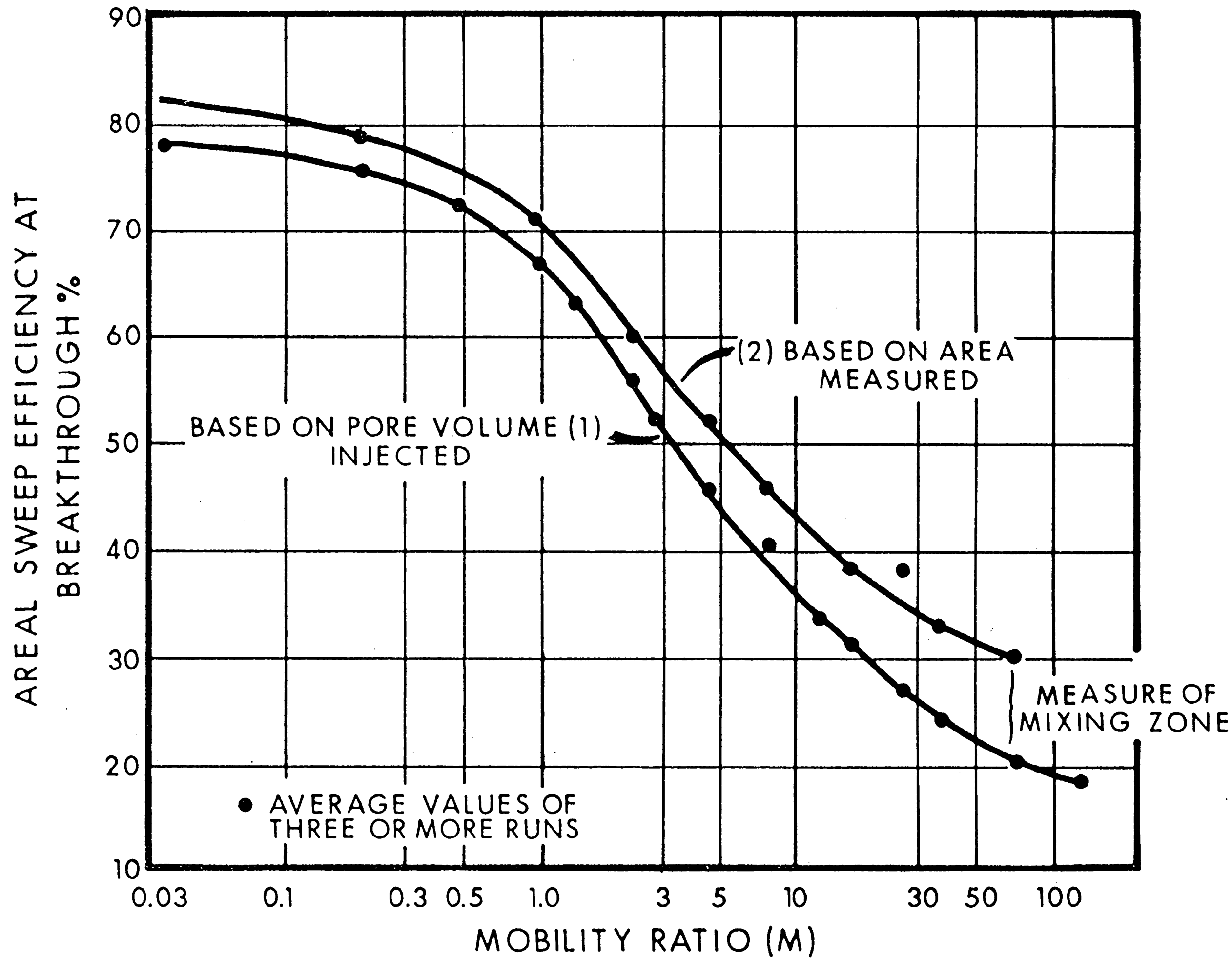


Figure 57.--Breakthrough sweep efficiencies and a measure of mixing zone for two-zone displacements in a five-spot (from Habermann [79]).

IV. SUMMARY AND SYNTHESIS OF CO_2 FIELD TEST DATA

As mentioned in the Introduction, information was compiled from published reports and other public records for CO_2 injection projects in 16 oil fields. From this information, reports were prepared in as much detail as the reference material allowed for each project. These reports are included in the Appendix (Volume 2) to this report.

Basic data for these projects are summarized in Table IV-1. Full-scale, commercial-intent projects have been undertaken in seven fields: three in West Texas, two on the Gulf Coast, and two in Arkansas. Only two of these projects are in carbonate reservoirs; the rest are in sandstone reservoirs. In addition, 12 tertiary pilot projects have been or are being conducted in 9 fields. Of these 12 projects, 8 are in 6 fields in west Texas, 3 are in West Virginia, and 1 is in Mississippi. Seven of the eight west Texas projects are in carbonate reservoirs. All the rest are in sandstone reservoirs.

The preponderance of projects, both full-scale and pilot, in West Texas (Fig. 58) should be no surprise. Source CO_2 in large quantities has long been available in the region as a by-product of natural gas processing, a fact which encouraged early application. In addition, the region contains many large fields in which waterflooding, while efficient and commercial, would leave hundreds of millions of barrels of residual oil as a target for tertiary recovery [22]. It is encouraging to note that CO_2 projects are being conducted in 5 of the 18 fields listed by these authors as candidates for CO_2 flooding (Table IV-2).

Table IV-1 shows that CO_2 injection has been done at depths ranging from 2,100 to 12,700 feet and over a reservoir temperature range from 74°F to 248°F. Projects have been conducted in fields having stock-tank oil gravities ranging from 15° to 45°API. Data from virtually all of these projects demonstrate that CO_2 is technically (as distinguished from economically) capable of displacing oil from underground reservoir rocks over this entire range of physical conditions. The data for these projects may be compared with various guidelines for applicability, such as:

Guideline	NPC [26]	Gruy Contract [32,33]
Oil gravity - greater than:	27° API	36° API
Oil viscosity - less than:	10 cp	10 cp
Depth - greater than:	2300 feet	Unspecified
Temperature - less than:	250°F	Unspecified

This is discussed in more detail in the project summary discussions that follow. (Note: These discussions assume that the reader has digested or will refer as necessary to the detailed field reports with the related reference lists contained in the Appendix, Volume 2.)

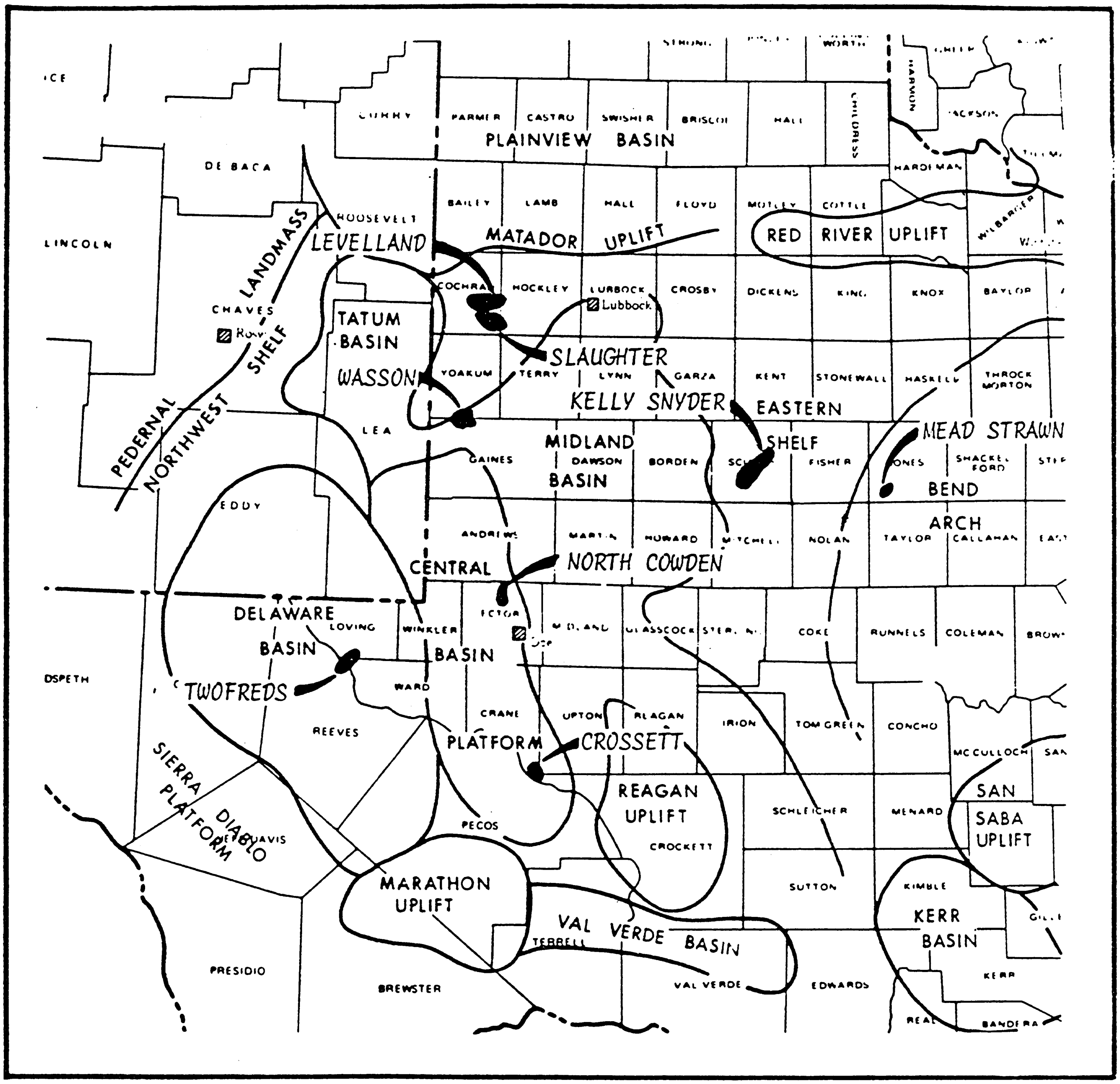


Figure 58.--Carbon dioxide projects in west Texas.

TABLE IV-1

SUMMARY OF DATA FOR PAST AND ONGOING CO_2 INJECTION FIELD PROJECTS

FULL-SCALE PROJECTS

FIELD / STATE OR REGION			CROSSETT (NORTH CROSS) WEST TEX.	LICK CREEK ARK.	KELLY SNYDER(SACROC) WEST TEX.	RITCHEY ARK.	SOUTH GILLOCK TEX. GULF COAST	TWOFREDS WEST TEX.	WEEKS ISLAND LA. GULF COAST
RESERVOIR NAME			DEVONIAN	MEAKIN	CANYON REEF	BAKER	FRIO	BELL CANYON	"S" SAND
ROCK TYPE			CHERTY DOLO.	SANDSTONE	LIMESTONE	SANDSTONE	SANDSTONE	SANDSTONE	SANDSTONE
POROSITY %			22	33	3.9	30.7	29.5	19.5	26
PERMEABILITY md			3-5	1200	19.4	2800	1156	32	3500
INITIAL WATER SATUR. %			35	32	21.9	20	22.5	43.5	7
AVG. THICKNESS (NET PAY) FT.			96	12	139	9	39	25	250±
AVG. DEPTH FT.			5300	2500	6700	2600	9000	4820	12,700
RESERVOIR TEMP. °F			106	118	130	126	214	104	225
STOCK TANK OIL GRAV. °API			44	17	41.8	15-16	38	36	32
INITIAL RES. PRESS. PSIA			2328	1200	3137	1250	4354	2385	5100
BUBBLE POINT PRESS. PSIA			2328	85	1820	100sst.	4354	2285	5100
BUBBLE POINT OIL VISCOS. C'POISE			—	160	.38	195	.64	1.467	.34
FORMATION VOLUME FACTORS	INITIAL	VOL/VOL	1.986	1.05	—	1.05	1.585	1.179	1.7
	BUBBLE POINT	VOL/VOL	1.986	1.05	1.5	1.05	1.585	—	1.7
CO_2 MISC. PRESS. PSIA			1650a	?	1600a	?	?	2285b	5100b
PROJECT SIZE	AREA	ACRES	1120	900	51,000	220	5940	4392	5±
	NO. WELLS	PROD	19	38	305	15	30±	40	1
		INJ	9	16	659	1	6	22	1
TYPE PROJECT			SECONDARY	SECONDARY*	SECONDARY	TERTIARY	SECONDARY*	TERTIARY?	SECONDARY*
OPERATOR			SHELL	PHILLIPS	CHEVRON	U.S.O.R./ PHILLIPS	AMOCO	HNG	SHELL
START DATE			1972	1976	1972	1969	1971	1974	1978
PRESENT STATUS			ONGOING	ONGOING	ONGOING	RESUMED 1978	TERMINATED	ONGOING	ONGOING

a - LABORATORY MEASURED b - ESTIMATED FROM MMP CORRELATION * - AFTER NATURAL WATER DRIVE

TABLE IV-1 (CONT.)
PILOT PROJECTS

FIELD / STATE OR REGION	GRANNY'S CREEK WEST VA.	GRIFFITHSVILLE WEST VA.	LEVELLAND WEST TEX.	LITTLE CREEK MISS.	MEAD WEST TEX.	NORTH COWDEN WEST TEX.	ROCK CREEK WEST VA.	SLAUGHTER WEST TEX.	WASSON WEST TEX.			KELLY-SNYDER(SACROC) WEST TEX.
RESERVOIR NAME	BIG INJUN	BEREA	SAN ANDRES	TUSCALOOSA	STRAWN	GRAYBURG	BIG INJUN	SAN ANDRES	SAN ANDRES			CANYON REEF
ROCK TYPE	SANDSTONE	SANDSTONE	DOLOMITE	SANDSTONE	SANDSTONE	SDY.DOLO.	SANDSTONE	DOLOMITE	DOLOMITE			LIMESTONE
POROSITY %	18	11	11	23	9.4	9	21.7	10	8.5			3.9
PERMEABILITY md	2-4	14	3	90	12	5.3	19.3	8.1	3			19.4
INITIAL WATER SATUR. %	?	?	23.4	56	40	15	50+	13	15			21.9
AVG. THICKNESS (NET PAY) FT.	20	23	80	29	9	92	32	89	66			139
AVG. DEPTH FT.	2100	2350	4750	10,600	4500-4900	4400	2050	4950	5100			6700
RESERVOIR TEMP. °F	77	78	102	248	135	94	74	105	107			130
STOCK TANK OIL GRAV. °API	45	43	30	39	41	36	43.5	32	33			41.8
INITIAL RES. PRESS. PSIA	?	?	1620	4840	1807	1800	?	1710	1805			3137
BUBBLE POINT PRESS. PSIA	?	?	1620	2150	1500	1800	?	1710	1805			1820
BUBBLE POINT OIL VISCOS. C POISE	2.5	2.8	2.3	.30	1.3	1.45	3.1	1.38	1.18			.38
FORMATION VOLUME FACTORS — INITIAL VOL/VOL	?	?	1.209	1.32	1.29	1.25	?	1.228	1.312			—
FORMATION VOLUME FACTORS — BUBBLE POINT VOL/VOL	?	?	—	?	—	1.25	?	1.228	1.312			1.5
CO_2 MISC. PRESS. PSIA	1000a	1100a	1050±a	4500a	850a	1050±a	1000a	1050±a	1250a			1600a
PROJECT SIZE — AREA ACRES	6.4		13.2	31	44.5	12	20	13.2	(1)425	(2)0.7	(3)0.7	80+
PROJECT SIZE — NO. WELLS — PROD.	1	9	2	3	2	2	2	2	15	1	1	2
PROJECT SIZE — NO. WELLS — INJ.	4	16	6	1	4	6	6	6	8	1	1	6
TYPE PROJECT	TERTIARY	TERTIARY	TERTIARY	TERTIARY	TERTIARY	TERTIARY	TERTIARY	TERTIARY	SEC.?	TERT.	TERT.	TERTIARY
OPERATOR	COLUMBIA	GUYAN	AMOCO	SHELL	UNION	AMOCO	PENNZOIL	AMOCO	ARCO	ARCO	SHELL	CHEVRON
START DATE	1975	1977	1973	1973	1964	1973	1976	1972	1972	1973	1977	1974
PRESENT STATUS	CONCLUDED	SUSPENDED?	ONGOING	CONCLUDED	CONCLUDED	ONGOING	ONGOING	ONGOING	TERM.	CONCL	ONGO.	CONCLUDED

a - LABORATORY MEASURED

TABLE IV-2

FIELDS SELECTED AS CANDIDATES
FOR CO_2 DISPLACEMENT IN THE PERMIAN BASIN [22]

Field Name	District/ State	Major Reservoir	Cumulative Production to 1976, bbl	Hypothesized Recovery, MMbbl
Wasson*	8A/Texas	San Andres	875,657,116	670
Slaughter*	8A/Texas	San Andres	642,687,368	260
Levelland*	8A/Texas	San Andres	242,675,781	200
Seminole	8A/Texas	San Andres	203,777,244	80
Fullerton	8/Texas	Permian	177,379,697	160
Kelly-Snyder*	8A/Texas	Canyon	816,372,830	310
Diamond M	8A/Texas	Clear Fork	2,648,127	60
Goldsmith	8/Texas	San Andres	285,990,706	130
N. Cowden*	8/Texas	Permian	259,005,979	130
N. Cowden	8/Texas	San Andres	105,536,037	80
Foster	8/Texas	Grayburg	177,647,850	90
Howard-Glasscock	8/Texas	Yates	302,775,723	230
Ward Estes	8/Texas	Yates-Seven Rivers	17,777,706	120
Sand Hills	8/Texas	San Andres	94,933,812	220
McElroy	8/Texas	Grayburg	321,110,539	380
Yates	8/Texas	Grayburg-San Andres	619,642,206	500
Hobbs	N.M.	San Andres	226,978,885	160
Vacuum	N.M.	Grayburg	159,307,712	270

*CO_2 project being conducted.

Full-Scale Projects

The three most mature full-scale CO_2 injection projects listed in Table IV-1 are in the Crossett (North Cross), Twofreds, and Kelly-Snyder (SACROC) fields. The North Cross project is a clear-cut secondary recovery application in a carbonate reservoir whose permeability is too low to allow economical waterflooding. CO_2 injection has been continuous, including recycling of produced CO_2-contaminated gas. Production response has been excellent. The Twofreds project is similar, because the preponderance of CO_2 injection and response has been in the east reservoir of the Bell Canyon sandstone, in which waterflooding was unsuccessful and was terminated early. CO_2 is being injected continuously in the project. The SACROC project is also a secondary recovery application; however, it was implemented by choice in a limestone reef reservoir in which waterflooding was being successfully applied. The centerline flood could have been expanded to waterflood the area of the CO_2 project. In view of the early implementation of alternating water and CO_2 injection, the initial water injection into Phases 2 and 3, and the relatively small slug of CO_2 injected into each pattern before continuous water injection was applied, it could be argued that this project is as much a waterflood as it is a CO_2 miscible flood. All of these projects fit within the NPC guidelines of applicability and may, indeed, have been influential in defining them. While economic data are proprietary, all three of these projects are evidently commercially successful.

Each of the two Gulf Coast projects, at South Gillock and Weeks Island, fits within the NPC guidelines of applicability. However, they are conceptually different from the three West Texas projects discussed above. Both were designed to inject CO_2 at the gas/oil contact of a dipping reservoir to achieve gravity-stabilized downward miscible displacement of residual oil in a watered-out oil column below a gas cap. The South Gillock project was aborted before meaningful results could be observed. The Weeks Island project continues, with what appears to be favorable initial response.

The two Arkansas projects, at Lick Creek and Ritchie, obviously fall far below the minimum API gravity guideline and far above the maximum viscosity guideline for CO_2 miscible flooding. On the basis of available information, it is doubtful that miscible conditions are being achieved in either project. Nonetheless, the favorable response obtained in each project suggests that CO_2 injection may be a viable method for enhanced oil recovery in thin, shallow, intermediate-viscosity oil reservoirs in which waterflooding (conventional or enhanced) is inefficient and in which thermal methods cannot be applied economically.

Pilot Projects

Ten of the 12 pilot tests listed in Table IV-1 are on field-scale spacing, with several hundred feet separating injection and production wells. The other two, the ARCO and Shell projects in Wasson, are small-scale "mini-tests." Five of the field-scale projects are in sandstone reservoirs, three in West Virginia and one each in Mississippi and west Texas. The other five field-scale and two mini-test pilot projects are all in carbonate reservoirs in west Texas. All of these projects fall within the NPC guidelines.

Sandstone Reservoir Projects. As mentioned, the three West Virginia projects are all in sandstone reservoirs. Reservoir temperatures in these projects are below the critical temperature of CO_2 (88°F). Laboratory tests established that liquid CO_2 (1000± psi, 74-78°F) would achieve miscible displacement efficiencies. Results from the field project at Granny's Creek, now concluded, verified that injection of CO_2 could successfully mobilize and drive tertiary (waterflood residual) oil under actual field reservoir conditions. In this project, however, response was minimal because CO_2 escaped from the project pattern area. Causes of this are apparently geological and not easily remedied. Further testing is now under way. The CO_2 project at Griffithsville has apparently been suspended after considerable water injection but before any CO_2 was injected. While reasons for the suspension are not related to the merits of the CO_2 injection process, there are no CO_2 injection and response data for this project. CO_2 injection is under way in the third project, at Rock Creek, after the pilot area was extensively waterflooded. Oil production response to CO_2 injection has been observed for several months.

The CO_2 injection pilot project in the Strawn sandstone reservoir of the Mead field in West Texas was concluded in 1968. In this project, a 4 percent pore volume slug of CO_2 was followed by a 12 percent pore volume slug of carbonated water, which was followed by regular brine. Results indicated that miscible recoveries were attained, and oil recovery from the CO_2 pilot area was approximately 100 percent greater than that realized from a comparable waterflood area. However, low permeability and attendant low injectivities apparently precluded economic full-scale application.

The Little Creek project in Mississippi was conducted at the highest reservoir temperature (248°F) of any of the projects. In this project, concluded in 1977, continuous CO_2 injection was highly successful in mobilizing, banking, and displacing a low (21 percent) immobile waterflood-residual oil saturation. However, the high CO_2/incremental oil ratio suggests that full-scale application may require modification of the injection plan and CO_2 volume used in the pilot.

Carbonate Reservoir Projects. Two of the seven West Texas CO_2 injection pilot tests in carbonate reservoirs are concluded. These are the field-scale tertiary pilot test conducted by Chevron in the SACROC unit of the Kelly-Snyder field and the mini-test conducted by ARCO in the Willard unit of the Wasson field. A third project, ARCO's "Phase I" project in the Willard unit, was terminated because of a field accident. The four remaining projects, three field-scale and one mini-test, are continuing in various states of maturity.

In the field-scale tertiary pilot test conducted by Chevron in the SACROC unit, CO_2 injection successfully mobilized and displaced waterflood residual oil in a two-pattern pilot. Response was unbalanced between the patterns; one responded well and the other poorly. Oil production was still increasing when CO_2 injection was stopped. On the basis of an estimated 20 Mcf/bbl CO_2-to-incremental-oil ratio, full-scale tertiary flooding was considered economically unjustifiable.

The ARCO mini-test in the Willard Unit at Wasson demonstrated, through log, pressure-core, and production-sampling tests, that CO_2 mobilized and displaced waterflood residual oil from the San Andres reservoir rock. Data from this test were used to calibrate a simulation model study, which indicated that full-scale tertiary flooding could be economically feasible.

Available data from the terminated test by ARCO at Wasson and the four ongoing projects--three field-scale by Amoco in Levelland, North Cowden, and Slaughter and a mini-test by Shell in the Denver unit of Wasson--are insufficient to permit any meaningful summary of results. The Amoco projects are expected to require 2 to 3 more years to evaluate. The Shell mini-test is nearing completion. Evaluation of full-scale project installation will require simulator studies to scale up mini-test results.

V. CONCLUSIONS AND RECOMMENDATIONS

The use of CO_2 as an agent for enhanced oil recovery has been the subject of research by many investigators for more than 20 years. Many of these investigations were obviously done in support of specific projects and hence were somewhat narrowly focused. As a consequence, if the results of one research effort are compared with those of another, seemingly conflicting and paradoxical phenomenological observations have been reported in the literature. Presently, however, the spectrum of published research appears broad enough to provide the basis for a general understanding of the phenomenon termed "miscible displacement" when CO_2 is used to displace oil from porous materials, either in the laboratory or in the field. The main points of this general understanding can be summarized as follows:

(1) When high concentrations of CO_2 are mixed with oil, mass transfer of components between the CO_2 and the oil results in complex phase behavior in which as many as four separate fluid and solid phases may coexist.

(2) The two predominant phases in the system can generally be described as a more-volatile CO_2-rich phase and a less-volatile hydrocarbon-rich phase.

(3) At relatively low temperatures (less than about 120°F), both the more-volatile CO_2-rich phase and the less-volatile hydrocarbon-rich phase are liquids within a measurable pressure range. As pressure is reduced, vapors evolve predominantly from the CO_2-rich phase.

(4) At higher temperatures (above 120°±F), the entire system will be in the vapor phase at high pressure (and high CO_2 concentration). As pressure is reduced, a hydrocarbon-rich liquid phase condenses, while the CO_2-rich phase remains a vapor.

(5) This seemingly paradoxical behavior is probably related to the critical temperature of the CO_2-rich phase, which two separate investigations [55,56] have measured to be in the vicinity of 120°F.

(6) The mechanisms by which multiple-contact miscibility develops between CO_2 and oil are controlled by the temperature-dependent phase behavior. At lower temperatures, the mechanism is analogous to the "condensing gas" mechanism seen in hydrocarbon miscible flooding. At higher temperatures, the mechanism is analogous to the "vaporizing gas" mechanism of hydrocarbon miscible flooding.

Conclusion (6) is based on the experimental observations of Metcalfe and Yarborough [56] using a very light synthetic oil. More recent work by other investigators [97,98] indicates that miscibility also develops by a vaporization or extraction mechanism (rather than "condensing gas") at low temperature because of the effects of heavy components in natural crude oils.

On a pragmatic basis the mechanisms by which miscibility develops may seem unimportant, because results from both laboratory studies and field tests suggest that displacement efficiency of the process is more or less the same regardless of temperature. However, an understanding of the mechanism seems important to the development of mathematical models that more accurately portray the process. Availability of better models could allow implementation of projects without the need for expensive and time-consuming pilot tests for model calibration, much as the "black oil" models now allow routine implementation of water and gas injection projects without the need for pilot tests.

Data from the field tests reviewed in this report indicate that CO_2 injection is technically capable of displacing oil from reservoir rocks over a wide range of geological and physical conditions. Projects have been conducted at depths ranging from 2,100 feet to 12,700 feet over a reservoir temperature range from 74°F to 248°F in rocks whose lithologies included unconsolidated Gulf Coast sands, cemented sandstones, limestones, and cherty dolomites. These projects included reservoirs whose stock tank oil gravities ranged from 15° to 45°API. This spectrum of technical applicability is much less restrictive than any of the other known enhanced oil recovery methods being developed or field-tested [26-29].

The capacity to move and recover oil on a field scale (as distinguished from laboratory cores or packs of porous material) is amply demonstrated for "secondary" conditions by the North Cross, Twofreds, and SACROC projects. In addition, the potential of CO_2 injection under "tertiary" (i.e., waterflood-residual oil) conditions has been demonstrated for a wide variety of reservoir conditions by the projects in West Virginia and Arkansas and by the Little Creek, Mead-Strawn, Weeks Island, and west Texas carbonate reservoir projects. It thus seems that the limitations to widespread application of CO_2 flooding are economic rather than technical.

Review of full-scale field applications to date indicates that the largest recovery increase is attained in secondary applications by continuous injection of CO_2. This is probably practical only in relatively thin reservoirs where layering effects do not control sweep efficiency so that alternate injection of water and gas is unnecessary. The main thrust of current efforts in CO_2 flooding field pilot tests is directed toward tertiary applications in large waterflooded carbonate reservoirs, which constitute an identifiably large target for enhanced recovery. However, the potential of other projects, such as North Cross or Twofreds, should not be neglected in the rush to CO_2-flood the San Andres. Low-permeability reservoirs not amenable to waterflooding certainly seem to represent a second target for CO_2 flooding.

Response seen in the two heavy-oil projects in Arkansas is encouraging. While the swelling and viscosity reduction effects of mixing CO_2 with heavier oils has been documented for several years, these two projects indicate that CO_2 injection in reservoirs like this can indeed recover oil unrecoverable by any other practical means. More research and field applications are obviously necessary to evaluate the economics of application. The shallow Cretaceous sand reservoirs of east Texas, north Louisiana, and southern Arkansas, the Mirando Trend reservoirs in south Texas, and, no doubt, reservoirs in other areas represent targets for application.

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PREFACE

This Appendix to the Task One report entitled "Review and Analysis of Past and Ongoing Carbon Dioxide Injection Field Tests" presents detailed reports on 19 CO_2 injection projects in 16 separate oil fields. The information presented here was compiled from published literature and other public records, and the reports were prepared in as much detail as the source material allowed. It will be noted that some reports are relatively brief and that others are reasonably detailed. This is a direct reflection of the source material available to us.

The authors of these reports (identified on the individual field reports) are all present or former members of the Gruy Federal staff. Jerry A. Watson was principally responsible for the geological material included in the reports. The other authors named were responsible for the reservoir engineering and the other operational information, and for any interpretive material included.

For convenience, this volume is organized in two parts. Part One presents reports on the full-scale field projects while Part Two contains reports on field pilot test projects.

CO_2 FIELD INJECTION PROJECT CONDUCTED BY SHELL OIL COMPANY CROSSETT FIELD, WEST TEXAS

by
Elbert N. Durham and Jerry A. Watson

Location and General History

The Crossett Field is located on the Central Basin Platform of the Permian Basin in Upton and Crane Counties, Texas (Fig. 1).* Production is from a Devonian reservoir (Fig. 2) at a depth of 5,300 feet from 28 wells in a project area of 1,120 acres. The field was discovered in 1944 and had an estimated 53 million stock tank barrels of oil originally in place. The reservoir produced 3.5 million barrels of oil to 1964, when the field was unitized and a program of partial pressure maintenance by updip residue-gas injection was initiated. Cumulative production at the start of the CO_2 injection project in 1972 was 6.9 million barrels. Estimated cumulative production to January 1, 1979, was 11.3 million barrels, and the estimated cumulative incremental recovery from CO_2 injection was 2.2 million barrels. Carbon dioxide injection is continuing.

Geologic and Petrophysical Data

The Devonian reservoir is a stratigraphic trap bounded on the north, south, and west flanks by porosity pinchouts and on the east side by a producing water level at -3,040 feet. The reservoir rock is a tripolitic chert with calcareous cementation. The pay section has an average porosity of 22 percent and an average permeability of 5 md. Table 1 at the end of this report shows engineering, petrophysical, and statistical data.

Structure on top of the eroded Devonian is shown in Fig. 3 [1]. The eastward dip is approximately 250 feet per mile. The Devonian section through the pay is a relatively uniform, single depositional unit with thickness variations resulting from erosion of the upper surface [2].

An isopach of the gross pay section is shown in Fig. 4 [1]. Pay thicknesses of 140 to 180 feet are found in the northern and southern sections of the field, with a much thinner section (80 to 100 feet) in the central portion. Core data suggest that porosity and permeability are relatively uniform in the pay zone [3]. Figure 5 is a typical log of the reservoir.

A small gas cap, comprising about 12 percent of the hydrocarbon reservoir volume, is present above subsea datum 2,860 and a free water table is present at 3,040 subsea. Connate water saturation in the hydrocarbon-productive interval is estimated at 35 percent.

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*For all the reports in this volume, tables and figures are grouped together at the end of each report.

Reservoir Fluid Data

The oil from the Devonian reservoir has a gravity of 44°API and a viscosity of 0.37 cp. The oil was saturated at initial reservoir conditions of 2,328 psi and 106°F. Initial formation volume factor was 1.986 and initial GOR was 1,688 cu ft/bbl. Laboratory-determined minimum miscibility pressure of the reservoir oil at the beginning of CO_2 injection was 1,650 psi, equal to the average reservoir pressure existing at that time.

Reservoir Performance Data

Performance of the Crossett Devonian reservoir from discovery in 1944 to the start of partial pressure maintenance in 1964 is shown in Figs. 6 and 7, reproduced from files of the Texas Railroad Commission. A predominantly solution-gas drive mechanism has been apparent. No significant bottomwater or gas-cap expansion into the oil-bearing portion of the reservoir has been noted. Fig. 8 shows performance history from 1964 through 1978 [4]. Projected oil production without CO_2 injection, shown in Fig. 8, is based on estimates reported by Pontius and Tham [1]. These authors report estimated ultimate recovery applicable to each recovery mechanism effective in Crossett as follows (CO_2 performance predictions were based on reservoir simulator model studies, Fig. 9):

	Thousand Stock Tank Barrels	% OOIP
Original oil in place	53,000	100
Ultimate by primary solution gas depletion	6,800	12.9
Incremental ultimate by partial pressure maintenance	3,100	5.8
Subtotal without CO_2 injection	9,900	18.7
Incremental ultimate by CO_2 injection	20,000	37.7
Total ultimate	29,900	56.4

Carbon Dioxide Project Data

Carbon dioxide for the Crossett project is obtained from several gasoline plants processing CO_2-rich natural gas in the Val Verde Basin. Shell-owned CO_2 is transported via leased space in the SACROC CO_2 pipeline (Fig. 10).

The injector-producer pattern currently being used in Crossett is shown in Fig. 11, as well as the locations of new wells drilled since the start of the project. Original operational plans provided for continuous injection of a total of 73 Bcf of source CO_2, or about 40 percent of the oil column hydrocarbon pore volume, over a period of 10 years. Water injection was considered impractical because of low reservoir permeability. The plan provides for continued injection of plant residue and produced gas of low CO_2 content into updip pressure maintenance gas injectors. Produced gas of 60 percent or more CO_2 content is recycled directly into CO_2 injectors. Recycling of produced CO_2 is scheduled to continue beyond the 10-year period of injection of source CO_2.

An injection rate of 20 MMcf/D into two original and four ultimate CO_2 injectors was originally anticipated. However, substantial losses in injectivity were experienced early in the project, which required increasing the number of injectors from two to seven and the surface injection pressure from 1,800 psig to 2,300 psig to maintain a level of about 18 MMcf of source CO_2 per day. This injectivity impairment has been attributed to the formation of a low-mobility mixed zone involving multiple fluid phases.

Cumulative CO_2 injection as of January 1, 1979, including recycled CO_2-rich gas, is approximately 41 Bcf, equivalent to 22 percent of the oil column hydrocarbon pore volume. Cumulative produced CO_2 is about 2.2 Bcf, for a net retention of 38.8 Bcf or 95 percent of injected volume.

The original prediction of ultimate incremental oil recovery was 20 million barrels, giving an ultimate CO_2 utilization factor of 3.65 Mcf/bbl.

On the basis of cumulative operating statistics to December 1, 1976, reported by Pontius and Tham and subsequent monthly volumes plotted in Fig. 8, the status as of January 1, 1979, is estimated to be as follows:

	Thousand Stock Tank Barrels	% OOIP
Cumulative primary recovery	6,800	12.9
Estimated primary reserves	-----	----
Cumulative incremental recovery from pressure maintenance	2,300	4.3
Cumulative incremental recovery from CO_2 injection	2,200	4.2
Total cumulative recovery, 1/1/79	11,300	21.4

Approximate production statistics as of December 1978 are:

Oil production	2,600 B/D
Projected without CO_2	400 B/D
Estimated incremental	2,200 B/D
CO_2 production	3,900 Mcf/D
% CO_2 injection rate	20%

The cumulative ratio of gross injected CO_2 to incremental oil produced is 41.0/2.2 = 18.6 Mcf/bbl. The cumulative ratio of net retained CO_2 to incremental oil produced is 38.8/2.2 = 17.6 Mcf/bbl. An updated ultimate recovery estimate has not been published by the operator.

Interpretations and Conclusions

Combined rock and fluid characteristics at Crossett are probably as favorable for high recovery efficiency as might be expected in any miscible CO_2 flooding project. Unless injectivity problems seriously interfere with the ability to maintain reasonable rates and effective balance in volumes and pressures, the results achieved at this project may represent an upper level target for miscible projects in carbonate reservoirs.

Comparison of Figs. 8 and 9 shows that actual oil production response to January 1, 1979, is less than originally predicted (actual production rate about 2,600 BOPD in December 1978 compared to about 4,000 BOPD predicted). However, injection rates were also lower (actual total CO_2 plus CO_2-rich gas injection rate about 18.7 MMcf/D, compared to about 35 MMcf/D predicted). It appears that several years of additional history (through at least 1982) will be required before estimates based on extrapolation of a declining actual production trend can be made.

The ultimate of 20 million barrels predicted by the model can reasonably be considered to represent an upper limit of expected incremental recovery, considering the following facts:

1. The original estimate is based on a reservoir simulation which cannot take into account all potential negative effects existing under actual field conditions, and

2. A high proportion (75 percent) of the estimated ultimate is projected to be recovered following peak production at a very low annual decline rate (approximately 8 percent per year) over a period of approximately 40 years.

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TABLE 1

FIELD DATA FOR CARBON DIOXIDE INJECTION PROJECTS

FIELD: CROSSETT

LOCATION AND GENERAL DATA

State: Texas County: Crane and Upton

Discovery Date: August 1944 Date First Production

No. Wells: 28 @ Date:

Developed Area: 1120 Acres

GEOLOGY AND PETROPHYSICS

Reservoir Name: Devonian

Reservoir Rock Type: Calcareous tripolitic chert, uniform granular porosity

Trap: Stratigraphic

Average Depth: 5300 ft.

Primary Gas Cap (Y/N) - Yes

Gas/Oil Contact Depth: 2860 feet subsea
Oil/Water Contact Depth: 3040 feet subsea

Average Net Pay Thickness: 96 feet

Net/Gross Ratio: Range 0.7 to 1.0
Average Porosity: 22 %
Initial Water Saturation 35 %
Average Permeability: 3 to 5 millidarcies

Permeability Range: 0.1 to 40 millidarcies

Permeability Variation: 0.67

k_v/k_h: approx. 1.0

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

BASIC RESERVOIR AND VOLUMETRIC DATA

Initial Reservoir Pressure: 2328 psi
Reservoir Temperature: 106 °F
Bubble Point Pressure: 2328 psi
Formation Volume Factors:
B_{oi} 1.986
B_{ob} 1.986
Reservoir Oil Viscosity Data:
μ_{oi} 0.37 centipoise
μ_{ob} 0.37 centipoise

Initial Solution Gas-Oil Ratio:
R_{si} 1688 cu.ft./bbl.
Stock Tank Oil Gravity: 44 °API

Reservoir Hydrocarbon Pore Volumes:
Oil Column: 105,300 M Bbl Gas Cap: 14,500 M Bbl
Standard Volume Original Hydrocarbons in Place
Oil: 53,000 M Bbl Free Gas: 11,900,000 Mcf

RESERVOIR PERFORMANCE DATA

Primary Recovery Drive Mechanism: Solution gas drive

Estimated Ultimate Primary Recovery: 12.9 % ISTOIP

Supplemental Recovery Method(s) and Date Started: Updip gas injection - 1964

Cumulative Oil Production at Start Supplemental:
3,500 M Bbls 6.6 % ISTOIP

Unit Operator(s): Shell Oil

Average Pressure at Start Supplemental: 1850 psi

Estimated Additional Supplemental Recovery (Ultimate): 5.8 % ISTOIP

Estimated Total Ultimate Recovery (Primary+Supplemental) 18.7 % ISTOIP

Cumulative Total Production to: April, 1972 (Date)
6,900 M Bbls 13.0 % ISTOIP

Average Pressure: 1650 psi @ April, 1972 (Date)
Calculated Average Oil Saturation 0.49 %@ April, 1972 (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

CARBON DIOXIDE INJECTION PROJECT DATA

Project Operator: Shell Oil Company

Project Type: Mini-Test ____ Pilot Test ____ Full-Scale Project X
Recovery Mode: Secondary (1) Tertiary ____
Project Area: 1120 Acres
No. of Wells: Injection 10 Production 19 Other ____

Pattern Geometry: Inverted 9-spot

Date Project Commenced: April, 1972 (2) Ended active
Injection Fluid Composition (mol percent) (3)
CO_2 93% H_2S ____ C_1 7%

C_2-C_6 ____ C_7+ ____ Other ____

Estimated miscibility pressure: 1650 psi
Injection Fluid Source(s): Val Verde Basin gas plants
60 Mcf via SACROC CO_2 pipeline
CO_2 Injection Rate (Excluding Recycle): 16,000 Mcf/day 12/78 (Date)
Recycle Gas Injection Rate: 3,000 (3) Mcf/day 12/78 (Date)
Water Injection Rate: 0 Bbl/day 12/78 (Date)

Water Injection Mode (i.e., alternating, continuous after "slug", etc.)
Discuss: No water injected as of Jan. 1, 1979

Injection Pressures:

CO_2:	Surface	2300	psi	Bottomhole		psi
Recycle:	Surface		psi	Bottomhole		psi
Water:	Surface		psi	Bottomhole		psi

Cumulative Injection @ January 1, 1979 (Date)

CO_2	40,700 (4)	MMcf	22	%HCPV
Recycle:	200	MMcf	NIL	%HCPV
Water:		MMcf		%HCPV

Current Production Rates: (Date) December, 1978

Oil: 2580 Bbl/day Gas: 17,300 Mcf/day
CO_2: 3800 Mcf/day Water: --- Bbl/day

Date First Response: August 1973

Date CO_2 Breakthrough: February 1975

Cumulative CO_2 Production: 2200 MMcf @ Jan. 1, 1979 (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

Incremental Response: 2160 Bbl/day @ Dec. 1978 (Date)

Cumulative Incremental Oil @ Jan.1, 1979(Date) 2,200 M Bbl

CO_2 Utilization Ratio-Cumulative Injection CO_2/Cumulative Incremental Oil 18.5 (5) Mcf/Bbl.

Expected Ultimate Incremental Production:
20,000 (5) M Bbls 37.7 % ISTOIP

SUPPLEMENTAL INFORMATION:

Supplemental Information

1. No waterflood operations, however, partial pressure maintenance by up-dip gas injection effected.

2. CO_2 injection. No pre-flush or prior flooding.

3. Composition of CO_2 source. Injection program also includes recycling of gas production from CO_2 rich gas producers (CO_2 content > 60%).

4. Includes recycled injection volumes.

5. Original plan calls for ultimate injection of 73 Bcf CO_2, equivalent to 40% oil column hydrocarbon pore volume. Original estimate of incremental oil recovery represents CO_2 utilization ratio of 3.65. No subsequent revisions in estimated recovery reported.

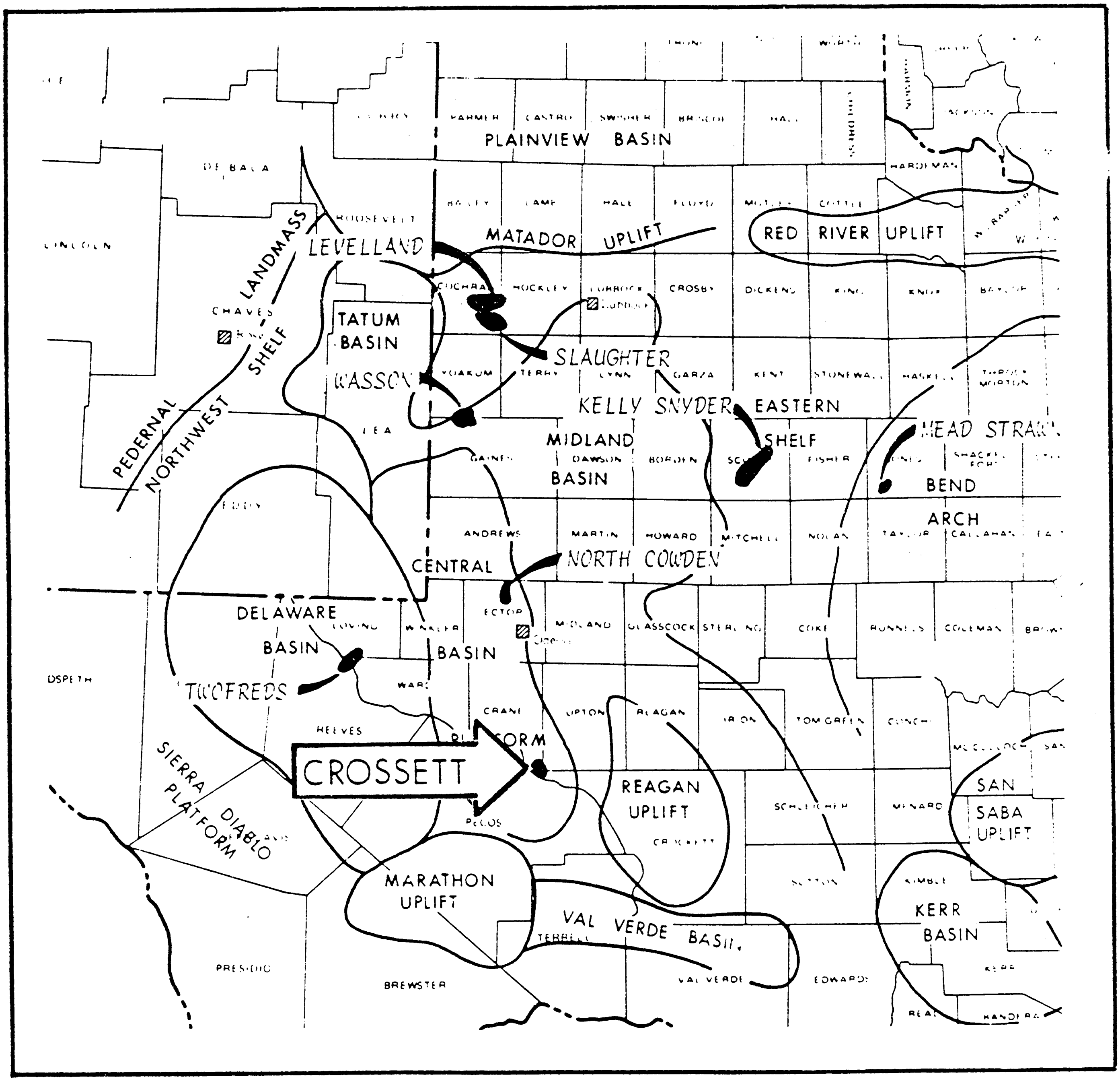


Figure 1.--Index map: carbon dioxide injection projects in west Texas.

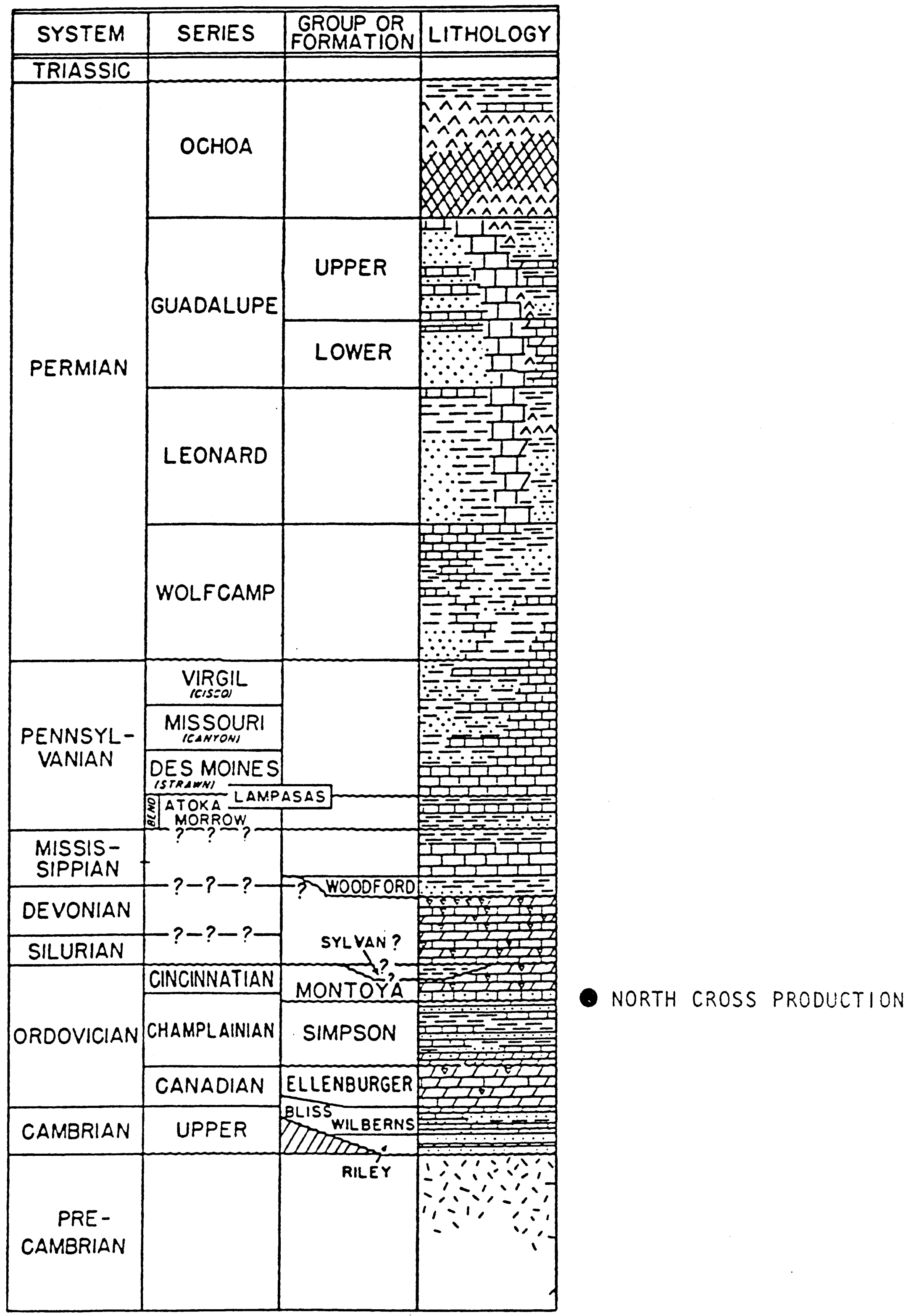


Figure 2.--Generalized stratigraphic and lithologic column for the Permian Basin, Texas.

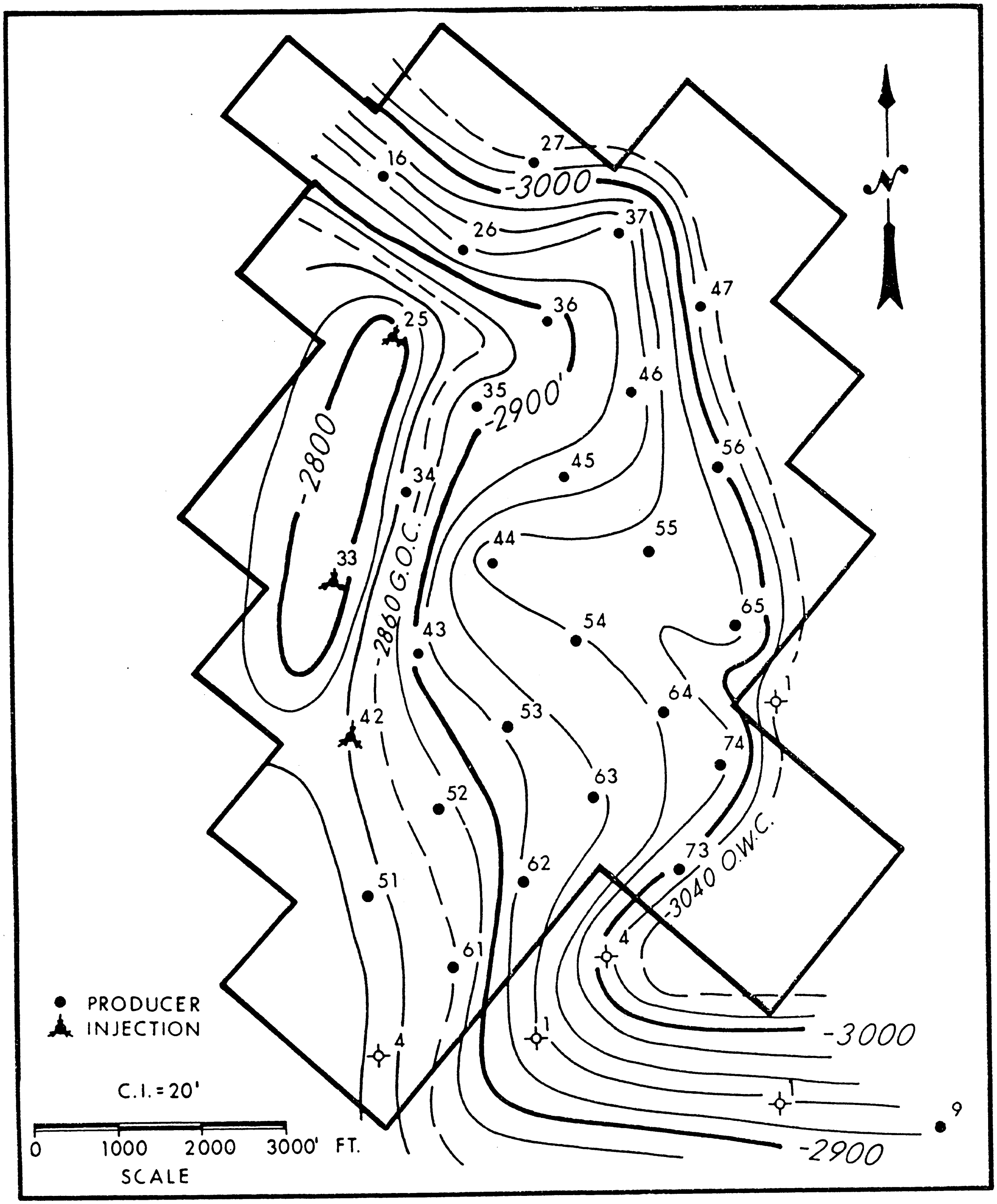


Figure 3.--Structure on top of the eroded Devonian, North Cross Devonian unit, Crossett field, Texas.

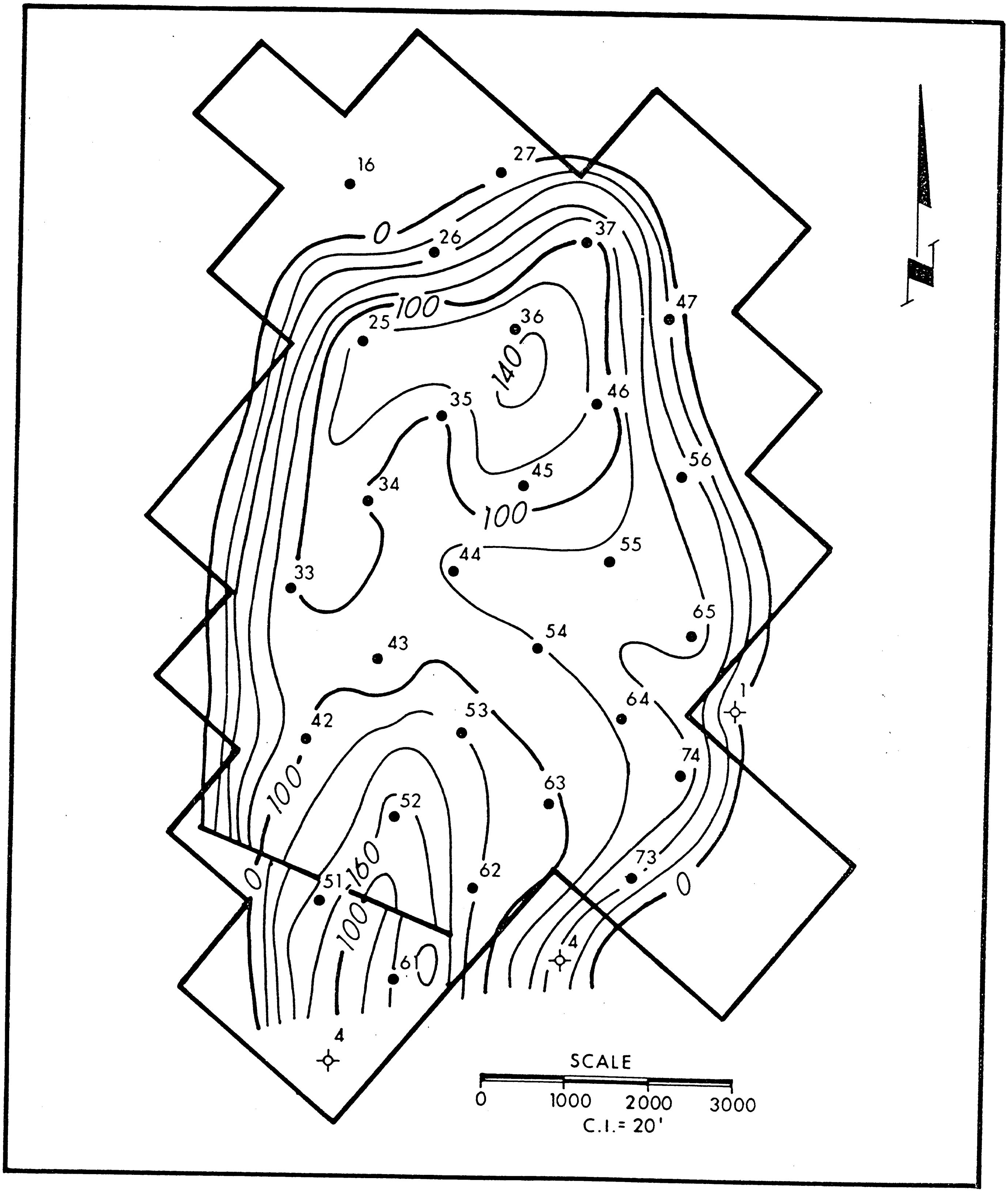


Figure 4.--Isopach map, gross pay, North Cross Devonian unit, Crossett field, Texas.

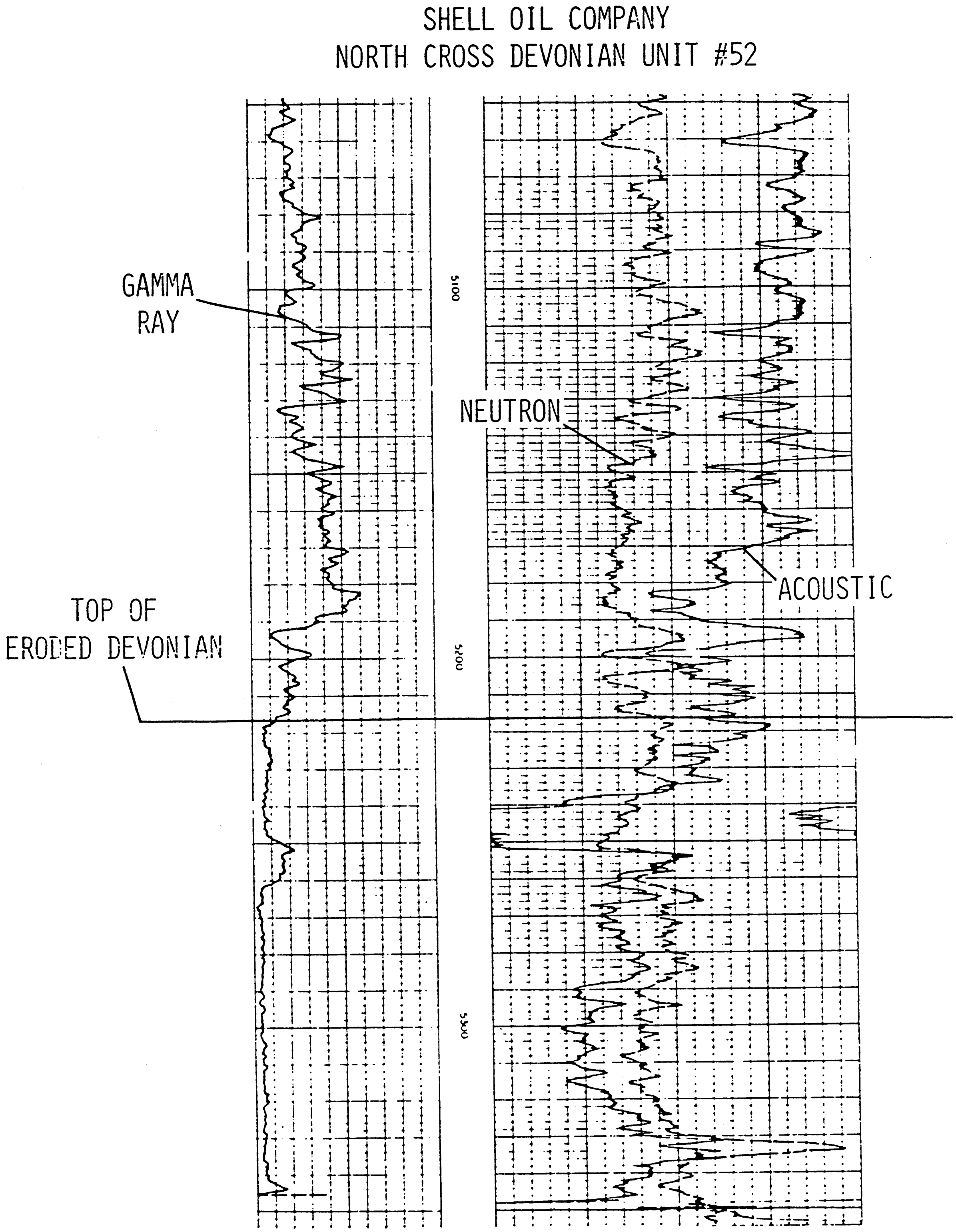


Figure 5.--Sample log from the North Cross Devonian unit, Crossett field, Texas.

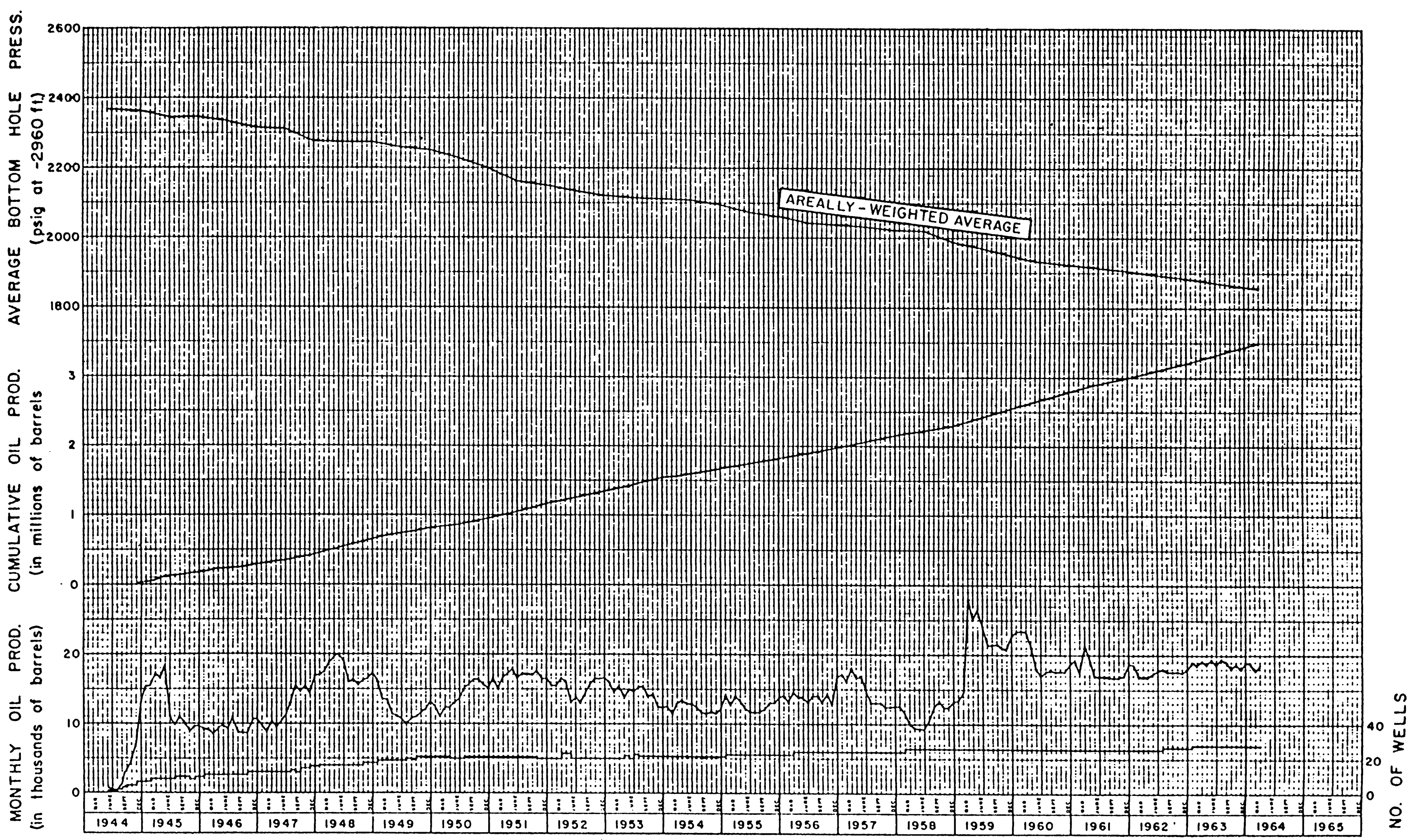


Figure 6.--Reservoir performance curves, Crossett (Devonian) field, Texas.

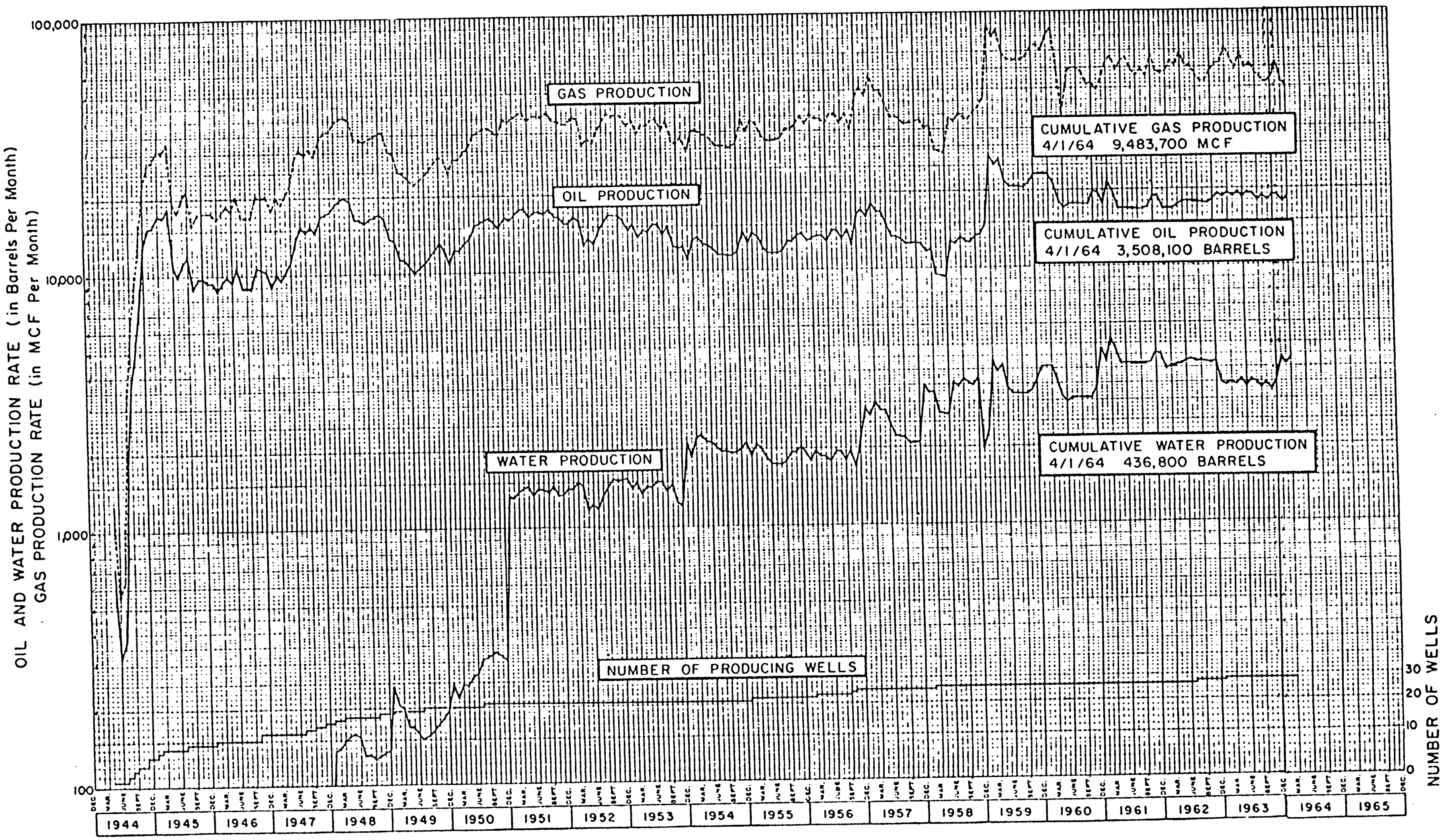


Figure 7.--Oil, gas, and water production and number of producing wells vs time, Crossett (Devonian) field, Texas.

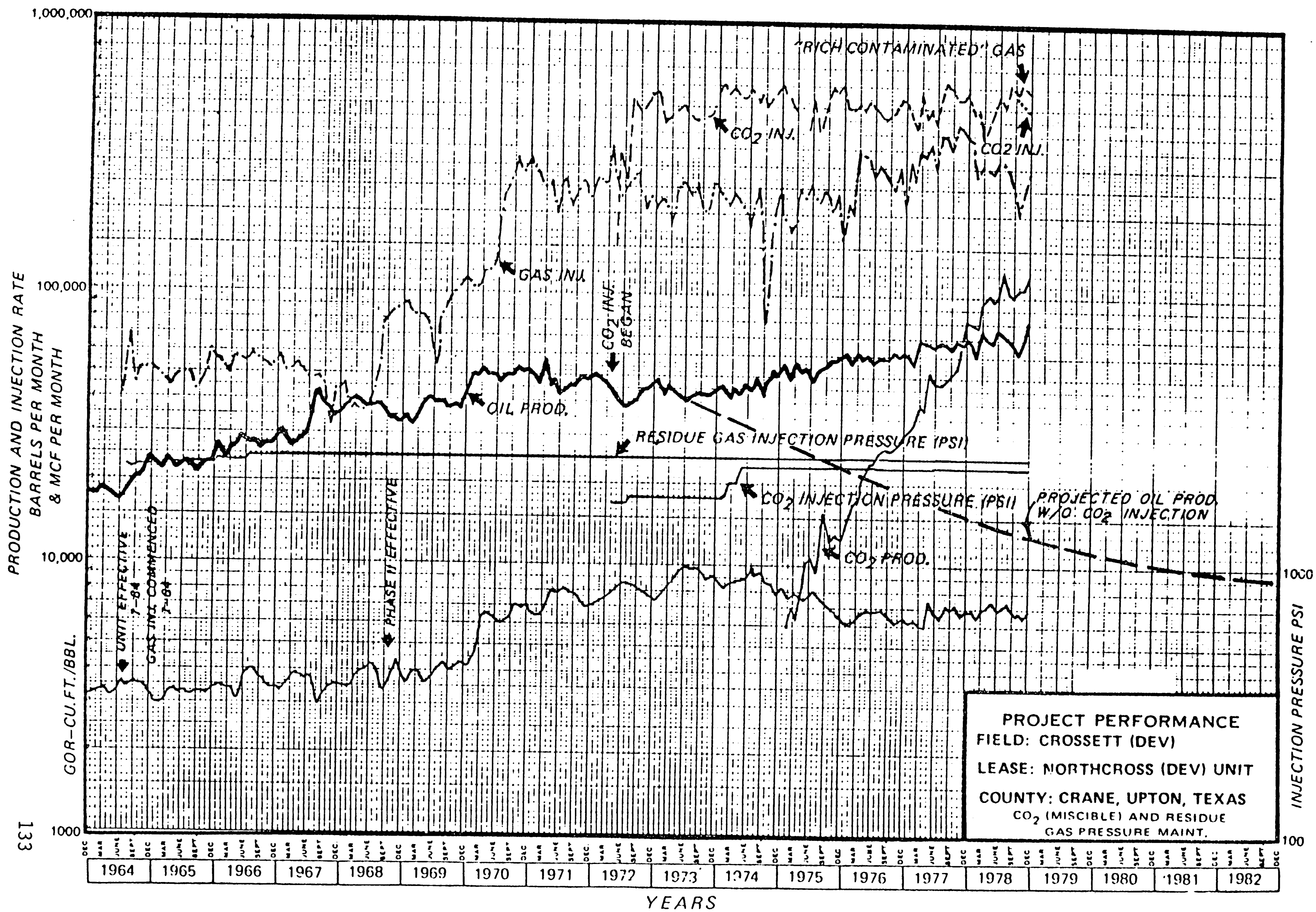


Figure 8.--Project performance, North Cross Devonian unit, Crossett field, Texas.

NORTH CROSS PERFORMANCE FORECAST
(1972 SIMULATION STUDY)

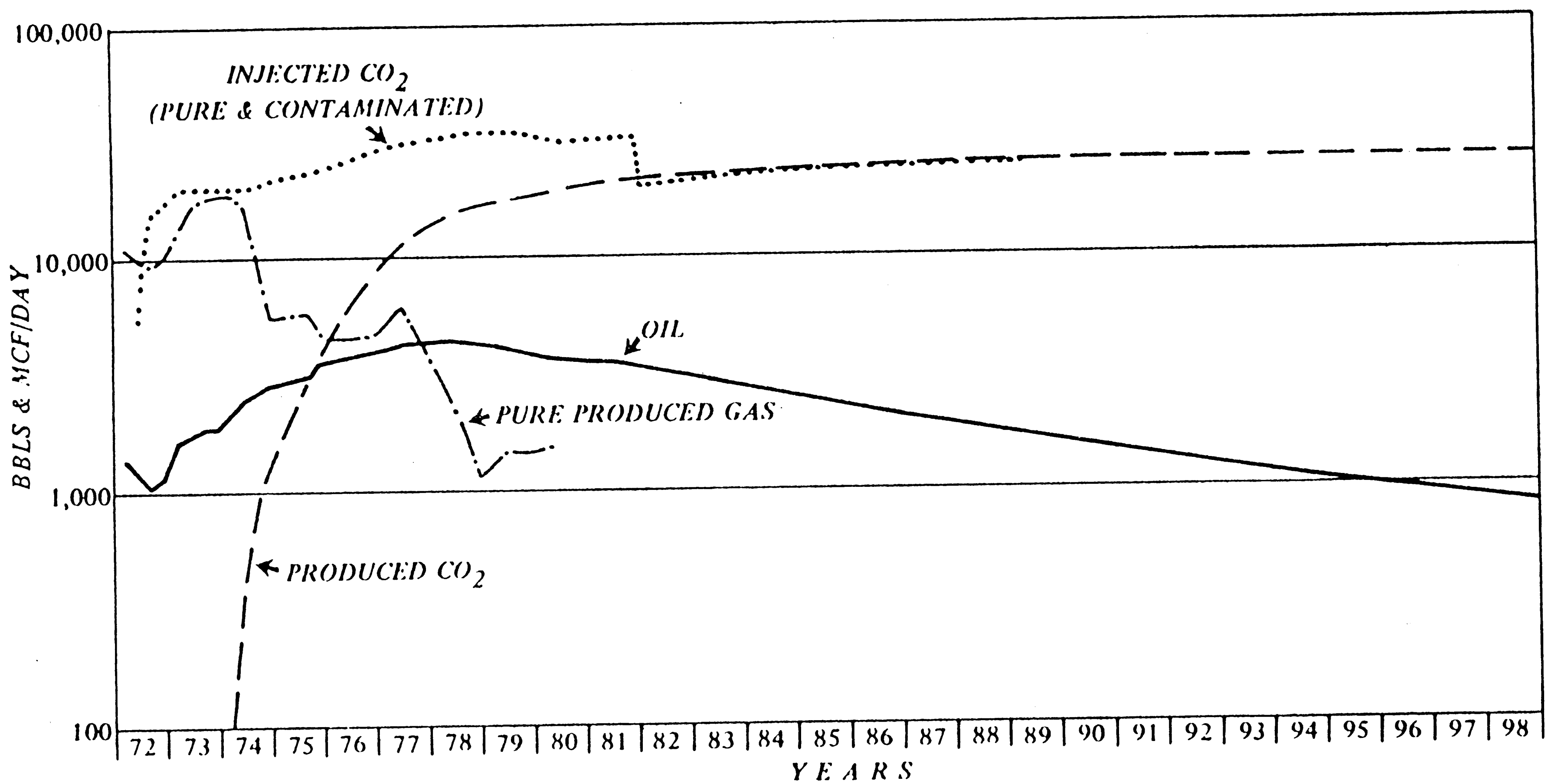


Figure 9.--North Cross unit performance forecast, from a 1972 simulation study. (from Pontius and Tham, J. Pet. Tech., Dec. 1978, p. 1708; ©1978, Society of Petroleum Engineers of AIME; reproduced by permission.)

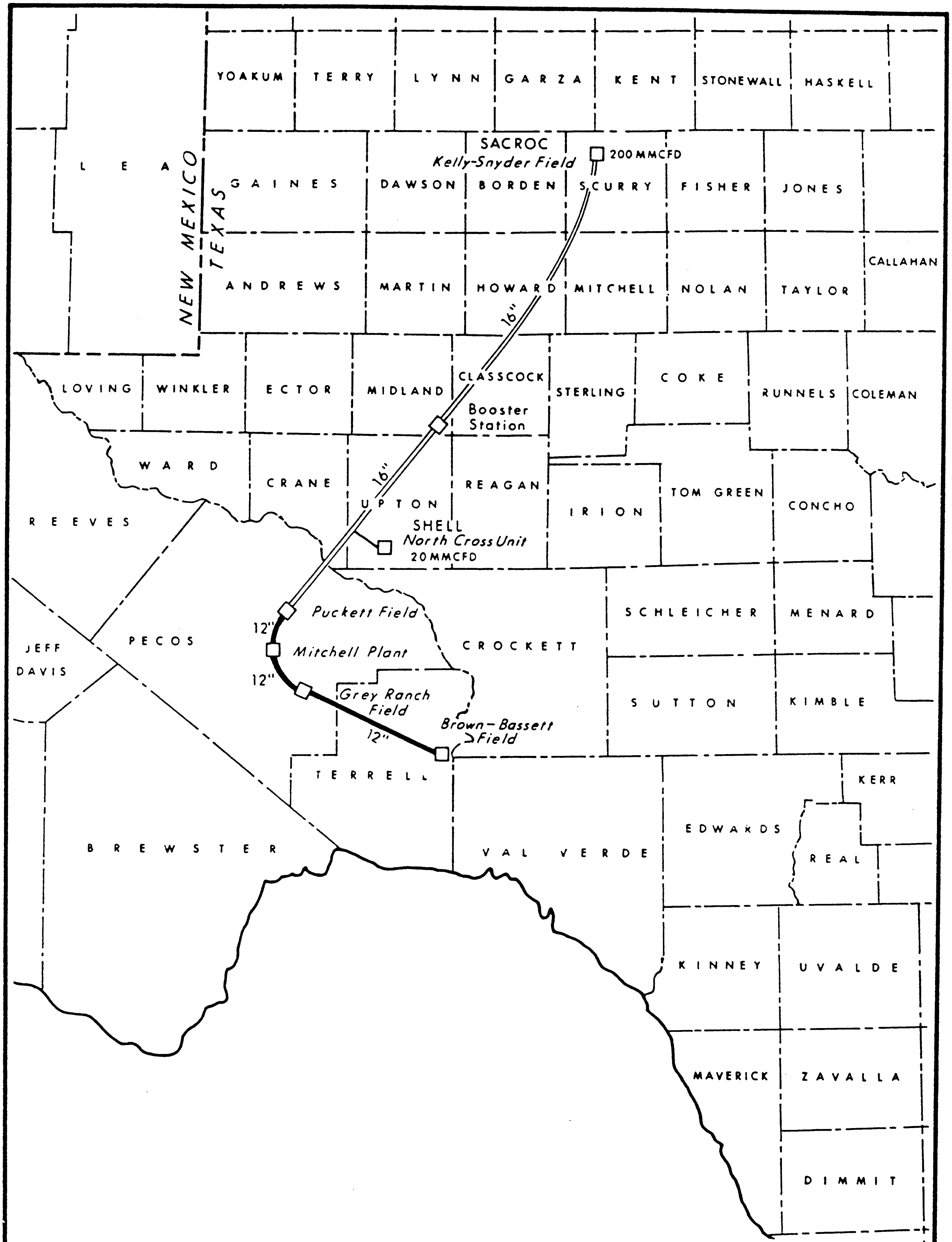
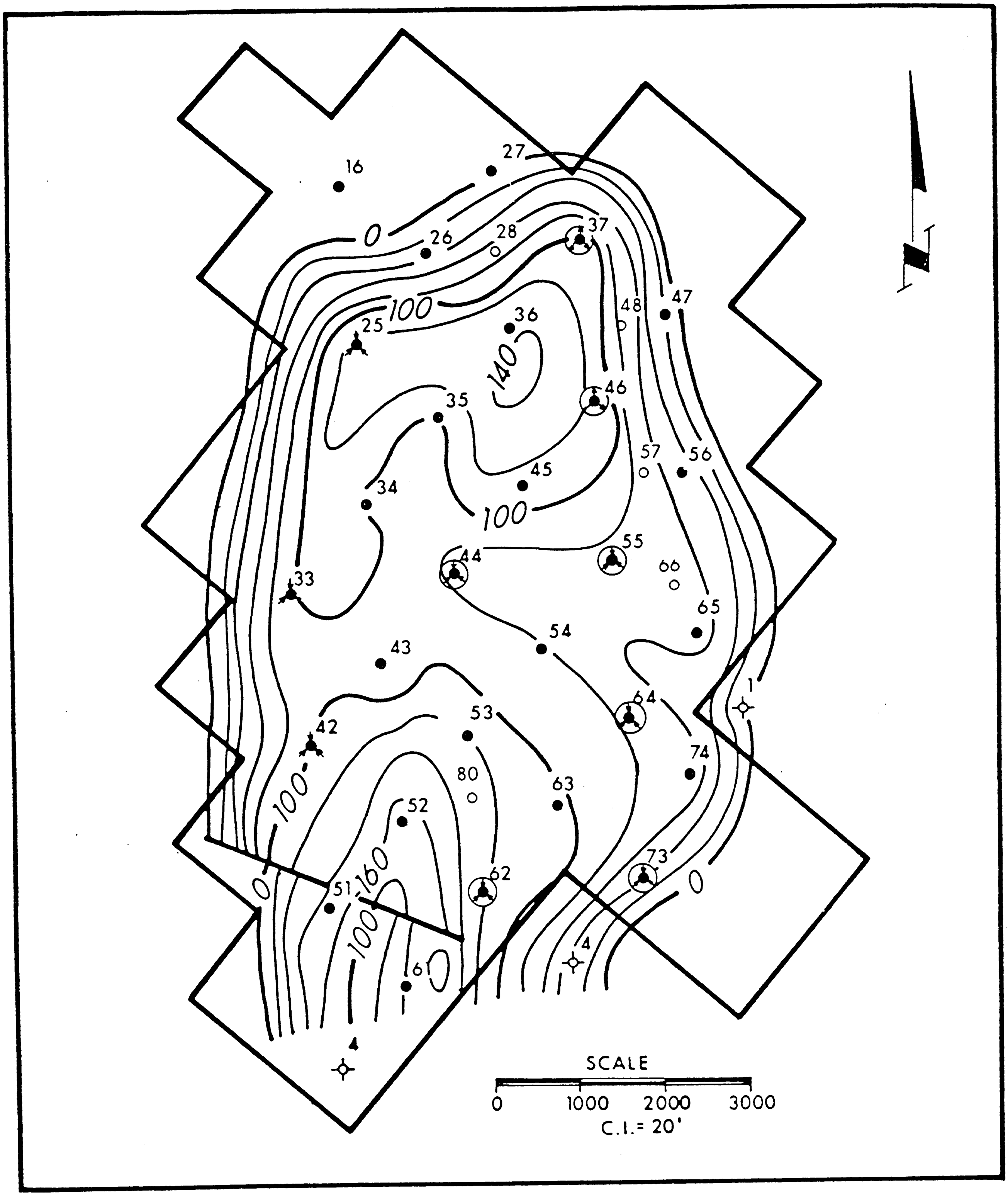


Figure 10.--Carbon dioxide supply system for Crossett and Kelly-Snyder fields, Texas.



LEGEND

INJECTORS PRESSURE MAINTENANCE

CO_2 INJECTORS

• ORIGINAL PRODUCERS

o ADDED 1977 - 78

Figure 11.--Well status map, North Cross Devonian unit, Crossett field, Texas.

CO_2 FIELD INJECTION PROJECT CONDUCTED BY PHILLIPS PETROLEUM COMPANY LICK CREEK FIELD, BRADLEY AND UNION COUNTIES, ARKANSAS

by
Elbert N. Durham and Jerry A. Watson

Location and General History

The Lick Creek Field is located in southern Arkansas on the west flank of the Monroe Uplift (Fig. 1). Production is from the Meakin sand (Fig. 2) at a depth of 2,500 feet. The field was discovered in 1957 and was fully developed for primary production by 68 wells generally on 20-acre spacing. Estimated original oil in place was 23.4 million barrels. Oil production declined from a peak of about 1,900 B/D in 1960 to about 250 B/D from 22 active wells in January 1976. Cumulative production is about 4.5 million barrels.

Carbon dioxide injection operations were initiated in February 1976, with Phillips Petroleum Company as operator of the field-wide Meakin Sand Unit formed in 1975. Response from these operations has been encouraging and the project is currently active.

Statistics and Information Summary

Table 1 (at the end of this report) contains a complete summary of statistics and information pertaining to the producing reservoir and the enhanced recovery project. Except as specifically noted, all data in the table were derived from records of the Arkansas Oil and Gas Commission or from unpublished information supplied by the operator.

Geology and Petrophysics

The Meakin Sand reservoir at Lick Creek field is a fault trap reservoir bounded on the south by a fault and on the north, east, and west by water (Fig. 3). Dip is toward the northwest, the Meakin Sand being encountered at depths ranging from -2,440 feet in the southeast section of the field to -2,476 feet in the northwest section.

The Meakin is a fine-grained sandstone in the Ozan Formation, of Upper Cretaceous age. It is one of a series of Ozan sands which produce in southern Arkansas, others being the Baker, Graves, and Buckrange. The Meakin Sand ranges up to 16 feet thick, averaging 12 feet in the principal productive area. Average porosity of the sand is 33 percent, the average permeability is 1,200 md, and connate water saturation is estimated at 32 percent.

Figure 4 is an isopach of the Meakin Sand pay. A maximum thickness of 16 feet occurs in the northeast section; most of the field has a pay section of 11 to 14 feet. The pay section is continuous across the field and is readily correlated. Review of a typical core analysis (Table 2) shows good porosity development throughout the section. Permeability is highest in the middle of the pay zone. Figure 5 is a typical electrical log from the field.

Fluid Characteristics

The reservoir produces an oil of 17°API gravity, which was undersaturated at the original reservoir pressure of 1,200 psi. The bubble-point pressure is only 85 psi and the solution gas-oil ratio only 25 cu ft/bbl. Table 3 is an analysis of the stock tank crude reported by the Bureau of Mines in 1969. The viscosity of the reservoir crude is 160 cp at current reservoir conditions. Table 4 shows laboratory-measured properties of the oil saturated with CO_2 at reservoir temperature (118°F) and at pressures from 150 to 1,600 psia. From these data it is apparent that at the project operating reservoir pressure (about 1,000 psi) the reservoir crude will dissolve about 51 mole percent of CO_2. The CO_2-enriched oil exhibits approximately a sevenfold decrease in viscosity, an 11 percent increase in volume, and a 2 percent increase in density relative to the uncontaminated crude. Each of these effects contributes to improving recovery efficiency by water displacement.

Reservoir Performance Prior to Carbon Dioxide Project

Figure 6 shows the production performance history of the field. Primary production through 1975 is shown on the upper section of the graph as a smoothed curve, reflecting a fairly consistent decline rate of about 9 percent per year over the 10 years preceding the commencement of CO_2 operations.

Water production data obtained before 1975 are limited to November 1964 data reported by the Bureau of Mines [1] and December 1973 data reported by Phillips in the 1974 unitization proceedings. These data, together with monthly water production figures obtained beginning in January 1975, are shown in Fig. 6 in terms of water-to-oil ratio (WOR) values. They indicate active water encroachment during primary production. The extent of this encroachment as of January 1974 is clear from Fig. 7. Data shown on this map also support the operator's observation that the fault plane bounding the reservoir on the southeast is one source of water encroachment.

Reservoir pressures were reported in 1974 to vary between 1,000 psi at the outer limits of the then-producing area and about 150 psi at its center.

Finally, the predicted ultimate primary recovery for this heavy-oil reservoir--21.6 percent of original oil in place--is on the order of twice the average recovery expected from similar heavy-oil reservoirs in southern Arkansas which have no water drive, and is much greater than would be expected solely from pressure depletion under the conditions present in Lick Creek. It is therefore apparent that water encroachment has been an important factor in the primary performance of the reservoir.

Carbon Dioxide Project Review

Carbon dioxide for the Lick Creek project is obtained from the IMC Corporation ammonia plant at Sterlington, Louisiana. The gas is compressed, dehydrated to a dewpoint of -10°F, and transported in the supercritical state through 65 miles of 6-inch ID pipeline to the Lick Creek unit. Average pipeline pressure is 1,350 psig.

Strategic planning for the project focused on the objectives of contacting as much of the oil in the reservoir as feasible and achieving effective displacement. The injector-producer pattern adopted for this project, shown in Fig. 8, uses 16 injectors and 38 producers. Except for one new injector, existing producers were converted to injector service.

The general operational plan was structured in four phases:

- Phase I provides for cyclic injection ("huff-and-puff" technique) applied to all of the producers and selected injectors.

- Phase II involves starting continuous injection with the injection of an initial slug of CO_2 into the 16 permanent injectors.

- Phase III provides for alternate injection of slugs of water and gas into the permanent injectors.

- Phase IV covers final continuous water injection into the permanent injectors.

Recycling of produced CO_2 is integral to all phases of the operational plan for as long as volume and benefits are considered sufficient to justify its continuation.

An important initial incentive to undertake the CO_2 injection project was the favorable response obtained in 1969 by injecting a small volume of CO_2 into the Baker Sand heavy-oil reservoir in the nearby Ritchie Field. Original performance projections for Lick Creek were based on scaling up the Ritchie operation and on a simplified reservoir simulation model analysis of the proposed Lick Creek project used as a confirming technique. The principal features of the original performance projection were:

- CO_2 requirements were estimated at approximately 11 Bcf, based on a solvent capacity of the reservoir fluids of 6.1 Bcf plus approximately 80 percent excess to allow for losses. This volume could be achieved over a two-year period at the rate of 15 MMcf/D of CO_2, which was the quantity expected to be available.

- Incremental oil recovery was estimated at three million barrels (upper limit). Details of the basis for this estimate have not been obtained; however, information presented to the Arkansas Oil and Gas Commission indicates that two primary factors in the model analysis favored a high apparent incremental recovery: a reduction in oil viscosity and an anticipated reduction in irreducible residual oil saturation compared to that expected from water displacement without CO_2 injection.

The predicted CO_2 utilization factor based on the above-described estimates is approximately 3.7 Mcf per barrel of oil recovered.

Injection Performance

Total project injection performance is shown in Fig. 9.

Phase I operations began in February 1976. Individual well data have not been analyzed; however, by mid-1977 (with few exceptions) all of the 38 producers and most of the 16 injectors had been subjected to one or more cycles of injection, and back flow and continuous injection into some of the permanent injectors had begun.

By November 1978 all of the primary injectors were in continuous service. Since that time Phase I-type cyclic injection has been limited primarily to a few producers not previously treated.

From an overview of the injection information, it appears that Phase II (continuous CO_2 injection) was minimized. Injection of alternate slugs of CO_2 and water began immediately or shortly after start of continuous injection in most, if not all, injectors.

As Fig. 9 shows, Phase I was characterized by a total injection rate averaging about 13 MMcf/D, with purchased CO_2 comprising about 7 MMcf of this volume. Total CO_2 injection during Phases II and III has averaged about 8 MMcf/D, only about 3 MMcf of this being purchased. Water injection during Phases II and III has increased from an average rate of about 700 B/D at the start to about 5,000 B/D at full operation. Reduced activity in April and May 1979 was due to operational problems resulting from surface flooding from the Ouachita River, which bisects the field.

Figure 10 illustrates the cumulative balance of CO_2 volumes as of June 1, 1979. Pertinent features to be noted from this figure are:

- After 2-1/3 years of operation, utilization of source CO_2 is only half that originally anticipated as the total project requirement (to be achieved in two years).
- Recycling of a high percentage of produced gas (cumulative average 77 percent) has resulted in achieving a reservoir retention of CO_2 equivalent to 68 percent of purchased volume, or more than twice the percentage that could have been attained without recycling.
- The cumulative amount retained represents 62 percent of the solvent capacity of the reservoir fluids computed by Phillips. It is our understanding that current operating plans anticipate injecting much less CO_2 than originally anticipated, and that injection of purchased gas will probably be discontinued in the near future.

Production Performance

The projected production, assuming continued primary production after January 1976 at an extrapolated decline rate of 9 percent per year shown in Fig. 6, is somewhat more optimistic than Phillips originally projected on the basis of production data through 1973. The consistency of the additional two-year production history with the previous eight-year decline rate is believed to support the higher rate projection, at least for several years. Primary operations are assumed to cease when the total field rate reaches 2,000 barrels per month. On this basis, the estimated primary reserve as of February 1, 1976, was 750,000 barrels and the estimated primary ultimate 5.2 million barrels.

Figure 11 shows total project production of oil, water, and gas, the latter being essentially all recycled CO_2. One of the principal features of the performance shown by Fig. 11 is the sharp drop in water production associated with Phase I operations. Subsequent field water production responded rapidly to the start of water injection in Phases II and III and by March 1979 was about 160,000 barrels per month more than the rate before the start of water injection. During this time injection rate had reached 150,000 barrels per month.

Monthly oil production increased from 8,000 barrels to a peak rate of 28,000 barrels during March 1977, late in Phase I operations, and had dropped to about 21,000 barrels at the start of water injection in mid-1977.

Interpretations and Conclusions

Based on the projection of primary performance shown in Fig. 11, project incremental recovery to June 1, 1979, is 400,000 barrels. Discounting the abnormally low production rate during April and May 1979, the incremental production rate over the past 1-1/2 years has averaged about 11,000 barrels per month, with no apparent decline. As noted previously, the upper limit of ultimate incremental recovery was originally predicted to be 3 million barrels, based on analogy with the Ritchie Field and other model studies. This prediction anticipated that a maximum oil production level averaging 46,000 barrels per month would be achieved during the fourth year of project operation. The maximum actually obtained through 3-1/2 years of operation was in the second year and averaged about 21,000 barrels per month. Because of the present high percentage production of injected fluids, and because of indications from the operator that source-CO_2 injection may soon be discontinued, it appears likely that this rate will not be exceeded and that ultimate incremental recovery will be much less than originally predicted.

As a basis for a preliminary revision of the original estimate, it has been assumed that, under full uninterrupted operations, an average oil production rate of 20,000 barrels per month could be maintained through 1980, and further, that oil production would decline thereafter at a rate of 16 percent per year to a limiting rate of 4,000 barrels per month. With this assumed future performance, which is shown in Figs. 6 and 11, future incremental recovery as of June 1, 1979, would be approximately 1 million barrels, giving an estimated ultimate incremental recovery of 1.4 million barrels. For preliminary evaluation purposes, therefore, ultimate incremental recovery is estimated to be in the range of 1.0 to 1.5 million barrels from the injection of an ultimate volume of purchased CO_2 of 6 to 7 billion cubic feet.

On the basis of this preliminary estimate of ultimate performance, a CO_2 utilization ratio of about 5 Mcf per barrel of incremental oil recovered is indicated for the Lick Creek Meakin Sand Unit project.

REFERENCES

1. Park, W. G., Wood, S. O., Jr., and Carrales, J., Jr.: "Heavy Oil Reservoirs in Arkansas," U. S. Bureau of Mines Information Circular No. 8428 (1969).

TABLE 1

FIELD DATA FOR CARBON DIOXIDE INJECTION PROJECTS

FIELD: LICK CREEK

LOCATION AND GENERAL DATA

State: Arkansas County: Bradley & Union

Discovery Date: 1957 Date First Production ________

No. Wells: 68 @ Date: 1974

Developed Area: 1640 Acres

GEOLOGY AND PETROPHYSICS

Reservoir Name: Meakin Sand

Reservoir Rock Type: Fine grained sandstone

Trap: Anticline bounded by fault and water level

Average Depth: 2500 feet

Primary Gas Cap (Y/N) - No

Gas/Oil Contact Depth: --- feet subsea
Oil/Water Contact Depth: 2480 feet subsea

Average Net Pay Thickness: 8.6 (1) feet (Range 0-16')

Net/Gross Ratio: approx. 1.0
Average Porosity: 33 (2) %
Initial Water Saturation 32 %
Average Permeability: 1200 millidarcies

Permeability Range: to 6000 millidarcies

Permeability Variation: ________

k_v/k_h: ________

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

BASIC RESERVOIR AND VOLUMETRIC DATA

Initial Reservoir Pressure: 1200 psi
Reservoir Temperature: 118 °F
Bubble Point Pressure: 85 psi
Formation Volume Factors:
B_{oi} est. 1.05
B_{ob} est. 1.05
Reservoir Oil Viscosity Data:
μ_{oi} 160 (3) centipoise
μ_{ob} ___ centipoise

Initial Solution Gas-Oil Ratio:
R_{si} est. 25 cu.ft./bbl.
Stock Tank Oil Gravity: 17.2 °API

Reservoir Hydrocarbon Pore Volumes:
Oil Column: 24,600 M Bbl Gas Cap: --- M Bbl
Standard Volume Original Hydrocarbons in Place
Oil: 23,400 M Bbl Free Gas: --- Mcf

RESERVOIR PERFORMANCE DATA

Primary Recovery Drive Mechanism: Solution gas plus water drive

Estimated Ultimate Primary Recovery: 21.6 (4) % ISTOIP

Supplemental Recovery Method(s) and Date Started: None prior to CO_2 (see pg. 3 - CO_2 project data)

Cumulative Oil Production at Start Supplemental: ___ M Bbls ___ % ISTOIP

Unit Operator(s): ___

Average Pressure at Start Supplemental: ___ psi

Estimated Additional Supplemental Recovery (Ultimate): ___ % ISTOIP

Estimated Total Ultimate Recovery (Primary+Supplemental) ___ % ISTOIP

Cumulative Total Production to: 2/1/76 (Date)
4,485 M Bbls 19.2 % ISTOIP

Average Pressure: range 150-1000 psi @ 1/1/74 (Date)
Calculated Average Oil Saturation 55 (5) %@ 2/1/76 (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

CARBON DIOXIDE INJECTION PROJECT DATA

Project Operator: PHILLIPS PETROLEUM

Project Type: Mini-Test ___ Pilot Test ___ Full-Scale Project X
Recovery Mode: Secondary X Tertiary ___
Project Area: est. 900 (6) Acres
No. of Wells: Injection 16 Production 38 Other ___

Pattern Geometry: Irregular, approximating inverted 9-spot with 5 complete inside patterns and eleven incomplete peripheral patterns.

Date Project Commenced: Feb. 1976 Ended Active 6/1/79
Injection Fluid Composition (mol percent)
CO_2 est. 98 ± (7) H_2S ___ C_1 ___

C_2-C_6 ___ C_7+ ___ Other some water

Estimated miscibility pressure: not determined psi
Injection Fluid Source(s): CO_2 via pipeline supplied by ammonia plant in Sterling, La. Water is produced water.
CO_2 Injection Rate (Excluding Recycle): 3200 Mcf/day 1979 (Date)
Recycle Gas Injection Rate: 3900 Mcf/day 1979 (Date) 5 mos. avg.
Water Injection Rate: 3600 Bbl/day 1979 (Date)

Water Injection Mode (i.e., alternating, continuous after "slug", etc.)
Discuss: Phase I - Huff-puff of producers & injectors; Phase II - CO_2 slug injectors; Phase III - W.A.G. in injectors; Phase IV - water injection (with some recycled CO_2). Operations now in Phase III.

Injection Pressures:
CO_2: Surface 700-1100 (8) psi Bottomhole (9) psi
Recycle: Surface ___ psi Bottomhole ___ psi
Water: Surface 0-500 psi Bottomhole ___ psi

Cumulative Injection @ 6/1/79 (Date)
CO_2 5540 MMcf 19.6 (10) %HCPV
Recycle: 5803 MMcf 20.6 (10) %HCPV
Water: 1377 ~~MMcf~~ Thous. BBL 7.5 %HCPV

Current Production Rates: (Date) Approx. avg. 1978-79

Oil: 560 Bbl/day Gas: 6000 Mcf/day
CO_2: 6000 Mcf/day Water: 4500 Bbl/day

Date First Response: April, 1976

Date CO_2 Breakthrough: March, 1976

Cumulative CO_2 Production: 7576 MMcf @ 6/1/79 (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

Incremental Response: 370 Bbl/day @ Approx. avg. 1978-79 (Date)

Cumulative Incremental Oil @ 6/1/79 (Date) 400 M Bbl

CO_2 Utilization Ratio-Cumulative Injection CO_2/Cumulative Incremental Oil 13.9 Mcf/Bbl, based on CO_2 supply only (11)

Expected Ultimate Incremental Production:
3000 M Bbls (12) 12.8 % ISTOIP

Supplemental Information

(1) Based on reported productive area and productive acre-feet, net pay in principal area of production averages about 12 feet.

(2) Reported by operator at 33% (core data) and 25% (log data).

(3) Viscosity of stock tank crude = 240 cp.

(4) Operators estimate of primary ultimate (1974) = 5.055 MMBBL.

(5) Will vary within field with degree of water encroachment.

(6) Total original productive area unitized, however, operator estimates only 10,527 acre-feet of "effective" floodable rock volume. Acreage estimate assumes average net pay = 11.7 feet in floodable volume.

(7) Purchased CO_2 - essentially pure

Recycled CO_2 - assumed very near to purchased because of very low natural gas volume and high recycle rate.

(8) CO_2 supply line pressure = 1350 psig.

(9) "Reservoir pressure being maintained at 1000-1100 psig" per operator.

(10) Based on effective floodable hydrocarbon pore volume = 18.326 million barrels and estimated CO_2 unit volume at reservoir conditions = 0.65 Mcf/Bbl.

(11) Cumulative utilization ratio based on total injection (including recycled CO_2) = 28.4.

(12) Operator projected "Upper Limit".

TABLE 2

TYPICAL CORE ANALYSIS (SOUTHERN "A" 2)

Depth, feet (RKB)	Porosity, %	Abs. perm., md	Resid. water satn., %
2542.5	29.3	410	71.7
43.5	30.3	112	74.2
44.5	28.5	1470	66.6
45.5	27.5	26	69.8
46.5	34.3	755	57.4
47.5	32.8	1585	31.4
48.5	34.8	3780	44.9
49.5	34.4	5980	34.3
50.5	32.6	3750	43.3
51.5	33.8	4130	42.3
52.5	33.9	2950	46.4
53.5	31.5	349	54.0
54.5	30.9	482	67.0
55.5	27.9	545	66.3
56.5	30.1	980	68.0
57.5	30.6	985	69.2
58.5	29.2	119	73.3

Average porosity for the interval 2543.5 to 2555.5 feet is 31.8%.

TABLE 3

6-456 D (April 1955)

CRUDE PETROLEUM ANALYSIS

Bureau of Mines Bartlesville Laboratory
Sample 65016

IDENTIFICATION

Lick Creek field
Meakin, Upper Cretaceous
2,522 - 2,547 feet

Arkansas
Union County

GENERAL CHARACTERISTICS

Gravity, specific, 0.950 Gravity, ° API, 17.4 Pour point, ° F., 20
Sulfur, percent, 2.92 Color, brownish black
Viscosity, Saybolt Universal at 100°F. 2,580 sec.; at 180°F. 260 sec. Nitrogen, percent, 0.116

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 751 mm. Hg
First drop, 174 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum. percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122									
2	167									
3	212	0.9	0.9	0.693	72.7	-	1.39248	130.2		
4	257	1.2	2.1	.710	67.8	7.5	1.40007	125.7		
5	302	1.4	3.5	.736	60.8	12	1.41182	127.5		
6	347	1.3	4.8	.757	55.4	15	1.42446	132.3		
7	392	1.4	6.2	.789	47.8	24	1.43705	135.2		
8	437	1.8	8.0	.807	43.8	27	1.44845	140.9		
9	482	3.0	11.0	.826	39.8	31	1.45778	143.9		
1/ 10	527	3.7	14.7	.843	36.4	34	1.46687	150.4		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	3.9	18.6	0.868	31.5	42	1.47870	157.6	41	Below 5
12	437	6.0	24.6	.884	28.6	46	1.48731	166.5	51	20
13	482	6.2	30.8	900	25.7	50	1.49920	-	73	35
2/ 14	527	3.3	34.1	.919	22.5	56			100	50
15	572									
Residuum		64.9	99.0	1.006	9.2					

Carbon residue, Conradson: Residuum, 8.2 percent; crude, 5.6 percent.

C/H 7.42

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	0.9	0.693	72.7	
Total gasoline and naphtha	6.2	0.741	59.4	
Kerosine distillate	1.8	.807	43.8	
Gas oil	13.1	.853	34.3	
Nonviscous lubricating distillate	11.3	.882-.919	28.9-22.5	50-100
Medium lubricating distillate	1.7	.919-.926	22.5-21.4	100-200
Viscous lubricating distillate	-	-	-	Above 200
Residuum	64.9	1.006	9.2	
Distillation loss	1.0			

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1/ Distillation discontinued at 509°F.
2/ Distillation discontinued at 495°F.

TABLE 4

PHYSICAL PROPERTIES OF CARBON DIOXIDE-SATURATED CRUDE OIL

CO_2 Pressure psia	CO_2 Content wt. %	CO_2 Content mole %	Viscosity, cp rolling ball	Viscosity, cp capillary	Density g/cc	Swelling factor vol sol/ vol crude
			Lick Creek Crude Oil at 118°F			
Crude	---	---	207	188	0.9317	1.00
150	---	---	---	140	---	---
250	---	---	---	116	---	---
350	---	---	---	94	---	---
440	---	---	53	64	0.934	---
880	9.24	48.0	32	29	0.939	1.093
1325	13.95	59.8	20	17	0.950	1.140
1600	15.95	63.6	17.5	--	0.941	1.178

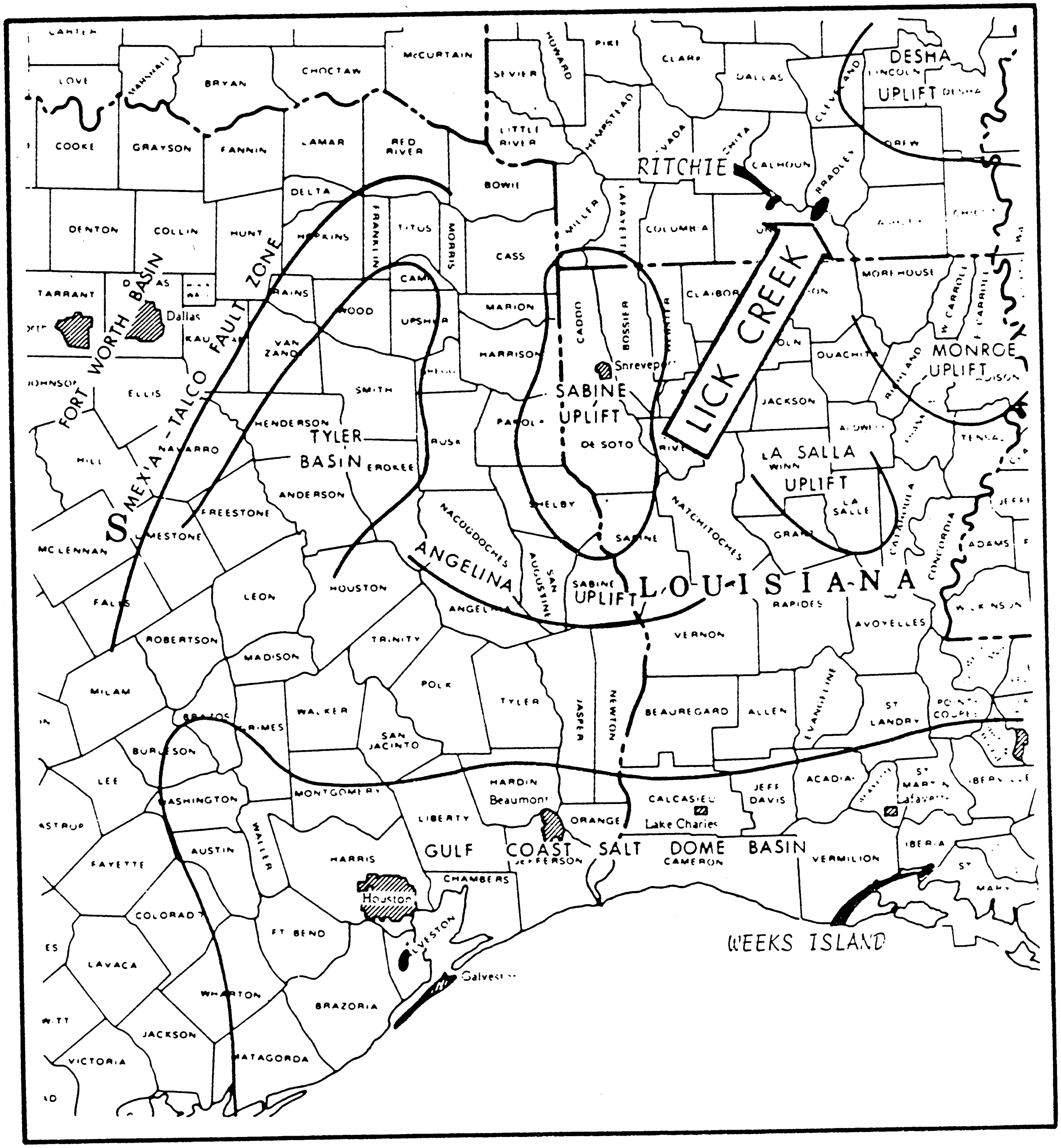


Figure 1.--Index map, carbon dioxide injection projects in Arkansas.

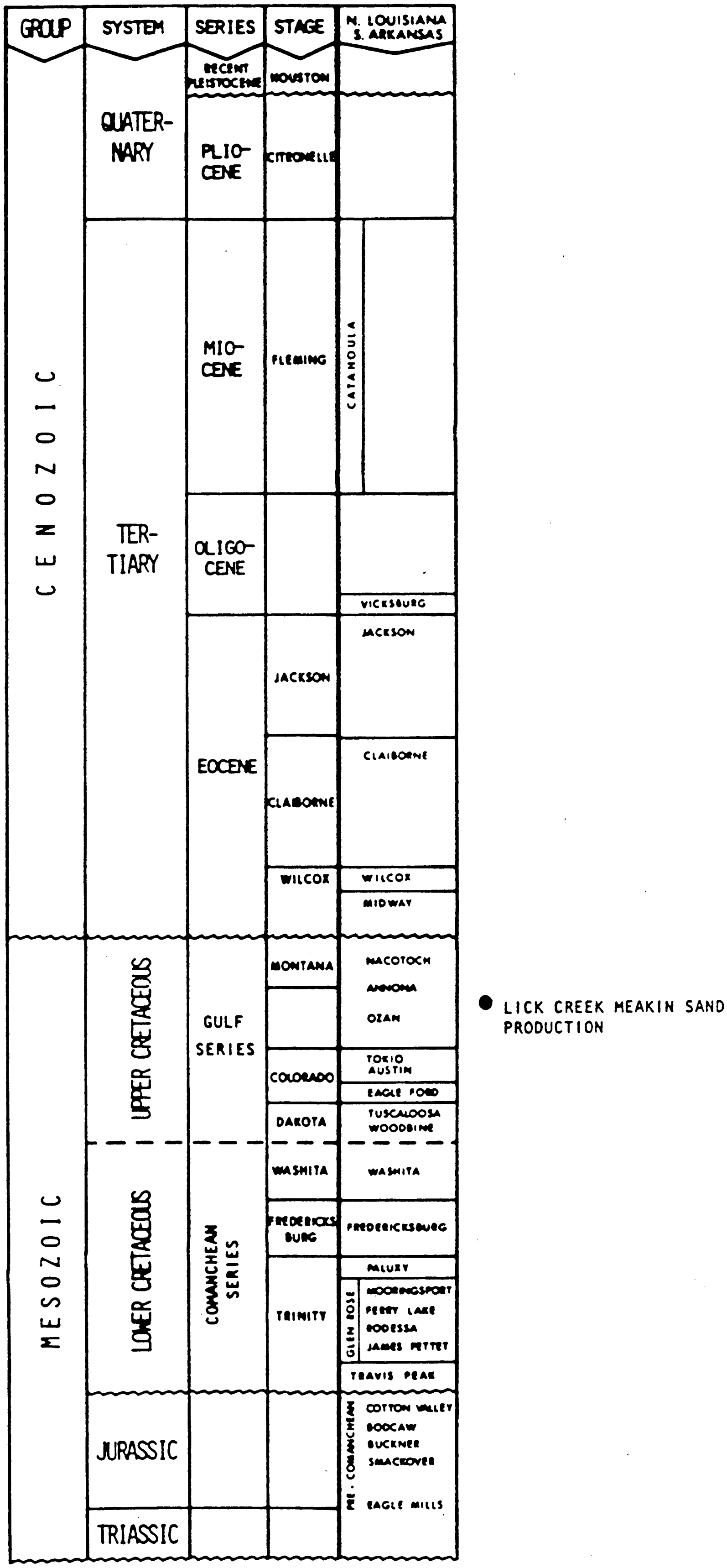


Figure 2.--Generalized stratigraphic column for southern Arkansas.

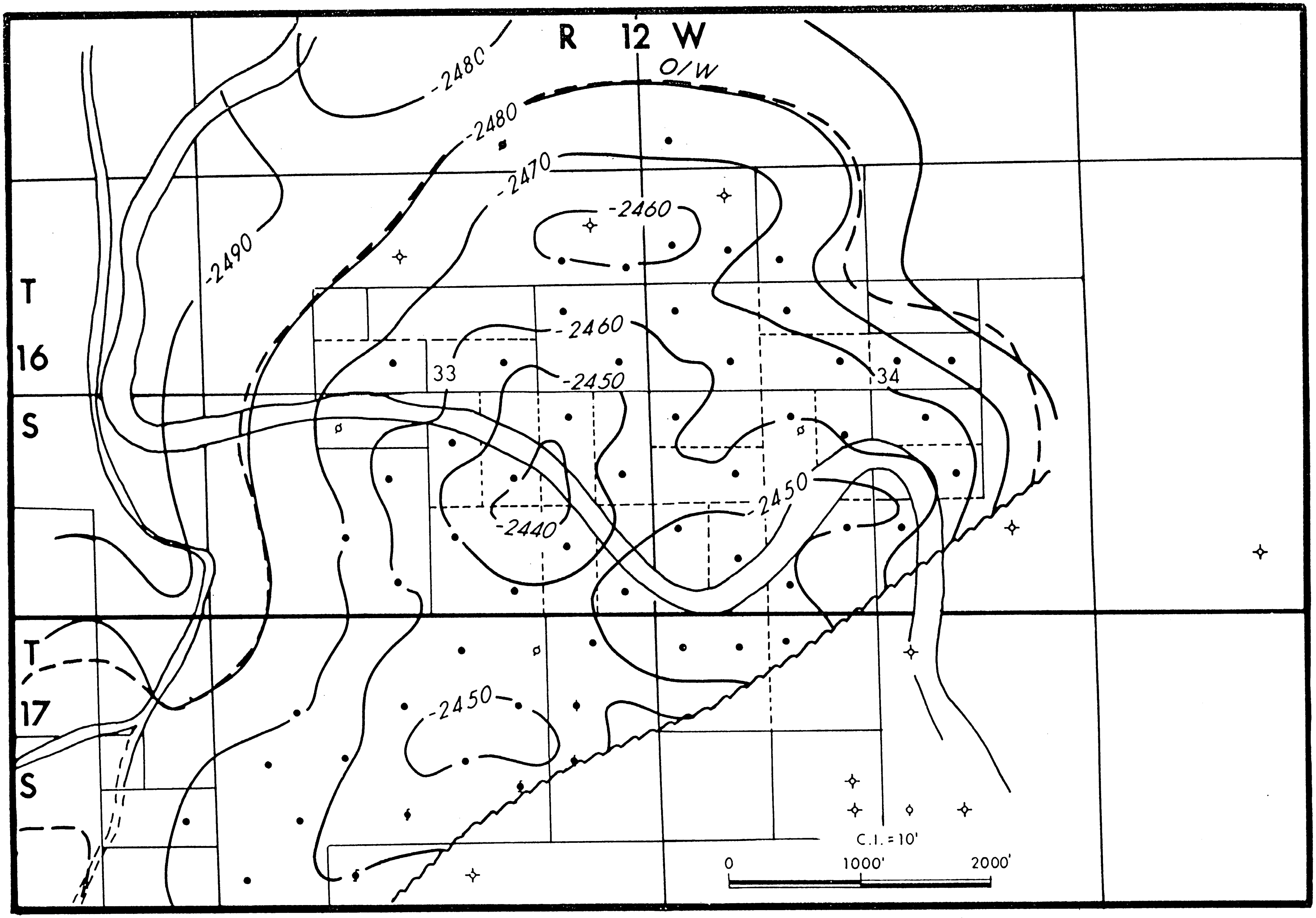


Figure 3.--Structure on top of Meakin sand, Lick Creek field, Arkansas.

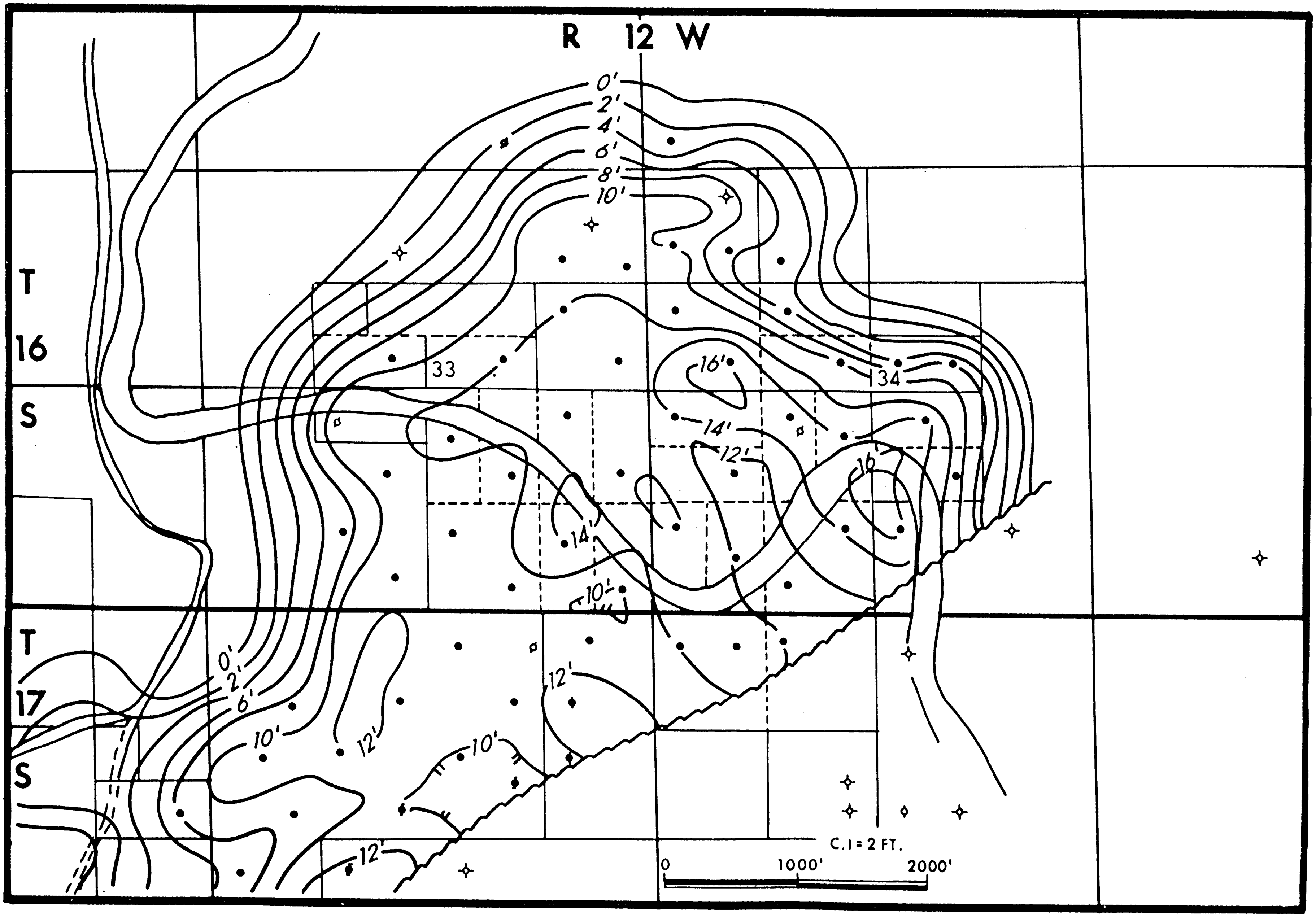


Figure 4.--Isopach map, productive Meakin sand, Lick Creek field, Arkansas.

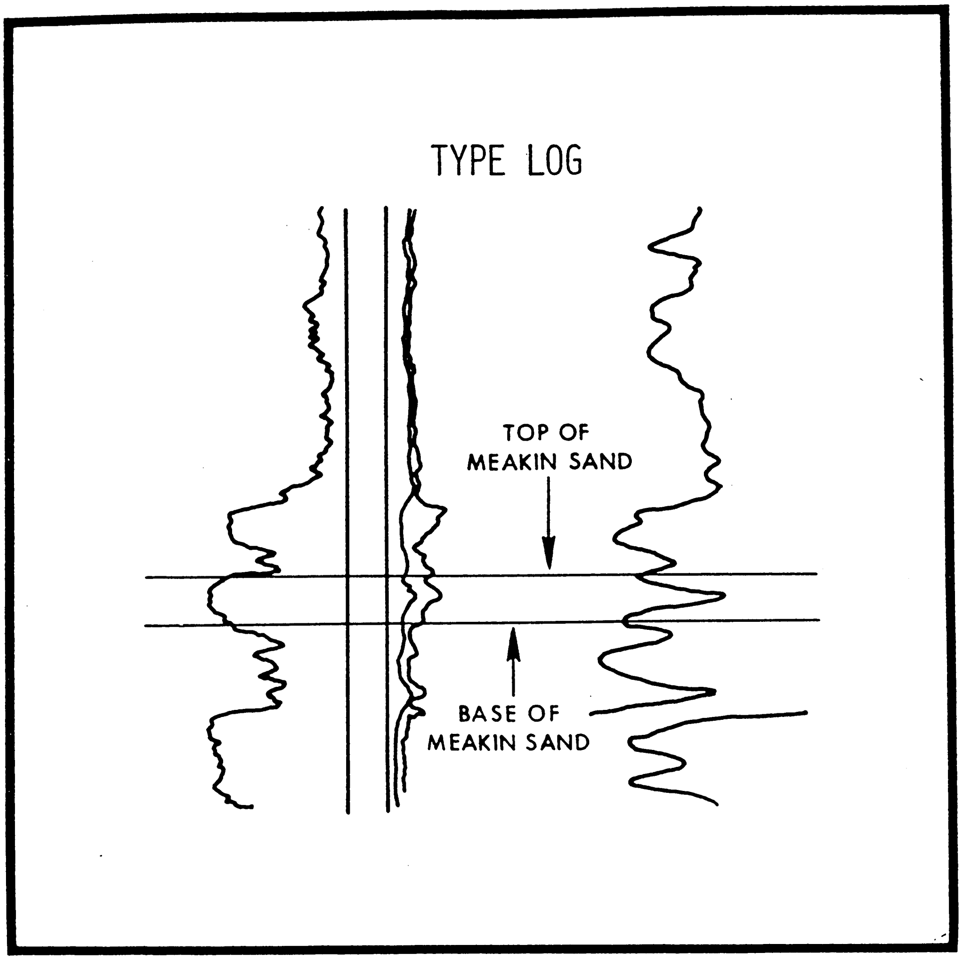


Figure 5.--Typical log for the Meakin sand, Lick Creek field, Arkansas.

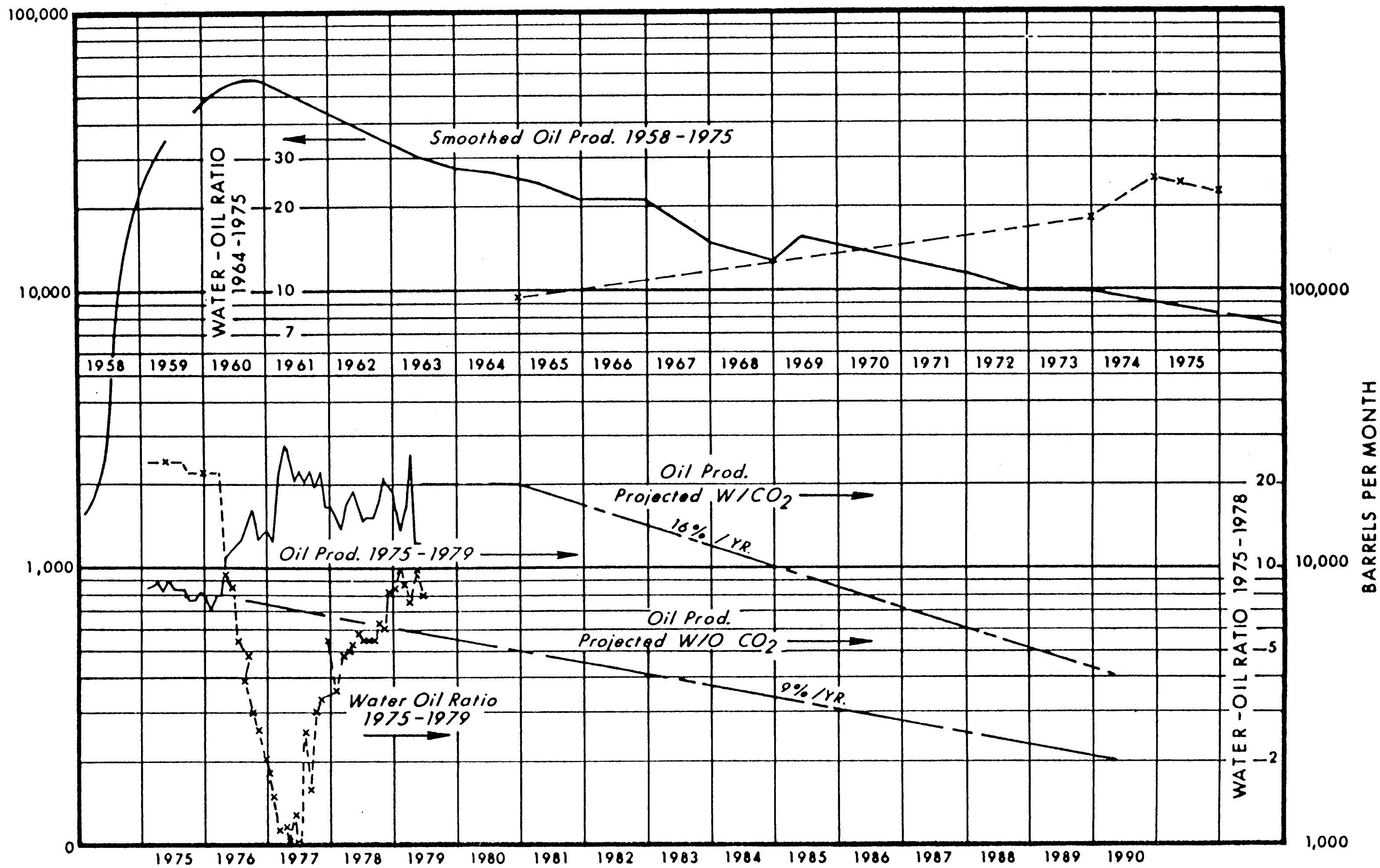


Figure 6.--Production history, Meakin sand unit, Lick Creek field, Arkansas.

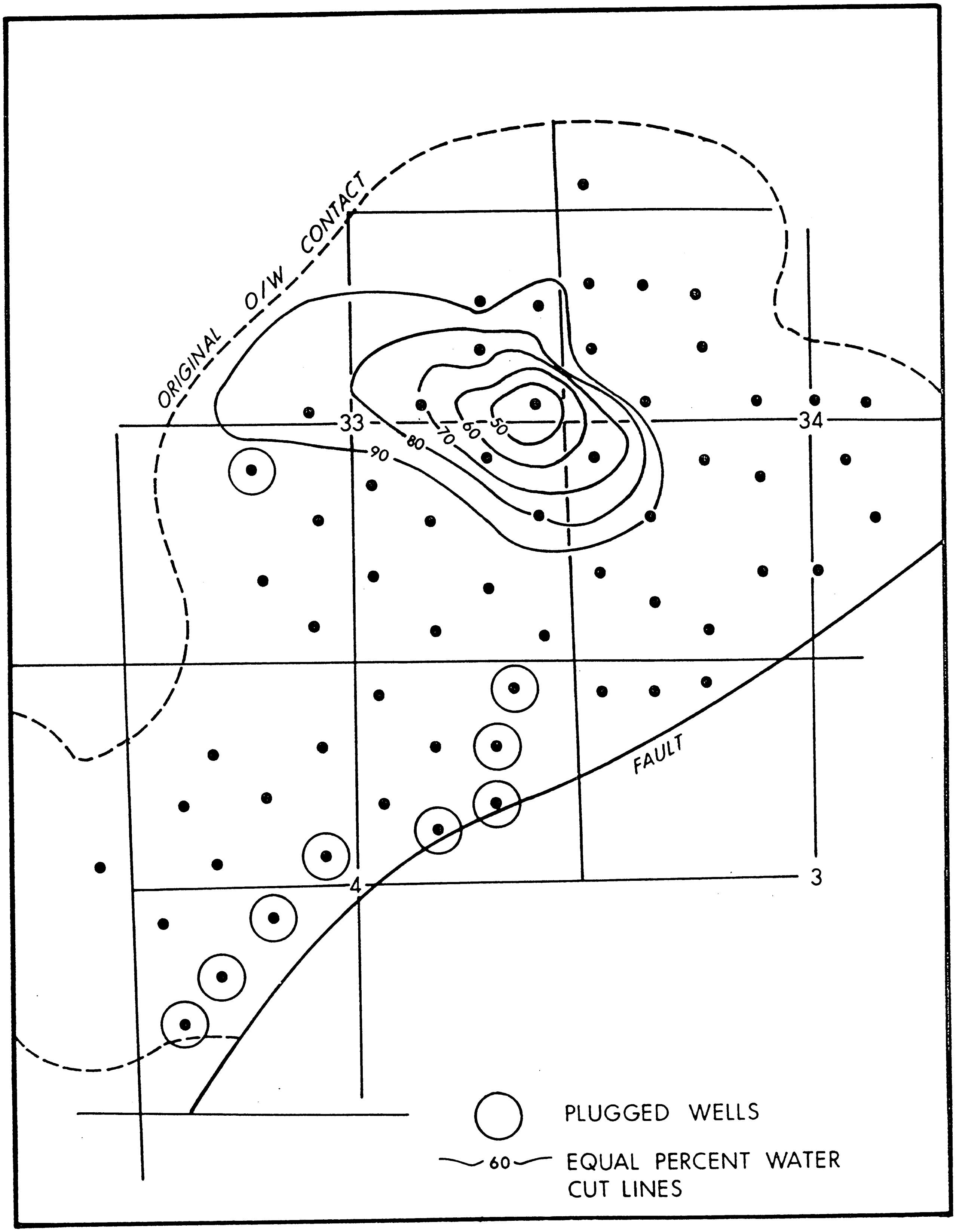


Figure 7.--Water encroachment as of January 1974, Meakin sand unit, Lick Creek field, Arkansas.

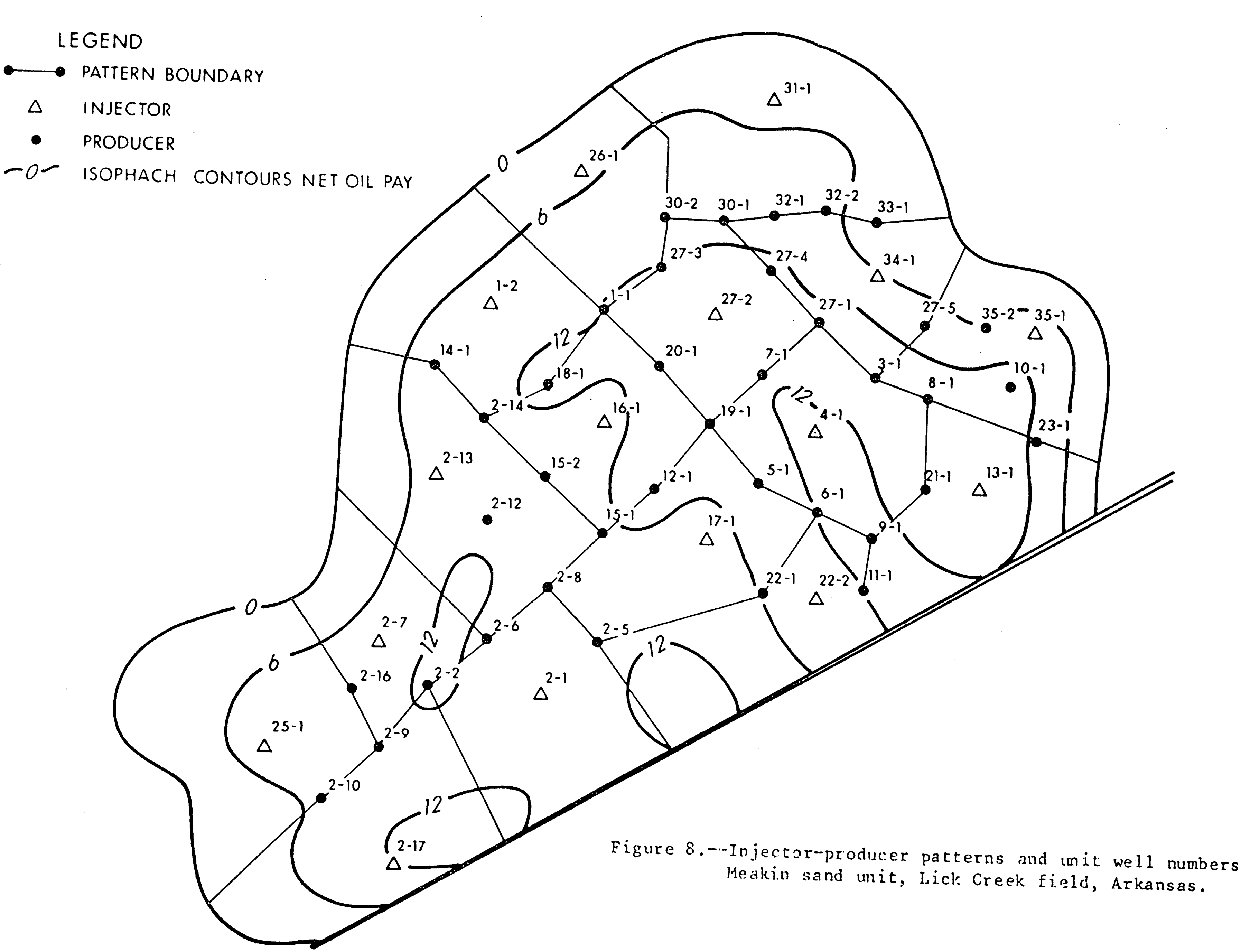


Figure 8.--Injector-producer patterns and unit well numbers, Meakin sand unit, Lick Creek field, Arkansas.

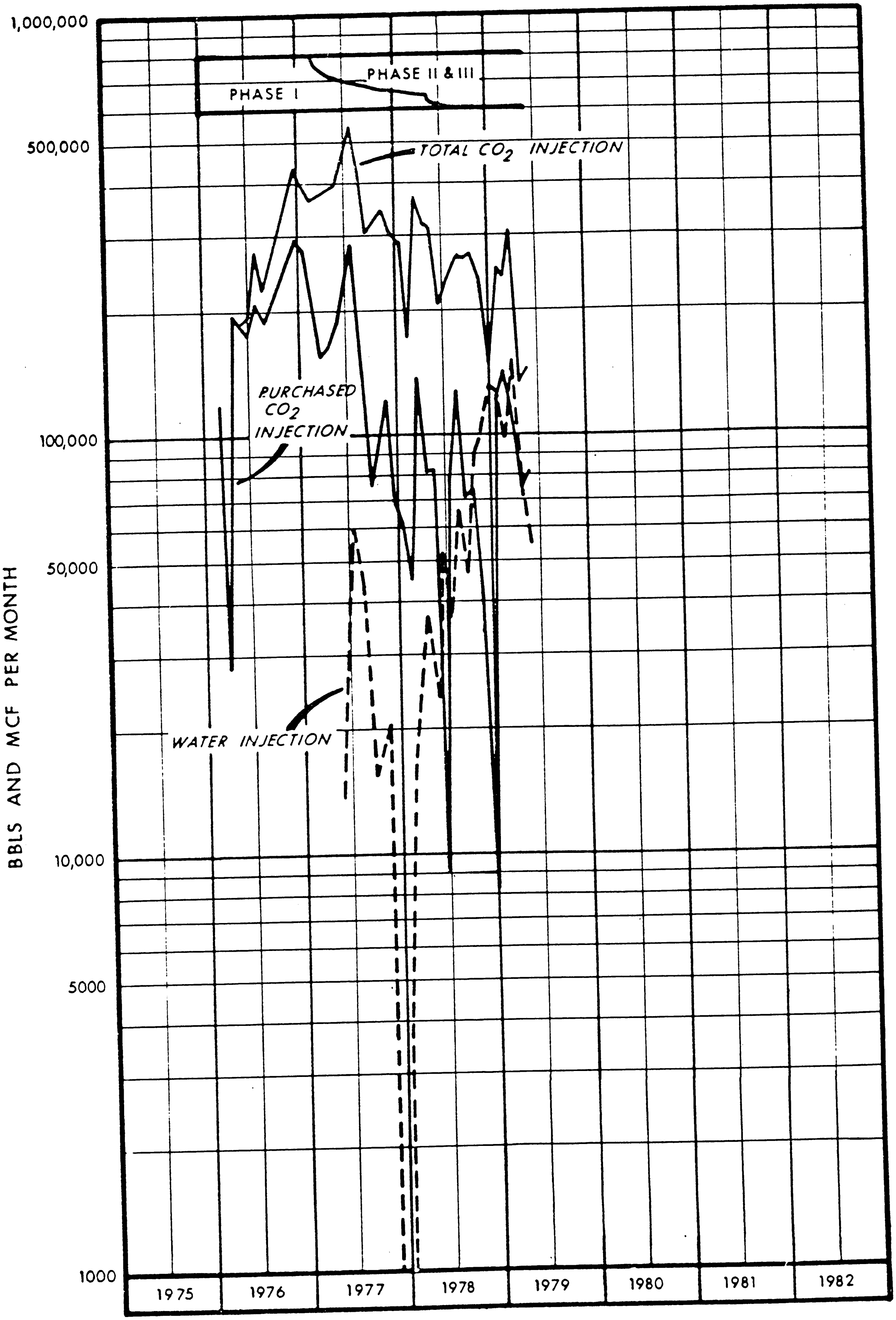


Figure 9.--Carbon dioxide injection project performance, Meakin sand unit, Lick Creek field, Arkansas.

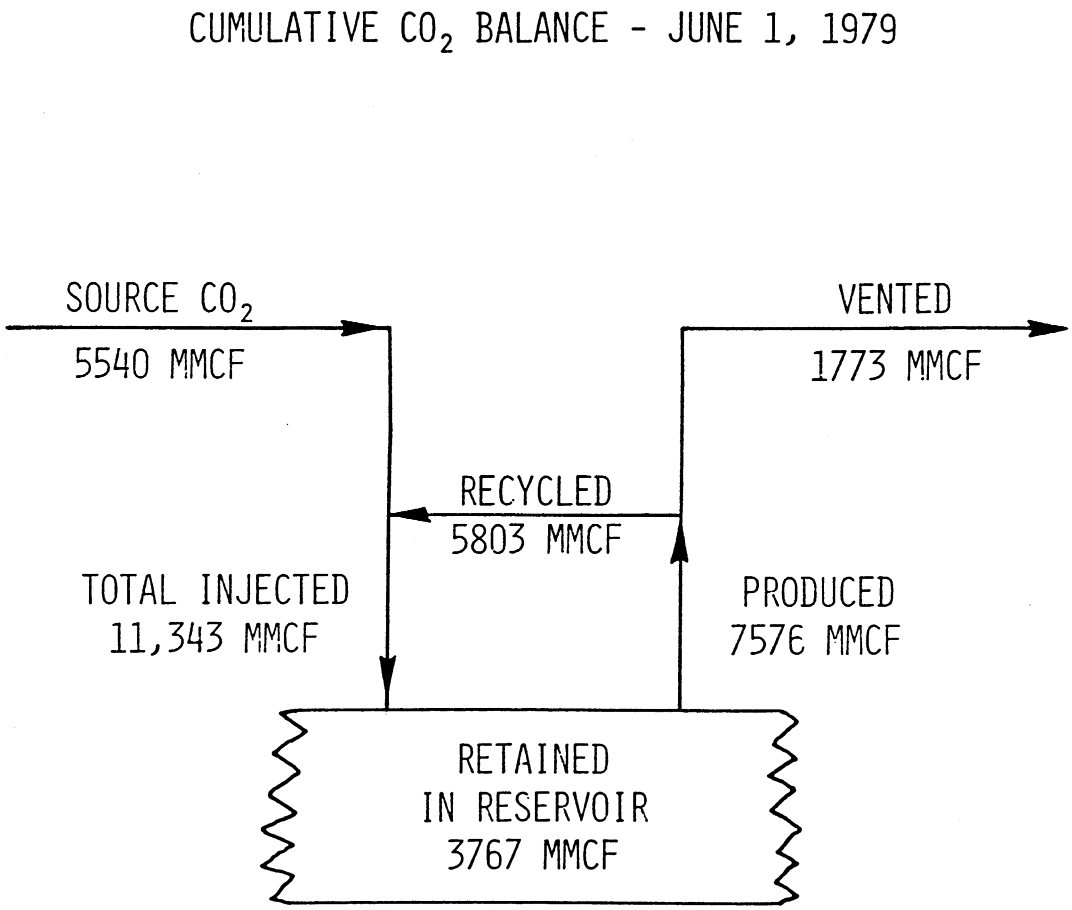
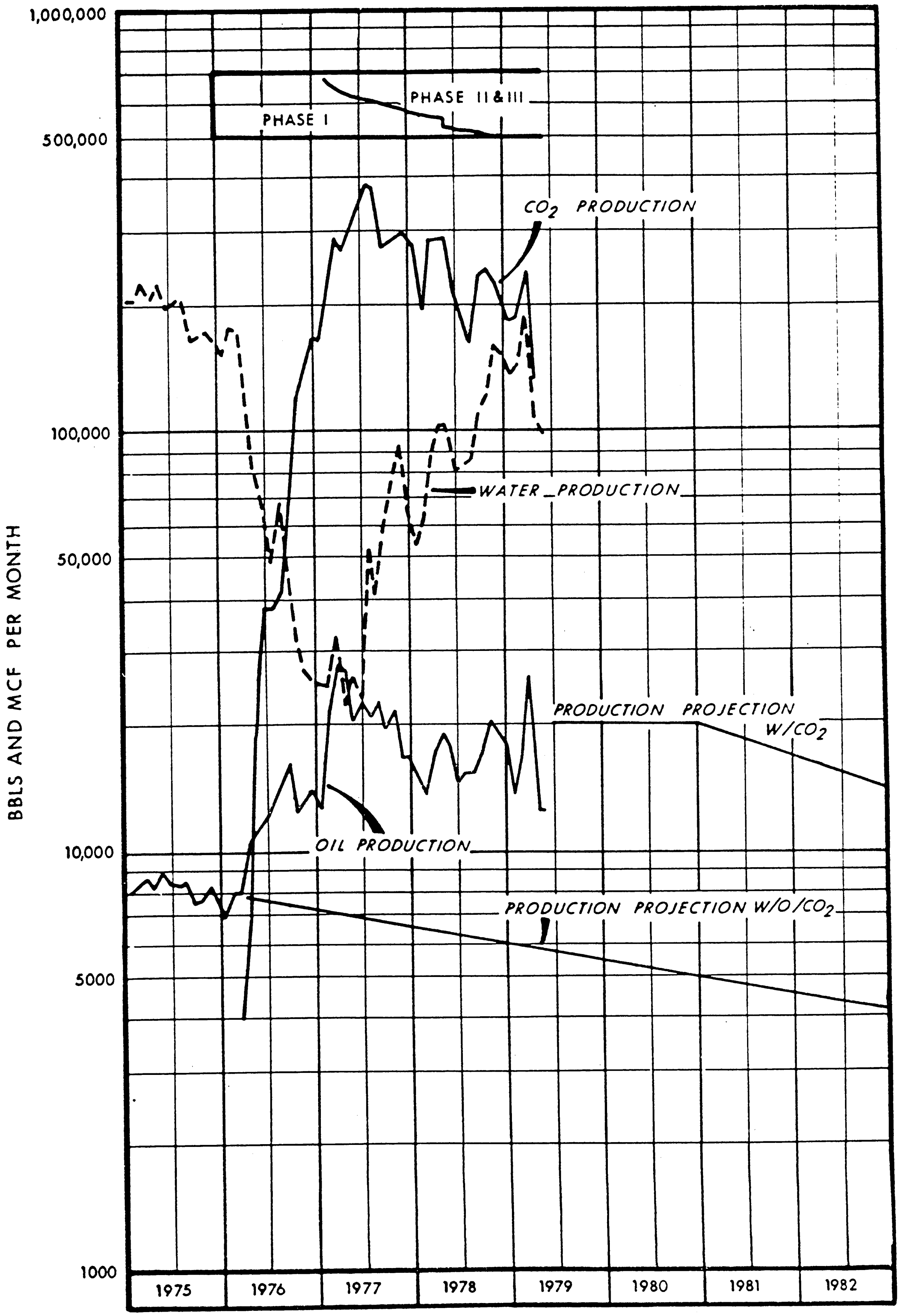


Figure 10.--Cumulative carbon dioxide balance, CO_2 injection project, Meakin sand unit, Lick Creek field, Arkansas.



160 Figure 11.--Production performance, CO_2 injection project, Meakin sand unit, Lick Creek field, Arkansas.

CO_2 FIELD INJECTION PROJECT CONDUCTED BY
CHEVRON OIL COMPANY
KELLY-SNYDER FIELD, WEST TEXAS

by
Raj M. Kumar and Jerry A. Watson

Location and General History

Kelly-Snyder Field, located in Scurry County, Texas (Fig. 1), comprises the major portion of the Scurry Canyon Field, the largest of 15 reservoirs along the crest of the horseshoe atoll, an arcuate chain of limestone mounds that extends for 175 miles in the northern part of the Midland Basin in West Texas. Kelly-Snyder field includes the central and northern portion of the Scurry Canyon Field and contains approximately 85 percent of the reservoir volume; Diamond M Field, occupying the southern portion of Scurry Canyon, contains the remainder.

Kelly-Snyder Field was discovered in 1948 and development was essentially complete by 1951, when 1,671 producing wells had been drilled [2]. Early in the development of the field it was recognized that with a solution-gas drive, pressure maintenance would be necessary to increase ultimate recovery. Accordingly, in 1953 the Kelly-Snyder portion of Scurry Field was unitized (Scurry Area Canyon Reef Operators Committee, SACROC), with Standard Oil Company of Texas (later becoming Chevron Oil Company) as unit operator. The 50,000-acre unit comprises 98 percent of the Kelly-Snyder Field and is the major unitized field among the four contiguous fields along the 5- by 35-mile canyon reef formation. Most of the Diamond M portion of Scurry Field is operated by two pressure maintenance units, the Lion Diamond M Unit and the Sharon Ridge Canyon Unit (Fig. 2).

Water injection into a centerline pattern was begun in the SACROC Unit in 1954. Although the waterflood was highly successful, studies indicated that it would leave an estimated 1 billion barrels unrecovered at project completion. In 1968 the decision was made to develop a CO_2 injection program for improved recovery; CO_2 injection began in 1972.

The Scurry Field contains approximately 73,000 productive acres; Kelly-Snyder comprises 51,000 acres of this field. The original estimate of oil in place in the SACROC Unit, 2.73 billion barrels, was revised to 2.113 billion barrels in 1973, based on a 24-year history match of more than 1,500 wells. Cumulative production at SACROC through 1977 was 937 million barrels; the December 1977 production rate was 139,886 barrels per day.

Geologic and Petrophysical Data

The Scurry Reef, of late Pennsylvanian to early Permian age (Fig. 3), in Scurry County, Texas, is a northeast-southwest trending subsurface feature 23 miles long and 4 to 8 miles wide (Fig. 4). The reef is a low mound of bioclastic debris, having a maximum thickness in the Kelly-Snyder area of 1,535 feet (Fig. 5) [5]. Maximum relief above the oil-water contact (-4,500 ft) is 765 feet; the average relief above water is 250 feet. Depth to the reef ranges from 6,300 to 6,800 feet. The reef limestone is composed of organic debris bonded by crystalline calcite and lithified carbonate mud [3]. The hard parts of organisms comprising the reef have been broken and ground into fragments ranging in size from a few millimeters to submicroscopic [4]. Examination of cores shows that approximately one-third of the material comprising the reef is clay size (calcilutite), one-half is material from 1/6 mm to 2 mm in diameter (calcarenite), and one-sixth is material larger than 2 mm in diameter (calcirudite). In general lithologic types cannot be correlated over appreciable distances. With the exception of shale zones within the reef complex, the structure is almost pure calcium carbonate.

Most of the porosity is secondary, primary porosity being limited to the hollow interiors of some shells. Initial primary porosity was probably significant, but was subsequently filled with calcium carbonate [5]. Secondary porosity, consisting of small interconnecting vugs [5], was eventually developed through leaching [8]. Some of the secondary porosity was subsequently destroyed by deposition of calcite and, in some cases, quartz. The pay zone has an average porosity of 7 percent and an average permeability of 15 md [6]. Figure 6 is a typical log from a reef crestal position.

Studies of zonation within the reef [3,4,5,7] have delineated two distinct types of zones. One type is a low-porosity zone (<4.5 percent) indicative of a lithology containing thin shale beds and more argillaceous material than zones of higher porosity. The second type of zone has a porosity greater than 4.5 percent, usually with less than 1 percent insoluble residue. Paleontological studies suggest that the zones of high and low porosity are related to the recognized stratigraphic units of the Pennsylvanian and Permian rocks [4]. Figure 7 shows typical zonation of high and low porosity types in the Kelly-Snyder Field [1]. Correlation of the zones is often difficult, some being traceable throughout the area while others are of very limited extent [4]. Reservoir communication in the laterally more continuous lower portions of the reef is indicated by updip migration of oil [1]. Vertical migration of oil seems to be uninhibited, although more tortuous, despite the separation of porous and permeable limestone zones by impermeable zones within the reef complex.

Table 1 (at the end of this report) shows engineering, petrophysical, and statistical data.

Reservoir Fluid Data

The reservoir oil of the Kelly-Snyder field was undersaturated at the initial reservoir pressure of 3,137 psia and had a solution gas content of slightly under 1,000 scf/STB and a bubble-point pressure of 1,820 psia. The average reservoir fluid composition and properties are shown in Table 2. The reservoir oil is rich in intermediates and formation volume factor is very sensitive to separator conditions.

Reservoir Performance Data

Performance Prior to Unitization. Early in the life of the field it became evident that the primary producing mechanism was solution-gas drive. Only very limited water influx was detected, indicating a relatively small aquifer in the immediate area. This was demonstrated by the fact that the production of 128 million barrels of oil was accompanied by a 50 percent reduction in reservoir pressure, to 1,560 psi. The average producing gas-oil ratio rose to about 1,350 scf/STB. Figure 8 shows the performance history from 1948 to 1954, when water injection was initiated. It became apparent from the rapid pressure decline that a pressure maintenance program would be required. Late in 1950 the Scurry Area Canyon Reef Operators Committee (SACROC) was formed to investigate the feasibility of a pressure maintenance program. The Texas Railroad Commission approved formation of the SACROC Unit in 1953.

Performance Since Unitization. Water injection into a pattern involving the 72 centerline injectors began in September 1954. The wells were located generally along the longitudinal crest of the structure in the thicker portion of the reservoir. With the growth in oil demand, 72 additional wells were converted to injection service in 1969-1971 to meet higher allowables. Operation of this centerline water injection continues at the present time.

The centerline water injection program has been effective in maintaining the bottomhole pressures in the producing area of the unit. Figures 9 and 10 depict the BHP conditions at four different times in the life of the field.

By the end of 1971, 771 million barrels of water had been injected in the unit; about 410 million barrels of oil had been produced. This over-injection resulted in an increase in the volumetrically weighted average reservoir pressure from 1,560 psia in mid-1954 to 2,350 psia at the end of 1971. Most of the reservoir was restored to liquid-saturated conditions and the producing GOR stabilized at a value near the solution ratio.

Figure 11 shows the advance of the water front as a function of time. The water breakthrough time at individual wells was noted and contoured at 20-month intervals to locate the leading edge. The figure shows that the movement of the water front has been relatively uniform, with no serious bypassing or channeling. Although the performance of the centerline water injection has been encouraging, the effective maintenance of bottomhole pressures in the flank area by continued centerline water injection alone could not be expected. Early conversion of the flank areas to the pattern injection would be necessary to provide the required productivity support. Studies to evaluate alternatives indicate that injection of CO_2 into these unflooded areas was more attractive than expansion of the centerline waterflood. Injection of CO_2 was started early in 1972. The reservoir performance after CO_2 injection is discussed in detail in a subsequent section.

Carbon Dioxide Project Data

With the favorable mobility ratio of water to oil (0.3), little could be done to improve conformance. The best opportunity for increasing the recovery from the reservoir at SACROC was to reduce the oil saturation in the swept area. Two feasible alternatives were investigated and evaluated: use of residue gas enriched with propane, and injection of CO_2 miscible slugs. The latter was chosen because of more attractive economics and a better chance of success.

The performance prediction and incremental reserves estimated earlier were based on the assumption that only that part of the reservoir ahead of the centerline waterflood would be processed by CO_2. This volume of reservoir was estimated to be 1.703 billion barrels at the start of CO_2 flood and a pattern of 174 nine-spots was chosen. However, this was later reviewed before the distribution system was designed. The review indicated that an additional 28 injection wells along and slightly behind the leading edge position were warranted. The addition of these wells provides for processing areas near the leading edge which will be only partially waterflooded at the start of CO_2 injection and which represent a substantial volume of yet-unrecovered oil, as well as assuring that all volume within this area not invaded by water will be processed with CO_2. The resulting expanded pattern was designed to process a total of 1.966 billion barrels of hydrocarbon pore volume, approximately 49 percent of the original unit HCPV.

At the time it was planned, the project was estimated to produce an additional 230 million barrels of oil by injection of about 630 billion cubic feet of CO_2 over a period of approximately nine years [13].

Carbon Dioxide Source. A CO_2 source large enough to meet the demand of the SACROC Unit was obtained from Val Verde Basin gas wells about 200 miles south of the field. These wells were producing gas containing 25 to 52 percent CO_2, which was available from the vent stacks of several gas processing plants. Canyon Reef Carriers, Inc. (CRC) was formed in December 1970 for the purpose of providing facilities to the SACROC Unit. The final system design employed a 180-mile segment of 16-inch pipeline operating at 1,400-2,000 psi, and a 40-mile segment of 12.75-inch pipeline operating in the 2,000 to 2,400 psi range. The system includes four gathering stations, one located in each of the Brown-Bassett, Grey Ranch, Mitchell, and Puckett Fields, and two booster stations, one at SACROC and one along the pipeline. Figure 12 illustrates the location of the facilities and Fig. 13 is a schematic of the SACROC CO_2 injection system. Total compressor capacity is 81,000 hp. The system was designed to deliver 220 MMcf/D to SACROC and 20 MMcf/D to the North Cross unit.

Operating Plan

The original operating plan called for injecting 200 MMcf/D of CO_2 in a continuous slug amounting to 20 percent of the hydrocarbon pore volume (HCPV), to be followed by water injection in 160-acre inverted nine-spot patterns. However, on the basis of laboratory work and a model study, two changes were made. First, it was decided to inject smaller slugs of CO_2 alternating with slugs of water (water-alternating-gas, or "WAG" process) rather than a continuous slug of CO_2. The model study indicated better recovery with the WAG process. Second, injection of water in low-pressure areas before injecting any CO_2 was recommended. This pre-injection of water is planned to raise bottomhole pressure in these areas to a level sufficient to redissolve any free gas that may be present, and to prevent channeling of CO_2, which might have resulted from the presence of a continuous gas phase.

The field was divided into three areas as shown in Fig. 14; the Phase I area was to be processed first, then Phase II and Phase III. These changes, besides providing additional incremental oil, would expedite the processing of the reservoir. It was estimated that with the new plan the entire unit could be put on pattern injection within 40 months, compared to 70 months under the old plan. The operating plan at the time pattern injection started called for injecting 6 percent HCPV within a phase area, followed by a slug of water equivalent to 2.8 percent HCPV. Alternation of these slugs would continue until total cumulative CO_2 injection amounted to 20 percent HCPV. In late 1975 and early 1976, four centerline producers in Phase I and Phase II were converted to CO_2-WAG injectors, bringing the total number of CO_2-WAG patterns in the project to 206.

A dual injection distribution system was considered necessary because it presented fewer operational problems, created less severe corrosion problems, and offered greater flexibility.

An extensive workover program was initiated in July 1970 at SACROC to meet the increasing producing and water-injection capacities which resulted from increasing allowables associated with the approval and installation of the miscible CO_2 injection program. During the period July 1, 1970, to December 1, 1971, 561 wells were worked over for the following purposes:

1. to increase water injectivity
2. to increase producing capacity
3. to remedy equipment failures
4. to provide water source wells
5. to accomplish recompletions required in the CO_2 injection programs.

A summary of well work at SACROC is shown in Table 3.

Injection Performance

Operational problems associated with CRC compressors restricted CO_2 injection to about 75 percent of design specifications. To increase injection rates and to utilize produced CO_2, two recompression stations were installed: one in May 1975 near the Sun CO_2 removal plant and one in January 1976 at the Chevron CO_2 removal plant, to inject CO_2 removed at these plants into the inlet of the CRC booster compressor. The combined total injection rate for these two plants peaked at 40 MMcf/D in 1976 and has been averaging about 34 MMcf/D. A complete history of CO_2 injection in the SACROC Unit is shown in Fig. 15. Produced gas is processed at three gasoline plants at SACROC having a total CO_2-removal capacity of 56 MMcf/D.

Injectivity of both CO_2 and water increased initially, but poor water quality caused plugging in the injector wells. A stimulation program was implemented for periodic restoration of injectivity.

Water and CO_2 injection rate performance of both the pattern and center-line areas is shown in the upper parts of Figs. 16 through 18, for Phases I through III. Similar performance for the entire field is shown in the upper part of Fig. 19. Cumulative injection volumes are summarized in Table 4. A summary of bottomhole pressure surveys in the pattern areas of the SACROC Unit CO_2-WAG Project is presented in Table 5.

Soon after CO_2 injection started it was realized that poor injection profiles at SACROC had to be corrected to prevent premature breakthrough of CO_2. Of the several methods available, the one that proved effective was the installation of liner across the reef, followed by installation of downhole flow equipment. Two wells (37-2 and 49-2) in Phase II were chosen to determine the effectiveness of this technique. Although injection profiles shown in Figs. 20 and 21 for the two wells run with only a liner and no downhole flow control equipment show reasonable coverage, the large hydrocarbon pore volumes of the patterns and the high cost of CO_2 justified further improvement. To achieve this, downhole flow control equipment was run in both wells, as shown in Figs. 22 and 23. The equipment run in well 37-2 consisted of five hydrostatic packers, four side-pocket mandrels, and one seating nipple; well 49-2 had four hydrostatic packers, three side-pocket mandrels, and one seating nipple. It was proved that reduction in CO_2 production and improved vertical conformance could be achieved by the following program:

1. WAG ratio of 1:1 for wells with 6 percent HCPV CO_2 injection
2. WAG ratio of 1.5:1 for wells with 6-12 percent HCPV CO_2 injection
3. WAG ratio of 3:1 for injectors whose producers have CO_2 production greater than 33 percent of total injection, irrespective of cumulative CO_2 injected
4. Recompletion of some injectors with liners and selective perforation to optimize profiles.

Injection coverage was improved considerably by the installation of downhole flow control equipment. The performance of these two patterns in terms of CO_2 production rates has been substantially better than the average pattern without this type of control. About 80 injectors were recompleted with liners, some also having selective injection equipment (including packers, offset mandrels, seating nipples, and plugs or chokes) installed to maintain a reasonable balance of CO_2 and water in the various zones of the reservoir.

Complementary injectors were also drilled in patterns where the original injector was located off center, resulting in improved volumetric efficiency. As of December 1977, 36 injectors had been drilled and completed with casing throughout the pay.

Production Performance

As mentioned above, earlier injection of CO_2 at SACROC was carried out in three phases. Production performance of the individual phases for the entire field is discussed below.

Phase I. The production performance of Phase I is shown in Fig. 24. Phase I responded with a rapid rise in production from 30,000 B/D early in 1972 to 108,500 B/D in September 1973. Because of immediate CO_2 production, oil production was curtailed until July 1973 while waiting on CO_2 removal facilities. There was a period of reduced CO_2 injection from late 1973 to early 1974 because of operational problems with the pipeline and conversion of 16 wells from a WAG ratio of 1:1 to 3:1. This resulted in water breakthrough accompanied by declining oil production. However, this decline was reduced after the fourth quarter of 1975 as a result of zonal injection control and addition of 16 more injectors in early 1976.

Water production rose steadily as a result of increased WAG and additional patterns encountering water breakthrough. This increase was slowed when a zonal injection control program was initiated about mid-1975.

Carbon dioxide production at SACROC was almost immediate, two years earlier than predicted by the model studies. At the end of 1972, 100 of the 236 patterns were producing CO_2 at a total rate of 3 MMcf/D. The rate increased to 21 MMcf/D in November 1973. However, CO_2 production was reduced significantly when 16 injectors were converted from a WAG ratio of 1:1 to 3:1. The CO_2 production is shown in Fig. 25, from which it is apparent that only about 16 percent of the total CO_2 injected in Phase I has been produced.

Phase II. Production performance of Phase II is shown in Fig. 26. Phase II did not respond with as dramatic an increase as Phase I because of higher reservoir pressure caused by pre-injection of water and centerline waterflood in Phase II. The oil production rate increased gradually from 70,000 to 85,600 B/D from the combined effects of infill drilling and CO_2 injection. However, oil production declined severely from April through July 1976, reaching a low of 72,400 B/D. At this point an extensive program was carried out to control injection imbalances and increase total injection capacity, consisting of stimulating certain injectors, converting some producers to injection service, zonal injection control, and adding waterinjection pump capacity. This program raised the oil production rate to 76,900 B/D in August 1976. Carbon dioxide injection was directed to Phase III in December 1976, but pipeline failure in Phase III necessitated returning injection to Phase II.

The water production rate rose steadily from early 1973 to mid-1976. Several high-water-cut producers were shut in in mid-1976, resulting in decreased water production. However, the water production rate increased to 121,000 B/D in October 1977 in response to the increase in WAG ratio in December 1976.

Carbon dioxide production in Phase II is shown in Fig. 27. The overall response of CO_2 to WAG and zonal injection control is identical to Phase I. Carbon dioxide breakthrough occurred within six months after full-scale injection commenced.

Phase III. As a result of pre-injection of water beginning in April 1973, oil production increased from 32,000 B/D in September 1973 to 50,000 B/D in October 1974. After a gradual decline in April 1975 to 46,000 B/D, production again increased to 53,000 B/D in January 1976. This increase is attributed to opening some previously shut-in producers, an infill drilling program, and installation of artificial lift in previously flowing wells. Since January 1976 production has declined, except during the second quarter of 1977 when it increased due to total voidage increase (Fig. 28).

Carbon dioxide injection in Phase III began in November 1976, but because of an immediate pipeline failure it was not resumed until July 1977. Flattening out of the oil production decline in mid-1977 is the result of CO_2 injection. Carbon dioxide breakthrough and production in Phase III (shown in Fig. 29) so far has not been as severe as in Phase I.

Total Field. Figure 30 shows the performance summary and Fig. 31 shows total CO_2 production performance for the entire SACROC Unit.

Total cumulative CO_2 produced is equivalent to 15.3 percent of the total CO_2 injected up to the end of 1977. Ultimate production of CO_2 is expected to be 23 percent of the ultimate CO_2 injected for a 12 percent HCPV slug. Thus about 77 percent of the CO_2 ultimately injected will be retained in the reservoir.

Infill Drilling Program

The main objective of the infill drilling program was to recover additional oil from areas bypassed by centerline waterflooding. Complementary injectors were also drilled in certain patterns where original injectors were off center, and, where necessary, additional producers were drilled to complete irregularly shaped patterns.

Significant contribution to production has been made by new wells, as shown by the shaded portions of Fig. 30. Oil production from new wells averaged 21,600 B/D in December 1977 and cumulative new-well oil production was 23.8 million STB at the end of 1977.

Conclusions

Because of the complexity of the project at SACROC, it is difficult to determine exactly how much of the increased oil production is attributable to CO_2 flooding. The project did not do as well as initially anticipated. The main reasons are:

1. Original oil in place was revised in 1973, resulting in a smaller target volume;
2. Reservoir heterogeneity is much more dominant than expected;
3. Free gas stringers are present, especially in Phase I;
4. Immiscible gas performance in certain patterns, attributable to lower initial pressures;
5. Increased investment and operating costs.

Nevertheless, the project is considered an economic success. The last published information estimated additional ultimate oil recovery from CO_2 flooding to be about 88 million STB over waterflooding, if CO_2 injection is carried out to a total of 12 percent HCPV cumulative injection [2]. This end point was chosen because studies showed that even though oil recovery increased with increasing cumulative injection, higher CO_2 requirements and higher operating costs per additional barrel of oil made it uneconomical to inject more than 12 percent HCPV.

SACROC Tertiary Pilot Project

A tertiary pilot CO_2 flooding project was conducted in 1974-75 to assess the possibility of additional oil recovery at SACROC in watered-out areas, where an estimated 407 million STB of oil has been left in place by centerline waterflooding. Obviously this is an attractive target for improved recovery techniques.

Two producers were drilled among six injectors (Fig. 14), resulting in two adjacent five-spot patterns. The configuration of the injectors and producers is shown in Fig. 32. These producers were pressure-cored and logged to determine residual oil saturation, which was determined to be 35 percent. Zones producing oil-free water were located and all eight wells were completed in those zones. Any production from these zones by CO_2 would then be tertiary oil.

A total of 2.3 Bscf of CO_2 was injected over a nine-month period. The total CO_2 and water injection is depicted in Fig. 33. Production performance of the two producers is shown in Figs. 34 (Well No. 118-13) and 35 (Well No. 147-9).

A total of 64,000 STB of oil was produced by the two producers. Total CO_2 produced was 421 MMscf. The volumetric sweep efficiency of CO_2 was calculated to be 33 percent. Estimated CO_2 requirement for a full-scale project is 15-20 Mscf/STBO to give an incremental recovery of 4 to 6 percent for a 30-percent HCPV slug of CO_2 [14]. Current operating costs and oil prices make this economically unattractive.

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9. Dicharry, R. M., Perryman, T. L., and Ronquille, J. D.: "Evaluations and Design of CO_2 Miscible Flood Project--SACROC Unit, Kelly Snyder Field," Trans., AIME (1973) 255, 1309-18.

10. Dicharry, R. M., Perryman, T. L., and Ronquille, J. D.: "Evaluation and Design of a CO_2 Miscible Flood Project, SACROC Unit, Kelly Snyder Field," Paper SPE 4083 presented at SPE-AIME 47th Annual Fall Meeting, Oct. 8-11, 1972.

11. Hull, P.: "SACROC: An Engineering Conservation Triumph," Oil and Gas J., Aug. 17, 1970.

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15. Perryman, T. L.: "Workovers: Key to SACROC Reservoir Control," Pet. Eng. (Feb. 1972), 35-38.

16. Crockett, David H.: "CO_2 Profile Control at SACROC," Pet. Eng. (Nov. 1975), 44-52.

TABLE I

FIELD DATA FOR CARBON DIOXIDE INJECTION PROJECTS

FIELD: Kelly Snyder

LOCATION AND GENERAL DATA

State:	Texas	County:	Scurry
Discovery Date:	November 1948	Date First Production	1949
No. Wells:	1671	@ Date:	November 1951
Developed Area:	51000		Acres

GEOLOGY AND PETROPHYSICS

Reservoir Name:	Canyon Reef
Reservoir Rock Type:	Pennsylvanian Age Limestone
Trap:	Anticlinal
Average Depth:	6700'

Primary Gas Cap (Y/N) N

Gas/Oil Contact Depth:	-	feet subsea
Oil/Water Contact Depth:	4500	feet subsea
Average Net Pay Thickness:	139	feet
Net/Gross Ratio:	0.52 (1)	
Average Porosity:	3.93	% (over the gross pay)
Initial Water Saturation	21.9	%
Average Permeability:	19.4	millidarcies
Permeability Range:		millidarcies
Permeability Variation:		
k_v/k_h:		

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

BASIC RESERVOIR AND VOLUMETRIC DATA

Initial Reservoir Pressure: 3137 psi
Reservoir Temperature: 130 °F
Bubble Point Pressure: 1820 psi
Formation Volume Factors:
B_{oi} ______
B_{ob} 1.5 RB/STB
Reservoir Oil Viscosity Data:
μ_{oi} ______ centipoise
μ_{ob} .38 centipoise

Initial Solution Gas-Oil Ratio:
R_{si} 990 cu.ft./bbl.
Stock Tank Oil Gravity: 41.8 °API

Reservoir Hydrocarbon Pore Volumes:
Oil Column: 4014253 M Bbl Gas Cap: - M Bbl
Standard Volume Original Hydrocarbons in Place
Oil: 2727000 (2) M Bbl Free Gas: - Mcf

RESERVOIR PERFORMANCE DATA

Primary Recovery Drive Mechanism: Solution Gas Drive

Estimated Ultimate Primary Recovery: 19% % ISTOIP

Supplemental Recovery Method(s) and Date Started: Centre-Line Water Flood - September, 1954

Cumulative Oil Production at Start Supplemental: 128,000 M Bbls 6 % ISTOIP

Unit Operator(s): SACROC

Average Pressure at Start Supplemental: 1560 psi

Estimated Additional Supplemental Recovery (Ultimate): 45.4 % ISTOIP

Estimated Total Ultimate Recovery (Primary+Supplemental) 51.4 % ISTOIP

Cumulative Total Production to: 1-1-78 (Date)
937000 M Bbls 44.3 % ISTOIP

Average Pressure: 2800 psi @ January 1977 (Date)
Calculated Average Oil Saturation ______ %@ ______ (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

CARBON DIOXIDE INJECTION PROJECT DATA

Project Operator: SACROC

Project Type: Mini-Test ___ Pilot Test ___ Full-Scale Project X
Recovery Mode: Secondary ___ Tertiary ___
Project Area: 1.966 billion barrels of HCPV
No. of Wells: Injection 305(3) Production 659(4) Other 394 shut-in

Pattern Geometry: Inverted Nine-spot

Date Project Commenced: January 1972 Ended Continuing as of 1-1-78
Injection Fluid Composition (mol percent)
CO_2 100% H_2S ___ C_1 ___

C_2-C_6 ___ C_7+ ___ Other ___

Estimated miscibility pressure: 1600 psi
Injection Fluid Source(s): Gas fields of the Val-Verde Basin

CO_2 Injection Rate (Excluding Recycle): 115 M Mcf/day 12/77 (Date)
Recycle Gas Injection Rate: 32MMcf/day 12/77 (Date)
Water Injection Rate: 596000 (6) Bbl/day 12/77 (Date)

Water Injection Mode (i.e., alternating, continuous after "slug", etc.)
Discuss: Alternating

Injection Pressures:
CO_2: Surface ___ psi Bottomhole ___ psi
Recycle: Surface ___ psi Bottomhole ___ psi
Water: Surface ___ psi Bottomhole ___ psi

Cumulative Injection @ ___ (Date)
CO_2 346 MMMcf (5) ___ %HCPV
Recycle: ___ MMMcf ___ %HCPV
Water: 1809 MMBbl (6) ___ %HCPV

Current Production Rates: (Date) December 1977

Oil: 139,886 Bbl/day Gas: 136,847 Mcf/day
CO_2: 35,864 Mcf/day Water: 411,974 Bbl/day

Date First Response: Immediate

Date CO_2 Breakthrough: June 1972 (First breakthrough)

Cumulative CO_2 Production: 53 MMMcf @ 12/77 (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

Incremental Response: ____________ Bbl/day @ ____________(Date)

Cumulative Incremental Oil @ 12/77 (Date) 71 MM Bbl

CO_2 Utilization Ratio-Cumulative Injection CO_2/Cumulative Incremental Oil 6.1 Mcf/Bbl. (Ultimate)

Expected Ultimate Incremental Production:
74-88 MM Bbls 5.7 - 6.7 % ISTOIP (7)

Supplemental Information

(1) Formation thickness varies from an average of 800 feet on the structure crest to less than 50 feet on the productive flank edges and averages 268 feet overall.

(2) This was reduced to 2113000 in 1973 when Chevron conducted a history match using a two dimensional black oil simulator.

(3) Also includes Center-line water injectors.

(4) Also includes some additional in-fill drill wells.

(5) Total cumulative injection including recycled CO_2.

(6) Also includes Center-line water injection.

(7) Based on two different assumptions - The lower limit was predicated on curtailment of CO_2 injection beginning January 1978 and the higher limit assumes continued injection until 12% HCPV is injected.

TABLE 2

KELLY-SNYDER FIELD
AVERAGE RESERVOIR FLUID
COMPOSITION AND PROPERTIES

Reservoir Fluid Composition*

Component	Mol percent
CO_2	0.32
N_2	0.83
C_1	28.65
C_2	11.29
C_3	12.39
$i\text{-}C_4$	1.36
$n\text{-}C_4$	6.46
$i\text{-}C_5$	1.98
$n\text{-}C_5$	2.51
C_6	4.06
C_7*	30.15
Total	100.00

Molecular weight of C_7+	=	197.4
Specific gravity of C_7+	=	0.841
Bubble-point pressure (at 130°F), psia	=	1820
Reservoir fluid viscosity at 1820 psia and 130°F, cp	=	0.38
Reservoir fluid density at 1820 psia and 130°F, lb/cu ft	=	41.8

Flash Separation Data

First-stage separator conditions:	25 psia and 95°F	31 psia and 75°F
Solution GOR, scf/STB	990	910
Stock tank oil gravity, °API	41.0	42.7
Casinghead gas gravity	1.087	1.030
FVF** at 3137 psia, bbl/STB	1.528	1.472
FVF at 1820 psia, bbl/STB	1.557	1.500

*Average of 11 samples.
**Formation volume factor.

TABLE 3

SUMMARY OF WELL WORK, SACROC UNIT
July 1, 1970 to December 1, 1971 [15]

	Total No.	Avg. Well Cost	Avg. Production Increase, BOPD
Artificial lift			
DPN and/or perf.	97*	$23,000	370
Stimulate	2	7,200	400
Remedial	2	25,000	680
Producing Wells			
DPN and/or perf.	119	$11,900	140
Stimulate	12	5,900	160
Remedial	9	9,600	40
Inj. wells ret. to prod.	3	21,700	720
Shut-in wells (dead)			
DPN and/or perf., equip.	116 §	11,500	270
Stimulate	8	6,400	230
Remedial	12	11,200	60
			Avg. Injection Increase, BWPD
Water injection wells			
Convert	58	$21,500	3590
Stimulate, run tbg	20	11,500	750
Remedial	26	17,200	360
CO_2 injection wells			
Convert	64	26,800	0
Water source wells	13	32,600	12,240
Totals	561	$17,000	230 BOPD ¶ Inj. 2240 BWPD

*77 wells tested, 50 placed on pump, 14 left shut in, 6 no test

§57 wells tested, 68 left shut in

¶Average for only wells tested. Total average for all producing wells, including shut-in wells, is 180 BOPD.

TABLE 4

INJECTION STATUS IN NINE-SPOT PATTERN AREAS, CO_2-WAG PROJECT, SACROC UNIT[2]

	Phase 1	Phase 2	Phase 3	Total
Cumulatives through December 1977				
CO_2, Bcf	184	142	18	344
CO_2, % HCPV	14.3	10.0	1.4	8.6
Water, MMbbl	290	200	193	683
Water, % HCPV	49.9	30.3	31.2	36.6
Rates (December 1977)				
CO_2, MMcf/D	20	93	34	147
Water, thousand B/D	189	150	141	480

TABLE 5

SUMMARY OF PATTERN AREA BOTTOMHOLE
PRESSURE SURVEYS, SACROC UNIT CO_2 WAG PROJECT [2]

Date	Average Reservoir Pressure (psig)		
	Phase 1	Phase 2	Phase 3
September 1971	1582	----	----
April 1972	1846	1838	1843
April 1973	2487	----	----
May 1973	----	2077	----
June 1973	----	----	1816
September 1973	2860	----	----
December 1973	----	2209	----
January 1974	----	----	1936
January 1976	2789	2690	2472
January 1977	2946	2852	2696

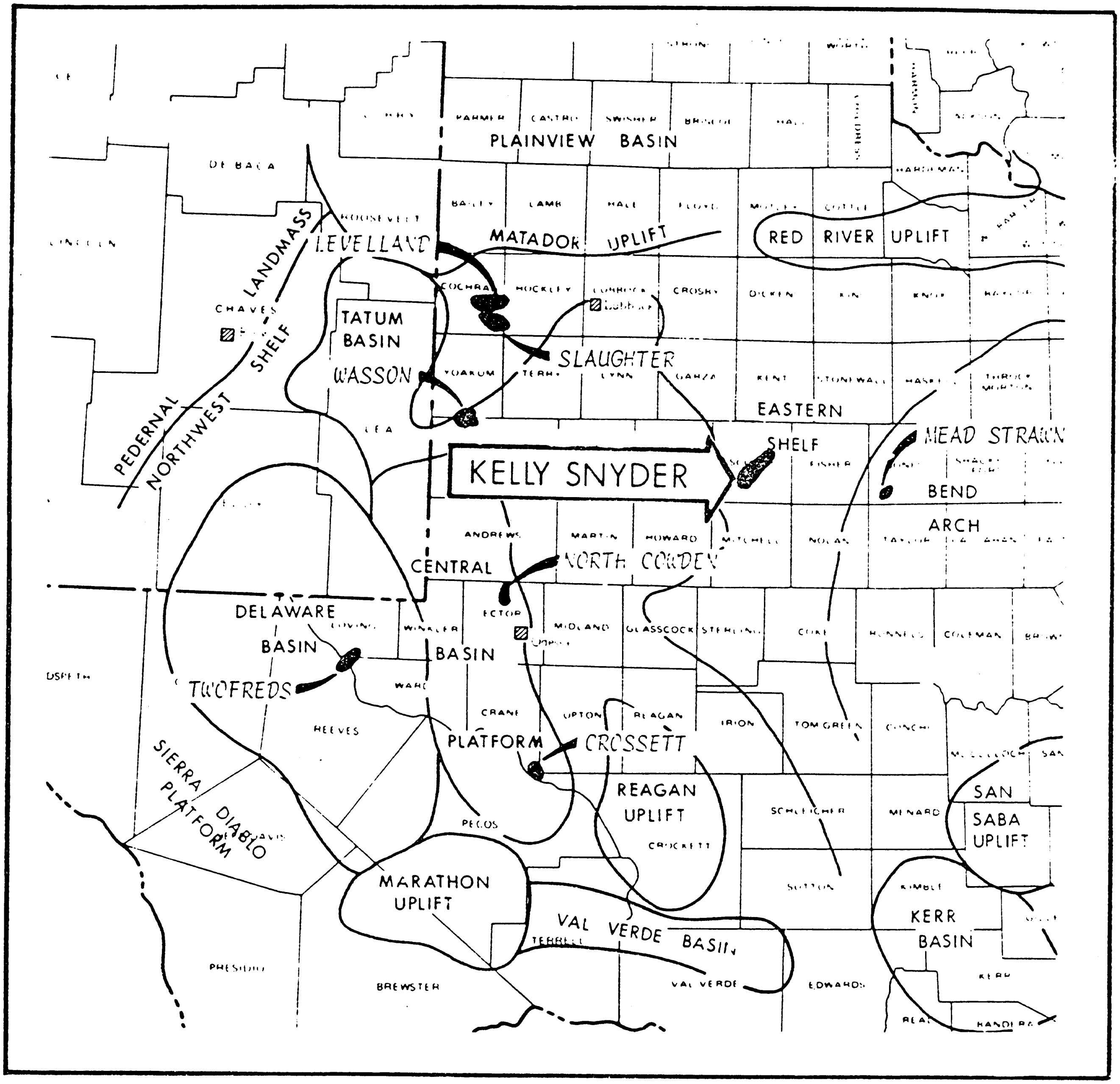

Figure 1.--Index map: carbon dioxide injection projects in west Texas.

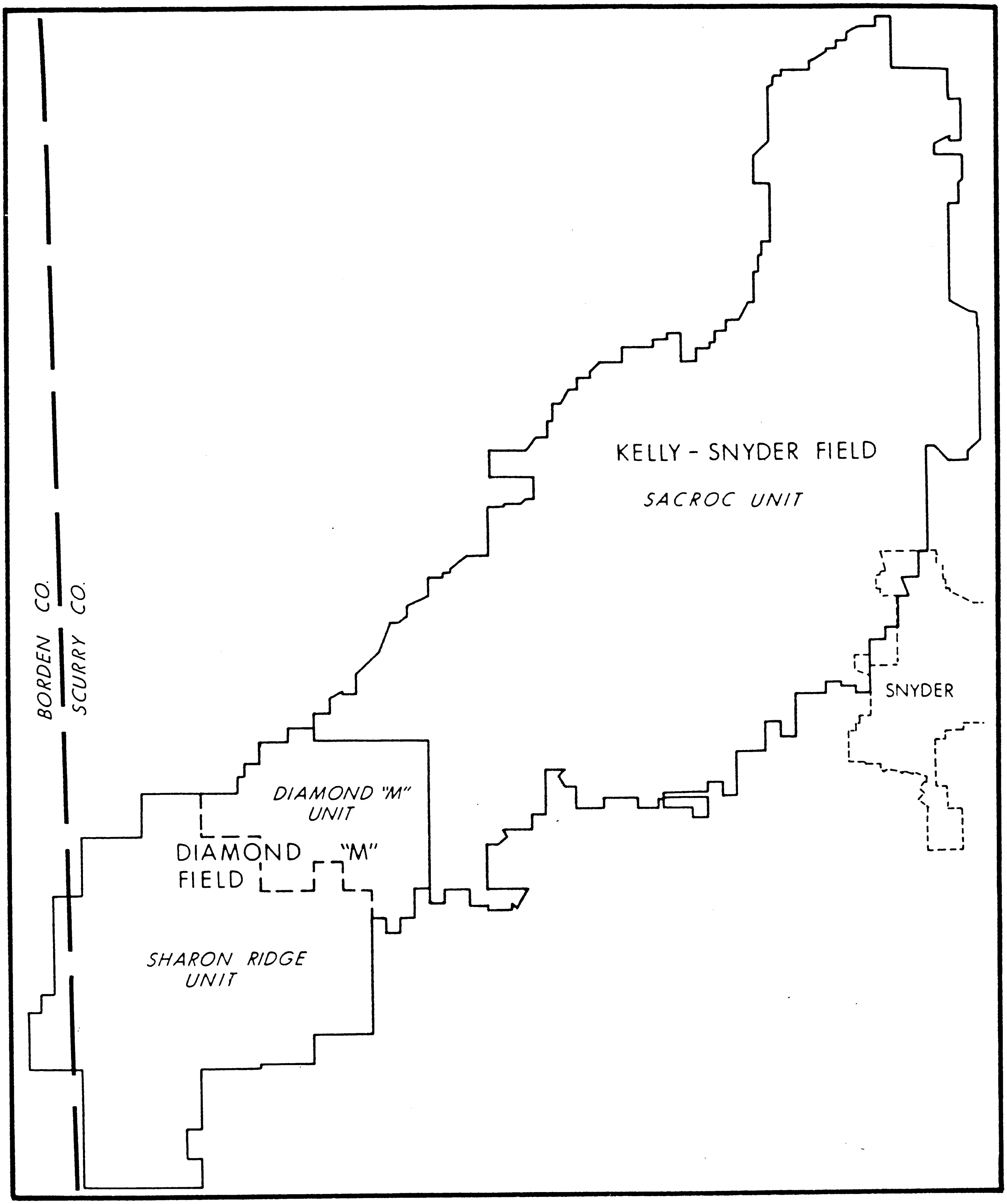

Figure 2.--Scurry Canyon field area, Texas.

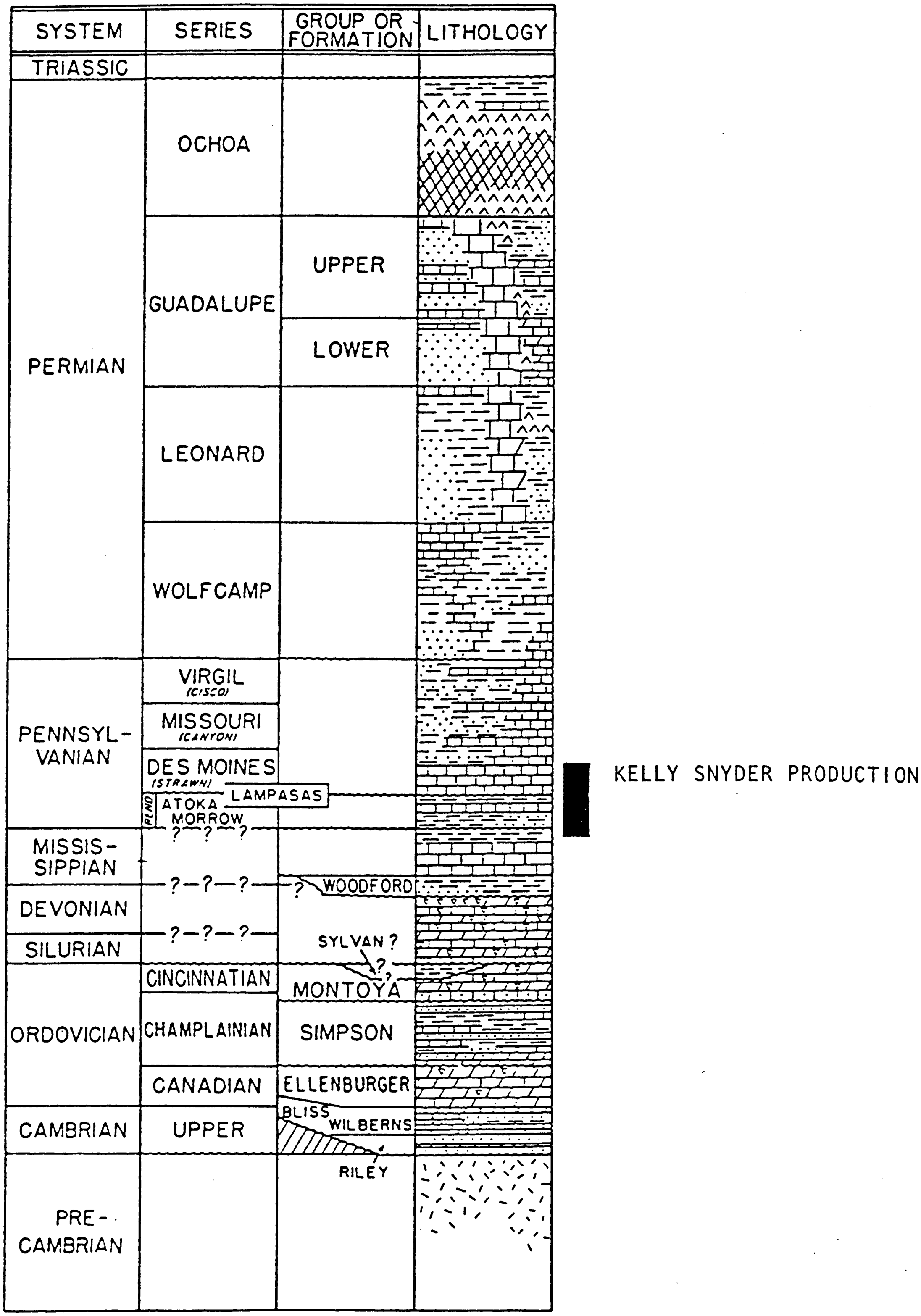

Figure 3.--Generalized stratigraphic and lithologic column for the Permian Basin, Texas.

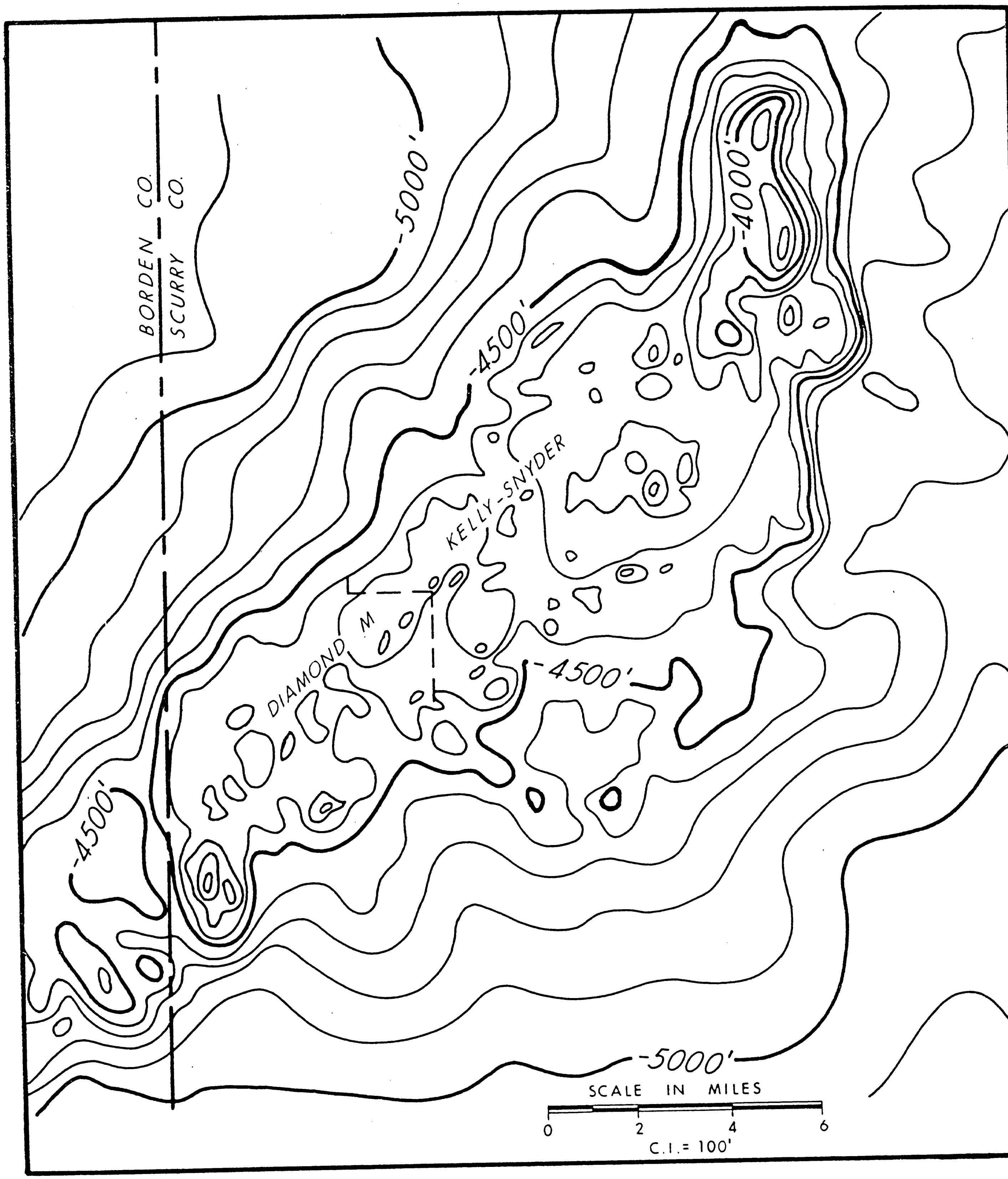

Figure 4.--Structure map on top of the Horseshoe Reef complex, SACROC unit, Kelly-Snyder field, Texas.

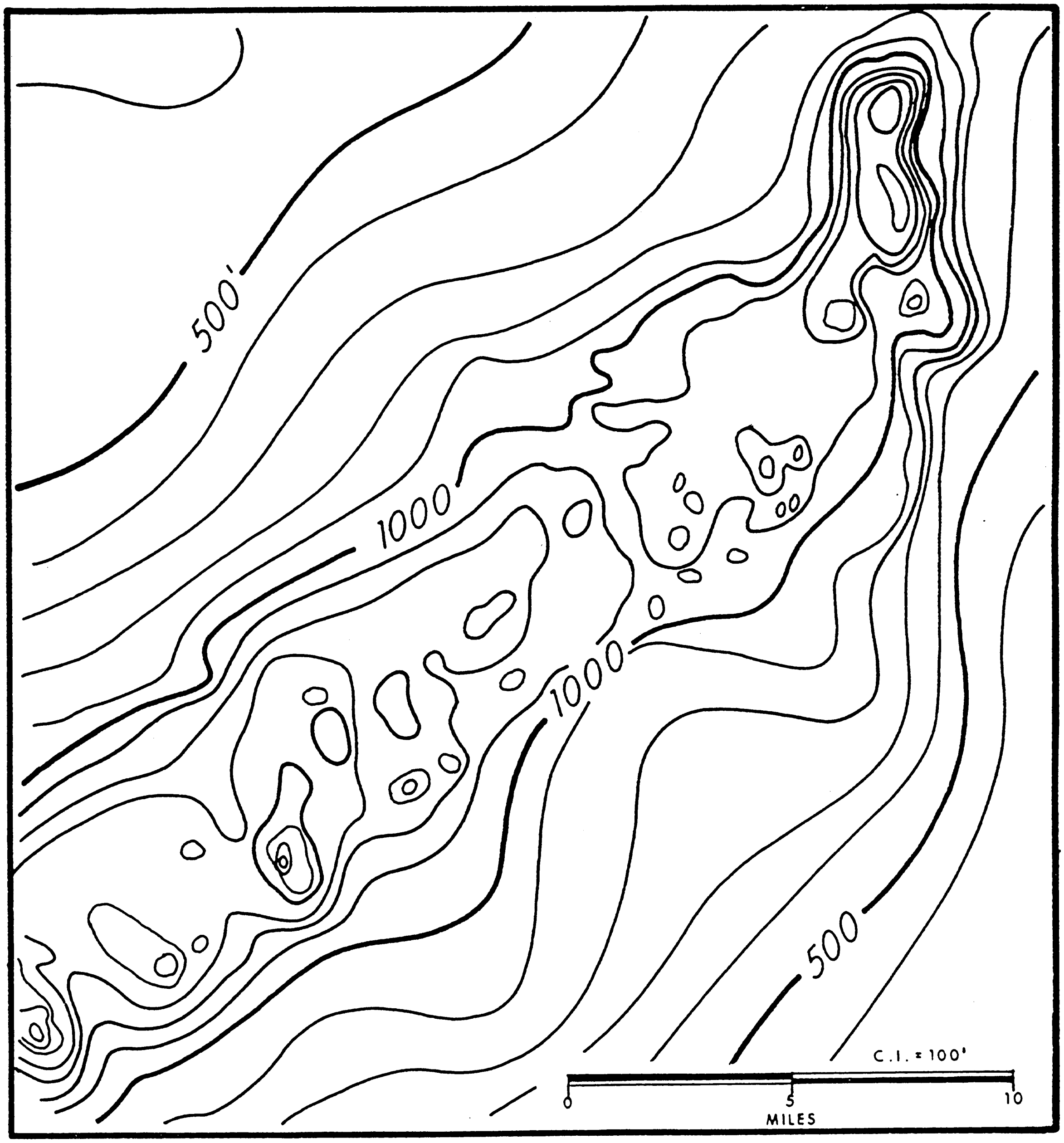

Figure 5.--Isopach map, reef complex, SACROC unit, Kelly-Snyder field, Texas.

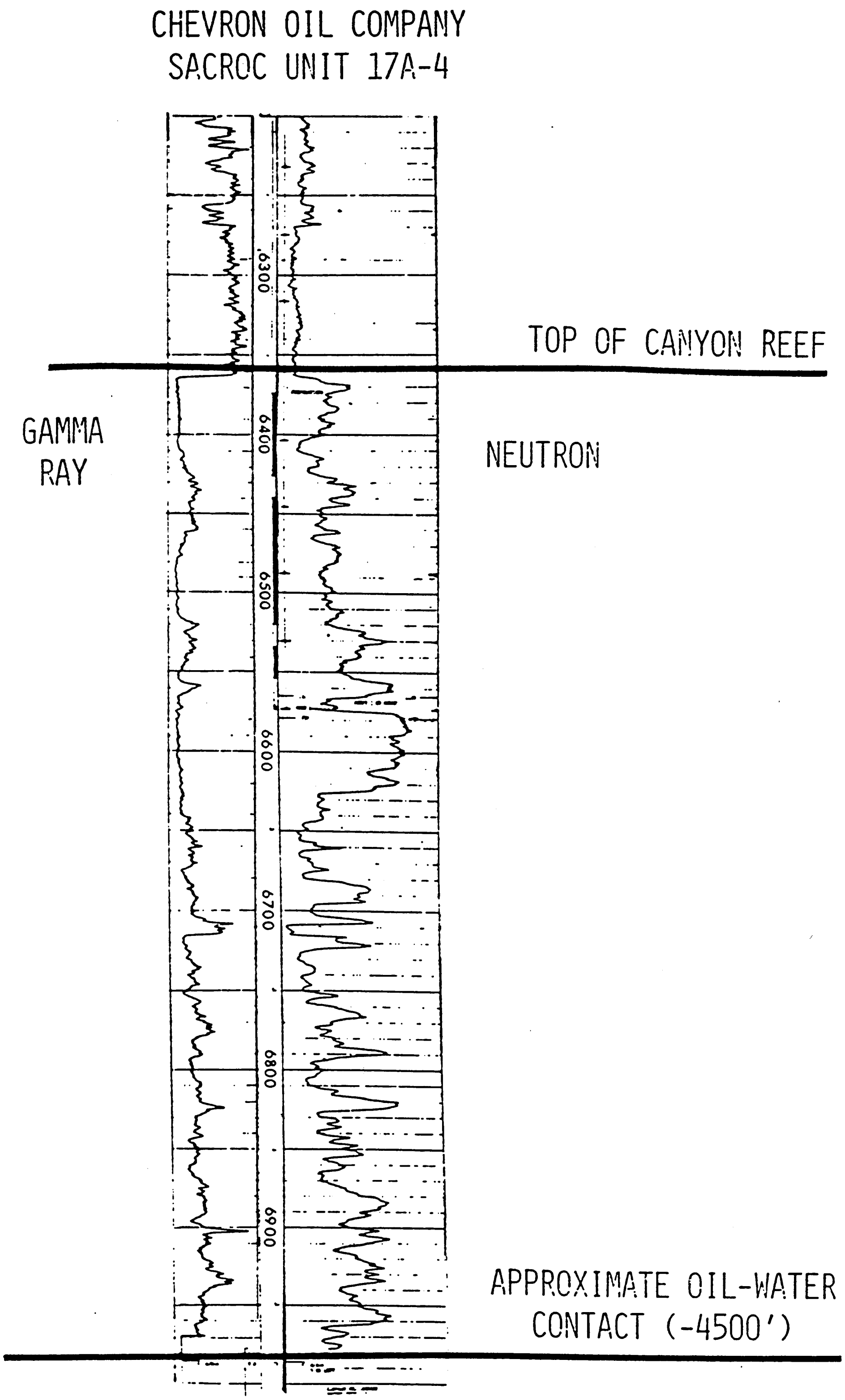

Figure 6.--Typical log from crestal reef location, SACROC unit, Kelly-Snyder field, Texas.

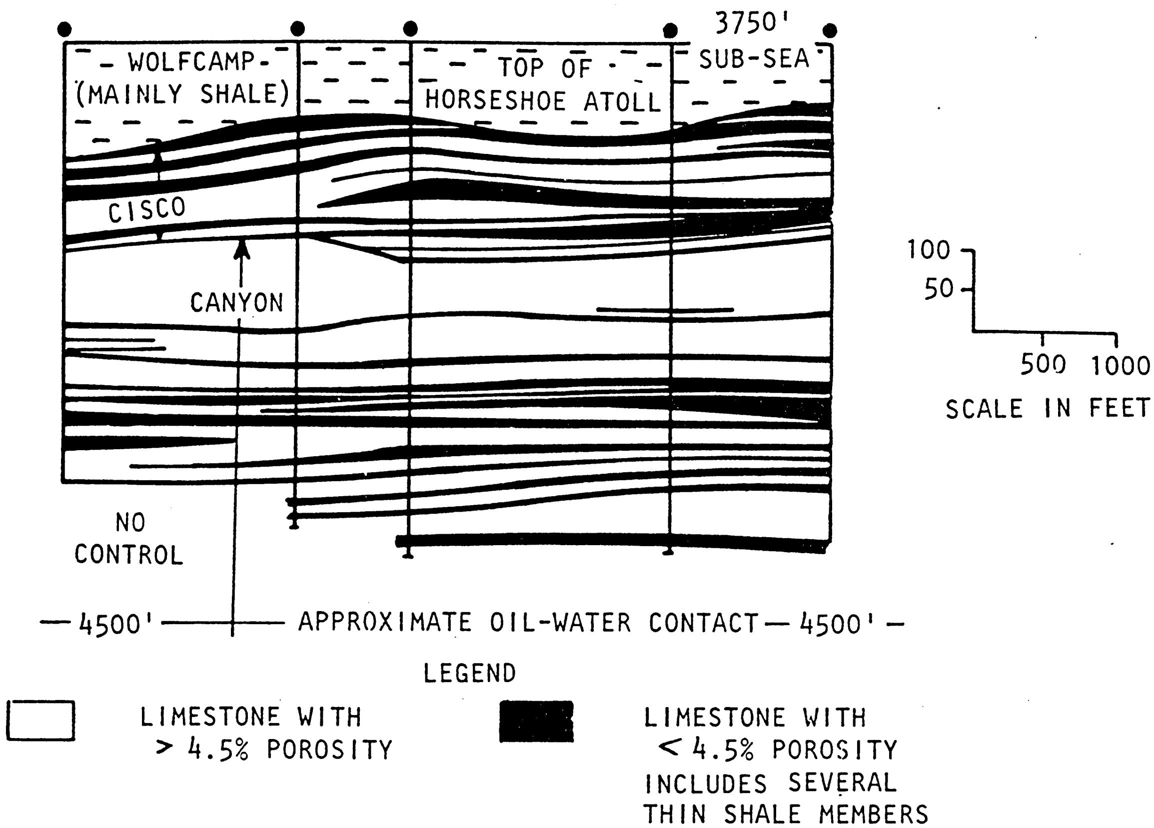

Figure 7.--Typical porosity layering, SACROC unit, Kelly-Snyder field, Texas.

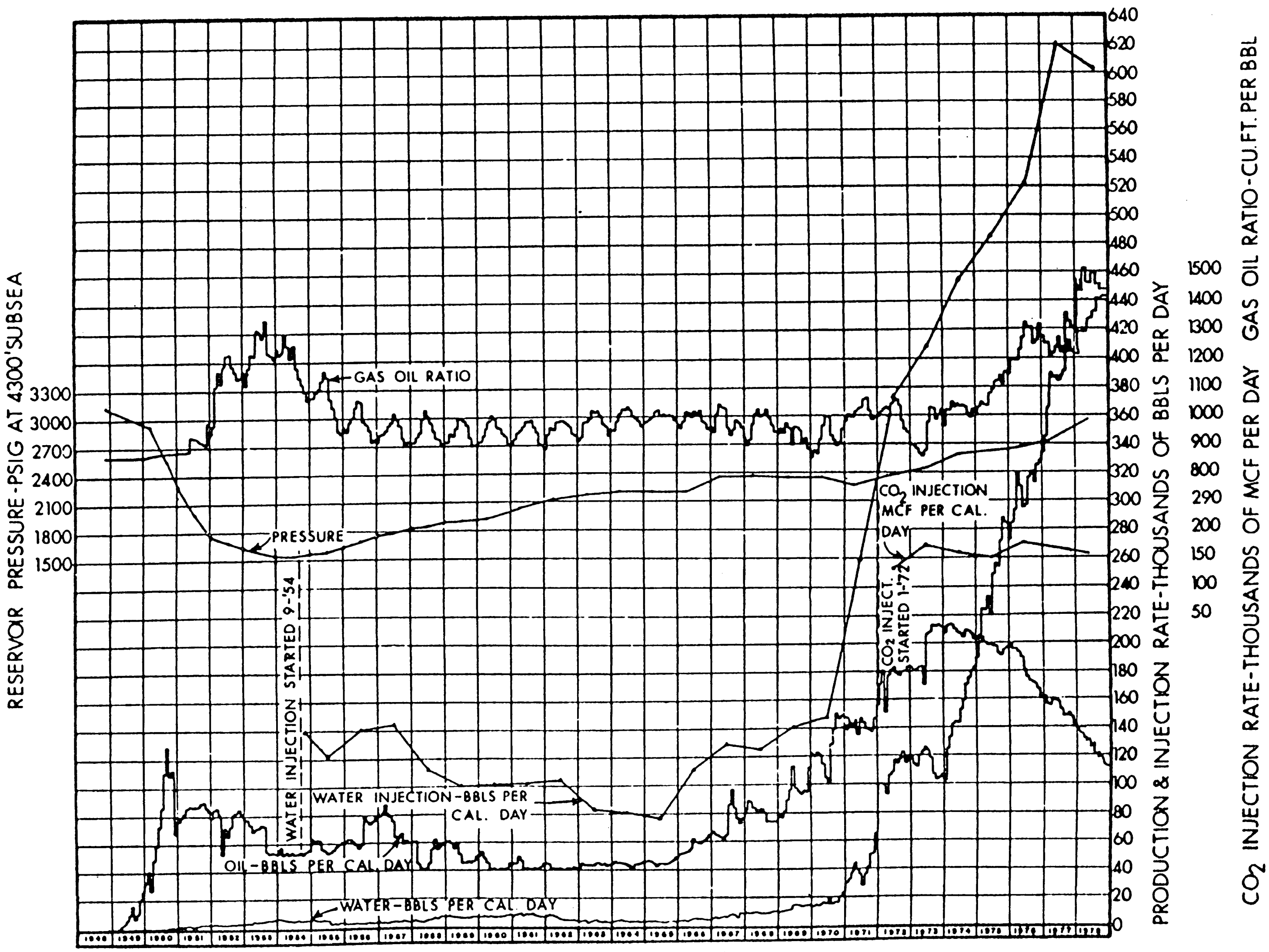

Figure 8.--Performance summary, Kelly-Snyder field, Texas.

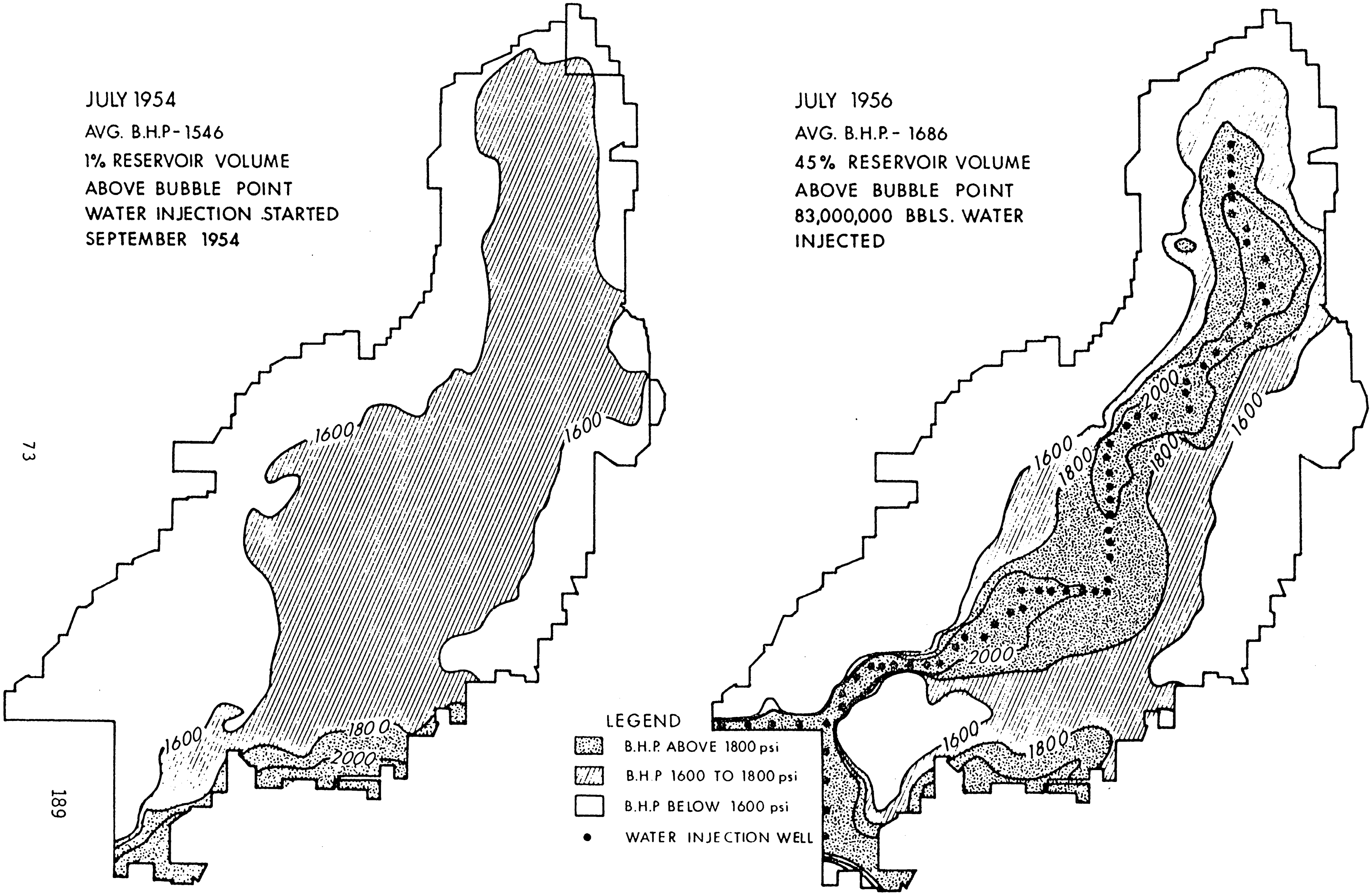

Figure 9.--Generalized bottomhole pressure maps, 1954-1956,
SACROC unit, Kelly-Snyder field, Texas.

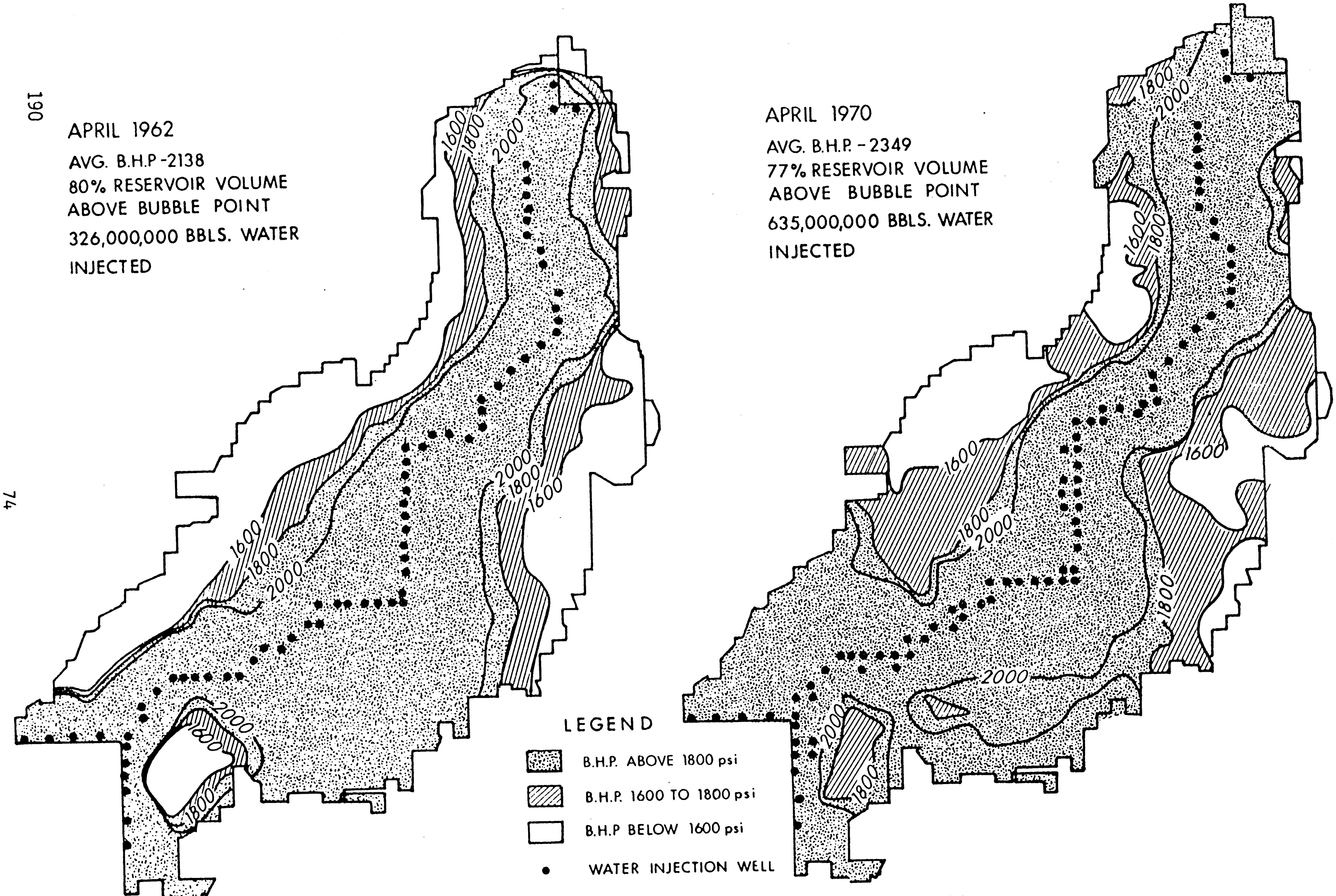

Figure 10.--Generalized bottomhole pressure maps, 1962-1970, SACROC unit, Kelly-Snyder field, Texas.

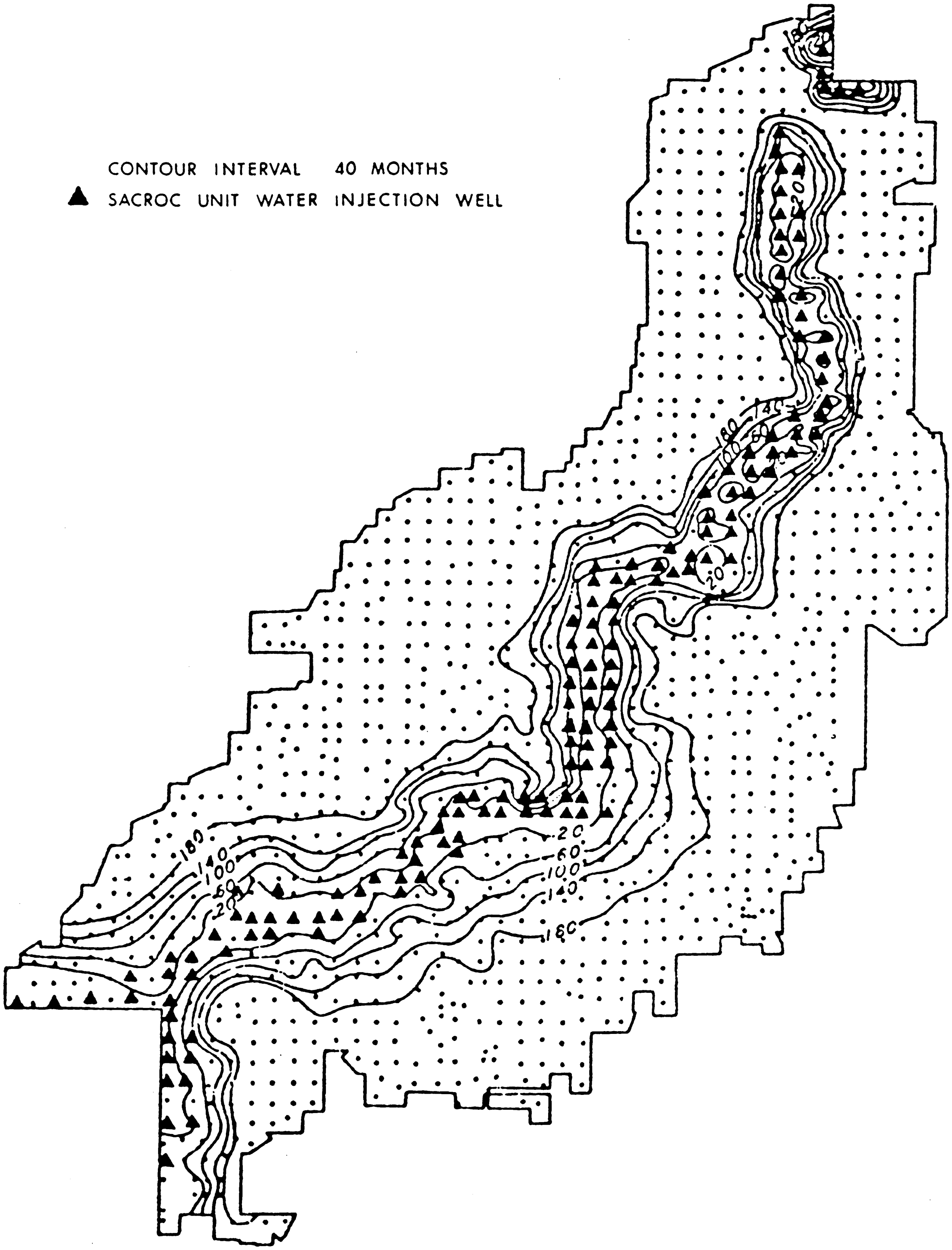

Figure 11.--Advance of centerline water injection front, SACROC unit area, Kelly-Snyder field, Texas.

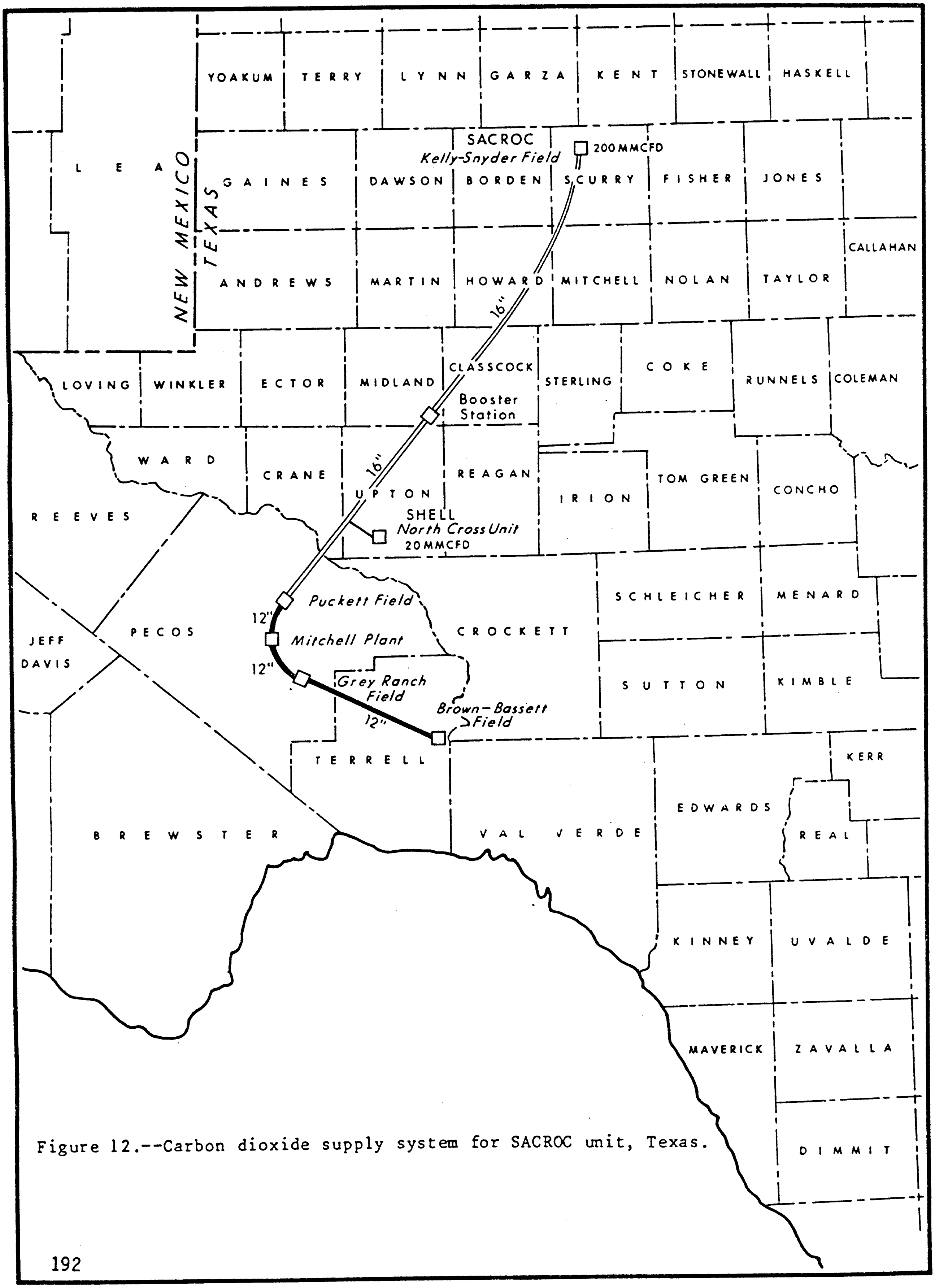

Figure 12.--Carbon dioxide supply system for SACROC unit, Texas.

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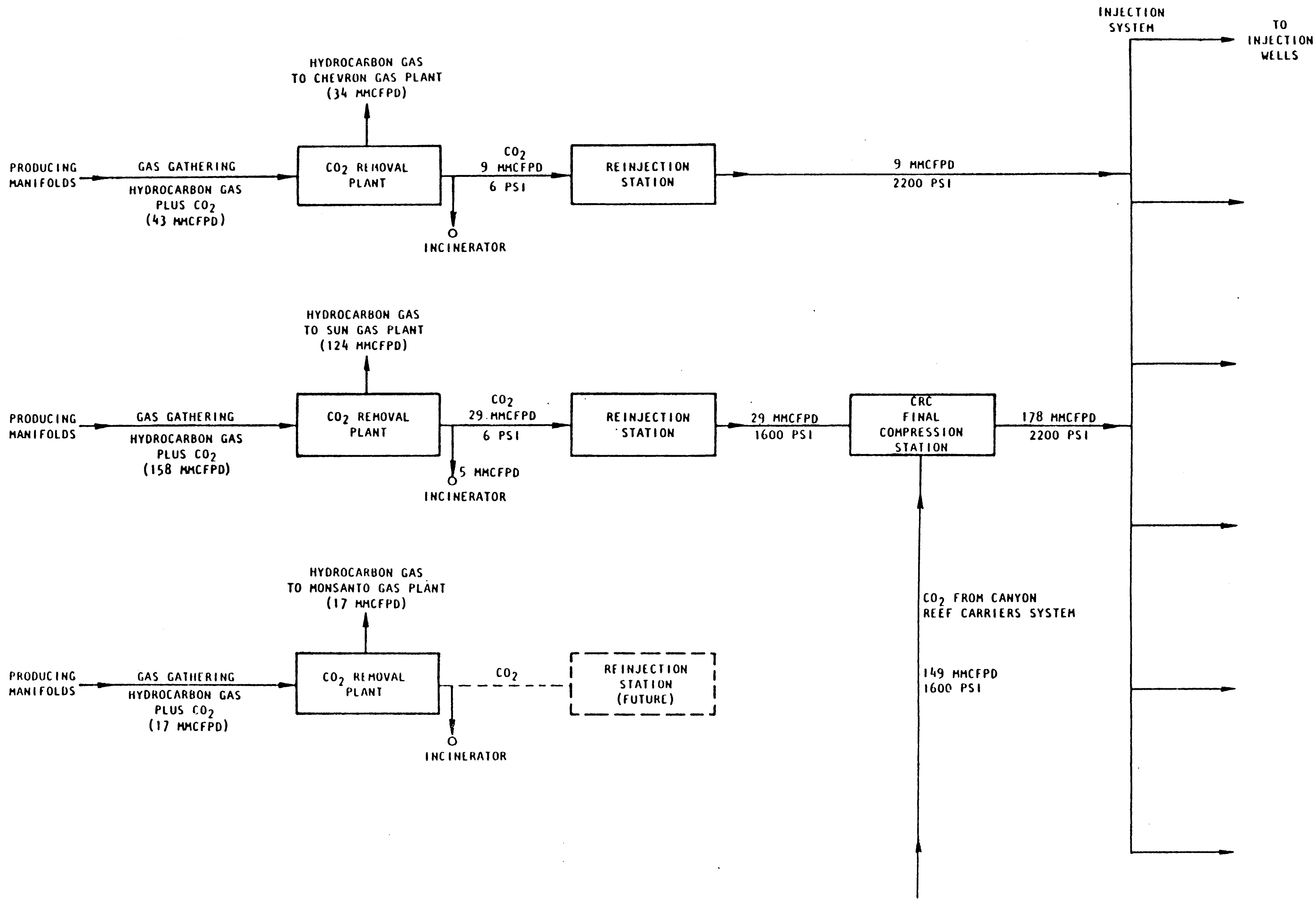

Figure 13.--Schematic diagram of SACROC unit carbon dioxide injection system. Figures are actual volumes for August 1976.

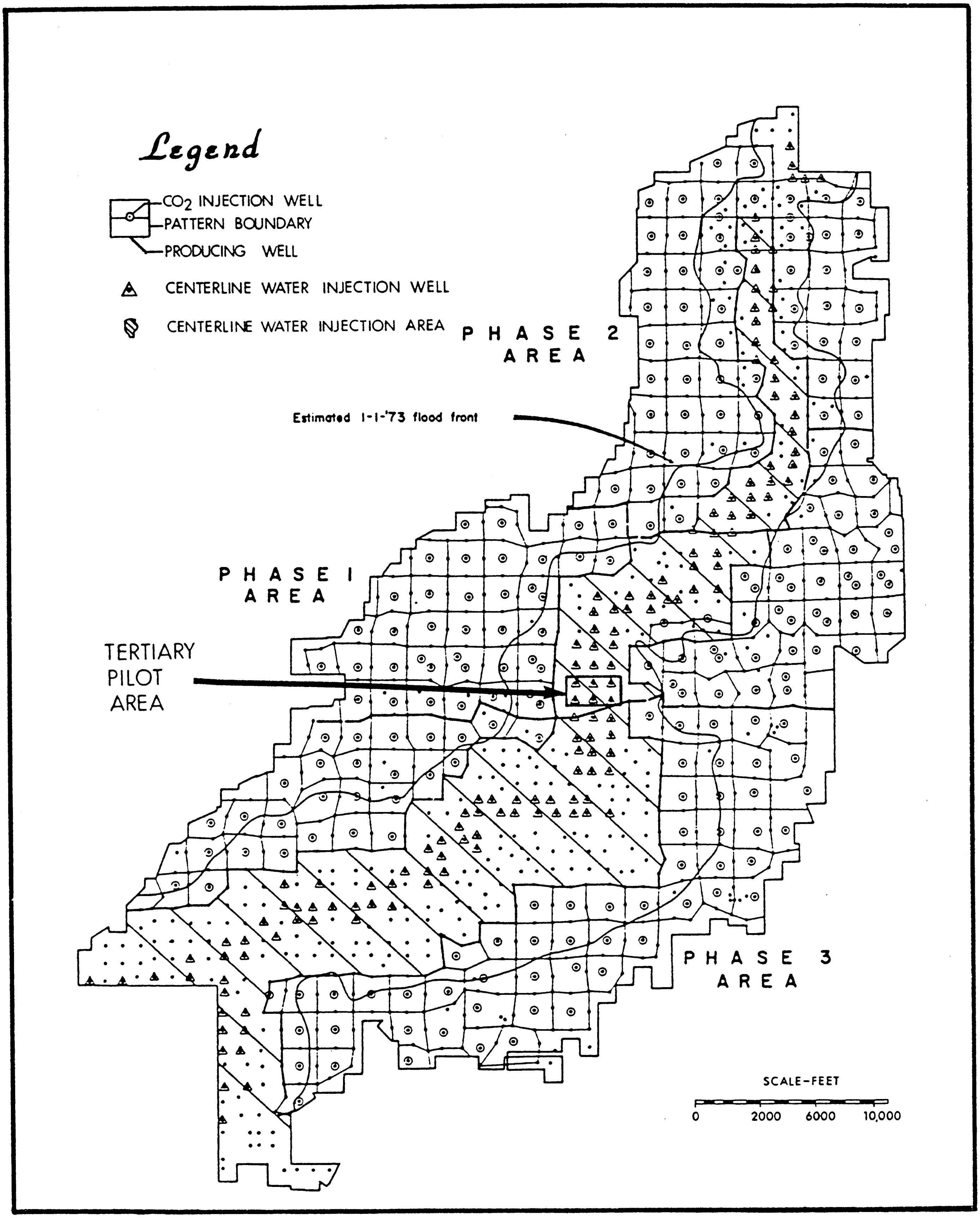

Figure 14.--Map of SACROC unit area.

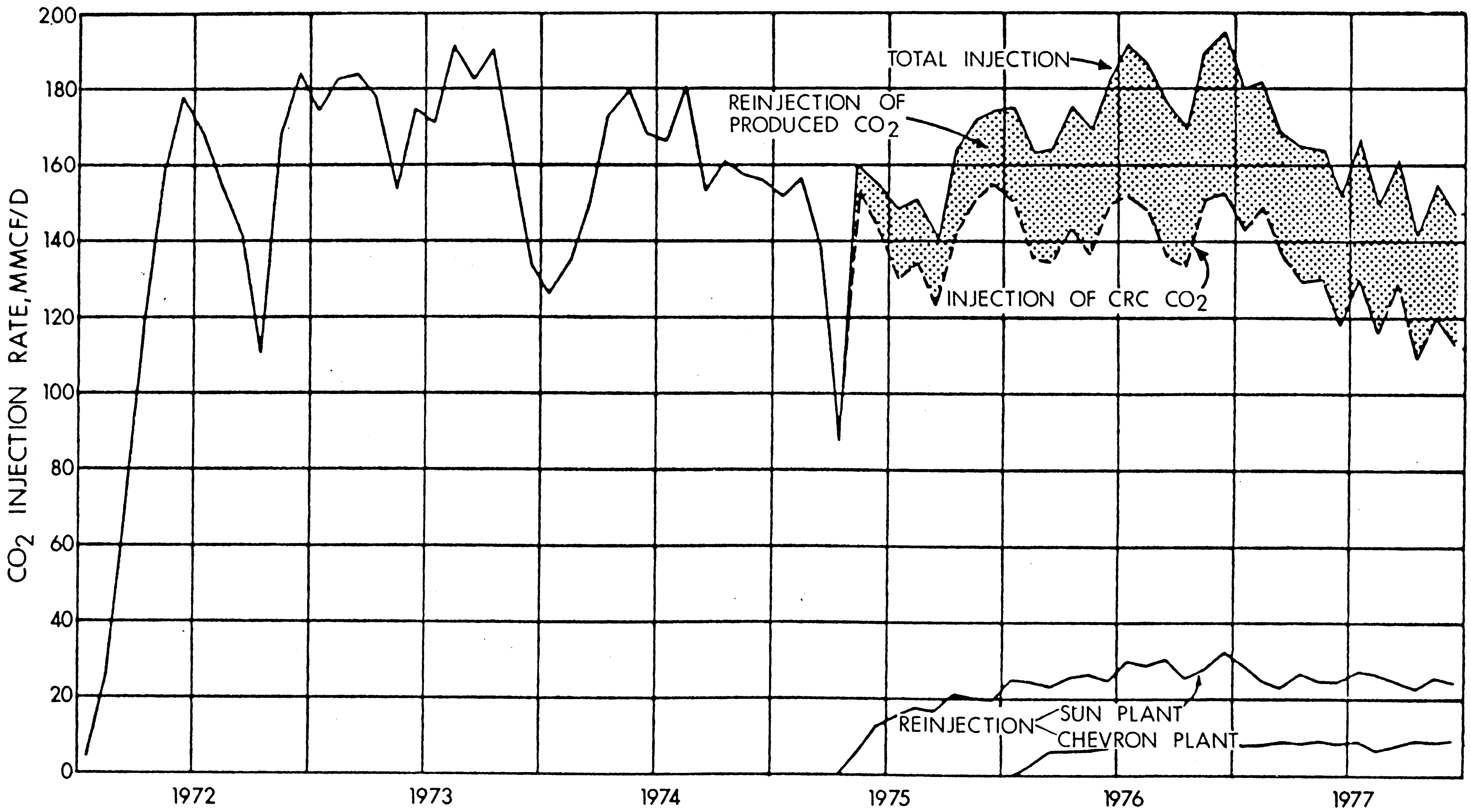

Figure 15.--Carbon dioxide injection history for entire SACROC unit.

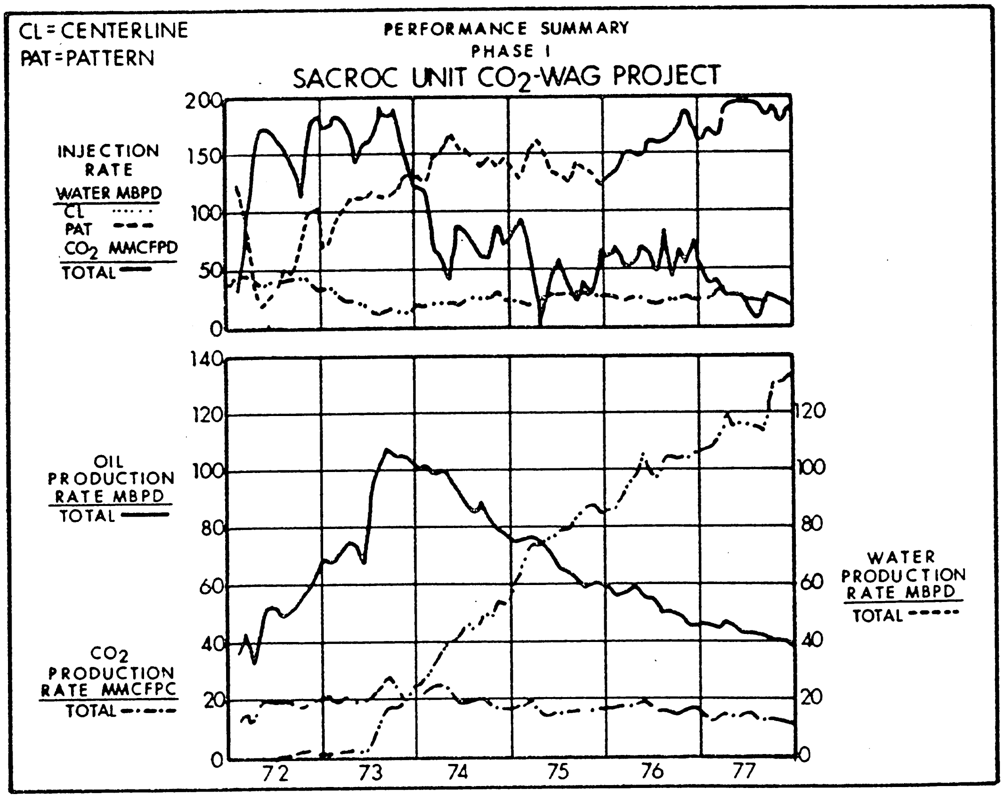

Figure 16.--Performance summary for Phase I, SACROC unit carbon dioxide injection project.

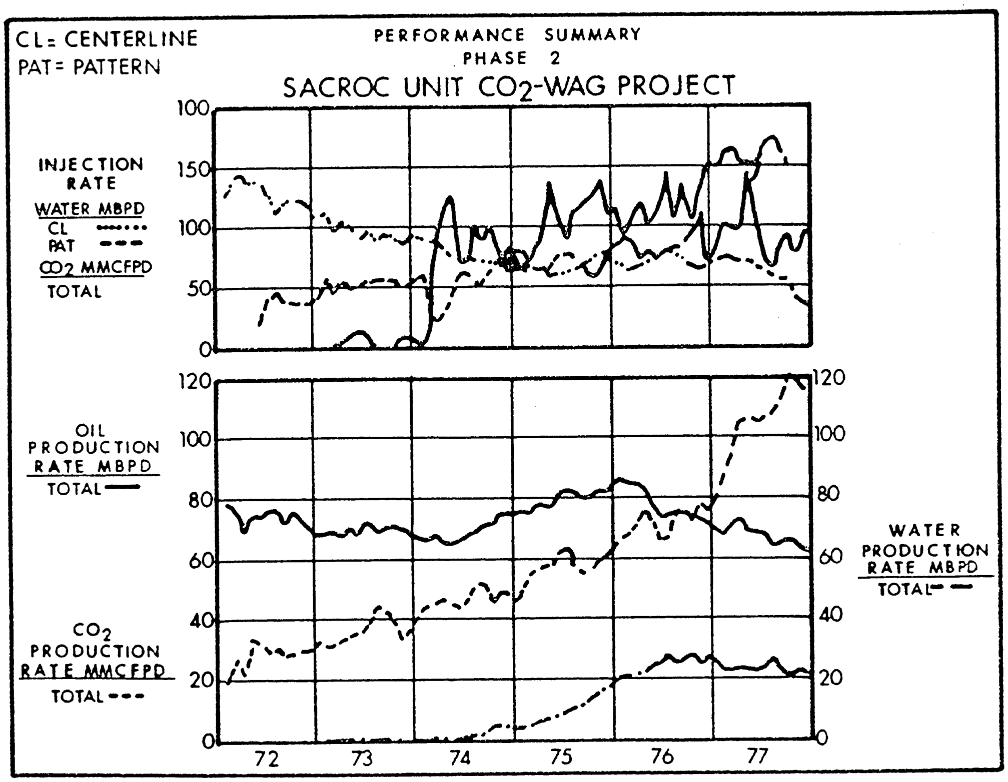

Figure 17.--Performance summary for Phase II, SACROC unit carbon dioxide injection project.

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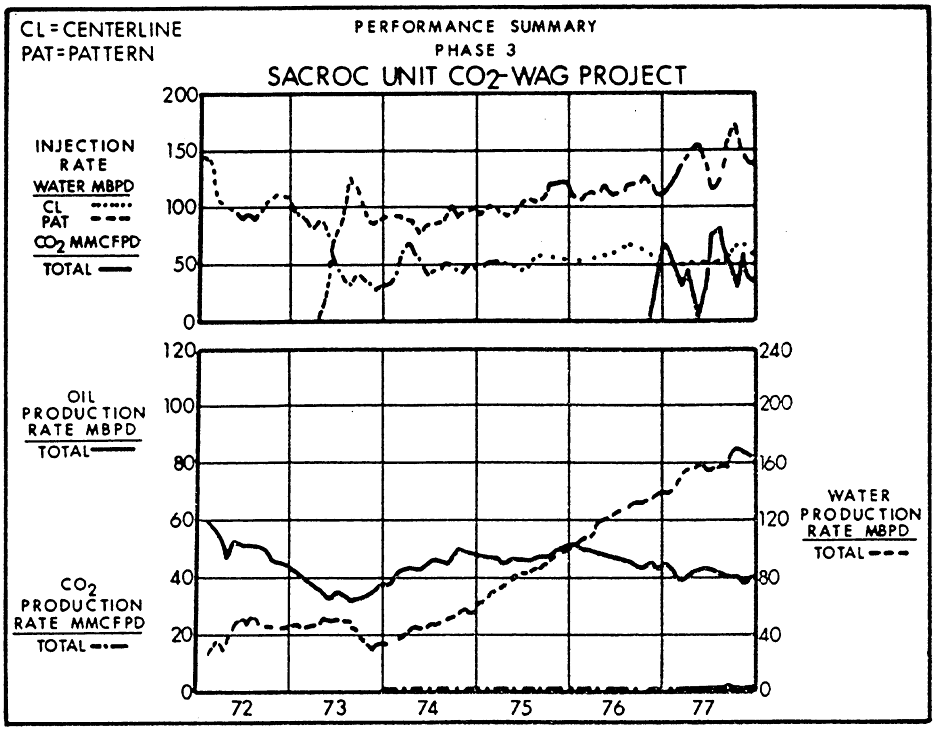

Figure 18.--Performance summary for Phase 3, SACROC unit carbon dioxide injection project.

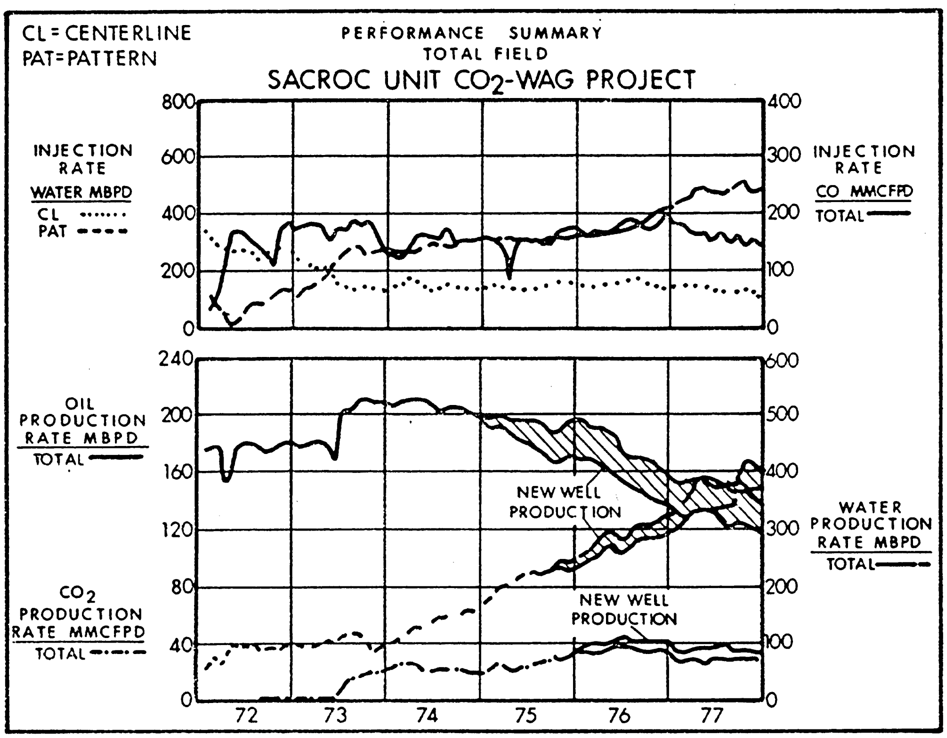

Figure 19.--Performance summary for total field, SACROC unit carbon dioxide injection project.

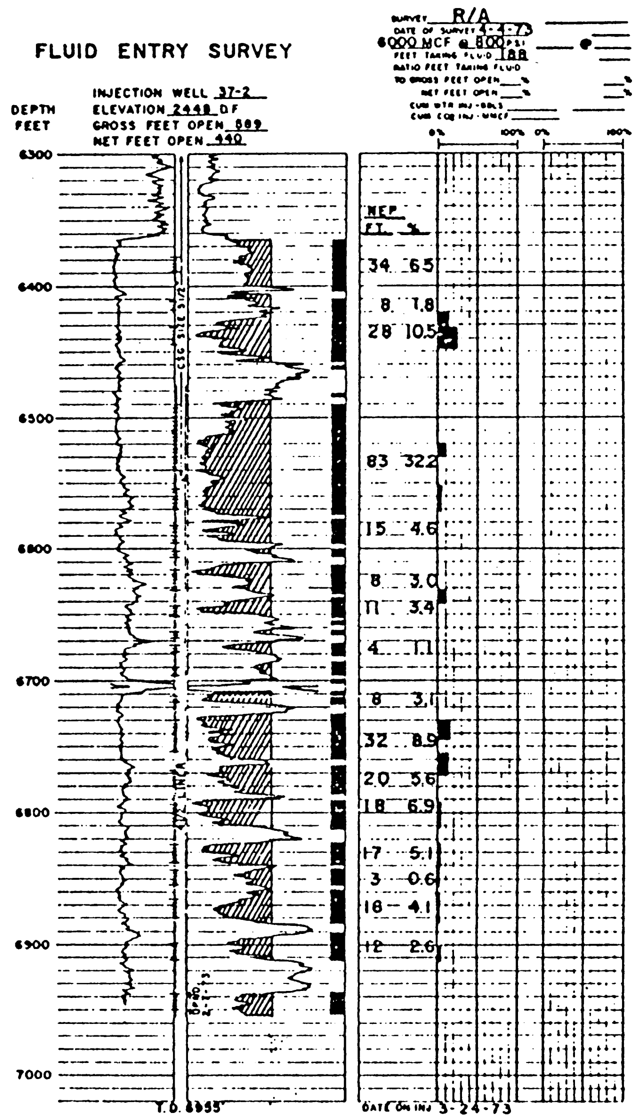

Figure 20.--Downhole injection profile, injection well 37-2, SACROC unit.

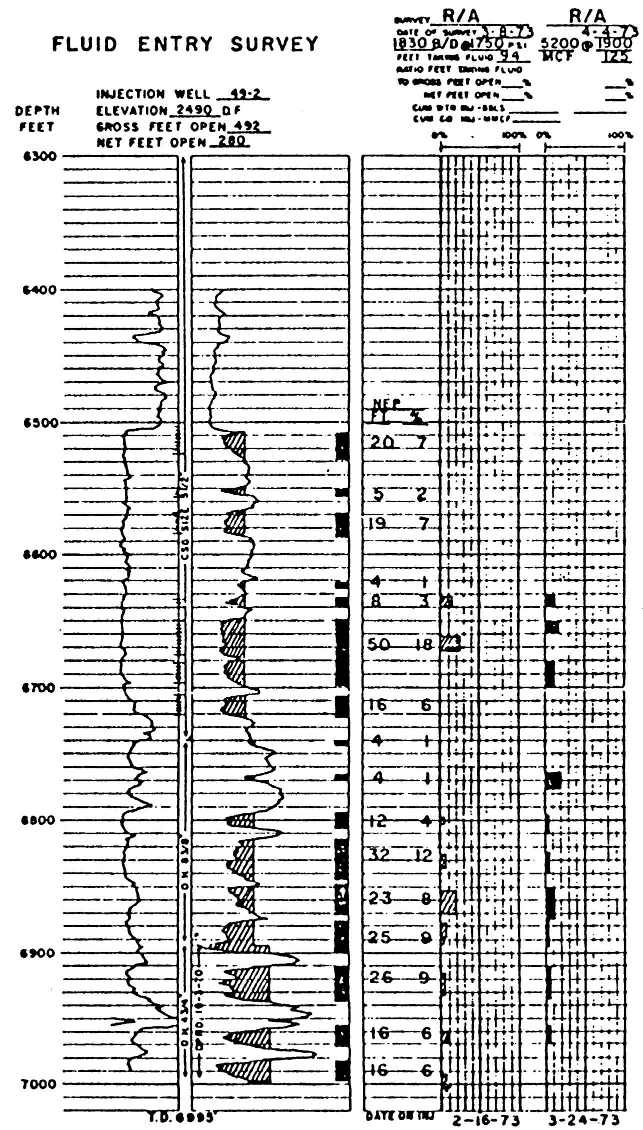

Figure 21.--Downhole injection profile, well 49-2, SACROC unit.

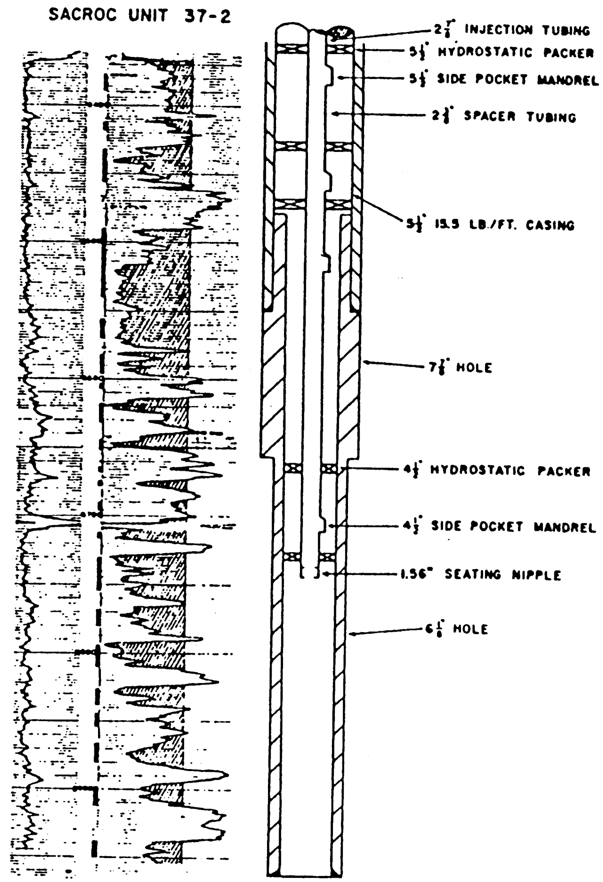

Figure 22.--Equipment run in well 37-2, SACROC unit.

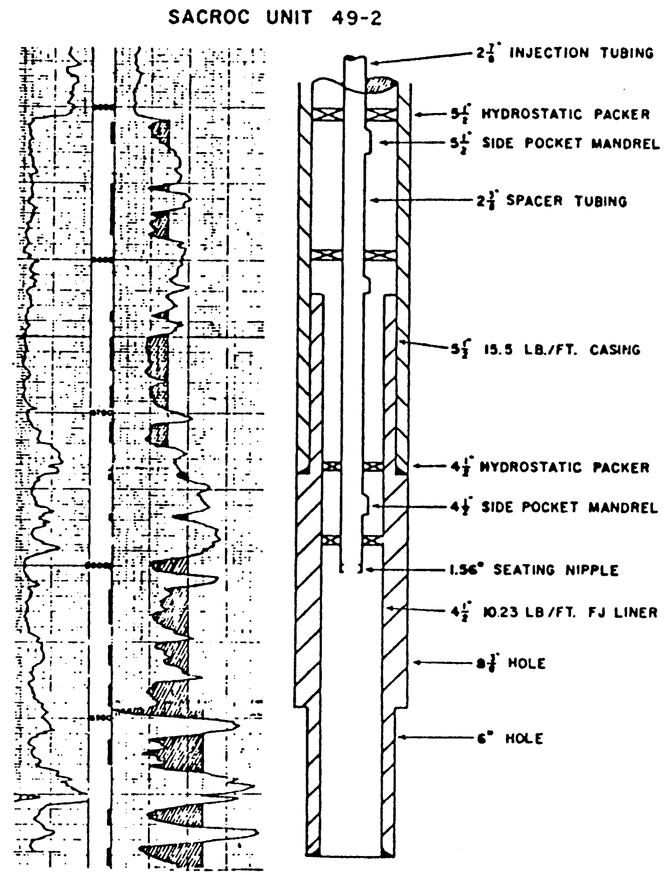

Figure 23.--Equipment run in well 49-2, SACROC unit.

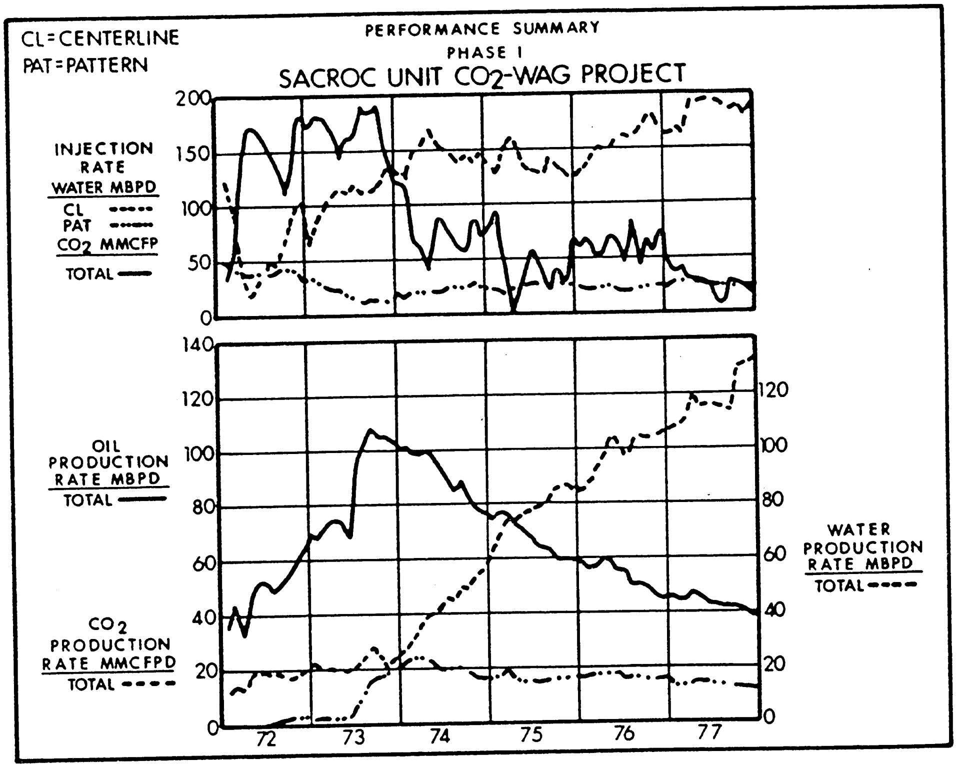

Figure 24.--Performance summary for SACROC unit Phase I.

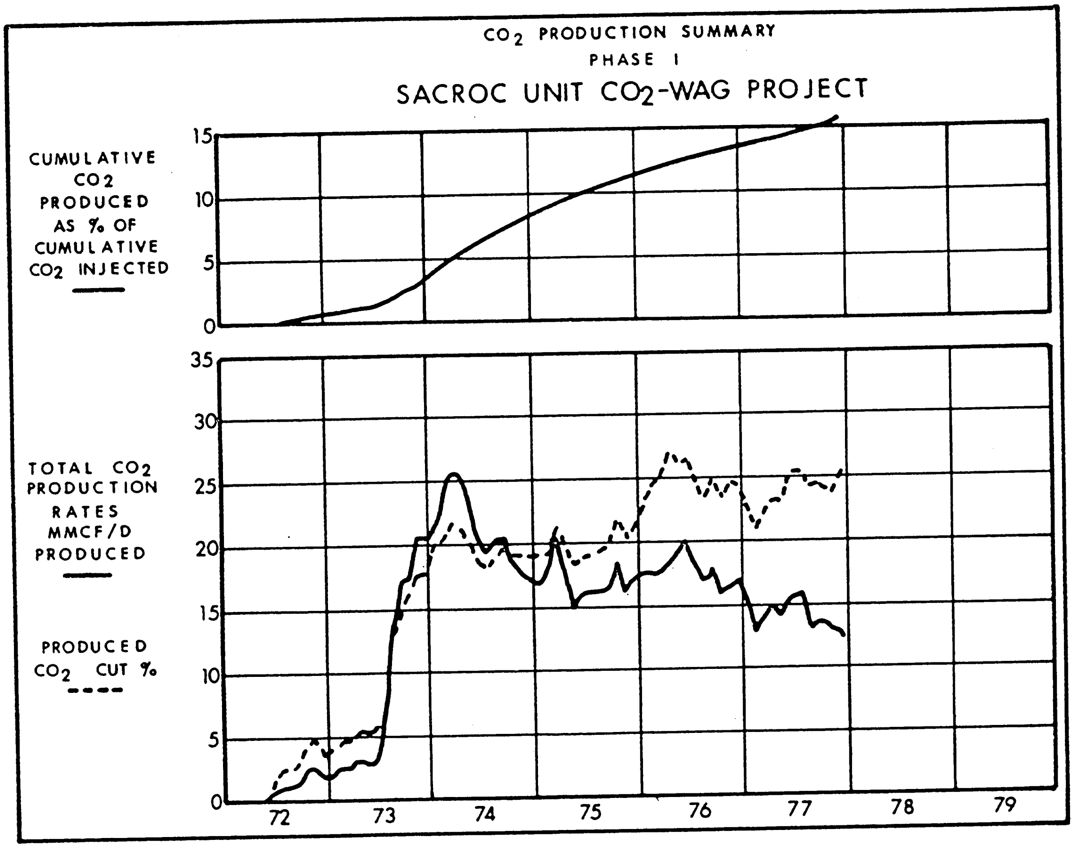

Figure 25.--CO_2 production summary for SACROC unit Phase I.

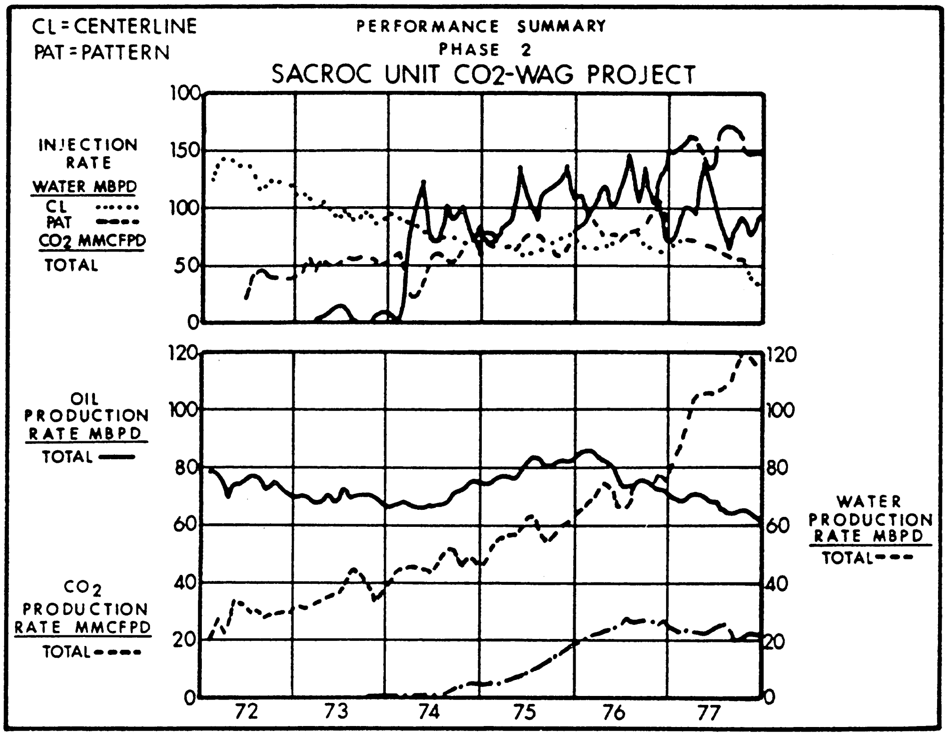

Figure 26.--Performance summary for SACROC unit Phase II.

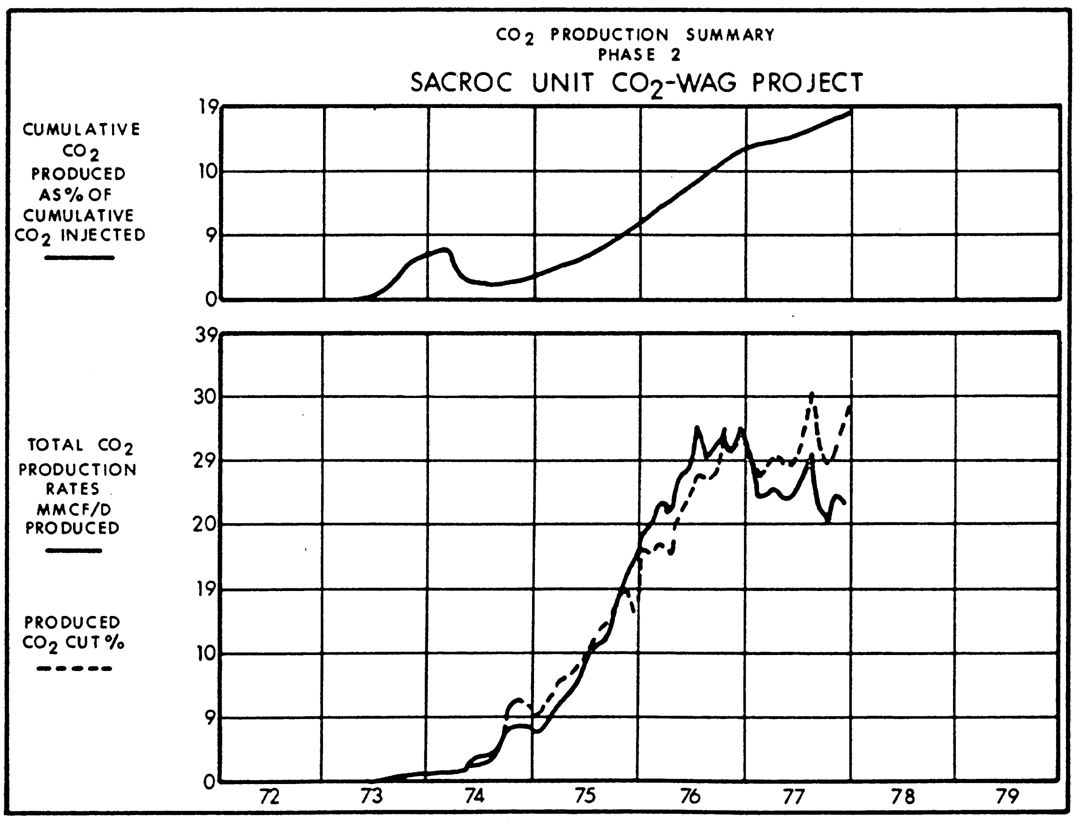

Figure 27.--CO_2 production summary for SACROC unit Phase II.

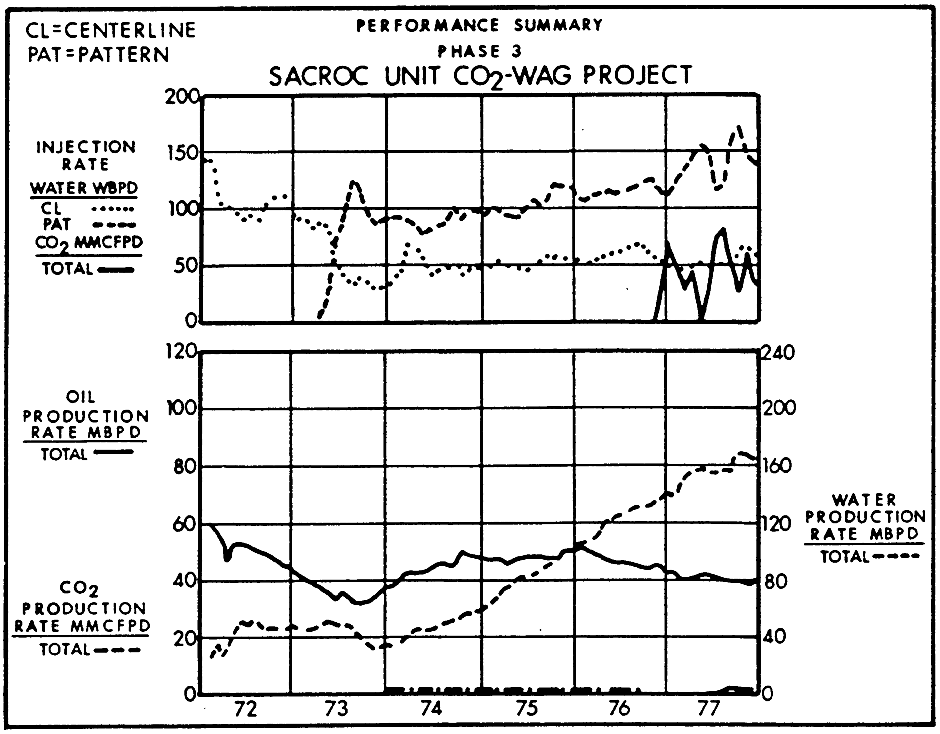

Figure 28.--Performance summary for SACROC unit Phase III.

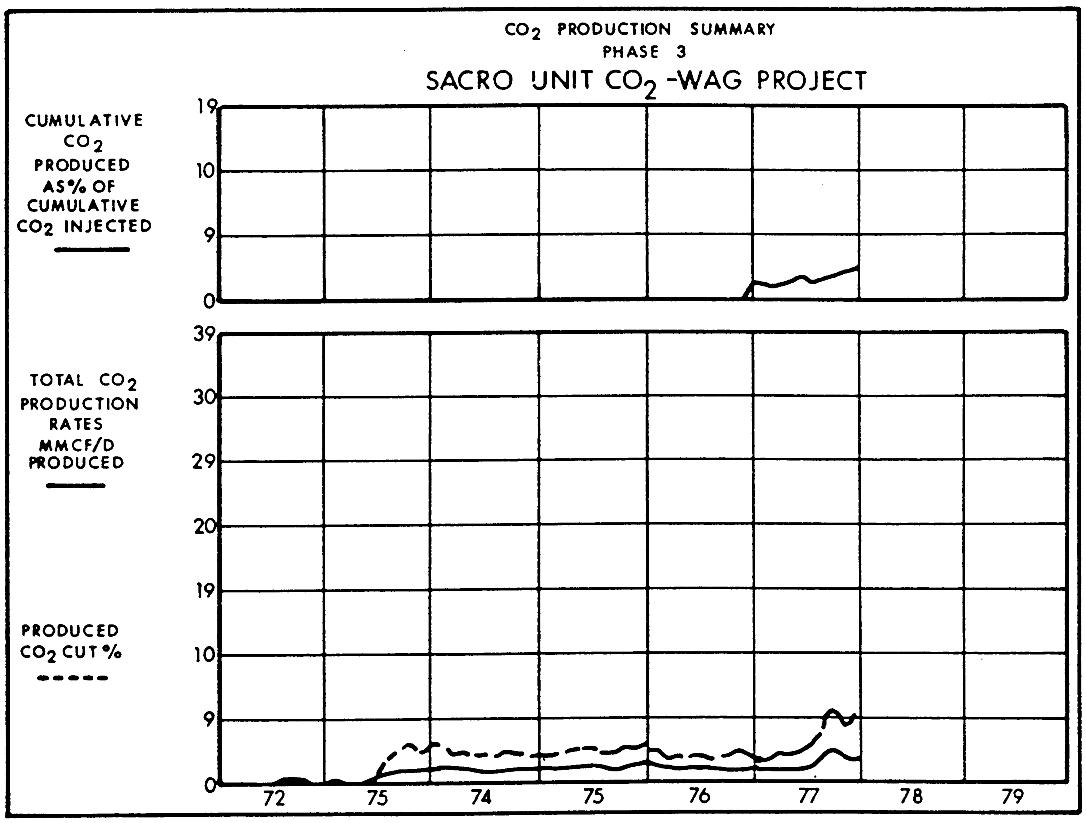

Figure 29.--CO_2 production summary for SACROC unit Phase III.

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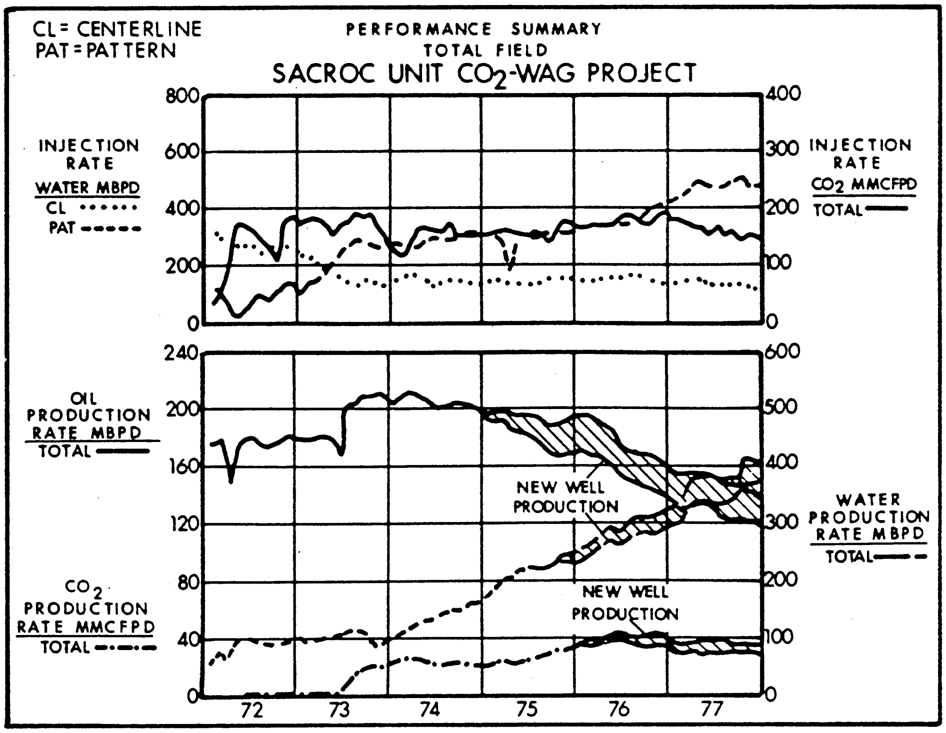

Figure 30.--Performance summary for total SACROC unit.

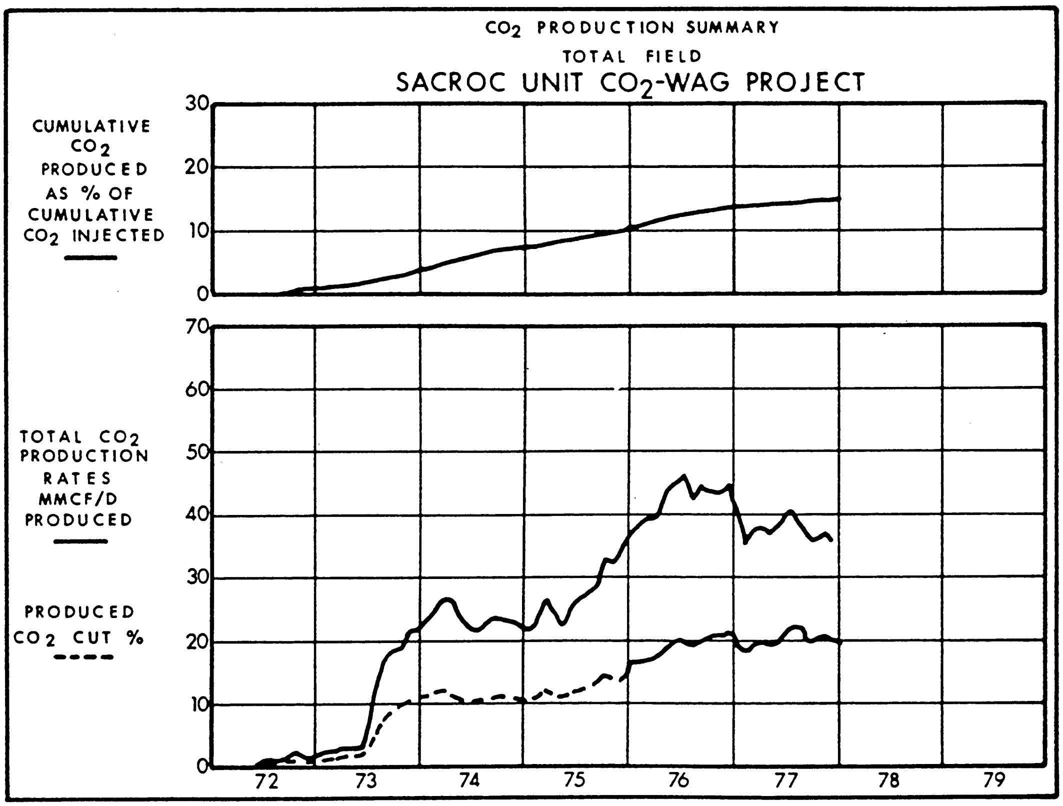

Figure 31.--CO_2 production summary for total SACROC unit.

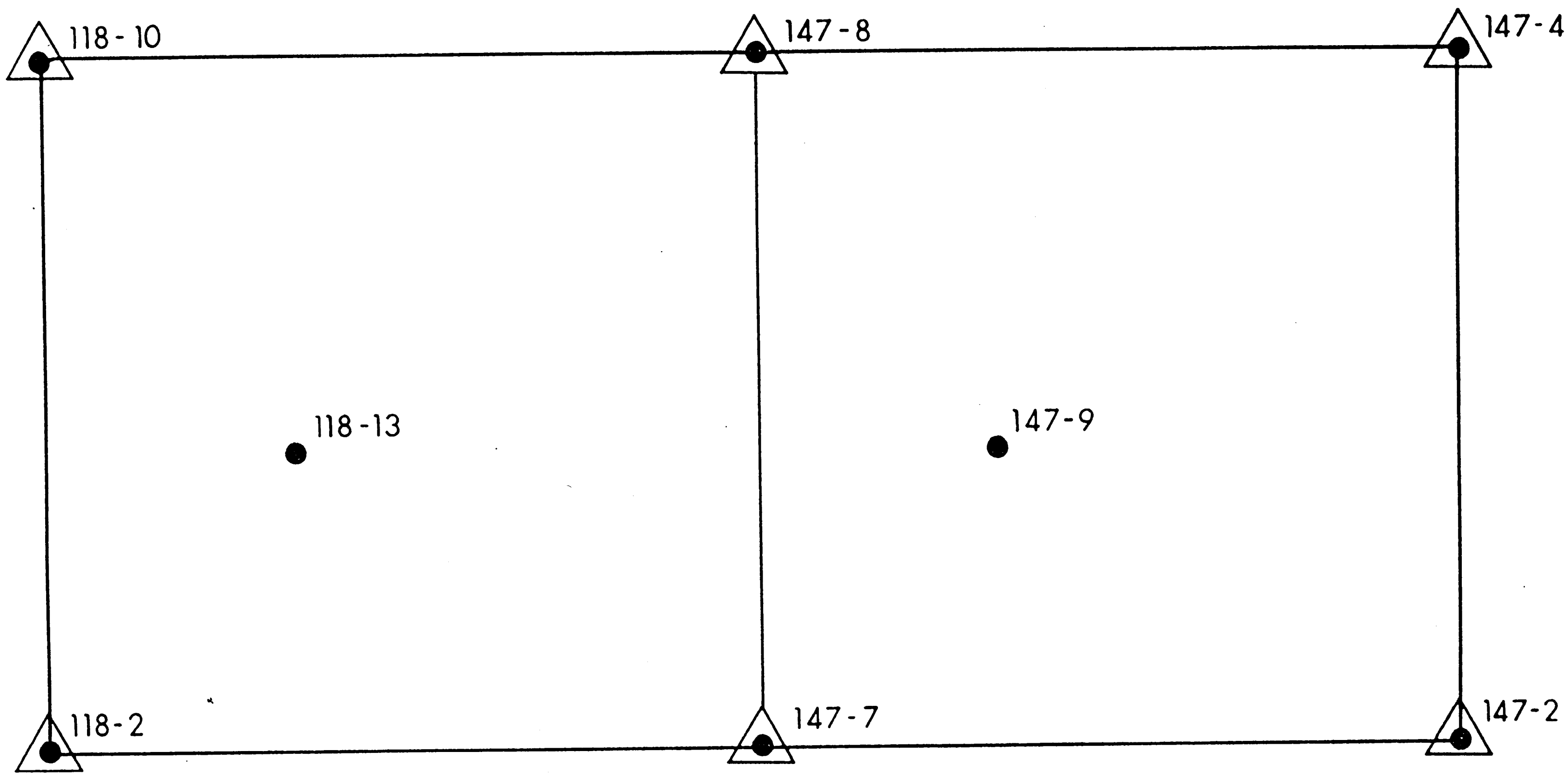

Figure 32.--Injector-producer configuration, SACROC unit tertiary pilot CO_2 recovery project.

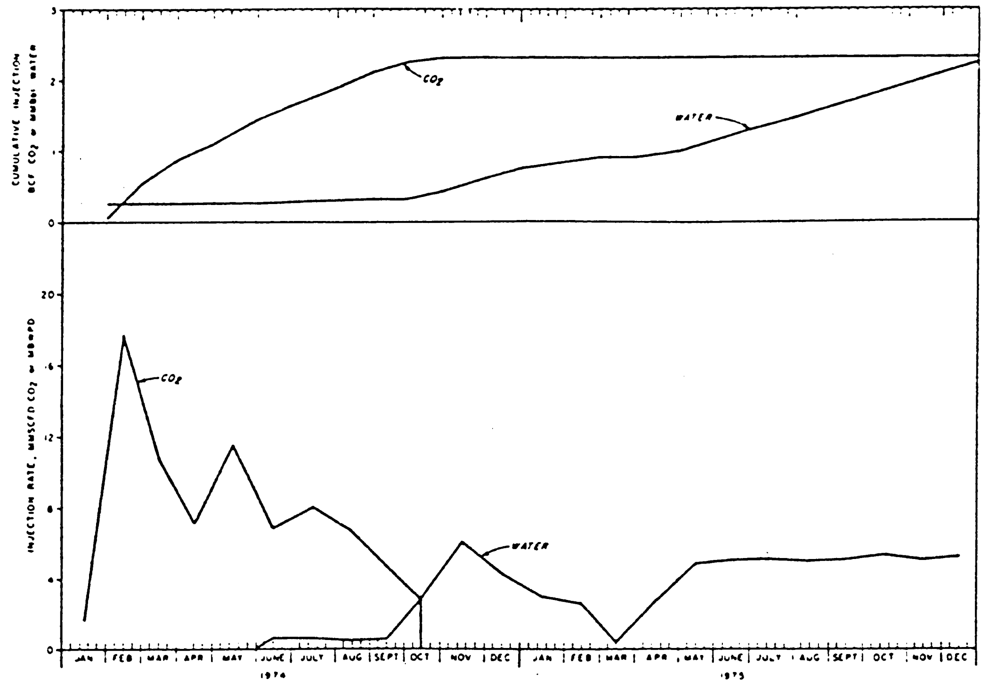

Figure 33.--Injection into six tertiary pilot wells SACROC unit.

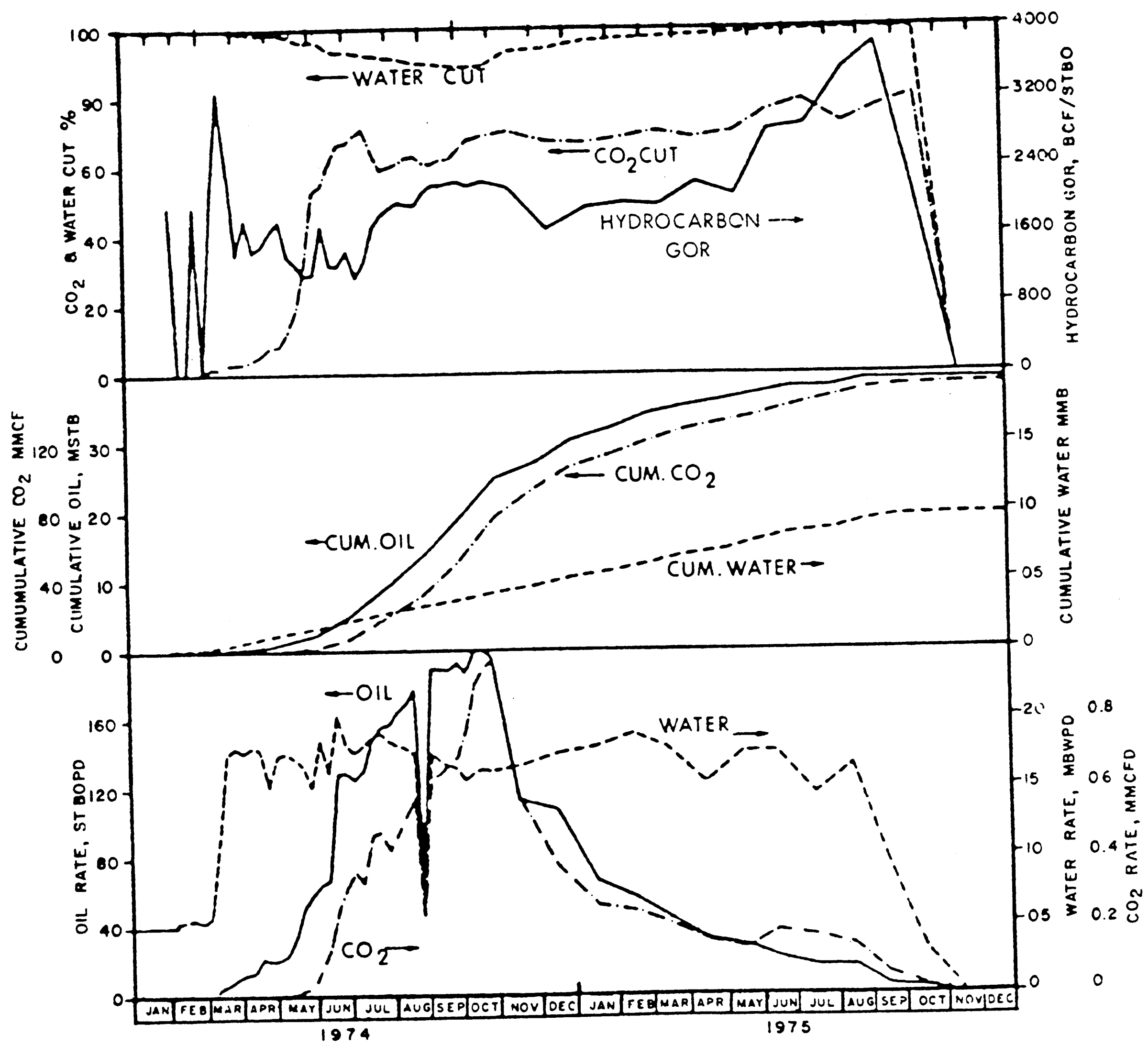

Figure 34.--Production history for Well 118-13, SACROC unit.

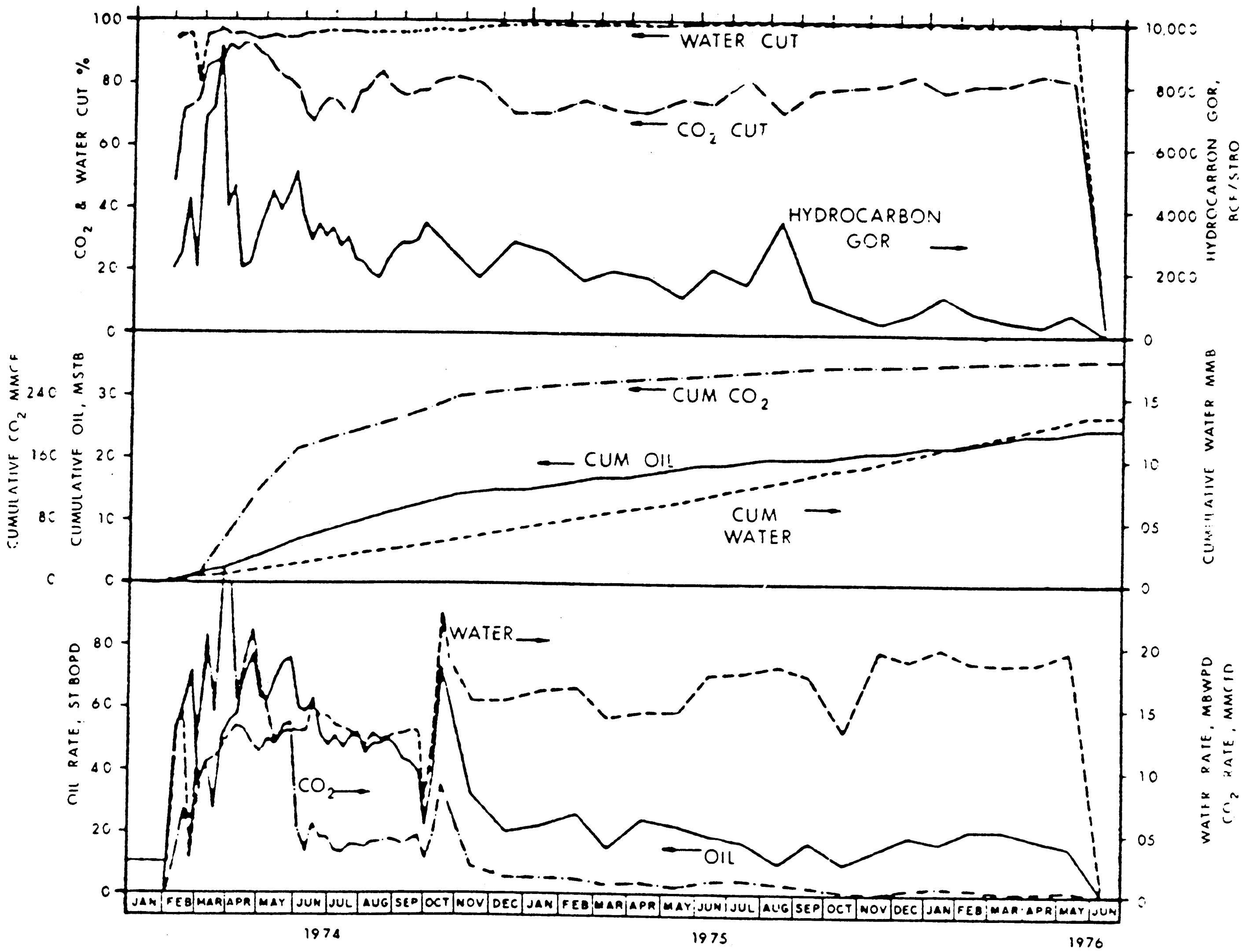

Figure 35.--Production history for Well 147-9 SACROC unit.

CO_2 FIELD INJECTION PROJECT CONDUCTED BY PHILLIPS PETROLEUM CO. (OPERATOR/SUCCESSOR TO U.S. OIL AND REFINING COMPANY) RITCHIE FIELD, UNION COUNTY, ARKANSAS

by

Elbert N. Durham and Jerry A. Watson

Location and General History

Ritchie Field is located in Union County in southern Arkansas, west of the Monroe Uplift (Fig. 1). The field was discovered in 1963 and 16 wells were completed in the Baker Sand by late 1964. Production is obtained from a depth of 2,600 feet in an area encompassing about 220 acres. Original oil in place is estimated to be 3.47 million barrels; cumulative production was 905,600 barrels through May 1979.

The field was near primary depletion when it was unitized in 1968 with U.S. Oil and Refining Company as the operator. Limited CO_2 injection and water injection operations were performed between 1969 and 1975, achieving substantial oil production response. No further enhanced recovery efforts were made, however, and production again declined to near the economic limit by July 1978, when the field was completely shut in and a second phase of CO_2 injection begun using a new source of CO_2. Phillips Petroleum Company is the current operator.

Statistics and Information Summary

Summary data on the Ritchie Baker Sand reservoir and the CO_2 project are presented in Table 1 at the end of this report. Except as specifically noted, all of the information in Table 1 and elsewhere in this report was derived from the Arkansas State Oil and Gas Commission's records or from unpublished information supplied by the operator.

Geology and Petrophysics

The Baker Sand, a member of the Ozan Formation, is one of a series of oil-productive Upper Cretaceous sands in southern Arkansas (Fig. 2). The Baker Sand reservoir at the Ritchie Field is a combination structural/stratigraphic trap (Fig. 3). The structure map on top of the Baker Sand shows the southeast dip interrupted by a northwest-southeast trending positive feature of 10 to 20 feet relief.

The associated sand development is shown in the isopach in Fig. 4. Maximum sand development is 14 feet; average pay thickness is about 9 feet. A type log from the field is shown in Fig. 5. The SP curve indicates a clean sand underlain and overlain by shale beds.

The Baker Sand has an average porosity of 30.7 percent, an average permeability of 2,754 md, and a connate water saturation of approximately 20 percent.

Reservoir Fluid Data

The Ritchie Baker Sand crude has a gravity of approximately 16°API. The viscosity of the stock tank oil at reservoir temperature (126°F) is 195 centipoises. A crude petroleum analysis reported by the Bureau of Mines (1969) is particularly notable for the absence of a significant volume of light ends (none recorded at distillation temperatures as high as 347°F).

No data have been reported on the characteristics of Ritchie crude-CO_2 mixtures; however, laboratory measurements reported by Phillips to the Arkansas Oil and Gas Commission on Lick Creek crude (17°API) and Smackover crude (23°API) have shown that at a pressure equal to the original reservoir pressure at Ritchie, these crudes will accept into solution approximately 50 to 60 mol percent of CO_2, resulting in a 12 to 16 percent increase in volume, an 8- to 10-fold reduction in viscosity, and a slight increase in density. Each of these effects contributes to improved efficiency of displacement of the crude by water.

Reservoir Performance History Prior to CO_2 Project Review

Oil production history for the Ritchie Baker Sand reservoir is shown in Fig. 6. The reservoir was nearing depletion by primary methods when CO_2 injection was begun in January 1969. Cumulative oil production was 438,000 barrels to January 1, 1969, at which time the field production rate had declined to about 100 B/D from a peak rate of about 430 B/D in 1964. Water production was minor, with no evidence of active natural water encroachment. The primary recovery mechanism was apparently limited to fluid expansion and solution gas drive. Remaining primary reserves as of January 1, 1969, were approximately 52,000 barrels, equivalent to an estimated primary ultimate of 490,000 barrels.

CO_2 Project Review

The initial CO_2 injection in early 1969 used 3 to 4 MMcf/D of high-purity CO_2 from a local chemical plant. Because of a change in plant processing operations, this supply was lost after only 78 days. After this, injection was limited to recycling of a diminishing volume of produced CO_2.

CO_2 injection data for individual wells are not available for stage 1 injection operations. However, it has been determined from the operator that the initial 264 MMcf of purchased gas was concentrated primarily in the three wells shown in Fig. 7. Subsequently, all captured produced gas was used in successive cyclic stimulation of all producers by alternating CO_2 injection and production. Water injection, which began in May 1970, was concentrated principally in two of the four peripheral wells used for this purpose (Fig. 7). Water injection volumes were chosen at approximately the level required to maintain a balance with total fluid withdrawal (Fig. 6). Cumulative water injected to July 1978 was 3.8 million barrels, or about 83 percent of the net pay pore volume. Makeup water is obtained from a sand slightly shallower than the Baker. Disposal of produced water since termination of water injection in August 1975 has been in the Meakin sandstone.

As shown in Fig. 6, the initial cyclic stimulation operations resulted in a project oil production rate of about 4,000 barrels per month, or twice the predicted primary rate. Immediately following the start of water injection, production was further increased to an average rate of about 12,000 barrels per month through 1971. Production then declined steadily to an average rate of about 1,500 barrels per month, with a water-oil ratio of 25, before production was shut in during 1974. At that time, incremental recovery over primary was 415,000 barrels; reserves under continued operations were nil.

A second stage of CO_2 injection, commenced in July 1978, utilizes excess CO_2 available from a pipeline originally constructed by Phillips and others to supply the Lick Creek Field. This line receives CO_2 from the IMC ammonia plant in Sterlington, Louisiana.

Upon establishment of a new source of CO_2, a second stage of injection was begun in July 1978 into Unit Well No. 7-4 as shown in Fig. 6. Concurrent with start-up of this injection stage, all production was shut in. It is the stated plan of the operator to inject about 500 MMcf into this well, to be followed by water. Cumulative Stage 2 injection to June 1, 1979 was 366 MMcf. Injection continues at an average rate of about 40 MMcf per month.

Interpretations and Conclusions

The injection of a small volume of CO_2 with multiple reinjection of produced gas in cyclic stimulation operations, together with the injection of about 0.8 pore volumes of water, has resulted in an enhanced oil recovery from the Ritchie Baker Sand heavy oil reservoir of 415,000 barrels, representing 85 percent of the estimated primary ultimate, 12.5 percent of the original oil in place, and 15.7 percent of the oil in place at start of the project.

Because of the high oil viscosity, the probability of recovering a significant volume of incremental oil at Ritchie by conventional waterflooding seems small. However, there is evidence of a significant positive influence of a natural water drive on recovery from the nearby Lick Creek Meakin Sand heavy oil reservoir.

If the total enhanced oil recovery achieved to date is credited to CO_2 injection, the indicated CO_2 utilization factor is 0.64 Mcf of CO_2 per barrel of incremental oil recovered.

No estimate has been reported of the additional incremental oil expected as a result of the current second-stage CO_2 injection operations. It is significant, however, that operations currently in progress in the Lick Creek Meakin Sand Unit, following natural water drive recovery to an estimated average residual oil saturation of 55 percent, show promise of reducing this saturation to the range of 45 to 50 percent. This provides some incentive to extend CO_2 application in Ritchie, where the present estimated oil saturation is still 59 percent following first-stage enhanced recovery operations.

TABLE 1

FIELD DATA FOR CARBON DIOXIDE INJECTION PROJECTS

FIELD: RITCHIE

LOCATION AND GENERAL DATA

State: Arkansas County: Union

Discovery Date: 1963 Date First Production May, 1963

No. Wells: 16 @ Date: Late 1964

Developed Area: 220 ± (1) Acres

GEOLOGY AND PETROPHYSICS

Reservoir Name: Baker Sand

Reservoir Rock Type: Sandstone

Trap: sand lens

Average Depth: 2600 feet

Primary Gas Cap (Y/N) -

Gas/Oil Contact Depth: ________ feet subsea
Oil/Water Contact Depth: ________ feet subsea

Average Net Pay Thickness: 9 ± (1) feet Range 1 ft. to 14 ft.

Net/Gross Ratio: Approx. 1.0
Average Porosity: 30.7 %
Initial Water Saturation 20 %
Average Permeability: 2800 millidarcies

Permeability Range: ________ millidarcies

Permeability Variation: ________

k_v/k_h: ________

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

BASIC RESERVOIR AND VOLUMETRIC DATA

Initial Reservoir Pressure: est. 1250$\pm$ (2) psi
Reservoir Temperature: 126 °F
Bubble Point Pressure: not reported psi
Formation Volume Factors:
B_{oi} est. 1.05
B_{ob} ______
Reservoir Oil Viscosity Data:
μ_{oi} 195 (3) centipoise
μ_{ob} ______ centipoise

Initial Solution Gas-Oil Ratio:
R_{si} ______ cu.ft./bbl.
Stock Tank Oil Gravity: 15 - 16 °API

Reservoir Hydrocarbon Pore Volumes:
Oil Column: 3.650 (4) M Bbl Gas Cap: 0 M Bbl
Standard Volume Original Hydrocarbons in Place
Oil: 3,470 (4) M Bbl Free Gas: 0 Mcf

RESERVOIR PERFORMANCE DATA

Primary Recovery Drive Mechanism: Fluid expansion

Estimated Ultimate Primary Recovery: 14.1 % ISTOIP

Supplemental Recovery Method(s) and Date Started: ______
None prior to CO_2 injection - see CO_2 project data (pg. 3)

Cumulative Oil Production at Start Supplemental: ______
______ M Bbls ______ % ISTOIP

Unit Operator(s): ______

Average Pressure at Start Supplemental: ______ psi

Estimated Additional Supplemental Recovery (Ultimate): ____ % ISTOIP

Estimated Total Ultimate Recovery (Primary+Supplemental) ____ % ISTOIP

Cumulative Total Production to: January, 1969 (Date)
438 M Bbls 12.6 % ISTOIP
est. 298 Jan. 1969
Average Pressure: 800 (5) psi @ 1971 (Date)
Calculated Average Oil Saturation 70 %@ Jan. 1969 (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

CARBON DIOXIDE INJECTION PROJECT DATA

Project Operator: Phillips Petroleum Co. (formerly U.S. Oil & Refining)

Project Type: Mini-Test ____ Pilot Test ___ Full-Scale Project X
Recovery Mode: Secondary X Tertiary ______
Project Area: 220 ± Acres
No. of Wells: Injection ______ Production ______ Other ______

Pattern Geometry: Stage 1 - CO_2 cyclic stimulation of all wells with continuous water injection into eastern periphery. Stage 2 - CO_2 injection in one crestal well.

Date Project Commenced: 1/12/69 Ended Active May 1969
Injection Fluid Composition (mol percent)
CO_2 98% ± H_2S ______ C_1 ______

C_2-C_6 ______ C_7+ ______ Other ______

Estimated miscibility pressure: Not determined psi
Injection Fluid Source(s): Current CO_2 from pipeline originating in Sterlington, Louisiana. Water from subsurface
CO_2 Injection Rate (Excluding Recycle): 1500 Mcf/day May,1979 (Date)
Recycle Gas Injection Rate: not measured Mcf/day 1969-1975 (Date)
Water Injection Rate: 2000-2500 Bbl/day 1970-1975 (Date)

Water Injection Mode (i.e., alternating, continuous after "slug", etc.)
Discuss: Stage 1 - (see pattern geometry above). Stage 2 - water injection planned to follow CO_2 in crestal well.

Injection Pressures:

CO_2:	Surface	900-300	psi	Bottomhole	psi
Recycle:	Surface		psi	Bottomhole	psi
Water:	Surface	0-400	psi	Bottomhole	psi

Cumulative Injection @ June 1, 1979 (Date)

CO_2	630 (6)	MMcf		%HCPV
Recycle:	not measured	MMcf		%HCPV
Water:	3,808	~~XXXXX~~ Thous.BBL	104	%HCPV

Current Production Rates: (Date) June 1, 1979 - Shut-in production prior to shut-in in July, 1978.
Oil: 50 Bbl/day Gas: Nil Mcf/day
CO_2: Nil Mcf/day Water: 1250 Bbl/day

Date First Response: July, 1969

Date CO_2 Breakthrough: (stimulation technique)

Cumulative CO_2 Production: not measured MMcf @ ______ (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

Incremental Response: 50 Bbl/day @ July 1978 (Date)
Prior to shut-in

Cumulative Incremental Oil @ 6/1/79 (Date) 415 M Bbl

CO_2 Utilization Ratio-Cumulative Injection CO_2/Cumulative Incremental Oil 0.64 Mcf/Bbl, following Stage 1.

Expected Ultimate Incremental Production:
________ M Bbls ________ % ISTOIP

Supplemental Information

1. Reservoir net pay (unitization basis) = 1968 AC-FT.
2. Estimated based on an assumed gradient equal to Lick Creek Field.
3. Stock tank oil viscosity at reservoir temperature.
4. Based on reported cumulative to 8/1/68 of 427,000 BBL, equal 12.3% OOIP, and assumed FVF equal 1.05.
5. Estimates by representatives of U. S. Oil and Refining, original unit operator, via personal communications.
6. Includes 264 MMcf during Stage 1, cyclic stimulation and 366 MMcf to 6/1/79 during Stage 2, continuous injection.

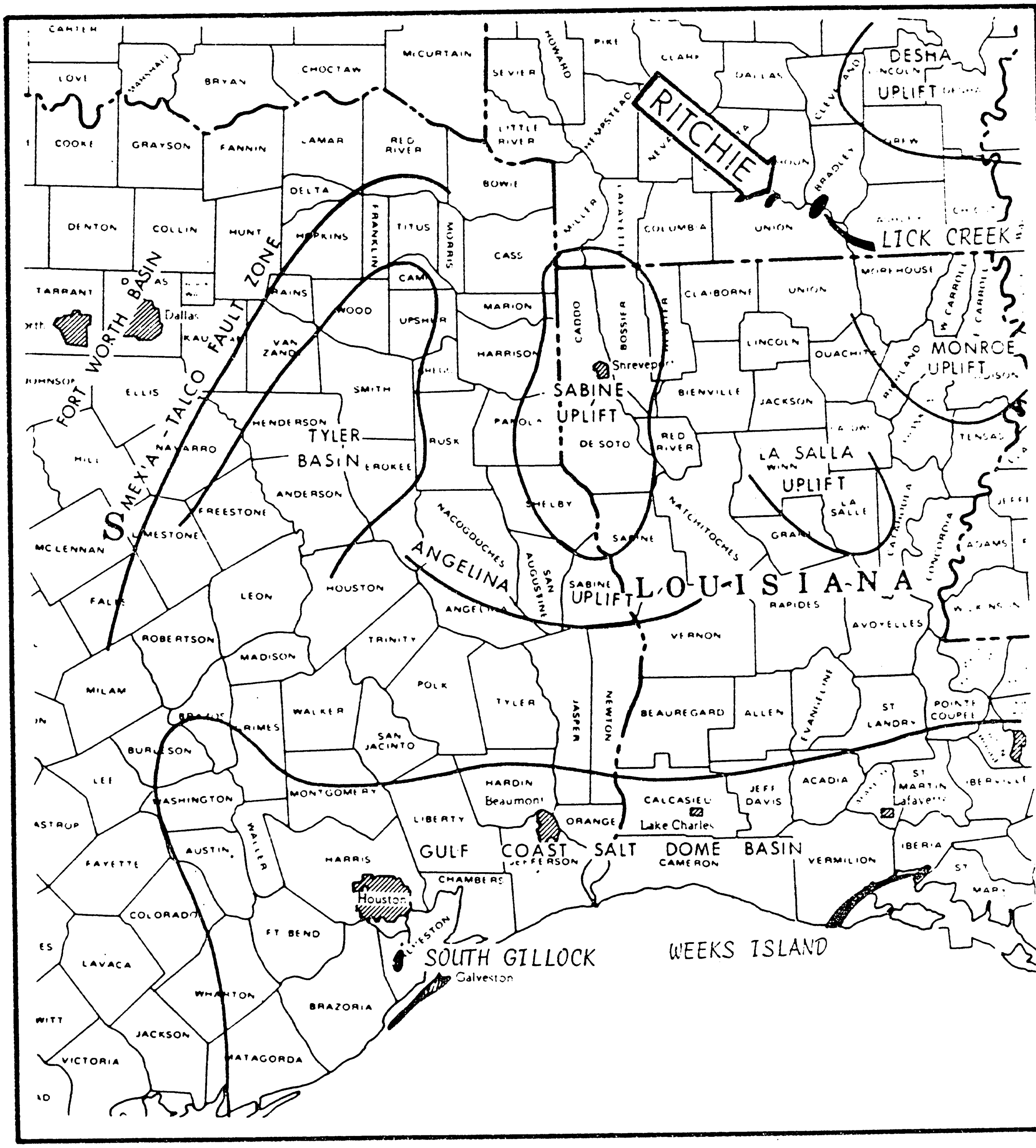

Figure 1.--Index map, carbon dioxide projects in Arkansas.

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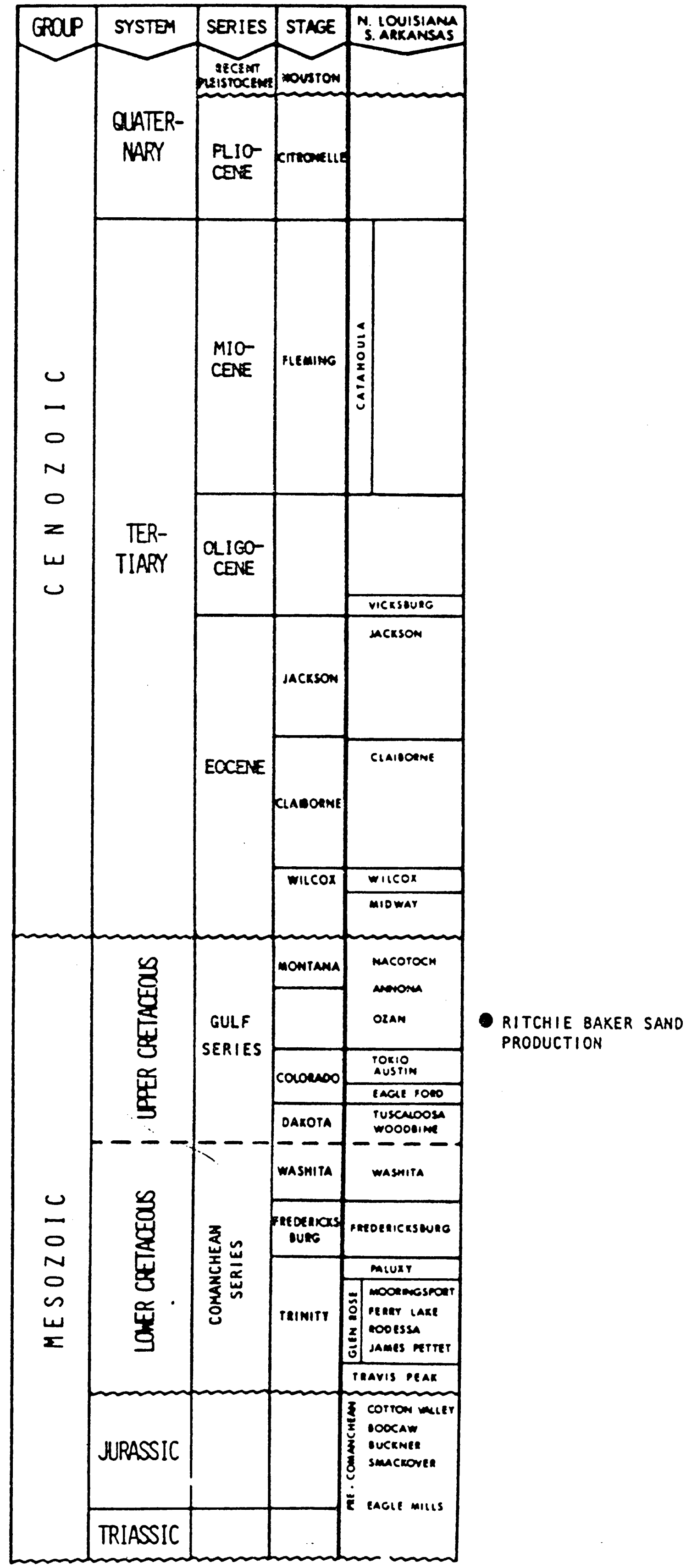


Figure 2.--Generalized stratigraphic column for southern Arkansas.

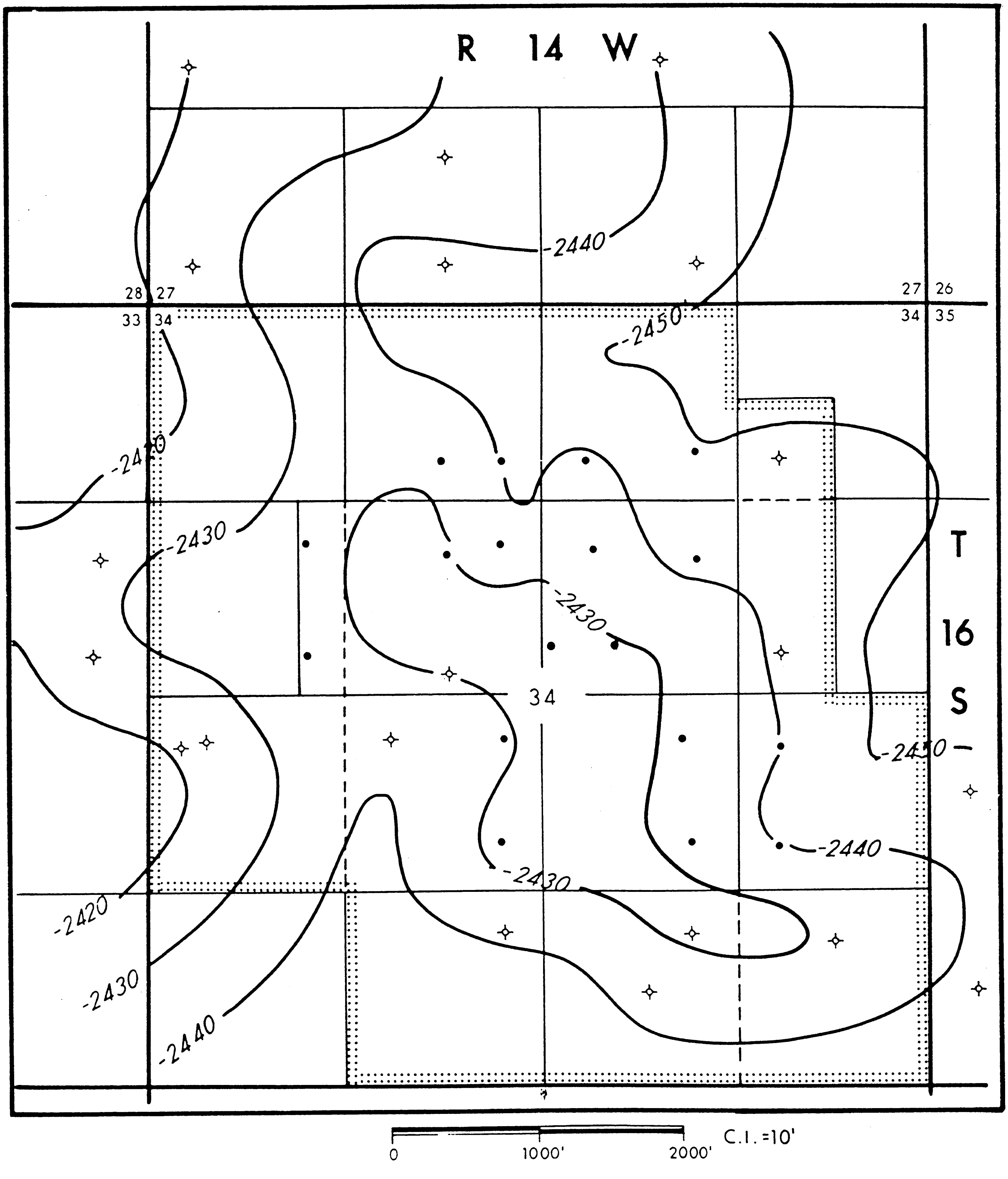


Figure 3.--Structure on top of the Baker sand, Richie field, Arkansas.

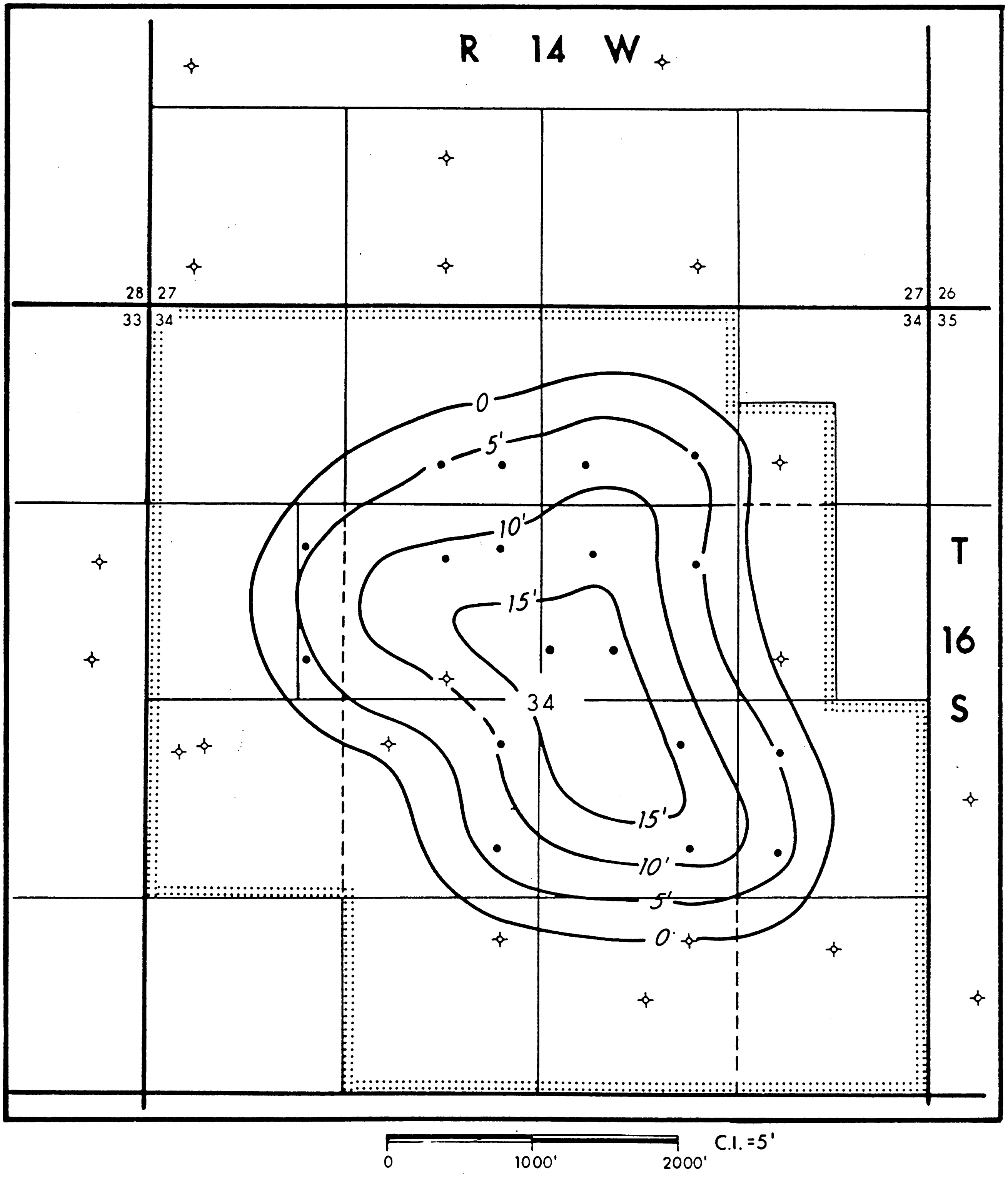


Figure 4.--Isopach map, net Baker sand, Ritchie field, Arkansas.

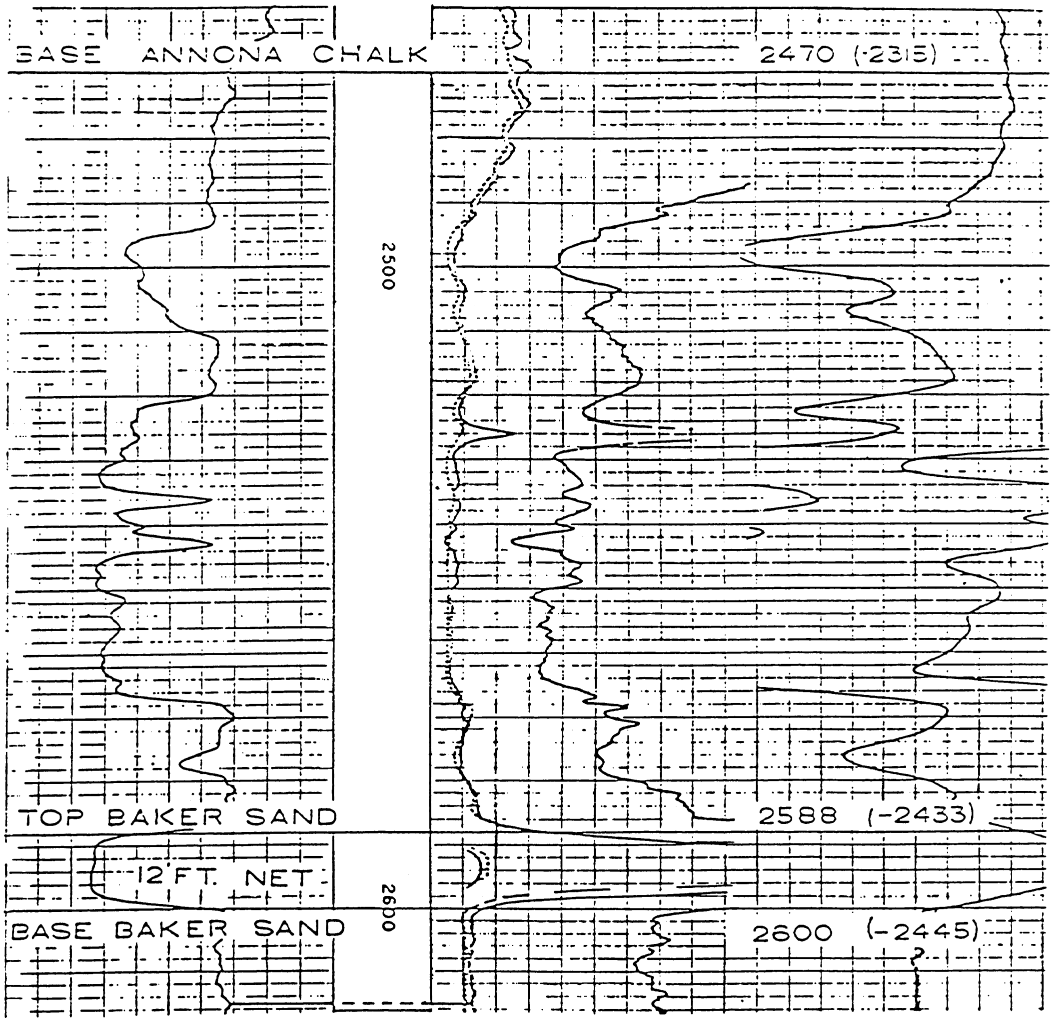


Figure 5.--Type log from Ritchie field, Arkansas.

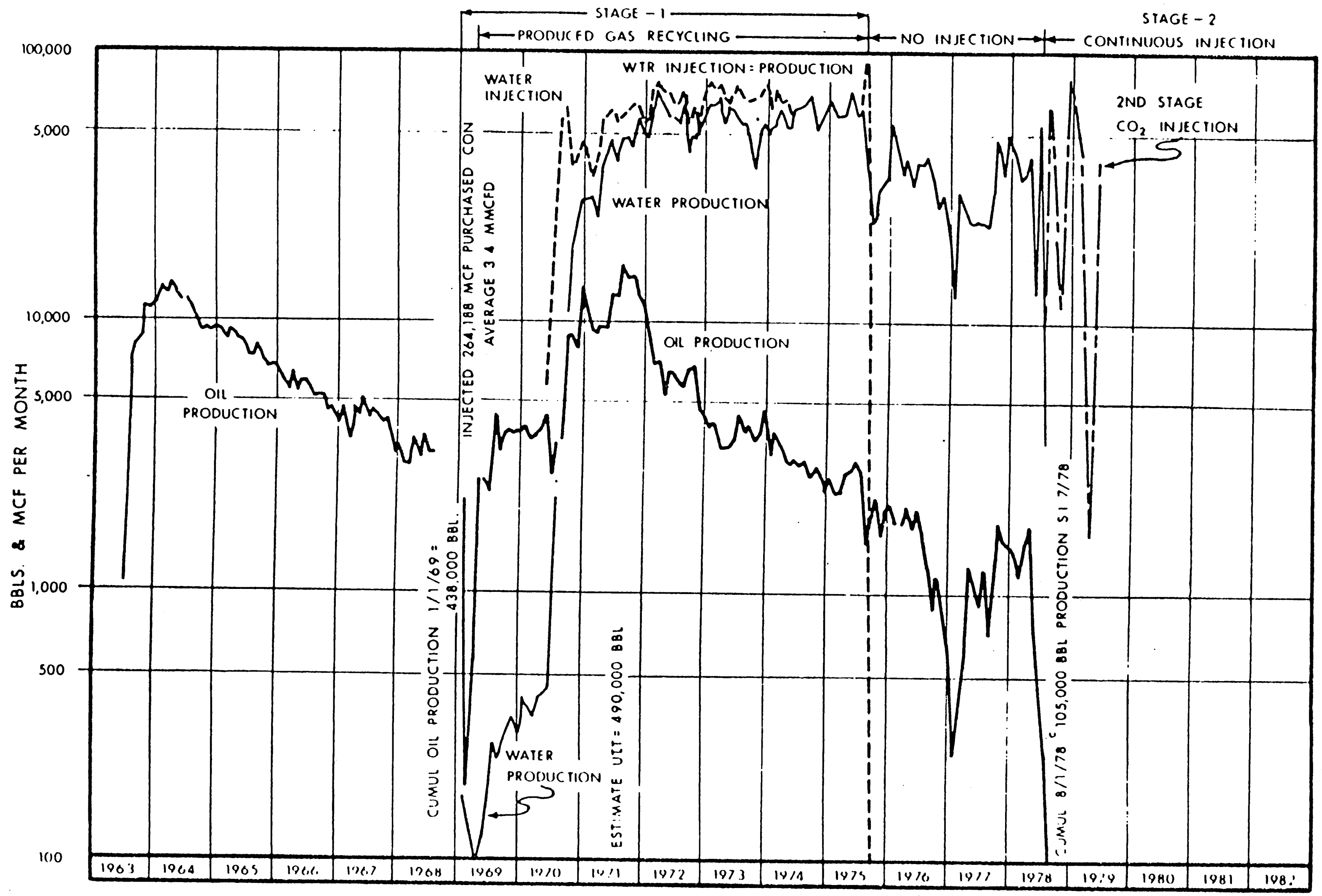
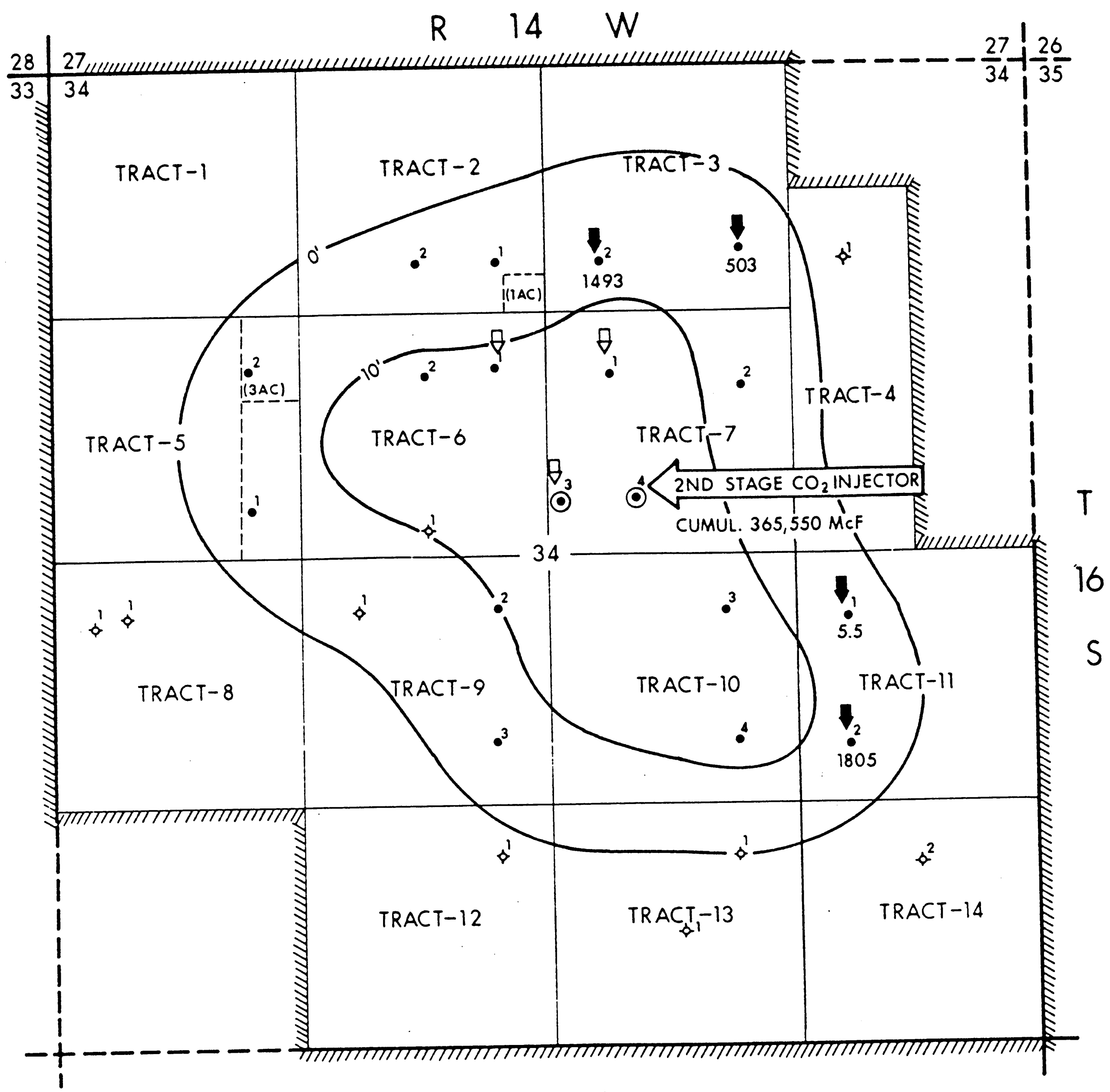


Figure 6.--Performance history, carbon dioxide injection project, Baker sand unit, Ritchie field, Arkansas.



Legend

10' ISOPACH – NET OIL PAY

UNIT BOUNDARY

1,493 WATER INJECTOR
CUMUL. WATER INJECTED 6/1/79
THOUSANDS BBL

ORIGINAL PRODUCER

NEW PRODUCER

PRINCIPAL CONCENTRATION OF FIRST 264 MMCF OF 1ST. STAGE CO_2

NOTE: ALL 1ST. STAGE CO_2 USED IN STIMULATION – ALL WELLS

Figure 7.--Operational pattern, carbon dioxide injection project, Baker sand unit, Ritchie field, Arkansas.

CO_2 FIELD INJECTION PROJECT
CONDUCTED BY AMOCO PRODUCTION COMPANY
SOUTH GILLOCK FIELD, GALVESTON COUNTY, TEXAS

by
Raj M. Kumar and Jerry A. Watson

Location and General History

South Gillock field is located in Galveston County, Texas, in the Gulf Coast Salt Dome Basin (Fig. 1). The field was developed after its discovery in 1939, but was exploited as an oil producer beginning in 1948 producing from the Big Gas Sand at depths of 8,500 to 9,500 feet. The field produced 2,394,000 barrels of oil in 1975 from 40 wells in a project area of 5,940 acres. Cumulative production through 1975 was 37.955 million barrels. The field was unitized in 1966 for a water pressure-maintenance project with Pan American (now Amoco) as operator.

Geologic and Petrophysical Data

South Gillock field is located near the axis of maximum deposition of Middle Cenozoic sediments in the Gulf Coast geosyncline. Production is obtained from the Big Gas Sand (Fig. 2), one of a series of Frio sands of Oligocene age that are productive in the region. South Gillock field is located on an isolated fault segment of the Gillock-Dickinson uplift (Fig. 3), which is associated with a deep-seated salt dome. South Gillock is located on the south flank of the dome [1]. The field is bounded by an oil/water contact on the downdip side. A series of faults with 50 to 100 feet displacement bisects and defines the field limits.

The depth to the top of the pay ranges from 8,500 to 9,500 feet. The average effective net pay is 39 feet, the average porosity 29.5 percent. Permeability ranges from 10 to 10,000 md, averaging of 1,156 md. Connate water saturation is 22.5 percent. Figure 4 is a type log from the field showing sand development in the pay section. Table 1 at the end of this report shows engineering, petrophysical, and statistical data.

Reservoir Fluid Data

The reservoir fluid at South Gillock at the time of discovery was saturated with gas and contained a gas cap which was 14 times the oil volume. Some of the important reservoir fluid properties are:

Initial Viscosity = 0.64 cp
Initial Formation Volume Factor = 1.585
Initial Solution Gas Oil Ratio = 708 scf/bbl
API Gravity = 38°

Reservoir Performance Data

The South Gillock Unit performance history for the period 1940-1969 is shown in Fig. 5; Fig. 6 depicts the South Gillock Unit gas cap performance history. During the period 1939-1948, reservoir pressure declined from 4,354 psi to about 3,415 psi because of gas production from the gas cap. However, on discovery of the oil zone, all the casinghead gas was injected back into the reservoir beginning in July 1949, to avoid further loss of pressure. As a result of gas injection and natural partial water drive, the reservoir pressure declined less sharply. However, to improve recovery, a pilot waterflood was attempted in June 1954, followed by full-scale water injection in September 1966 after fieldwide unitization in January 1966. At the time full-scale waterflooding was initiated, reservoir pressure was about 3,220 psia.

CO_2 Project Data

A CO_2 miscible displacement flood to enhance recovery at South Gillock was started in 1971. Not much information is publicly available. Based on scant published information and data obtained from the Texas Railroad Commission, CO_2 was supposed to be injected at the gas-oil contact followed by downdip displacement. The plan called for injecting 118 Bcf of CO_2 through six injectors. Fig. 7 shows the predicted future performance from the time CO_2 injection starts. Additional oil recovery was predicted to be 11.286 million barrels, which is about 9 percent of original oil in place.

However, as a result of complex fault geometry, premature breakthrough of CO_2 occurred in very early stages of the flood [2]. The project was terminated after a total of 3.4 Bcf of CO_2 had been injected.

REFERENCES

1. Gardner, F. J., 1952, The Oil and Gas Fields of the Texas Upper Gulf Coast. Petroleum Neirs Corporation, p. 169.

2. McRee, Boyd C., 1977, "CC_2: How it Works, Where it Works", Pet. Eng., Nov. 1977.

FIELD DATA FOR CARBON DIOXIDE INJECTION PROJECTS

FIELD: South Gillock

LOCATION AND GENERAL DATA

State: Texas County: Galveston

Discovery Date: 1939 (1) Date First Production

No. Wells: 47 (Producing) @ Date: 1971

Developed Area: 5940 Acres

GEOLOGY AND PETROPHYSICS

Reservoir Name: Big Gas Sand

Reservoir Rock Type: Sandstone

Trap: Isolated fault segment of the Gillock-Dickinson uplift.

Average Depth: 8500 - 9500

Primary Gas Cap (Y/N) - Y

Gas/Oil Contact Depth: 9000 feet subsea
Oil/Water Contact Depth: 9575 feet subsea

Average Net Pay Thickness: 39 feet

Net/Gross Ratio:
Average Porosity: 29.5 %
Initial Water Saturation 22.5 %
Average Permeability: 1156 millidarcies

Permeability Range: 10 - 10000 millidarcies

Permeability Variation:

k_v/k_h:

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

BASIC RESERVOIR AND VOLUMETRIC DATA

Initial Reservoir Pressure: 4354 psi
Reservoir Temperature: ______ °F
Bubble Point Pressure: ______ psi
Formation Volume Factors:
B_{oi} 1.585
B_{ob} ______
Reservoir Oil Viscosity Data:
μ_{oi} .64 centipoise
μ_{ob} ______ centipoise

Initial Solution Gas-Oil Ratio:
R_{si} ______ cu.ft./bbl.
Stock Tank Oil Gravity: 38 °API

Reservoir Hydrocarbon Pore Volumes:
Oil Column: ______ M Bbl Gas Cap: ______ M Bbl
Standard Volume Original Hydrocarbons in Place
Oil: ______ M Bbl Free Gas: ______ Mcf

RESERVOIR PERFORMANCE DATA

Primary Recovery Drive Mechanism: Partial water/gas cap drive

Estimated Ultimate Primary Recovery: ______ % ISTOIP

Supplemental Recovery Method(s) and Date Started: Waterflooding
September, 1966

Cumulative Oil Production at Start Supplemental: ______
______ M Bbls ______ % ISTOIP

Unit Operator(s): Pan American Petroleum Corporation

Average Pressure at Start Supplemental: 3220 psi

Estimated Additional Supplemental Recovery (Ultimate): ______ % ISTOIP

Estimated Total Ultimate Recovery (Primary+Supplemental) 51 % ISTOIP

Cumulative Total Production to: ______ (Date)
______ M Bbls ______ % ISTOIP

Average Pressure: ______ psi @ ______ (Date)
Calculated Average Oil Saturation ______ %@ ______ (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

ARBON DIOXIDE INJECTION PROJECT DATA (2)

Project Operator: ______

Project Type: Mini-Test ___ Pilot Test ___ Full-Scale Project X
Recovery Mode: Secondary ___ Tertiary X
Project Area: ______ Acres
No. of Wells: Injection ___ Production ___ Other ___

Pattern Geometry: ______

Date Project Commenced: 1971 Ended ______
Injection Fluid Composition (mol percent)
CO_2 100 % H_2S ___ C_1 ___

C_2-C_6 ___ C_7+ ___ Other ___

Estimated miscibility pressure: ______ psi
Injection Fluid Source(s): Nearby Ammonia Plant

CO_2 Injection Rate (Excluding Recycle): ___ Mcf/day ___ (Date)
Recycle Gas Injection Rate: ___ Mcf/day ___ (Date)
Water Injection Rate: ___ Bbl/day ___ (Date)

Water Injection Mode (i.e., alternating, continuous after "slug", etc.)
Discuss: ______

jection Pressures:

CO_2:	Surface		psi	Bottomhole		psi
Recycle:	Surface		psi	Bottomhole		psi
Water:	Surface		psi	Bottomhole		psi

mulative Injection @ Termination of the project (Date)

CO_2	3400	MMcf		%HCPV
Recycle:		MMcf		%HCPV
Water:		MMcf		%HCPV

rrent Production Rates: (Date) ______

Oil: ___ Bbl/day Gas: ___ Mcf/day
CO_2: ___ Mcf/day Water: ___ Bbl/day

te First Response: ______

te CO_2 Breakthrough: ______

mulative CO_2 Production: ___ MMcf @ ___ (Date)

) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

Incremental Response: ______________ Bbl/day @ ____________ (Date)

Cumulative Incremental Oil @ ________ (Date) ______________ M Bbl

CO_2 Utilization Ratio-Cumulative Injection CO_2/Cumulative Incremental Oil __________ Mcf/Bbl.

Expected Ultimate Incremental Production:
11286 M Bbls 8.7 % ISTOIP

Supplemental Information

(1) The field was discovered in 1939 as a gas field but was reclassified as an oil field in 1948.

(2) At the time the project was initiated, ultimate additional recovery was estimated at 11.3 million barrels. No performance data has been released but the test has been terminated because of premature CO_2 breakthrough as a result of complex fault geometry.

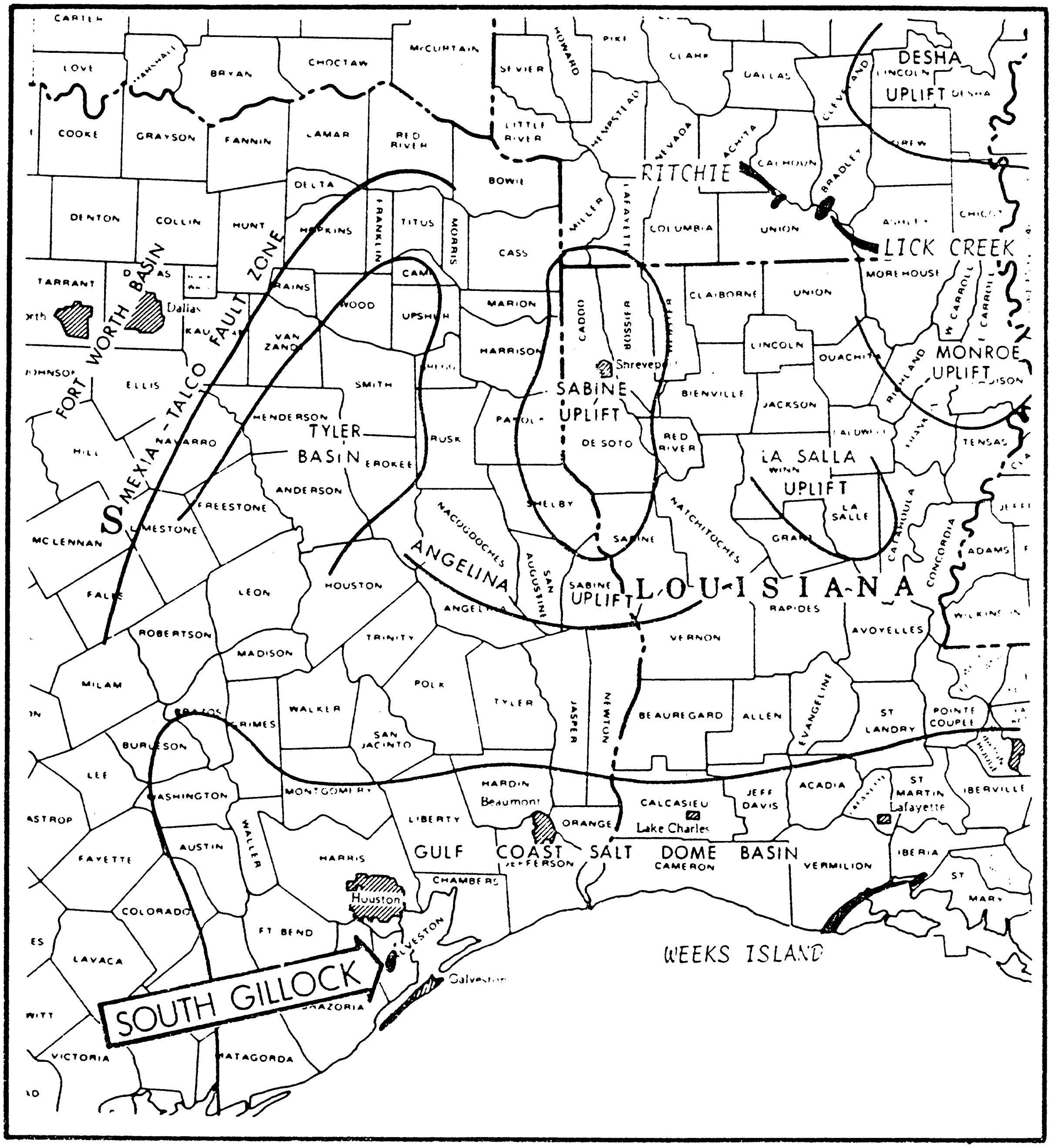


Figure 1.--Index map, carbon dioxide injection projects, Gulf Coast.

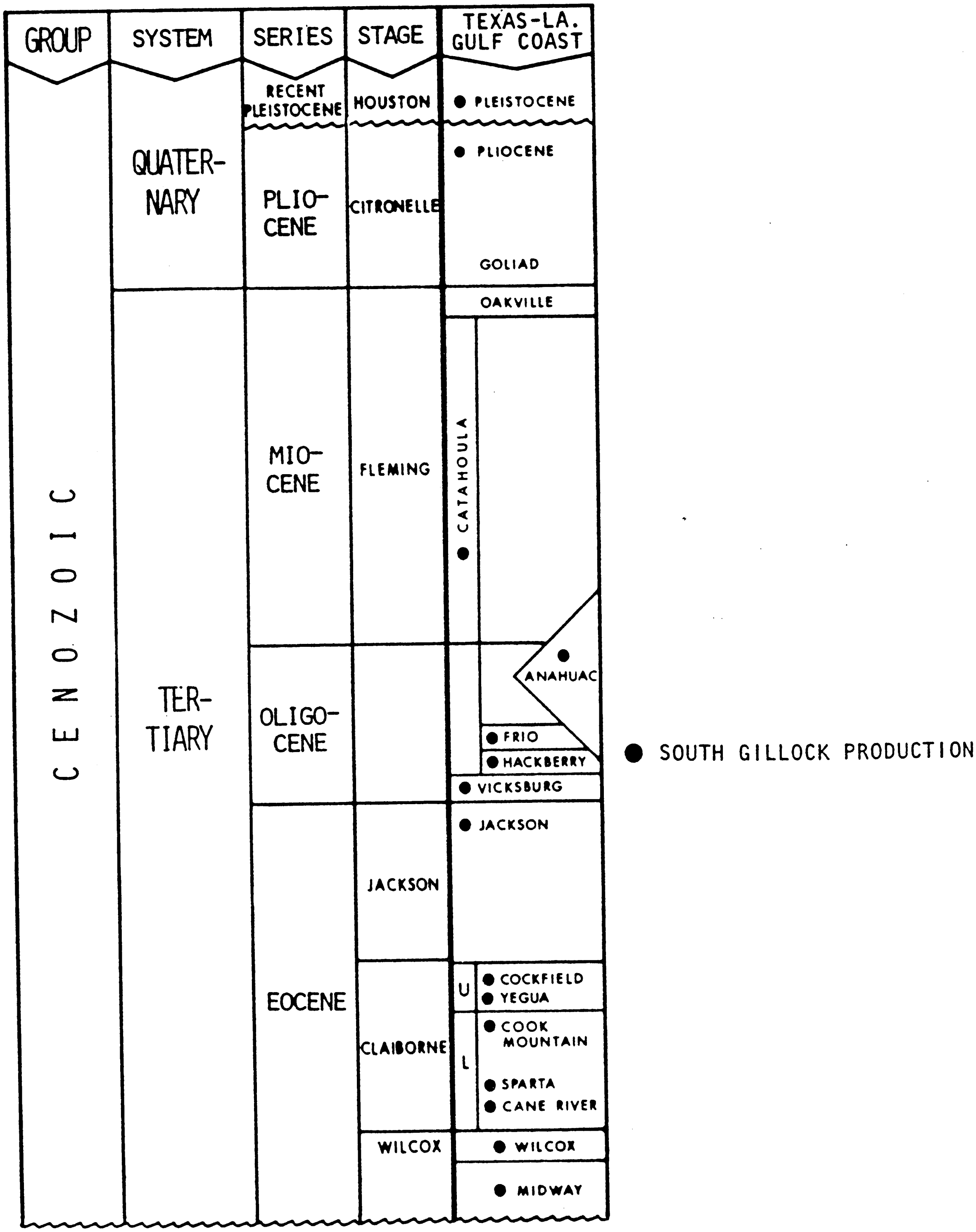


Figure 2.--Generalized stratigraphic column for the Texas Gulf Coast.

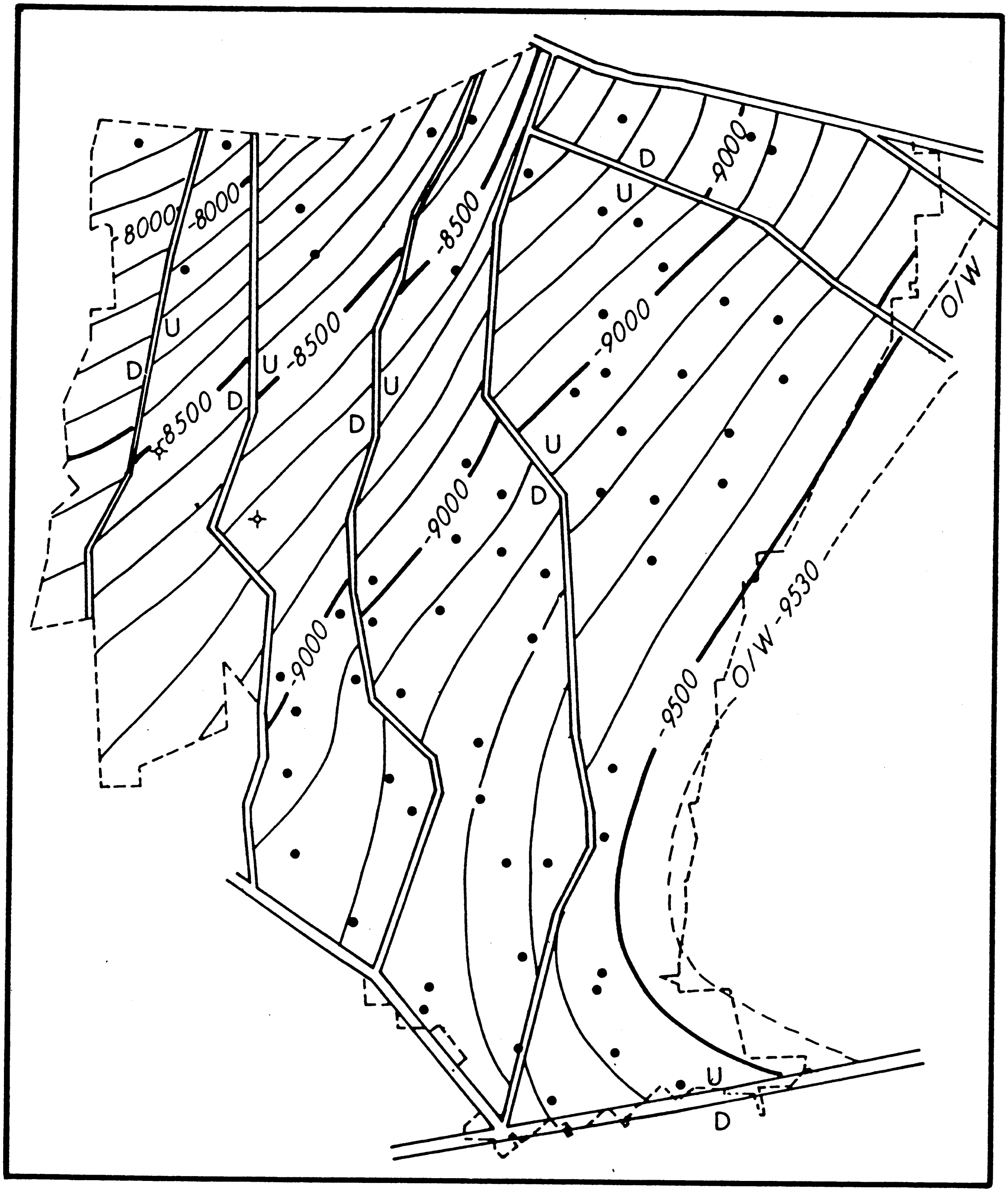


Figure 3.--Structure on top of the Big Gas sand, South Gillock field, Texas.

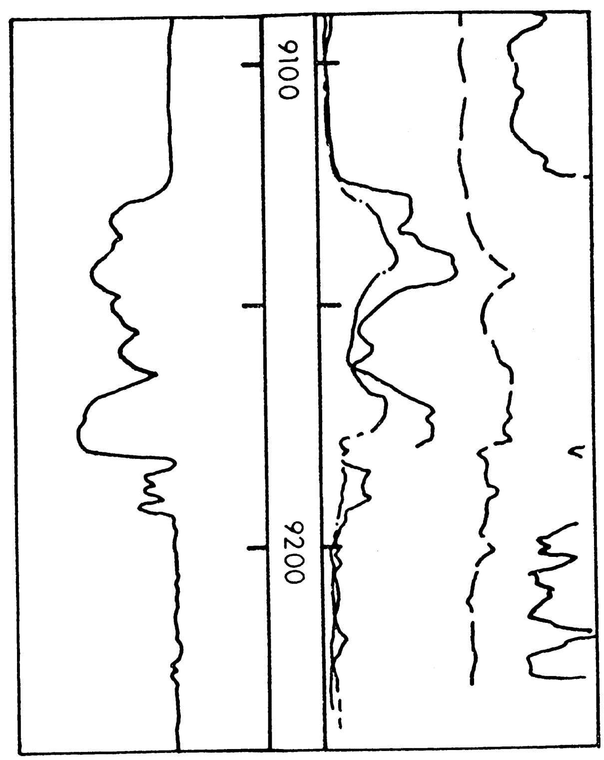


Figure 4.--Typical log from the
Big Gas sand, South
Gillock field, Texas.

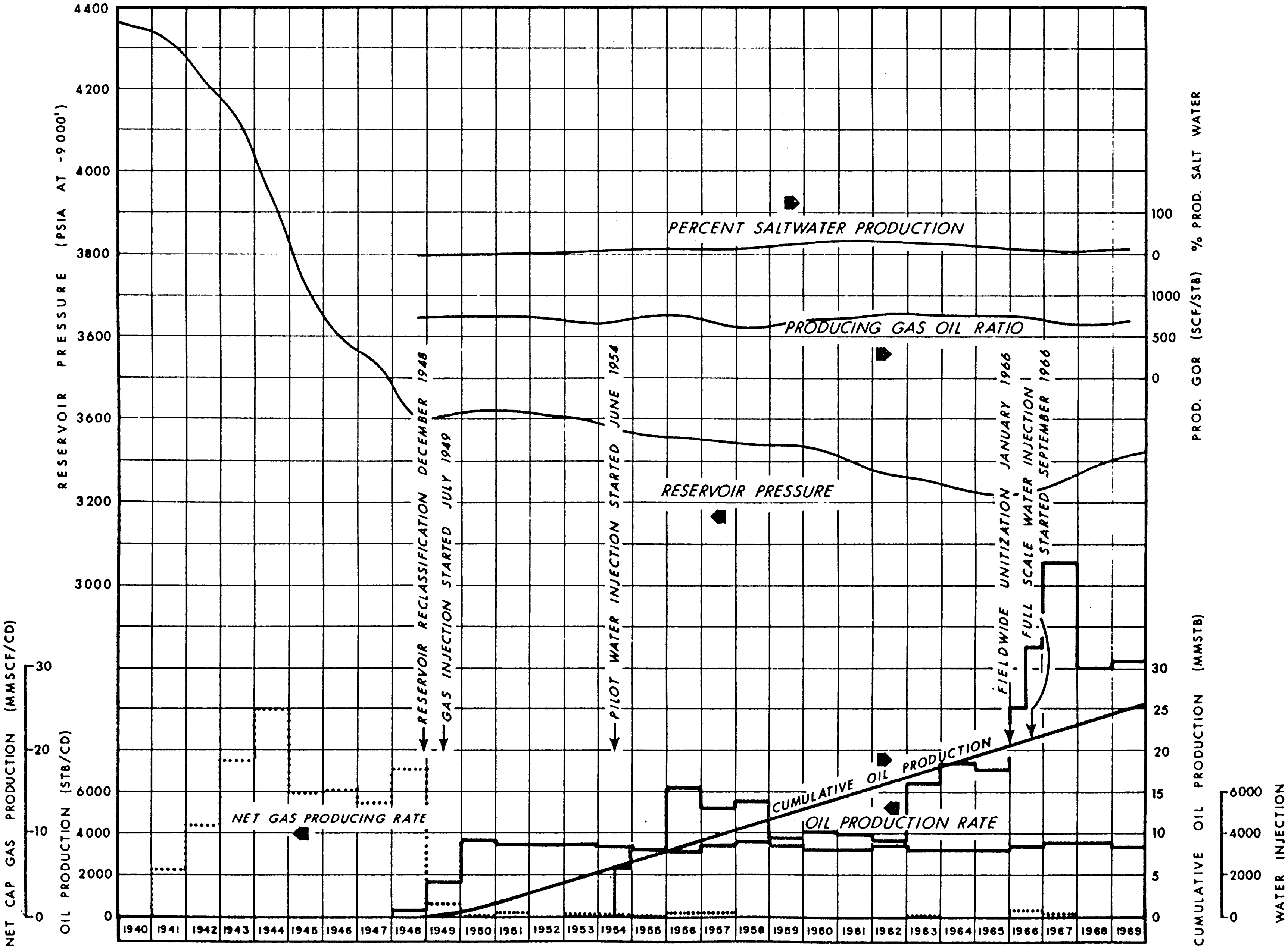


Figure 5.--Performance history, South Gillock unit, Texas.

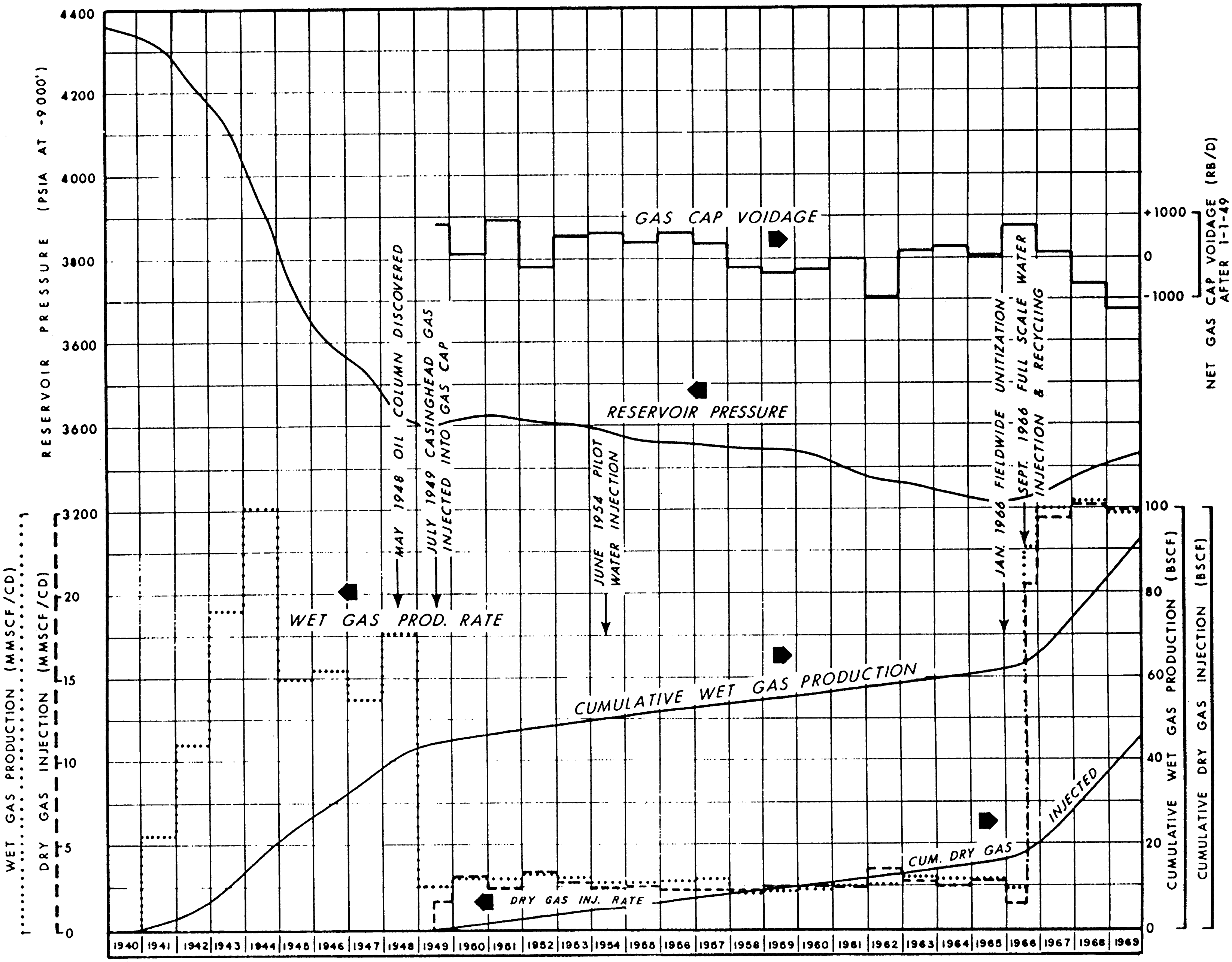


Figure 6.--Gas cap performance history, South Gillock unit, Texas.

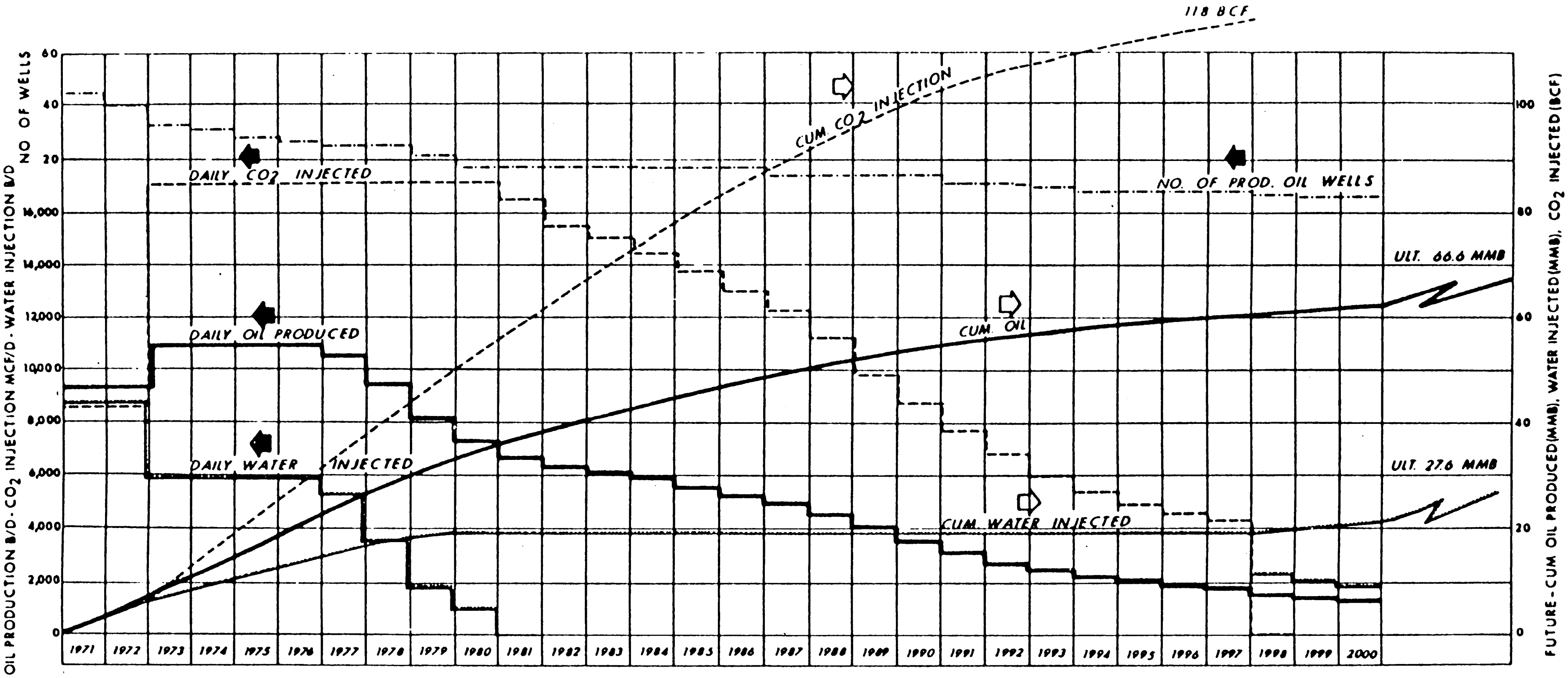


Figure 7.--Predicted future performance, South Gillock unit.

CO_2 FIELD INJECTION PROJECT CONDUCTED BY HNG FOSSIL FUELS COMPANY TWOFREDS FIELD, WEST TEXAS

by
Raj M. Kumar, Jerry A. Watson, and John H. Goodrich

Location and General History

The Twofreds field is located in the Delaware Basin in Loving, Ward, and Reeves Counties, West Texas (Fig. 1). The field produces from the Delaware sand at a depth of approximately 4,800 feet. Discovered in 1957, the field was essentially developed by 1960, with 76 producing wells in a project area of 4,500 acres. Original oil-in-place is estimated at 52 million barrels. Cumulative production through 1975 was 8,667,500 barrels, with an annual production in 1975 of 99,600 barrels. Secondary recovery by waterflooding began in 1963, when the field was unitized with Mobil as operator. CO_2 injection in a portion of the field was initiated in 1974 by HNG Fossil Fuels Co. (Houston Natural Gas Company), and approximately 10 MMcf/D is currently being injected into 14 wells.

Geologic and Petrophysical Data

The producing interval in the Twofreds field is the Bell Canyon Member of the Delaware Mountain group of middle Permian age (Fig. 2). More than 100 fields in the Delaware Basin produce from this formation (Fig. 3) [1]. Production depths in fields in the region vary from 2,500 to 5,000 feet.

The Twofreds field is an elongate sand body approximately 7-1/2 miles long and 1 mile wide oriented N 30° E. Regional dip in the area is slightly south of east. There is no pronounced structure to serve as a trapping mechanism [2]. Accumulation of petroleum appears to be related to stratigraphic and petrophysical conditions. Most of the wells in the field encounter a clean, uniform, slightly calcareous, fine-grained sandstone. However, in most of the northwesterly row of wells and in other wells scattered throughout the field (Fig. 4), laminated shale and sand are present in all or part of the pay zone, with attendant low permeabilities [2].

The section grades into a laminated shale and shaly sand in the non- productive areas [3]. Shale or shaly sand streaks from a few inches to three feet thick occur in the pay zone over much of the field.

The producing formation averages 25 feet in thickness, varying from 2 to 43 feet (Fig. 5). Average porosity is 20 percent and permeability averages 33 md [4]. Well performance and pressure differences indicate that two separate reservoirs, east and west are present [5]. They are evidently separated by a permeability barrier whose approximate location is shown on Figure 5. Figure 6 shows petrophysical data for a typical producing section at Twofreds.

Reservoir Data

A summary of data pertinent to the Delaware sand reservoir is given [5] in Table 1 at the end of this report. The reservoir oil of the Twofreds was saturated at the initial reservoir pressure of 2,385 psi. Some of the reservoir fluid properties are:

Bubble-point pressure (BPP)	2285 psi
Viscosity at BPP	1.467 cp
Formation volume factor at BPP	1.179 RB/STB
Gas solubility at BPP	441 scf/bbl
at 1,000 psi	211 scf/bbl
API gravity	36°
Reservoir temperature	104°F

Reservoir Performance Data

Early reservoir performance at Twofreds indicated that the primary producing mechanism was solution gas drive. The bottomhole pressure declined from 2,385 to 1,600 psi in three years and the producing gas-oil ratio increased from about 650 to about 1,500 scf/bbl. Because the 43.5 percent initial water saturation was mobile at Twofreds, water production was almost equal to oil production in 1961. Average reservoir pressure had declined to about 1,300 psi by 1963, a drop of 1,085 psi from the original pressure, and the producing gas-oil ratio was about 3,200 scf/bbl.

The field was unitized in 1962 and a five-spot water injection pilot was initiated in 1963 for the purpose of studying operational and injectivity problems. The need for such a pilot emerged from lack of successful water-injection projects in Delaware reservoirs. An area near the center of the unit was chosen for the pilot and four wells in a five-spot pattern were converted to water injectors. When evaluation of the pilot performance indicated encouraging results, the water injection program was expanded to cover the entire field in 1966. Twenty-one additional wells were converted to water injectors.

Figure 7 depicts overall reservoir performance history. From the entire unit, oil production rose steadily from 1,400 B/D in June 1965 to a peak rate of 2,450 B/D in June 1967, accompanied by a reduction in the water-oil ratio. Of the 1,050 B/D oil production increase, 200 B/D was due to four new wells drilled along the southern edge of the pilot area and 850 B/D was attributable to water injection.

Because of poor response, water injection was terminated in the east reservoir in 1969. Water injection continued in the west reservoir and the bulk of the waterflood response shown in Fig. 6 was attained there. Total field production by 1973, as the field neared economic limit, was 8.4 million barrels of the estimated 52 million barrels in place. Of this, an estimated 2.8 million barrels resulted from waterflooding [5]. Carbon dioxide injection, principally in the east (non-waterflooded) reservoir, began in 1974. Response to this can be seen in Fig. 7. This aspect is discussed in more detail below.

Carbon Dioxide Injection Project

The carbon dioxide injection project operated by HNG Fossil Fuels began in 1974, using CO_2 from Oasis Pipeline Company's MiVada Gas Processing Plant, which processes an Ellenburger produced gas stream containing 45 percent CO_2 and 55 percent hydrocarbons. Carbon dioxide is compressed at the plant and delivered to the field through a 12-mile pipeline with a discharge pressure of 1,800 psig, which is sufficient for injection in the field without additional compression.

Injection of CO_2 into the east reservoir began in February 1974, at which time only 3 of 30 wells in the reservoir were still producing. Total production rate from these wells was then 27 BOPD plus 180 BWPD. Carbon dioxide injection has been continuous since then. The field is being CO_2 flooded on a modified five-spot pattern using former water-injection wells. Production response and injection data since that time are shown graphically in Figure 8. Oil production rates have increased to 700 B/D and there is no indication that peak rates have been reached. Water production from the east reservoir averages 1,200 B/D. Field gas production is 3,300 Mcf/D, of which 2,400 Mcf/D is CO_2 from the east reservoir. Figure 7 also shows production rates from the west block, in which CO_2 injection has been minimal. Water injection was stopped in the west block to allow the 3,300 psia reservoir pressure to decline sufficiently so that CO_2 could be injected below 2,900 psia (0.61 psi/ft, equal to the fracture gradient). Current statistics for the project are given in Table 2. Average CO_2 injection rate is currently 12,260 Mcf/D into 22 injectors, 15 of which are in the east reservoir and 7 in the west. Figure 8 indicates little response in the west reservoir.

On the basis of the data given in Figure 8, incremental oil production though mid-1979 has been approximately 750,000 barrels from a cumulative CO_2 injection of 18,173 MMcf. This is a current ratio of CO_2 to incremental oil of 24.5 Mcf/bbl. Current injection and production rates give an "instantaneous" CO_2/incremental oil ratio of 15.8 Mcf/bbl. Obviously, substantial response in the western reservoir could improve these ratios. Total ultimate recovery and corresponding ultimate CO_2/oil ratios cannot be predicted from the data available at this time [5].

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1. Delaware Basin Exploration, West Texas, Reference Book, 1964. Reinhart Oil News Company, Dallas, Texas.

2. West Texas Geological Society: Geology of the Delaware Basin and Field Trip Guidebook (1960).

3. McRee, B. C.: "CO_2, How It Works, Where It Works," Pet. Eng. (Nov. 1977) p. 53-63.

4. Jones, R. W.: "Hard-To-Flood Sand Gives Up Secondary Oil In West Texas," World Oil (Sept. 1968) p. 72.

5. Thrash, John C.: "Twofreds Field--A Tertiary Recovery Project," paper SPE 8382 presented at the SPE-AIME 54th Annual Technical Conference and Exhibition, Las Vegas, Sept. 23-26, 1979.

TABLE 1

FIELD DATA FOR CARBON DIOXIDE INJECTION PROJECTS

FIELD: Two Freds

LOCATION AND GENERAL DATA

State: Texas
County: Loving, Ward & Reeves

Discovery Date: 1957
Date First Production 1957

No. Wells: 76
@ Date: 1960

Developed Area: 4500 Acres

GEOLOGY AND PETROPHYSICS

Reservoir Name: Delaware

Reservoir Rock Type: Sandstone

Trap: Stratigraphic

Average Depth: 4820'

Primary Gas Cap (Y/N) -

Gas/Oil Contact Depth: ______ feet subsea
Oil/Water Contact Depth: ______ feet subsea

Average Net Pay Thickness: 16 feet

Net/Gross Ratio: .64
Average Porosity: 20 %
Initial Water Saturation 43.5 %
Average Permeability: 33 millidarcies

Permeability Range: 14 - 70 millidarcies

Permeability Variation: ______

k_v/k_h: ______

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

BASIC RESERVOIR AND VOLUMETRIC DATA

Initial Reservoir Pressure: 2385 psi
Reservoir Temperature: 98 °F
Bubble Point Pressure: 2285 psi
Formation Volume Factors:
B_{oi} ______
B_{ob} 1.179
Reservoir Oil Viscosity Data:
μ_{oi} ______ centipoise
μ_{ob} 1.467 centipoise

Initial Solution Gas-Oil Ratio:
R_{si} 441 cu.ft./bbl.
Stock Tank Oil Gravity: 36 °API

Reservoir Hydrocarbon Pore Volumes:
Oil Column: ______ M Bbl Gas Cap: ______ M Bbl
Standard Volume Original Hydrocarbons in Place
Oil: 53,000 M Bbl Free Gas: ______ Mcf

RESERVOIR PERFORMANCE DATA

Primary Recovery Drive Mechanism: Solution Gas

Estimated Ultimate Primary Recovery: 11 % ISTOIP

Supplemental Recovery Method(s) and Date Started: Pilot waterflooding in May, 1963, followed by full scale injection in Jan. 1966.

Cumulative Oil Production at Start Supplemental: 3000 (1) M Bbls 5.7 % ISTOIP

Unit Operator(s): Mobil Oil Company

Average Pressure at Start Supplemental: 1000 psi

Estimated Additional Supplemental Recovery (Ultimate): 5 % ISTOIP

Estimated Total Ultimate Recovery (Primary+Supplemental) 16 % ISTOIP

Cumulative Total Production to: ______ (Date)
______ M Bbls ______ % ISTOIP

Average Pressure: ______ psi @ ______ (Date)
Calculated Average Oil Saturation ______ %@ ______ (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

CARBON DIOXIDE INJECTION PROJECT DATA

Project Operator: HNG Fossils Fuel Company

Project Type: Mini-Test ___ Pilot Test ___ Full-Scale Project X

Recovery Mode: Secondary ___ Tertiary X

Project Area: ______ Acres

No. of Wells: Injection ___ Production ___ Other ___

Pattern Geometry: ______

Date Project Commenced: Feb., 1974 Ended ______

Injection Fluid Composition (mol percent)

CO_2 ___ H_2S ___ C_1 ___

C_2-C_6 ___ C_7+ ___ Other ___

Estimated miscibility pressure: ______ psi

Injection Fluid Source(s): Carbon dioxide supply comes from a separation plant in a nearby gas field.

CO_2 Injection Rate (Excluding Recycle): ___ Mcf/day ___ (Date)

Recycle Gas Injection Rate: ___ Mcf/day ___ (Date)

Water Injection Rate: ___ Bbl/day ___ (Date)

Water Injection Mode (i.e., alternating, continuous after "slug", etc.)

Discuss: ______

Injection Pressures:

CO_2:	Surface	___ psi	Bottomhole	___	psi
Recycle:	Surface	___ psi	Bottomhole	___	psi
Water:	Surface	___ psi	Bottomhole	___	psi

Cumulative Injection @ ______ (Date)

CO_2	___	MMcf	___	%HCPV
Recycle:	___	MMcf	___	%HCPV
Water:	___	MMcf	___	%HCPV

Current Production Rates: (Date) ______

Oil: ___ Bbl/day Gas: ___ Mcf/day

CO_2: ___ Mcf/day Water: ___ Bbl/day

Date First Response: ______

Date CO_2 Breakthrough: ______

Cumulative CO_2 Production: ___ MMcf @ ___ (Date)

( ) Reference number keyed to Supplemental Information item number, page 4 of Field Data form.

Incremental Response: ____________ Bbl/day @ ____________ (Date)

Cumulative Incremental Oil @ ____________ (Date) ____________ M Bbl

CO_2 Utilization Ratio-Cumulative Injection CO_2/Cumulative Incremental Oil 1.25 Mcf/Bbl.

Expected Ultimate Incremental Production:
8400 M Bbls 15.8 % ISTOIP

Supplemental Information

(1) Cumulative production on the date of unitization (Dec., 1962). Waterflood was initiated much later.

TABLE 2

TWOFREDS FIELD
CO_2 INJECTION - OIL RECOVERY DATA

	Total Field	East Reservoir	West Reservoir
			Status June 1979
Producing wells	40	16	24
Injection wells	22	15	7
Shut-in wells	24	0	24
	86	31	55

Cumulative CO_2 injection	18,173 MMcf
Average injection since Jan. 1, 1974	12.26 MMcf/D
Cumulative % PV injected	13.99
Average oil production	776 BOPD
Average water production	2113 BWPD
Average gas production	3.30 MMcf/D
Average CO_2 production	2.42 MMcf/D
Cumulative oil production since Jan. 1, 1974	1,007,553 bbl
Cumulative water production since Jan. 1, 1974	5,965,640 bbl

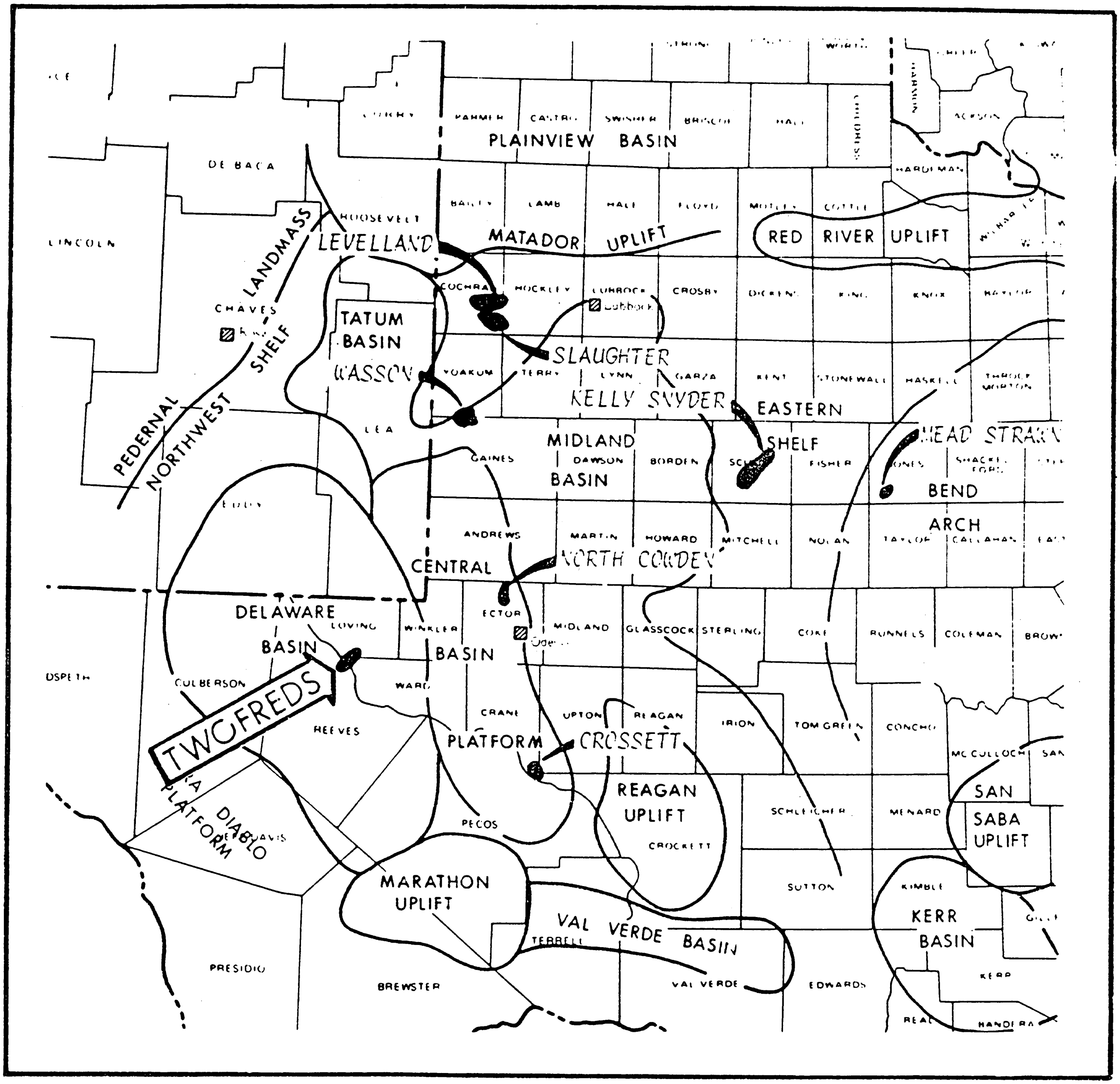

Figure 1.--Index map: carbon dioxide projects in west Texas.

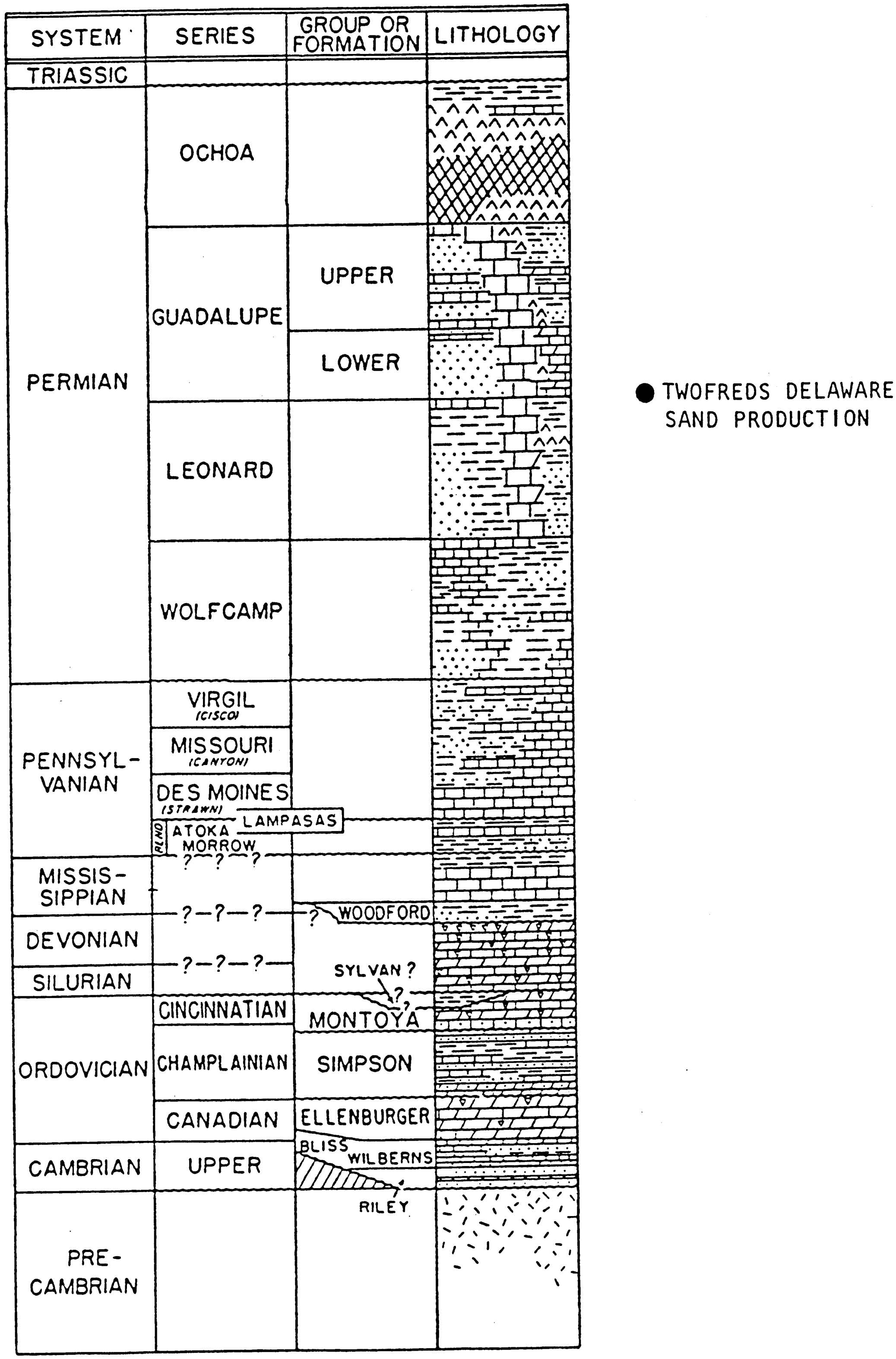

Figure 2.--Generalized stratigraphic column for the Delaware Basin, west Texas and southeast New Mexico.

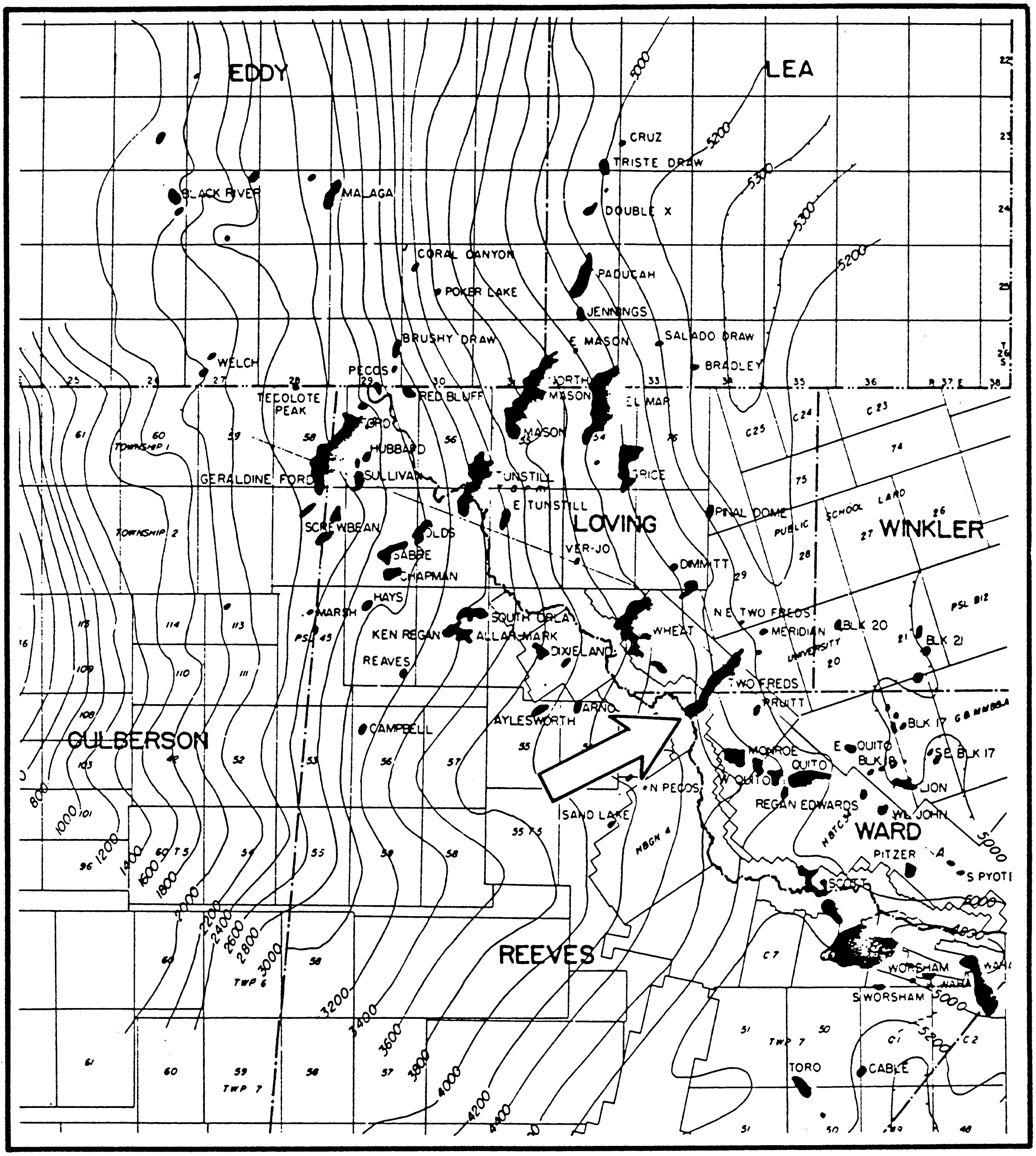

Figure 3.--Contour map showing depth to Delaware sand in the principal Delaware fields in west Texas.

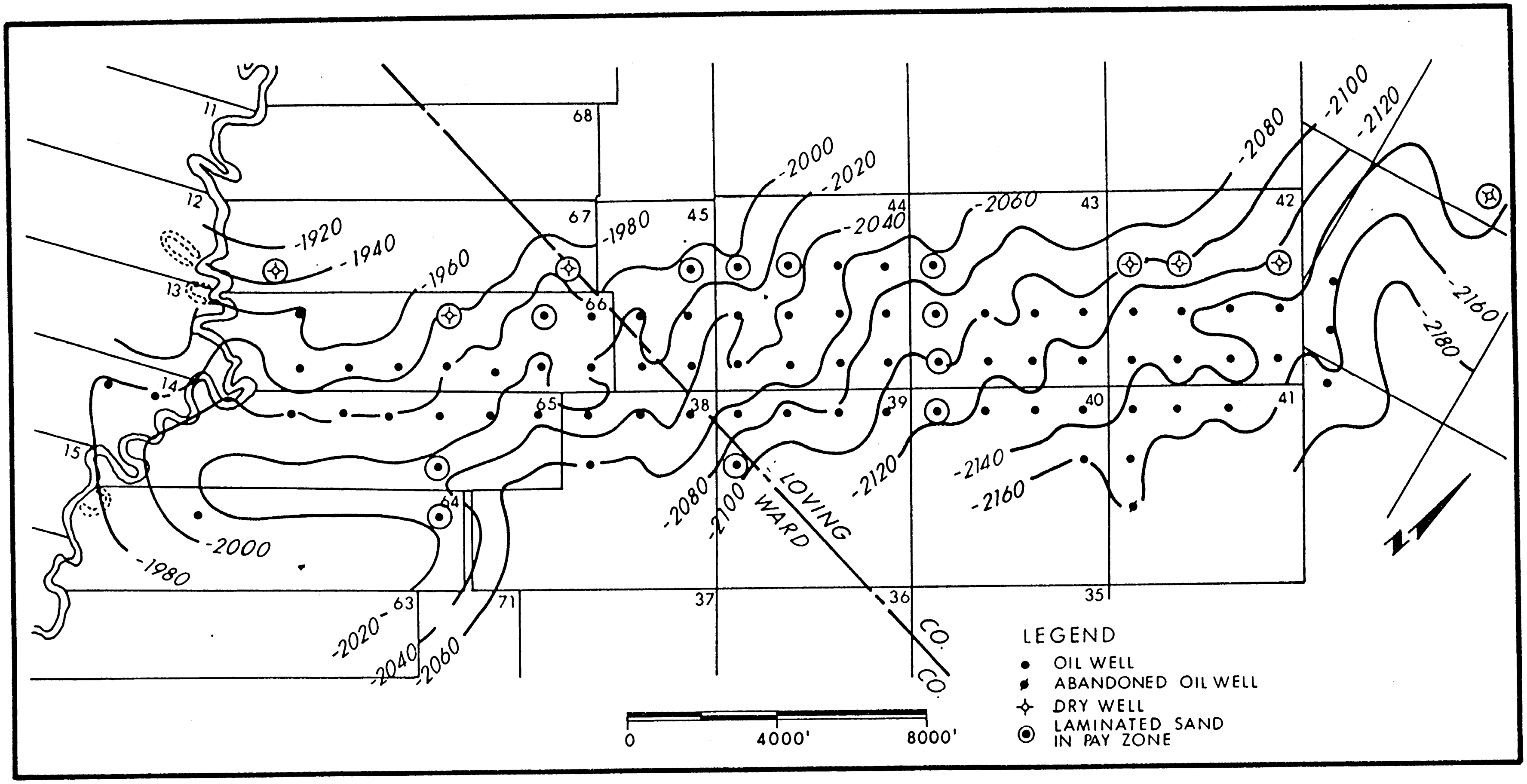

Figure 4.--Structure on top of the Delaware sand, Twofreds field, Texas.

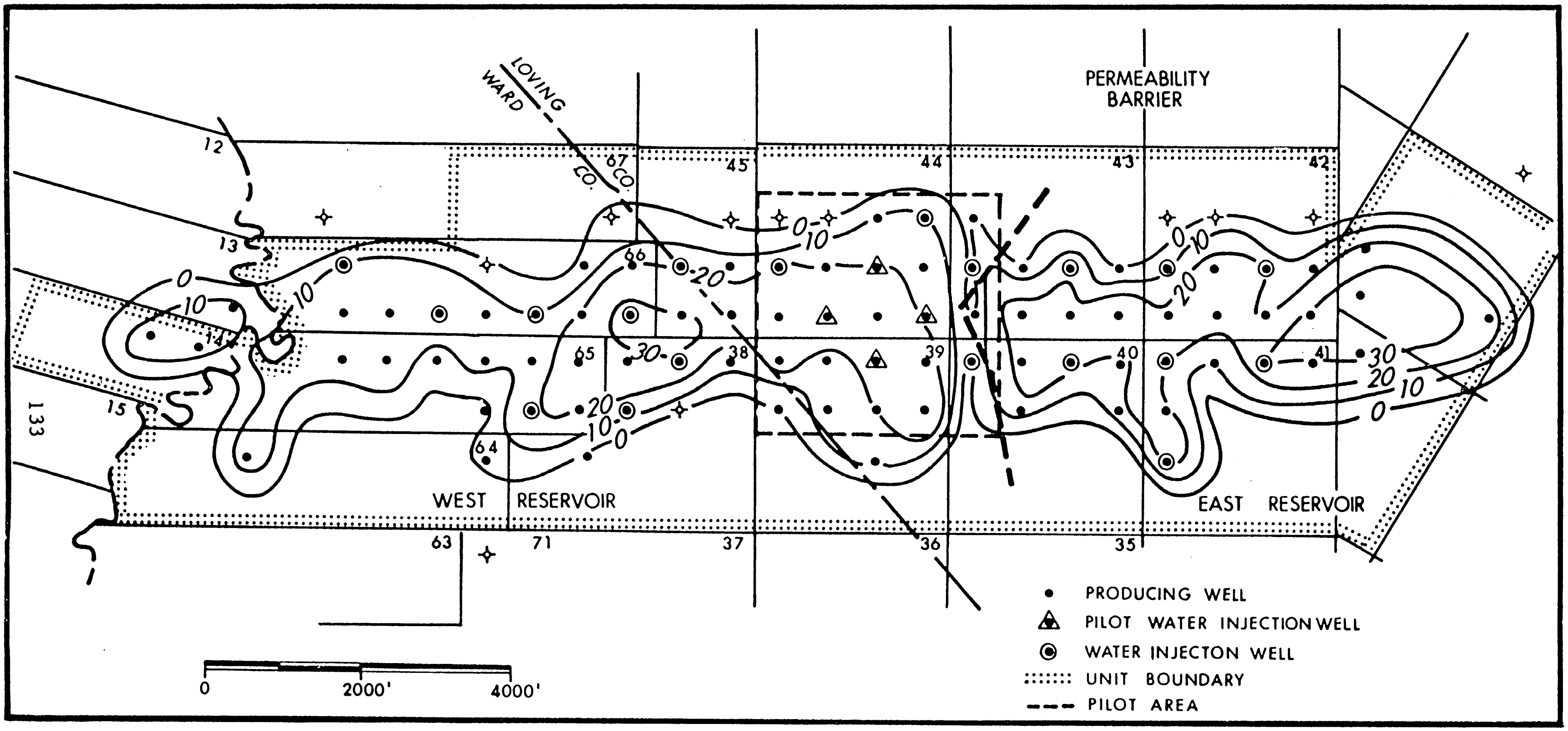

Figure 5.--Isopach map of the Delaware sand, Twofreds field, Texas.

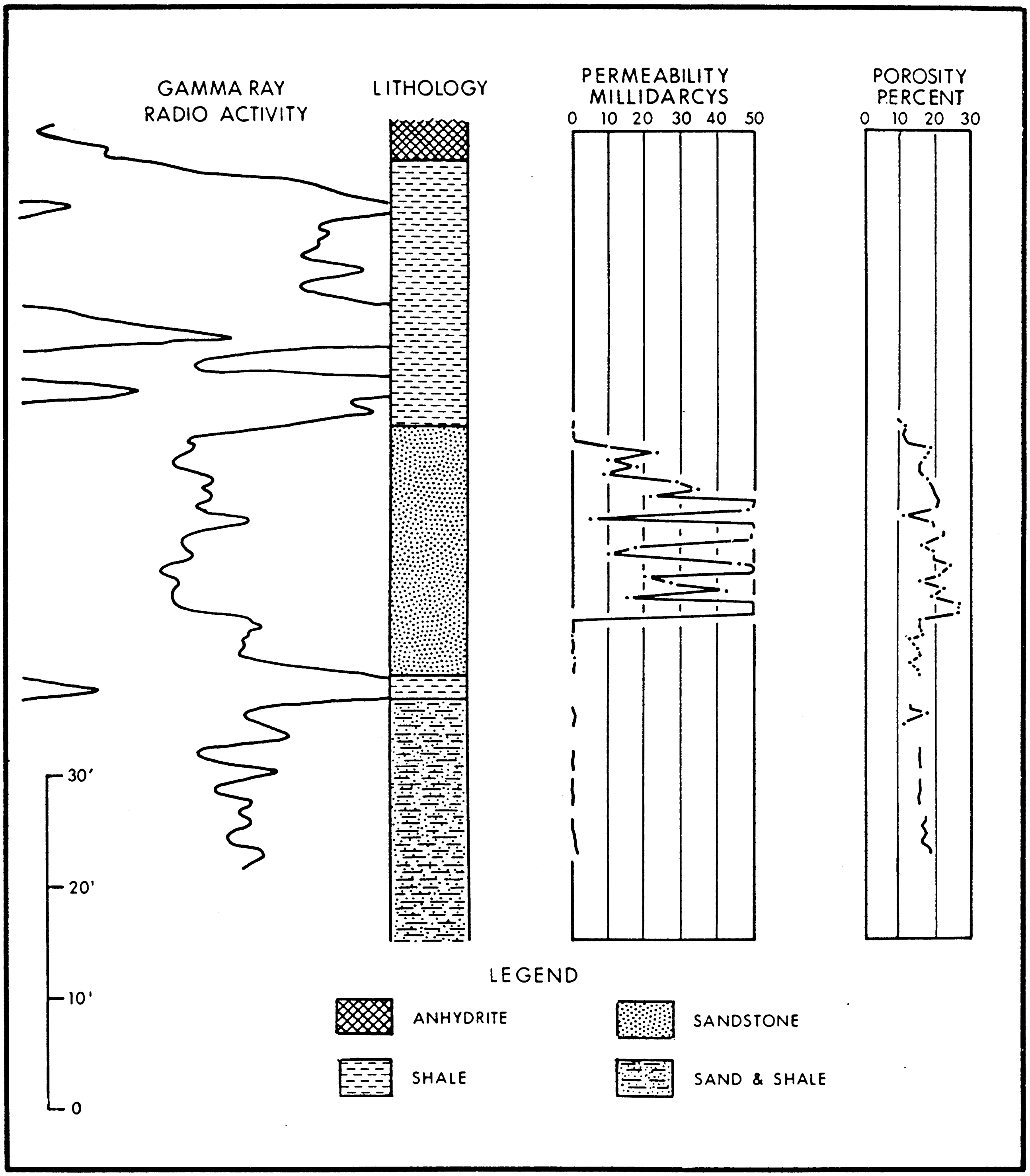

Figure 6.--Petrophysical data from a typical producing zone, Twofreds field, Texas.

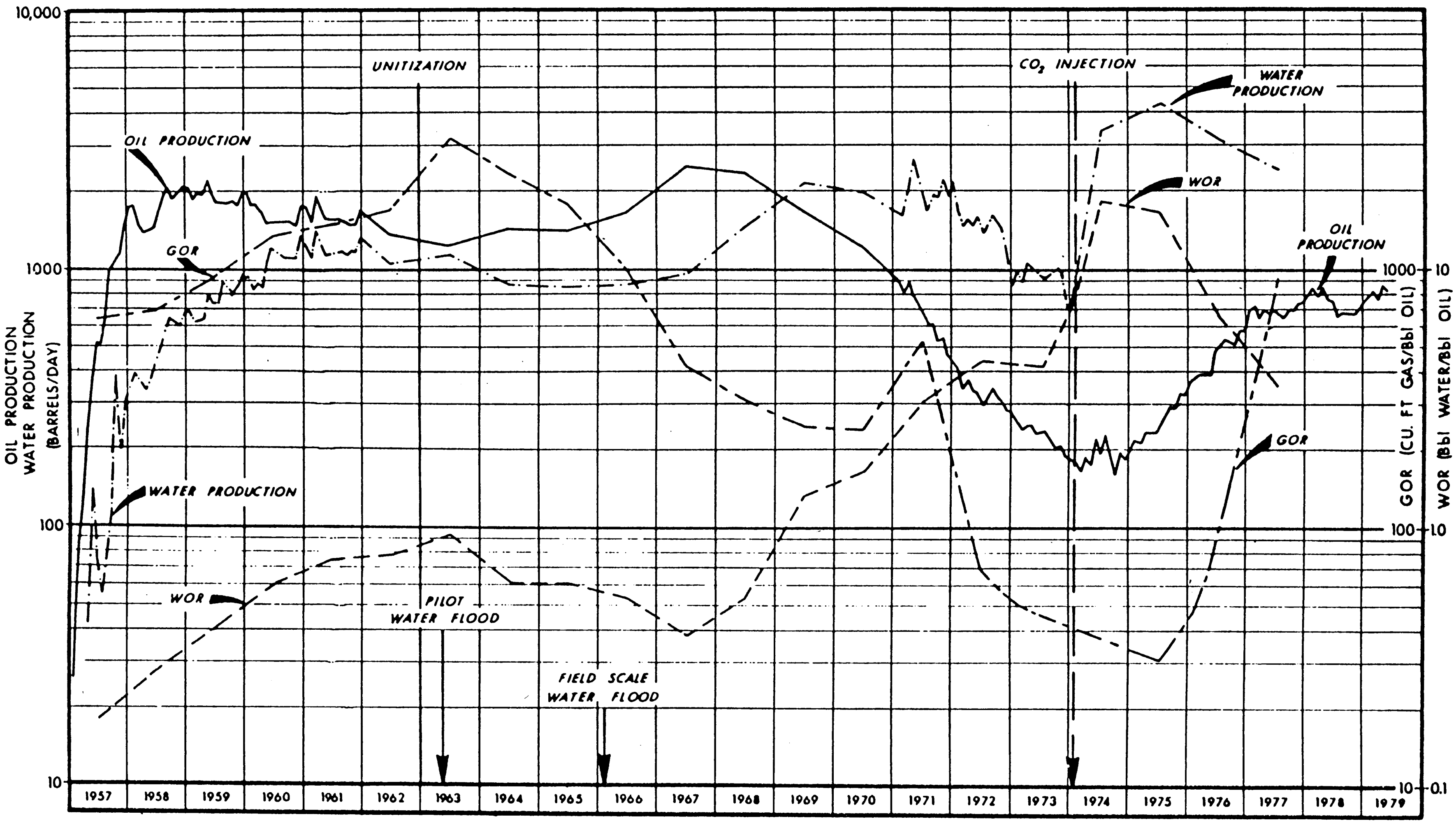

Figure 7.--Carbon dioxide injection project, production history, Twofreds field, Texas.

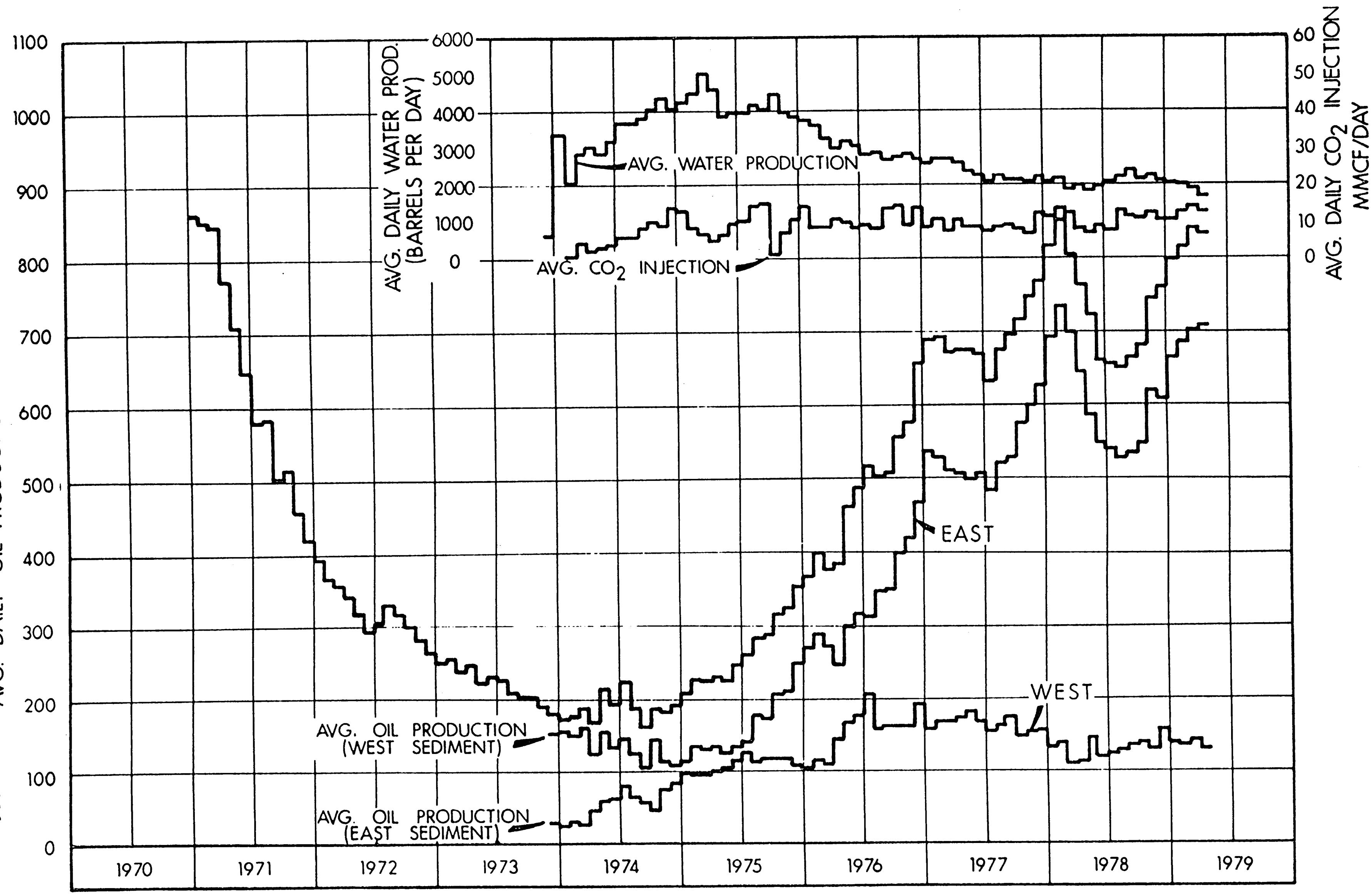

Figure 8.--Production curves, Delaware unit, Twofreds field, Texas.

CO_2 INJECTION PROJECT CONDUCTED BY SHELL OIL COMPANY IN WEEKS ISLAND "S" SAND RESERVOIR B

Location and General History

Weeks Island Field is located in Iberia Parish, Louisiana, in the Gulf Coast Salt Dome Province (Fig. 1) in an area of high-temperature and high-pressure reservoirs. The "S" Sand Reservoir B produces from Miocene sand (Fig. 2) at a depth of 12,700 feet. Initial reservoir temperature and pressure were 225°F and 5,100 psi, respectively.

In 1973 the field was unitized with Shell Oil Company at unit operator, and pressure maintenance by fresh-water injection was initiated. A CO_2 injection pilot project was begun in October 1978. The "S" Sand Reservoir B was selected for this test because it is a small sealed reservoir. In addition to providing a confined displacement, the sealed reservoir should provide an accurate measure of the net displacement. Injection is updip with downward CO_2 displacement, designed to utilize gravity to stabilize the displacement forces and increase the sweep efficiency. This process, if successful, could be used to recover tertiary oil from natural water-drive reservoirs which are too hot and saline for present surfactant systems. The recovery potential from the major reservoirs in the Weeks Island Field is estimated to be 26 million barrels [1].

Weeks Island Field is located on and around a piercement type salt dome, which rises to within 35 feet of sea level and has a maximum surface expression of 135 feet. Regional structure consists of a homocline dipping toward the coast with the sediment wedge thickening southward into the Gulf Coast geosyncline. Sands and shales were deposited in this region in a continental shelf environment throughout the Cenozoic.

Hydrocarbon shows have been found in sands of Pleistocene to Lower Miocene age, at depths of 1,000 to 17,500 feet. Commercial production has been established in 37 middle to lower Miocene sands, predominantly below 9,500 feet. The bulk of the original oil-in-place (87%) was trapped on the downthrown north flank of the field, where reservoir hydrocarbon column heights of up to 2,600 feet have been proven.

The "S" Sand Reservoir B occurs on a fault block on the north flank of the salt dome. Reservoir seal is provided by radial and peripheral faults. Figure 3 shows the structure and the steeply dipping fault dip section in the area of the CO_2 project [1]. Core analysis of the producing interval of the "S" Reservoir B shows it to be fine-grained, often friable, moderately well sorted sandstone. The reservoir rock has an average porosity of 26 percent and an average unstressed permeability of 3,500 md.

The hydrocarbon accumulation in Reservoir B consists of a gas cap extending from the apex of the structure to oil columns on the east and west ends. Originally, a gas column of about 1,400 feet overlay an oil column estimated at 298 feet on the west end, while on the east, a gas column of some 700 feet overlay an oil column of about 23 feet. Original oil-in-place is estimated over 3 million barrels, with 24 Bcf of wet gas [1]. The CO_2 displacement is being undertaken in the west flank oil column, which contained all but 200,000 barrels of the original in-place oil.

Reservoir Performance Data

Weeks Island "S" Sand Reservoir B was initially produced by a single well, Weeks Island Unit A-16A. The field was unitized in 1973 for pressure maintenance.

On the western end, fresh-water injection into Smith State Unit G No. 2 at a position below the original water contact began in August 1973. Cumulative injection through February 1978 was 3.14 million barrels; cumulative oil produced from Weeks Island State Unit A-16A was 2.58 million barrels, including 1.8 million barrels since water injection. On the eastern end, wet gas and oil have been produced from perforations at the oil-water contact in Myles No. 25 and processed gas is returned to the gas cap through Myles No. 22. Cumulative liquid production through April 1976 was 0.96 million barrels. Out of a total of 16.7 Bcf of gas produced during this period, 16.1 Bcf has been returned to the gas cap.

The indicated water drive recovery from the "S" sands is about 70 percent. The high recovery is the result of a favorable displacement mobility ratio, oil being three times more mobile than water. Figure 4 shows the production of Weeks Island State Unit and the water injection into Smith State Unit G-2 prior to CO_2 injection [2].

CO_2 Project Data

Besides the oil trapped in the watered-out sand, a thin oil column was left out in the vicinity of producing perforations in Weeks Island State Unit A-16A. It is believed that the presence of this column should aid in the reconnection of the oil trapped in watered-out sand. CO_2 injection was initiated in October 1978.

Before initiating the CO_2 project, a new well (Weeks Island State Unit Well No. A-17) was drilled to evaluate reservoir parameters, monitor the CO_2 displacement process, and ultimately serve as a downdip producer. Residual oil values were determined by log-inject-log (LIL), core analyses, and open-hole log analysis. The separate techniques are in good agreement: 0.22 ± 0.025 for the LIL, 0.23 ± 0.042 for the conventional core analysis, and 0.234 ± 0.054 for the open-hole log analysis. A 22 percent residual oil saturation amounts to 288 barrels per acre-foot.

Laboratory work indicated that the process will not achieve first-contact miscibility, as miscibility was not developed in 5-foot sand-pack displacements.

Carbon Dioxide Source

Information published in 1977 indicated that CO_2 was intended to come by truck from several CO_2 vendors located at 150-270 miles [1].

Operating Plan

The plan called for injecting approximately 50,000 tons of a CO_2-natural gas slug at a rate of about 130 tons per day into Weeks Island State Unit A-16A. Mixing 5 percent natural gas with CO_2 reduces the slug density to 95 percent of in-place oil density and thus allows a gravity-stable downward displacement. Injection of pure CO_2 at a low structural position may result in a thin narrow tongue of CO_2 rising through the waterinvaded region, because pure CO_2 is denser than reservoir oil and lighter than reservoir water. The slug would be injected through perforations just above the original gas-oil contact at 12,760 feet subsea and displaced to the Weeks Island Unit Well No. A-17.

Since the reservoir is sealed by faults, downward displacement of a CO_2-methane slug would require either injecting 1.5 Bcf of gas into the gas cap or reduction of 400 psi in reservoir pressure, which could be achieved by gas lifting 1,500 B/D of water from the present downdip injector, Smith State G No. 2 [1].

Injection Performance

Injection began on October 4, 1978, and has averaged 107 tons per day. Injection of the 50,000-ton slug was expected to be completed by the end of 1979. Injection was delayed two months by plugging of the injection well and a maintenance shutdown of the ammonia plant that supplies the CO_2. It appears that plugging resulted from mobilization of the oil deposits in the former gas injection line, which was being used for CO_2 injection. Figure 5 shows daily injection volumes and pressures [2].

Production Performance

The initial invasion of CO_2, as indicated by a pulsed neutron log on December 20, 1978, was essentially above the producing gas-oil contact. Downward movement of CO_2 was detected by logs taken on February 21 and April 12, 1979. However, the poor quality of the sand interval from 12,882 to 12,888 feet obscured any further movement between February and April (Fig. 6), and the leading edge of CO_2 column cannot be seen. The apparent decrease in neutron porosity with depth as indicated by the April 12 log shows that CO_2 saturation is increasing downwards. Possible reasons for the increase in CO_2 concentration are spreading of the CO_2 or additional downdip displacement of the CO_2 above the poor porosity interval. As the displacement proceeds further, the leading edge of CO_2 column may be seen below the poor porosity interval.

The observation perforations located at 12,910 to 12,920 feet in the Weeks Island A-17 are 21 feet lower than the water level logged when the well was drilled in December 1977. Production of 17 barrels of oil along with 32 barrels of water during a 6-hour test on May 2, 1979, suggests that a gravity-segregated displacement is taking place. This is confirmed by comparing the capture cross section of the base log with the last monitor run (Fig. 7), which gives some indication that oil or fresh water is being pushed down into the saltier interval below 12,920 feet [2].

Conclusions

Available data are insufficient to evaluate the effectiveness of CO_2 displacement and perhaps it is too early to do so. However, it is estimated that 270,000 barrels of oil will be produced from this 8-acre plot if 90 percent of the residual oil can be recovered [1]. Tertiary oil production will not begin before the third year of the project.

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2. Perry, E. E., and Kidwell, C. M., "Weeks Island "S" Sand Reservoir B, Gravity Miscible CO_2 Displacement," Proc., vol. 2, pp. N1-N15, Fifth Annual DOE Symposium on Enhanced Oil and Gas Recovery and Improved Drilling Technology; see also Shell Oil Company, Weeks Island "S" Sand Reservoir B, Gravity Stable Miscible CO_2 Displacement, Iberia Parish, Louisiana, Second Annual Report under DOE Contract No. EF-77-C-05-5232, 1979.

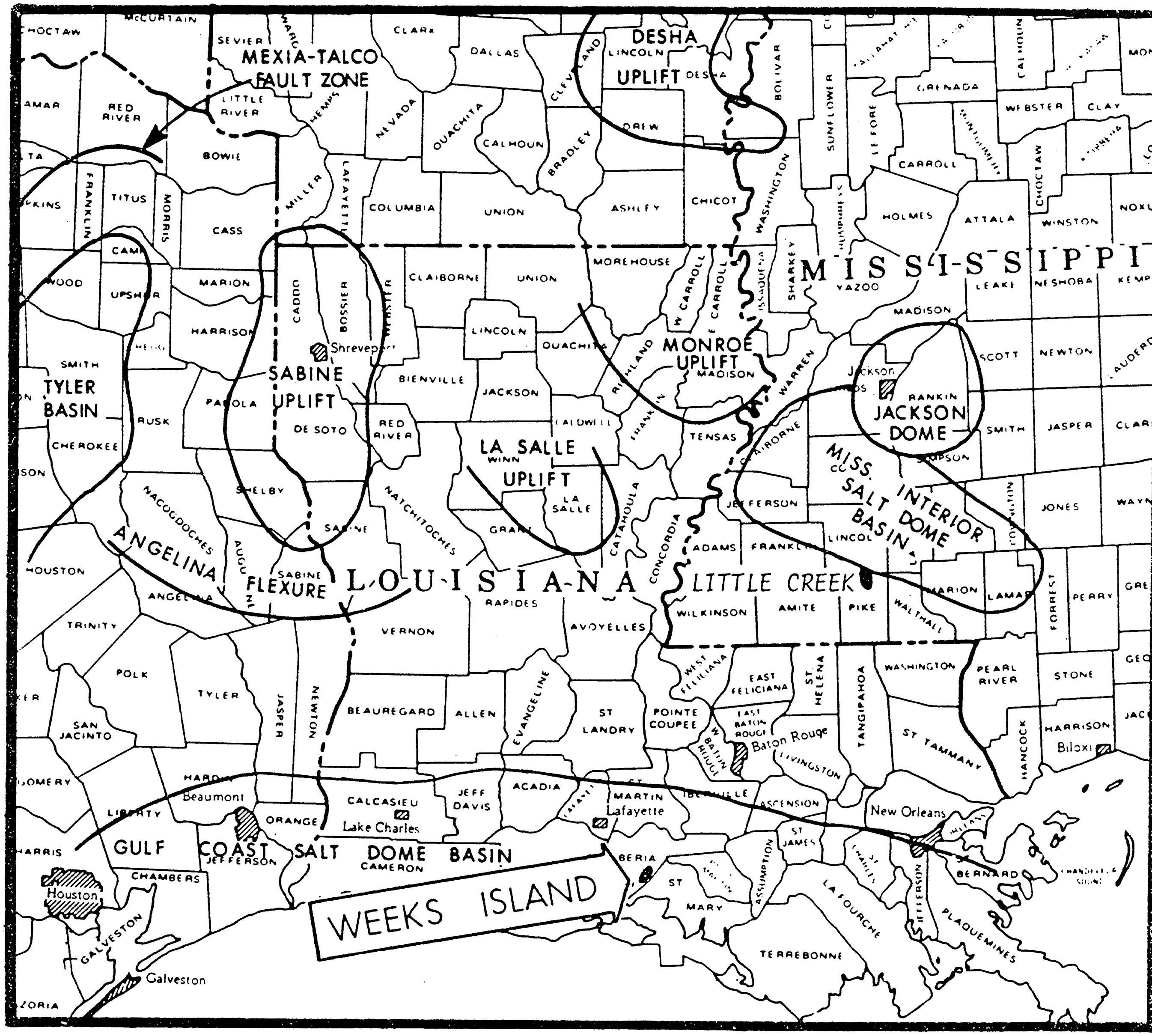

Figure 1.--Index map: carbon dioxide projects, Gulf Coast.

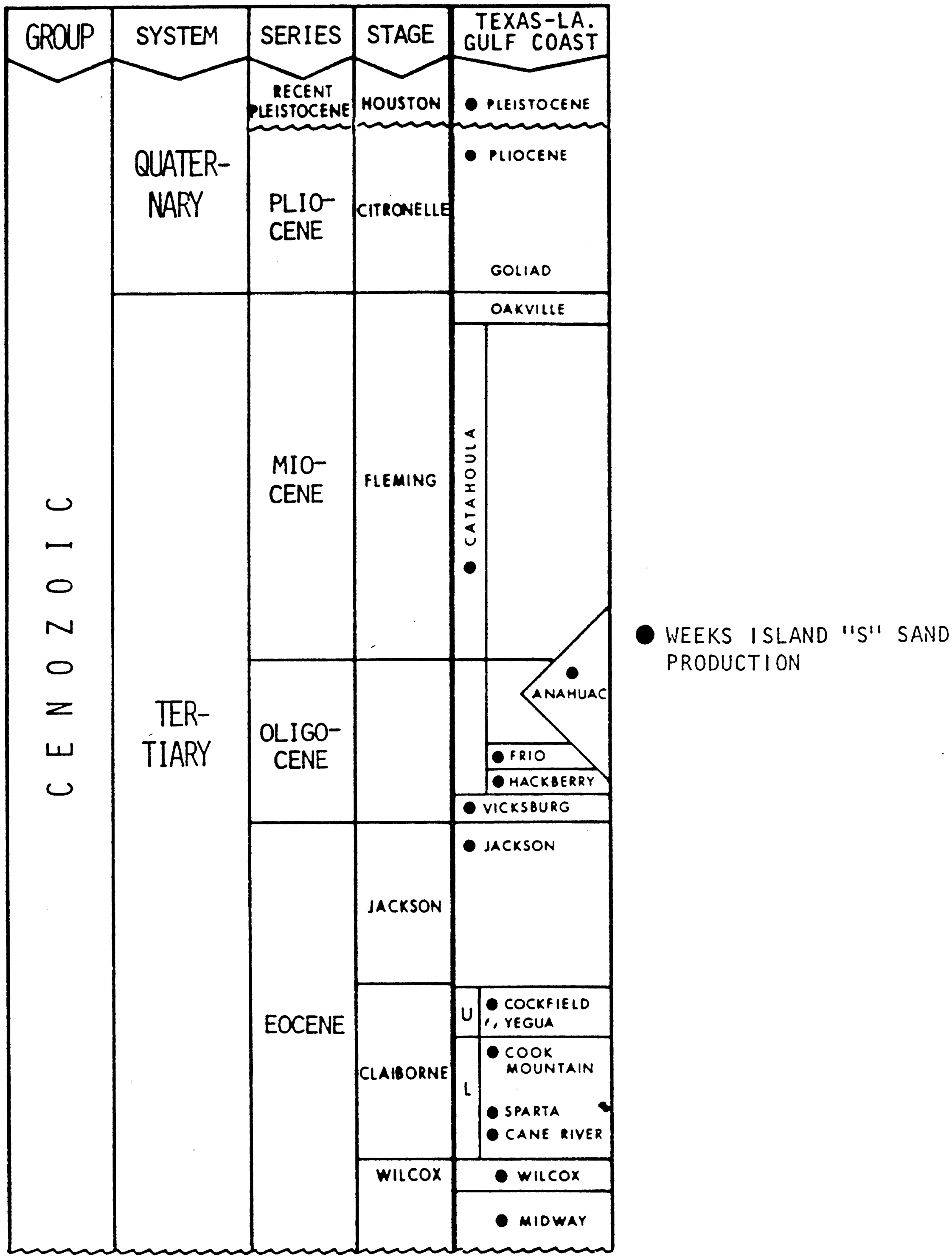

Figure 2.--Generalized stratigraphic column for the Gulf Coast.

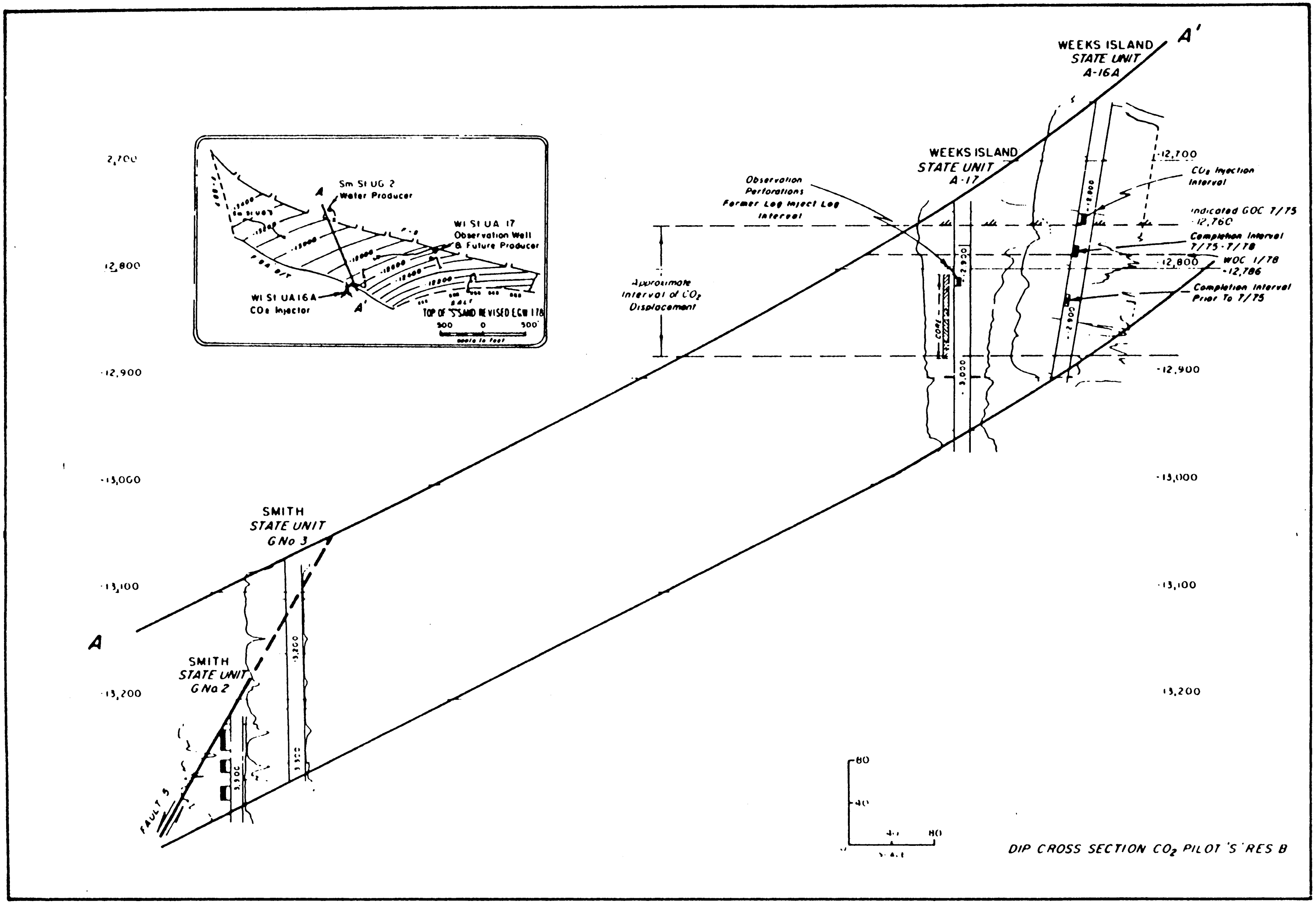

Figure 3.--Dip cross section, CO_2 pilot, "S" sand, Reservoir B, Weeks Island Field, Louisiana.

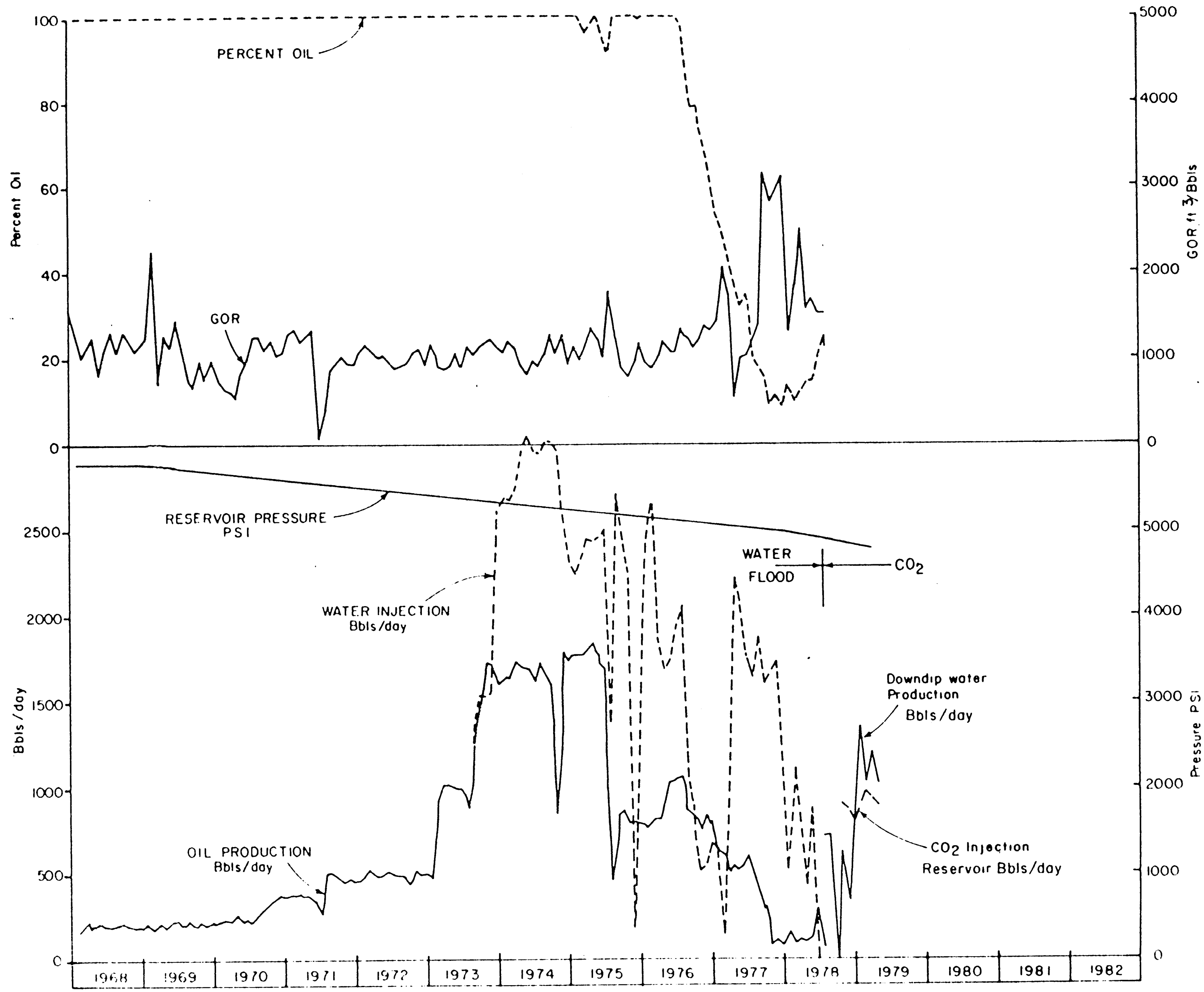

Figure 4.--Production and injection history for the "S" sand Reservoir B oil column, Weeks Island Field, Louisiana.

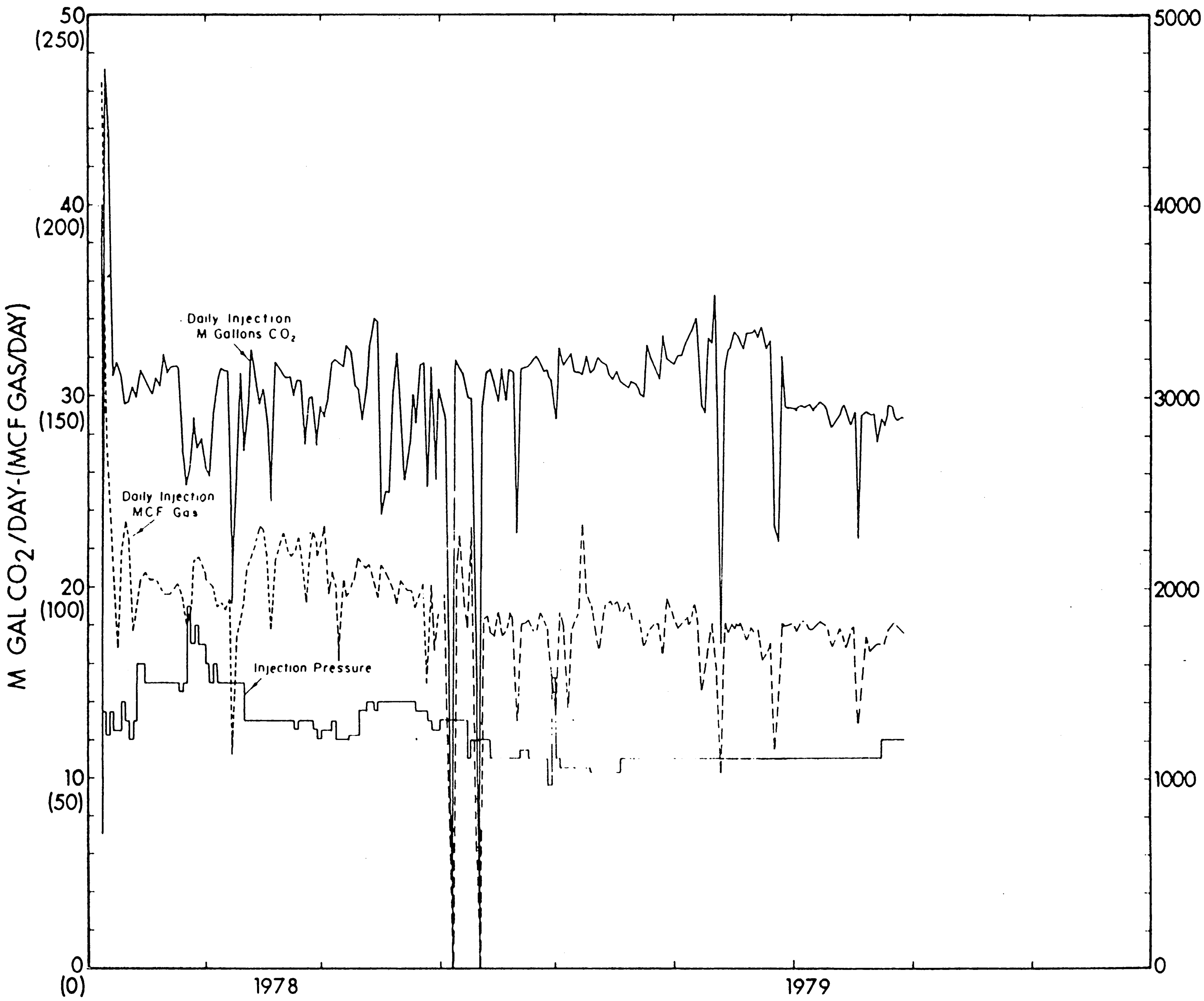

Figure 5.--Injection history for the gravity-stable CO_2 displacement project, "S" sand Reservoir B, Weeks Island Field, Louisiana.

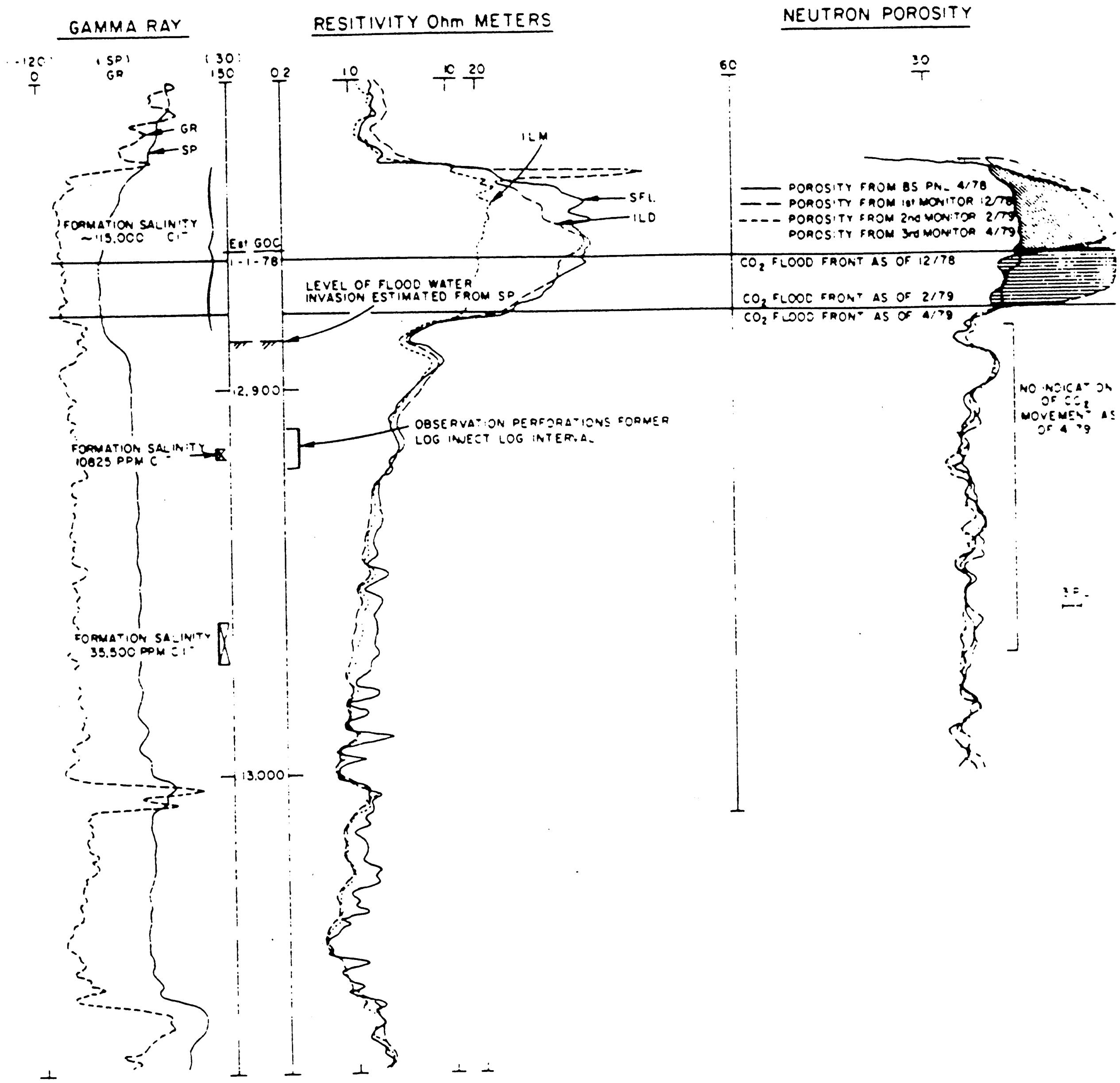

Figure 6.--Neutron porosity monitoring of CO_2 injection, "S" sand Reservoir B, Weeks Island Field, Louisiana.

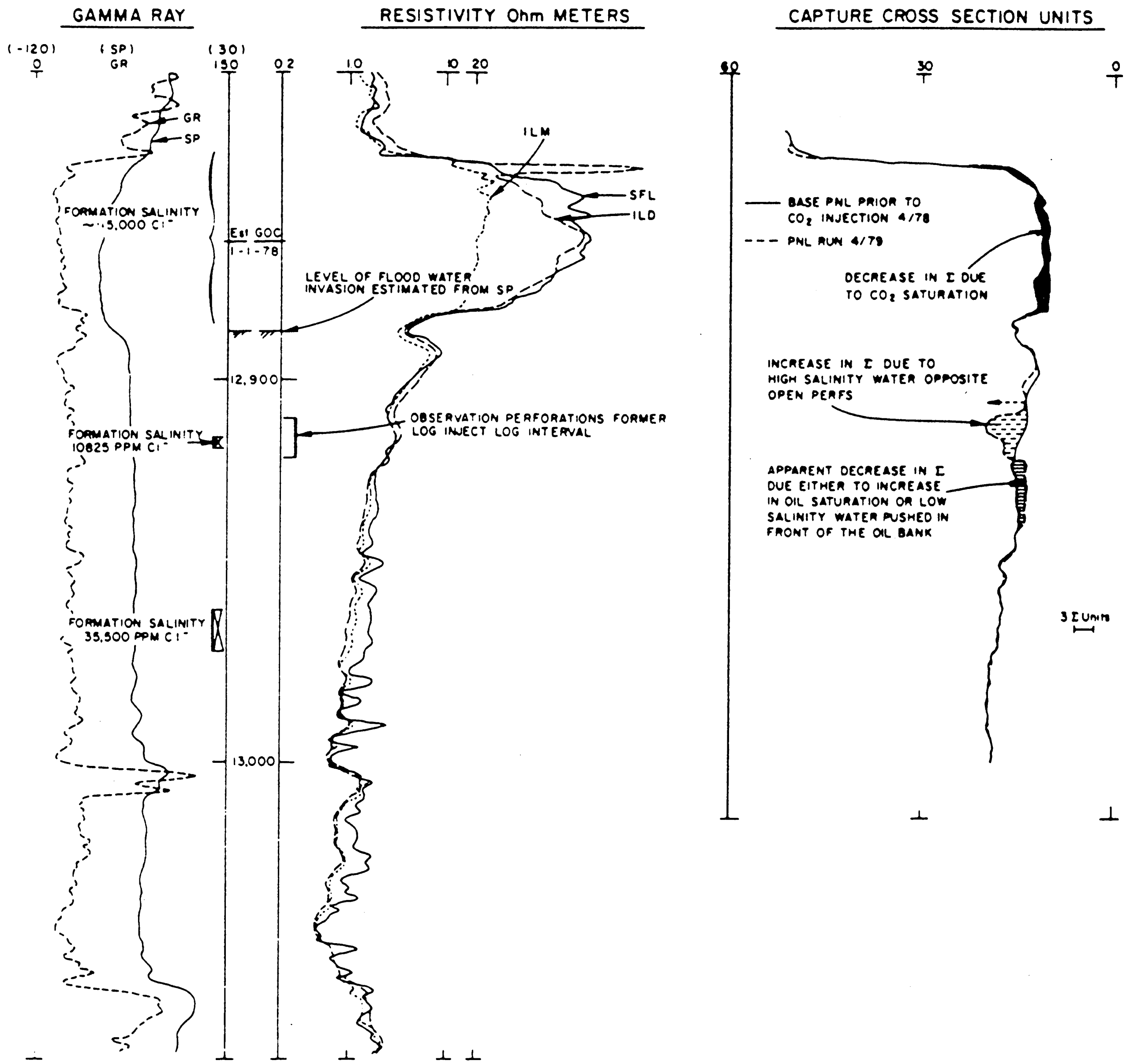

Figure 7.--Capture cross-section change due to CO_2 injection, "S" sand Reservoir B, Weeks Island Field, Louisiana.

CO_2 FIELD INJECTION PROJECTS IN WEST VIRGINIA

by
John H. Goodrich

A recent study estimates that approximately one billion barrels of oil will remain unrecovered by present methods in 17 relatively large oil fields in West Virginia [1]. On the basis of published screening criteria [2, 3, 4], these reservoirs appear technically amenable to CO_2 flooding processes. Three DOE-supported field pilot CO_2 injection projects have been undertaken in three of the fields identified as having CO_2 flooding potential:

Field:	Granny's Creek	Griffithsville	Rock Creek
Operator:	Columbia Gas Transmission Co.	Guyan Oil Co.	Pennzoil Co.
DOE Contract Date:	June 3, 1976	Sept. 1, 1975	June 30, 1976

This report discusses these projects first in terms of the features common to all of them and then in greater detail for each individual project.

The locations of the fields containing the three projects are shown in Fig. 1. These fields produce at depths of 2,000 to 2,300 feet from the Big Injun and Berea sandstones of lower Mississippian age (Fig. 2). As shown in Table 1, all three fields are old and have been subjected to various gas injection and waterflooding processes. The reservoir rocks are relatively thin, cemented sandstones characterized by low porosity and relatively low permeability. Permeability variation measured in cores taken in the three fields is shown in Fig. 3. The oil in place is a high-gravity "Penn Grade" crude having a tank oil viscosity of 2.5 to 3.0 cp. The low reservoir temperatures (73-78°F) are significant to CO_2 flooding considerations [5] because CO_2 will be in the liquid phase at these (subcritical) temperatures at pressures above the vapor pressure (950$\pm$ psi).

TABLE 1

HISTORICAL AND OTHER DATA
FOR WEST VIRGINIA CO_2 FLOOD PROJECT FIELDS

	Granny's Creek	Griffithsville	Rock Creek
Discovery date	1924	1907	1907
Gas Injection date	1943	1926	1935
Waterflood data	1963	1945	1954
Average depth, ft	2,100	2,350	2,050
Producing zone	Big Injun	Berea	Big Injun
Rock type	Sandstone	Sandstone	Sandstone
Average porosity, %	17-20	11	21.7
Average thickness, ft	20+	23	32
Oil gravity, °API	45-46	43	43.5
Tank oil viscosity, cp	2.5	2.8	3.1
Reservoir temperature, °F	77	78	73-75

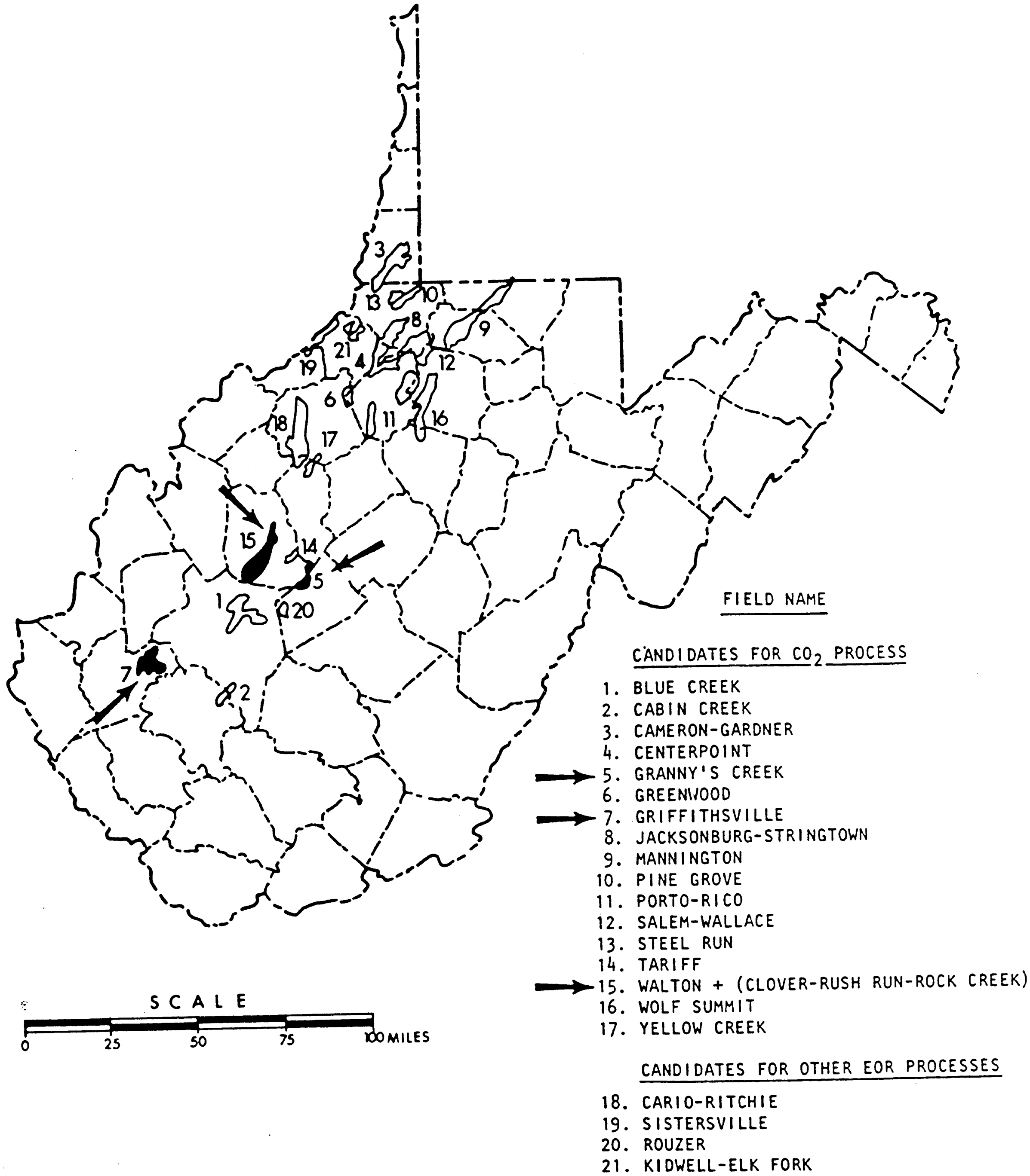

Figure 1.--Location of West Virginia reservoirs having significant enhanced oil recovery potential.

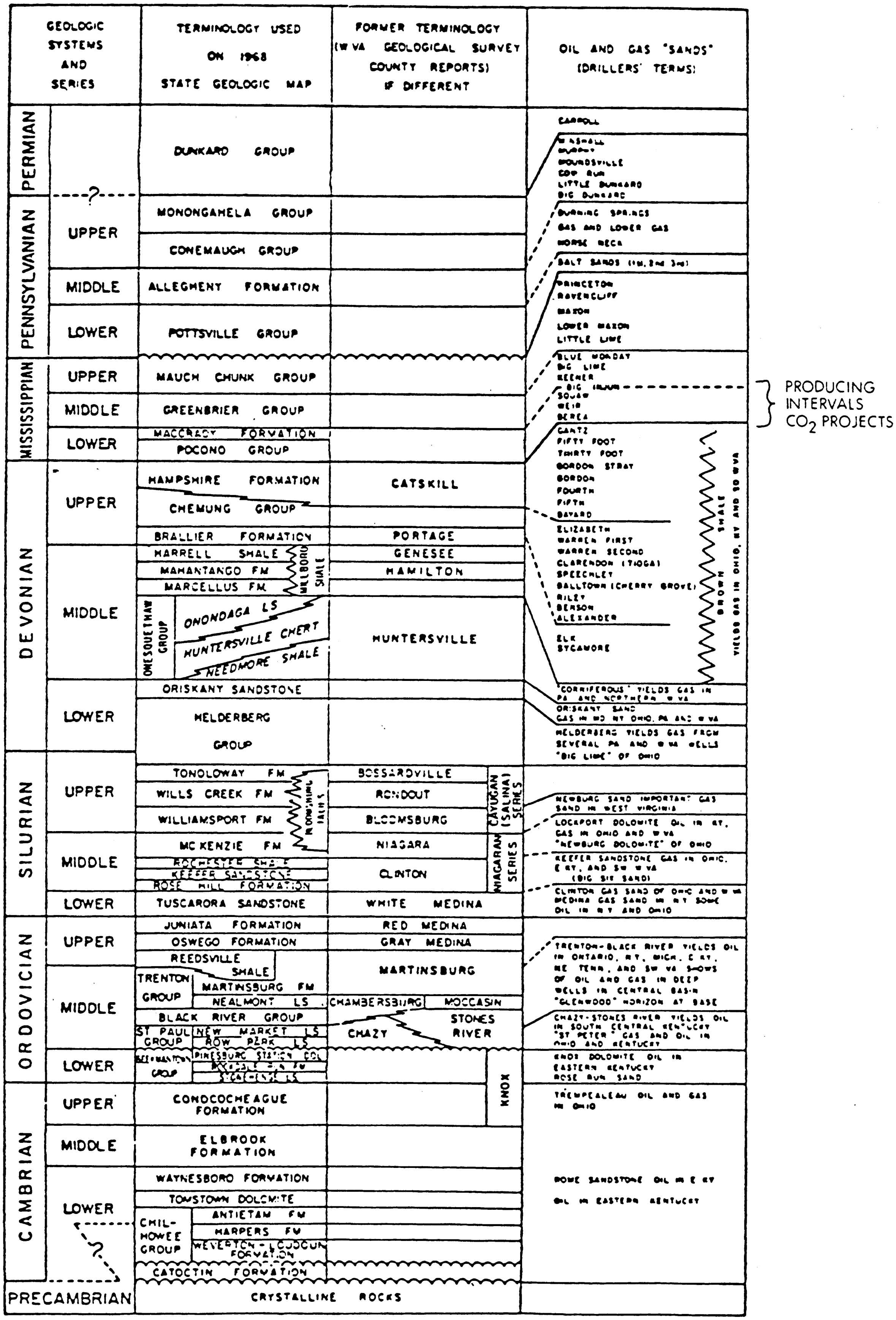

Figure 2.--Generalized stratigraphic column for West Virginia, showing oil and gas reservoirs.

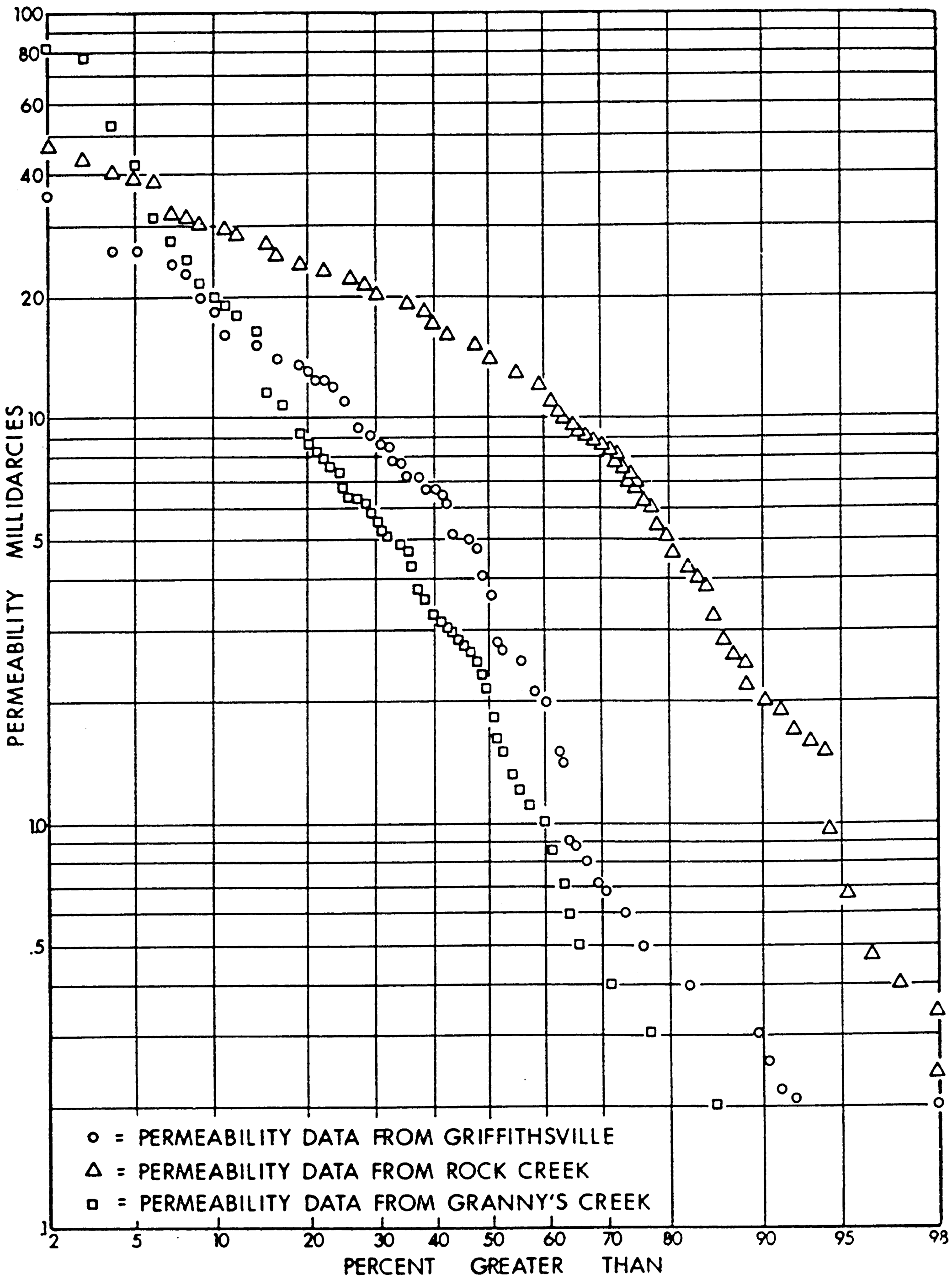

Figure 3.--Permeability variation in three West Virginia CO_2 injection project areas using 0.1-md cutoff.

GRANNY'S CREEK CO_2 INJECTION PROJECT

Location and General History

Granny's Creek oil field is located in south central West Virginia on the border between Roane and Clay Counties (Fig. 4). The field was discovered in 1925 and primary development continued into the early 1940's. The field underlies approximately 2,800 surface acres; wells were drilled on approximately 500-foot spacing (Fig. 5). Gas injection to maintain production commenced in limited areas of the field in 1940-1943. A waterflood project encompassing approximately 350 acres in the southern end of the field was initiated in 1964. A tertiary CO_2 injection pilot project was installed in the waterflood area in 1976.

Geologic and Petrophysical Data

The oil accumulation at Granny's Creek lies in a structural syncline. The field is one of several along the Grassland syncline [6]. It produces from the Big Injun sands of the Maccrady formation of lower Mississippian age, as shown in Fig. 6. The top of the producing zone, found at depths of 2,000 to 2,100 feet, is an erosional unconformity overlain by the Greenbrier limestone. Figure 7 shows schematically the general stratigraphic and structural relationships of the Granny's Creek oil accumulation [7].

Detailed geologic study indicates that the Big Injun sand interval consists of a basal sand that originated as an offshore bar or barrier island upon which stream channel sands were later deposited, resulting in the designations "Lower Injun" and "Upper Injun," respectively [8]. Reviews of log and core analysis data identified three porous, permeable sand intervals within these sediments [7,8]. These have been designated the "A" and "B" zones in the upper Injun and the "C" zone in the lower Injun (see Fig. 8) [7].

The upper Injun sands containing the A and B zones have been described as clean, medium- to coarse-grained, slightly calcareous, poor to well sorted, silica-cemented sands [7]. The lower zone is described as a more uniformly sorted, fine-grained, argillaceous sand. Log response of these zones is illustrated in Fig. 9. Core analysis data typical of the three zones are listed in Table 2 [9]. Oriented core studies showed no significant horizontal permeability anisotropy.

Reservoir Performance Data

Early wells showed limited productivity, with maximum reported rates of 50 BOPD. No overall field performance data have been published. Estimated cumulative production through November 1935 was reported as 3.358 million barrels [10].

Gas injection in Granny's Creek started when primary depletion was well advanced. The typical West Virginia gas injection project has been described as low-pressure gas recycling rather than gas-injection pressure maintenance [11]. Characteristically, these projects may involve only a few injection wells surrounded by one or more rings or clusters of producers. These projects are thus not gas drives in the more conventional pressure-maintenance sense. The performance of one such cluster of wells surrounding a gas injection well in Granny's Creek is illustrated in Fig. 10.

Primary and waterflood performance through 1975 of some 1,200 acres operated by Columbia Gas Transmission [12] in Granny's Creek is shown in Fig. 11. The waterflood response shown reflects pilot operations, which began in February 1964, and an expansion of the flood initiated in 1968 and continued through 1971. The expansion encompassed about 350 acres and 19 new patterns. The response of the 10.7-acre pilot area, which was encompassed by six water injection wells and contained three producing wells inside the injection well perimeter, is shown in Fig. 12. These data clearly reflect substantial oil bank buildup and movement in the pilot area. The pilot was shut in during 1975 in preparation for conversion to a CO_2 injection pilot.

CO_2 Project Data

The location of the CO_2 pilot project in the field is indicated in Fig. 5. The project used the same area and wells utilized in the earlier waterflood pilot [13]. Detailed project layout is shown in Fig. 13.

The pattern utilized four CO_2 injectors, approximately 530 feet apart, encompassing approximately 6.4 acres that contained an off-center production well (No. 4254) and an observation well (No. 20274). Work done before project implementation indicated that waterflood residual oil saturation in the pilot area was in the range of 30 to 35 percent of pore space [12]. Also, laboratory tests showed that the high displacement efficiency typical of miscible recovery could be attained with CO_2 injection at 1,000 psig and 75°F [14].

Pilot operations commenced in August 1975 with the resumption of water injection to raise pressure in the pilot area reservoir above the 1,000-psig miscibility pressure [13]. This was accomplished by June 1976. CO_2 injection began on June 2, 1976, following the injection of 300 barrels of gasoline to promote miscibility. Total injection rate of CO_2 averaged 770 to 850 Mscf (45 to 50 tons) per day. After about two months of injection (during late July and early August 1976), CO_2 was detected in the produced gas of production wells inside and outside the project area. It was decided to begin injection of 1,000-barrel slugs of water into each injector and thereafter to follow a schedule of injection whereby each well would receive in the future:

1) 800 tons CO_2
2) 1000 barrels water
3) 500 tons CO_2
4) 850 barrels water
5) 400 tons CO_2
6) 680 barrels water
7) 300 tons CO_2
8) 510 barrels of water

Interruptions of the CO_2 supply during the severe winter of 1976-1977 prevented full implementation of this schedule. When a CO_2 supply became available in April 1977, the remaining CO_2 was injected as a continuous slug until June 14, 1977, when CO_2 injection was completed and water injection resumed. Cumulative CO_2 injected per well during the entire injection period is reported as follows:

Well		CO_2 Injected
2020		2,364 tons
2022		2,794 "
2023		2,264 "
2025		2,456 "
	Total	9,878 tons

Figure 14 shows composite CO_2 and water injection data for the pilot operation [15]. This injection schedule was successful in maintaining reservoir pressure in the project area above the minimum 1,000 psig miscibility pressure, as shown by the data (from observation well 20274) portrayed in Fig. 15.

Production response from Well No. 4254, enclosed by the CO_2 injection pattern, is shown in Fig. 16 [15]. It may be noted that the response occurred in two nodes or peaks more or less coinciding with the periods of active CO_2 injection. Water production was minimal during this period. The composite production response from 12 producing wells (including No. 4254) associated with the project is illustrated in Fig. 17 [15]. Similar production peaks and relatively low water cuts may be noted in these composite statistics. It has been estimated that about 8,500 barrels of tertiary oil was recovered from these wells [1].

From these data, it is apparent that CO_2 injection mobilized waterflood residual oil into a low-water-cut oil bank. However, total CO_2 injected was 170 MMscf, yielding a CO_2/oil ratio of 20 Mcf per barrel. The injected CO_2 spread rapidly over some 200 acres. Geologic and permeability heterogeneities [1] are the most probable causes of the low recovery efficiency realized. Calculations indicate that only 6 to 12 percent of the injected CO_2 entered the pattern [16]. On this basis, a fully confined project could be expected to show considerable improvement in CO_2/oil ratio. Additional CO_2 injection into the project has recently been commenced.

TABLE 2

GRANNY'S CREEK FIELD, WEST VIRGINIA
CO_2 INJECTION PROJECT
CORE DATA SUMMARY

COMPANY: ERDA, Morgantown Energy Research Center

WELL: Columbia Gas Transmission Corporation Gerry Well No. 20274

Depth, ft	Permeability, md			Porosity, %	Saturation, %	
	Maximum	90 Degrees	Vertical		Oil	Water
1978-2005	1.9	1.5	0.6	7.2	14.8	49.3
2005-2022	5.6	7.8	3.4	17.6	13.2	55.6
2022-2067	0.2	0.4	0.1	13.7	13.4	47.9

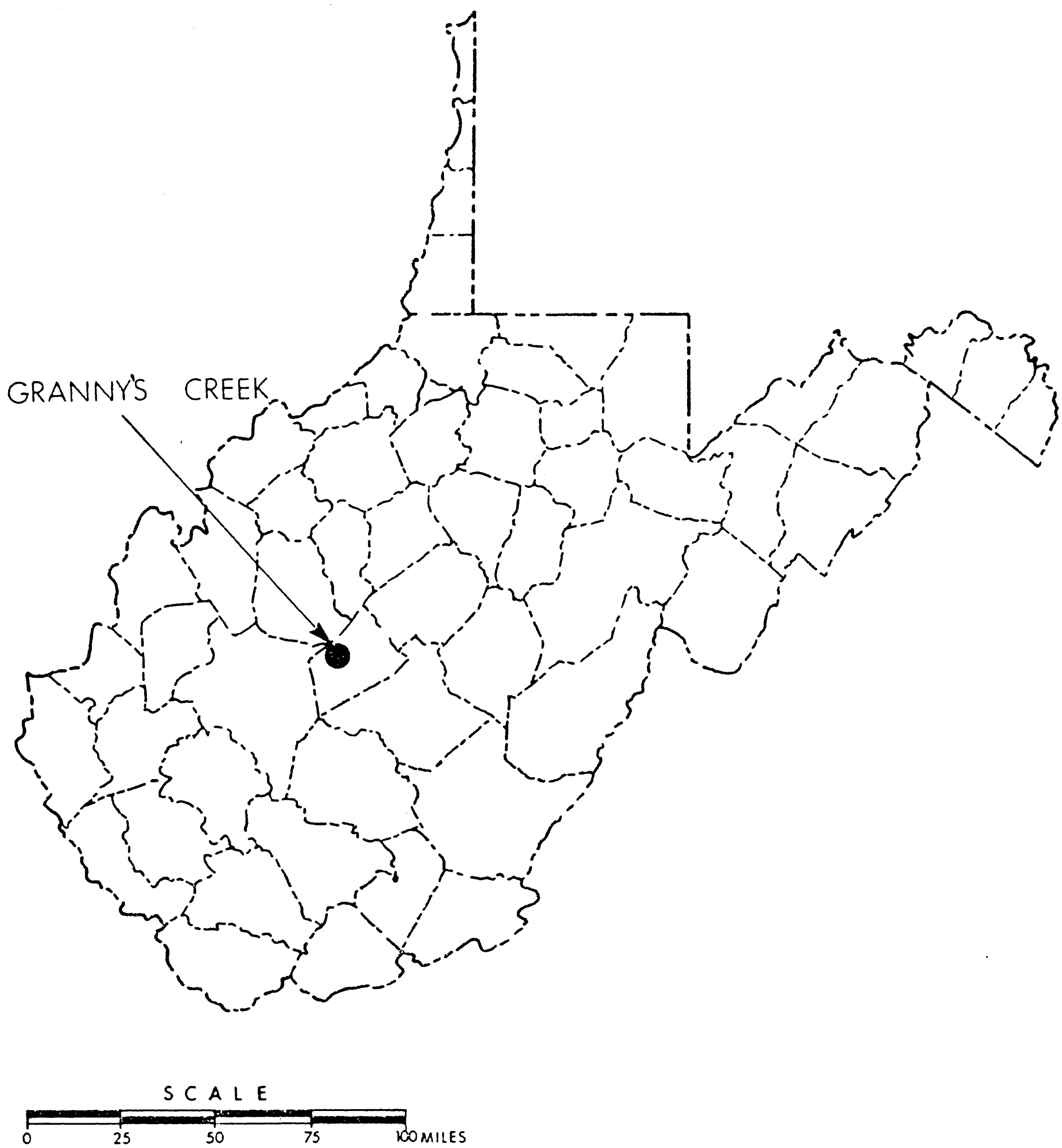

Figure 4.--County map of West Virginia showing location of Granny's Creek field.

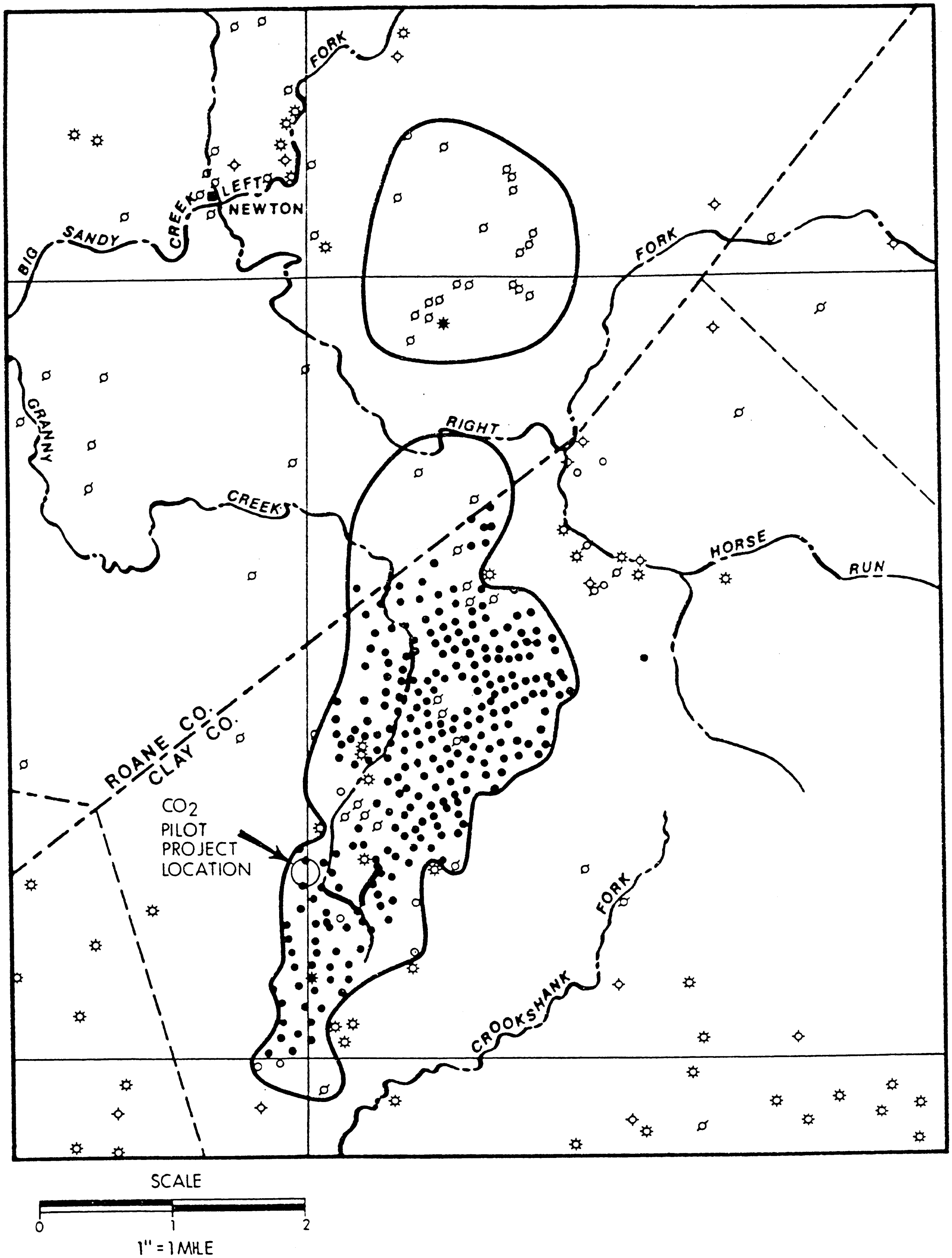

Figure 5.--Location of wells in Granny's Creek field (from W.Va. Mines Dept., Oil and Gas Division, and other sources)

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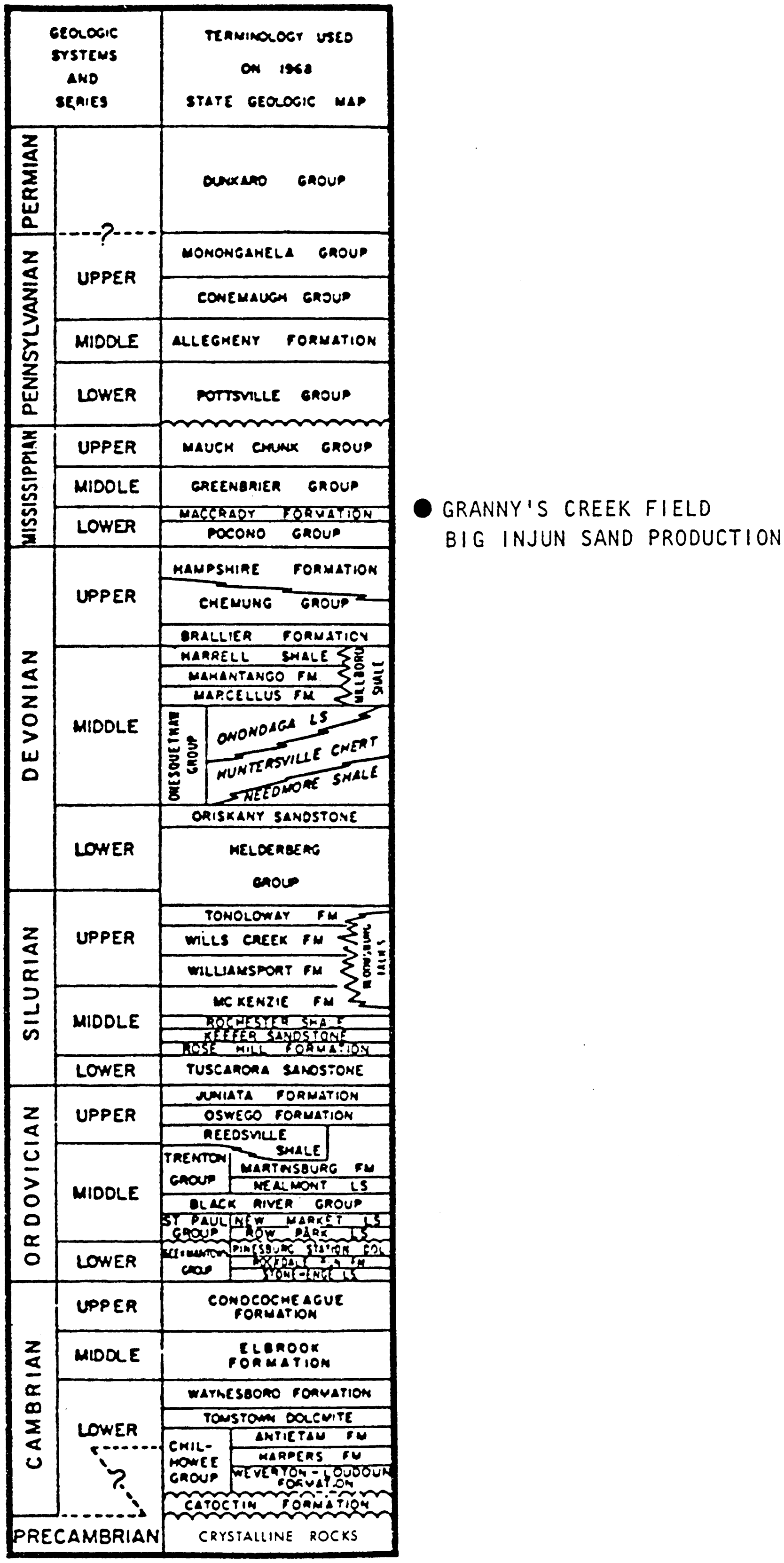

Figure 6.--Generalized stratigraphic column for West Virginia, with oil and gas reservoirs.

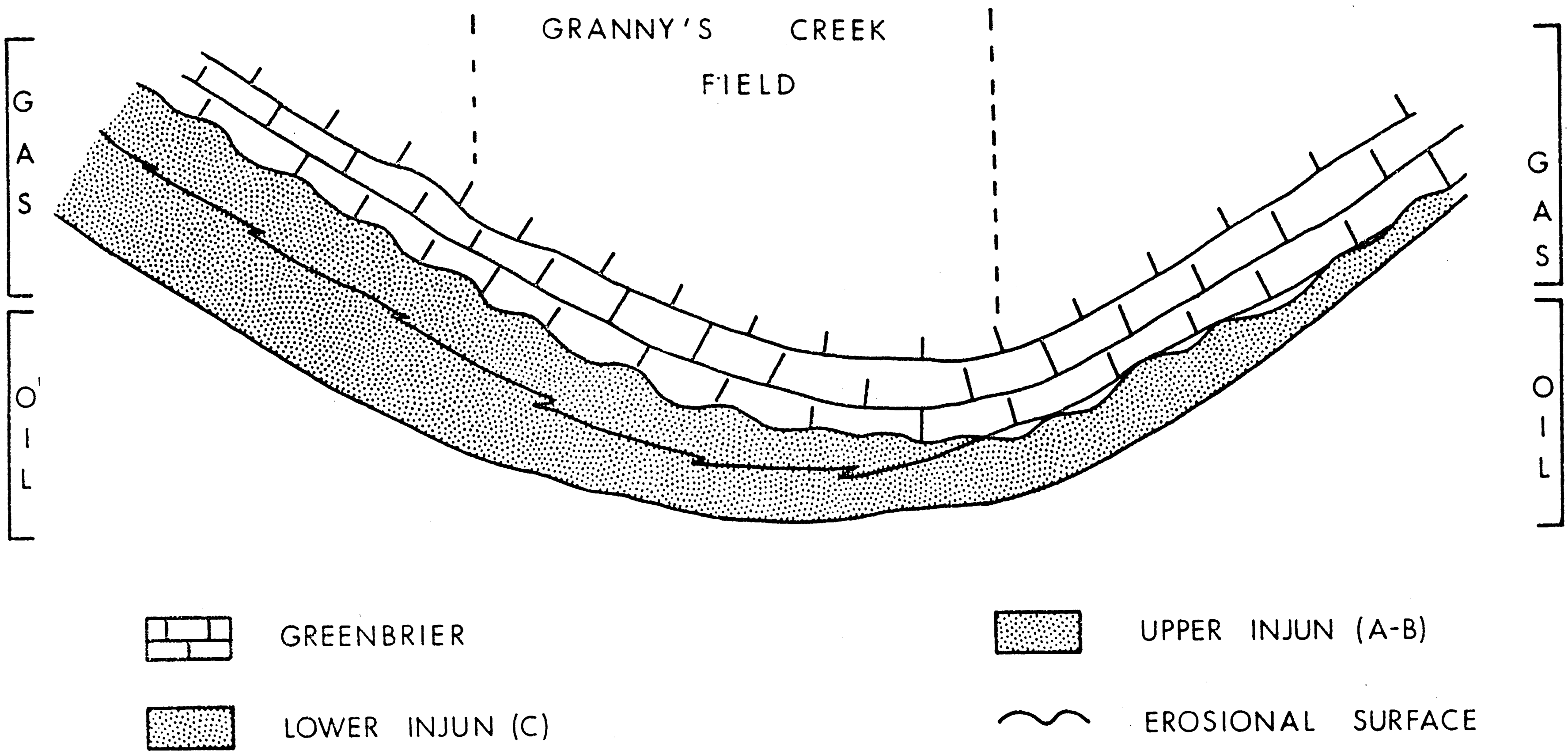

Figure 7.--Generalized cross section, Granny's Creek field, West Virginia.

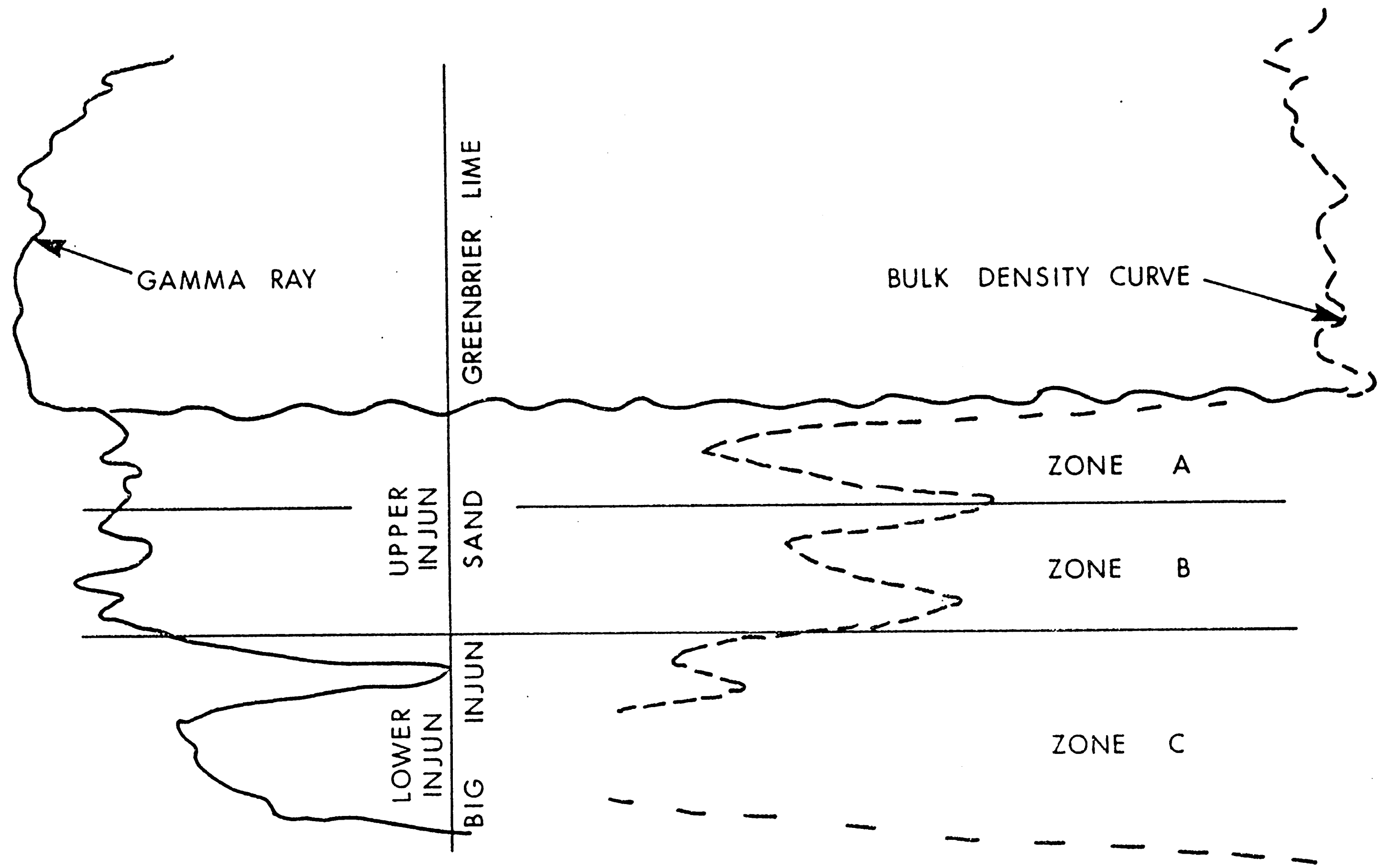

Figure 8.--Schematic diagram showing zonal subdivisions of the Big Injun sand, Granny's Creek field, West Virginia.

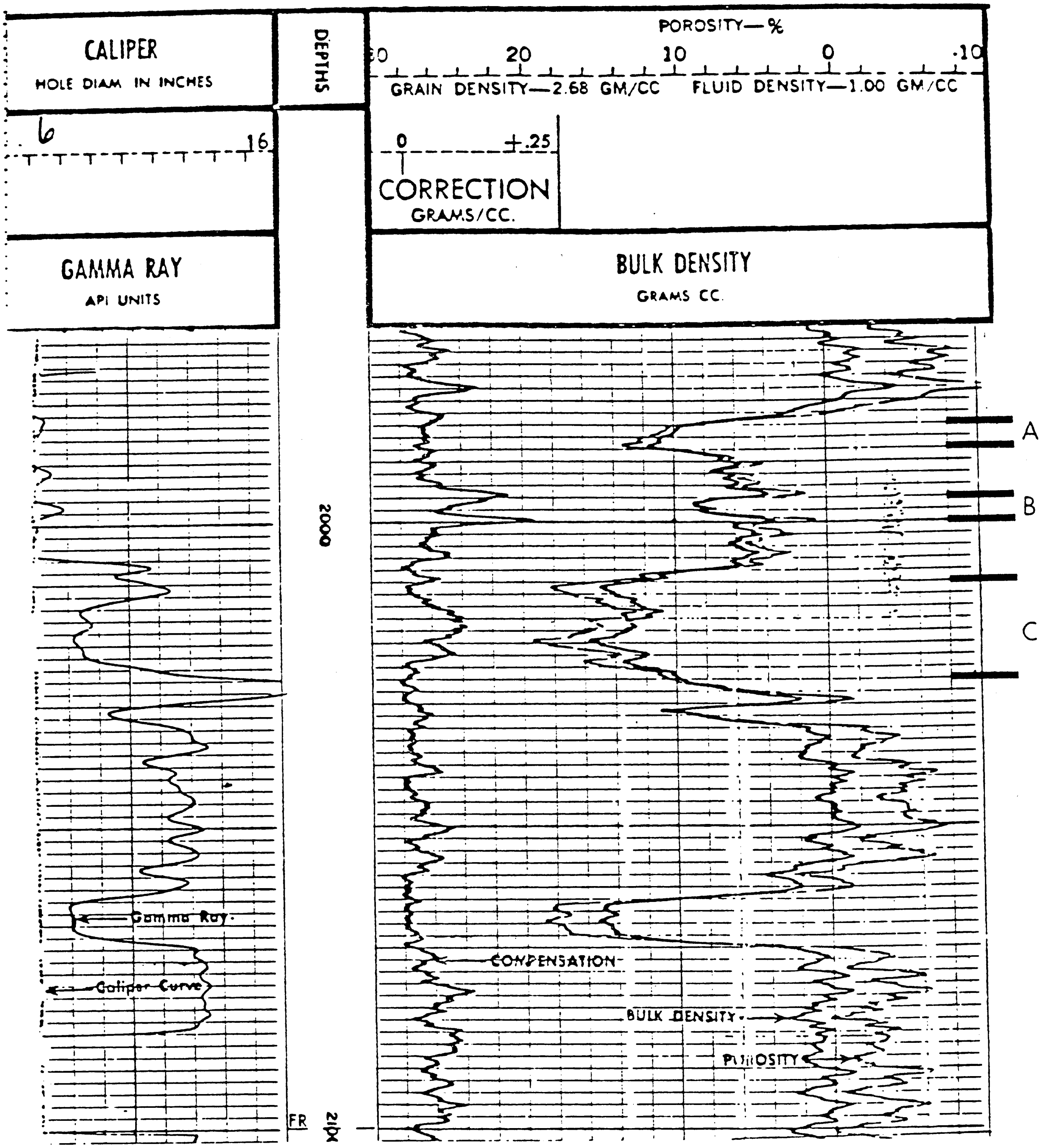

Figure 9.--Log of Big Injun sand, pay section, Granny's Creek field, West Virginia.

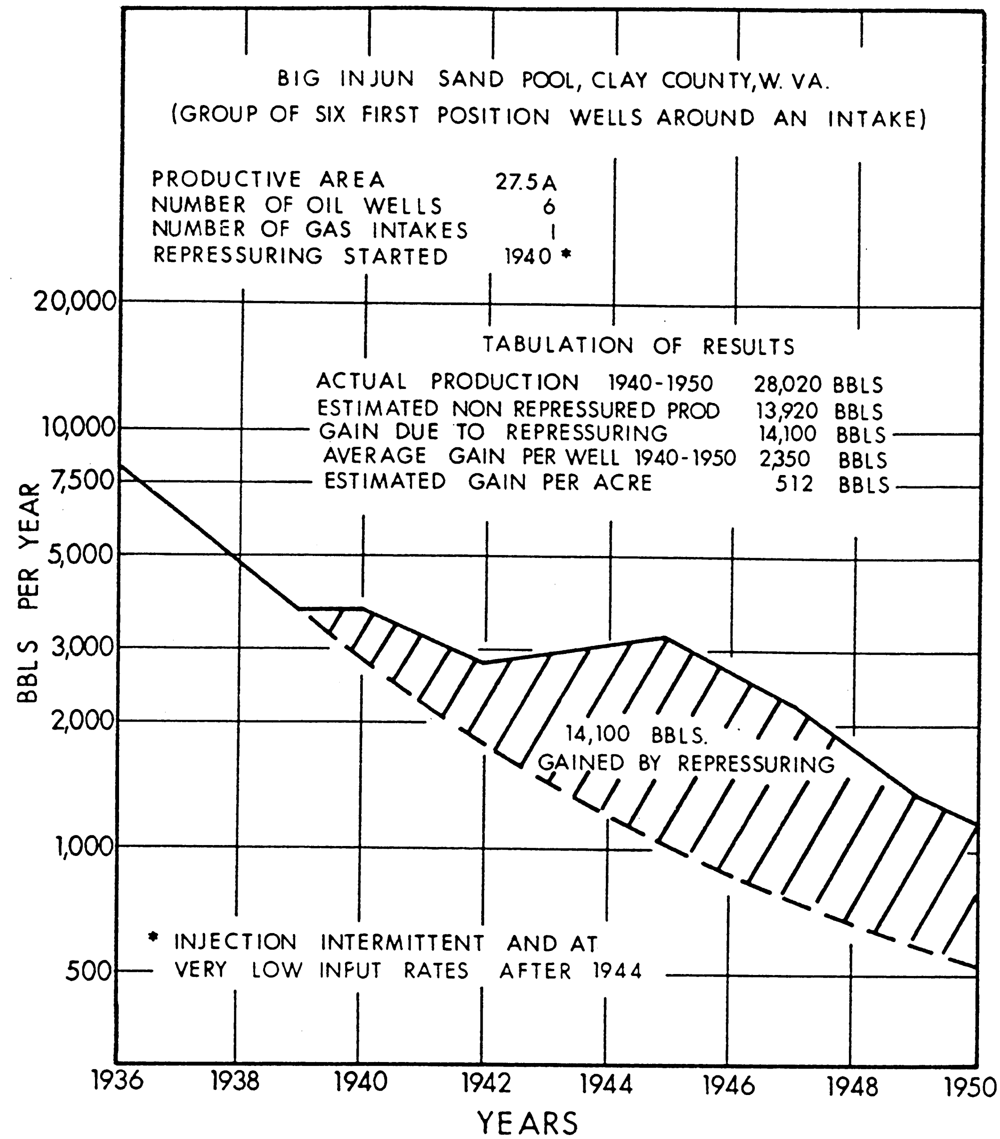

Figure 10.--Production history, gas injection project, Big Injun sand pool, West Virginia.

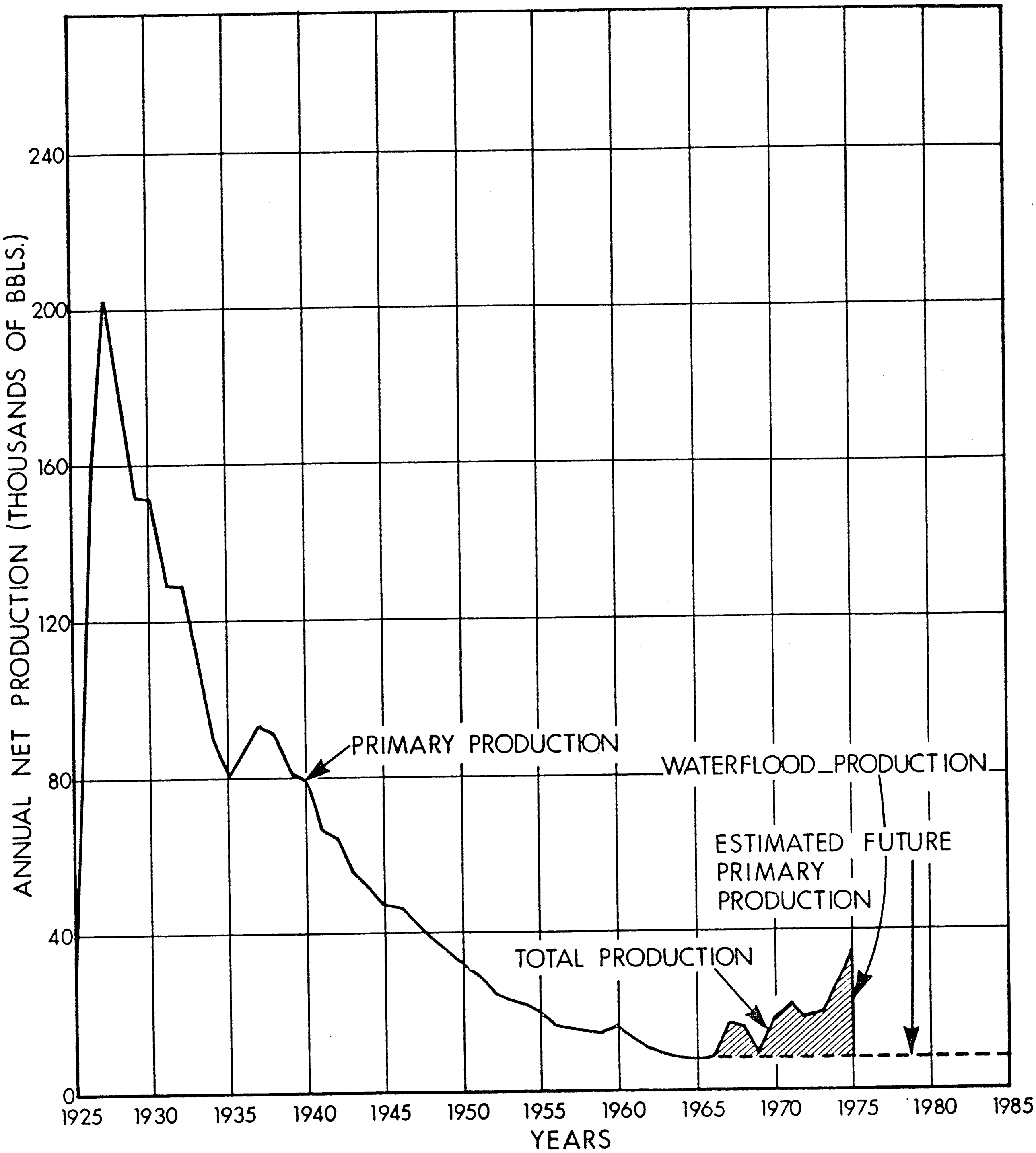

Figure 11.--Primary and waterflood production history of 1,200 acres operated by Columbia Gas Transmission Corp., Granny's Creek field, West Virginia.

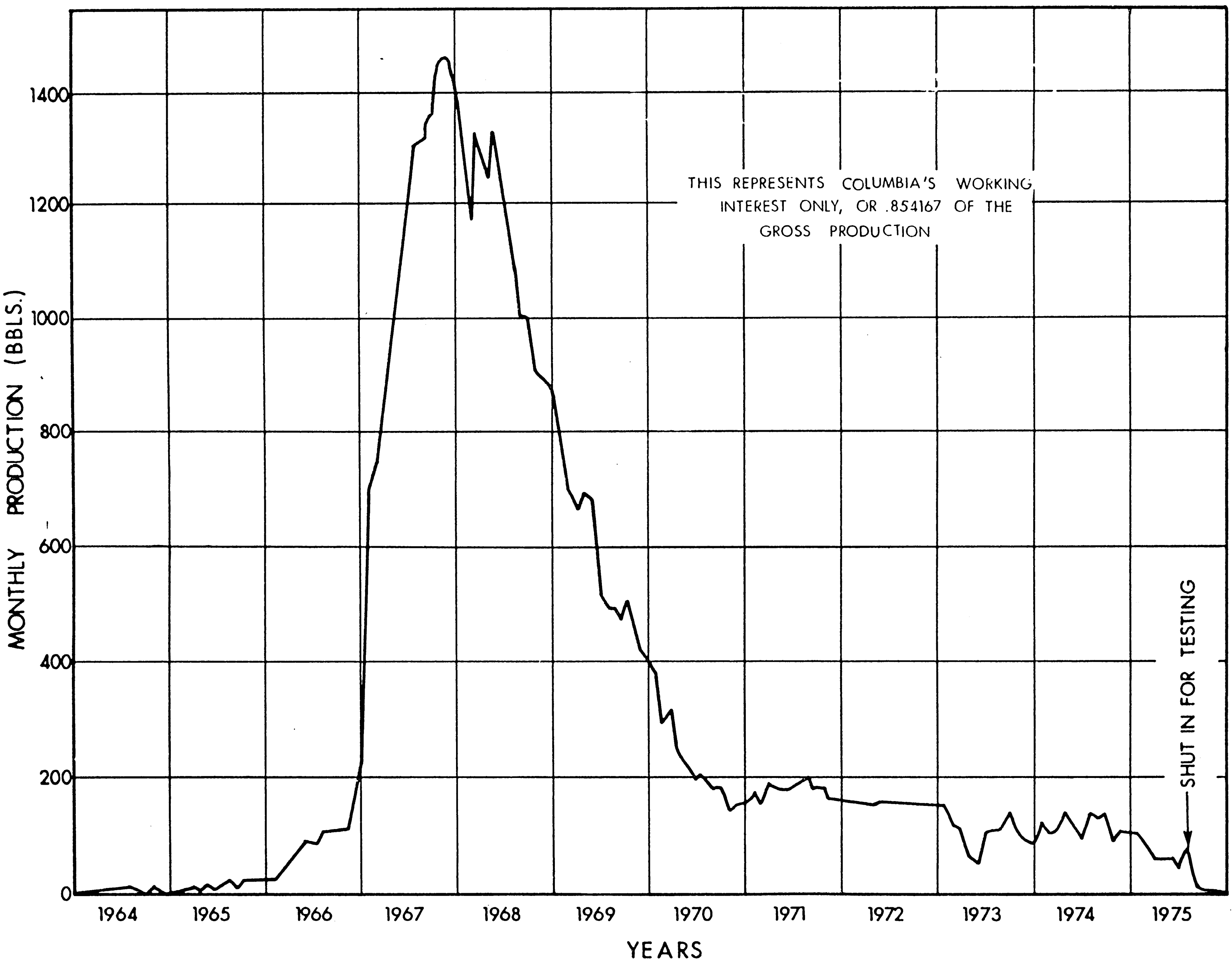

Figure 12.--Production history of a pilot waterflood project operated by Columbia Gas Transmission Corp., Granny's Creek field, West Virginia.

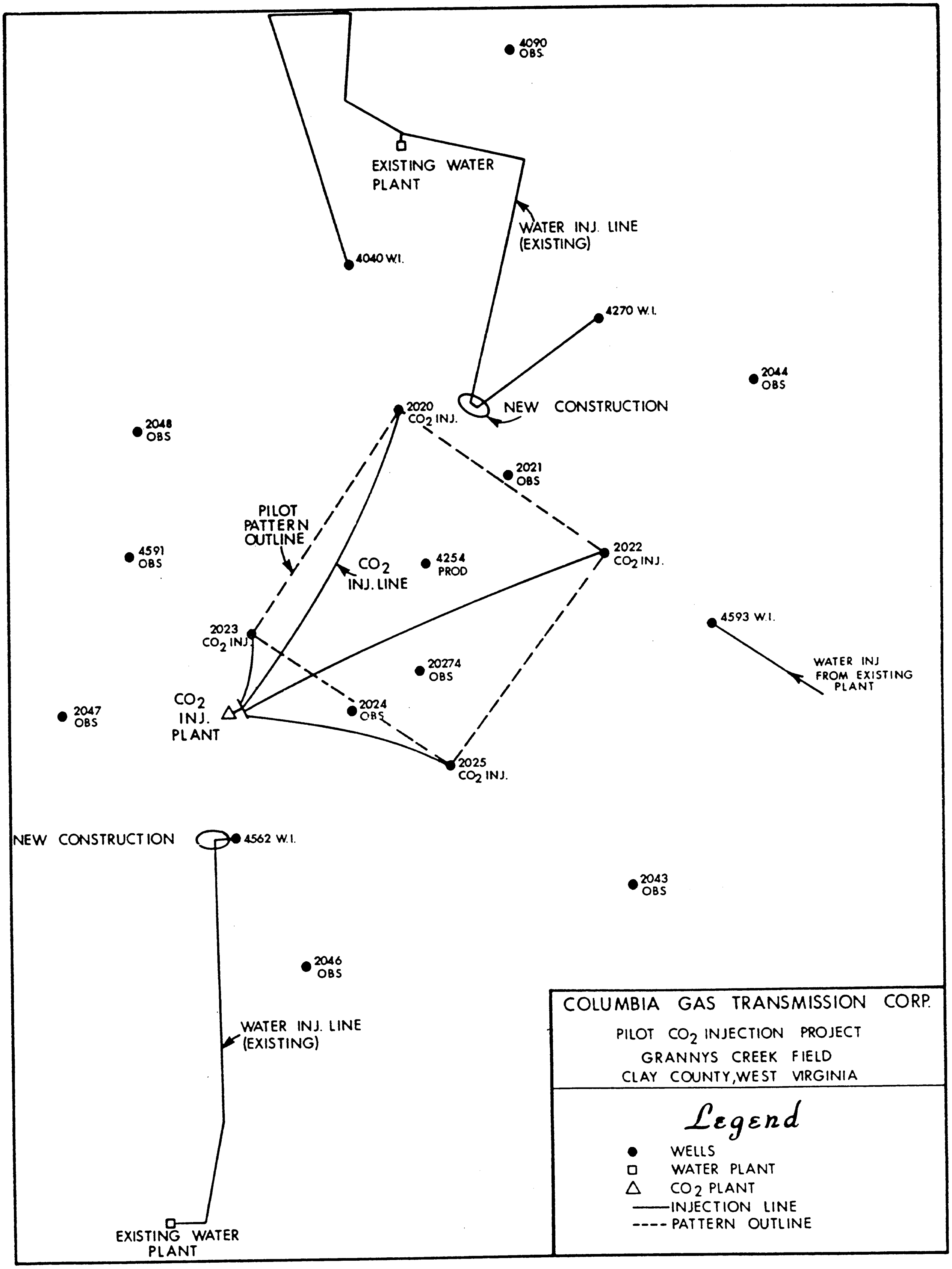

Figure 13.--Pilot carbon dioxide injection project operated by Columbia Gas Transmission Corp., Granny's Creek field, West Virginia.

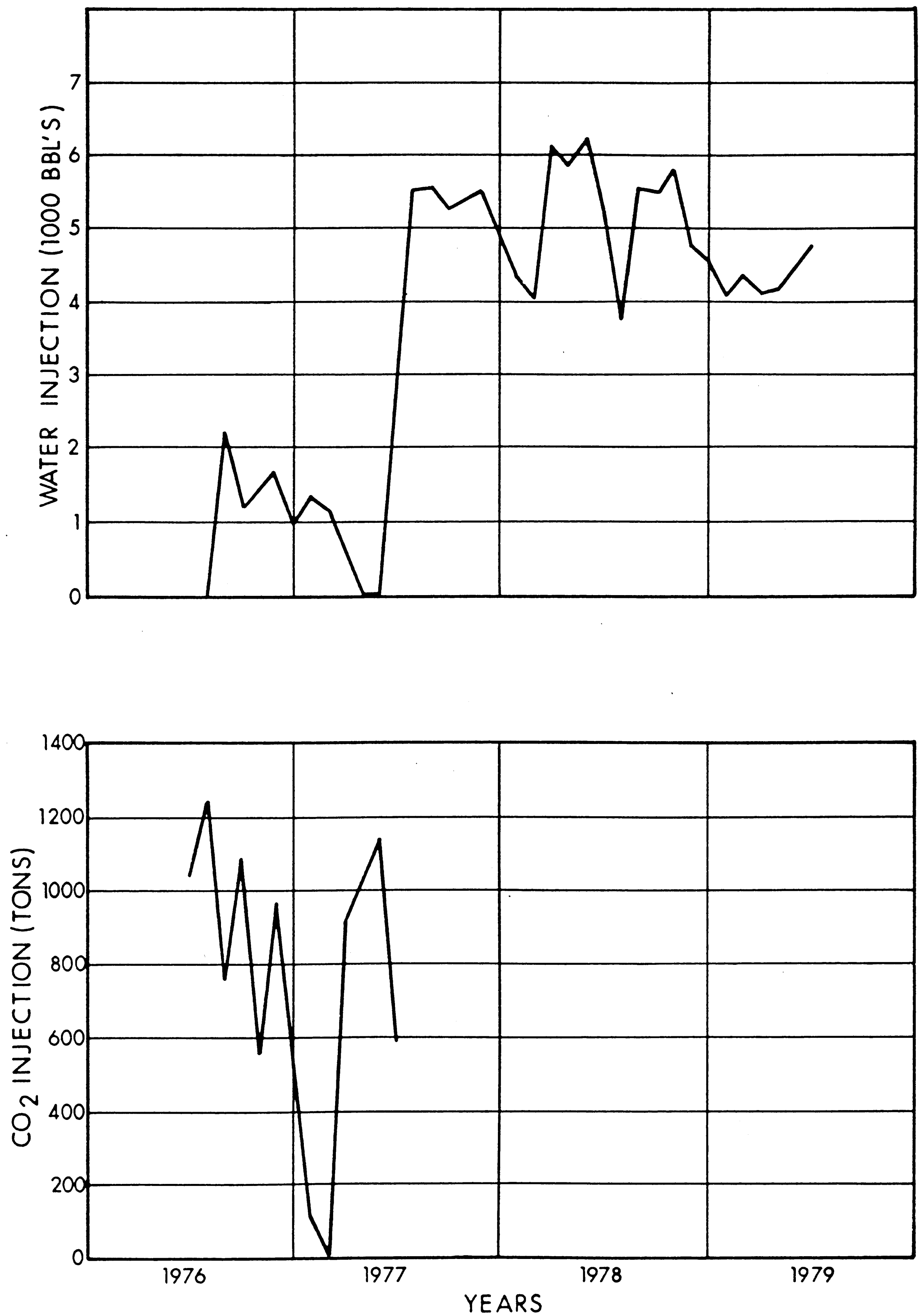

Figure 14.--CO_2 and water injection data, CO_2 injection project, Granny's Creek Field, West Virginia.

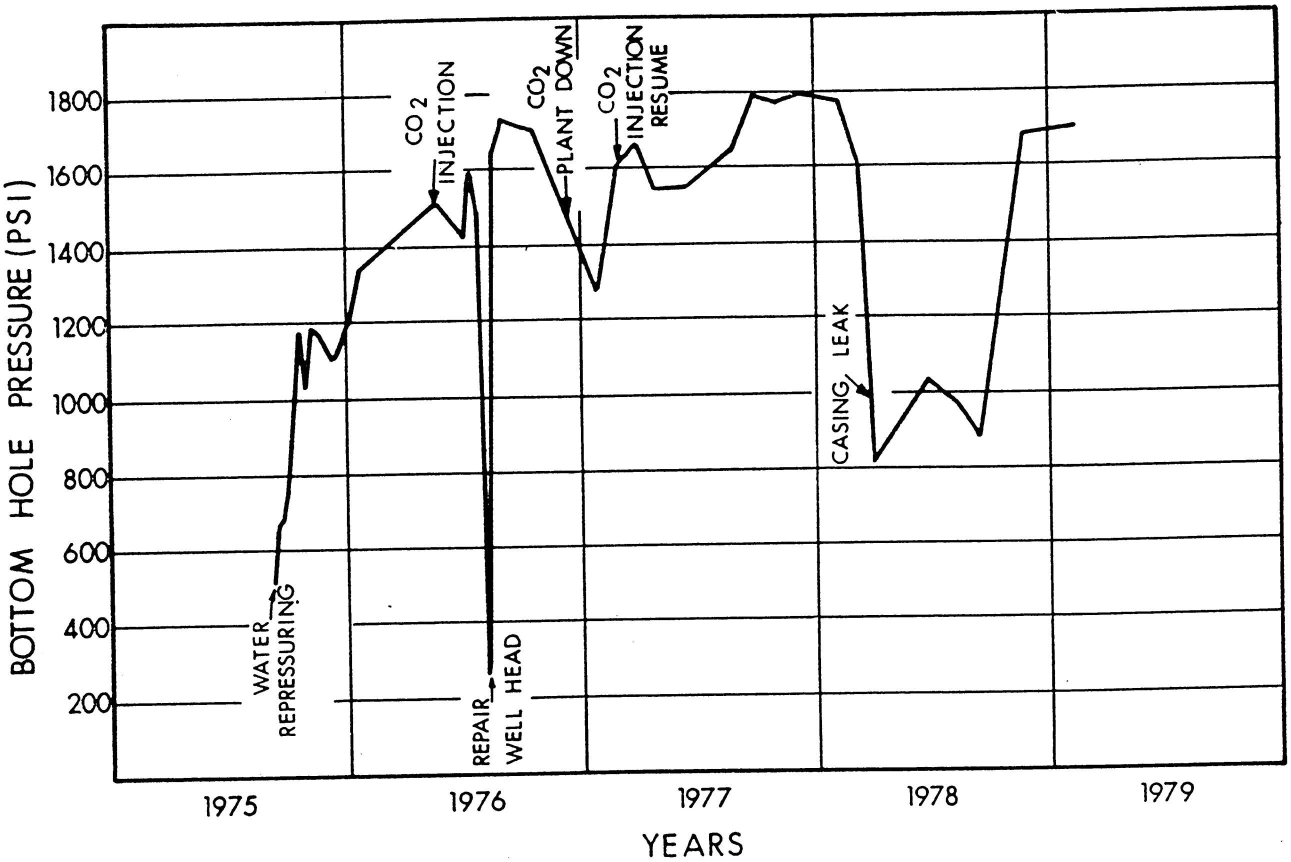

Figure 15.--Bottomhole pressure data, CO_2 injection project, Granny's Creek Field, West Virginia.

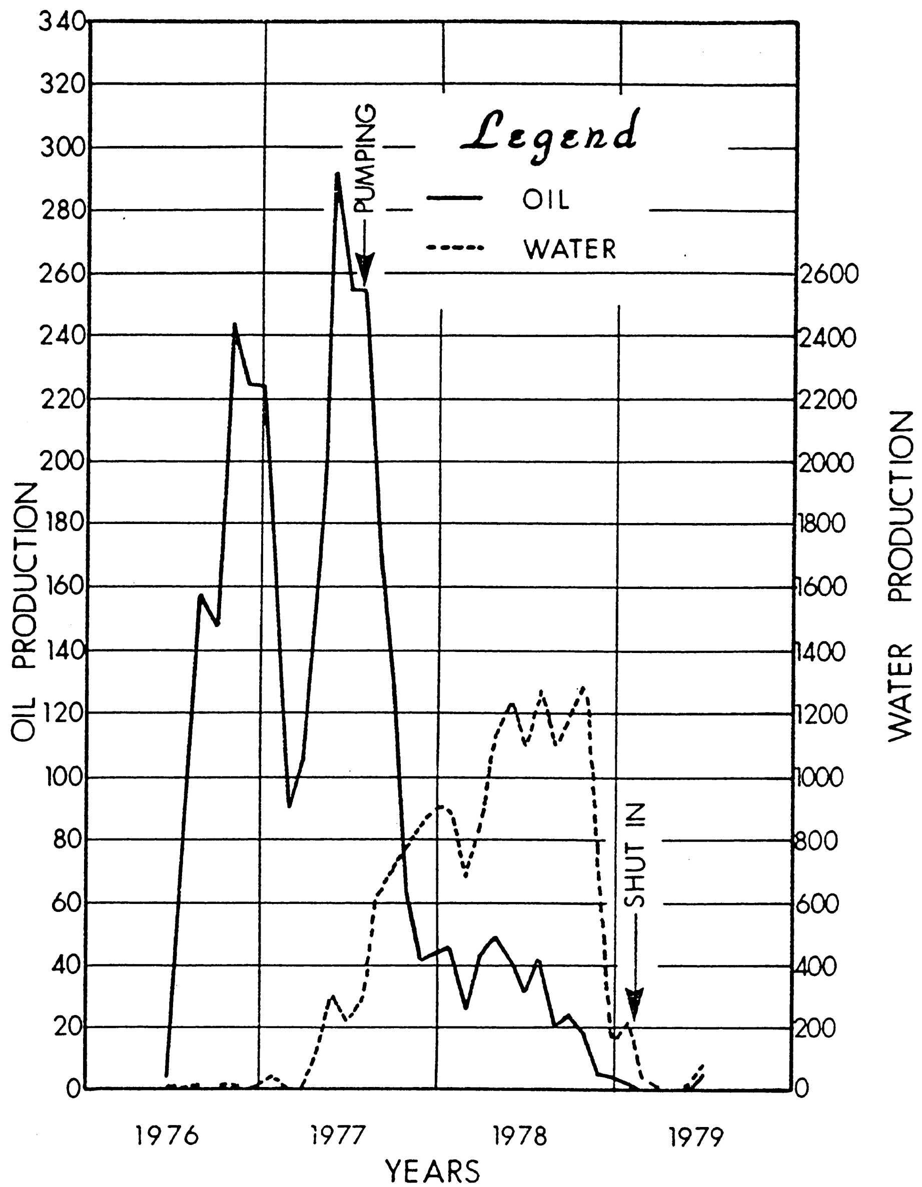

Figure 16.--Production history for Well 4254, CO_2 injection project, Granny's Creek field, West Virginia.

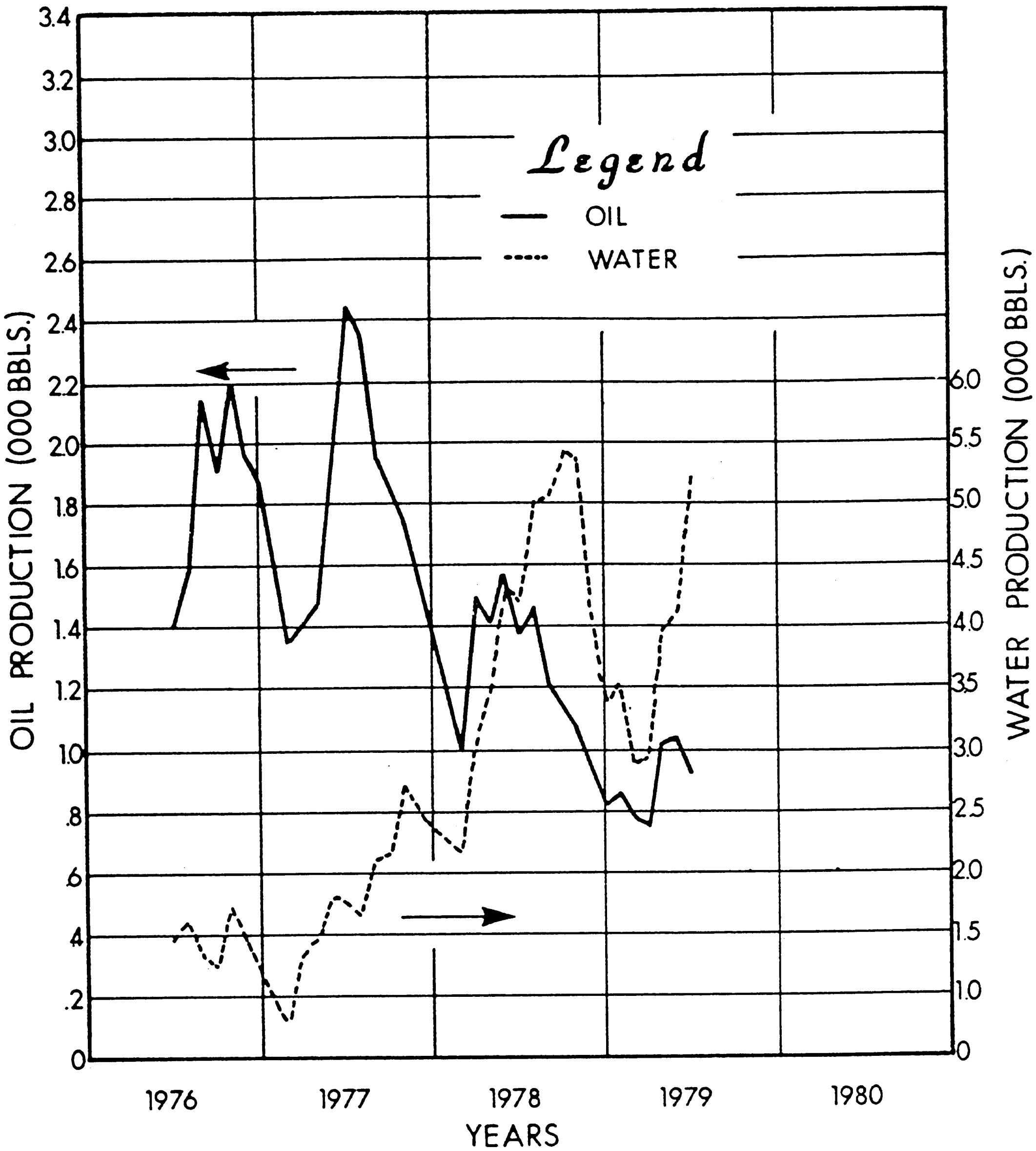

Figure 17.—Total oil and water production from 12 wells CO_2 injection project, Granny's Creekfield, West Virginia.

GRIFFITHSVILLE CO_2 INJECTION PROJECT

Location and General History

Griffithsville oil field is located in Lincoln County in western West Virginia (Fig. 1). The field was discovered in 1908 and eventually developed to encompass some 15,000 acres; wells were drilled on approximately 500-foot spacing (Fig. 18). Gas injection, as described earlier for Granny's Creek, began in 1926. Limited waterflooding was conducted from 1945 to 1953. Work started on a CO_2 injection pilot project in 1975. At that time, the field was described as generally abandoned except for a few isolated small producers [17].

Geologic and Petrophysical Data

The Griffithsville oil accumulation is in a structural syncline [6]. The field produces from the Berea sandstone (see Fig. 19) found at an average depth of 2,300 feet. The field contains no identified oil/water contact. The oil column extends from the bottom of the structure at 1,480 feet subsea up the flanks of the syncline to an elevation of approximately 1,400 feet subsea. The Berea sandstone is gas-bearing above this elevation, and was described as a major gas-producing area [6,17]. The Berea sandstone is a fine-grained, well-cemented rock with generally low permeability and a gross thickness of 23 to 24 feet. Typical log response is shown in Fig. 20. Core analysis and log data for the pilot area indicate a net pay thickness of 14 feet with greater than 1 md permeability, an average porosity of 12 percent, and an average permeability of 14 md in the net pay interval [18].

Reservoir Performance Data

Little information is available concerning reservoir performance. Early wells had initial production rates ranging from 20 to 25 B/D but reportedly maintained settled production rates for many years [6]. Cumulative production at the time CO_2 flooding was being considered was about 14 million barrels, or less than 20 percent of original oil in place [18]. The field was largely abandoned at the time CO_2 project planning commenced in 1975 [17].

CO_2 Project Data

As planned and implemented by Guyan Oil Company, Inc., the CO_2 pilot, located on the southern end of the Griffithsville structure, occupied 90 acres and contained 9 normal 10-acre five-spot patterns (see Fig. 21). The project was implemented by drilling 15 new injection wells and 9 new production wells and converting 1 existing modern well to injection service [17]. It also proved necessary to re-enter and plug with cement 17 improperly abandoned old wells in the immediate project area.

There was no production from the project area at the time the pilot was initiated, and reservoir pressure ranged from 725 to 925 psig. Well tests run in the pilot wells showed that the reservoir in the pilot area was liquid-saturated as a result of an accidental (non-producing) dump flood of the Berea by percolation of brine from the overlying salt sand into improperly plugged old wells.

Project implementation was delayed by construction and drilling difficulties during severe winter weather in mountainous terrain, and environmental problems required restoration of the surface area damaged by project work. These difficulties substantially increased project costs [17].

Project planning provided that the 12 exterior injection wells would be water injectors and that the 4 interior injectors (see Fig. 21) surrounding the enclosed central five-spot would receive alternate slugs of CO_2 and water. Water injection into the exterior injectors was intended to increase reservoir pressure to the laboratory-determined miscibility pressure of 1,100 psig and to confine injected CO_2 to the pattern area.

Water injection began in December 1977. By May 1978, project area pressure had increased to an average of 1,000 psig after a cumulative water injection of 117,000 barrels [18]. By the end of 1978, approximately 275,000 barrels of water had been injected. During this time project area had produced an estimated 16,000 barrels of oil and 144,000 barrels of water (160,000 barrels of total fluid) [19]. No CO_2 injection had taken place at that time. Since then, no further technical progress has been made [20,21].

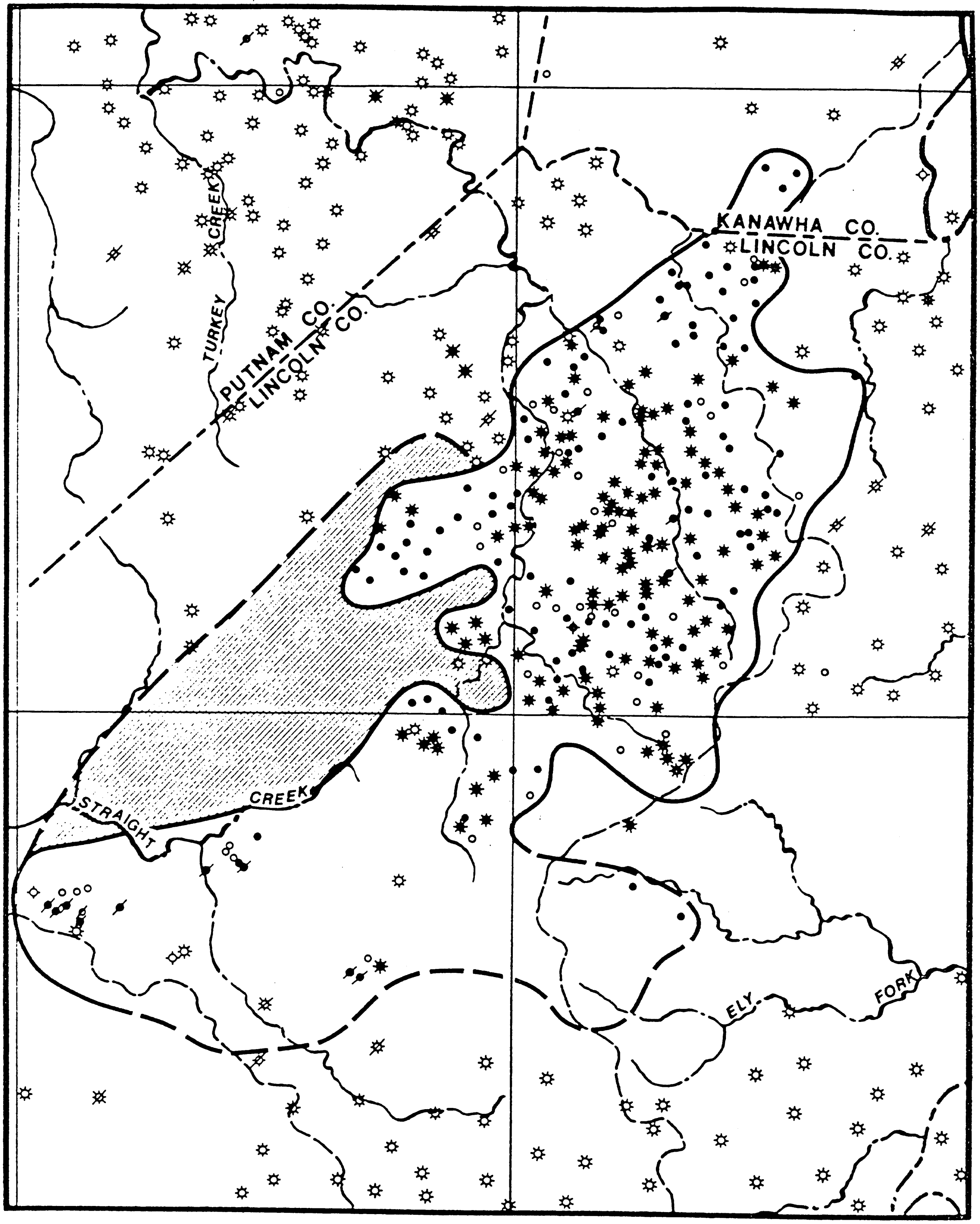

Figure 18.--Location of all wells drilled or plugged since 1929, Griffithsville field (map from W.Va. Mines Dept., Oil & Gas Div., 1978).

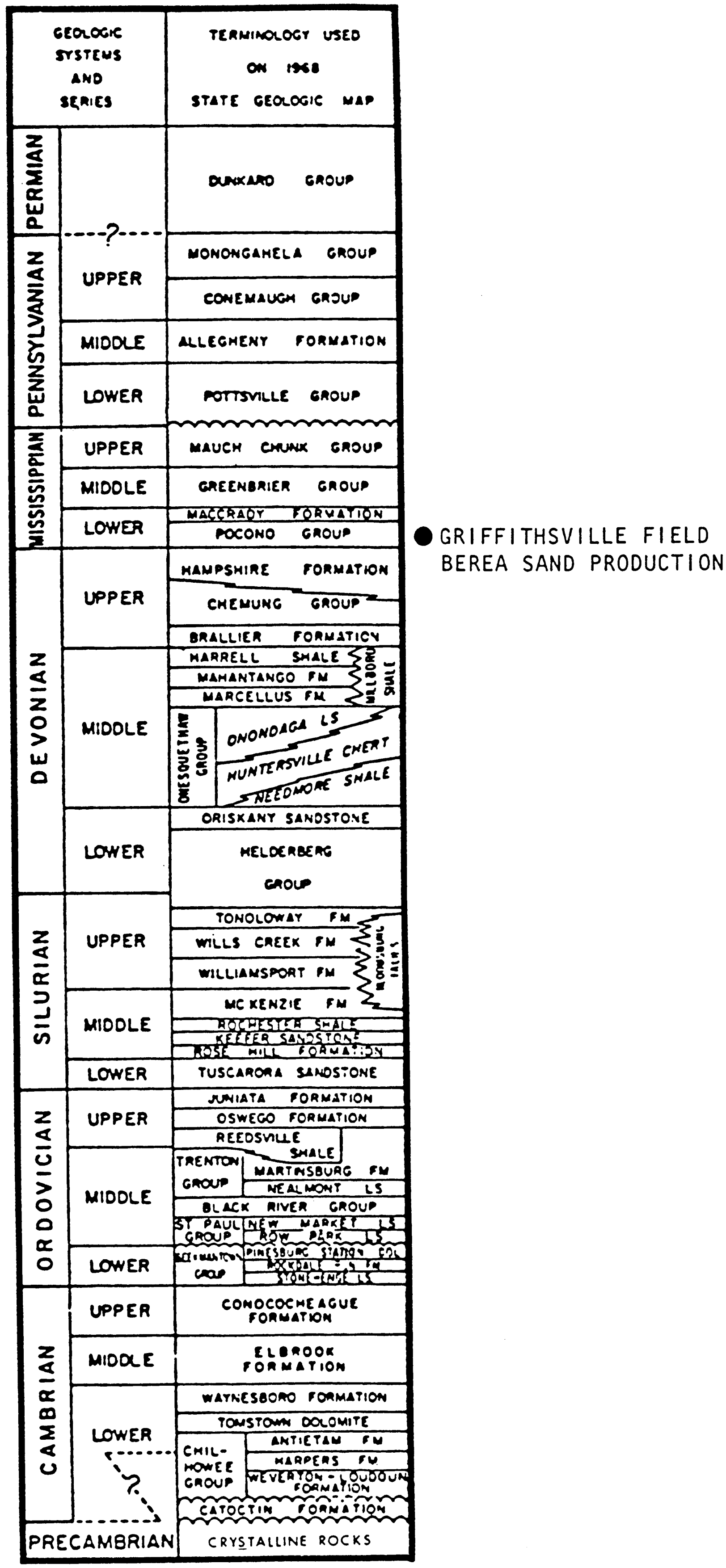

Figure 19.--Generalized stratigraphic column for West Virginia, showing oil and gas reservoir.

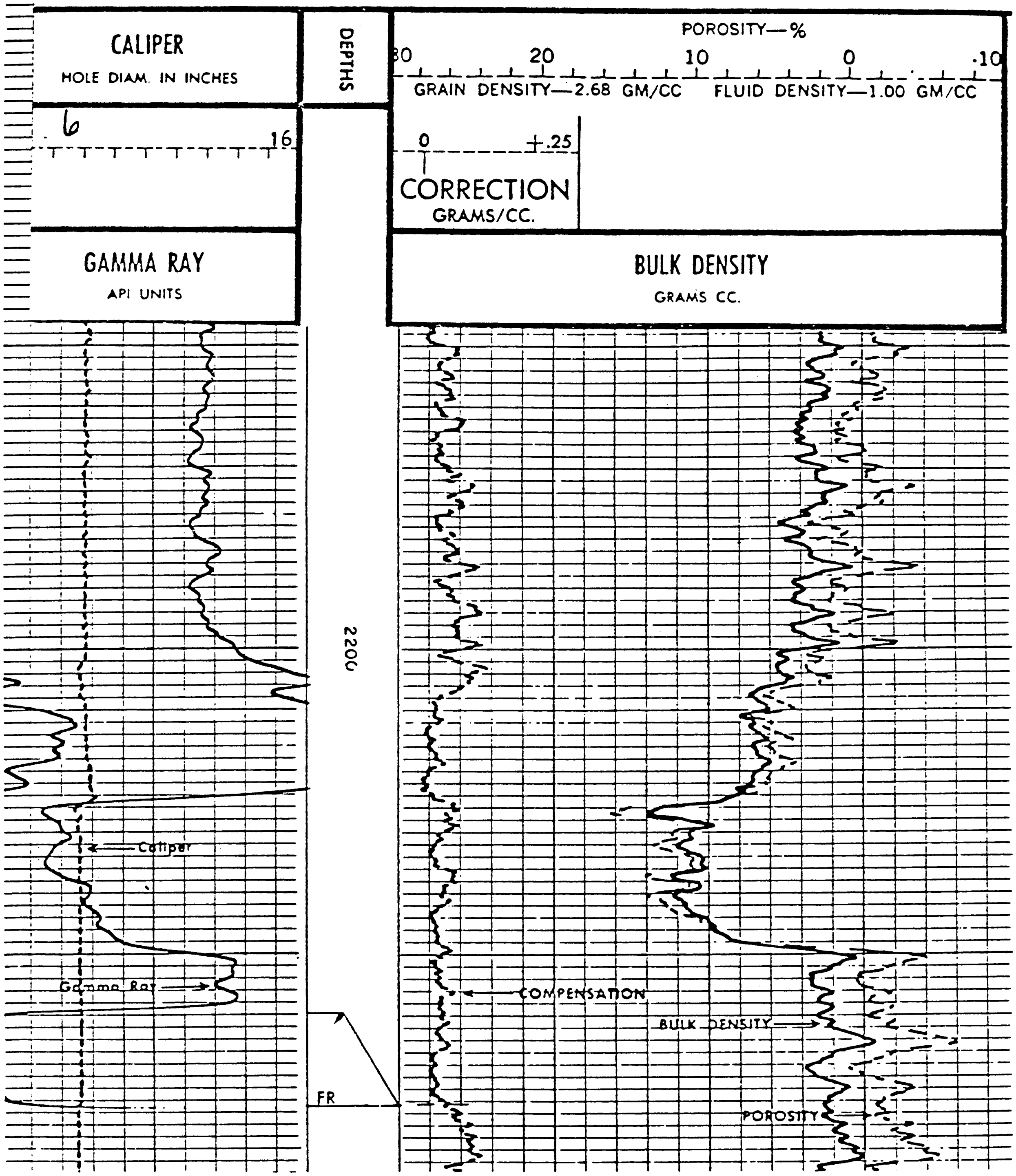

Figure 20.--Typical log from Griffithsville field, West Virginia.

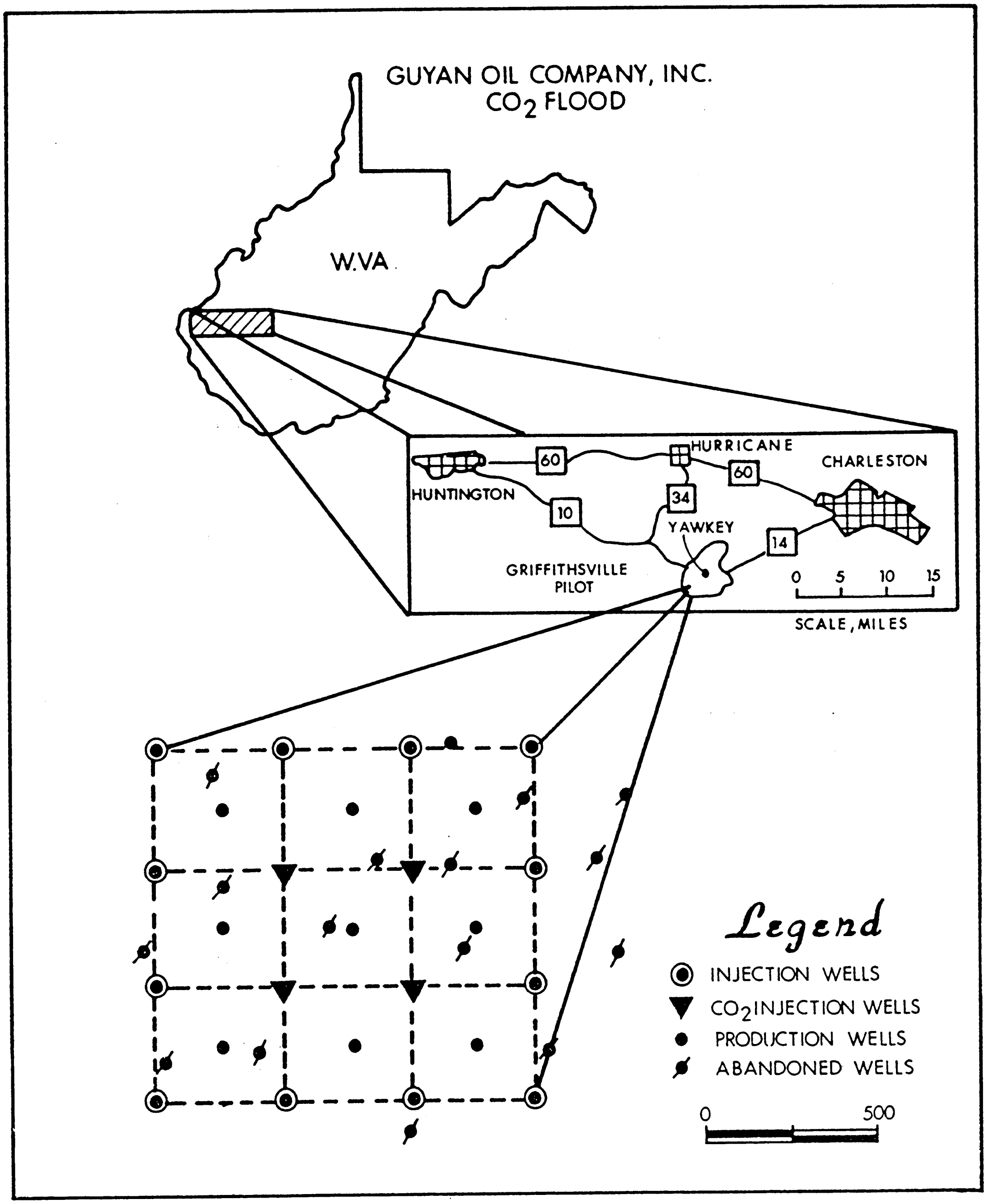

Figure 21.--Pilot CO_2 flood project conducted by Guyan Oil Co. Griffithsville field, West Virginia.

ROCK CREEK CO_2 INJECTION PROJECT

Location and General History

Rock Creek field is located in Roane County, West Virginia, approximately 20 miles northeast of Charleston (Fig. 1). The field was discovered in 1906 and developed during the next seven years [22]. The Rock Creek trend, including the adjacent Hammack field to the northeast, underlies approximately 11,200 surface acres and has been intensively developed (Fig. 22). Low-pressure gas recycling was initiated in limited areas of the field in 1935. Pilot waterflooding projects during the 1950's and 1960's demonstrated the infeasibility of waterflooding to improve recovery. A pilot steam flood during 1970 was unsuccessful in mobilizing oil because of low steam injectivity and attendant excessive heat losses. A CO_2 pilot project was designed and installed during 1976 and 1977.

Geologic and Petrophysical Data

The field produces from the Big Injun sand (Fig. 2) found at average depths of 2,000 to 2,050 feet. As shown in Fig. 23, the accumulation straddles the Jarrett structural syncline, which dips northeasterly at 35 feet per mile [22]. The accumulation is overlain by the Greenbrier limestone and is trapped by deteriorating sand quality at the southwest (upstructure) limit. This area contained a gas cap above 1,000 feet subsea. A clean oil column was contained from 1,000 to 1,050 feet subsea, overlying a 70-foot oil/water transition zone to 1,120 feet subsea, below which only water was produced.

On the basis of core and log data from the CO_2 pilot area (discussed below), the Big Injun sand has an average gross thickness of 47 feet with 32 feet of "net pay" having a permeability greater than 5 millidarcies. Typical log response is shown in Fig. 24. Cores of the net pay had an average porosity of 21.7 percent and an average permeability of 19.3 millidarcies. Log calculations indicated an interstitial water content of approximately 50 percent. The zone is described as a "very fine to medium grained, well sorted, sub-angular sandstone slightly to moderately calcareous" that becomes coarser grained in the upper part [22].

Reservoir Performance Data

Because of the long production history and limited early records, no overall field performance statistics are available. On the basis of limited data, it was estimated that primary recovery alone would average 10 percent of original oil in place [22]. Low-pressure gas recycling began in 1935 and continues to date. Performance of the original project through 1950 is illustrated in Fig. 25 [11]. Operations of this type are expected to recover an additional 10 percent of original oil in place [22]. Field total cumulative oil production through 1963 was estimated to be 18 million barrels [10].

CO_2 Project Data

A CO_2 pilot injection project, operated by Pennzoil Company, was installed in the Rock Creek field during 1976 and 1977. The location of the project with respect to the field outline is shown in Fig. 26. Structurally, the pilot site is in the clean-oil-column reservoir interval between 1,030 and 1,040 feet subsea (Fig. 27). Figure 28 shows a detailed map of the wells involved in the pilot, which comprises 2 approximately 10-acre normal five-spots surrounded by 13 backup water injection wells.

The six injection wells in the pattern, which serve both as CO_2 and water injection wells, were drilled for this project. After coring and logging, these wells were completed with 4-1/2 inch casing set through the Big Injun zone, cemented, perforated, and acidized. The two center production wells had originally been completed in 1908 and 1909 with 5-1/2 inch uncemented casing. They were reconditioned for this project by installing new 4-1/2 inch casing set with a packer immediately above the producing horizon. Six of the 13 backup water injection wells were drilled for this project. The other seven were converted from five active producers and two low-pressure gas injection wells.

The operating plan provided for water injection into all injectors to raise the reservoir pressure above the miscibility pressure (1,000± psig). Water injection into the 13 backup wells was initiated in October 1976, and into the 6 pilot injectors in April 1977. Water injection and reservoir pressure data since that time are shown in Fig. 29 [22]. As can be seen, miscibility pressure was reached early in 1978 and has been maintained since then. As of April 1, 1979, the 13 backup water-injection wells had a cumulative injection volume of 1,325,000 barrels and injection was continuing at an average rate of 64 barrels per day per well.

CO_2 injection into the six pattern injectors began in February 1979, after a cumulative total of 391,000 barrels of water had been injected into these wells. Through July 1, 1979, approximately 10,000 tons had been injected of a planned initial slug of 17,000 tons [21]. CO_2 injection continues at this writing.

Composite production history of the two pattern producers is shown in Fig. 30. As can be seen, oil production response to water injection began in May 1978, peaked in July and August 1978, and declined sharply to essentially zero by December 1978. Performance similar to this was observed in other pilot waterfloods in the field, with thin oil banks followed by water breakthrough and floodout [23]. Oil production response to CO_2 injection began in mid-1979 and continues to date [24]. This increase is directly creditable to the effects of CO_2 flooding.

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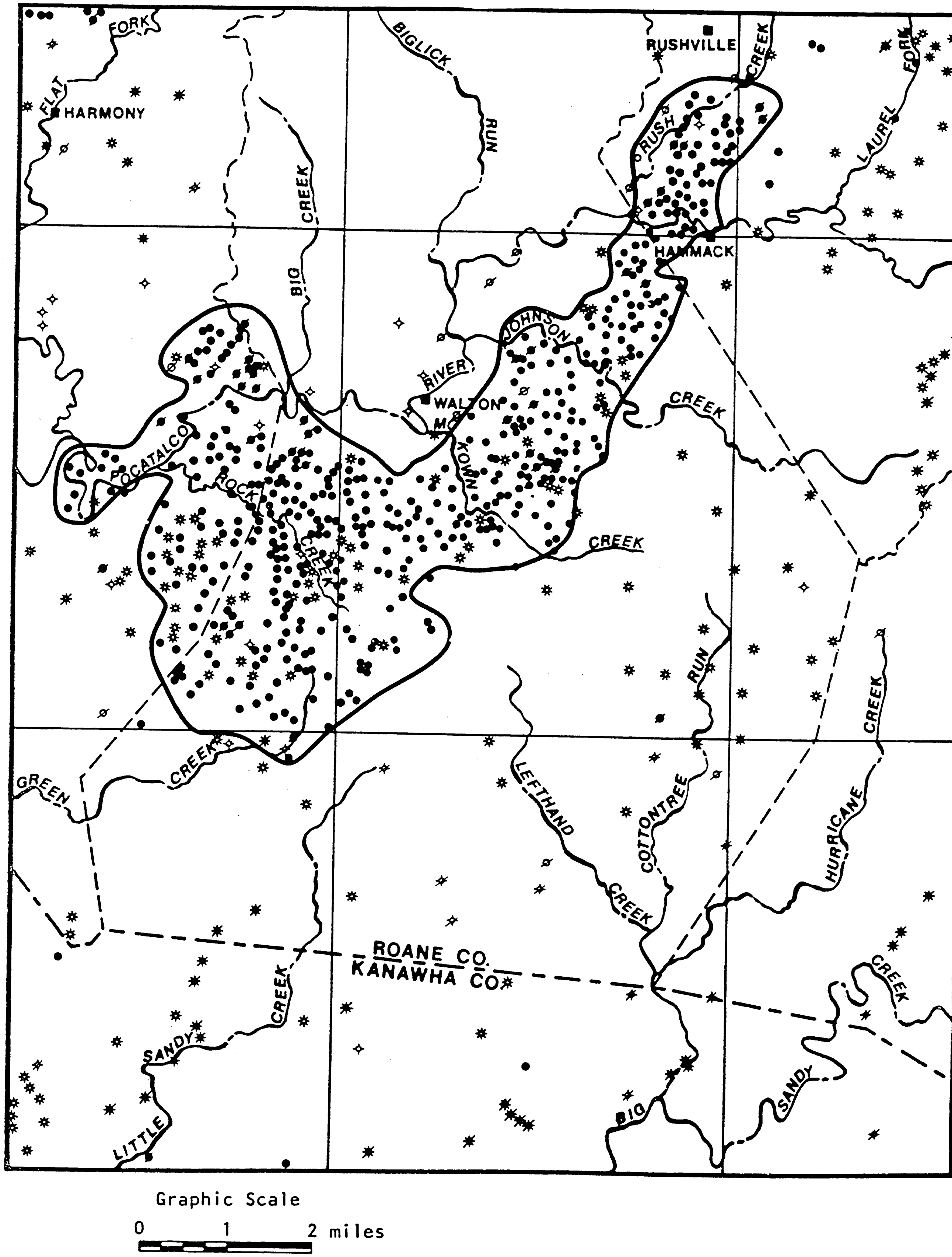


Figure 22.--Location of all wells drilled or plugged since 1929, Rock Creek field (map from W.Va. Mines Dept., Oil & Gas Div., 1978).

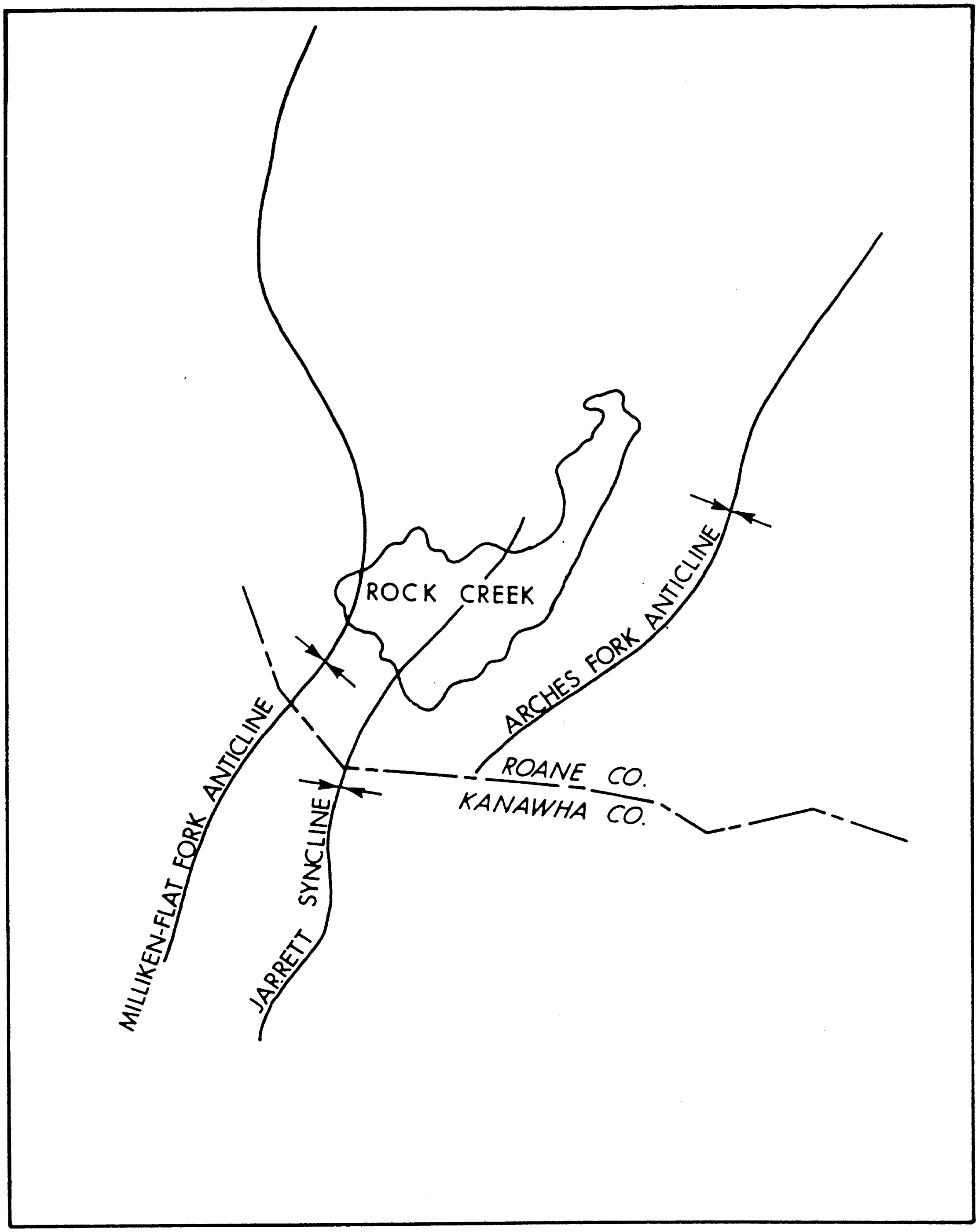


Figure 23.--Controlling structural axes of the Rock Creek-Big Injun field, West Virginia.

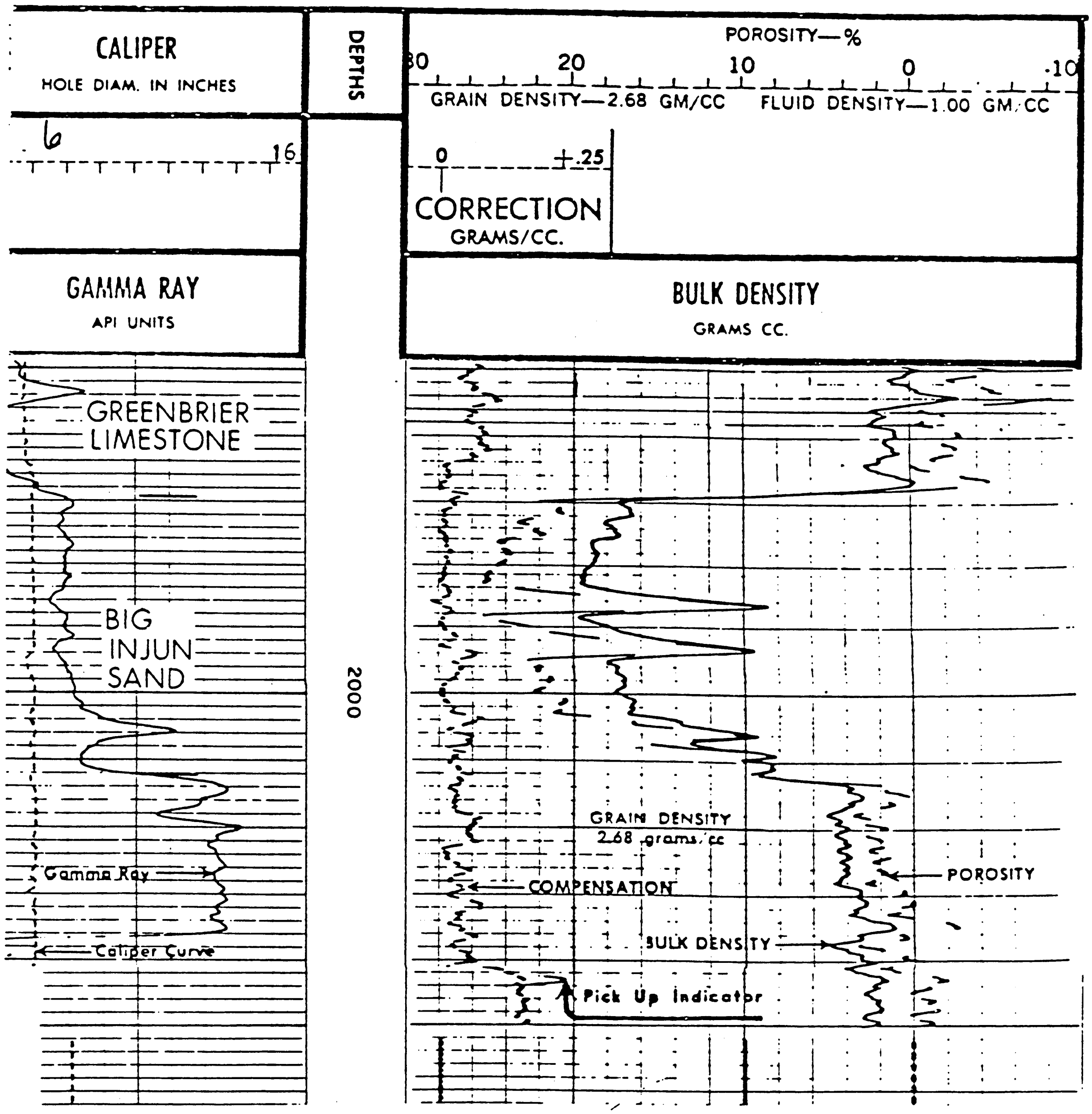
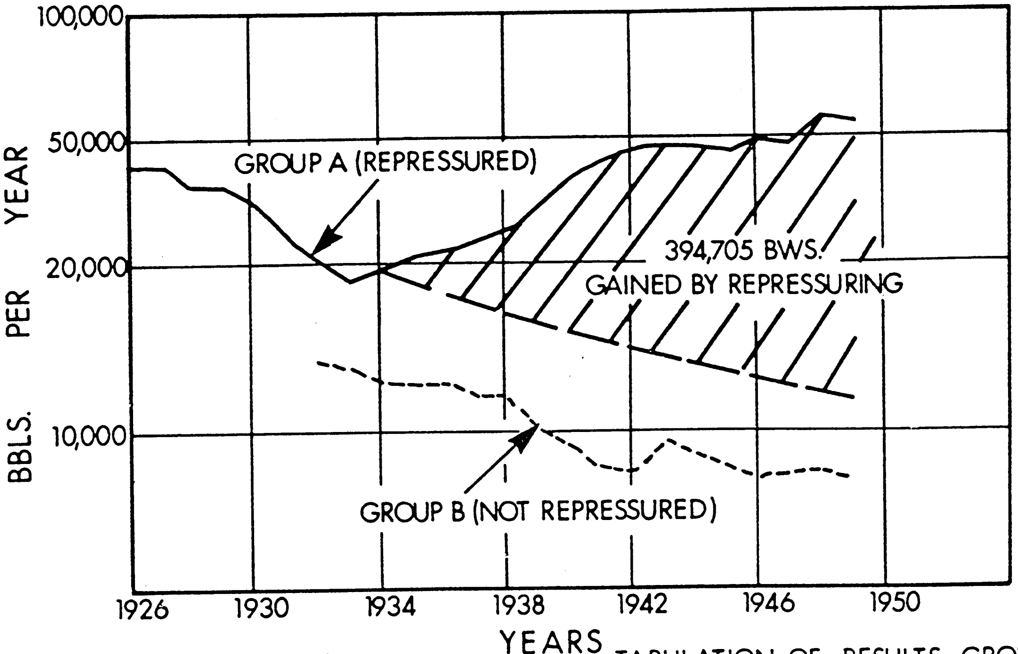


Figure 24.--Typical log from Walton-Rock Creek field, West Virginia.



GROUP A

PRODUCING AREA	1482°
NO OF OIL WELLS	100
NO OF GAS INTAKES	6
REPRESSURING STARTED	1935

GROUP B (NOT REPRESSURED)

PRODUCING AREA	504
NO. OF OIL WELLS	39

TABULATION OF RESULTS GROUP A

TOTAL RECOVERY TO 1/1/50	4,616,221 BBLS
PRODUCED UNDER PRIMARY	3,993,666 BBLS
PRODUCED UNDER SEC.	622,555 BBLS
BBL/ACRE RECOVERY TO 1/1/50	3,115 BBLS
BBL/ACRE GAINED BY SEC.	265 BBLS
AVG. BBL GAINED PER WELL	3,947 BBLS

Figure 25.--Production history, Big Injun sand pool, Rock Creek field, West Virginia.

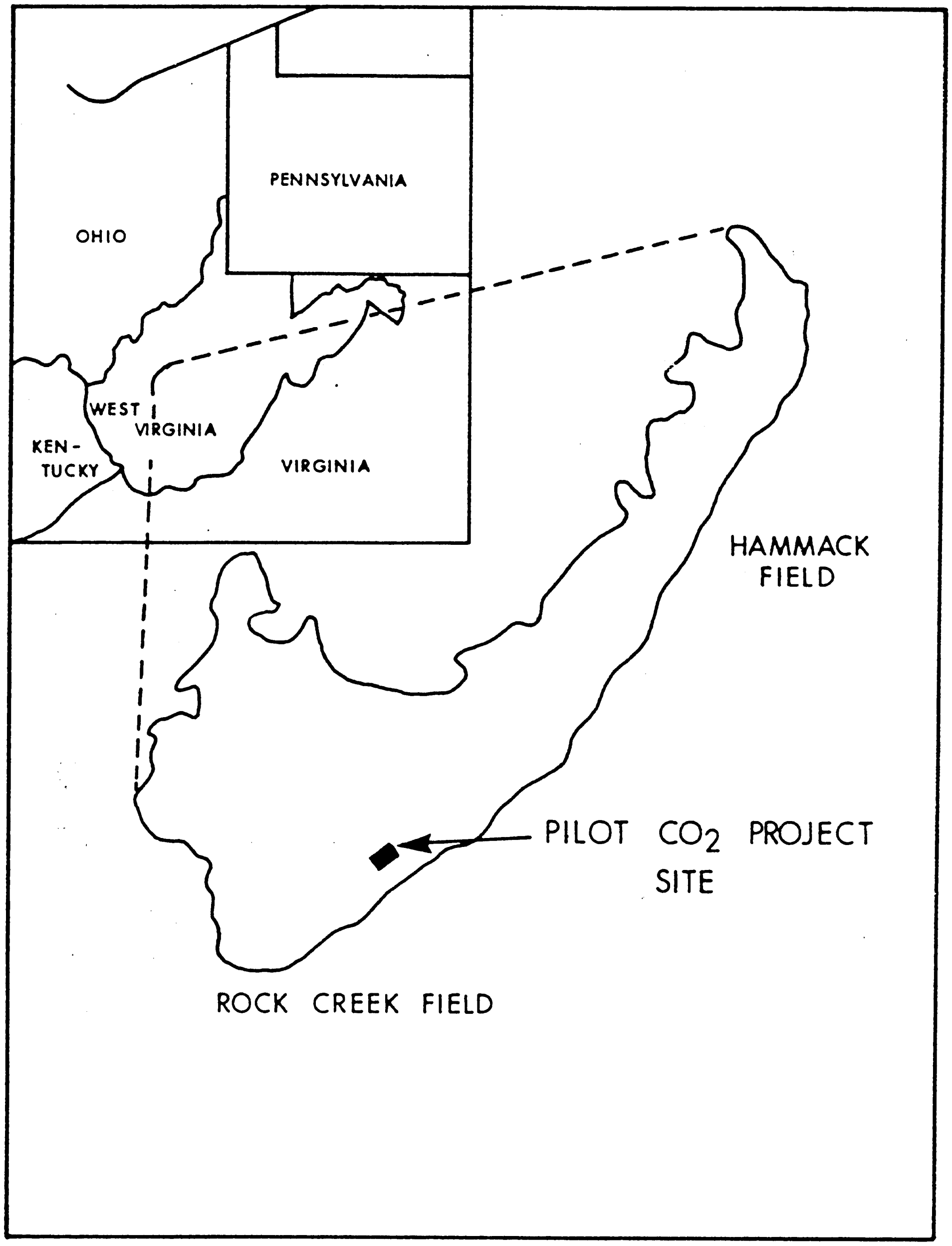


Figure 26.--Index map showing location of carbon dioxide injection project, Rock Creek field, West Virginia

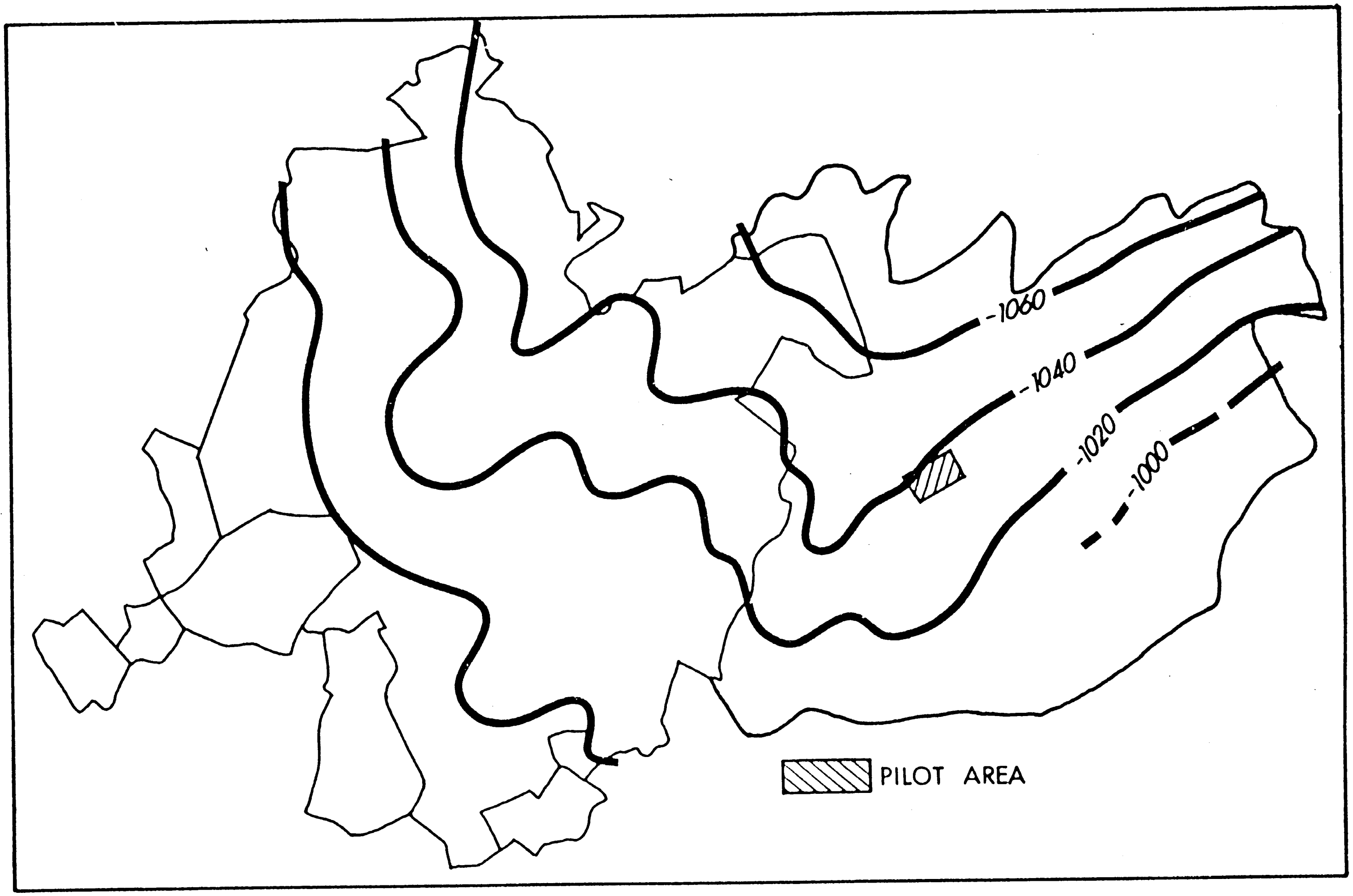


Figure 27.--Structure map on top of the Big Injun sand, Rock Creek field, West Virginia.

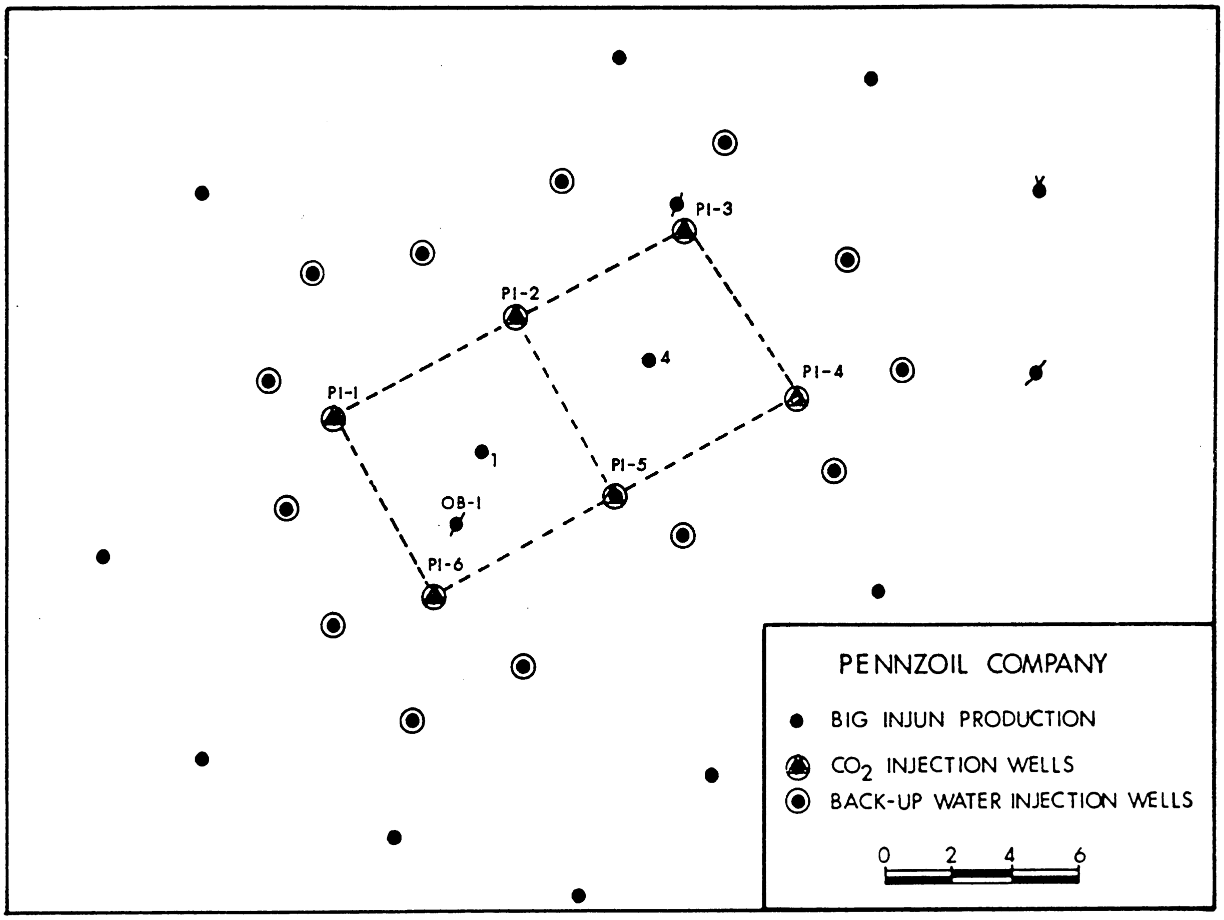


Figure 28.--Pilot CO_2 injection project, Rock Creek field, West Virginia.

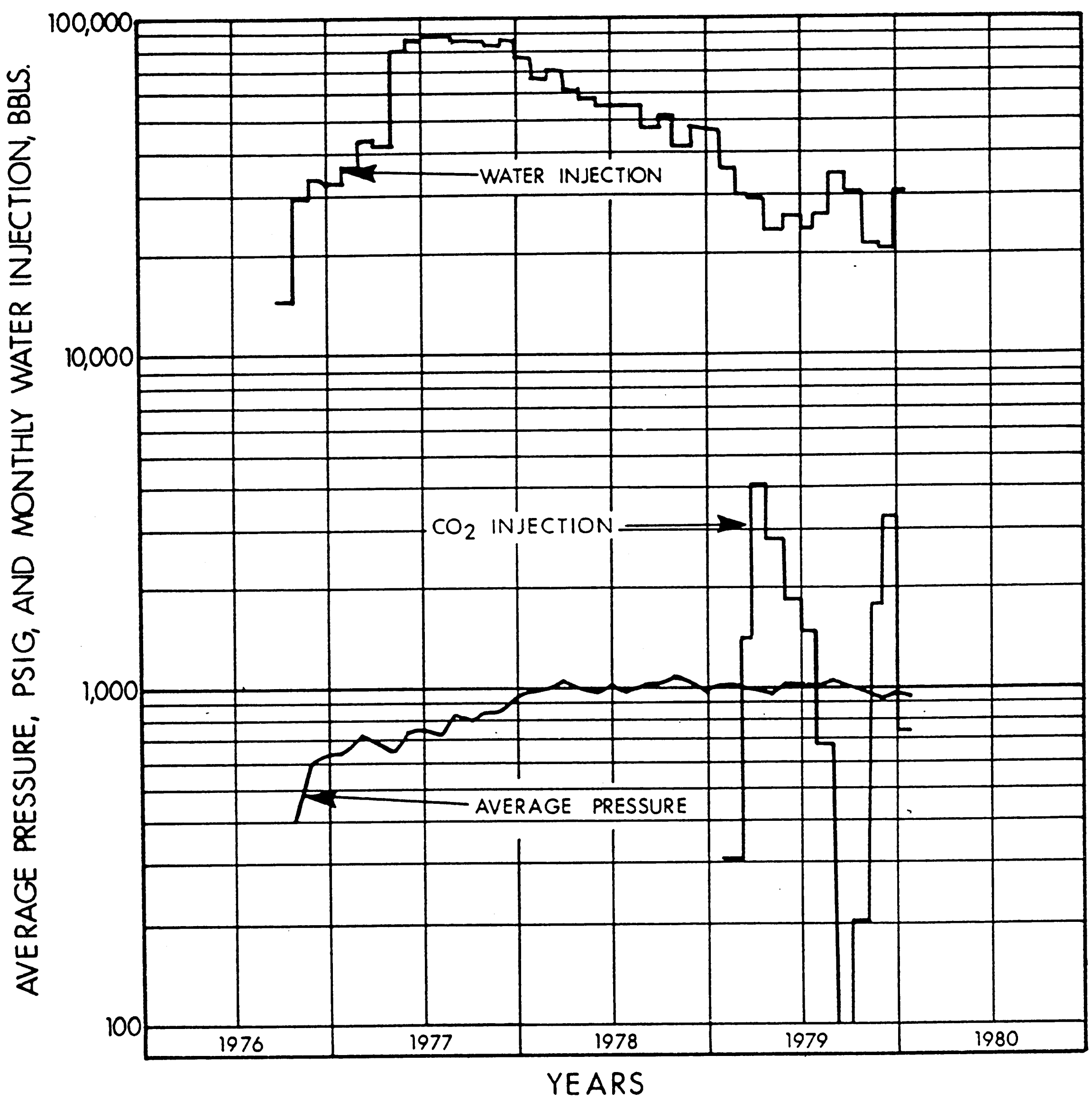


Figure 29.--Water injection history, CO_2 pilot project, Rock Creek field, West Virginia.

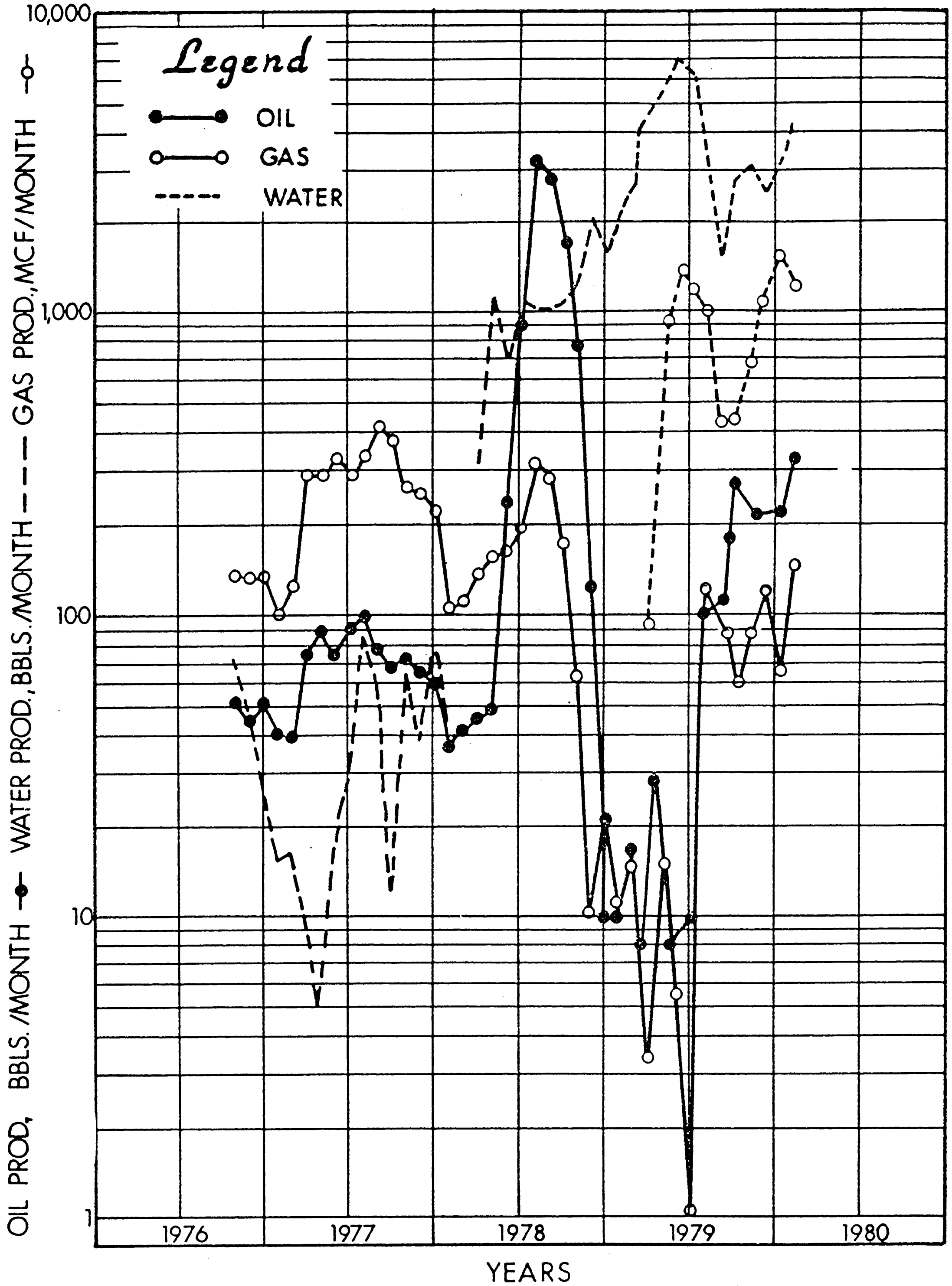


Figure 30.--Production history for two wells in the pilot CO_2 injection project, Rock Creek field, West Virginia.

CO_2 FIELD INJECTION TESTS CONDUCTED BY AMOCO OIL COMPANY SAN ANDRES RESERVOIRS, WEST TEXAS

by
Raj M. Kumar and Jerry A. Watson

SLAUGHTER FIELD, WEST TEXAS

Location and General History

Slaughter Field is located on the North Basin Platform in Cochran, Hockley, and Terry Counties in West Texas (Fig. 1). San Andres production is obtained from a depth of 4,950 feet. Slaughter is one of the largest fields in Texas, having 2,858 wells in a productive area of 87,250 acres. It was discovered in 1937 and through 1975 had produced 642,687,400 barrels of oil. Production during 1975 was 46,578,900 barrels. Amoco was named operator of the 5,704-acre Slaughter Estate Unit when waterflood operations were initiated in 1963.

The 6,413-acre Central Mallet Unit was formed in 1964 with Amoco as operator. A pilot project using enriched gas injection is under way in this unit.

Figure 3 shows the location of these units in Slaughter Field.

Geologic and Petrophysical Data

The San Andres, in the lower Guadalupe Series (Fig. 2) of the middle Permian system, is productive over a large area of West Texas, principally on the Central Basin Platform, the Northwest Shelf, and the North Basin Platform (Fig. 1). It is estimated that at least half the oil production in the entire Permian Basin is obtained from reservoirs of Guadalupe age [1].

Slaughter is adjacent to the Levelland Field and slightly downdip. It is separated from Levelland by a narrow region of non-porous carbonates. Production is obtained from porous intervals 700 to 800 feet below the top of the San Andres. Four zones of porosity development exist; one or two usually constitute the dominant pay.

The producing interval is an anhydritic dolomite. Core data from the Slaughter Estate Unit area indicate no fracturing or permeability orientation [3]. Porosity development is of the intercrystalline and microporosity types. The gross pay interval averages 149 feet thick in the Slaughter Estate Unit. Net pay is 89 feet, with an average porosity and permeability of 10 percent and 8.1 md, respectively.

Reservoir Fluid Data

Slaughter Field produces essentially by solution gas drive. Some of the important reservoir fluid properties at the original bottomhole pressure (1,710 psi) were:

Formation volume factor	1.228
Viscosity, cp	1.382
Gravity, °API	32

CO_2 Project Data

Amoco initiated a CO_2 pilot in Slaughter Estate Unit in November 1972. The pilot comprises two 6.6-acre five-spot patterns (Fig. 4). Water was injected into six injectors until August 1976 to ensure that the area had been completely watered out. Since then, acid gas (consisting of 30 percent H_2S and 70 percent CO_2) and water have been injected simultaneously into different wells; i.e., water is injected in three wells and gas in three, and injection is then alternated. The pilot requires 27 MMcf/D of acid gas, which is obtained from Amoco's Slaughter gasoline plant.

Figure 5 depicts the performance of the tertiary pilot. It is still too early for accurate evaluation of the project, although an oil production response is noticeable.

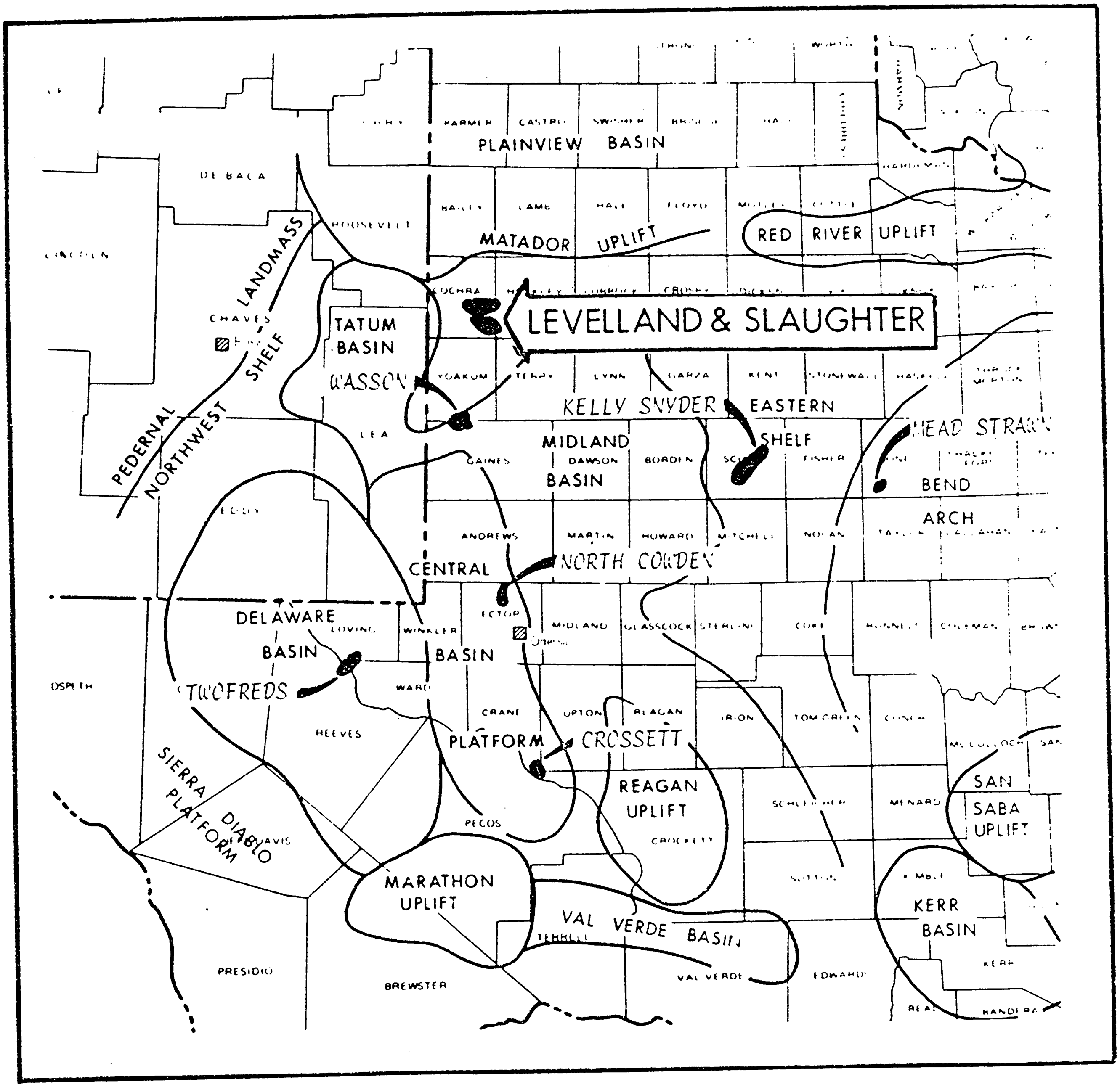


Figure 1.--Index map: carbon dioxide projects in west Texas.

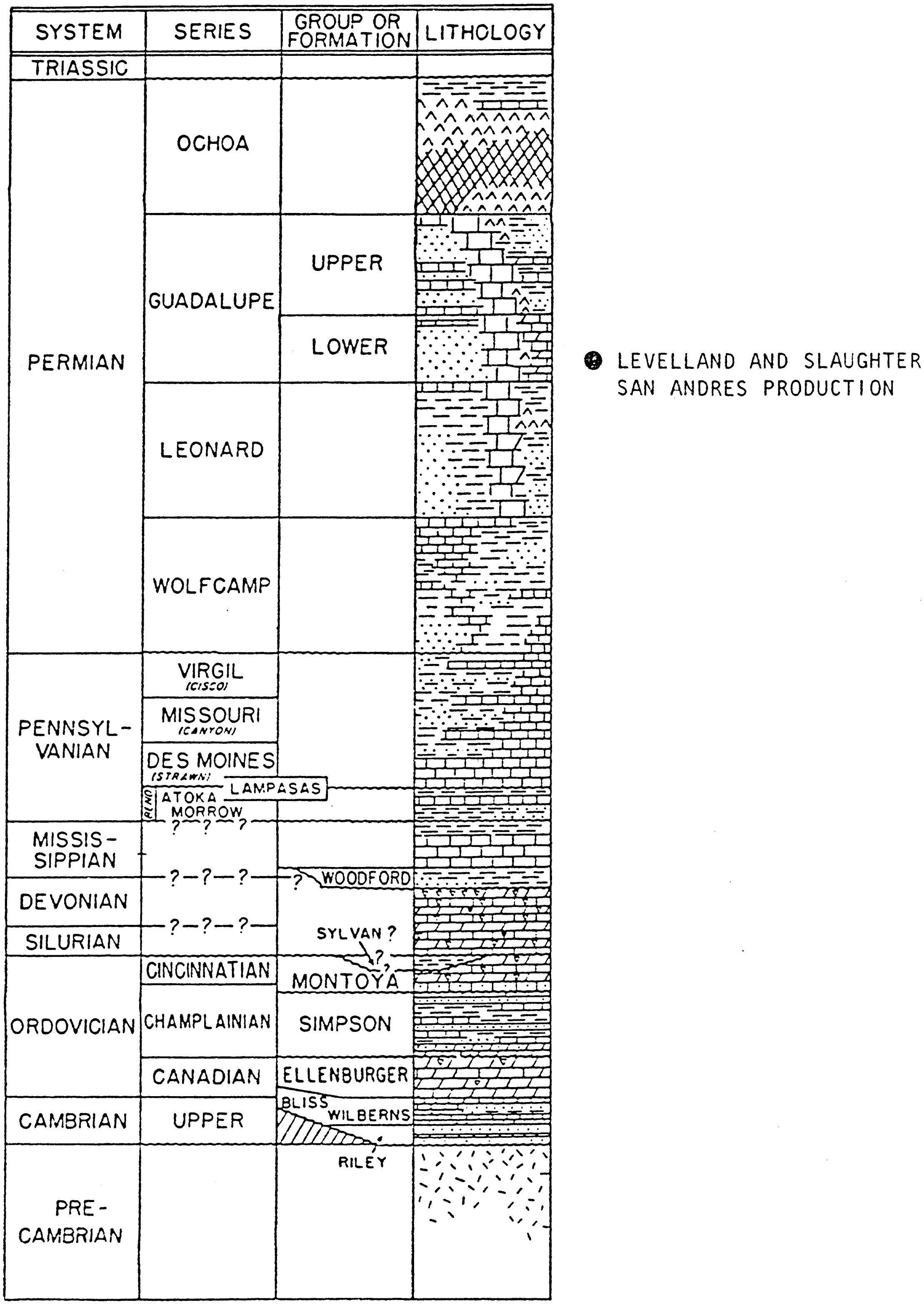


Figure 2.--Generalized stratigraphic column for west Texas.

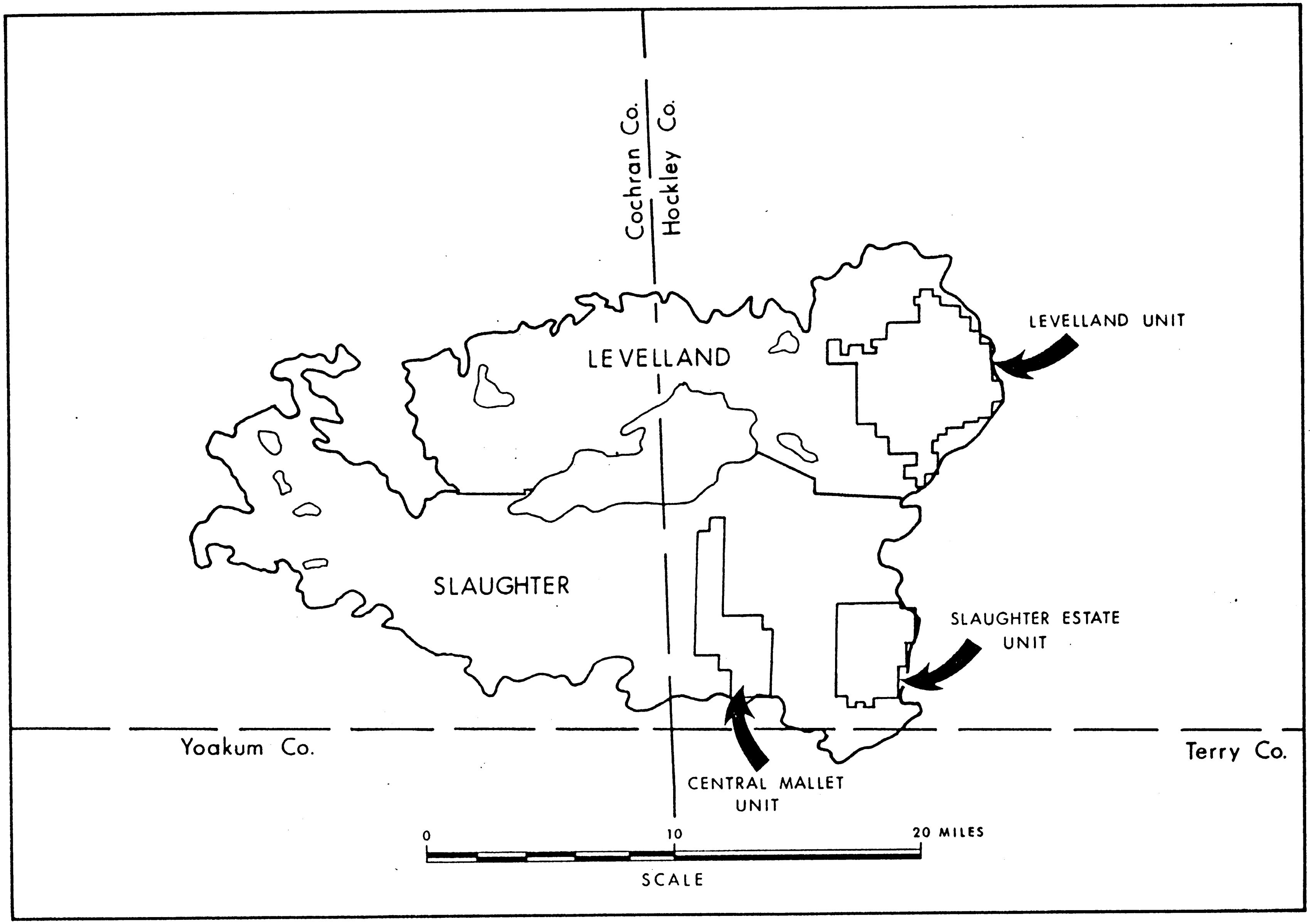


Figure 3.--Carbon dioxide injection projects in Levelland and Slaughter fields, Texas.

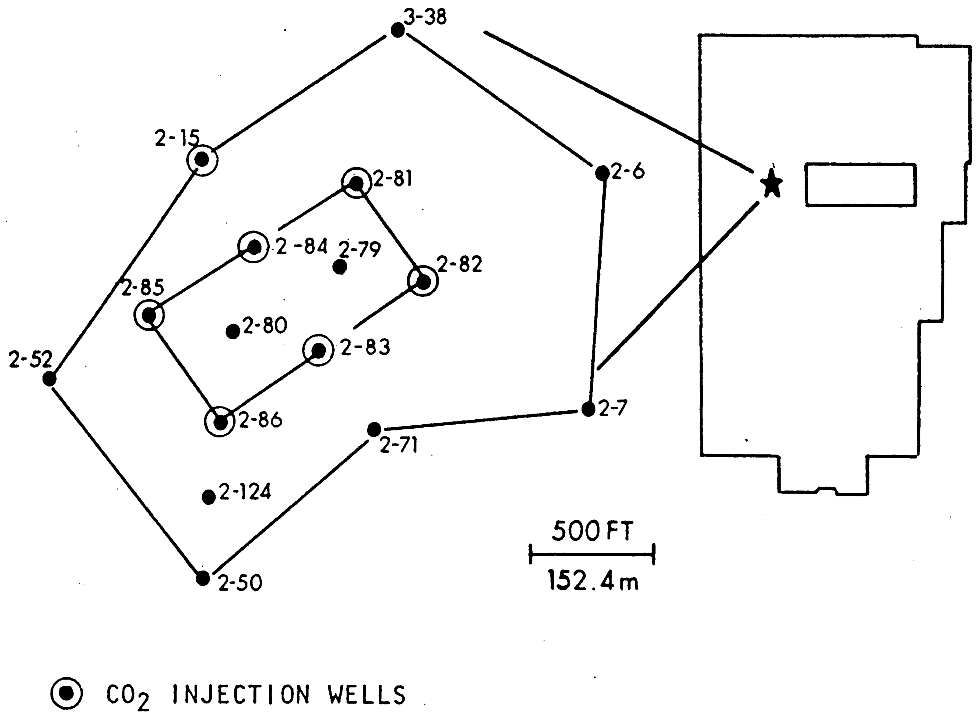


Figure 4.--Location and configuration of Slaughter Estate pilot carbon dioxide injection project, Slaughter field, Texas.

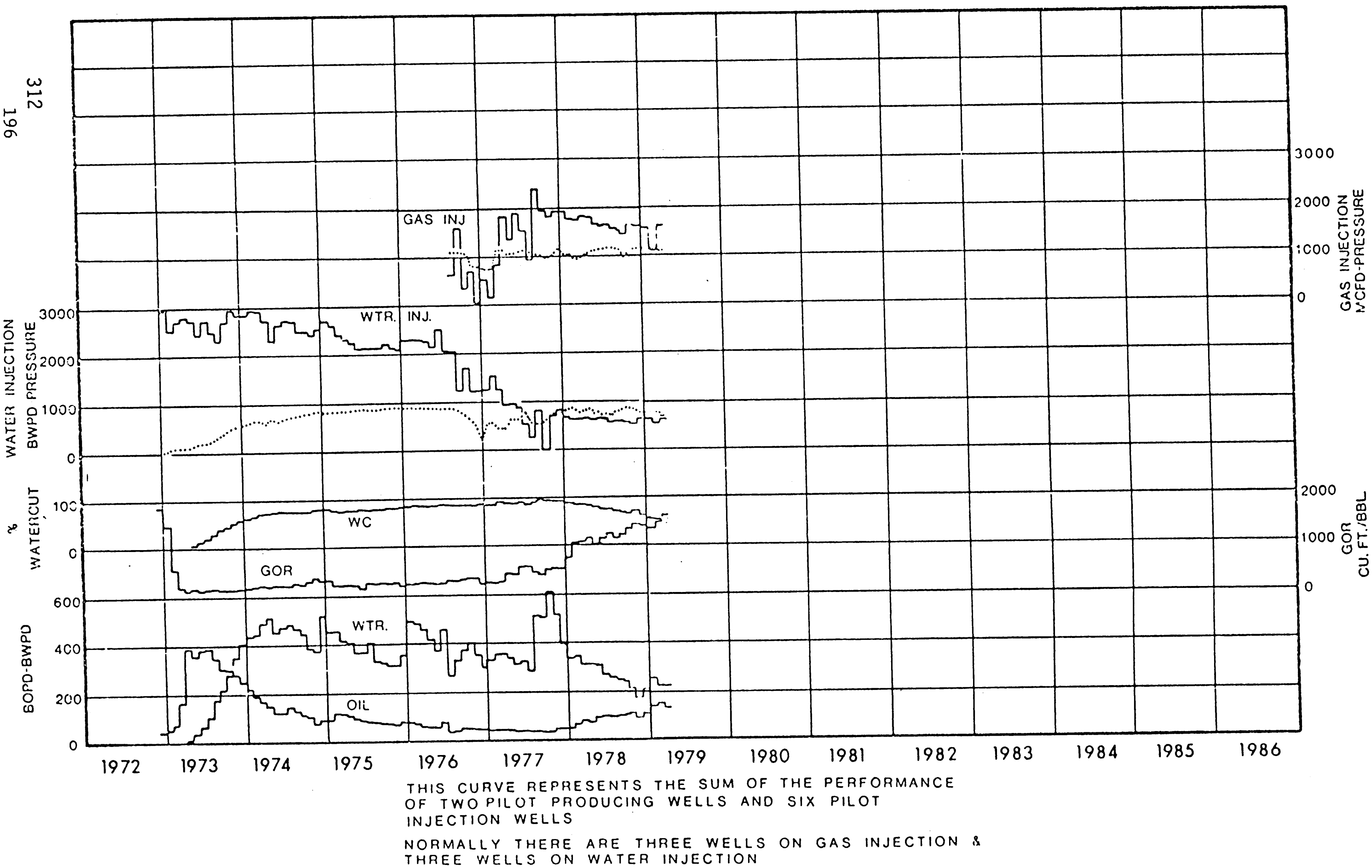


Figure 5.--Production history, Slaughter Estate pilot project, Slaughter field, Texas

LEVELLAND FIELD, WEST TEXAS

Location and General History

Levelland Field, discovered in 1945, is located in Cochran and Hockley Counties, West Texas, on the North Basin Platform (Fig. 1). Levelland is one of the largest fields in West Texas, producing from the San Andres, a middle Permian formation in the lower Guadalupe Series (Fig. 2). It is separated from the Slaughter Field by a narrow (often only a few locations wide) area of non-porous carbonates. The field produces from 1,690 wells in a productive area of 88,660 acres. San Andres production is obtained from a depth of 4,750 feet. Cumulative production to 1976 was 242,675,800 barrels; 1975 production was 13,977,300 barrels.

Figure 3 shows the location of the Levelland Unit in Levelland Field.

Geologic and Petrophysical Data

The pay zone in Levelland Field occurs at 800 to 900 feet below the top of the San Andres. Four zones of porosity development exist; usually a single zone is the primary pay.

The producing interval is a dolomite with varying amounts of anhydrite, shale, salt, and chert. In the area of the Levelland Unit, net pay is 80 feet. Over the entire field, the average gross pay is 180 feet. Porosity and permeability for the pay zone in the Levelland Unit are 11 percent and 3 md, respectively.

Reservoir Fluid Data

Some of the important reservoir fluid properties are:

Original formation volume factor	1.209
Original viscosity, cp	2.3
Gravity, °API	30

CO_2 Project Data

Levelland Pilot is identical with Slaughter Estate Pilot (two 6.6-acre five-spots). Figure 6 depicts the secondary performance of the tertiary pilot. CO_2 injection has not yet begun, although initial plans called for injection to start in mid-1977. The chronology of significant events is as follows:

March 1973	Waterflood began.
Aug.-Dec. 1977	Pulse tests.
Jan.-April 1978	Observation well drilled and completed to monitor saturation changes during pilot life.
February 1978	Short-term step rate tests performed.

June 1978	Injection bottomhole pressure increased from 2,600 to 2,850 psi.
Dec. 1978-Jan. 1979	Two fluid sampling wells drilled to monitor CO_2 and oil mixing zone growth between injector and producer.
January 1979	Two offset pilot wells returned to production at limited rates.

Figure 7 shows the predicted performance of the tertiary pilot. Evaluation at this stage is not possible.

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3. Faulkner, B. L., "Reservoir Engineering Design of a Tertiary Miscible Gas Drive Pilot Design," paper SPE 5539 presented at the SPE-AIME 50th Annual Fall Technical Conference and Exhibition, Sept. 28-Oct. 1, 1975.

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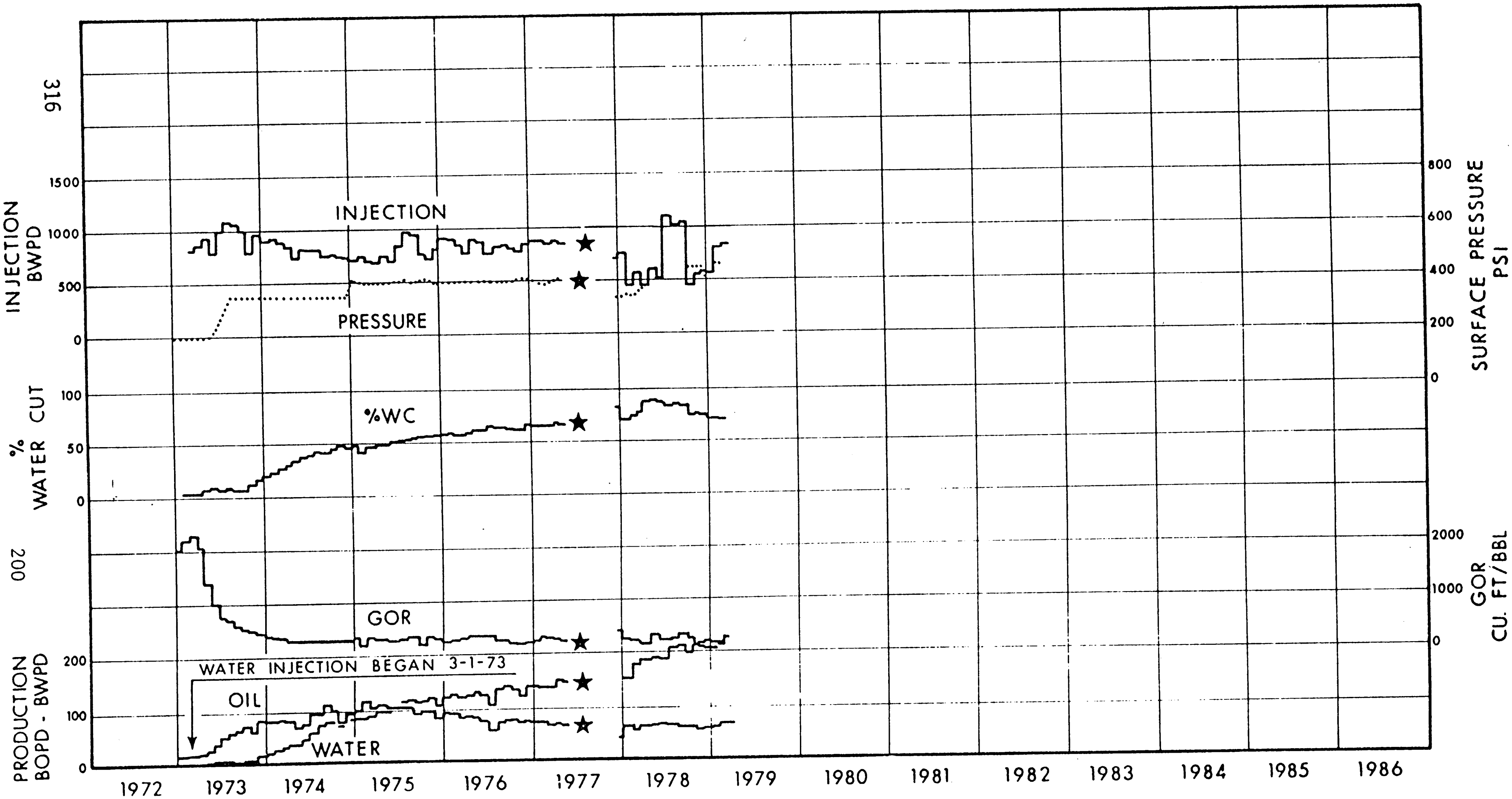

THIS CURVE REPRESENTS THE SUM OF THE PERFORMANCE OF TWO PILOT PRODUCING WELLS AND SIX INJECTION WELLS

★ S.I. DUE TO PULSE TESTING STARTING AUG. 23 TO DEC. 15

Figure 6.--Production history, Levelland unit tertiary pilot (secondary performance), Levelland field, Texas.

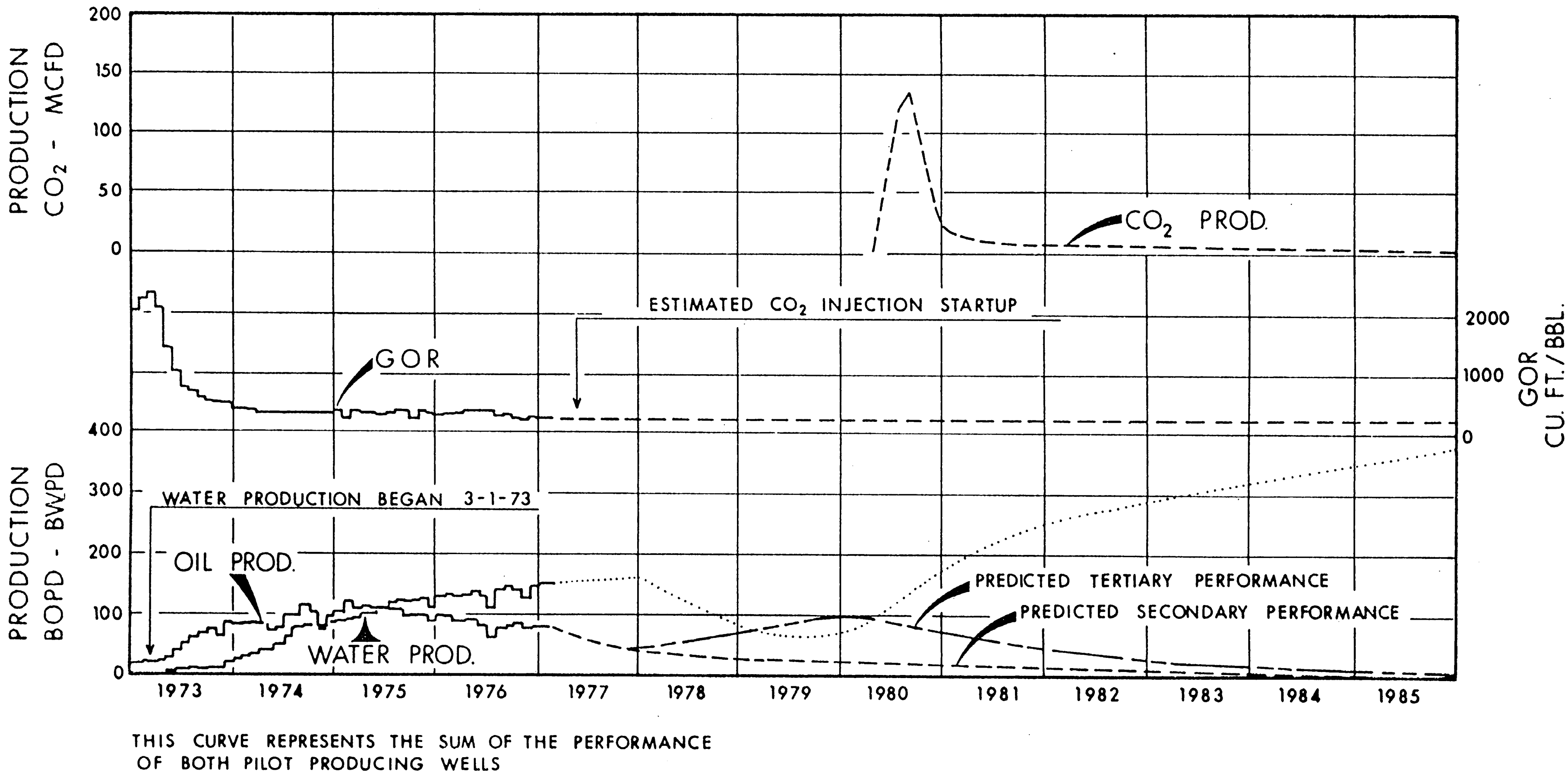

Figure 7.--Predicted performance for the Levelland unit tertiary pilot, Levelland field, Texas.

CO_2 TERTIARY RECOVERY FIELD PILOT
LITTLE CREEK FIELD
PIKE COUNTY, MISSISSIPPI

by
John H. Goodrich and Jerry A. Watson

Location and General History

Little Creek field, discovered in 1958, is located in Pike County in southwest Mississippi (Fig. 1). The field produces from the lower Cretaceous Tuscaloosa formation at an average depth of 10,600 feet. The field was essentially developed by 1961, with 155 producers on 40-acre spacing. Thirty-five dry holes defined a productive area of approximately 6,200 acres. The field was produced by primary methods from 1958 to 1962 and was unitized for waterflooding in 1962 with Shell Oil Company as operator. Water injection was discontinued in 1970. An estimated 55 million barrels of oil remained after completion of primary and secondary operations. Shell instituted a pilot project in 1973 to evaluate CO_2 miscible displacement as a tertiary recovery technique.

Geologic and Petrophysical Data

Regionally, structural dip is toward the coast. The sediment wedge thickens southward into the Gulf Coast geosyncline. Production is obtained from the Denkman sand in the lower Tuscaloosa formation (Fig. 2). The areal structure is a north-south trending nose with maximum dips of 2° on the flanks [1]. Closure on the structure is less than 40 feet, and with an oil column of almost 100 feet, stratigraphy is the controlling entrapment mechanism as the producing sand interval pinches out across the crest of the structure. Figure 3 is a structural map contoured on a horizon just above the main producing interval. The field is composed of a north segment and a south segment joined by a narrow band of production.

Average net pay in the field is 29 feet. The main pay is the "Q" sand, ranging in thickness up to 40 feet (Fig. 4). Lateral continuity of the moderately well cemented, argillaceous sandstone is good. The sand is interpreted as a series of alluvial sand bars deposited in an ancient river system. A discontinuous lower sand, "Q2," lies just below the "Q" sand in some parts of the field (Fig. 5). On the basis of pressure behavior and floodout performance, the two sands appear to be a common reservoir.

A typical electric log from the field is shown in Fig. 6. Only the "Q" sand is shown on this particular log. Resistivity is unusually low, and the water saturation correspondingly high, as shown in Table 1. High connate water saturations are characteristic of Tuscaloosa sands in this area, and are apparently the results of clay coatings on the sand grains [1]. Average porosity of the pay is 23 percent and average permeability is 90 md.

Reservoir Performance Data

Initial reservoir conditions and fluid properties are given in Table 2. These data show that the reservoir oil was initially at a pressure of 4,840 psi while its bubble-point pressure was 2,150 psi. Hence there was no primary gas cap and the pressure could decline considerably before free gas would be evolved in the reservoir. Volumetric and material balance calculations indicated initial oil in place was 102 million stock tank barrels.

Field-wide primary and waterflood production and pressure history data are shown in Fig. 7. Water injection, begun in 1962, obviously repressured the reservoir and reversed the increasing gas/oil trend. Waterflooding was conducted as a peripheral line drive and is credited with increasing oil recovery from the field by 21.7 million stock tank barrels [2]. Water injection operations were discontinued in February 1970. Production continued from a declining number of wells and was minimal by 1977, when cumulative primary and secondary recovery totaled 46.8 million barrels. This left some 55 million barrels of original stock tank oil as a target for tertiary recovery.

CO_2 Project Data

A tertiary recovery CO_2 injection pilot project was begun by Shell Oil Company, operator of the unit, during 1973 [2]. The pilot utilized existing wells on field-scale spacing and was located in an area of the field where sand pinchout provided east and south confining boundaries (see Fig. 4). As shown in Fig. 8, the pilot formed a quarter symmetry element of an inverted nine-spot pattern, with a central CO_2 injection well (1-10) offset by three production wells (1-6, 1-7, 1-11). Confinement to the west and north was provided by five water injection wells (1-2, 1-3, 1-4, 1-5, and 1-12) exterior to the producers. Reservoir and fluid data for the pilot area are listed in Table 3. The waterflood residual oil saturation, only 21 percent of pore space, seems especially significant.

The original operating plan provided for initial water injection to increase pilot area reservoir pressure from the existing 4,400 psig to approximately 5,500 psig [2]. At this pressure, pilot producers would flow even while producing pure formation water. In addition, pressure would be well above the indicated miscibility pressure of 4,500 psig. CO_2 would then be injected into well 1-10 while water injection continued (for pilot confinement) in the five peripheral water injectors.

This plan was implemented during August and September 1973. Pilot area pressure averaged about 5,500 psig after a cumulative injection of 185,000 barrels of water. Water injection was discontinued at this point, during November 1973. By January 1974, reservoir pressure in the pilot area had declined to 5,100 psig as a result of fluid expansion into the surrounding reservoir during the time water injection was suspended.

Injection of purchased CO_2 began in February 1974. Shortly afterward, in March and April 1974, the pilot producing wells were placed on flowing production. During May 1974, each produced 100 percent formation water at average daily rates as follows:

Well 1-6	346 B/D
1-7	164
1-11	206

First oil response was noted in Well 1-11 on June 5, 1974, when the well tested 3 BOPD with 223 BWPD. This response increased to 87 BOPD with 193 BWPD by mid-July. At that time, producing gas-oil ratio was 4,000 scf/bbl with 85 percent CO_2 in the gas. To avoid venting large volumes of CO_2 and to promote fluid movement to the other producers, Well 1-11 was shut in July 11, 1974. Thereafter, this well was produced only for short test periods until March 1975, when recycle gas facilities became operational. Oil response was observed in Well 1-7 on August 30, 1974, and in Well 1-6 on September 3, 1974. In November 1974, a series of well problems occurred that significantly curtailed operations.

Producers were down 50 percent of the time until April 1975. Thereafter, full-scale pilot operations, including produced gas recycling, were resumed. Individual producing well responses during the period from pilot initiation to mid-1977 are shown in Figs. 9 through 11. The oil rate and water cut data for these wells clearly indicate banking and movement of tertiary oil.

Composite production and injection statistics for the pilot operation are shown in Fig. 12. The impact of reduced operations during late 1974 and early 1975 is clearly evident. After restoration of full-scale operations, oil production from the pilot peaked in October and November 1975 at an average rate of 195 B/D. Thereafter, oil production declined more or less exponentially as gas/oil ratios continued to increase. Produced CO_2-contaminated gas was recycled beginning in March 1975 and gradually became the predominant injection gas, as shown in Fig. 13. Injection of purchased CO_2 ended on January 19, 1977, and recycle gas injection (90+% CO_2) was terminated on February 23, 1977. Total gas injection statistics are as follows:

Purchased CO_2	1,589,899 Mcf
Recycle gas	1,782,907 Mcf
Total injected	3,372,806 Mcf

This gas was injected as a continuous slug that represented approximately 1.6 hydrocarbon pore volumes of the pilot area [3].

After termination of gas injection, the CO_2 injection well 1-10 and the pilot producer 1-11 were converted to water injection while Wells 1-6 and 1-7 continued to produce. Cumulative production data from all wells through July 1, 1977, is listed in Table 4. These data show that a total of 122,000 barrels of oil were produced to this time, when Well 1-6 was essentially producing only water (Fig. 9). Later data indicate an additional 2,000 barrels of oil was later produced from Well 1-7 through March 1978, for a total pilot cumulative production of 124,000 barrels, or 62 percent of residual oil in place [3]. Cumulative CO_2/oil ratios based on this are 12.8 Mcf/bbl purchased and 27.1 Mcf/bbl total (including recycle). These data show that CO_2 injection was technically successful in mobilizing, banking, and moving waterflood residual oil that occupied only 21 percent of pore space. However, the high CO_2/oil ratios cast doubt on the economics of full-scale operation. Further studies are now in progress [3].

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1. Cronquist, C. R.: "Waterflooding by Linear Displacement in Little Creek, Mississippi." J. Pet. Tech., May 1968, p. 525-535.

2. Hansen, P. W.: "A CO_2 Tertiary Recovery Pilot, Little Creek Field, Mississippi," paper SPE 6747 presented at the SPE/AIME 52nd Annual Fall Technical Conference and Exhibition, Denver, Oct. 9-12, 1977.

3. Youngren, Gary K., and Charlson, Gary S.: "History Match Analysis of the Little Creek CO_2 Pilot Test," paper SPE 8200 presented at 54th SPE/AIME Annual Fall Technical Conference and Exhibition, Las Vegas, Sept. 23-26, 1979.

TABLE 1

LITTLE CREEK FIELD
ROCK AND FLUID SATURATION DATA

Fluid saturations	
Initial oil saturation	
above transition zone	0.44
transition zone	0.30
weighted average	0.41
Waterflood residual oil saturation	
above transition zone	0.22
transition zone	0.19
weighted average	0.21
Rock properties	
Porosity	0.234
Air permeability	90 md
Oil permeability at initial oil saturation	45 md
Water permeability at residual oil saturation	9 md

TABLE 2

LITTLE CREEK FIELD
INITIAL RESERVOIR CONDITIONS AND FLUID PROPERTIES

Reservoir conditions @ 10,375 ft subsea	
Initial pressure	4840 psi
Temperature	248°F
Oil properties	
Bubble-point pressure	2150 psi
Gas-oil ratio	555 scf/STB
Tank oil gravity	39°API
Formation volume factor	1.32 RB/STB
Viscosity @ P_i	0.40 cp
@ P_b	0.30 cp
Connate water properties	
Salinity	170,000 ppm
Viscosity	0.37 cp
Density	1.07 gm/cc

TABLE 3

LITTLE CREEK FIELD
RESERVOIR AND FLUID DATA

Pilot area	31 acres
Pilot volume	693 NAF
Residual OOIP in pilot	200 M STB
Porosity	0.234
Average residual oil saturation	0.210
Initial oil saturation	0.440
Permeability (reservoir geometric mean)	33 md
Initial reservoir pressure	4840 psia
Reservoir temperature	248°F
Original bubble-point pressure	2150 psia
Gas/oil ratio	555 scf/STB
Oil gravity	39°API
Formation volume factor at P_i	1.32 RB/STB
Oil viscosity at P_i	0.40 cp
Oil viscosity at P_b	0.30 cp

TABLE 4

LITTLE CREEK FIELD
PRODUCTION AND INJECTION DATA TO JULY 1, 1977

	Production		
Pilot Well	Oil bbl	Water bbl	Gas Mcf
1-2	-	51,083	-
1-6	42,523	578,175	644,554
1-7	61,796	180,692	996,489
1-11	17,880	113,956	568,683
Total	122,199	923,906	2,209,726

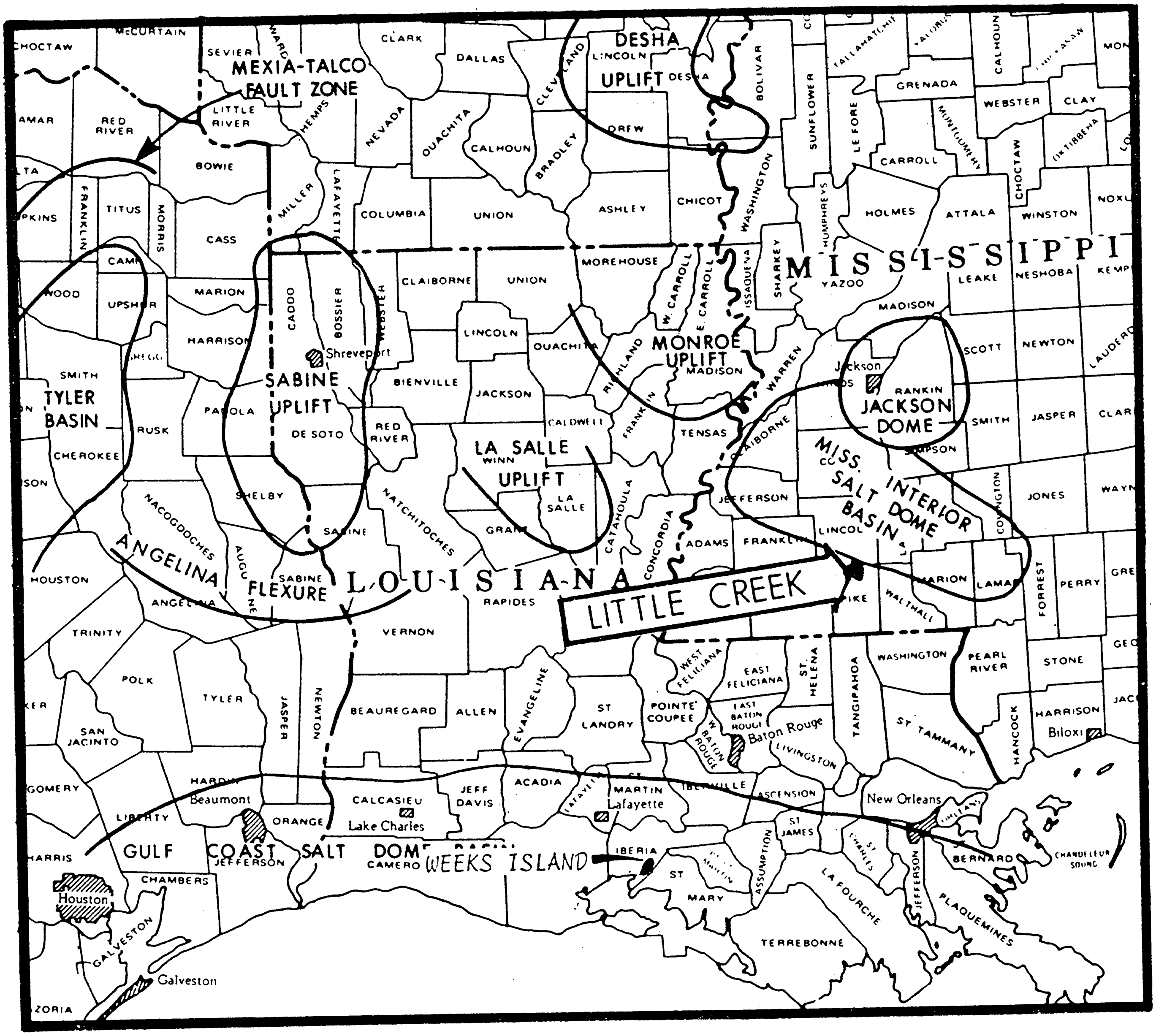

Figure 1.--Index map: carbon dioxide projects in the Gulf Coast region.

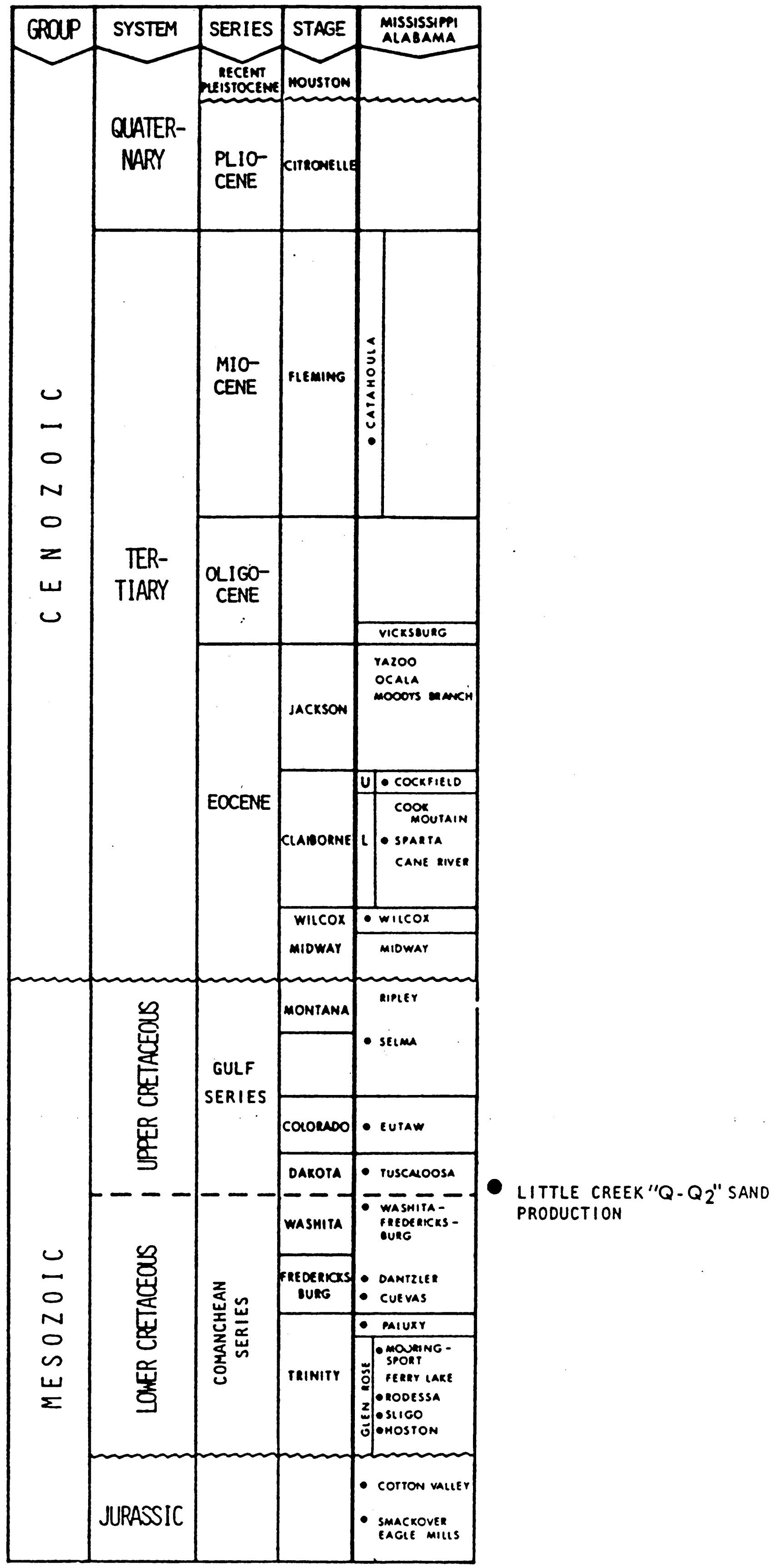

Figure 2.--Generalized stratigraphic column for the Gulf Coast.

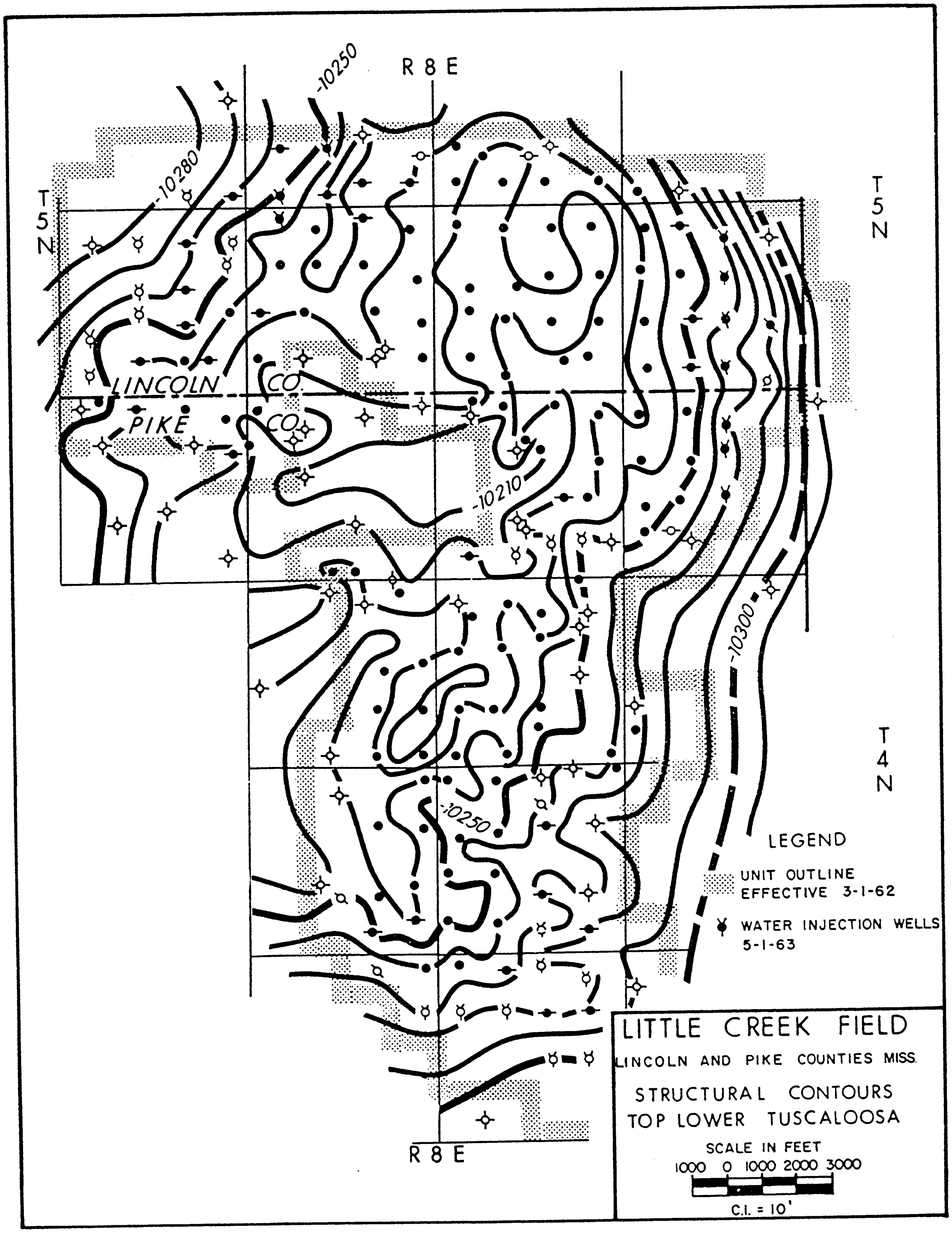

Figure 3.--Structure on top of the Lower Tuscaloosa, Little Creek field, Mississippi.

Figure 4.--Net Q sand oil pay, Little Creek field, Mississippi.

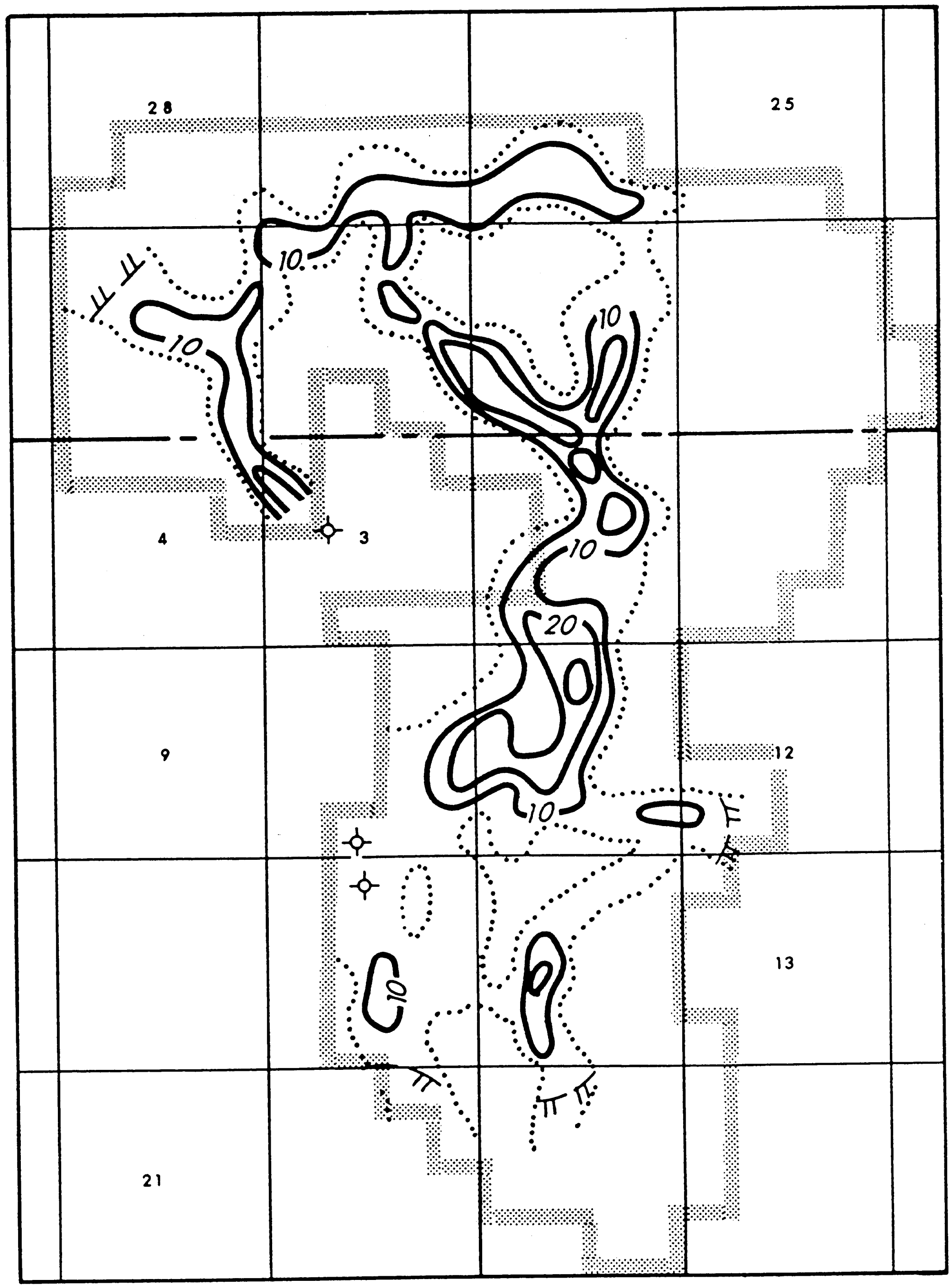

Figure 5.--Net Q2 sand oil pay, Little Creek field, Mississippi.

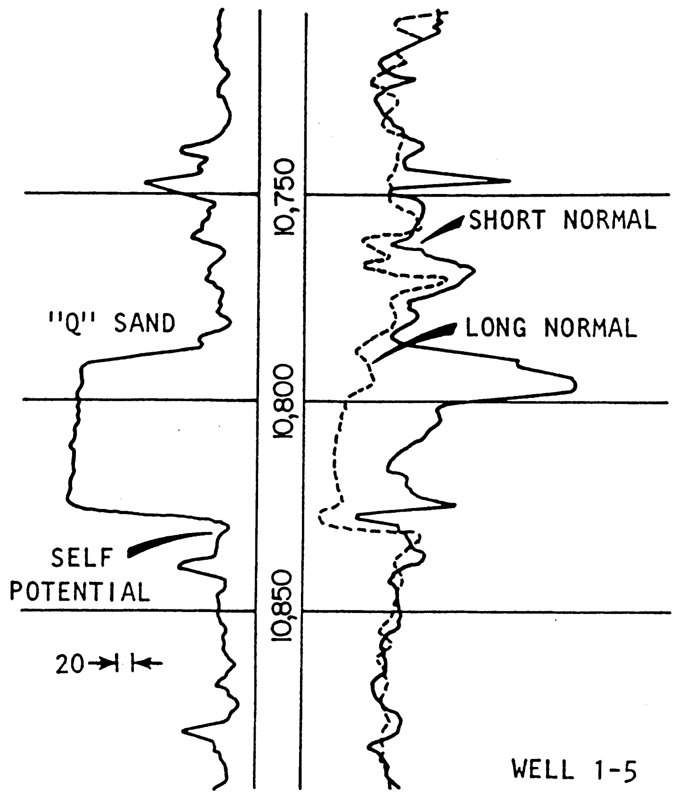

Figure 6.--Typical electric log from the Little Creek field, Mississippi.

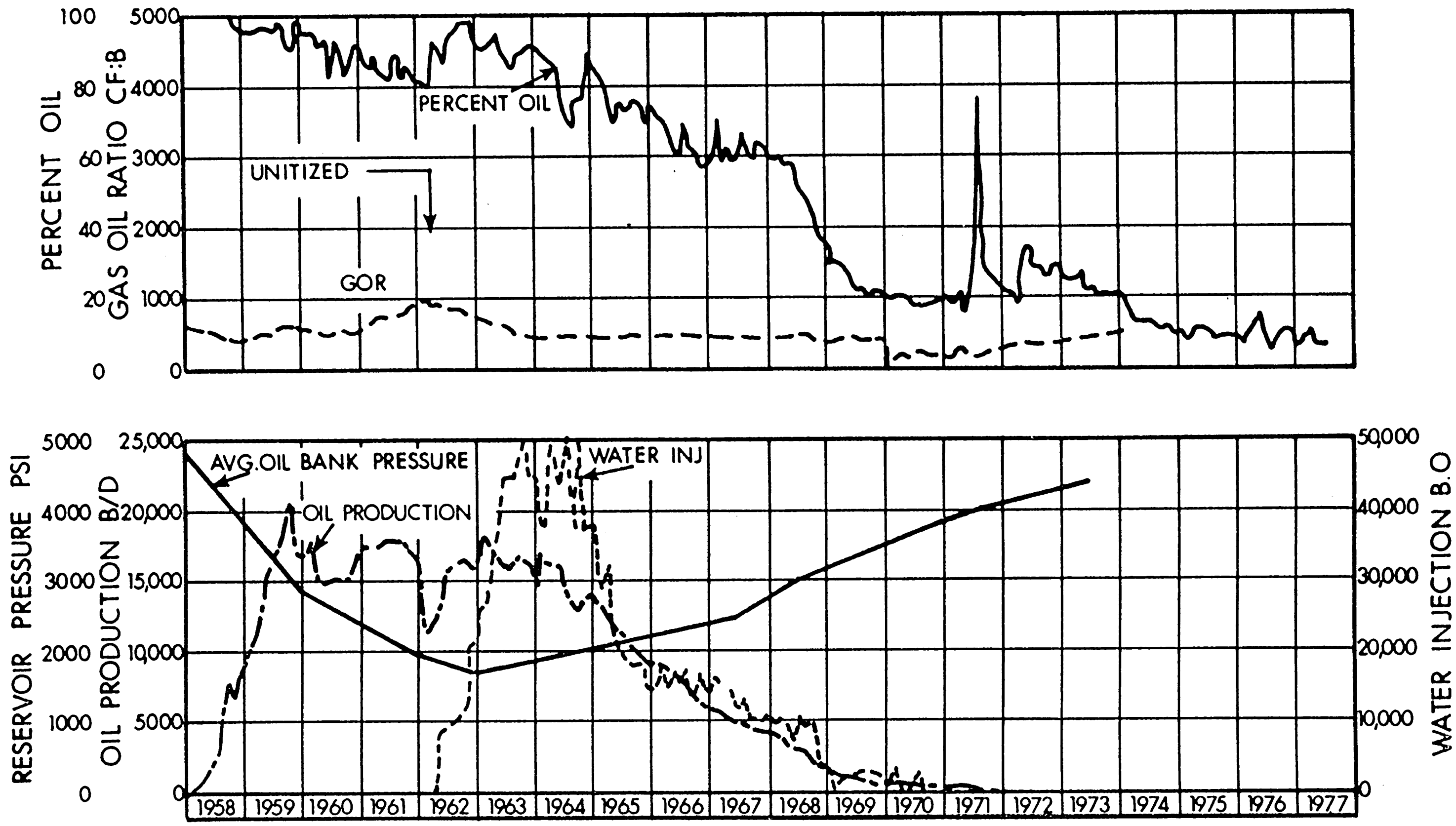

Figure 7.--Production history, Little Creek field, Mississippi.

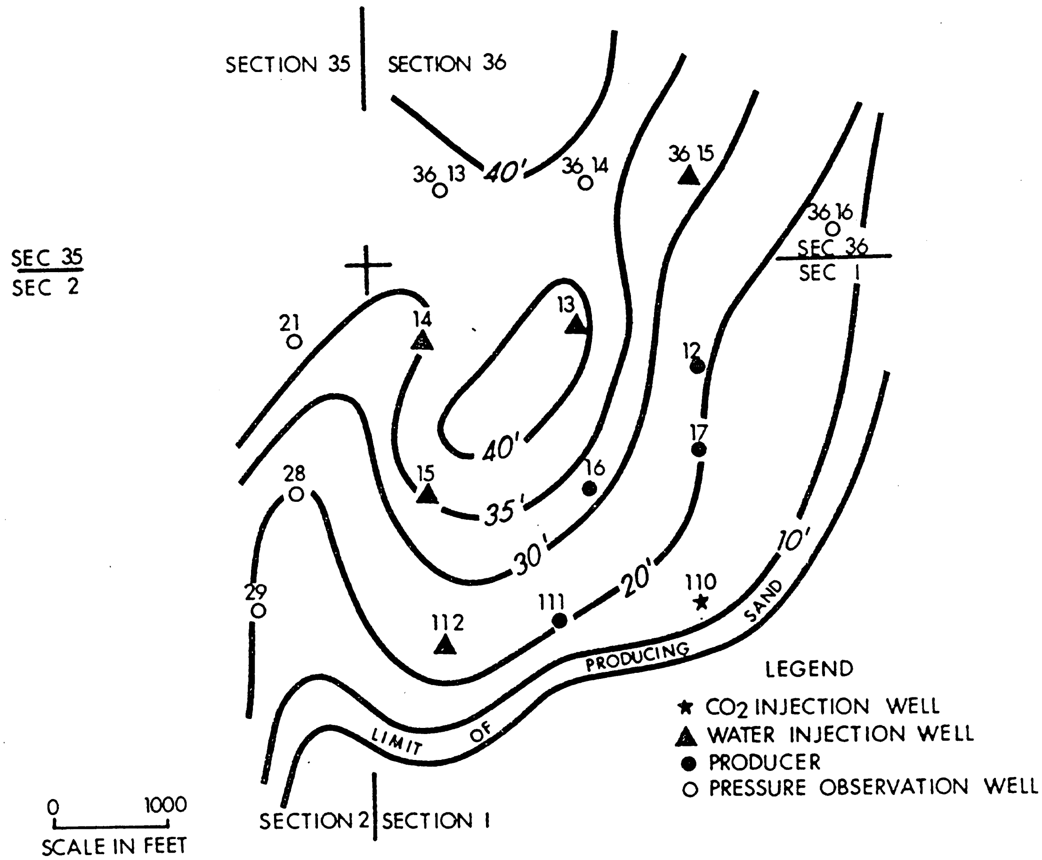

Figure 8.--Net pay isopach, CO_2 pilot area, Little Creek field, Mississippi.

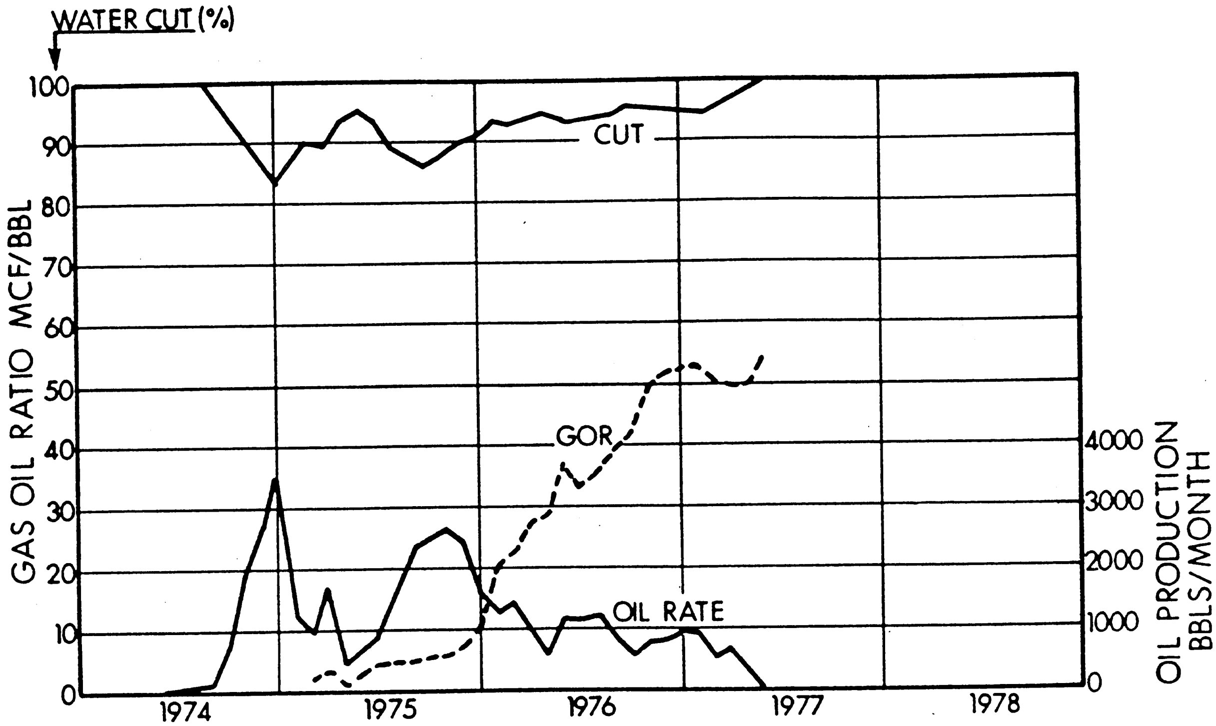

Figure 9.--Performance history, pilot producer Well 1-6, Little Creek field, Mississippi.

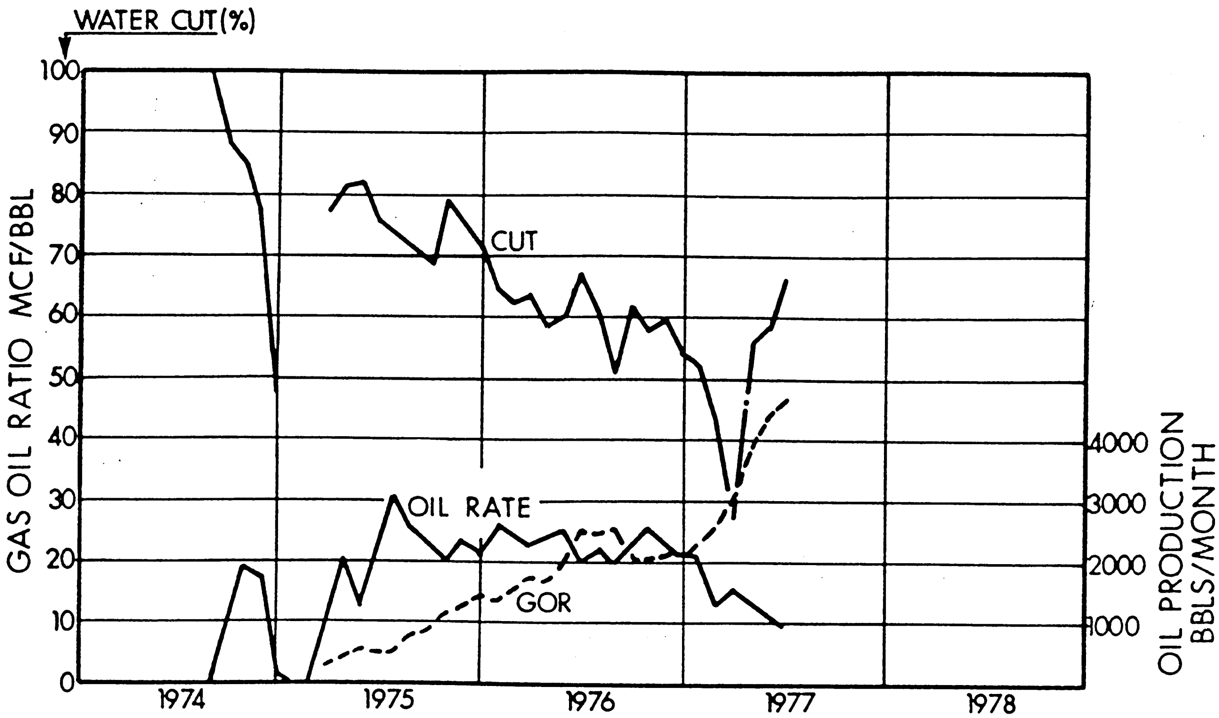

Figure 10.--Performance history, pilot producer Well 1-7, Little Creek field, Mississippi.

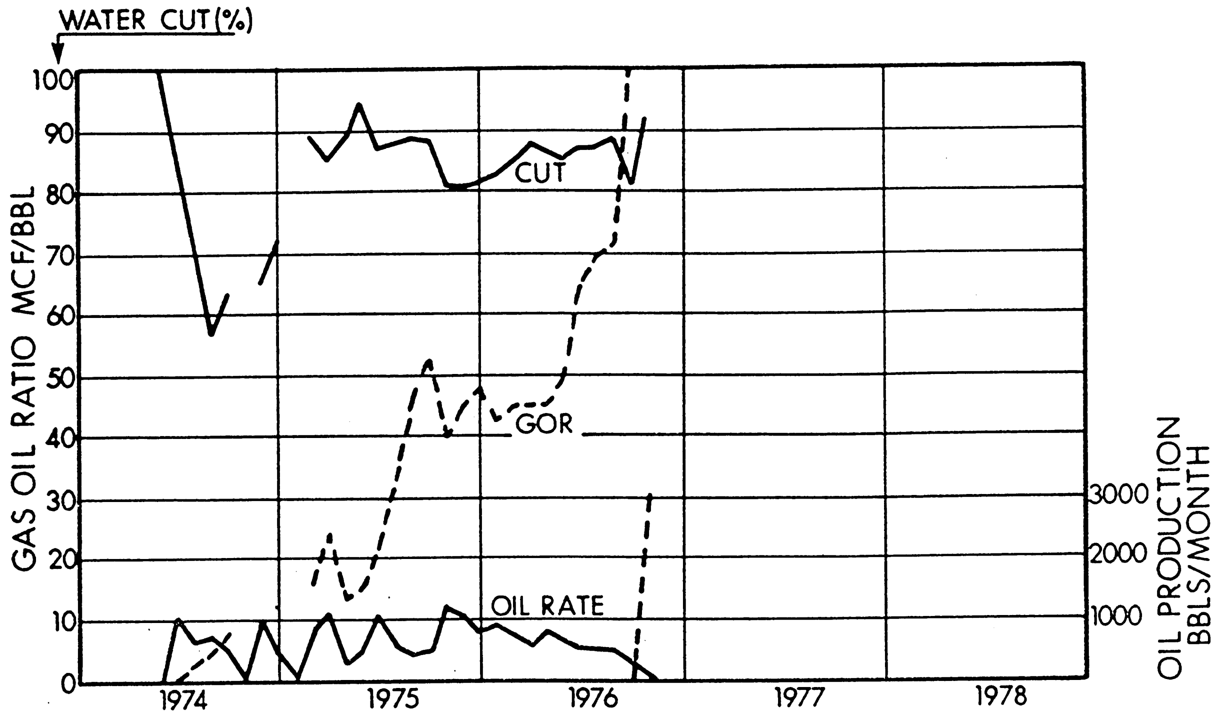

Figure 11.--Performance history, pilot producer Well 1-11, Little Creek field, Mississippi.

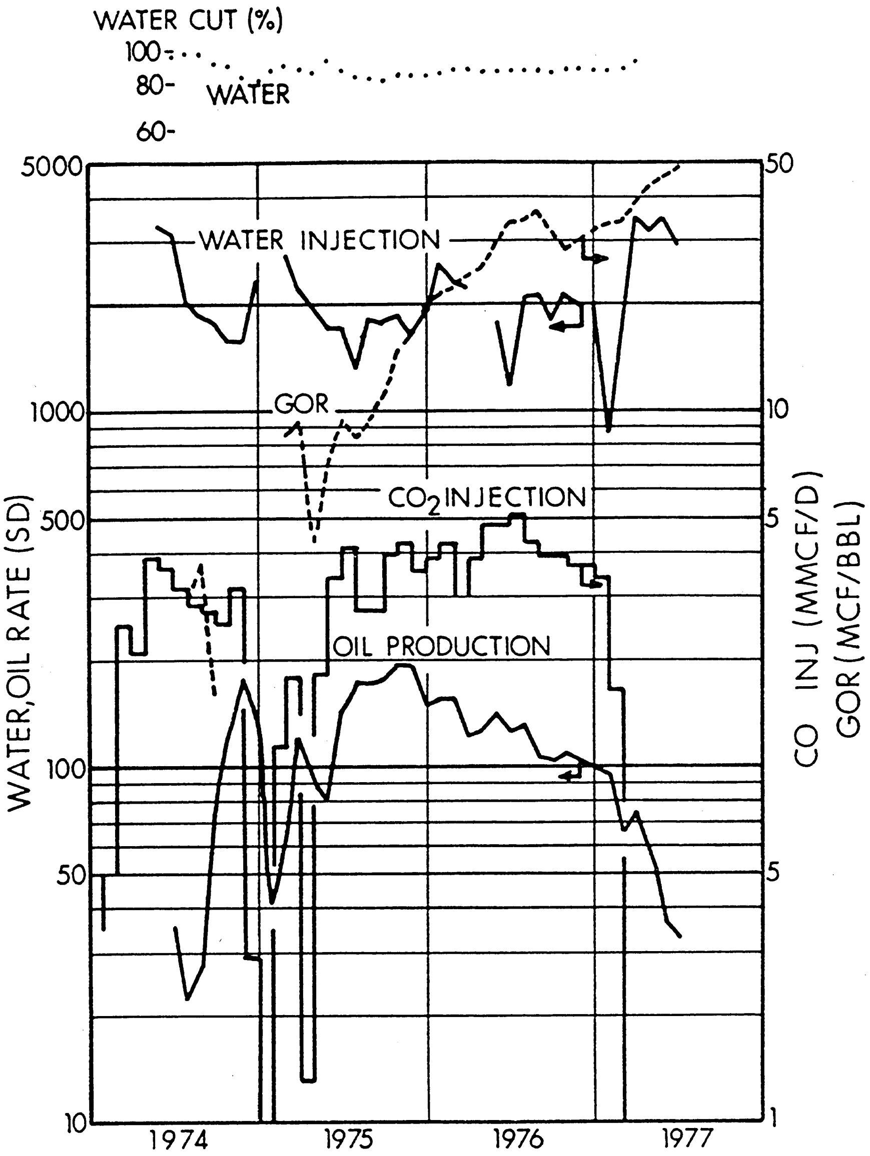

Figure 12.--Performance history, CO_2 pilot project, Little Creek field, Mississippi.

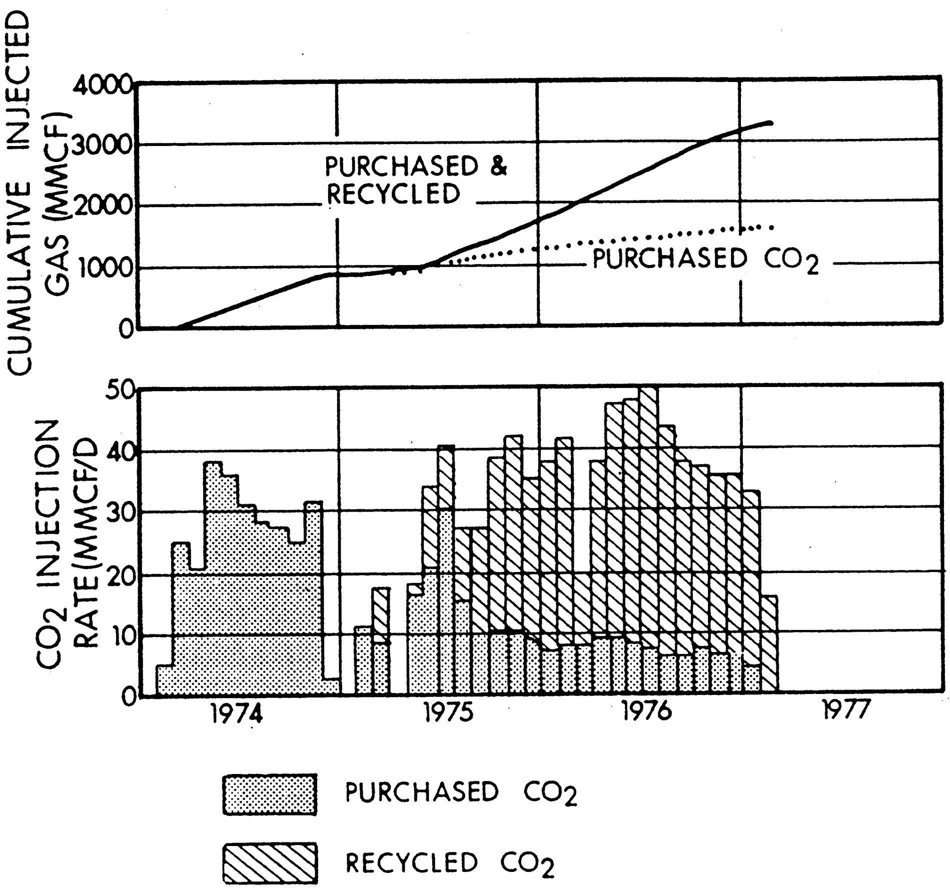

Figure 13.--CO_2 and produced gas injection, pilot project, Little Creek field, Mississippi.

CO_2 FIELD INJECTION PROJECT CONDUCTED BY UNION OIL COMPANY OF CALIFORNIA MEAD FIELD, STRAWN UNIT, JONES COUNTY, TEXAS

by
Raj M. Kumar and Jerry A. Watson

Location and General History

Mead Field is located in Jones County, on the eastern margin of the Permian Basin in West Texas (Fig. 1). The Strawn unit produces from sands at 4,500 and 4,900 feet; wells are completed in either or both of the pay zones. The field was discovered in 1951. Cumulative production through 1975 was 1,105,028 barrels of oil; production during 1975 was 10,835 barrels from 10 producing wells in a project area of 1,000 acres. Estimated original oil in place is 4,585,000 barrels [1]. The field was unitized in 1964 with Union Oil Company of California as operator. Secondary recovery by conventional waterflood was applied to the lower zone and to a portion of the upper zone. A CO_2 pilot test was performed on an area comprising 44 acres.

Geologic and Petrophysical Data

Mead Field produces from upper and lower Strawn sands of upper Pennsylvanian age (Fig. 2). The field is located on the Bend Arch, a north-south oriented positive feature adjacent to the eastern shelf of the Permian Basin. Figure 3 illustrates the relationship of the eastern shelf and Bend Arch (Mead is located in Jones County), and shows the thinning of upper Pennsylvanian and Permian sections on the eastern margin of the Permian Basin.

The upper Pennsylvanian structure in the region is monoclinal, having a west-northwestly dip of 80 to 100 feet per mile. A structure map on top of the upper Strawn pay zone in Mead Field (Fig. 4) reflects the regional dip.

Sand development in the Strawn occurs as elongate offshore bars parallel to the shoreline, in which traps are controlled by porosity and permeability pinchouts [2]. The sands are often poorly developed and have thinly interbedded shale and limestone stringers. The pay zones at Mead consist of clean, fine to very fine grained sands. Secondary growth on the quartz grains reduces porosity and permeability. Figure 5, an isopach of the upper Strawn pay, shows the elongate nature of the reservoir, which averages 9 feet in thickness. Average porosity of the pay is 9.4 percent, and the average permeability is 12 md. Figure 6 is a type log from the field, showing sand development in the pay zones.

Reservoir Fluid Data

Some important reservoir fluid properties at the Mead-Strawn Field are listed below:

Connate water saturation, percent	40
Original reservoir pressure, psig	1,807
Reservoir pressure as of Jan. 1, 1964, psig	115
Reservoir temperature, °F	135
Original oil saturation pressure, psig	1,500
Original formation volume factor	1.29
Present formation volume factor	1.12
Original solution gas/oil ratio scf/bbl	526
Stock-tank oil gravity, °API	41
Oil viscosity at reservoir temperature, cp	1.3

Reservoir Performance

The early reservoir performance at Mead-Strawn indicated solution gas drive mechanism with no water encroachment. The reservoir pressure declined sharply from an initial value of 1,807 psig to 115 psig during the period 1951-1964. No detailed data are available, but it is apparent that oil production had declined to a very low level, with a high water-oil ratio, by early 1964.

Carbon Dioxide Project Data [2]

In 1964, a decision was made to conduct a CO_2 pilot test and to conventionally waterflood the entire 2,000 acre-feet of the lower zone plus approximately 2,000 acre-feet of the upper zone south and west of the CO_2 pilot. The purpose of conducting the two projects simultaneously was to compare the relative effectiveness of waterflooding and CO_2 flooding.

Figure 7 shows the area selected for the CO_2 test. A study of core, electric log, and primary production data yielded the following information for the pilot area:

Average thickness, percent	10.3
Average porosity, percent	11
Average permeability to air, md	9
Reservoir oil in place, percent PV	39
Water saturation, percent PV	40

Data on pertinent properties of CO_2 and of CO_2-saturated Mead-Strawn oil and injection water are presented in Table 2.

The carbon dioxide was transported approximately 400 miles from the source to the test site by insulated trucks. The injection system consisted of 125-bbl storage tank, a CO_2 feeder pump, and a triplex injection pump. Turbine meters were installed to measure the input to each of the four injection wells.

The injected water was Cambrian brine produced from a depth of 5,900 feet. It was treated to control bacteria and corrosion, as it contained 75,000 ppm of dissolved solids and H_2S.

The area for the CO_2 test was a slightly irregular five-spot of 33.5 acres and an adjacent 9 acres (Fig. 7). There were four injection wells (Nos. 1, 3, 4, and 19) and two production wells (Nos. 2 and 5). The area was bounded to the east, north, and west by dry holes, and on the south and southwest by two water injectors. This configuration helped to confine the injected fluids within the test area.

The operating plan called for injection of water before CO_2 injection to raise the reservoir pressure in the test area from 115 to 850 psi, the minimum pressure required to ensure effective displacement. This was followed by small slugs of CO_2 (4 percent PV) and carbonated water (12 percent PV) and then by brine.

Injection Performance

Water injection was started in mid-1964 and continued for about 5 months; 153,000 bbl of water (20 percent HCPV) was injected. On Dec. 1, 1964, injection of 5,000 tons (4 percent HCPV) of CO_2 was started at a rate of 55 tons per day. This phase lasted for 3 months. Alternating slugs of CO_2 and brine were then injected until an additional 500 tons of CO_2 had been injected. Regular floodwater (7 percent brine) was used to push the CO_2 and carbonated water slugs through the formation. Injection data are given in Table 3.

Despite severe channeling, indicated by water production from Wells 2 and 5, reservoir pressure in the pilot area reached 850 psi in 4 months after water injection began. There was no evidence of CO_2 channeling; in fact, less than 10 percent of the total CO_2 injected was produced up to 1968. Reservoir pressure in the pilot area continued to build up because of low productivity indices of the producers. The reservoir pressure in the CO_2 test area during the entire test period averaged about 2,200 psi.

Severe corrosion was encountered and there was evidence that it was caused by carbonated water, bacteria, and the Cambrian injection brine. It is difficult to assess the extent of corrosion caused by CO_2, because several producing wells outside the pilot area also experienced severe corrosion.

Production Performance

Limited published data indicate that the response of oil producers to CO_2 flooding was not as dramatic as expected. However, compared with the producers in the waterflooded areas, the producers in the test area sustained higher oil flow rates that declined less rapidly.

Well 10 (upper zone), although outside the CO_2 test area, produced more oil at a lower WOR than either Well 2 or Well 5 (Fig. 8). It appears that the performance of Well 10 was affected by CO_2 flood because:

1. fluids were pushed to Well 10 because Wells 2 and 5 had low flow capacity;

2. model studies and pressure profiles (Fig. 9) confirmed fluid migration in the direction of Well 10;

3. oil produced from Well 10 (Table 3) is more than could originally have been present in its drainage area.

Waterflooding itself did not prove to be as effective as anticipated; this was attributed to reservoir heterogenity, high initial water saturation, and inadequate flooding patterns.

The effectiveness of CO_2 flooding and of waterflooding is shown by the data in Table 3.

Well 5 is a poor performer in the CO_2 area, probably because in 1963 a water injectivity test was conducted in Well 11 and oil was produced from Well 5. This oil has not been credited to Well 5 in the evaluation shown in Table 3.

The drainage areas referred to in this table were estimated by potentiometric and mathematical model studies. The data indicate that 53 to 82 percent more oil was produced by the CO_2 flood than by water in the test areas of the waterflood (Table 3 and Fig. 10).

Figure 11 shows the history of CO_2 production from the test area. Even though Well 2 produced a high CO_2 cut, less than 10 percent of the total CO_2 injected had been produced until 1968. Such low CO_2 production is another indication of the effectiveness of CO_2 as a flooding agent.

Table 4 presents the core data in detail and Table 5 summarizes the results. It can be noted that Wells 22 and 23 contained appreciable amounts of CO_2 throughout the entire pay section. The residual oil saturation in the CO_2 test areas was found to be lower than in the waterflood area. These core data were consistent with observations in laboratory experiments using small Mead-Strawn cores.

Conclusions

The Mead-Strawn test flood showed that over 50 percent more oil was produced by the CO_2-carbonated-water flood, confirming the results of laboratory studies of the oil recovery process. However, low permeability, especially around the producing wells, extended the flood life and thus adversely affected the economics.

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1. Railroad Commission of Texas, A Survey of Secondary and Enhanced Recovery Operations in Texas to 1976 (1976), 487 pp.

2. Holm, L. W., and O'Brien, L. J., "Carbon Dioxide Test at the Mead-Strawn Field," J. Pet. Tech. (April 1971), p. 431-442.

TABLE 1

PROPERTIES OF CO_2 AND CO_2-SATURATED MEAD-STRAWN OIL AND INJECTION WATER

Properties of CO_2

Surface conditions: 0°F and 300 psi	
Density, lb/cu ft	63.69
Viscosity, cp	0.14
Reservoir conditions: 135°F	
Density, lb/cu ft	
at 1000 psi	9.8
at 1500 psi	20.8
at 2000 psi	36
Viscosity, cp	
at 1000 psi	0.02
at 1500 psi	0.02
Solubility in injection water at 135°F, scf/bbl	
at 1000 psi	104
at 1500 psi	118

Properties of CO_2-Saturated Mead-Strawn Crude Oil

Solution GOR, scf/bbl at 60°F	
at 1000 psi	640
at 1500 psi	1325
Oil viscosity, cp	
at 1000 psi	0.58
at 1500 psi	0.38
Oil density, gm/cc	
at 1000 psi	0.797
at 1500 psi	0.806
Relative oil volume	
at 1000 psi	1.25
at 1500 psi	1.5

TABLE 2

SUMMARY OF FLUID INJECTION INTO WELLS 1, 3, 4, AND 19

Fluid injected to January 1, 1968	Months	Tons	Barrels	Percent PV*
Brine (for pressure buildup)	5	---	153,000	22
Liquid CO_2	3	5000	27,200†	4†
Carbonated water¶	9	500	80,000	11.5
Brine	27	---	366,000§	53.5
Total	44	5500	626,200	91.0

*PV--797 acre-feet, 685,000 bbl.

†Measured at 0°F and 300 psi. Approximately 15 percent PV at reservoir conditions.

¶Alternate injection of CO_2 and brine--15 lb CO_2 per barrel of brine.

§Includes injection into wells 6 and 11.

TABLE 3

SUMMARY OF FLUID PRODUCTION FROM MEAD-STRAWN UPPER AND LOWER SANDS

Area in Field	Well No.	Liquid Recovered to Jan. 1, 1968 Oil, bbl	Liquid Recovered to Jan. 1, 1968 Water, bbl	1968 Water Cut, percent	Oil Recovery* Extrapolated to 95% Cut, bbl	Drainage Area Around Well, acre-feet†	Oil Recovered To Jan. 1, 1968 B/AF	Oil Recovered To 95% Cut B/AF
CO_2 test pattern	2	27,098	98,968	86	35,098	306	89	115
	5	17,016	99,570	87	22,846	333	51	70
	10	48,460	57,500	65	69,460	158	307	438
Total		92,574	256,038		127,404	797	Avg. 116	160
Entire waterflood	9U	11,200	34,721	89	12,660	158	71	80
	14U&L	6,400	61,727	97+	6,400	135	47	47
	7L	23,123	168,205	97+	23,123	263	88	88
	8U&L	5,092¶	11,800¶	50	9,700	---	--	--
	10L	17,592	84,637	88	23,222	254	70	92
	19L	7,025	17,126	91	7,935	176	40	45
		65,320	366,416		73,440	986	Avg. 66	75
Best waterflood wells	9U 7L	51,915	287,563	--	59,105	675	76	88

Oil Recovery--CO_2 Test Area Compared with Total Waterflood Area

To Jan. 1, 1968 (116 - 66)/66 = 76 percent increase
To 95 percent cut (160 - 75)/75 = 113 percent increase

Oil Recovery--CO_2 Test Area Compared with Best Three Waterflood Wells

To Jan. 1, 1968 (116 - 76)/76 = 53 percent increase
To 95 percent cut (160 - 88)/88 = 82 percent increase

*Using decline curve analysis.
†Calculations based on potentiometric and mathematical studies and on data from cores and logs from wells in the area.
¶Not included in totals because of lack of information to estimate drainage area.

TABLE 4

CORE ANALYSIS--CO_2 PILOT AREA AND WATERFLOOD AREA

Well 19 Upper After Primary--Before Secondary (1964)				Core Well 22 Upper Pressure Core After Secondary (1968)				
Depth of Sample, ft	Porosity, percent	Maximum Perme-ability, md	Oil Saturation, percent PV	Depth of Sample, ft	Porosity, percent	Maximum Perme-ability, md	Oil Saturation, percent PV	Percent CO_2 in Gas
4460.9-62.0	8.8	9.4	9.2	4479.2-79.7				
4462.0-63.3	7.9	7.9	14.2	4480.1-80.5				
4463.3-65.1	5.7	9.6	19.9	4480.5-81.1				
4465.1-66.7	3.7	4.4	20.6	4481.7-82.3	6.1	1.1	11.9	43.8
4466.9-67.7	8.7	2.0	18.5	4482.5-83.2	10.8	4.4	6.9	87.5
4467.7-69.0	6.8	4.4	13.2	4483.9-84.5	9.8	1.4	8.2	84.2
4469.0-70.2	8.8	3.1	13.2	4484.5-85.1	10.2	4.7	9.8	82.4
4470.2-71.0	7.1	5.3	--	4485.6-86.1	10.8	3.9	9.0	84.6
4471.0-72.0	7.3	9.3	21.7	4486.2-87.0	10.9	5.4	9.3	60.0
4472.0-73.1	7.8	46.0	21.3	4487.0-87.6	10.9	6.7	8.5	68.9
				4487.9-88.5	10.5	4.5	10.6	53.7
				4489.1-89.7	10.2	3.6	8.7	92.2
				4490.0-90.5	10.9	5.1	11.0	80.9
				4490.5-91.1	10.8	6.6	6.9	94.7
				4491.3-91.9	10.2	3.4	11.3	88.9
				4492.5-94.5	-----Shale-----			
				4494.0-95.0	6.1	2.7	11.0	29.7
				4495.0-96.0	10.2	1.4	18.0	7.6
Average--	7.3	10.1	16.9		9.9	3.9	10.1	
for following footage--	10	10	9		14	14	14	

TABLE 4 (continued)

CORE ANALYSIS--CO_2 PILOT AREA AND WATERFLOOD AREA

Core Well 23 Upper Pressure Core After Secondary (1968)					Core Well 23 Lower After Secondary (1968)*				
Depth of Sample, ft	Porosity, percent	Maximum Perme-ability, md	Oil Saturation, percent PV	Percent CO_2 in Gas	Depth of Sample, ft	Porosity, percent	Maximum Perme-ability, md	Oil Saturation, percent PV	Percent CO_2 in Gas
4462.0-62.7	9.1	3.0	10.2	46.3	4950-51	13.3	5.9	14.3	<0.5
4463.2-63.5	6.7	3.2	1.1	--	4951-52	12.5	4.8	15.3	<0.5
4463.8-64.4	6.1	6.3	2.2	30.8	4952-53	7.3	0.1	28.0	
4464.9-65.6	11.8	30.0	1.4	--	4953-54	10.9	0.1	15.7	
4466.1-66.7	10.7	7.5	4.4	19.3	4954-55	7.6	1.3	11.5	<0.5
4467.0-67.5	11.5	8.4	8.3	33.2	4955-56	7.0	0.5	12.5	
4467.9-68.6	11.8	8.9	2.8	--	4956-57	6.9	2.9	12.8	
4469.0-69.5	11.4	5.9	7.0	35.3	4957-58	5.7	<0.1	--	
4469.8-70.4	9.9	6.3	5.3	--	4958-59	6.8	0.2	9.2	<0.5
4471.4-72.0	11.4	1.3	7.4	70.3	4959-60	--	--	--	
4472.3-73.0	14.1	2.0	3.2	92.6					
4473.3-73.9	11.1	1.5	1.4	--					
4474.2-74.5	8.8	0.6	3.8	--					
4475.0-75.6	11.4	0.7	9.1	41.0					
4476.1-76.6	8.5	<0.1	--	--					
4477.2-77.6	8.6	0.1	--	--					
4477.9-78.4	8.6	0.1	2.4	69.4					
4478.8-79.3	9.5	0.2	5.5	77.5					
4479.5-79.9	12.1	0.2	3.9	72.2					
4481.2-81.7	12.1	0.2	2.3	76.5					
Average--	10.4	6.1	4.8			9.0	2.0	14.9	
for following footage--	14	14	14			8	8	8	
Average fluid recovery from cores, percent†					91+				71.5

*No pressure core obtained from lower zone; results are from a conventionally cut core.
†Includes gas measured from well 23 upper.

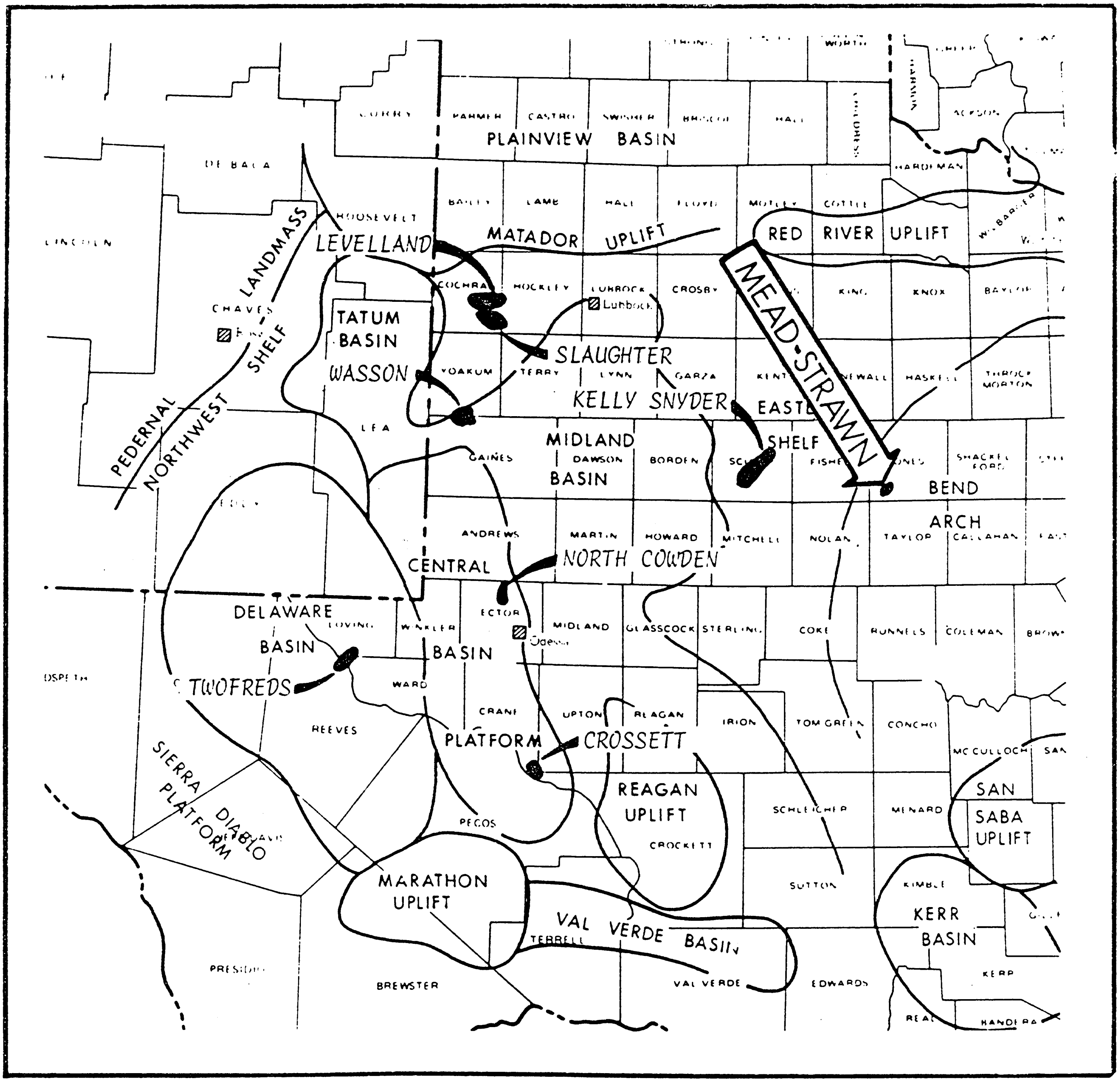


Figure 1.--Index map: carbon dioxide injection projects in west Texas.

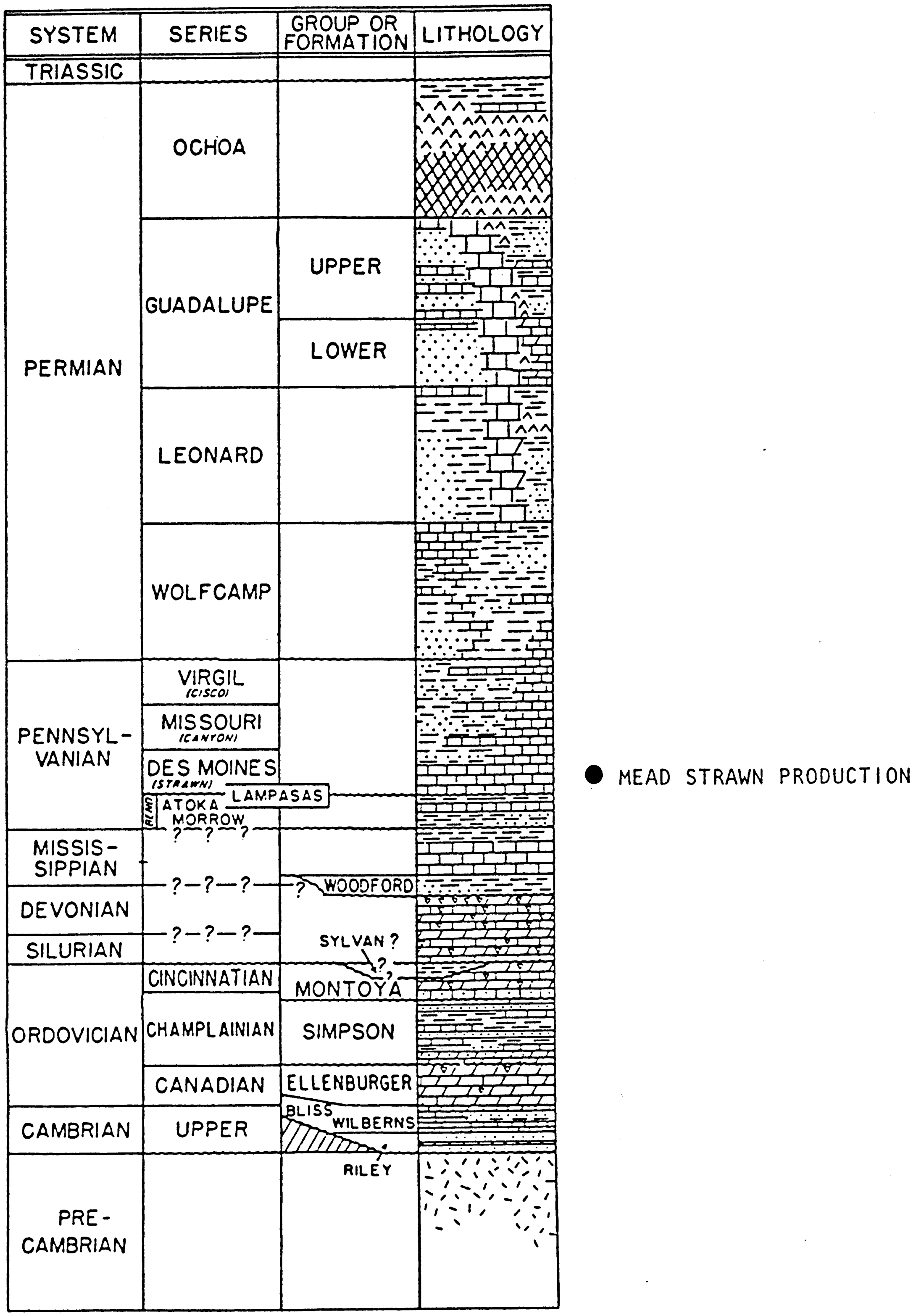


Figure 2.--Generalized stratigraphic column for west Texas.

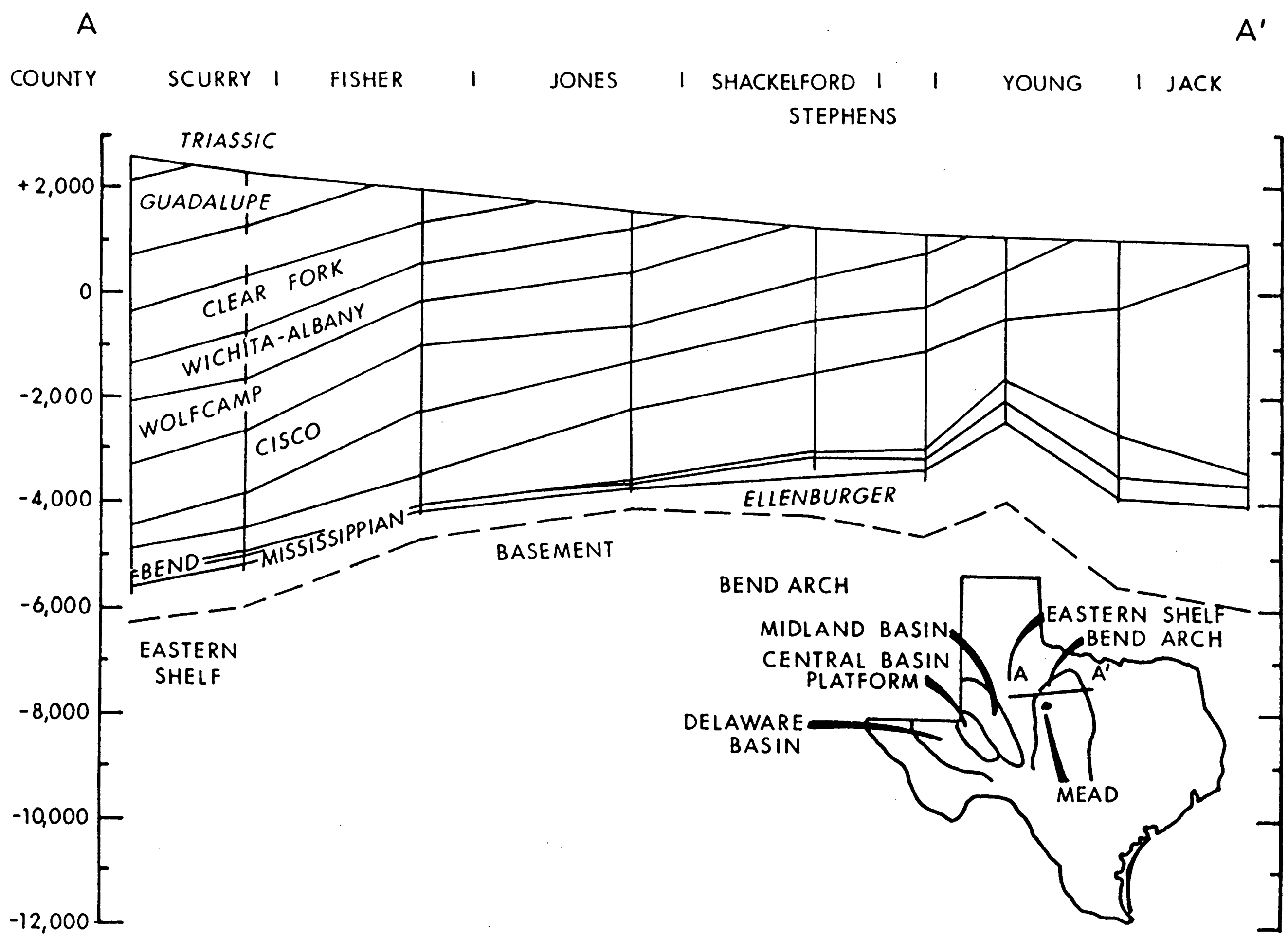


Figure 3.--Cross section of the eastern portion of the Permian Basin, west Texas.

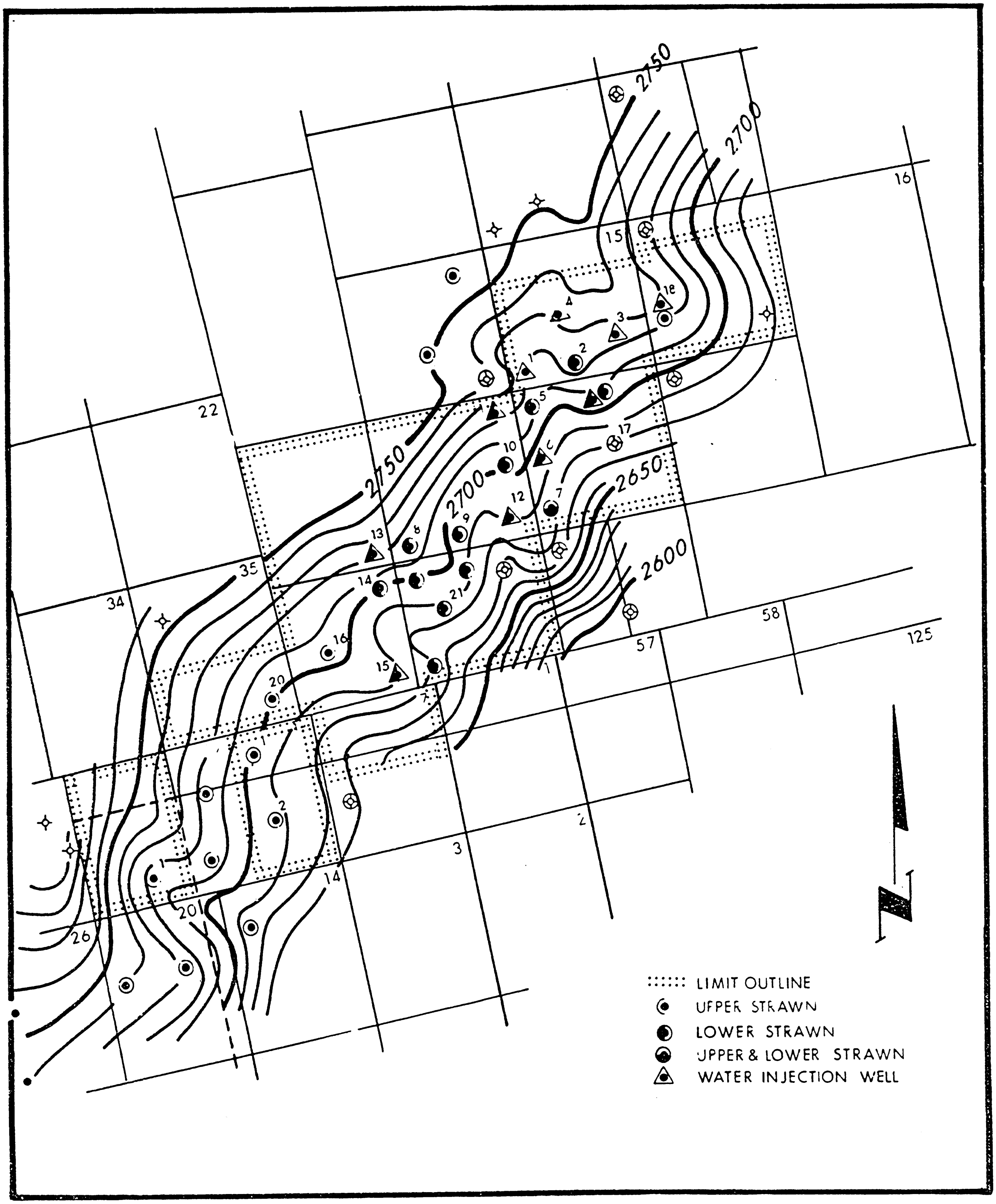


Figure 4.--Structure on top of the upper zone of Strawn sand, Mead (Strawn) field, Texas.

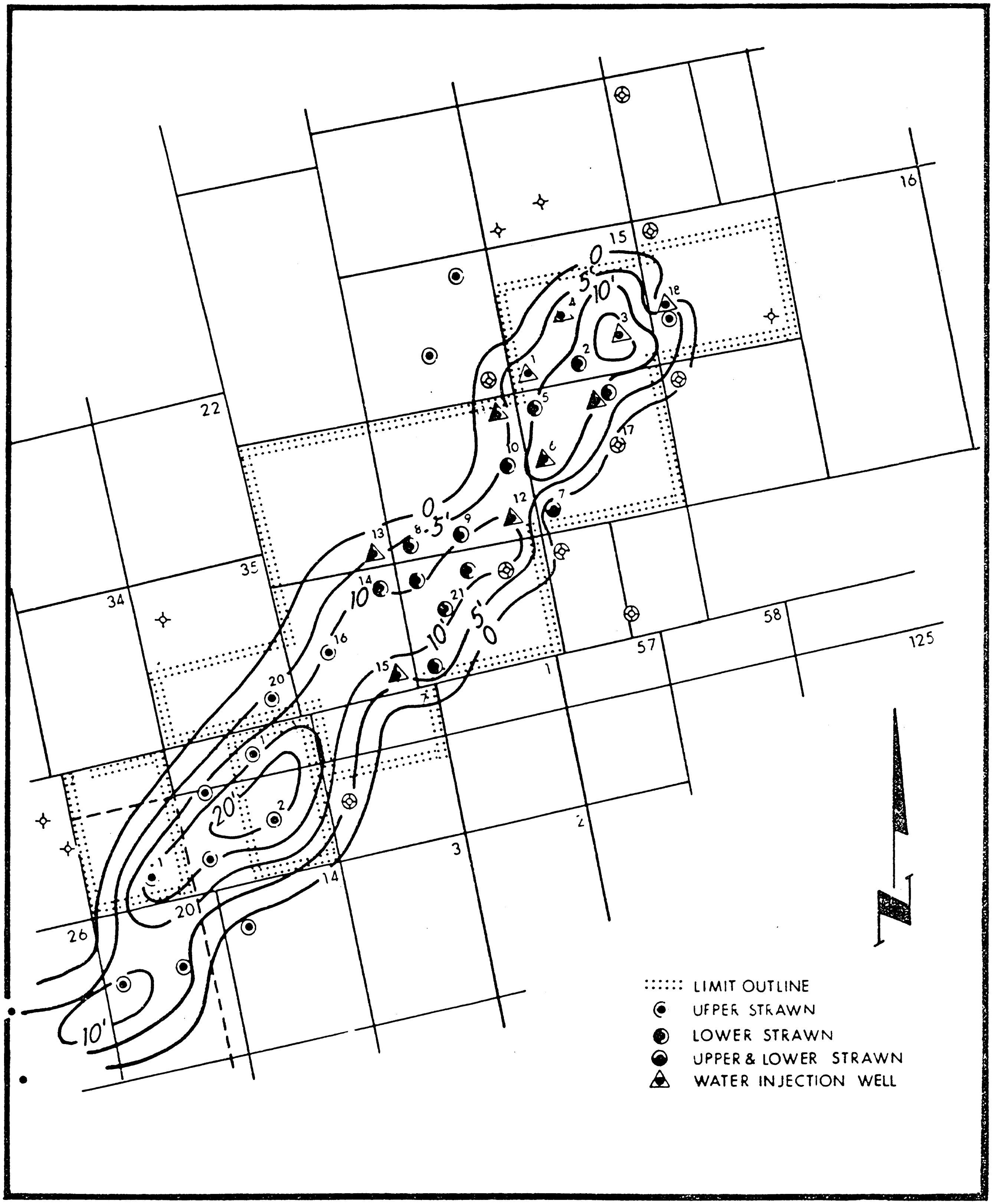


Figure 5.--Isopach map of upper zone of the Strawn sand, Mead (Strawn) field, Texas.

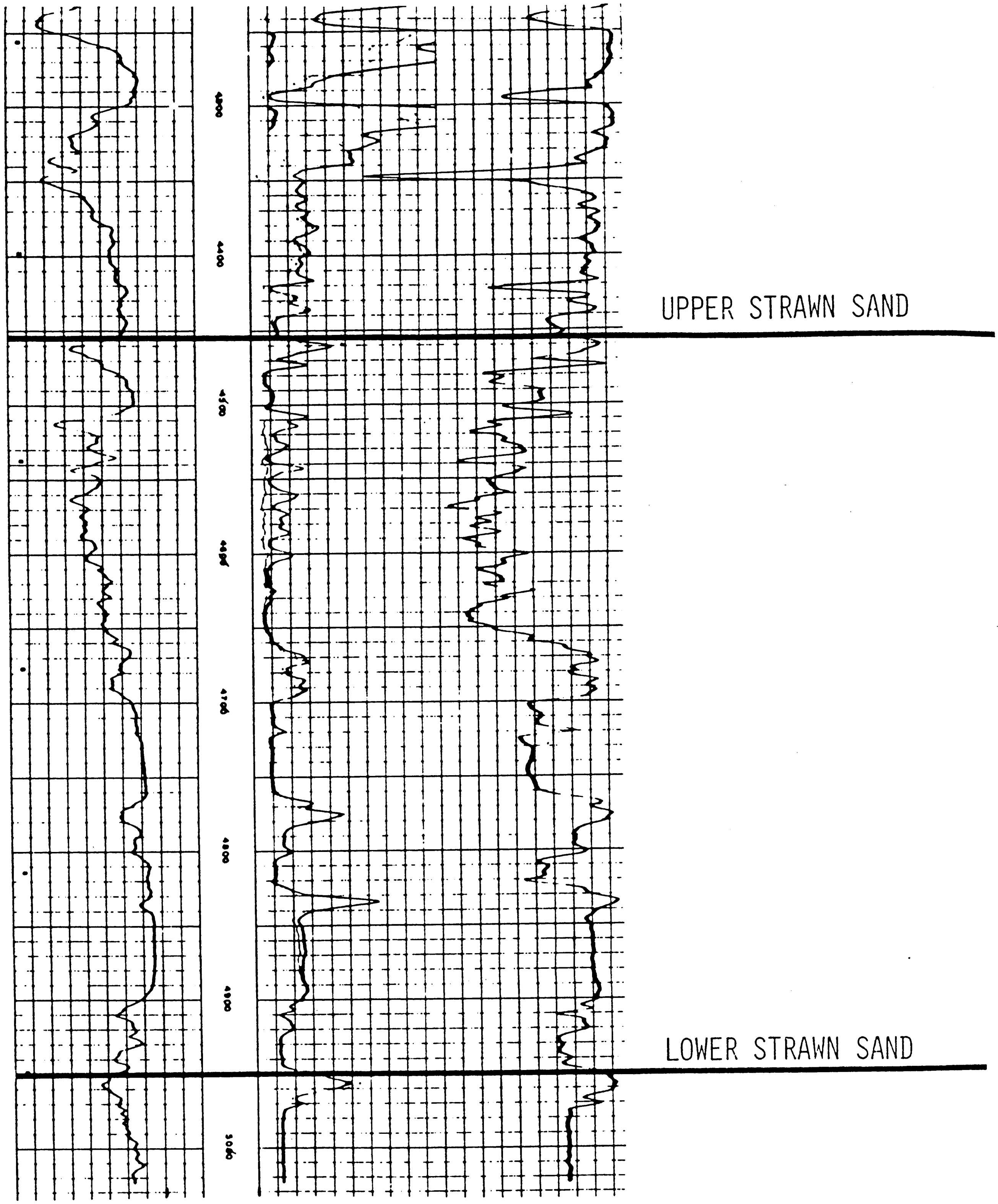


Figure 6.--Typical log from the Mead (Strawn) field, Texas.

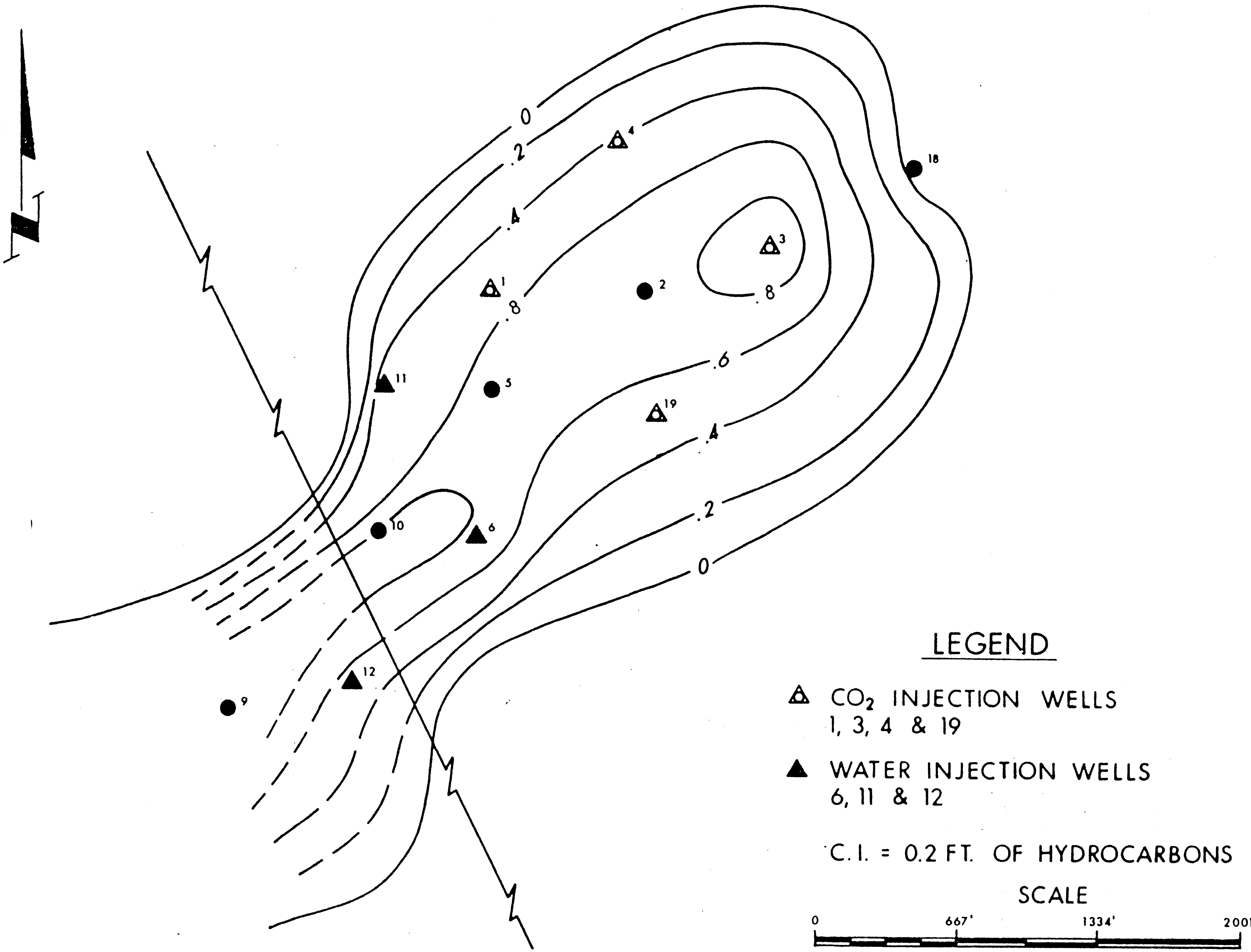
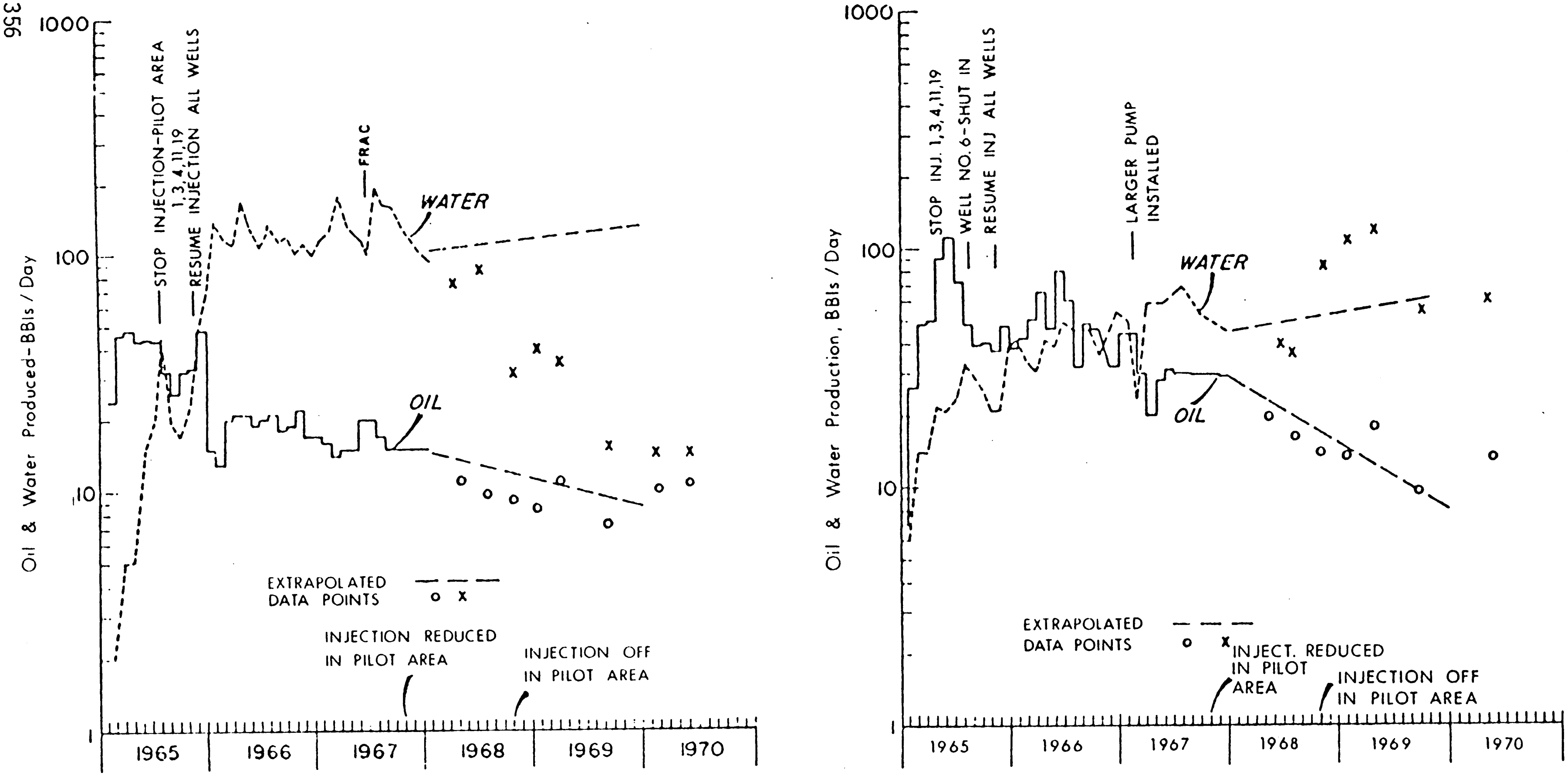


Figure 7.--Upper zone test area, Mead (Strawn) field, Texas.



PRODUCTION HISTORY - WELL 2

PRODUCTION HISTORY - WELL 10

Figure 8.--Production history for two wells in the CO_2 flood project, Mead (Strawn) field, Texas.

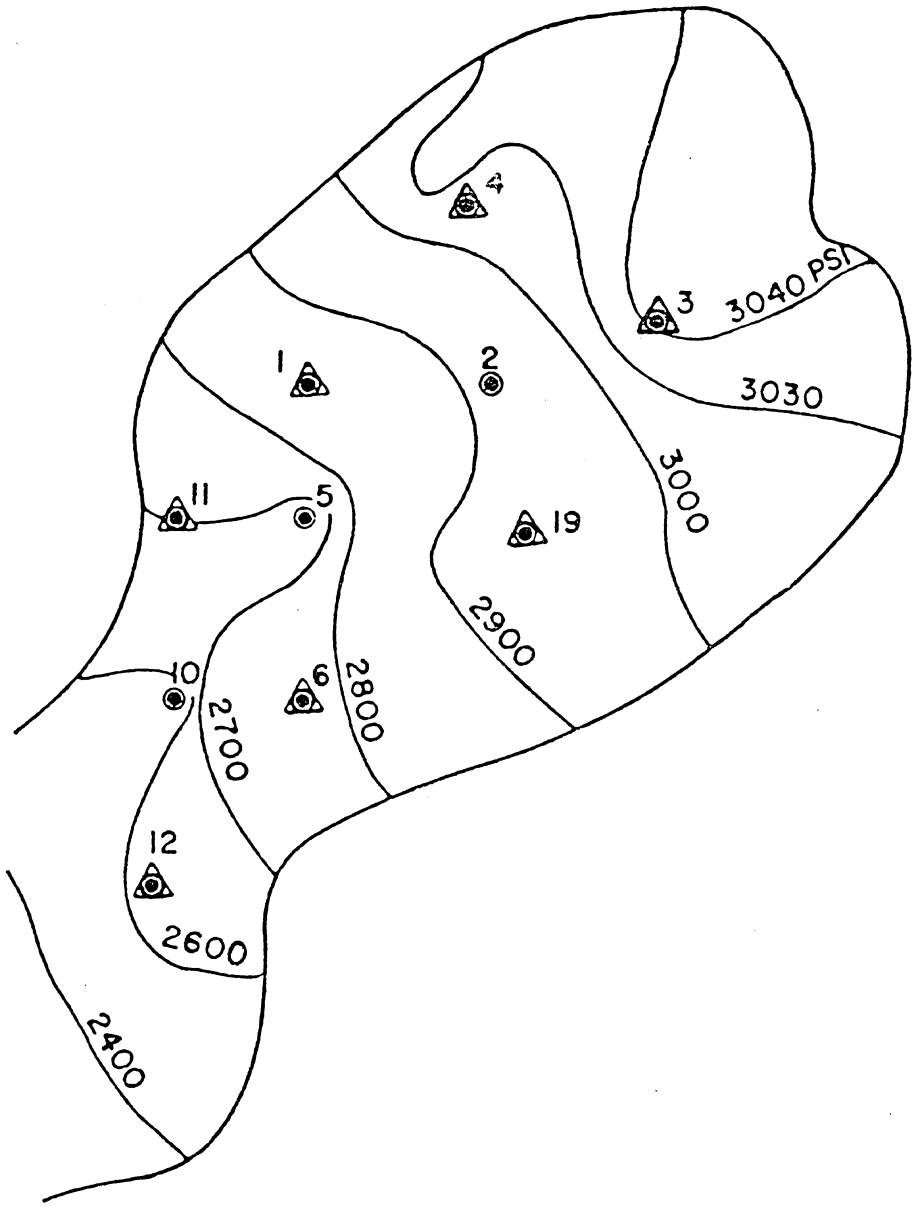


Figure 9.--Pressure profile for the upper zone,
(1967 computer model), Mead (Strawn) field, Texas.

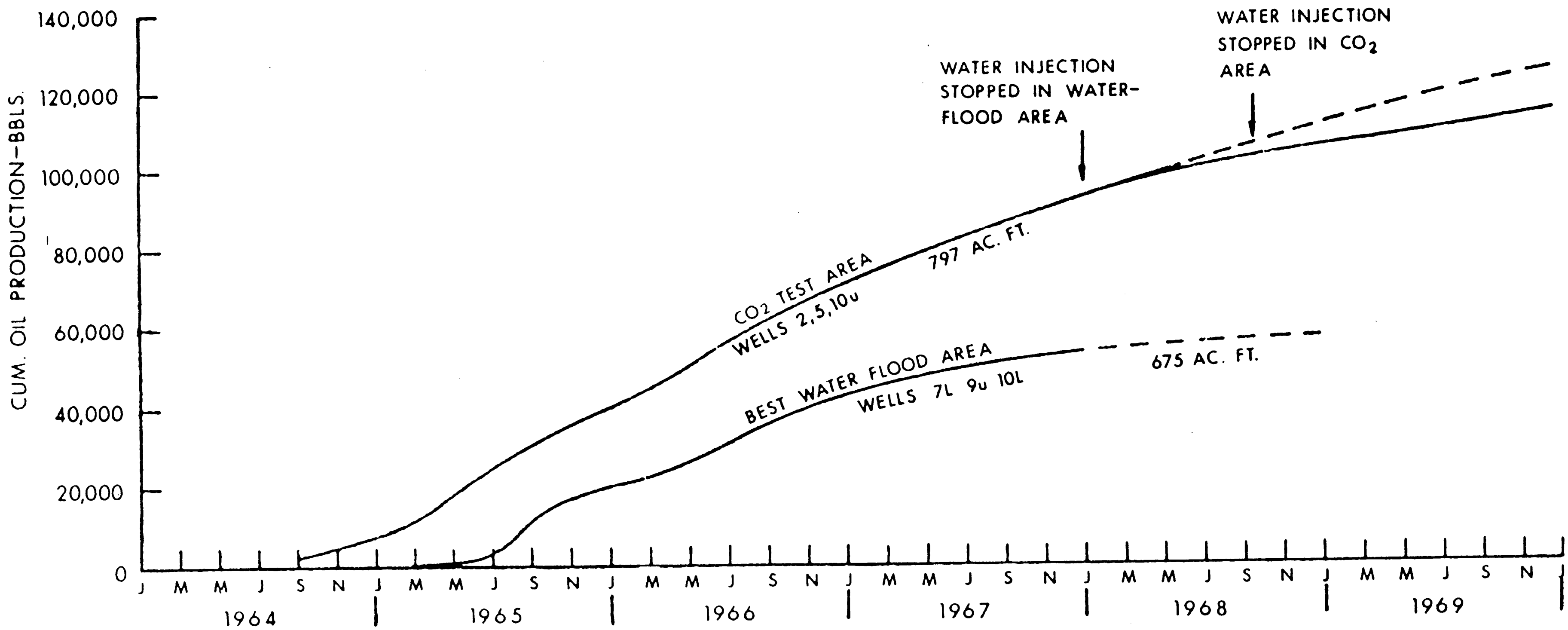


Figure 10.--Cumulative oil production from CO_2 test area wells and from best waterflood wells, Mead (Strawn) field, Texas.

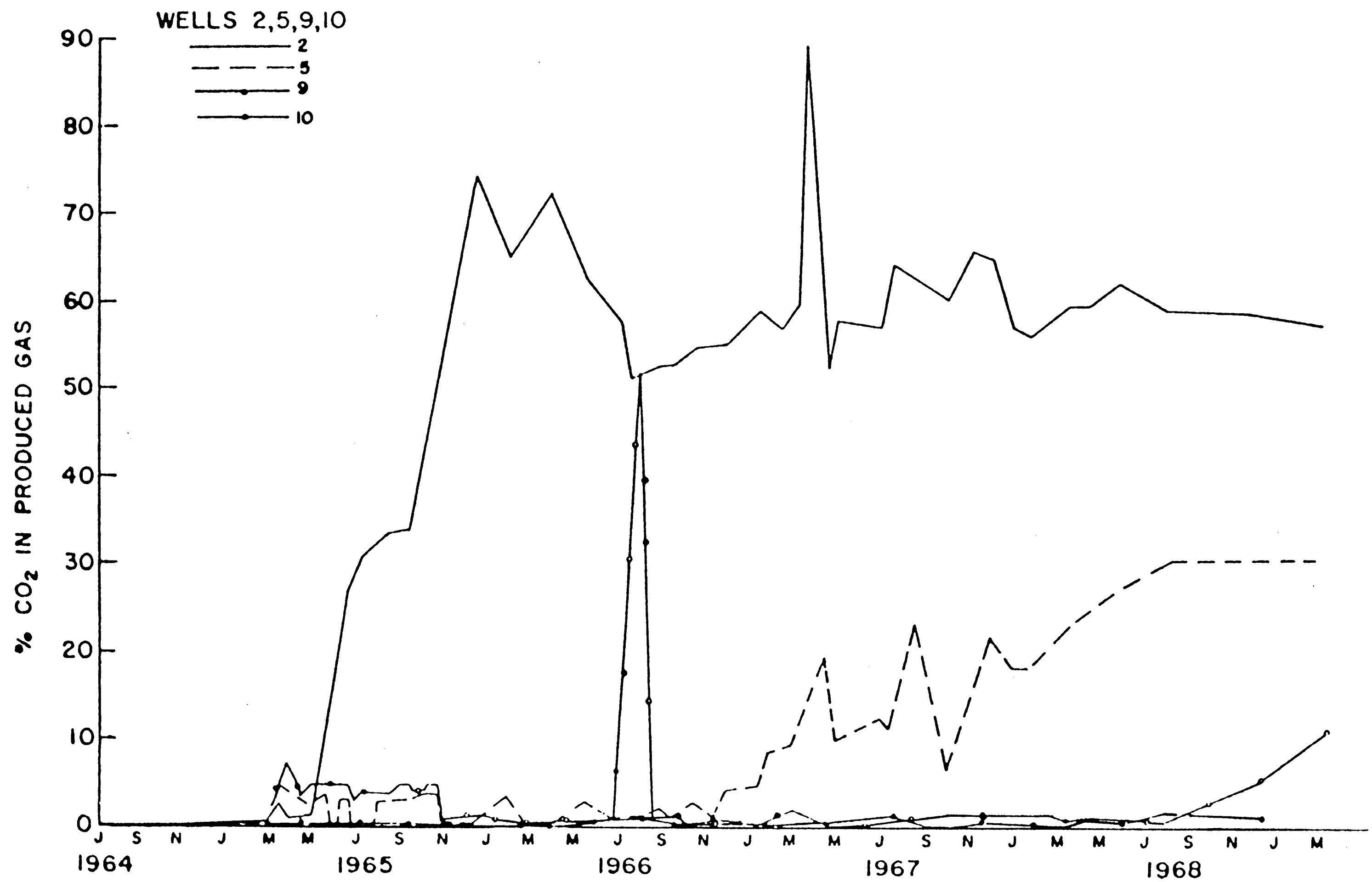


Figure 11.--Carbon dioxide produced from Mead (Strawn) field wells, Texas.

CO_2 FIELD INJECTION TEXT
CONDUCTED BY AMOCO OIL COMPANY
NORTH COWDEN FIELD, WEST TEXAS

by
Raj M. Kumar and Jerry A. Watson

Location and General History

North Cowden field is located on the eastern margin of the Central Basin Platform in Ector and Andrews Counties in West Texas (Fig. 1). Production is obtained from the Grayburg Formation at a depth of 4,400 feet. Discovered in 1930, the field encompasses 39,300 acres and produces from 1,003 wells. Cumulative production through 1975 was 259,005,000 barrels. Production during 1975 totaled 14,658,300 barrels. The 21,171-acre North Cowden Unit was formed when waterflood operations were started in 1966, with Amoco as the operator. Amoco began water injection in a tertiary pilot program in the North Cowden Unit in 1973.

Geology and Petrophysical Data

The Grayburg Formation is a member of the Guadalupe Series of middle Permian age (Fig. 2). At least half of the oil produced in the entire Permian Basin is estimated to come from Guadalupe age reservoirs.

Structurally, North Cowden is an asymmetrical anticline, positioned along strike on the eastern edge of the Central Basin Platform. Production is obtained from four sandy dolomite sections 10 to 70 feet thick [1]. The eastern portion of the field is the most productive area; this appears to be a result of greater pay thickness on the flanks of the structure, basinward from the crest.

The North Cowden Unit, which comprises over half of the field, has a gross pay interval of 400 feet [2]. Average porosity is 9 percent and average permeability is 5.3 md (range of permeability 2.9 to 5.5 md). Average net pay for the unit is 92 feet.

Reservoir Fluid Data

Some of the important reservoir fluid properties at North Cowden are:

Initial formation volume factor	1.25
Initial viscosity, cp	1.43
Gravity, °API	36

Reservoir Performance Data

When the North Cowden Field was discovered, bottomhole pressure was 1,800 psi. Gas cap was present initially, but the ratio of gas cap to oil zone volume was undefined. Waterflood operations began in 1966. On the basis of available information, waterflood seems to have been effective.

CO_2 Project Data

A pilot project was initiated in 1973 to determine the effectiveness of CO_2 injection in North Cowden. The project comprises two adjoining 6-acre five-spot patterns. The plan calls for injecting water into six injectors until the area is completely watered out, then to inject slugs of water and CO_2 alternately in the conventional manner. Two central wells will serve as producers. To monitor fluid saturation changes, a well was drilled and completed in May 1978 within the pilot area.

According to the latest published information, CO_2 injection did not begin until mid-1979. Figure 3 shows secondary performance of the tertiary pilot.

REFERENCES

1. Giesey, S. C., and Fulk, F. F.: "North Cowden Field, Ector County, Texas," Bull., AAPG (1941) 25, 593-629.

2. Railroad Commission of Texas: "Application to Inject Fluid Into A Reservoir Productive of Oil or Gas," Form H-1 (1978), North Cowden Field (North Cowden Unit).

3. Enhanced Oil Recovery Field Reports published by SPE.

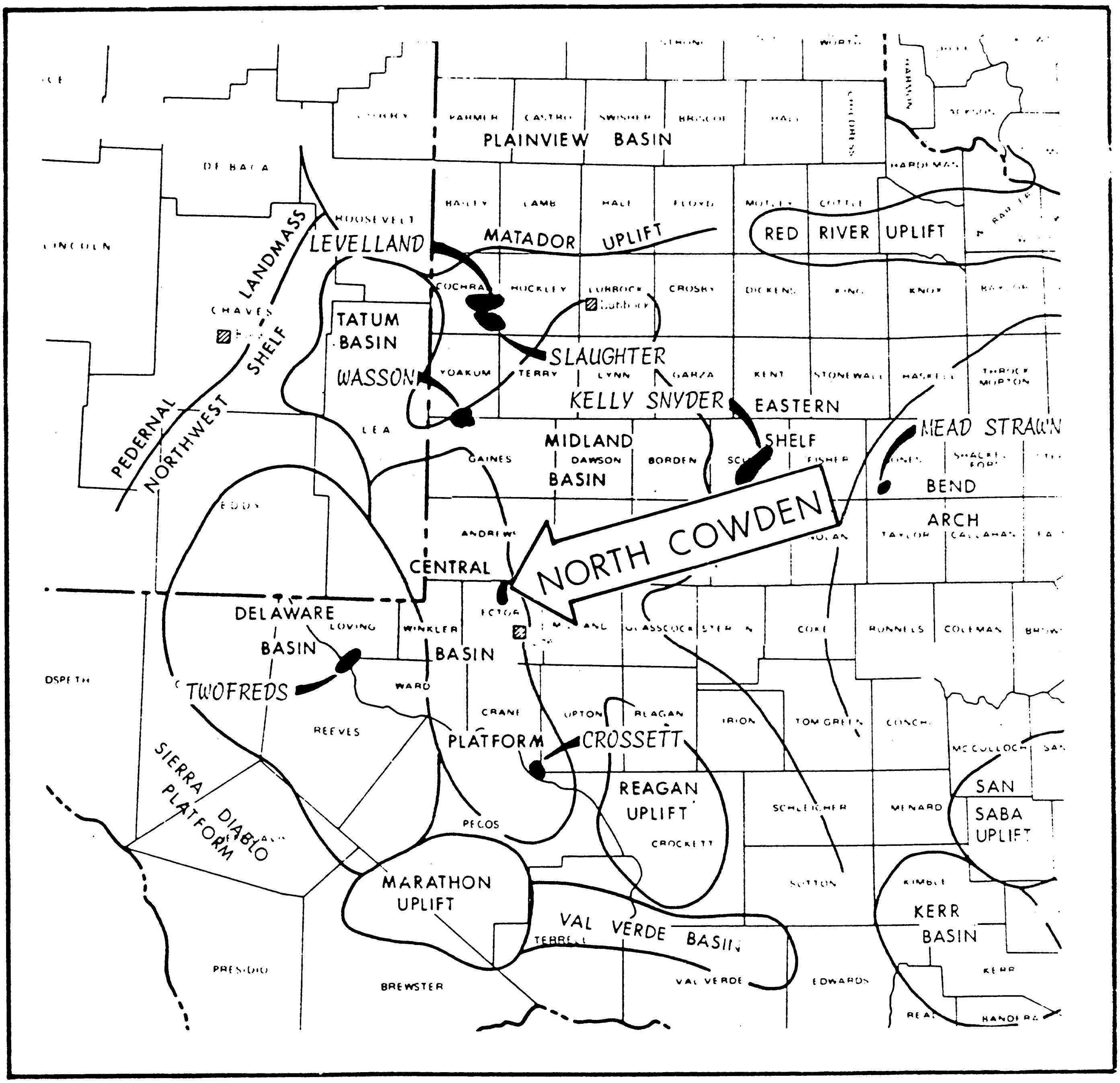


Figure 1.--Index map: carbon dioxide injection projects in west Texas.

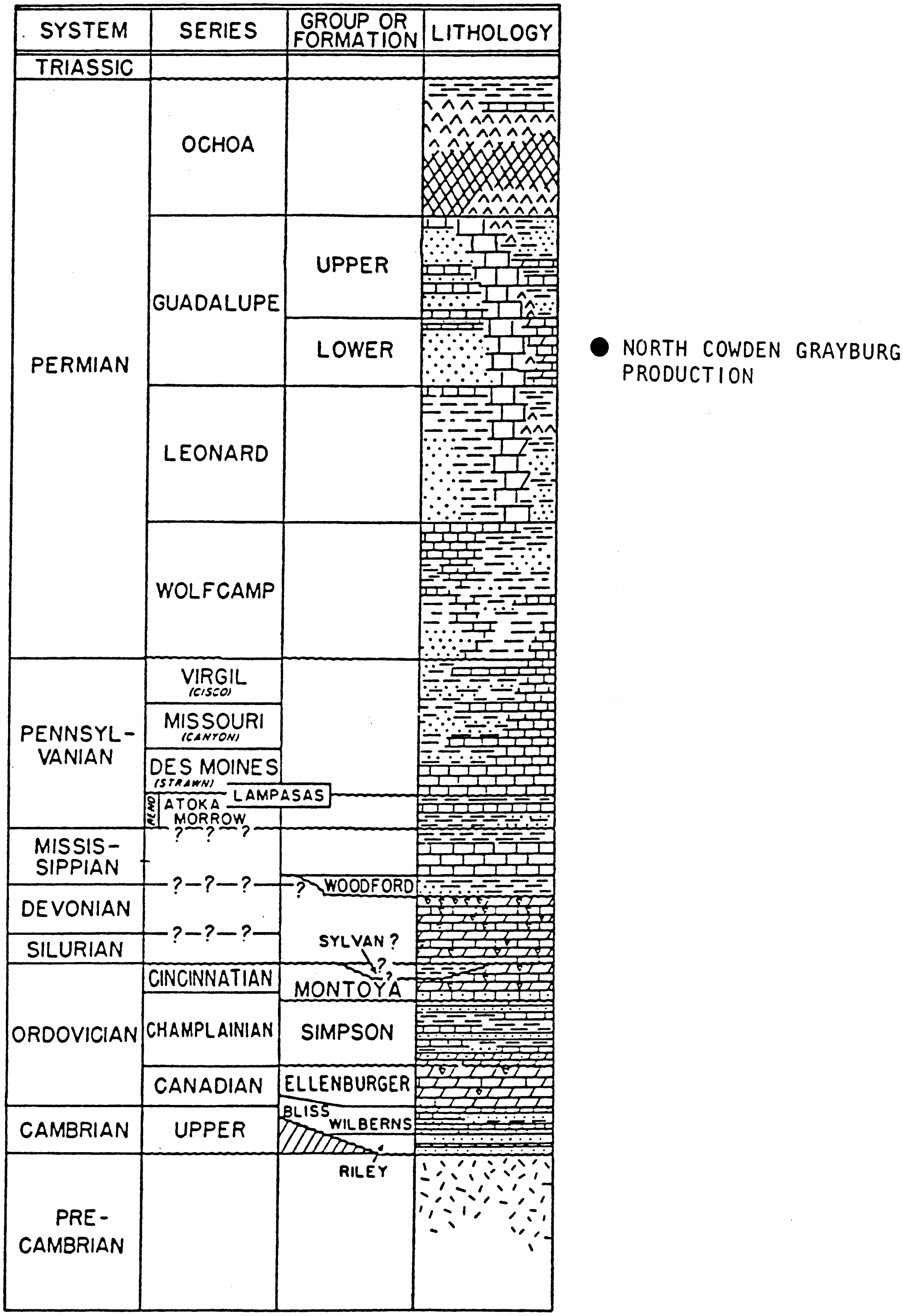


Figure 2.--Generalized stratigraphic column for west Texas.

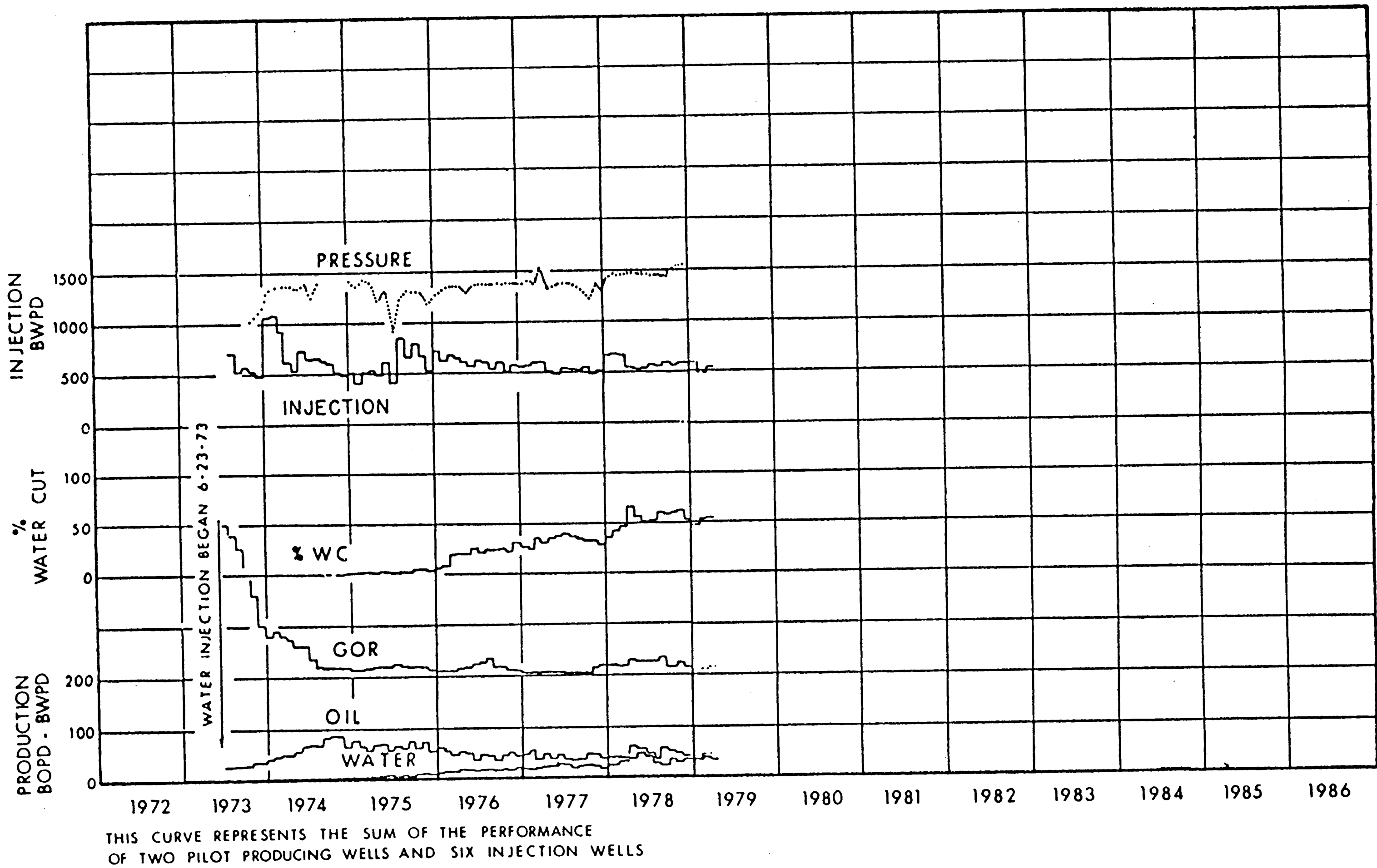


Figure 3.--Secondary performance history, North Cowden unit, North Cowden field, Texas.

CO_2 FIELD INJECTION PROJECTS CONDUCTED BY ATLANTIC RICHFIELD COMPANY (ARCO) AND SHELL OIL COMPANY WASSON FIELD, WEST TEXAS

by

Raj M. Kumar and Jerry A. Watson

This report summarizes information developed to date for two CO_2 field injection projects that have been conducted in the Wasson Field: one by ARCO in the Willard Unit and one by Shell in the Denver Unit.

Location and General History

The Wasson Field encompasses 68,500 acres in Gaines and Yoakum Counties, on the southeastern edge of the North Basin Platform (Fig. 1) of the Permian Basin of West Texas. Production from the San Andres dolomite of Permian age (Fig. 2) occurs at an average depth of 5,100 feet. The San Andres pay, discovered in 1936, was largely developed by 1941. Waterflood operations began in 1964. San Andres production through 1974 was 806 million barrels of oil. Remaining reserves are estimated at 600+ million barrels. Production during 1977 was 80.203 million barrels.

Wasson Field is one of the largest oil fields in the United States to be completely unitized. The names of the different units and their present operators are:

Unit	Operator	Area, Acres
Denver	Shell	25,505
ODC	Amoco	7,455
Willard	ARCO	13,500
Roberts	Texaco	11,240
Cornell	Cornell Oil Co.	1,920
Bennett Ranch	Texas Pacific	7,027
Mahoney	Mobil	640

Figure 3 shows the locations of ARCO's Willard Unit and Shell's Denver Unit.

Geological and Petrophysical Data

The Wasson structure measures about 15 miles from east to west and 14 miles from north to south. It is controlled by a northwest-southeast trending pre-Permian structural axis and by the buried Wichita-Albany shelf margin. The structure has two principal axes, one trending N.60°W. and the other N.30°E.

Figure 4 shows the structure on top of the first porous dolomite pay, approximately 400 feet below the top of the San Andres [1]. The pay zone is a finely crystalline dolomite with intergranular porosity. Sediments comprising the pay zone are calcareous particles, fragments, and grains, mixed in various combinations [2]. The sediments have been altered by diagenetic processes and dolomitization, commonly with loss of secondary porosity through deposition of secondary anhydrite [3].

Major potential barriers to vertical flow are common in the San Andres; they result from the occurrence of lime muds in the depositional framework. These barriers are often laterally continuous for 1,000 feet or more [4]. In addition, the concept of discontinuous porosity zones has been developed and applied to much of the carbonate production in West Texas, including Wasson [5-8]. This concept, depicted in Fig. 5, was developed in the mid-1960's and led to the practice of infill drilling to drain porosity stringers of limited extent. The idea of impermeable layers between the porosity stringers has necessitated new thinking concerning secondary/tertiary recovery techniques. The non-homogeneity of carbonate reservoirs has been extensively studied, and in several cases pay continuity relationships have been developed. Early studies at Wasson have shown a general decrease in pay continuity with distance, up to a 60 percent continuity at a distance of 5,000 feet. More recent studies [9], however, suggest that the pay discontinuity concept may have been overstated, as data from a pilot program in a San Andres reservoir showed significantly better pay continuity than previously projected.

On the basis of log and core analyses, the Wasson San Andres pay has been divided by field operators into zones [10, 11]. Different operators have used different schemes for subdividing the San Andres reservoir. This seeming confusion is an outgrowth of changing pay development in different areas of this large field. In some areas, the subzones can be further identified according to degree of reservoir development, i.e., generally good, occasionally good, and generally poor development.

In the Willard Unit, ARCO reports that the average porosity over the gross pay is 8.5 percent and the average permeability is 3 md. Average net pay in the unit is 66 feet. Table 1 at the end of this report shows engineering, petrophysical, and statistical data.

In Shell Oil Company's Denver Unit, the pay section is divided into First Porosity, Main Pay, and Lower Main Pay. The 3 pays are subdivided into 10 separate zones as shown later (Fig. 15).

Average porosity of the Denver Unit pay is 12 percent; water saturation averages 15 percent; and permeability averages 5 md. The average pay section is 137 feet thick.

Reservoir Fluid Data

The oil from the Wasson San Andres pay has a gravity of 33°API and a viscosity of 1.18 cp. Original formation saturations were: water, 15 percent; oil, 85 percent. The original reservoir formation volume factor was 1.312.

Reservoir Performance Data

Early production performance of the Wasson Field indicated that the production mechanism was essentially solution-gas drive, with limited assistance from gas-cap expansion. The reservoir pressure declined steadily, and it became obvious to the field operators that some kind of pressure maintenance program should be initiated to improve recovery. As a result, unitization efforts were pursued actively in 1964, and seven units were formed covering the entire field.

Original oil in place is estimated at 4.4 billion barrels. Ultimate recovery is projected to be 1.4 billicn barrels, giving a recovery efficiency of 32.7 percent. This combined primary and secondary (waterflood) recovery leaves a target of some 3 billion barrels for enhanced oil recovery methods.

The Willard Unit of the Wasson Field covers 13,500 productive acres (see Fig. 3). The original oil in place in this unit is estimated to be 535 million barrels. Ultimate recovery by waterflood and primary production is estimated to be 225 million barrels, which gives a recovery efficiency of 42 percent of OOIP. Unit oil production was less than 4,000 B/D before unitization in 1965 and peaked at 31,500 B/D in 1974 under waterflooding.

The Denver Unit of Wasson Field covers 25,505 acres. Original oil in place in this unit is estimated at 2,108 million barrels. On the basis of an estimated primary recovery efficiency of 16.8 percent, primary ultimate recovery was estimated to be some 354 million barrels. At the time waterflooding was initiated, additional incremental recovery was estimated to be about 266 million barrels, giving a recovery efficiency of about 29 percent of original oil in place. Unit oil production was less than 11,000 B/D before water injection began in 1963. For the last few years production has been in the neighborhood of 145,000 B/D.

Willard Unit CO_2 Project Data

Waterflooding, in progress since 1965, has been quite successful in the Willard Unit. However, in order to recover the substantial additional oil left by the waterflood, a CO_2 miscible displacement project was conducted in the unit to examine the application of such a technique for full-scale improved oil recovery.

The project consisted of two separate tests [12]. The first of these (called Phase I) consisted of eight adjacent CO_2 injection wells on regular waterflood spacing. The area bounded by the producers surrounding these injectors contained about 425 acres. The reservoir properties in the pilot area were representative of the average for the Willard Unit. This project was conducted with the following objectives in mind:

1. to study the various operational aspects;

2. to see if injection rates and pressures can be maintained to have a miscible displacement;

3. to investigate the control measures necessary to avoid CO_2 channeling problems;

4. to estimate additional oil recovery.

The second test (called pilot test) was designed for short-term investigation of factors affecting fluid flow behavior in this reservoir. The test, located directly south of the first pilot, consisted of one injector, one pressure-core well, one logging/observation well, and one pressure-monitoring and fluid-sampling well, located along a straight line within 125 feet. Flood responses during waterflood and alternate injection of CO_2 and water were monitored at a logging/observation well using compensated neutron and pulsed neutron logs. A pressure core was taken to measure residual oil saturations at the conclusion of the test. The test objectives were:

1. to determine the extent of gravity segregation across the entire pay interval and within porous zones;

2. to evaluate the importance of stratification and cross flow;

3. to measure the reduction in residual oil saturation.

The location of the Willard Unit CO_2 injection project is shown in Fig. 6. Figure 7 is a detailed map of the Phase I area and Fig. 8 shows the pilot area detailed spacing.

CO_2 Source and Operating Plan

The source of CO_2 for both tests was the acid gas effluent from the Wasson gas sweetening plant 3 miles away. This gas was composed of 95 percent CO_2, 4 percent H_2S, and traces of hydrocarbons.

Phase I Test. In Phase I, CO_2 and water were injected alternately, keeping the slug sizes equal on a reservoir basis to ensure equal frontal velocities of CO_2 and water, thereby minimizing CO_2 channeling. Extensive data were gathered for analysis:

1. casing-tubing annulus pressures on all injectors were recorded to to detect wellbore communication;

2. injection profiles were run occasionally to check for plugged perforations, channeling and changes in vertical distribution of injected fluids;

3. injection rates, injection pressures, and temperatures were recorded daily on all injectors;

4. produced water was periodically analyzed to detect water breakthrough and scaling problems;

5. migration of CO_2 outside the project area was detected by analysis of gas from the outside producers;

6. at least two production tests a month were run on offsetting producers.

The CO_2 injection in the first pilot was started in November 1972. The design called for injecting a volume of CO_2 equal to 15 percent of the hydrocarbon pore volume (HCPV). Significant mechanical problems restricted the total CO_2 injection to 2,360 reservoir barrels per day at 1,566 psi wellhead pressure.

Figure 9 is a plot of CO_2 injection performances. Fracture extension pressure was exceeded, resulting in CO_2 production along the axis of the fracture orientation. However, these problems were resolved and operations returned to normal by 1974. Injection rates and pressures were under control during 1974; average injection was 1,620 reservoir barrels per day at 1,480 psi wellhead pressure. The pilot was terminated in 1975 because of an accident caused by leaking H_2S. Cumulative injection amounted to 2.3 Bcf (4.4 percent HCPV) of CO_2. Table 2 summarizes the injection data by well for the project.

Table 3 is presented for comparative injection performance study of the project injectors and eight offsetting water injectors. As indicated by the data, the overall injection performance was good. Injection profiles showed good vertical conformance. Pressure transient tests run in the area around the test area indicated that reservoir pressure was maintained at about 2,000-2,500 psi.

As mentioned earlier, only 4.4 percent HCPV of CO_2 had been injected when the project was terminated because of the accident. Such a small quantity of CO_2 was apparently not sufficient to cause noticeable changes in oil production rates.

A total of 13 offsetting producers experienced CO_2 production, most of them located along the fracture orientation. Cumulative production of CO_2 amounted to only 2.5 percent of cumulative injected CO_2, and 59 percent of this production came from two wells (68A and 103B) located along the fracture orientation. Injection well 86 was suspected to be the source, since it had a high cumulative CO_2 production compared to other injectors. Figure 10 shows total CO_2 production from these wells and Fig. 11 shows CO_2 production from Wells 68A and 103B. Total production performance of Phase I is shown in Fig. 12. To summarize, CO_2 production is small and can be controlled by balancing water and CO_2 slug size. More than 97 percent of the CO_2 was retained in the reservoir.

Pilot Test. The pilot test included four wells: Well 32A, the CO_2 and water injector; Well 32AC, the pressure core well; Well 32AO, the logging and observation well; and Well 32AS, the pressure-monitoring and fluid-sampling well. Well 32AO, 100 feet from Well 32A, was completed with a liner and without perforation. It was used to run compensated neutron and pulsed neutron logs to detect and estimate changes in gas and water saturation using the time-lapse logging technique [10]. Well 32AS, 25 feet from 32AO, was completed with a full casing string and was selectively perforated over the same interval as Well 32A. Well 32AS was used for pressure observation and for sampling fluids. Well 32AC was drilled to take pressure cores across the entire pay interval at the conclusion of the test [13]. The extensive data-gathering and surveillance program included:

1. daily injection rates and temperature measurements at Well 32A and weekly injection rates on Wells 31A and 33A (east and west offset wells);

2. continuous injection and casing pressures on Well 32A and continuous injection pressures on Wells 31A and 33A;

3. periodic water injection profiles and fall-off tests on all three injectors;

4. monthly compensated and pulsed-neutron logging in Well 32AO;

5. periodic sampling and analysis of the produced fluid in Well 32AS;

6. analysis of produced water and gas in the offset producers, and of injected water in Well 32A;

7. weekly shut-in bottomhole pressure measurements in Well 32AS (when shut in) and fluid level determination when sampling.

Before the pilot test was begun, the area under test was completely waterflooded by injecting 447,000 barrels of water in Well 32A. Production sampling at Well 32AS indicated that the area had been essentially watered out.

CO_2 and water were alternately injected in equal reservoir volumes in Well 32A from December 15, 1973, to February 1975. Cumulative injection to February 1975 was 87,000 reservoir barrels of CO_2 and 75,000 barrels of water. Nineteen cores totaling 170 feet were taken by pressure-coring Well 32AC, which was completed in April 1976.

For this pilot test in 1974, injection rates were nearly constant at 400 B/D and surface injection pressure stabilized around 1,300 psi for CO_2 and 800 psi for water. Reservoir pressure was maintained above the miscibility pressure. Vertical conformance, as indicated by injection profiles, was good.

Interpretation

Preliminary analyses of the two field tests and the data gathered during those tests leads to several conclusions.

1. The injected fluids showed good vertical conformance.

2. Effective vertical permeability across the pay interval is very low, and gravity segregation of CO_2 and hydrocarbon gas will not be a problem.

3. Additional oil displacement can be achieved by CO_2 flooding.

4. Reservoir pressure was maintained above the miscibility pressure.

5. There is no evidence of unfavorable sweep conditions and a large fraction of the injected CO_2 was retained in the reservoir.

CO_2 Project Data (Denver Unit)

Shell's "mini-pilot" test at Wasson Field was initiated in 1978. Its objectives were similar to those of the pilot test conducted by ARCO in the Willard Unit. The pilot configuration is shown in Fig. 13. The injection interval was confined to the "M_3" zone (Fig. 14) of the San Andres. The test consisted of injecting 3 MMcf/D of CO_2 for 100 days through an injector in an area that was completely waterflooded. Three logging observation wells, cased with fiberglass to allow several types of logging in open-hole conditions, were located 100 feet from the injector in different directions. A fluid-sampling well was used to take samples periodically. An extensive pressure-coring program was included in the test. All the information gathered from the mini-pilot test will be used to calibrate the reservoir simulator for further full-scale projection of the Denver Unit.

Shell engineers were of the opinion that this large unit could produce some 280 million barrels of incremental oil by CO_2 injection. Evaluation of the pilot test should be under way.

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TABLE I

FIELD DATA FOR CARBON DIOXIDE INJECTION PROJECTS

FIELD: Wasson Field

LOCATION AND GENERAL DATA

State: Texas — County: Gaines/Yoakum

Discovery Date: 1936 — Date First Production ______

No. Wells: ______ @ Date: ______

Developed Area: 68,500 (Wasson) 13,500 (Willard) Acres

GEOLOGY AND PETROPHYSICS

Reservoir Name: San Andres

Reservoir Rock Type: Dolomite

Trap: Anticlinal

Average Depth: 5100'

Primary Gas Cap (Y/N) -

Gas/Oil Contact Depth: ______ feet subsea
Oil/Water Contact Depth: ______ feet subsea

Average Net Pay Thickness: 66' (Willard) feet

Net/Gross Ratio: ______
Average Porosity: 85 % (over the gross pay)
Initial Water Saturation 15 %
Average Permeability: 3 millidarcies

Permeability Range: ______ millidarcies

Permeability Variation: ______

k_v/k_h: 0.1

BASIC RESERVOIR AND VOLUMETRIC DATA

Initial Reservoir Pressure: 1805 psi
Reservoir Temperature: ____ °F
Bubble Point Pressure: ____ psi
Formation Volume Factors:
B_{oi} 1.312
B_{ob} ____
Reservoir Oil Viscosity Data:
μ_{oi} 1.18 centipoise
μ_{ob} ____ centipoise

Initial Solution Gas-Oil Ratio:
R_{si} 4382 cu.ft./bbl.
Stock Tank Oil Gravity: 33 °API

Reservoir Hydrocarbon Pore Volumes:
Oil: 702800 M Bbl Gas: ____ M Bbl
Standard Volume Original Hydrocarbons in Place
Oil: 535700 M Bbl Gas: ____ Mcf

RESERVOIR PERFORMANCE DATA

Primary Recovery Drive Mechanism: Solution Gas Drive

Estimated Ultimate Primary Recovery: 17% % ISTOIP

Supplemental Recovery Method(s) and Date Started: Waterflooding - Started in 1965. Still in progress.

Cumulative Oil Production at Start Supplemental: ____ M Bbls ____ % ISTOIP

Unit Operator(s): ARCO

Average Pressure at Start Supplemental: 800-900 psi

Estimated Additional Supplemental Recovery (Ultimate): 25 % ISTOIP

Estimated Total Ultimate Recovery (Primary+Supplemental) 42 % ISTOIP

Cumulative Total Production to: 1-1-75 (Date)
114,000 M Bbls 21% % ISTOIP

Average Pressure: ____ psi @ ____ (Date)
Calculated Average Oil Saturation ____ %@ ____ (Date)

CARBON DIOXIDE INJECTION PROJECT DATA I

Project Operator: ARCO

Project Type: Mini-Test ___ Pilot Test X Full-Scale Project ___
Recovery Mode: Secondary ___ Tertiary X
Project Area: 425 Acres
No. of Wells: Injection 8 Production 1 Other ___

Pattern Geometry: ___

Date Project Commenced: Nov. 1972 Ended Feb. 1975
Injection Fluid Composition (mol percent)
CO_2 95% H_2S 4% C_1 1%

C_2-C_6 ___ C_7+ ___ Other ___

Estimated miscibility pressure: 1250 psi
Injection Fluid Source(s): Acid gas effluent from Wasson Gas Sweetening Plant about three miles away
Current CO_2 Injection Rate: ___ Mcf/day
Current Recycle Gas Injection Rate: ___ Mcf/day
Water Injection Rate: ___ Bbl/day

Water Injection Mode (i.e., alternating, continuous after "slug", etc.)
Discuss: CO_2 and water was injected alternatively. The design called for injecting 15% HCPV of CO_2 but the project was terminated earlier due to an accident.

Injection Pressures:

CO_2:	Surface	1400-1600	psi	Bottomhole		psi
Recycle:	Surface		psi	Bottomhole		psi
Water:	Surface	1100-1300	psi	Bottomhole		psi

Cumulative Injection @ End of test (Date)

CO_2		M Mcf	4.36	%HCPV
Recycle:		M Mcf		%HCPV
Water:		M Mcf		%HCPV

Current Production Rates: (Date) ___)

Oil: ___ Bbl/day Gas: ___ Mcf/day
CO_2: ___ Mcf/day Water: ___ Bbl/day

Date First Response: Early

Date CO_2 Breakthrough: Early

Cumulative CO_2 Production: 25% of injection @ ___ (Date)

Incremental Response: ____________________ Bbl/day @ ______________ (Date)

Cumulative Incremental Oil @ ____________ (Date) __________________ M Bbl

CO_2 Utilization Ratio-Cumulative Injection CO_2/Cumulative Incremental Oil ____________ Mcf/Bbl.

Expected Ultimate Incremental Production:
64280 M Bbls 12% (reported) % ISTOIP

CARBON DIOXIDE INJECTION PROJECT DATA II

Project Operator: ______

Project Type: Mini-Test X Pilot Test ___ Full-Scale Project ___
Recovery Mode: Secondary ___ Tertiary X
Project Area: 125' Acres
No. of Wells: Injection 1 Production ___ Other ___

Pattern Geometry: One injector, one pressure core well, one logging and one observation and sampling well located on a straight line all within 125 f

Date Project Commenced: Dec. 15, 1973 Ended Feb., 1975
Injection Fluid Composition (mol percent)
CO_2 95% H_2S 4% C_1 1%

C_2-C_6 ___ C_7+ ___ Other ___

Estimated miscibility pressure: 1250 psi
Injection Fluid Source(s): Acid gas effluent from Wasson Gas Sweetening Plant about three miles away.
Current CO_2 Injection Rate: ___ Mcf/day
Current Recycle Gas Injection Rate: ___ Mcf/day
Water Injection Rate: ___ Bbl/day

Water Injection Mode (i.e., alternating, continuous after "slug", etc.)
Discuss: CO_2 and water was injected alternatively into one well

Injection Pressures:

CO_2:	Surface	1300	psi	Bottomhole		psi
Recycle:	Surface		psi	Bottomhole		psi
Water:	Surface	800	psi	Bottomhole		psi

Cumulative Injection @ During the test (Date)

CO_2	87 MRVB		%HCPV
Recycle:			%HCPV
Water:	75 MBW		%HCPV

Current Production Rates: (Date) ___)

Oil: ___ Bbl/day Gas: ___ Mcf/day
CO_2: ___ Mcf/day Water: ___ Bbl/day

Date First Response: ___

Date CO_2 Breakthrough: ___

Cumulative CO_2 Production: ___ M Mcf @ ___ (Date)

Incremental Response: ________________ Bbl/day @ ____________(Date)

Cumulative Incremental Oil @ __________ (Date) ________________ M Bbl

CO_2 Utilization Ratio-Cumulative Injection CO_2/Cumulative Incremental Oil ___________ Mcf/Bbl.

Expected Ultimate Incremental Production:
__________________ M Bbls ____________________________% ISTOIP

TABLE 2

WILLARD UNIT CO_2 PROJECT - PHASE I INJECTION DATA
(to Feb. 1, 1975)

Well	Date On CO_2 Injection	Cumulative CO_2 Injection MRVB	Cumulative CO_2 Injection % HCPV
64	4- 5-73	196.4	3.77
65	12-19-72	105.4	2.03
66	2-13-73	240.3	5.10
67	6-14-73	150.0	3.18
84	3-28-73	278.3	6.10
85	11-14-72	289.2	6.58
86	11-14-72	283.4	6.80
87	6-22-73	76.6	1.84
TOTALS		1,619.5	4.36

TABLE 3

WILLARD UNIT CO_2 PROJECT PHASE 1 INJECTION PERFORMANCE

Average Injection Rates and Surface Injection Pressure

	Eight Phase 1 CO_2 Wells				Eight Offset H_2O Wells	
	H_2O		CO_2			
Year	Rate, BWPD	Pressure, psi	Rate, RVBD	Pressure, psi	Rate, BWPD	Pressure, psi
1973	597	1115	709	1566	566	1131
1974	393	1108	396	1480	452	1189
1975	375	1261	---	----	418	1291

Cumulative water injection to 11/1/72

8 Phase 1	7929 MBW (991 MBW/well)
8 Offsets	7754 MBW (969/well)

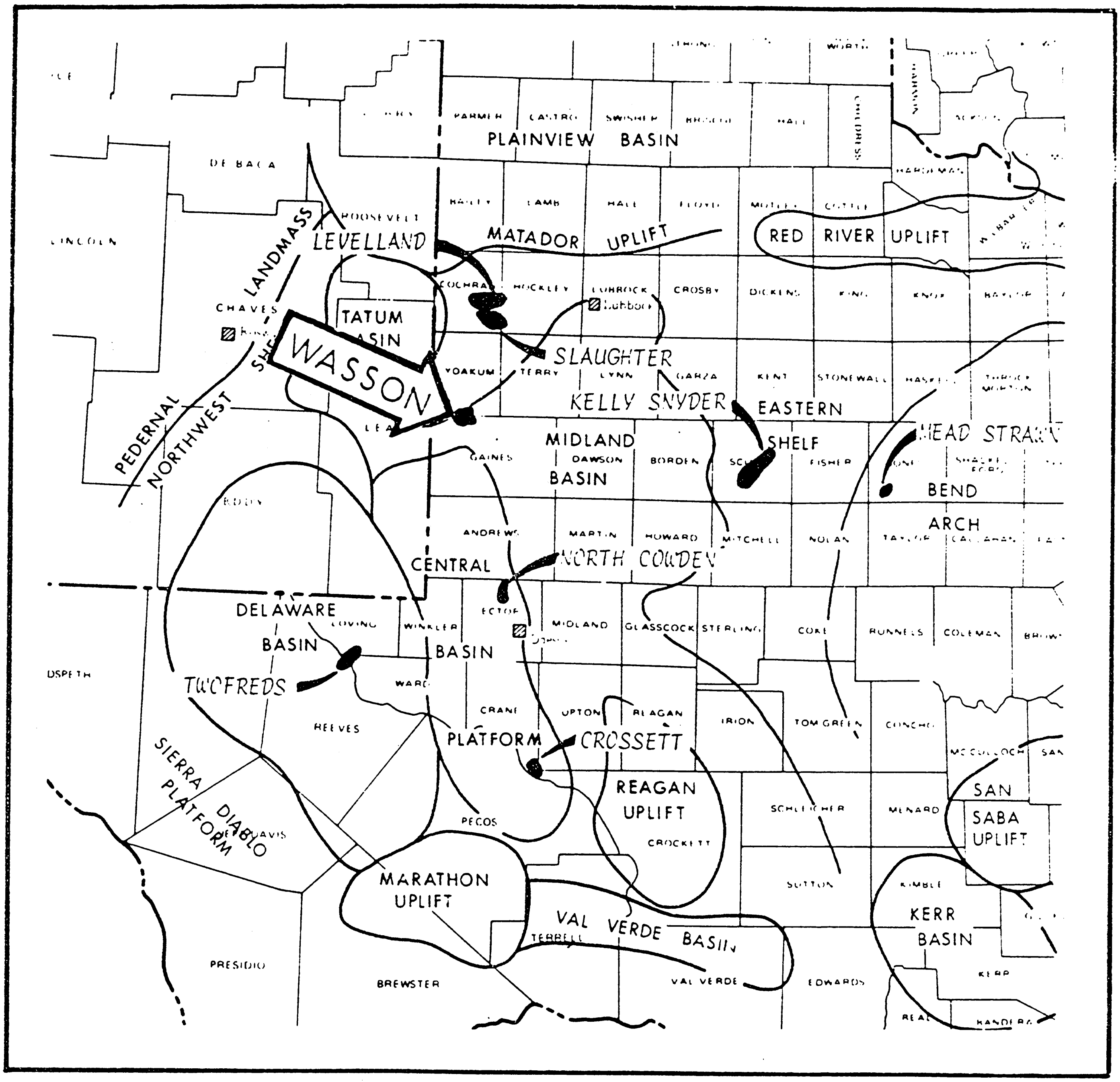

Figure 1.--Index map: carbon dioxide injection projects in west Texas.

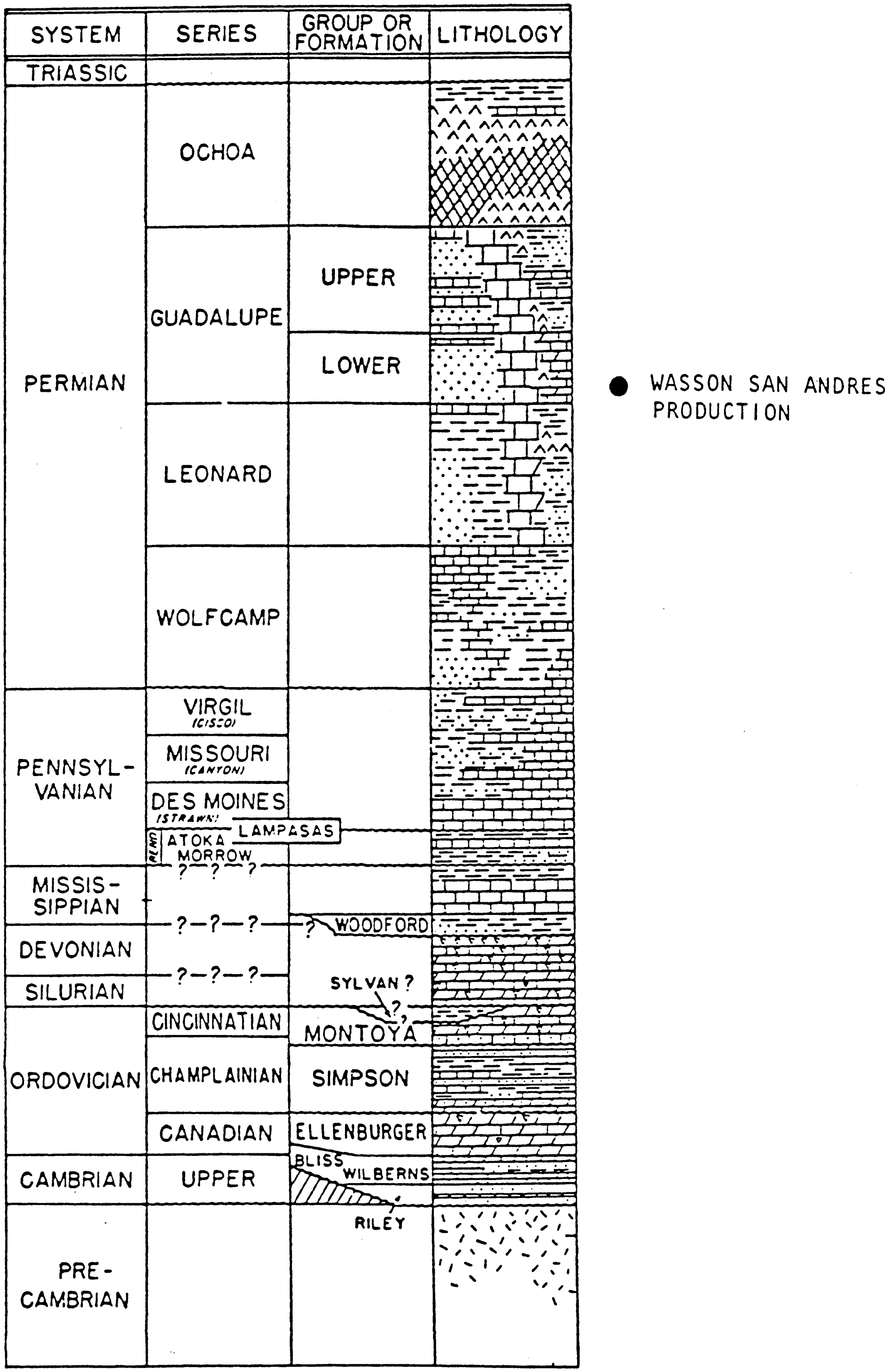

Figure 2.--Geologic column and stratigraphic nomenclature, Wasson field area, Permian Basin, west Texas.

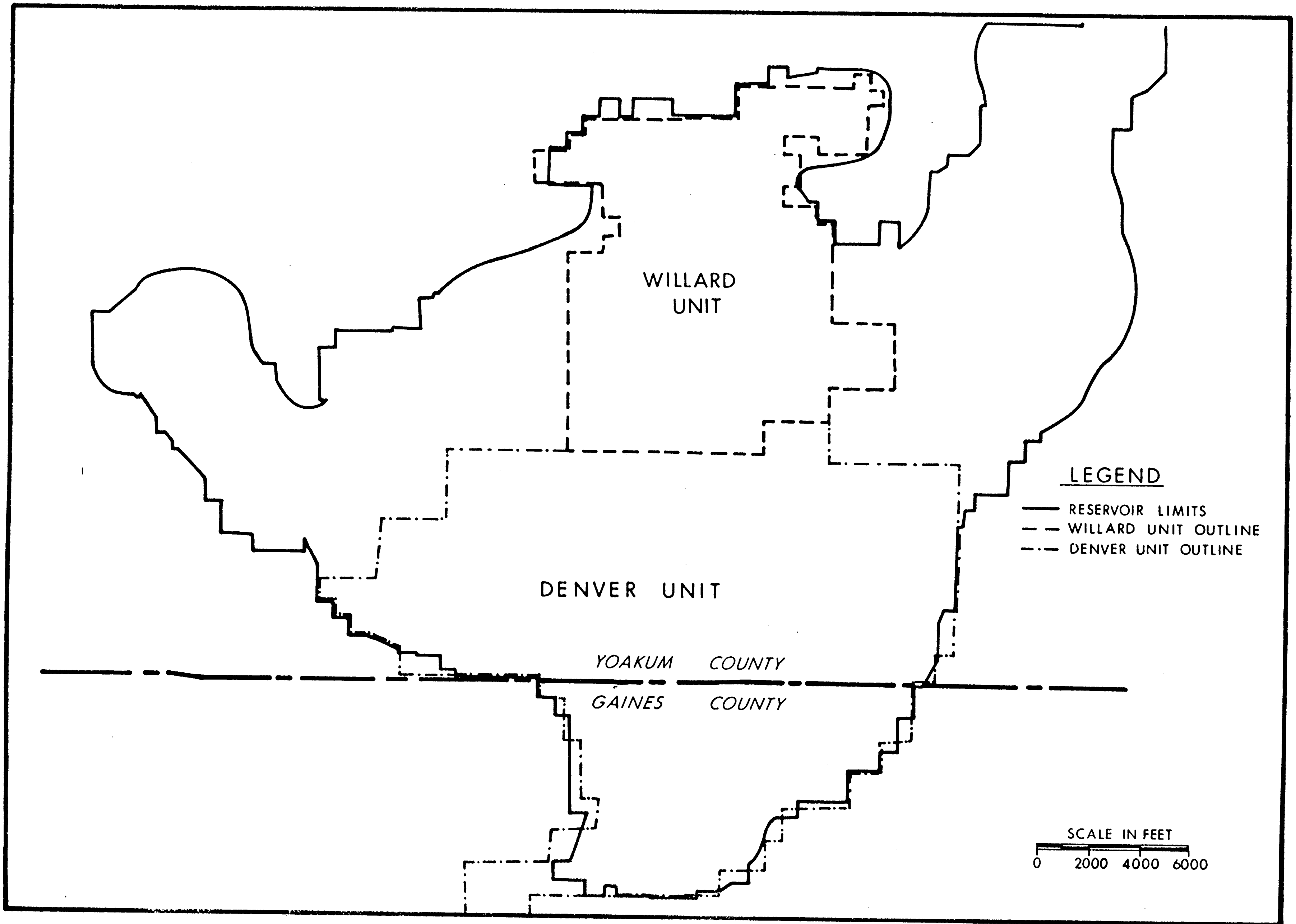

Figure 3.--Willard unit, Wasson field, Gaines and Yoakum Counties, Texas.

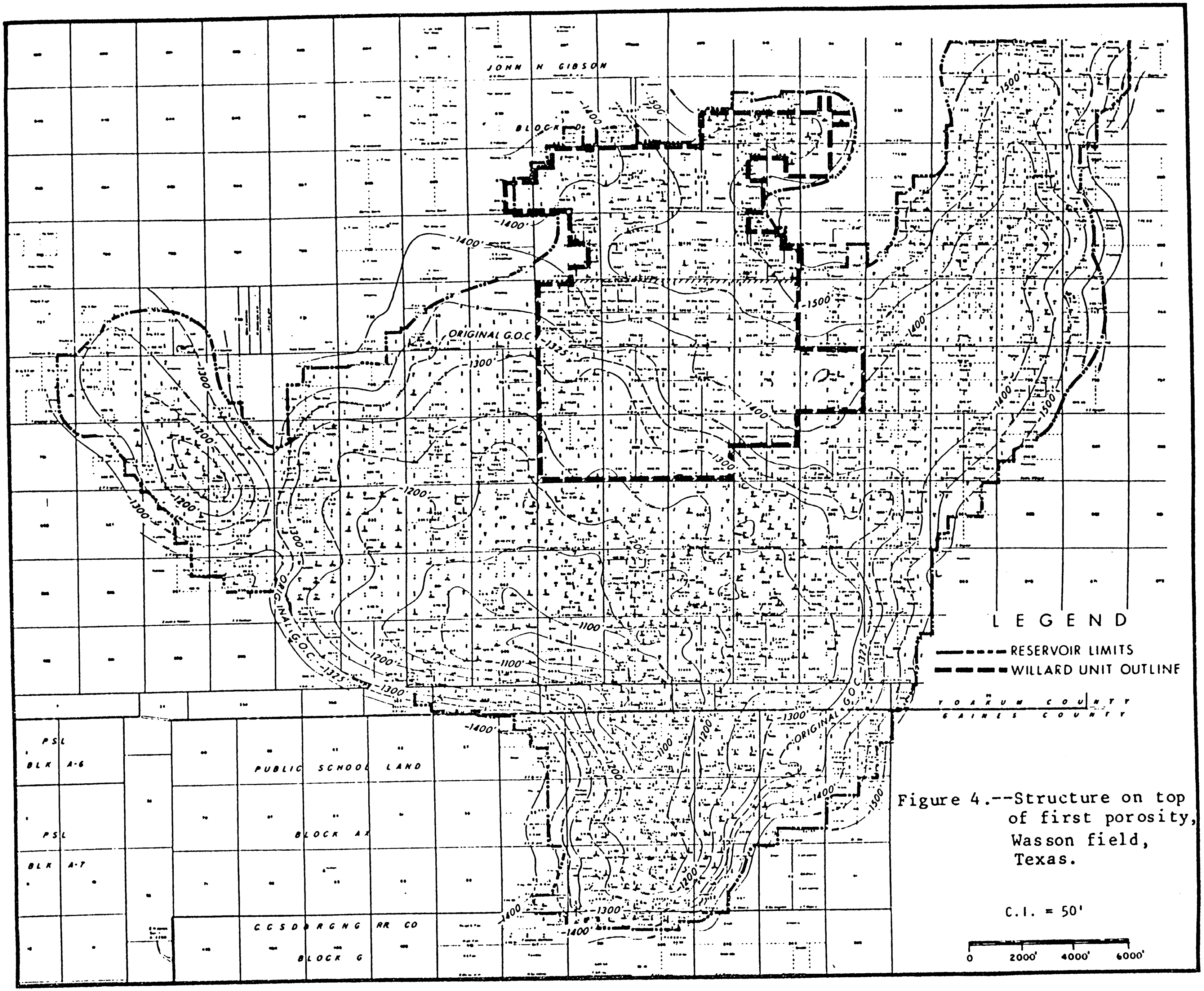

Figure 4.--Structure on top of first porosity, Wasson field, Texas.

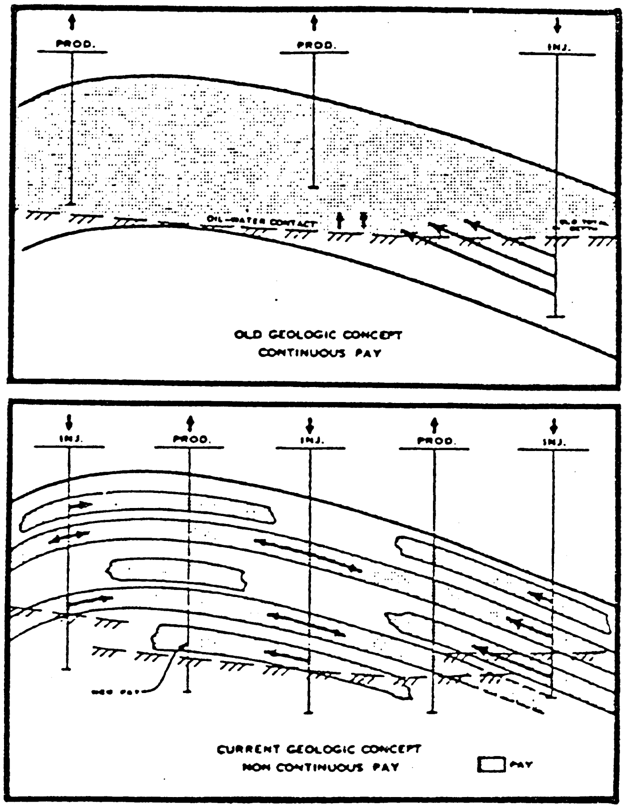

Figure 5.--Geologic concepts of pay continuity in carbonates.

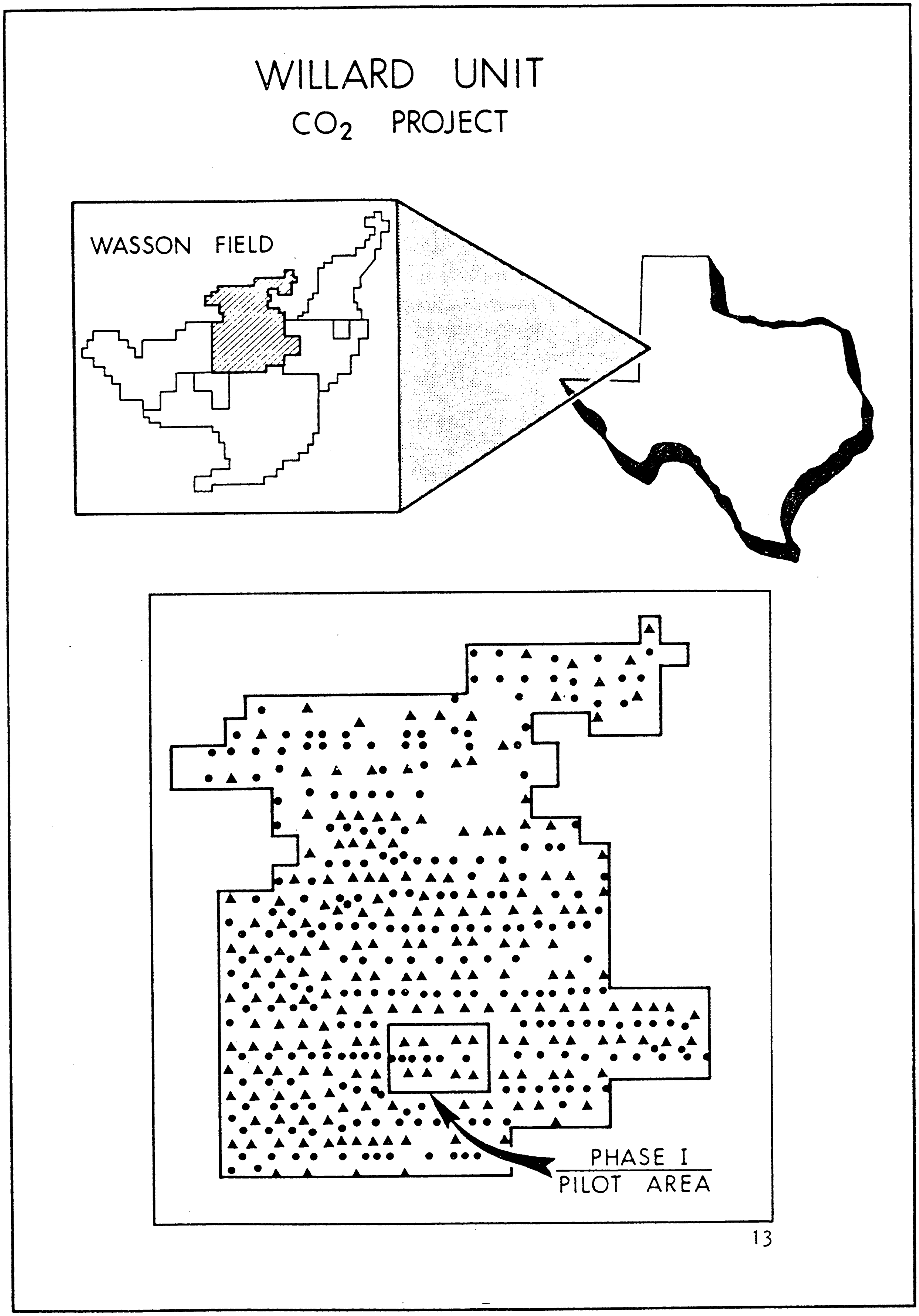

Figure 6.--Location of Willard unit CO_2 injection project, Wasson field, Texas.

WILLARD UNIT

PHASE I

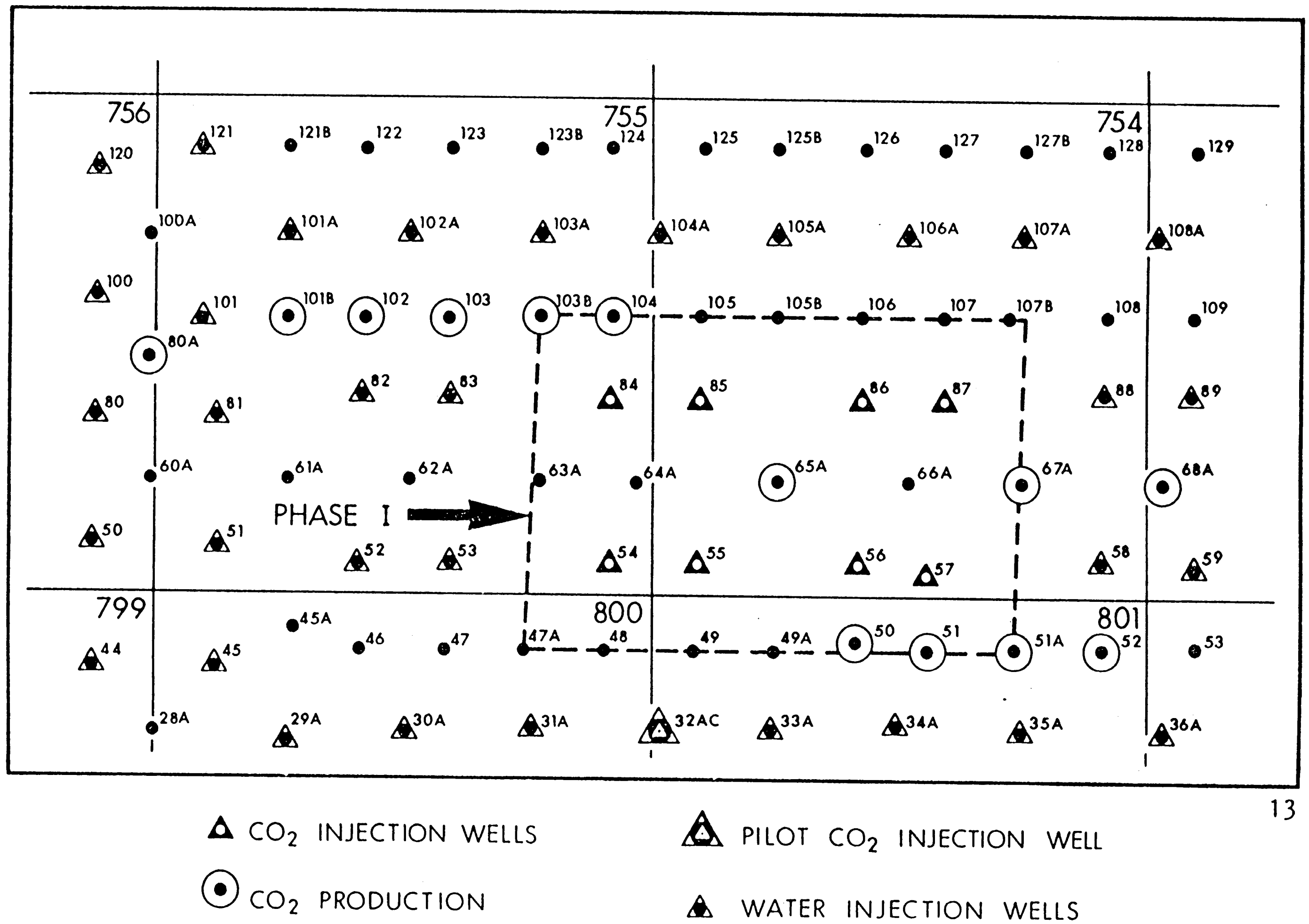

Figure 7.---Phase I area, Willard unit CO_2 injection project, Wasson field, Texas.

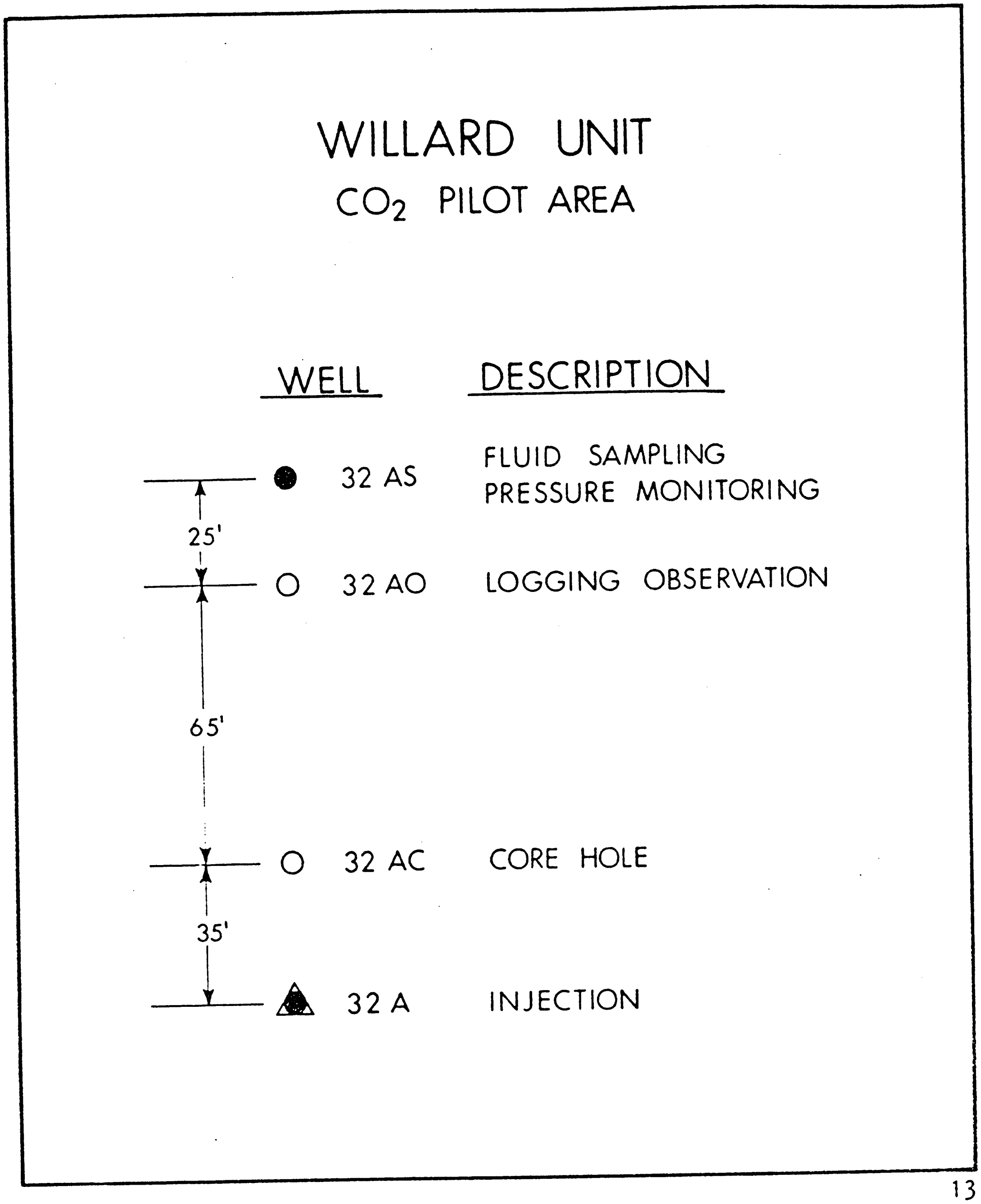

Figure 8.--Pilot area, Willard unit CO_2 injection project, Wasson field, Texas.

WILLARD UNIT

CO_2 PROJECT PHASE I
CO_2 INJECTION

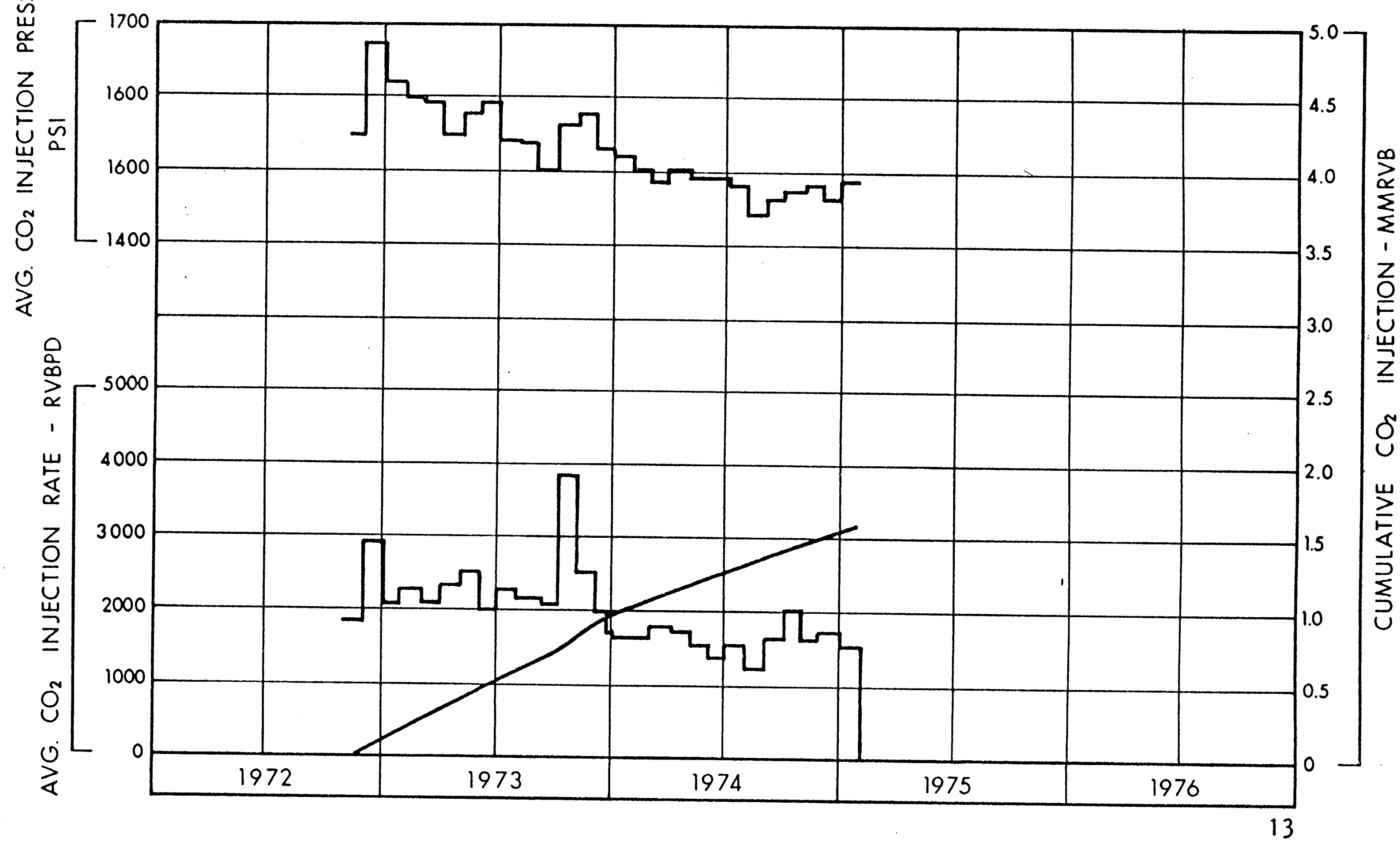

Figure 9.--Phase I injection, Willard unit CO_2 injection project, Wasson field, Texas.

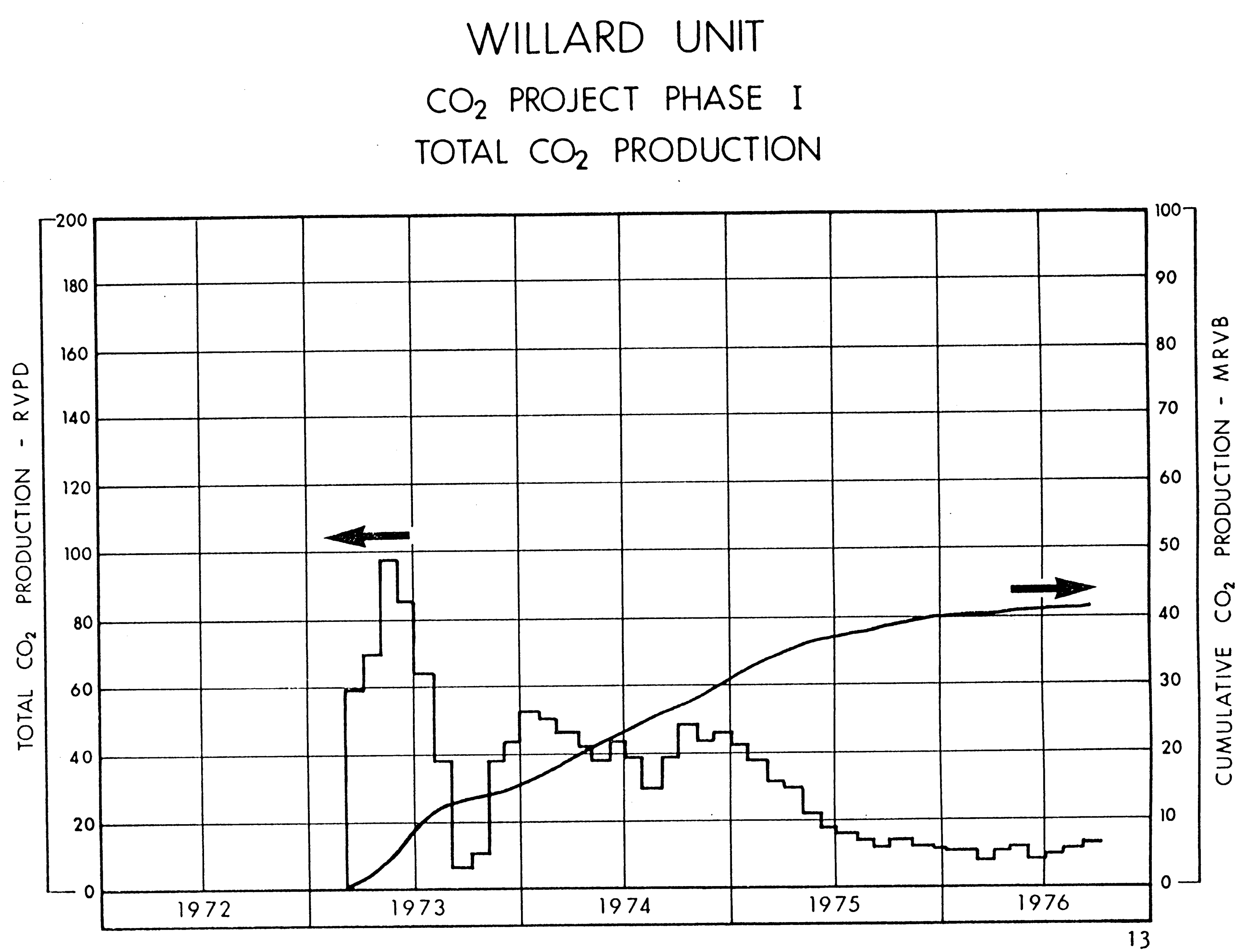

Figure 10.--Phase I total CO_2 production, Willard unit CO_2 project, Wasson field, Texas.

WILLARD UNIT

CO_2 PROJECT PHASE I

CO_2 PRODUCTION - WELLS 68A & 103B

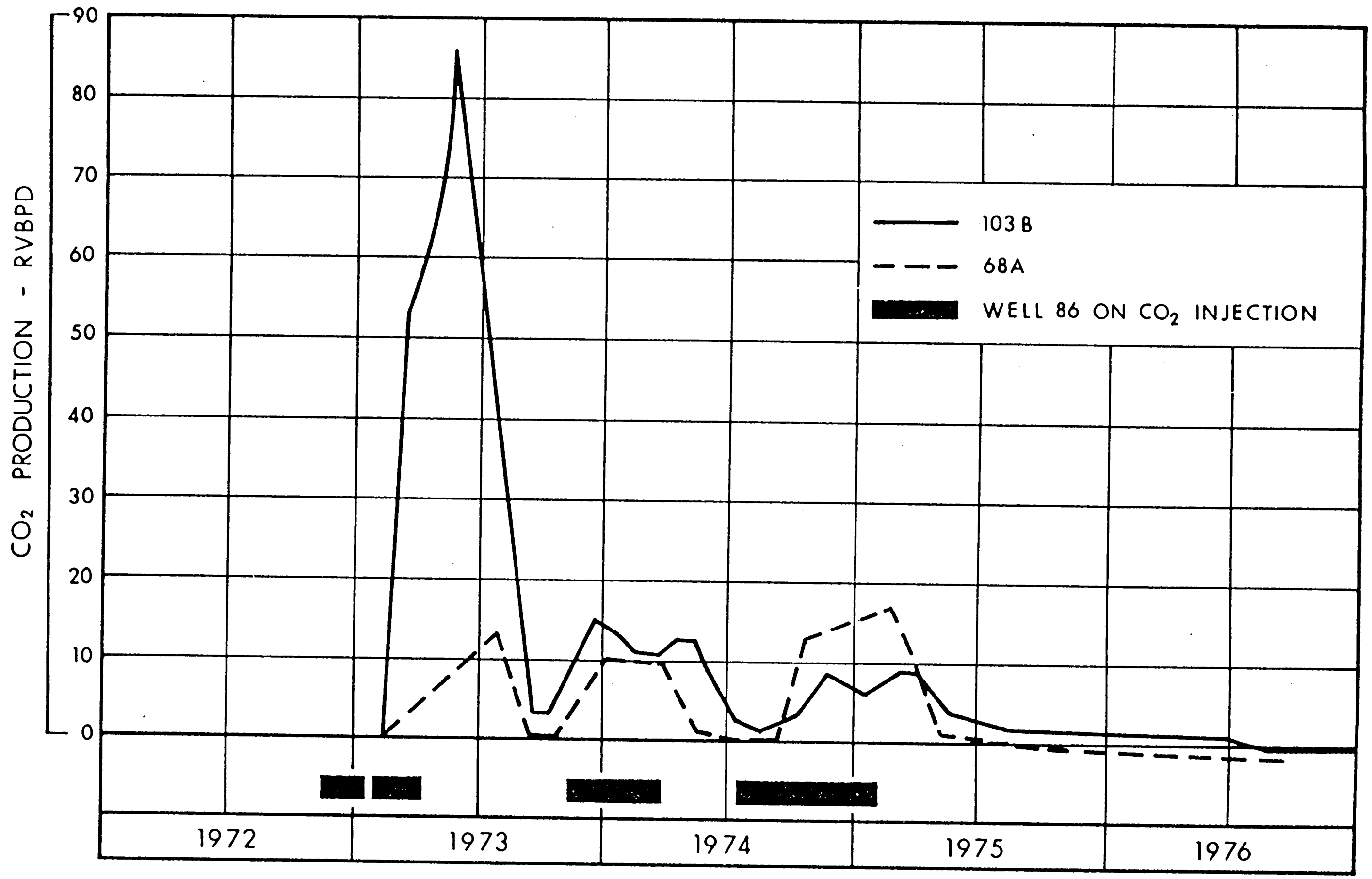

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Figure 11.--CO_2 production, Phase I Wells 68A and 1038, Willard Unit, Wasson field, Texas.

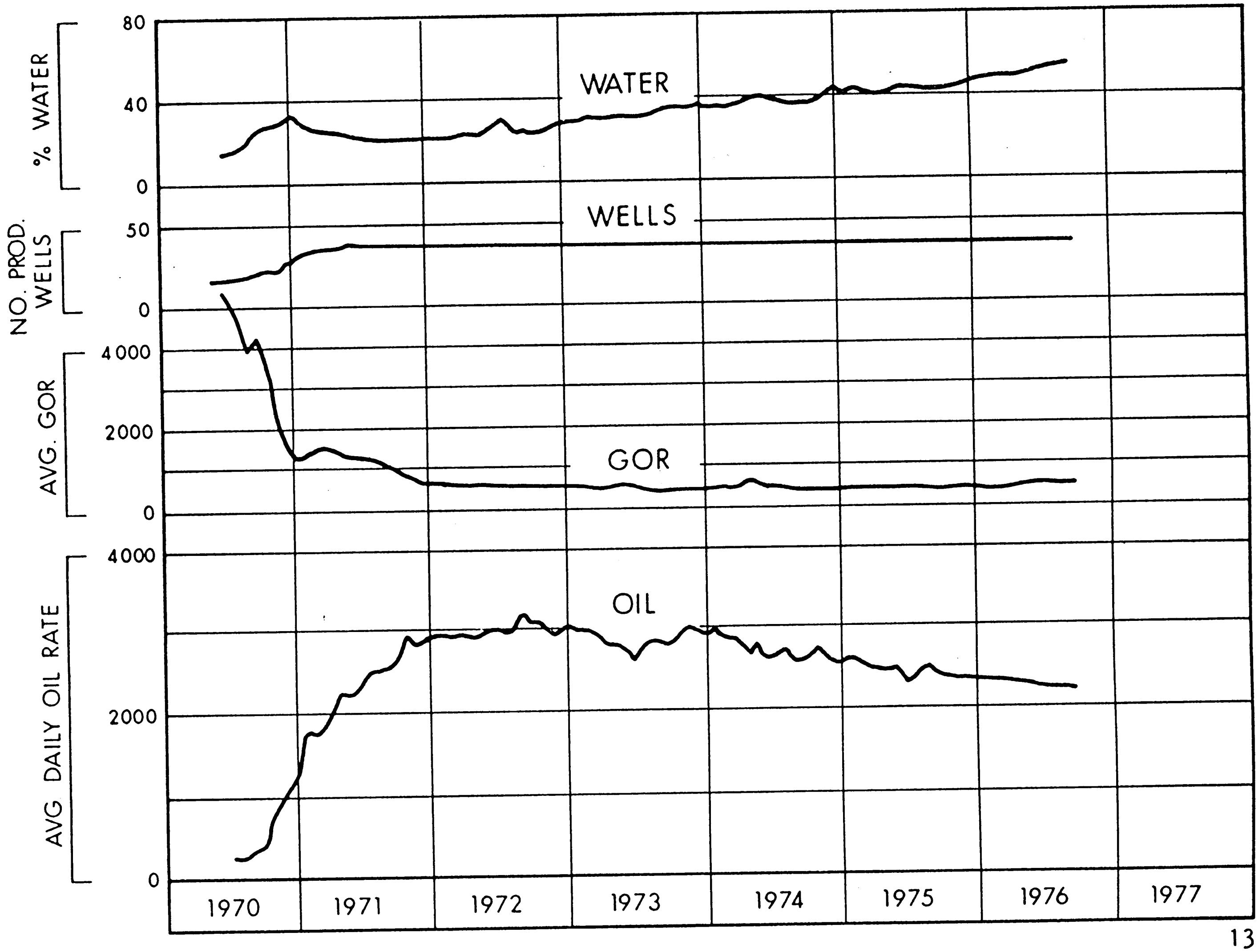

Figure 12.--Phase I production performance, Willard unit CO_2 project, Wasson field, Texas.

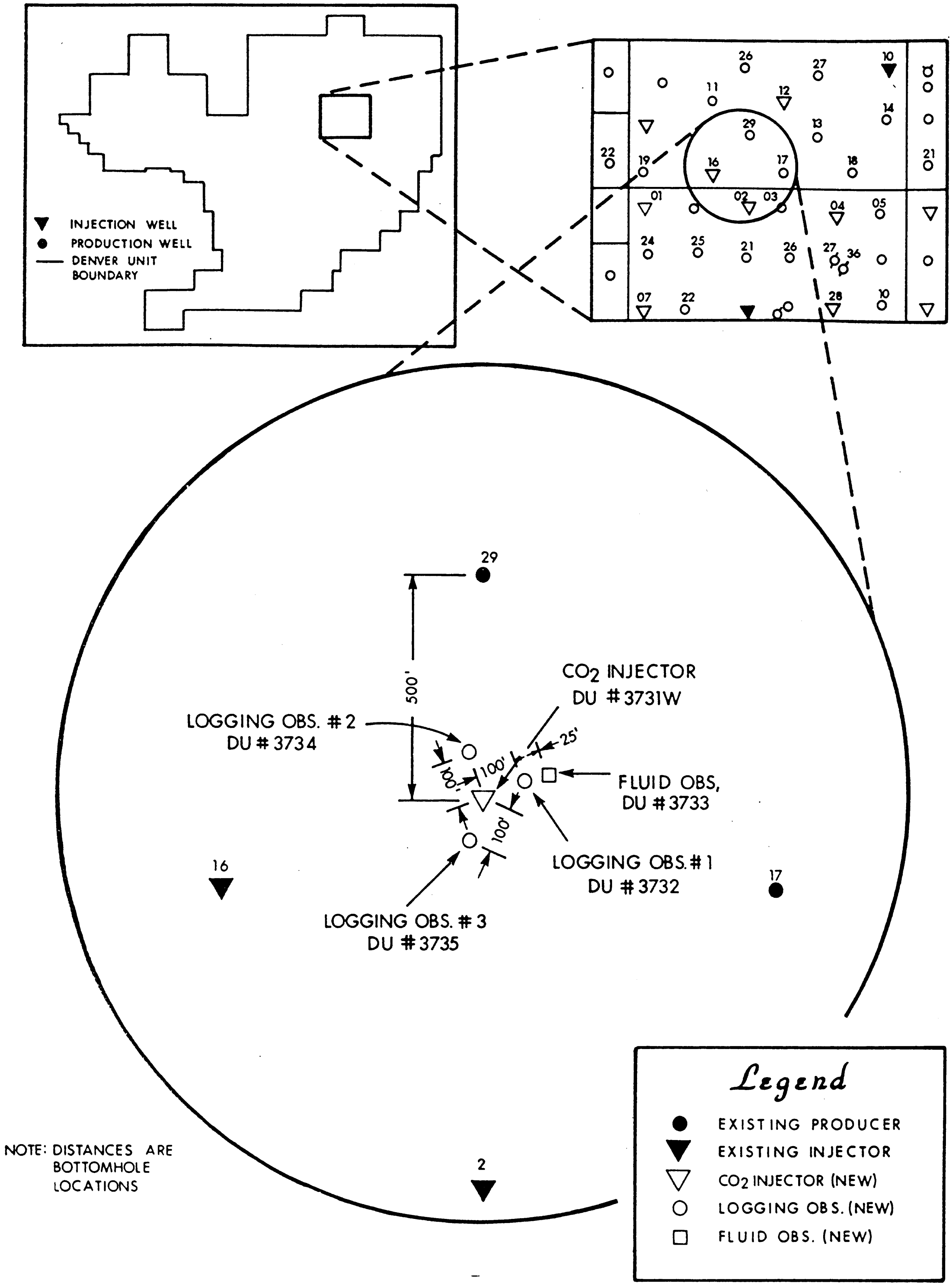

Figure 13.--CO_2 pilot configuration, Denver unit, Wasson field, Texas.

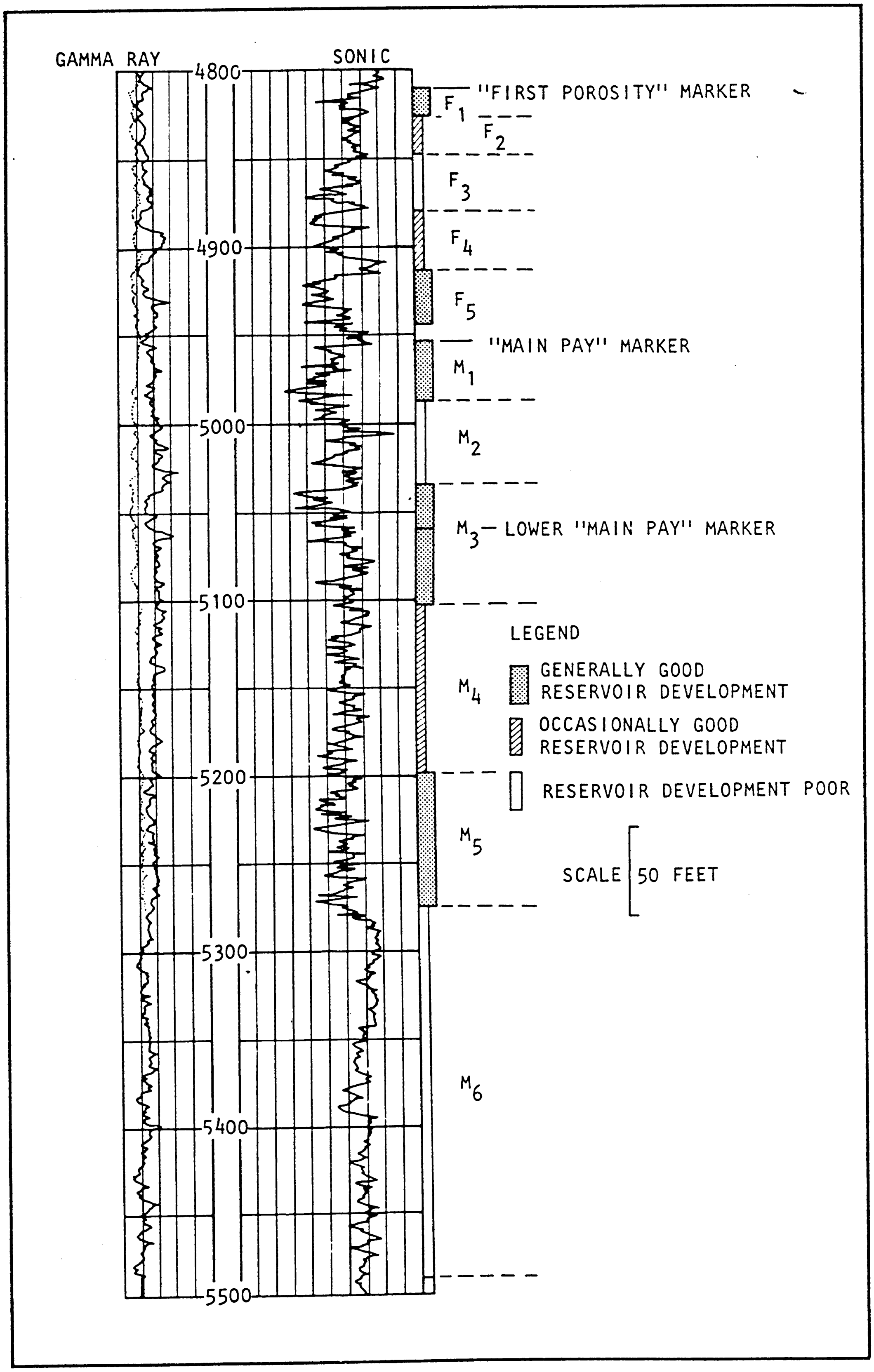

Figure 14.--Type log showing zonation of San Andres pay, Denver unit, Wasson field, Texas.

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