ACQUISITION, CLASSIFICATION, AND EVALUATION OF ENGINEERING AND GEOLIGIC INFORMATION AND CHARACTERISTICS OF WEST VIRGINIA PETROLEUM RESERVOIRS AMENABLE TO ENHANCED OIL RECOVERY TECHNOLOGY, PARTICULARLY CARBON DIOXIDE INJECTION

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FOREWORD

Under Contract No. DE-AC05-78MC05602 with the U. S. Department of Energy, Oak Ridge Operations Office and Morgantown Energy Technology Center, Gruy Federal, Inc. undertook a study with the following objectives:

- Prepare an overall assessment of West Virginia reservoirs as candidates for one or more EOR processes.
- Compile, synthesize and analyze the geologic/engineering data necessary to evaluate the EOR potential of those reservoirs identified as possible EOR candidates.
- Evaluate and interpret the results of ongoing and proposed CO_2 injection field tests in West Virginia.

This volume is the final report on the contract study. It presents Gruy Federal's methodology, results, and conclusions organized under the three study objectives listed above.

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The Need for Enhanced Oil Recovery in West Virginia

Historically, recovery from Appalachian Basin oil fields has been low, in spite of the fact that many of these reservoirs have produced oil continuously for more than 100 years. In West Virginia, the average total recovery, including both primary and secondary, is 160 barrels per acre-foot. Low-pressure gas displacement has been the most widely used technique to maintain production from the major reservoirs. Waterflooding has been successful in a few cases, but has not been widely used. Consequently, significant amounts of oil, producible with existing technology and awaiting favorable economics, still exist in West Virginia.

Enhanced oil recovery can be defined in the broadest sense as any oil production achieved after primary production has become ineffective. In current usage, the term is applied more narrowly to a group of techniques which can be used to obtain some of the oil left in the rocks after conventional primary and secondary production. In this report, enhanced oil recovery techniques or processes will refer to techniques that have not been widely applied in West Virginia. The techniques considered in this study are:

- nitrogen miscible, flue gas, and dry gas miscible displacement;
- enriched gas miscible displacement;
- CO_2 miscible displacement;
- polymer-augmented waterfloods and micellar-polymer techniques;
- in situ combustion;
- steam injection;
- caustic waterflooding.

I. AN OVERALL ASSESSMENT OF WEST VIRGINIA OIL RESERVOIRS AS CANDIDATES FOR ONE OR MORE ENHANCED OIL RECOVERY PROCESSES

Methodology.

To prepare an assessment of an oil reservoir as a candidate for one or more enhanced oil recovery (EOR) processes, complete reservoir information is, ideally, desirable. However, most West Virginia fields were discovered before the beginning of the 20th century, and many had been abandoned before the advent of modern logging practices. As a result, little if any of the desired reservoir information is directly available. Moreover, production records from the fields in West Virginia are largely non-existent.

Because the available information is limited, it was necessary to develop methods to use such data as was obtainable in performing this study within the time and scope of the initial contract. Fortunately, West Virginia oil fields are remarkably uniform in many important respects, which facilitates the use of such methods.

Two-Parameter Screening of West Virginia Reservoirs.

As they are currently understood, all EOR techniques except caustic waterflooding are primarily limited by oil gravity (or, more properly, viscosity) and all have either a maximum or minimum depth (or depth-related feature, such as pressure or temperature) constraint.[1-5] These two very important features of a reservoir, namely depth and oil gravity, are normally considered unchangeable. Thus a preliminary screening for potential amenability to EOR can be conducted using only these two parameters. A field that passes this primary screening for a particular technique can then be examined in greater detail to see whether it also meets the less-critical criteria (see Table 1).

The state-of-the-art limitations on oil gravity and reservoir depth for the EOR techniques listed above are shown graphically in Figure 1.

West Virginia oil reservoirs have a rather narrow depth distribution. Detailed data are not given in this report, but are summarized in Figure 2. This evaluation covered 157 fields for which separate depths could be found, including all the major fields and some very small ones. Reserve estimates have been published for only 104 of these. Over 300 field names for oil reservoirs in West Virginia have been found; however, many of these have been combined with other fields.

Complete oil analysis is available for only 27 fields in West Virginia (see Appendix B), and other published values (an additional 14) are surprisingly uniform.[11] The average of 62 gravity determinations from these fields is 44.6° API, with a standard deviation of 4.62° and a range of 30° to 65° (Fig. 3a). Even fewer viscosity measurements (only 40) are available.

Ignoring one 60 centipoise value as obviously atypical, the average dead oil viscosity is 3.99 cp, with a standard deviation of 1.79 (Fig. 3b).

Using these values for reservoir depth and oil gravity, it is clear from Figure 1 that CO_2 miscible displacement is the most promising EOR technique for the type of reservoir and the crude oil found in West Virginia. Micellar-polymer and caustic waterfloods, not shown on Figure 1, are considered to have minimum permeability requirements, given in the National Petroleum Council's Study[4] as 20 and 50 millidarcies, respectively. These minimum requirements seem to be higher than the typical permeability for West Virginia reservoirs, although few permeability values are available. This will be treated in greater detail in a subsequent section of this report.

Since it seems that the CO_2 miscible displacement process is potentially the most applicable to West Virginia reservoirs, this study concentrates on this method.

Screening of Reservoirs for the CO_2 Process

One critical prerequisite for the CO_2 process is that the reservoir will competently hold miscible pressure.* This has been determined in similar studies[3,4] by estimating the miscibility pressure and calculating the depth at which the rocks are competent to support this pressure loading, using established relationships to predict the breakdown pressure. Studies made in conjunction with the three CO_2 displacement processes now under way in West Virginia were scrutinized to determine the pressure at which highly efficient displacement occurred. For Griffithsville crude, this was 1100 psi at 85°F (reservoir temperature)[6]; for Rock Creek crude, 1000 psi at 73°F but not 800 psi at 73°F[7]; Granny's Creek crude was miscibly displaced at 1000 psi and 75°F.[8] These three oils are typical West Virginia Penn grade crudes.

Based on these tests and the uniformity of the crude oil, the pressure necessary for miscible displacement of West Virginia crude oils was judged to be approximately 900 to 1000 psi.

This pressure can be related to the minimum acceptable depth of a reservoir if the strength of the rocks is known. For unconsolidated sediments, using 0.465 psi per foot as hydrostatic gradient and 1 psi per foot for overburden pressure, and assuming the least principal stress is horizontal,

*Miscible pressure, as used here, is the pressure at which CO_2 will displace more than 90% of the oil in place before breakthrough in a linear sand pack.

a breakdown gradient of 0.68 psi per foot can be calculated.[5,9] However, the oil reservoirs of West Virginia are normally in well indurated and competent rocks. Data on breakdown pressures for Rock Creek and Griffithsville fields are presented in Table 2, showing that these rocks are locally capable of bearing hydraulic gradients in excess of 1 psi per foot. Both the Berea and Big Injun sands should be at least locally capable of bearing miscible pressures at depths as shallow as 1500 feet. In an attempt to confirm this estimate of the general strength of West Virginia reservoirs, field representatives of the Halliburton Company in the state were consulted. Discussions with them led to the conclusion that miscible pressures could normally be borne by reservoirs as shallow as 1800 feet,[9] where the pressure is not much more than the normal hydrostatic. Some reservoirs, however, fracture rather easily.

Other screening criteria for the CO_2 process include such factors as a minimum residual oil saturation of 20%[1-3] and a minimum net thickness of 10 feet (see Table 1).[3] Since the average West Virginia reservoir has never produced much water, and since few have been waterflooded, residual oil saturations are almost certainly greater than 20%. The net thickness requirement, found in only one set of screening criteria, was judged to be largely an economic criterion and was ignored in this screening.

Of the 104 most important fields in West Virginia, 56 have an average depth of 1800 feet or more.

The list of candidates can be further refined by considering only fields having an estimated 10 million barrels of oil remaining in place. Smaller volumes are likely to be uneconomic because of the initial costs of the EOR process. Estimates of remaining oil in place were obtained largely from previous studies.[10-14]

This reduces the number of candidates to 26 without dramatically reducing the amount of oil that might be recovered.

Another desirable feature for CO_2 miscible displacement is that the bulk of the reserves be in a single reservoir. This criterion limits the prime candidate list to 18 fields. One of these has been converted to gas storage and is inaccessible to EOR. The locations of the remaining 17 are given in Figure 4; the fields are further identified in Table 3. There are three Berea sand reservoirs, six Big Injun reservoirs, five Gordon sand reservoirs, one Gordon Stray sand reservoir, one Fifth sand reservoir, and one Squaw-Weir sand field. Also included in Figure 4 are four large reservoirs shallower than the 1800-foot minimum acceptable depth.

Figure 5 shows the potential applicability of CO_2 displacement to the major oil fields of West Virginia. The process is theoretically applicable to 22 of the 37 large (more than 10 million barrels of oil left in place) reservoirs of the state. Application of the CO_2 process to these reservoirs may be limited, however, by factors that cannot be properly assessed with the existing data. These include permeability variations, the difficulty of finding and abandoning or reabandoning old wells, and uncertain reservoir descriptions.

Screening of Reservoirs for Other EOR Technology

Although the CO_2 process is the most promising EOR technique for the high-gravity Penn grade crudes of West Virginia, it is not the only applicable one. Therefore other recovery processes, such as waterfloods, polymer-augmented waterfloods, steam displacement, caustic waterfloods, and low-pressure gas cycling, have been considered, both for the fields previously listed and for those where the CO_2 process does not seem well suited.

Waterflooding has been used very little in West Virginia. The Cabin Creek field has been successfully waterflooded, and Granny's Creek is now being waterflooded with economic success. Waterfloods attempted in several other fields, however, gave poor results. Some have failed because of low injectivity, which can be caused by inherently low effective permeability to the injected phase; some because of reactions of the injected fluid with the formation; and some because of wellbore skin damage. Waterfloods may fail for many other reasons, including the existence of thief zones, failure to bank oil, poor completion practices, inadequate engineering, drastic permeability variations, and unfavorable economics. These factors are not independent; the economic factor, for example, is strongly related to injectivity. Little is known about the previous waterflood attempts that failed except that they were attempted and they did fail.

Two of the current CO_2 projects in West Virginia are in reservoirs where waterflooding attempts have met with some success in the past, the Griffithsville and Granny's Creek fields; the third is in the Rock Creek field. Rock Creek has been considered impossible to waterflood because three attempts in the 1950's and 1960's were unsuccessful. Failure in these attempts was attributed to the high relative permeability to water and high connate water saturation, so that the resulting oil bank was small. However, in a water injection program to raise the reservoir pressure to that required for miscible displacement with CO_2, it was found that a significant oil bank had been formed.[58] It was also found that there is at least one thief zone in the bottom of the Big Lime formation, which directly overlies the Big Injun reservoir rock. This portion of the reservoir had been previously gas-cycled for many years and thus would seem to be a poor place to operate a successful waterflood; however, this is apparently not the case.

Similarly, the Griffithsville CO_2 project is in an area of the field which had not been intentionally waterflooded, though it was found to have been dump-flooded accidentally, presumably through and around leaking casings of old, improperly abandoned wells. Nine wells in the pilot area are currently producing approximately 70 barrels of oil per day[47], indicating that a significant oil bank had been formed.

The results of repressuring these fields by water injection suggests that a properly engineered waterflood can be successful in West Virginia, even in reservoirs with high connate water saturation.

If waterfloods can be successful, then polymer-augmented waterflooding should also be applicable, and even more effective, since the flow characteristics of polymer solutions can mitigate to some degree the adverse effects of unfavorable combinations of flow geometries and fluid mobilities. However, this assumes that the injectivity of the wells will not be drastically changed by the polymer solution, which is commonly the case in field applications of this technique. Intuitively it would seem that the injection of a more viscous phase would dramatically lower the injectivity; many years of actual field experience show that this is not normally the case,[15] but clay problems and low permeability (below 20 md) can produce disastrous results. The chief advantage of the technique, for West Virginia reservoirs where it will work, is that the chemicals are relatively inexpensive and high pressures are not necessary.

Polymer-augmented waterflooding should be applicable if the reservoir permeability is greater than 20 md. Unfortunately, permeability values for West Virginia reservoirs either have not been recorded or have not been published or even widely released.

Steam injection has been demonstrated to be effective for some unusual high-gravity, high-viscosity oils in Pennsylvania,[16] and more recently in a moderately high-gravity (34° API) reservoir, Texaco's Shiells Canyon project in California. Pratts has pointed out that the steam drive process may be used in light oil reservoirs, though it may not be economical.[17] The conditions deemed favorable for a steam flood of a light oil reservoir are those that would be favorable for a waterflood. Steam injection sometimes causes formation injectivity problems; Texaco used a system of co-injecting potassium chloride solution to control clay problems and maintain injectivity in their Shiells Canyon project.

For steam flooding to be attractive in West Virginia reservoirs, it would have to be demonstrated that the following reservoir characteristics exist[18]:

- oil with low distillation residue;
- low reservoir pressures;
- high injection rates;

- thick layers;
- high porosity.

The first two criteria are commonly met for West Virginia reservoirs, but the last three are not.

An attempt to steam-flood the Rock Creek Field failed because of high heat loss and low injectivity.

Low-pressure gas cycling has been conducted to some extent on most of the large fields in West Virginia, and these projects have generally been successful. The drawback of this technique is that recoveries are normally quite low.

Distribution of Fields with EOR Potential

Table 3 shows that there are 22 reservoirs which seem to have high potential as candidates for enhanced oil recovery: one each in the Salt, Keener, and Squaw-Weir sands, nine in the Big Injun, three in the Berea, and seven in the Gordon series sands. Figure 6 shows the stratigraphic relationship of these reservoirs, which occur in three periods.

If secondary recovery is not feasible, then the more difficult and often financially less rewarding EOR techniques should be applied only with great caution. Application of conventional secondary recovery techniques to these fields has been varied, and is discussed under each system description below.

Devonian System

The Gordon series sands (Gantz, Fiftyfoot, Thirtyfoot, Gordon Stray, Gordon Fourth, Fifth, Bayard) occur in the upper parts of the Devonian shale as irregularly distributed "casual sands".[19] They are usually thin zones with highly permeable streaks, often with low porosity and visibly conglomeratic.[10] These characteristics would hinder the successful application of EOR techniques.

Some reservoir properties of the Gordon series reservoirs covered in this report are included in Table 4. As the table shows, the Gordon series sands selected for their EOR potential by the rationale developed in this report could indeed be described as highly conglomeritic and highly variable in thickness.

Because of their nature almost all of the old Gordon series reservoirs have been abandoned for many years.

There have been four recorded waterflood attempts in the Gordon sands, all unsuccessful. Low-pressure gas cycling, however, has been successful; twelve reservoirs have been subjected to such cycling. Of the seven Gordon sand fields selected by our preliminary screening, three have undergone low-pressure gas cycling (see Table 5). Results of the low-pressure gas injection program for one of the fields selected have been reported in detail. This particular project, affecting 250 acres, showed a dramatic response in oil production to the gas injection program. Figure 8 shows the decline curve for this project from 1944 to 1950. The sharp peak in 1949 resulted from field operations changing hands and the "pumping off" of all wells. Further details on this project, the Mills Gordon Project, are given in Table 5; the information was taken from a previous report.[11]

A pilot waterflood project was carried out in the Mannington field. Details have not been made available, but some information has been disclosed. The following excerpt is from an unpublished report:

> <u>Gordon Sand Pilot Waterflood, Mannington Oilfield, Marion County, West Virginia</u>
>
> Pennzoil operated a pilot waterflood project in the Mannington oilfield, Marion County, West Virginia. Detailed information on this project is not available for publication. Development of the pilot began in 1964 with the drilling of four new wells which were completed as water injection wells. The pattern used in the pilot was one normal five-spot. . . . An old well in the center of the pattern was used for the production well. Approximate area enclosed by the four injection wells was 38 to 40 acres.
>
> The depth to the Gordon sand in the area of the pilot ranged from 2,700 to 2,950 feet. Thickness of the Gordon sand in the area usually ranges from 25 to 45 feet. Completion records of the new wells in the pilot area showed a range of sand thickness of 29 to 42 feet. The Gordon sand is not generally porous and permeable throughout, but usually contains one or more zones of porous and permeable "pay" sands. Often these are thin, highly permeable, pebbly or conglomeritic zones with several hundred millidarcys permeability. Porosity of the Gordon sand usually ranges between 9 and 15 percent and averages 12 percent. Porosity logs of the Gordon sand in Mannington oilfield also show this range of porosity. Fig. [7] shows some sand characteristics of the oilfield with gamma ray and density logs. No core

analyses of the Gordon in the Mannington oilfield are available for publication but a Gordon sand well in the Smithfield Gordon oilfield [refs. 21-23] approximately 8 miles west of the pilot area show very similar sand characteristics. In the Smithfield oilfield well, the Gordon sand was 16 feet thick, core analysis indicated a porosity range from 8 to 16 percent, and a permeability range from less than 1 to over 100 millidarcys. The "pay" zone in this well was 7 feet thick, typical of the Gordon "pay" zones. This 7-foot zone averaged 13 percent in porosity and 42 millidarcys in permeability, although only 3 feet of the zone contained high permeability. The water saturation of the Gordon reservoir in the Mannington area is usually low and wells produce very little water during primary production operations.

The success or failure of this pilot flood has not been reported. Permits to abandon some of the pilot wells were obtained for abandonment in 1970. One may therefore assume that the pilot test was a failure, inasmuch as it was not expanded beyond the original five-spot. Injection water was obtained from shallow water wells. Due to its low interstitial clay content, little trouble should have resulted from clay swelling or particle migration from contact by fresh water. Because this project enclosed a very large area, approximately 39 acres, for a pilot test, control could have been very difficult. A five-spot such as this may produce or sweep much more oil outside the pattern than would be produced in the pattern. The high permeability zones could also contribute to lack of control. These zones have probably produced a much higher percent of their initial oil in place during primary production than the low permeability zones and would have a correspondingly higher gas saturation. Channeling of flood water would probably occur because of the great range of permeability in the "pay" section.[20]

Conclusions.

(1) Gas injection has been shown to work quite effectively in several projects, 3 of which involved more than 20 wells.

(2) Waterflooding in the Gordon and Gordon series sands has never been effectively demonstrated.

(3) Even though gas injection has been conducted on 4 of 7 Gordon series reservoirs selected as having significant EOR potential, these projects have by no means included the entire field.

(4) As Table 5 shows, the injectivities of these projects has been in the neighborhood of 50-200 MCFD per well at approximately 100-130 psi.

Mississippian System.

The bulk of the oil production from West Virginia comes from the sands of Mississippian period, notably the Big Injun and Berea sands. They have been called "blanket sands," chiefly on account of their widespread occurrence, and the Big Injun is highly variable. Watts and Overbey have subdivided the Big Injun sandstone on the basis of mineralogy into two types: The Northern Big Injun, classified as a proquartzite; and the Southern, a borderline sub-graywacke or graywacke.[24] The Berea sandstone is more uniform than the Big Injun.

Big Injun Sands.

Four of the six Big Injun sand reservoirs selected as having EOR potential have been subjected to low-pressure gas cycling (Table 6). Several fields have had more than one injection project. The injectivity of the Big Injun sand reservoirs in these projects has ranged from 60 MCFD/well at 3 psi to 320 MCFD/well at 235 psi (Table 6).

There have also been 12 water injection projects and some pilot projects, injection tests, or waterflood attempts in the Big Injun sand. Information in Table 8 was compiled from the work of Watts[20] and from Interstate Oil Compact Commission (IOCC) reports.[11-14]

The injectivity in these Big Injun sand reservoirs can be computed from Table 8 as about 50-100 BWD/well at roughly 1000 psi. The highest injectivity of these projects was in the Big Injun sand in the Walton field. In one project in the Rock Creek field, the secondary recovery was about 44% of the primary when the 1950's reports were filed.

Berea Sands.

Two of the three Berea reservoirs have had low-pressure gas injection projects. Little information could be found on these projects, since they were inactive in the early 1950's when the secondary recovery information was published (Table 6a). The injectivity in two Cabin Creek projects seems to have been lower--roughly 20 MCFD/well at 50-200 psi. The Griffithsville project injected only 44 MCFD in 52 wells at 300 psi, if the information published in a previous report is correct.[11]

The Berea sand reservoirs selected as having significant EOR potential have had several water injection reports, including one successful fieldwide waterflood in the Cabin Creek field. Table 7 shows the injectivity in the Cabin Creek project ranged from 85 BWD/well at 210 psi to 115 BWD/well at 800 psi, and in the Griffithsville project, 28 BWD/well at 1400 psi. Little additional information is accessible at this time.

Squaw and Weir Sands.

The Squaw and Weir sands have undergone several small low-pressure gas injection and water injection tests, all in the Blue Creek field. Portions of the Blue Creek field have been the sites of at least seven secondary recovery projects or tests. The earliest of these was a low-pressure natural gas injection project started in 1926, involving about 190 acres; the last was a single-well water injection test, which ended sometime in the early 1960's. Five of the projects have been covered in IOCC reports on secondary recovery in West Virginia. The information given on these projects indicates that they have ranged from highly successful to unsuccessful. However, as can be seen from the acreage of the projects (see Table 9), the bulk of the Blue Creek field has not been subjected to any large-scale secondary recovery efforts.

The projects that were tried included four low-pressure gas injection projects, two water injection tests, and one low-pressure air injection project. The injectivities of natural gas in three projects (information is unavailable on the fourth) are 33, 19 and 33 MCFD at 147, 35, and 115 psi, respectively. Injectivity of water in one test (1946) was 100 BWD at an average wellhead pressure of 605 psi. The air injection project had a recorded injectivity of 103 MCFD at an average pressure of 46 psi.

The highly successful gas injection project which affected 202 acres is summarized in the following extract from the IOCC report.

> This field produces from the Squaw Sand (Pocono) at a depth of about 1,950 feet. The sand is lenticular with a pay thickness of about 15 feet. The production increase shown is rather unusual. Only three wells remained on the lease in question at the time repressuring was started in 1927. It is believed that the continued high recovery has been due, in part at least, to water encroachment because the amount of gained oil is far out of proportion to the secondary recovery potential by gas drive. A number of leases in this field have experienced water drives which have greatly augmented production from both primary and secondary recovery sources.[11]

Figure 9 shows the decline curve for this project. By "water encroachment" on this lease, the authors probably mean an uncontrolled cross-flow of water from another formation, since the field definitely did not have a natural water drive. This provides indirect evidence that a water drive will work--at least in selected areas of this field.

Figure 9a shows the decline curve for a different project of comparable dimensions in the Weir sand. This project was suspected of having great permeability variation. Nevertheless, some oil was recovered by this process at a cost which at the time was economic.[11]

Conclusions.

The significant conclusions for the Mississippian sand reservoirs are:

(1) Waterflooding has been demonstrated as an effective displacement mechanism in one Berea reservoir and one Big Injun reservoir. Injectivity of water in both cases was more than 50 BWD per well at pump pressures near 1000 psi.

(2) Waterflooding on a large scale has not been successfully demonstrated in Squaw or Weir sand reservoirs.

(3) Low-pressure gas injection has been found to be successful in the Berea, Big Injun, Squaw, and Weir sand reservoirs throughout the state. These projects have had injectivities ranging from 320 MCFD per well at 235 psi to 20 MCFD at 50-200 psi.

(4) Even with the successes of the low pressure gas injection, the projects have generally been limited in areal extent, usually involving less than 10 injection wells.

Pennsylvanian System.

Pennsylvanian System sands include the Salt, the Cow Run, the Burning Springs, and others. One Salt sand reservoir was selected as having high EOR potential, the Cairo-Ritchie field. The Salt sand has been described as highly variable in grain, size, thickness, and occurrence.[20]

The Cairo-Ritchie field is carried by the West Virginia Geological Survey as the Cairo-Ritchie-Mine-Hartley field on the most recent oil and gas field maps. The Hartley field has been the site of a low-pressure gas injection project; the available information on this project is compiled in Table 10, which shows that the injectivity of this project was approximately 50 MCFD/well at about 250 psi.

Waterflooding has been attempted in the Salt sand and other Pennsylvanian age reservoirs. Although some encouraging results have been obtained, there has been no large-scale and systematic use of this secondary recovery technique in these sands.

Summary.

The following West Virginia oil fields were selected as candidates for EOR by CO_2 injection:

1. Blue Creek
2. Cabin Creek
3. Cameron-Gardner
4. Centerpoint
5. Granny's Creek
6. Greenwood
7. Griffithsville
8. Jacksonburg-Stringtown
9. Mannington
10. Pine Grove
11. Porto Rico
12. Salem-Wallace
13. Steel Run
14. Tariff
15. Walton + Clover-Rush Run
16. Wolf Summit
17. Yellow Creek

Four other fields are candidates for other EOR processes:

18. Cairo-Richie
19. Sistersville
20. Rouzer
21. Kidwell-Elk Fork

II. EVALUATION OF THE EOR POTENTIAL OF CANDIDATE RESERVOIRS SELECTED IN SECTION I.

Reservoir features that limit the use of a secondary recovery technology often limit the utility of a more exotic EOR technology. Therefore the fields offering the lowest risk for EOR application are those in which secondary recovery techniques have been successfully applied. However, these fields generally have lower saturations than the ones where secondary recovery techniques have not been used, and therefore present a smaller target in terms of potential production.

The potential of any EOR technique in a particular reservoir depends upon the size of the reserve, the efficiency of the EOR technique, the relative difficulty in applying the technique (risk factor), a myriad of reservoir characteristics, and economic criteria (rate of return, tax incentives, and other factors). The scope of this study did not allow for any economic analysis, and therefore this factor will not be considered.

The best reservoir data that can be compiled at this time on the candidate reservoirs are contained in Appendix A.

Determination of Size of the Reserve.

The average total recovery for West Virginia reservoirs has been about 160 barrels per acre-foot. This estimate is based on the production figures for 24 largely single-pay fields (see Table 11). Production figures, acreage, and thickness values used to calculate these recoveries were taken largely from previous reports.[10,26-36] The field outlines were independently checked and the agreement with reported acreages is good for each of the 21 fields selected under Section I. Thickness was obtained from driller's logs or modern logs (if any exist) for the field. Although the acreage, thickness, and total production figures are merely estimates, they may be the most accurate reservoir information existing on West Virginia oilfields.

The reserves originally in place in these 21 fields could be calculated volumetrically if the porosity, acreage, thickness, and water saturation were known. In fact, the first three quantities are known for most of the reservoirs selected under Section I of this study; water saturation values, however, are not. Because these fields do not normally produce water along with oil, they must have water saturations near the irreducible value. Irreducible water saturations may be estimated, if permeability is known,[37] from empirical relationships such as

$$S_{w_{ir}} = \frac{250\phi^3}{k^{\frac{1}{2}}}, \text{ where } \phi \text{ is porosity and } k \text{ is permeability.}$$

The relationship seems to work well on three pilot areas where the original saturation values have been estimated, but this is scarcely a valid test. It seems also to work with a large portion of the reservoir information filed in a 1951 secondary recovery report.[11] Unfortunately, permeability is not known for most of the fields of interest in the present study.

Further evidence of the utility of this well known empirical relationship is found by comparing its predictions with saturations derived from air/brine capillary pressure measurements.[38] As can be seen from Figure 11, the agreement between these values is good.

Conventional volumetric calculations will yield necessary water saturation from the original reserve estimates (see Table 13). Such calculations show that in some instances the reserves have been grossly misestimated. Oil saturations in excess of 100 percent, which are indicated for some fields, certainly cannot exist; and it is hard to understand water-free oil production from reservoirs having oil saturations as low as 16 percent.

The IOCC has published several reports in which saturations obtained by core analysis of several fields and reservoirs were averaged.[12-14] These values are critical to estimating reserves, and a complete tabulation is given as Table 14. These average values can be used in estimating more realistic saturation values.

Reserve figures have been calculated for 10 of the fields selected in Section I, using data from two sources: original saturation and formation volume factors were taken from the 1954 IOCC report on secondary recovery in West Virginia[12]; values for acreage and thickness came from U.S. Bureau of Mines Bulletin No. 607.[10] Results of the calculations are shown in Table 15.

It should be stressed that neither the original saturation values nor the original formation volume factors have been determined directly; consequently these reserve figures are highly speculative estimates. In two instances the 1963 Bureau of Mines estimates of original oil in place appear to be more reasonable; in eight other fields the calculated reserve estimates seem satisfactory.

The total estimate of oil originally in place in these 10 fields is 741.6 million barrels. Total production is 112.6 million barrels, leading to an estimated total recovery of 15% for these 10 fields. This is certainly a respectable figure, considering the completion practices in use when these fields were developed (mostly before 1920). Using reasonable numbers for unknown values in the remaining 11 fields reveals that more than one billion barrels of oil may remain in fields where the CO_2 displacement process should work.

Reservoir Data.

For some of the candidate fields, such as the 10 in Table 13, reservoir information is available in the technical literature to estimate the potential of EOR technology; for others, very little quantitative information exists. In an attempt to overcome this difficulty, all the known values that could be found for certain key reservoir features have been gathered. These were determined independently of the IOCC report and thus serve as checks on the values reported there.

Porosity. The averages of all published porosity measurements in the various reservoirs are given in Table 16. This table includes the IOCC values for comparison. These values can be used as guides in estimating unknown porosity values.

Formation volume factors. Values for this parameter were established for all fields for which an API gravity was available, using published correlations and estimating the unknown values. The results appear in Table 17. In 1954, the IOCC's West Virginia Committee published state averages for the original formation volume factors of all the major producing sands in the state. This information is not available from any other source. The formation volume factors taken from this report are compared with estimates made for the present study by the correlation in Table 17.

Current formation volume factors have been estimated from recently measured values for the reservoirs in the Griffithsville, Rock Creek, and Granny's Creek fields; these values are 1.04, 1.15, and 1.11, respectively, at approximately 1000 psi. The first field has had no gas repressuring; the other two have had large-scale low pressure gas injection projects. Since the crude oil is remarkably uniform throughout the state, the current formation volume factor can be estimated at around 1.04 if the field has not undergone extensive gas repressuring, or 1.13 if it has.

Permeability. One factor impeding the assessment of the potential of EOR techniques in these fields is the lack of permeability data, either absolute or relative. An attempt was made to assess at least qualitatively the permeability to oil of those reservoirs selected as having significant EOR potential.

Since the major reservoirs in the state have a narrow depth distribution, the original bottomhole pressures and temperatures should have been comparable. The viscosity of West Virginia crude oils also has a narrow distribution, as previously mentioned. Another feature of these reservoirs is that they were all solution gas or gas expansion drive reservoirs. In view of all these similarities, it is tempting to calculate a permeability for a given reservoir by estimating the unknown factors in Darcy's law.

Darcy's law for radial flow, ignoring gravitational effects, can be stated as

$$q = \frac{7.08kh(P_e - P_w)}{\mu B_0 \ln(r_e/r_w)} \qquad \text{(Eq. 1)}$$

where B_0 = formation volume factor,

h = net sand thickness in feet,

k = permeability in millidarcies,

μ = viscosity of oil at reservoir conditions in centipoises,

P_e = pressure at edge of drainage in psi,

P_w = pressure within the well in psi,

q = flow in barrels per day,

r_e = effective drainage radius in feet, and

r_w = wellbore radius in feet.

Assuming $(P_e - P_w)$ = 500 psi, r_w = 0.3 feet, r_e = 600 feet, μ = 1 cp, and B_0 = 1.2, then k is given by

$$k = \frac{q}{388h} . \qquad \text{(Eq. 2)}$$

Admittedly, many approximations are used in deriving this relationship, but the agreement with results from the field tests studied in detail under Section I is quite good. Using the recorded maximum 24-hour potential and net thickness from driller's logs, the permeabilities calculated from Equation 2 for Rock Creek, Granny's Creek, and Griffithsville are 12, 6, and 9 md, respectively; the corresponding core-derived values from the pilot areas are 15, 2, and 4 md (geometric mean permeability using all measured values greater than 0.1 md).

The agreement is not perfect, suggesting that the above treatment and the relationship given by Equation 2 are oversimplified. However, permeability is inherently a property with a wide range of distributions, so it is not surprising that there is less than total agreement of the known permeabilities of the pilot areas with the approximated values for the whole fields derived above. Even though it is a roughly approximated value, such a number can at least be used to divide the candidate reservoirs into very high, medium, or low permeability categories. This has been done; the results are shown in Table 18 and graphically in Figure 9. Figure 9 shows that there are no obvious candidate reservoirs for the steam process.

Lack of permeability data means also that permeability variation is unknown, and high permeability variation is detrimental to all EOR processes. In an effort to provide reasonable values of this critical feature, permeability variations for selected formations have been determined from core analyses obtained in an earlier program.[22,23] These data are displayed graphically in Figures 12 - 14.

The logical candidates for waterflood or polymer-augmented waterflood are fields in the medium to high permeability brackets that have not been waterflooded. The high permeability fields may be candidates for chemical EOR processes; this would depend on the specific crude oil composition, resident brine composition, and many other factors whose evaluation is beyond the scope of this discussion. The low-pressure gas process should be applicable to all the reservoirs; it has been applied to at least some portion of most large fields.

A summary of many of the salient features of each reservoir selected in Section I is given in Table 19.

The CO_2 process is potentially applicable to all of the listed fields. This assessment is only preliminary, and the application of the process to any of these reservoirs by industry will probably be deferred until certain features of each reservoir needed to make an economic evaluation can be determined.

Economic Considerations.

For an adequate economic assessment of any EOR project, an accurate determination of the residual oil saturation is necessary. This could be done by analysis of logs from a recently drilled well in the field. The method is, however, hampered by difficulties in the determination of one key variable, water resistivity. Determination of the correct water resistivity factor to use in log analysis of old reservoirs is always a problem, since extraneous water may have been introduced into the formation by crossflow behind pipe or by attempted waterfloods. Produced water, if in fact it is from the formation, will normally come from the more permeable intervals of the sand, which are also the intervals most susceptible to flushing by extraneous water. Such intervals may also exhibit the most highly developed SP value. Thus both the SP-derived and the produced-water values for resistivity may be correct for the more permeable intervals but incorrect for the tighter portions of the sand. Salinity measurements on interstitial water may provide the correct resistivity to use in the tighter unswept and uncontaminated portions of the sand.

Other requirements for an adequate economic assessment include an evaluation of the current condition of the field and an estimate of the costs of rectifying any major problems.

One of the easily identifiable problems in applying the CO_2 miscible process (or any other process involving high pressure or expensive chemicals) is locating and properly plugging old wells. The nature of this problem is made clear in the discussion below, describing the casing practices used in drilling Walton Field. These were probably typical of the time, and most of the fields drilled before the late 1930's probably had similar programs.

> The casing program used during the early development period included wooden conductor pipe set through the surface soil and gravel. Water from fresh water sands was excluded from the hole by setting a string of 10-inch surface casing to a depth of about 300 feet. An intermediate string of 8-inch casing usually was set in the top of the Big Dunkard sand to exclude red-rock caving. The production string, usually of 6-5/8 inch casing, was set in the upper portion of the Big Lime to prevent the invasion of salt water from the Salt sands. The seal around the production casing was made by allowing the drill cuttings to fall around the casing. Open-hole drilling then continued through the Big Injun and Squaw sands, allowing a 25- to 30-foot pocket below the bottom of the Big Injun sand. In completion, most of the wells were shot with 30 to 50 quarts of nitroglycerin. The size of the "nitro" charge was governed by the thickness of the sand, designed as "oil pay" in driller logs. In many instances the 8- and 10-inch strings of casing were pulled from the hole after the production casing was set.[39]

Pulling the 8- and 10-inch casing leaves a 6-7/8 inch casing in a 10-inch hole, held in place by cuttings dropped down the hole. Of course the natural caving action of the shales would tend to fill this void, but without cement it appears that if the reservoir were subjected to high pressure the fluids could escape through and around the old well.

If the casing has been pulled and the hole plugged with cement, the danger of leakage will be less. Similarly, if the old wells are open and not concealed (cut off below ground level) it will be much easier to reenter and properly cement them. Therefore, fields still under production must be considered to have a higher potential for EOR by the CO_2 displacement method than those previously abandoned, simply because the location of the wells is known with certainty.

The last major obstacle to performing an adequate economic assessment at this time is the inability to estimate with any accuracy the amount of oil that might be gained by the application of the CO_2 process. Current industry estimates are that for a successful CO_2 displacement project, 2-7 MCF of CO_2 will be required for each barrel of additional oil. As will be discussed in Section III of this report, in the single CO_2 project for West Virginia for which results are available, the CO_2 required per barrel of additional oil was substantially higher than this.

III. EVALUATION AND INTERPRETATION OF THE RESULTS OF ONGOING AND PROPOSED CO_2 INJECTION FIELD TESTS IN WEST VIRGINIA

Three ongoing CO_2 projects in West Virginia, located in small portions of the Rock Creek, Granny's Creek, and Griffithsville fields, present a unique opportunity to thoroughly analyze the field performance of this EOR process. There are many similarities among these three projects, which may allow the evaluation of certain key variables if the reservoirs can be adequately characterized and which reduces the number of variables that must be considered in comparing the results of high-pressure CO_2 displacement.

The well spacing and injection patterns of two of the projects are very similar; the third is only slightly different. The total net sand thicknesses in all three pilot areas are also, within acceptable limits, comparable--approximately 14-35 feet (see Table 22).

The properties of the oil, and consequently of the CO_2-oil mixtures, are very similar in all three projects (see Table 20).

The geometric mean permeabilities in the pay sands are of the same order of magnitude (5-1.5, 8, 15 md).

Since in a miscible displacement the displacement efficiency is equal to 1, and in a near-miscible displacement it is nearly 1, the recovery from a reservoir is strongly dependent upon the amount of oil in place and the volume of the reservoir contacted.

The amount of oil currently in place is a function of the original saturations and subsequent field history. Two of the field reservoirs in the present study have similar current oil saturations, while that in the third project is higher. One of the reservoirs has been waterflooded, one has been subjected to low pressure gas injection, and the third has had only accidental crossflow since primary production.

The volume of oil contacted is a function of several factors:

- gravitational effects, which can separate the injected fluid from one or more of the resident fluids;
- stratification, permeability, and permeability distribution with in the reservoir, which can cause the displacing fluid to come in contact with only part of the reservoir;
- possible chemical reactions, which can dissipate the miscible fluid or damage the reservoir;

- well spacing and reservoir size;
- size of the slug of miscible fluid, rate of injection, and mobility ratios.

For any miscible displacement, "viscous fingering" effects and "gravity override" difficulties are normally considered the major problems. Gravity segregation has not been observed to be a problem in ARCO's well documented and thoroughly studied test in the Willard Unit of Wasson Field in West Texas.[40] However, this is a highly stratified carbonate reservoir, and the results may not warrant direct extrapolation to sandstone reservoirs.

Warner found that gravity segregation of CO_2 and water in waterflooded sandstones could be predicted by mathematical simulation of the displacement process.[41] The recovery predicted by the model decreased dramatically with increasing vertical/horizontal permeability ratios. Good agreement between the predicted and observed results of the Willard Unit minitest were obtained when the K_v/K_h ratio was about 0.1.[40] Warner's study predicted that relatively severe override problems would occur at this ratio, which is lower than the ratios in the three West Virginia project areas (0.3, 0.8, and 0.9) (see Table 22).

The temperatures and pressures at which highly effective displacement is predicted to occur in all three projects are near the critical point of CO_2 (see Figures 22 and 27). If pressures are above 1029 psi at reservoir temperatures found in these projects, the CO_2 will be liquid, with a density of about 0.46 gm/cm^3 and a viscosity of about 0.07 cp at 68°F. This density is about half that of the oil in the three projects, and the viscosity is lower by a factor of about 50. As oils become saturated with CO_2, the density increases; as water becomes saturated with CO_2, the density decreases.[46] Thus the inherently large differences in density between pure CO_2, oil, and water may not cause such serious gravity override problems as might be predicted. Limited field experience gives some evidence that this is the case.

Since the three CO_2 displacement field tests are in reservoirs of varying vertical permeability, it will be possible to determine whether the gravity override problem predicted by Warner's model will be observed in the field, and the K_v/K_h value at which gravitational effects become dominant (see Table 22). The plots of vertical vs. horizontal permeability for all the projects are given in Figures 28 through 30. Although the figures show some scatter in the data, there seems to be a fairly consistent relationship between horizontal and vertical permeability in all of the projects.

Permeability variation may be one of the most significant variables. The variation of permeability in the project areas can be found by plotting the permeability on log probability paper.[45] If these values are plotted using the same permeability cutoffs to refine the values as were used in computing net pay thickness, then the variation calculated is the variation of permeability within the pay zones. This was done for all of the field project areas. For such calculations, and for comparison purposes, a uniform permeability cutoff of 1 md was used for all projects (see Figure 15). It was found that the variations obtained for these groups of data were not dramatically different (0.46 to 0.70). However, critical examination revealed that filtering the permeability values had produced a comparison of only the high permeability zones of the Griffithsville and Granny's Creek fields with the entire Rock Creek reservoir (see Figure 15).

An apparently more useful approach to the permeability distribution is to use every permeability measurement greater than 0.1 md in the probability plots. Such a plot conveys more information than a simple net/gross ratio, and should be a more useful guide to predicting reservoir performance. This was done for all the CO_2 field projects, yielding the plot shown in Figure 16. Only cores taken through the total sand interval were used, to avoid biasing the data. As can be seen from this figure, there is a large difference between the Rock Creek and the Griffithsville and Granny's Creek fields.

Viscous fingering is normally aggravated when there is a high variation, but lateral continuity of the variation is also a key characteristic: even a very large permeability variation would not be especially detrimental if it were randomly distributed. If the porosity and permeability are controlled by the original distribution of features in a reservoir, then they will be stratified, since, in general, all sedimentary rocks are inherently stratified. However, if the permeability is controlled by secondary reactions, such as differential cementing in reworked sediments, then this should produce a rather unstratified distribution of permeability. The Berea sand in the Griffithsville field seems to fit this latter category, and even though there is a large permeability variation, the tight streaks correlate poorly from well to well within the field. Viscous fingering or early breakthrough may be a less serious problem in this reservoir than one might expect.

A plot such as Figure 16 suggests intuitively that the ratio of the high permeability zones (taken as those at probability 0.9) to the geometric mean permeability (k = 50%) should be of some use in predicting reservoir channeling problems, particularly if the permeability is stratified; however, not enough data exist at this time to validate this concept. Well spacing, slug size, injection rates, and mobility ratios would also have to be taken into account to make this treatment universally applicable. A plot of this type can be used to indicate the fraction of each reservoir that is accessible to CO_2, provided a minimum permeability can be assigned. For example, if a 5-md permeability cutoff is used for the Rock Creek field, more than 80% of the gross reservoir is accessible to CO_2 displacement. If a 1-md cutoff is used for Griffithsville, then 64% of the gross reservoir is accessible. (Gross reservoir is defined as all parts of the reservoir having a permeability greater than 0.1 md.)

A three-dimensional panel diagram is probably the best way to adequately describe porosity (and therefore permeability distribution or stratification) in an oil reservoir. Panel diagrams of all three project areas are shown in Figures 31 - 33.

Injecting CO_2 into a reservoir raises the possibility of chemical solution. Calcite, dolomite, and ankerite are found in some of the project areas as cementing agents (ankerite is similar to dolomite, with iron in place of magnesium). Solubility product constants for some carbonate minerals are given in Table 21. The solubility of $CaCO_3$ is related to pH and to the pressure of CO_2 by the equation[42]:

$$2\ \mathrm{pH} + \log P_{CO_2} = 9.76 + \log \frac{1}{[Ca^{++}]}$$

or $$\log [Ca^{++}] = 9.76 - 2\ \mathrm{pH} - \log P_{CO_2}$$

$[Ca^{++}]$ is the concentration of the Ca^{++} ion, which is a measure of the solubility of the mineral.

This equation shows that for a given pH of reservoir water, increasing the pressure of CO_2 will reduce the concentration of Ca^{++} ions. If the pH of the reservoir water is decreased by the addition of CO_2, then the $[Ca^{++}]$ should increase. Hence, increasing CO_2 pressure and decreasing pH tend to offset each other. Pushed too far in either direction, the effects are generally detrimental to EOR: permeability reduction could result from wholesale precipitation of $CaCO_3$, while high permeability channels could be created by large-scale dissolution of calcite.

All three of the projects have been designed to inject water and CO_2 alternately for mobility control.[6,7,8] In the Rock Creek and Griffithsville projects, the slug size was chosen to be about 20-30% of the hydrocarbon pore volume. The Rock Creek project is calling for about 15,000 tons of CO_2 and the Griffithsville project about 8000 tons (for the original pilot project as planned). Later papers[47] have called for the Griffithsville project to be expanded to use 30,000 tons and evaluate 90+ acres rather than about 35 acres in and around the 10-acre five-spot. The Granny's Creek project injected 9878 tons of CO_2 to evaluate a 6.5-acre five-spot. CO_2 was found far outside the pattern, however. This will be discussed in greater detail below.

Summary of Granny's Creek Project.

Since the Granny's Creek project is the only one in which CO_2 has been injected up to the present time, an understanding of the results obtained there is critical to the valid extrapolation of the CO_2 displacement technique in West Virginia.

The Granny's Creek project was designed to evaluate the effectiveness of CO_2 displacement in a watered-out portion of a waterflooded reservoir. The nucleus of the project was an unconfined 6.5-acre five-spot. The reservoir was repressured with water to approximately 1500 psi in the immediate area; CO_2 and water were alternately injected through the four corner wells of the five-spot. A total of 9878 tons of CO_2 was injected, producing 8500 barrels of additional oil from both inside and outside the project area. This works out to about 1 barrel of additional oil per 20 Mcf of CO_2. Proprietary information indicates a much higher efficiency than this, about 2.5 Mcf per barrel, based on the fact that only 6 percent of the injected CO_2 entered the pattern. Recent publications have listed the cost of CO_2 at \$0.25 to \$1.15 per Mcf, not including costs of transportation to the well site and injection. It would seem that this project was not an economic success, and it therefore becomes important to determine as accurately as possible why this was the case.

Geology.

The Big Injun sand in the project area, as described in Columbia Gas Transmission Company's original proposal and in later company reports, consists of at least three separate sand lenses, labeled A, B, and C. There is a fourth less well-developed zone (D) in the immediate project area; however, it is normally tight. The project is located on the northwest side of a syncline which plunges to the northeast. The formation dips rather gently in the immediate project area.

The Big Injun sand in this field is characterized as a tight friable sandstone. Core descriptions indicate the sand to be slightly limey, slightly conglomeratic, and silty near the bottom. The sand is also described in core reports as coarse- to very coarse-grained quartz with minor amounts of feldspar and glauconite, containing silica cement near the top. Other minerals specifically indicated on core descriptions are pyrite and mica.

The C zone of the lower Big Injun is described as an argillaceous fine-grained or silty sandstone. The A and B zones consist of very coarse- to fine-grained sand and are normally clearer than the C zone. The term "conglomeratic" has been applied to portions of the A and B zones.

Columbia interpreted the C zone as an offshore bar lying parallel to the ancient shoreline and thickening toward the paleobasin. After the formation of the bar, a regression of the seas, with subsequent deposition of strandline deposits, has been evoked to explain the A and B zones. This interpretation adequately explains the major features of the sand.

Permeability. The A and B zones are of higher permeability than the C zone. The plots of permeability against porosity for the three zones, shown in Figures 17, 18, and 19, show dramatically that the sands are different. This difference in character suggests that the sands had either different environments of deposition or different post-depositional histories.

The average permeabilities of net pay in the A, B, and C zones in the project area are 5, 5, and 1.5 md, respectively. The average permeability of each sand, however, does not fully characterize the permeability at each well. A plot of the typical permeability distribution for well #20274, which was cored in the center of the project area, is presented in Figure 21. The significance of the highly variable permeability distribution, especially in the A and B zones, can best be understood in light of other well documented field tests.

In their Willard Unit mini-CO_2 test, ARCO used time-lapse logging to monitor the formation of an oil bank and the changes in CO_2 saturation. They observed different responses with the passage of the CO_2 front. In zones thicker than 20 feet, the CO_2 displacement formed a CO_2-free oil bank; this was not true for thinner zones (approximately 10 feet and 5 feet). In light of the existence of many thin permeable zones in the immediate Granny's Creek project area, especially in the A and B zones (see Figures 4 through 9), it is not surprising that no CO_2-free oil bank was formed, even though CO_2 was injected alternately with water for mobility control.

Production Response. Injection rates of more than 10 tons per day per well (about 106 bbl of liquid CO_2 per day) were achieved. The amounts of CO_2 and water injected, and the exact sequence of injection, are well documented.[45,46] Deducing where these fluids went, however, is not an easy matter. Figure 20 shows the areal distribution of wells found to have concentrations of CO_2 greater than 4% at any time during the project. The fact that CO_2 was found over an area of more than 200 acres, rather than the 6.5 acres on which the project was based, will give new meaning to the recovery figures. See the panel diagram for the thickness and areal extent of the A, B, C, and D stratigraphic zones.

It is possible to calculate the number of pore volumes of CO_2 injected into each sand by apportioning the CO_2 injected on the basis of permeability and thickness, assuming the project area is representative of the entire field. The geometric mean permeabilities for zones A, B, and C are 5, 5, and 1.5 md, respectively. The D zone was tight in all wells. From the cored wells in the project area, the average net pay in the A zone sand with greater than 1 md permeability (no saturation cutoff was used because of lack of data) is 5 feet, in the B sand 3.2 feet, and in the C sand 17.5 feet. The product of permeability and thickness is 25 md-feet for zone A, 16 for zone B, and 26 for zone C. Allocating the injected CO_2 in these proportions gives 37% to zone A, 24% to zone B, and 39% to zone C.

Converting the total tonnage of CO_2 injected into cubic feet of pore space requires some knowledge of reservoir conditions. The pressure in the immediate project area was high enough that the CO_2 would remain liquid (see phase diagram, Fig. 15). At the critical point, CO_2 has a specific volume of 0.342 ft^3/lb, or 68.4 ft^3/ton. The project area was at slightly lower temperature (about 80°F) and higher pressure (1550 psi) than critical; at these conditions the Z factor for CO_2, if it is a super-compressed gas, should be 0.225 (from experimentally derived values), giving a specific volume of 39.2 ft^3/ton (Figure 22). However, as the CO_2 moved away from the project area, it expanded with decreasing pressure, so that the figure 68.4 ft^3/ton may be an adequate approximation for rough calculations. Assuming that it is, the 9878 tons of CO_2 injected would occupy 667,000 ft^3 in the reservoir. Using the allocations calculated above, approximately 9 to 13% of the hydrocarbon pore volume was injected into zone A, approximately 8 to 11% into zone B, and 2 to 3% into zone C. The ranges in these values result from variations in hydrocarbon saturation from 50% to 35%, i.e., between the original saturation and the present estimated post-waterflood saturation. It is difficult to estimate or calculate how much of the injected CO_2 remained within the pattern.

Fluid Saturations.

Hydrocarbon saturations can be determined from a proper log suite provided certain values are known or can be approximated. Information was obtained from Columbia on several wells outside the immediate project area that could allow the calculation of hydrocarbon saturations. The nearest wells are #20317, about 2000 feet northwest of the project area, and #20237, about 1000 feet to the north-northwest.

Factors that must be estimated in order to conduct log analysis are a, m, and n factors, plus (most importantly) the water resistivity. The a, m, and n factors for zones A, B, and C have been estimated to be 1, 2, and 2, respectively, by analogy with the Rock Creek Big Injun sand, where these values have been measured. The water resistivity calculated from SP in the 20317 well is 0.075; but analysis of interstitial water from two wells (Summer's Heirs V-2018 and #20274) drilled within the pattern at widely separated dates (1963, before the waterflood, and 1975, after) indicates that the resistivity should be much lower, at least in the C zone. When the lower resistivity was used in the log analysis, however, with appropriate corrections for shale, the hydrocarbon saturations turn out to be about twice as high as the value used by Columbia in planning the project. Their value was presumably determined from detailed studies, including two reservoir simulations; hence the values calculated may not be representative, and they have not been included in this report.

Rock Creek and Griffithsville Projects.

Since CO_2 injection has not yet been initiated in Rock Creek or Griffithsville, it is impossible at present to summarize or evaluate the projects. It is possible to set the stage for the evaluations of these projects by characterizing the rock properties, reservoir conditions, reservoir repressuring, and planned procedures as fully as possible. This is the subject of the following sections, where each project area is discussed under the following headings:

- Rock properties
- Reservoir conditions
- Saturations
- Design features

Rock Properties in the Project Area of Griffithsville Field

Lithology.

The Berea sand has been described in the Guyan Oil Company technical progress reports as a gray quartz sand, uniform in thickness, cross bedded, fine-grained, with subangular grains, fairly well sorted and closely cemented.

Crossplots of the neutron vs density log values indicate that the cementing material is probably calcite or dolomite. Petrographic work in the files of METC, done on cores from Well #I-7, shows that the cementing material is, by and large, dolomite. Other accessory minerals identified in core analysis are pyrite and calcite. Shale was not a major constituent of most cores, although some shale streaks were noted. The grain size decreased toward the base of the sand, according to the petrographic analysis. The detrital-illitic or sericitic material increases towards the bottom.

Porosity and Permeability.

Porosity and permeability measurements in the pilot area have been made on cores taken from six of the new project wells. Horizontal permeability, directional horizontal permeability 90° from maximum, and vertical permeability have been measured on some whole cores and plugs.

Porosity values measured by sidewall neutron, compensated neutron, and compensated formation density logs can be used to calculate an effective porosity, and the results compare favorably with the core values. Figure 23 gives a porosity vs permeability plot for all recorded measurements in the field.

Both the average porosity and permeability increase toward the top of the Berea sand. The overall average porosity of the pilot area is 11.2%. Permeability values vary dramatically; however, the overall geometric average of the gross sand is 5-6 md. A Dykstra-Parsons type permeability variation plot is given in Figure 16. If a 1-md permeability limit is used in calculating net pay, the reservoir contains approximately 14 feet of net sand (mostly at the top), with an average porosity of 12.3% and an average permeability of 8.2 md.

Vertical permeability from core analysis on Well #I-4 is estimated to be about 0.3 of the horizontal permeability (see Figure 30).

A plot of permeability vs depth in one of the project wells is given in Figure 24.

An injectivity test for CO_2 was performed in Well I-6 (which was completed in open hole after fracturing). At an unspecified wellhead pressure, CO_2 was injected into this formation at a rate of 3.8 tons per hour. At reservoir conditions, this is about 829 barrels of liquid CO_2 per day.

Three-Dimensional Porosity Distribution.

A panel diagram for the pilot area has been made with intervals correlated on as fine a scale as possible (Figure 33). GR-FDC porosity logs with core porosity and permeability plotted on them were used as the basis for correlations. The detail on this diagram shows that there are no apparent deadend porosity intervals, and that the tighter intervals (porosity less than 10%) are interdigitating and do not seem to effectively divide the sand into separate zones. However, the highest porosity and permeability intervals in each well are nearly always in the top portion of the sand. This section will probably be the path of least resistance to the CO_2 slug. Even if the sand were divided into separate lenses or zones, the abundance of old wells fractured with explosives in this portion of the field would allow communication of all zones.

The above discussion of lithology and other properties, together with the regional framework of the Berea sand, suggests that this deposit has been reworked and that the hard (or low permeability) streaks that do not correlate between wells result from differential cement development.

The Griffithsville field is a synclinal oil field[53]; the immediate project area dips gently (less than 0.5°) toward the northwest.[51]

Fractures.

To this point in the study, no evidence has been found for naturally occurring fractures in the field. The orientation of induced fractures has been carefully documented by impression packer work in Well #I-6. This direction is S. 55° E.

Reservoir Conditions.

The reservoir conditions in the pilot area are taken to be temperature, depth, original pressure, present pressure, and salinity and hardness of connate waters. The temperature of the reservoir corrected from the maximum reading taken at bottom hole (generally less than 100 feet below the formation) is 75-85°F. The depth of the field is approximately 1450 feet below sea level. Original pressure, as nearly as it can be established, was in the neighborhood of 1000 psi. Present pressure, of course, is dependent upon the amount and the rate of fluid injection. The properties of the connate water in the reservoir cannot be determined. However, the zone has been thoroughly flooded with water from the overlying Salt sand and analysis of produced water shows total dissolved solids of approximately 105,000 mg/l, with calcium and magnesium totaling 8800 mg/l.

Water Saturation Calculations.

Water saturations (S_w) were calculated for those wells in which an induction log and at least one porosity log have been run. (Table 5 lists the logs available for each well in the pilot area.) Porosities from cores were compared to porosities derived from logs to verify the efficacy of using log-derived data. Where two porosity logs were run (the FDC and CNL or SNP), a density-neutron solution for shale volume and effective porosity was performed. Since the volume of shale calculated by this method was normally very low or zero, shaly sand log analysis was considered unnecessary.

The water saturation value so obtained is about 54%, higher than the value of S_w = 40% calculated by using a lower water resistivity. Because of this difference, a short discussion is appropriate.

A Core Lab report dated March 2, 1978, shows a formation water resistivity of 0.065 ohm-meters[38], and the resulting computations of the water saturation yield values similar to those obtained in this study. On the other hand, measurements made in 1965 on Berea cores from Joe Stephen No. 1 gave interstitial water chloride concentrations averaging 216,000 ppm. Such highly saline formation water should have a resistivity of approximately 0.037 ohm-meters[51]; according to the SP measurement on the Griffithsville logs, the formation water resistivity in some wells was as low as 0.035 ohm-meters. Therefore it is impossible to ascertain the correct saturation value. Within the realm of engineering judgment either value could be taken as correct; for the purposes of this study, we have decided to carry both values (see Table 22).

Fluid Saturations in the Pilot Area.

In evaluating the efficiency of the CO_2 EOR process, it is probably better to use the highest reasonable in-place oil figure as a starting point, since this tends to underestimate rather than overestimate the efficiency of the displacement process.

In light of the reservoir's history, derived fluid saturations may vary widely across the project area. The reservoir, discovered in 1908, apparently produced by solution gas drive. Primary production probably left high residual gas saturation, on the order of 30-40%.

Estimates of oil recovery from the total field are around 20% of oil in place. The field has been abandoned for many years except for a few isolated producers.

The next significant event in the history of this portion of the field was accidental repressuring by crossflow (dump flooding), presumably from the Salt sand. This crossflow has repressured the reservoir in this area to around 725-975 psi, depending upon the exact location.[53,57] When the water entered the formation it may have traveled preferentially through the zones of high gas saturation and moved little oil, since a high oil saturation still exists in the pilot area. Existing gas was either displaced or forced back into solution by the rising pressures. Guyan Oil Company noted that waterflooding, either from crossflow or from repressuring operations, has now mobilized some of the oil remaining in the reservoir. The reservoir is currently producing at the rate of about 50 BOPD from 9 producing wells. Injection tests by Guyan have found that the wells will take 80-150 BWPD at bottomhole pressures of 1600+ psi.

Design features.

The wells used in this project are conventional wells with various casing sizes and completed by various techniques. One well, I-6, is an open-hole completion with 7-inch casing.[54,55] Other new wells in the project have 4-1/2 or 5-1/2-inch casing with set-through type completion. Well locations are plotted on the base maps of the panel diagrams included with this report.

Planned CO_2 injection rate is about 10 tons per day per well.[53] CO_2 for this project will be purchased, shipped, and stored at the location in liquid form. The planned facility calls for three storage tanks, each of 38-ton capacity, to store CO_2 at 250 psi and -15°F. Liquid will be moved from storage to main injection sites by electric booster pumps. Main injector pumps will have variable flow capacity.[54]

Corrosion mitigation plans have not been disclosed, possibly because they have not been completed.

Major problems in this project have resulted from the difficulty in reentering many old wells. Legal action by environmentalists has also imposed considerable remedial work.

Rock Properties in the Project Area of Rock Creek Field.

Lithology.

Pennzoil has provided what appears to be an excellent description of the lithology and mineralogy of the reservoir in their annual reports and two published articles. The following significant points are extracted from their work.[7,50]

The Big Injun sandstone is described as "a light greenish-gray, very fine to medium grained well sorted subangular sandstone that is slightly to moderately calcareous."

X-ray diffraction and petrographic analysis were performed by Halliburton on one sample from L. W. Shaffer PI-2 at a depth of 2104.54 feet. Core analysis on this sample gave a porosity of 23.2% and a permeability of 19 md. The sample exhibited slightly better petrophysical rock properties than the average of the total sand. It was described as "sandstone, poorly sorted, very fine to medium grained quartz, feldspar, mica and rock fragments forming the framework, small amounts of quartz overgrowth, predominant clay is chlorite present as coating on pore walls, small amount of calcite is observed as pore fill. Good visible porosity with chlorite linings."

Pennzoil also reported occurrences of ankerite and siderite. These, however, are of minor importance, except that they probably cause some minor pore filling.

Porosity and Permeability.

Porosity and permeability measurements have been made on cores taken from the entire interval from several of the project wells. Most of the core analyses in the field were performed on whole cores. Horizontal permeability at 90° to first reading, vertical permeability, porosity, and residual oil and total water saturations have been measured on all cores. Other porosity measurements have been made by FDC-GR logs run through the interval. A porosity vs permeability plot is given in Figure 25.

The overall average porosity for the pilot area using 5 md cutoff was reported by Pennzoil to be 21.7%. For a 1 md permeability cutoff, the overall average porosity is 21.2%. Using the method of determining geometric average permeability from plots of permeability vs probability, the geometric average for the project area would be 15 md or 12 md, respectively (Figure 16). As may be seen from Figure 16, the porosity cutoff of 19% used in the calculation of water saturation corresponds very nicely with the 5 md cutoff used by Pennzoil in their determination of net pay from core analysis.

As noted by Pennzoil, the vertical permeability measurements seem overly high, but they are consistent (see Figure 28). The vertical permeability appears to be 0.9 of the horizontal permeability, but this value is very high and may result from a consistent error in the data treatment.

Figure 26 is a plot of permeability vs depth for a typical well in this project.

Three-Dimensional Porosity Distribution.

A panel diagram has been made for the pilot area on which all porous intervals have been correlated on as fine a scale as possible. FDC-GR porosity logs and permeability from core analysis plotted on the logs were used as a basis for correlations, where possible. Where these logs were not available, the best available log was used instead. A half-size copy of the panel diagram for this project area is included with this report.

This diagram shows the sand to be remarkably uniform and consistent from well to well. There appears to be very little deadend porosity (see zone near the bottom of Shaffer #2 PI-#1 and Lewis #17). Most of the tight intervals of the sand are interdigitating and do not correlate from well to well (see zones in PI-#6). One tight zone, very near the bottom of the sand, does seem to be consistent and is present through most of the field (see PI-#2); it follows the zone through I-#3 and southerly through the field. Even if the sand were more extensively divided into lenses or zones, the abundance of old wells fractured with explosives would allow communication of all zones in the vicinity of the wellbores. Depositional and post-depositional environments of this sand should be very similar to those of the C zone at Granny's Creek. The Big Injun formation at Rock Creek correlates well with the C zone of the Big Injun sand of Granny's Creek, but the A and B zones are missing.

Pennzoil noted that depositional environment indicators other than textural and mineralogical data are largely nonexistent. Infrequent crossbedding has been noted with very low angle and of hummocky type. Also noted in the core were some micro-cross laminations, possibly from current ripples, as well as one pebble lens.

The occurrence of two chiefly syngenetic[43] (formed during diagenesis) minerals, siderite and ankerite, suggest that the deposit was subjected to a weakly-reducing to neutral environment shortly after deposition.

All of the above facts are consistent with the interpretation that the sand in this field was deposited as an offshore or near-shore bar with very little reworking of the sediment. This is also consistent with the overall geometry of the sand.

Structurally, the Walton field (which contains the Rock Creek field) is a synclinal oil field. The immediate project area is on the eastern flank of a northeast-plunging syncline. The formation dips toward the northwest at slightly more than 0.5°.

Fractures.

To this point in the study no evidence has been found for any naturally occurring fractures in this field. Some anomalies in injection water breakthrough have been attributed to a permeable zone in the Big Lime above the Big Injun sand.

Fluid Saturations in the Project Area of Rock Creek Field.

Special core analysis, an adequate suite of logs in some wells, and knowledge of the resistivity of the connate water of the reservoir allow the calculation of water saturation of the project area. The water saturation (Sw) of the project area is approximately 50-69% with an average of 54%. This value was calculated using a, m, and n factors from special core analysis (1.0, 2.0, and 1.97 respectively) and a water resistivity of 0.045 ohm-meters. The average water saturation was determined using a 19% porosity cutoff. These values are higher than those obtained by Pennzoil (Sw = 46.2%).[44] This difference is probably the result of a shale correction used by Pennzoil to correct for the chlorite content of the reservoir rock noted above. The value used in the present study was based on a clean sand approach, because the information necessary to make a quantitative shale correction was not available to us. Therefore, the actual value of the present water saturation is probably about 46-50% and certainly no higher than 54%.

Design Features of the Rock Creek CO_2 Injection Project.

The following summary of the design features of the Rock Creek project is taken from a Pennzoil report.[7]

The project area is in an old portion of the field and uses both old and new wells. The two center producers in each five-spot (see panel diagram included with this report) are very old wells, drilled in 1908 and 1909. They were reconditioned by replacing 5-1/2 inch casing with 4-1/2 inch, with open-hole completion. The six water injection wells are all new with 4-1/2 inch casing and set-through completion.

Many existing wells were converted to backup water injection wells, with a new well drilled to complete the confinement. These wells are mostly open hole completions, which was the standard practice when they were drilled.

Details of the CO_2 injection system are as follows, quoted directly from the Pennzoil report:

> Carbon dioxide will be maintained in the liquid state during the project. Four insulated tanks, each capable of storing 44 tons of carbon dioxide, have been installed at the plant site. Carbon dioxide will be hauled to the plant in tank trucks during the carbon dioxide injection phase. The carbon dioxide will be stored at approximately 0°F and 250 psi. A gear pump will take suction from the bottom of the tanks and charge a triplex pump with a 300 psi liquid. The triplex pump will then pressurize the carbon dioxide to the desired injection pressure. This injection pressure will be maintained through a by-pass system consisting of a series of back-pressure regulators.
>
> After pressurization, the carbon dioxide will pass through an in-line indirect heater capable of heating the fluid to 70°F. The heated carbon dioxide then travels to an injection header via an uncoated 2-inch line. From the injection header, internally coated 2-inch lines run to each of the six injection wells. The injection header is constructed so that either water or carbon dioxide can be injected into any well at any time. This header was constructed in this manner to allow alternate water and carbon dioxide injection into each well individually instead of simultaneously during the WAG phase of the project.

Planned injection rate is about 15-20 tons of CO_2 per day per well. The injection sequence will be (1) a slug of CO_2 amounting to 6.5% of the hydrocarbon pore volume, (2) a slug of water amounting to 3% of the hydrocarbon pore volume, (3) nine alternating CO_2 and water slugs, each 1.5% of the hydrocarbon pore volume.

STUDY SUMMARY

Based on available reservoir information, CO_2 displacement seems to be the enhanced oil recovery technique most suitable for most West Virginia oil reservoirs. Seventeen reservoirs have been identified as potential candidates for the CO_2 displacement process: three Berea, six Big Injun, five Gordon, one Gordon Stray, one Fifth, and one Squaw-Weir sand reservoir. The total volume of oil remaining in these 17 reservoirs is estimated to be more than one billion barrels. The fields are all within a relatively small geographic area and constitute a significant target for enhanced oil recovery technology. There are, however, many difficulties in working with expensive fluids in old fields containing many abandoned wells.

Injectivity of liquid CO_2 in West Virginia oil reservoirs has been demonstrated to be higher than that for water or natural gas.

In connection with raising pressures prior to CO_2 injection, waterflooding has been shown to be effective in two reservoirs previously considered impossible to flood.

In the single CO_2 displacement process completed in West Virginia, the Granny's Creek project, efficiency of recovery was not high: less than one barrel of additional oil per 20 MSCF of CO_2 injected. The injected liquid was found far outside the project area, however, indicating a need for effective confinement. The CO_2 process has been demonstrated as effective in displacing oil from a previously waterflooded portion of the reservoir.

The three ongoing or projected CO_2 projects in the state have many common features, which should simplify the complete analysis when they are completed.

RECOMMENDATIONS FOR FUTURE CONSIDERATIONS

Several pertinent recommendations can be made for high-pressure CO_2 displacement projects contemplated in this part of the country.

First, considering the wide areal distribution of CO_2 observed in the Granny's Creek project, the confinement of injected CO_2 by backup water injection must be effective.

Second, based on experience at the Griffithsville project site, any operator planning an enhanced oil recovery project of any kind should allocate a substantial sum of front-end money to locating and repairing old, improperly abandoned wells, and must provide for remedial environmental work.

Based on the effectiveness of waterflooding in two reservoirs where previous attempts had failed (Rock Creek and Griffithsville), waterflooding may be a cost-effective alternative to CO_2 miscible displacement. Since waterflooding has never been demonstrated to be effective in a Gordon sand reservoir, the potential exists for a limited waterflood project. If this is successful, then a CO_2 injection project could be run in another portion of the field, to compare results with a similar project in a watered-out section of the reservoir. Such a project would provide a sound basis for comparison of recovery by CO_2 injection before and after waterflood, and the comparative economics of the processes.

Naturally occurring CO_2 would probably be most economical in increasing oil production from the old reservoirs in the state. In fact, unless the efficiency of the process is substantially higher than was found in the Granny's Creek field, such naturally occurring supplies of CO_2 are probably the only source cheap enough to be considered for an enhanced oil recovery project.

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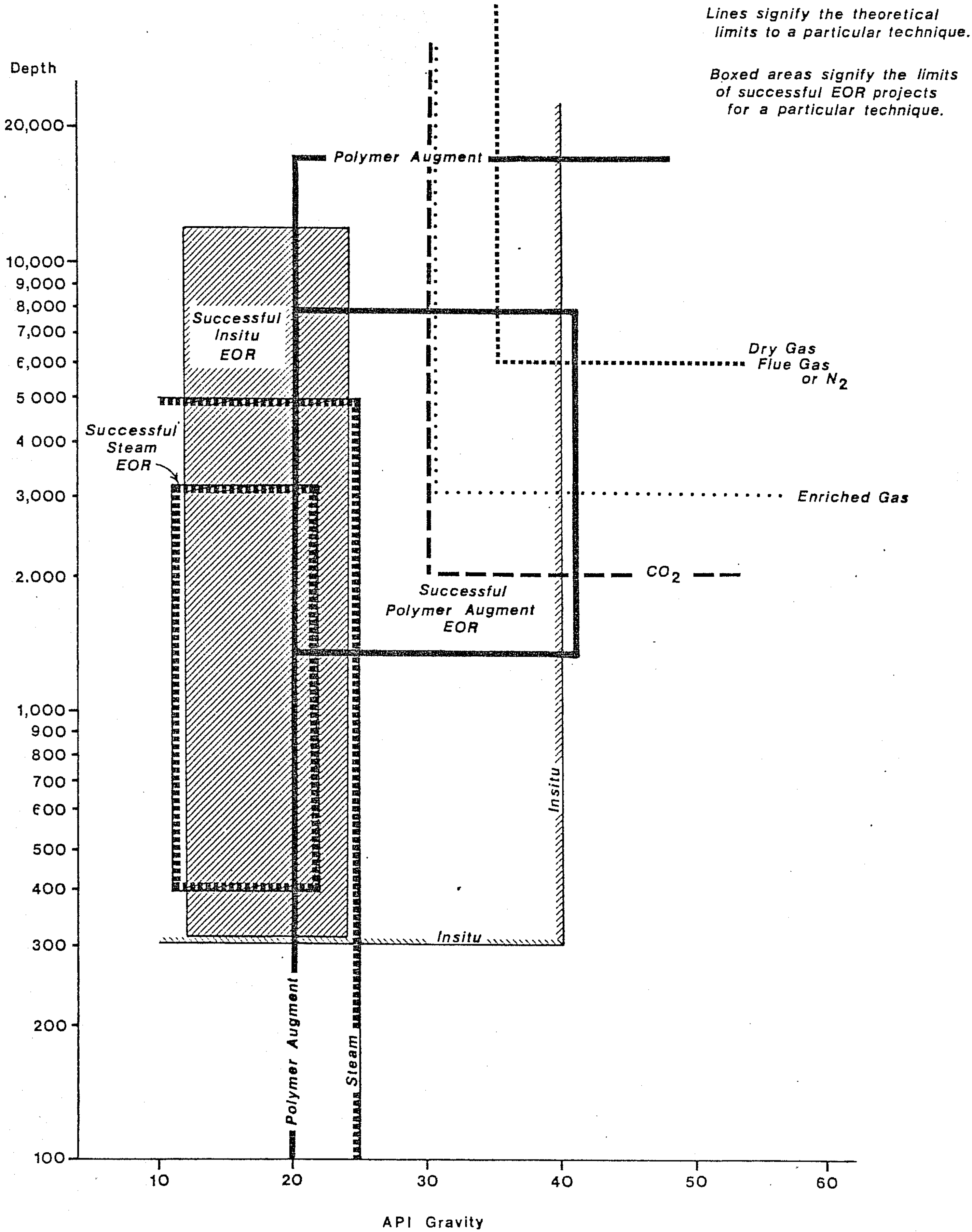
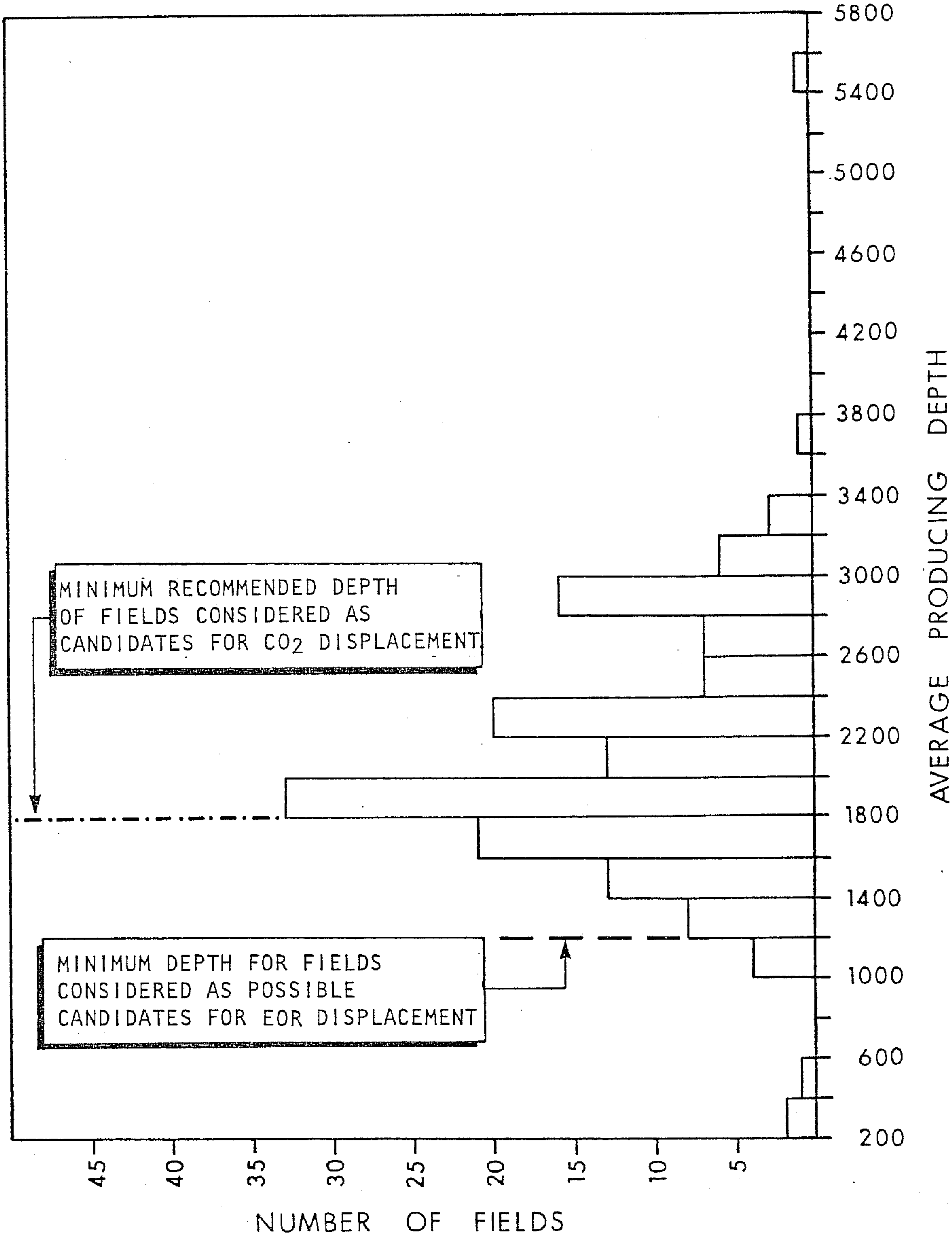


Fig. 1: Oil Gravity and Depth Limitations, Proven and Theoretical, of Most Enhanced Oil Recovery Techniques



DEPTH DISTRIBUTION OF WEST VIRGINIA OIL RESERVOIRS

Figure 2

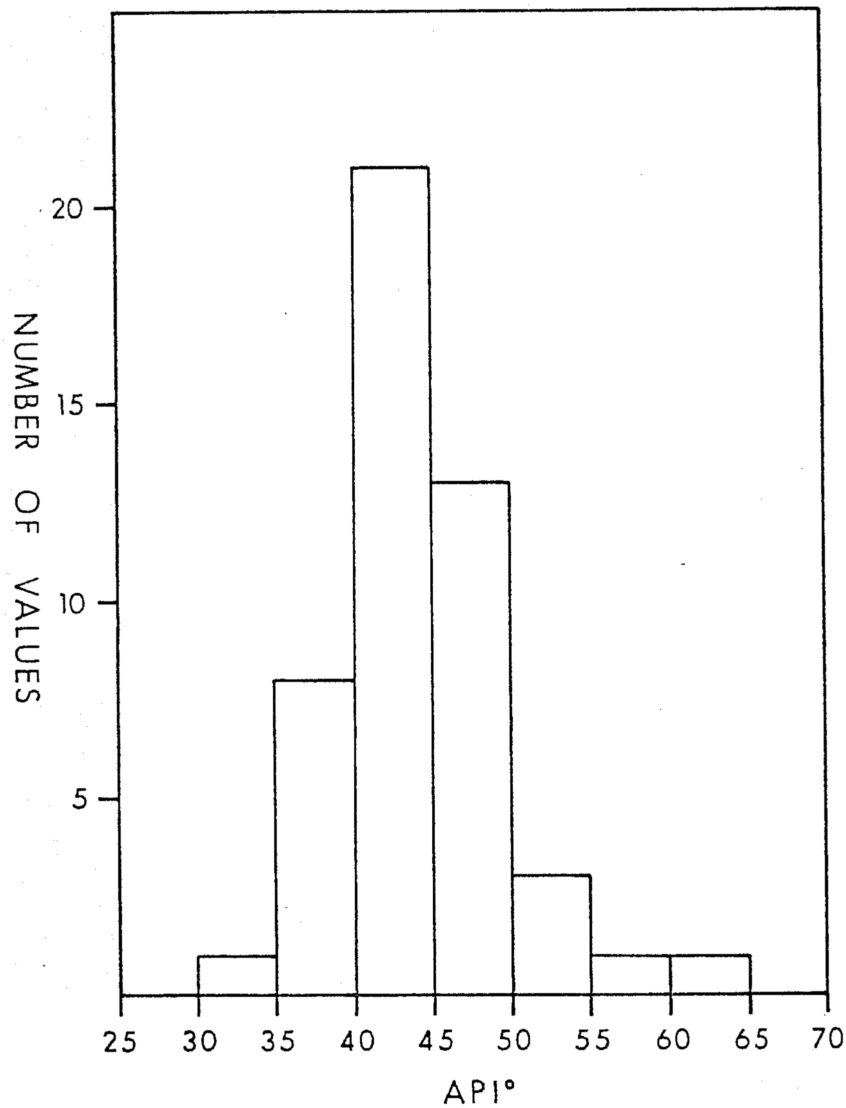


Fig. 3a: Gravity of West Virginia Crude Oils

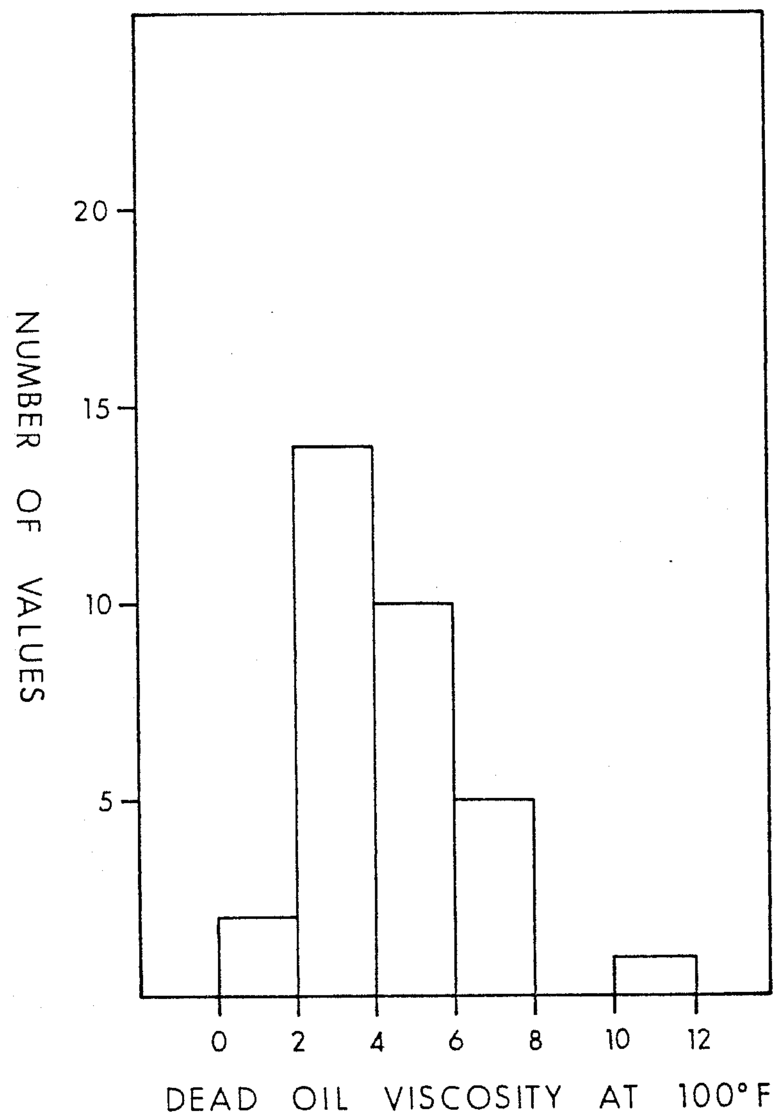
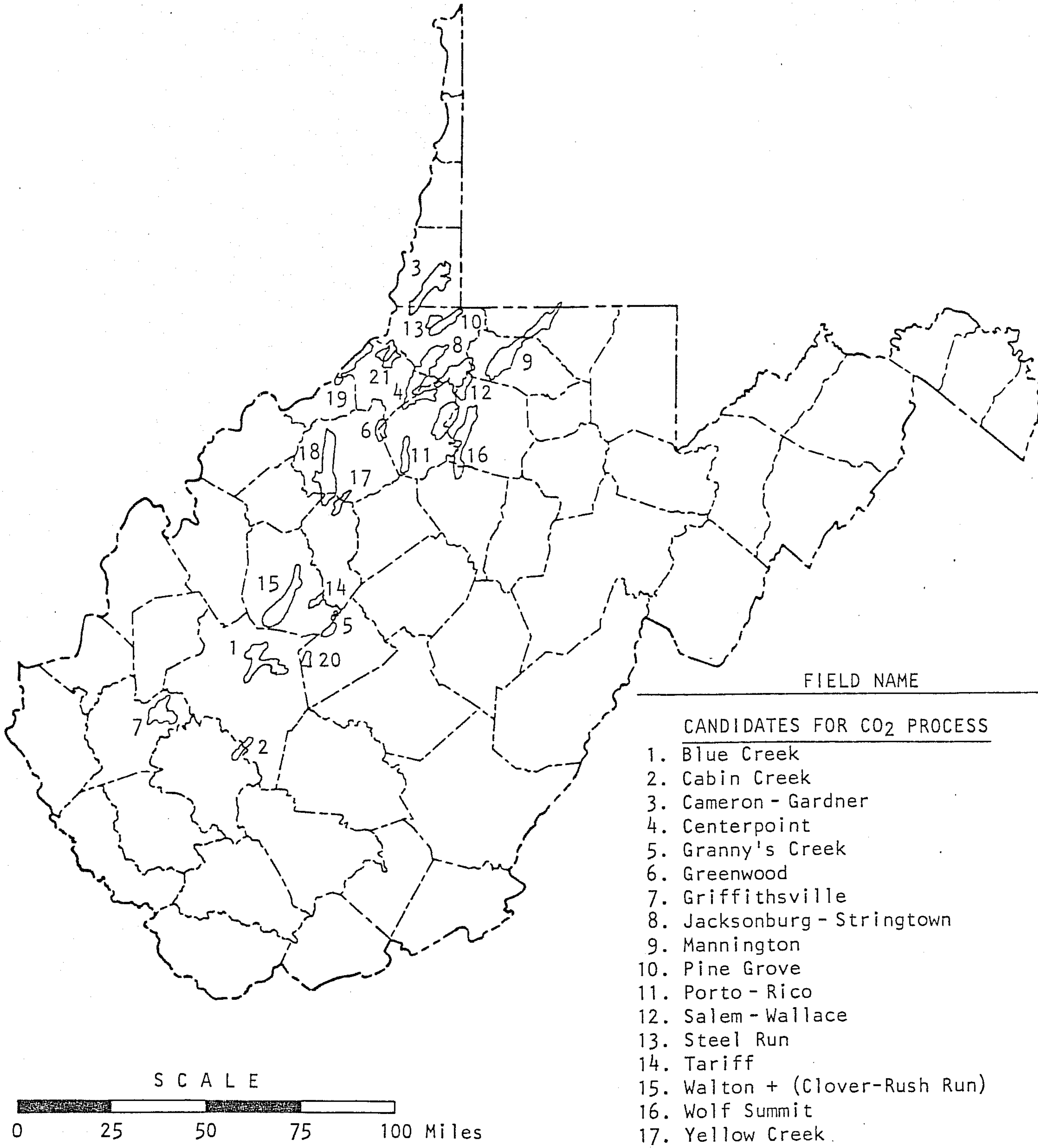


Fig. 3b: Viscosity of West Virginia Crude Oils



FIELD NAME

CANDIDATES FOR CO_2 PROCESS

1. Blue Creek
2. Cabin Creek
3. Cameron - Gardner
4. Centerpoint
5. Granny's Creek
6. Greenwood
7. Griffithsville
8. Jacksonburg - Stringtown
9. Mannington
10. Pine Grove
11. Porto - Rico
12. Salem - Wallace
13. Steel Run
14. Tariff
15. Walton + (Clover-Rush Run)
16. Wolf Summit
17. Yellow Creek

CANDIDATES FOR OTHER EOR PROCES

18. Cario - Ritchie
19. Sistersville
20. Rouzer
21. Kidwell - Elk Fork

Fig. 4: Location of West Virginia Reservoirs Having Significant EOR Potential

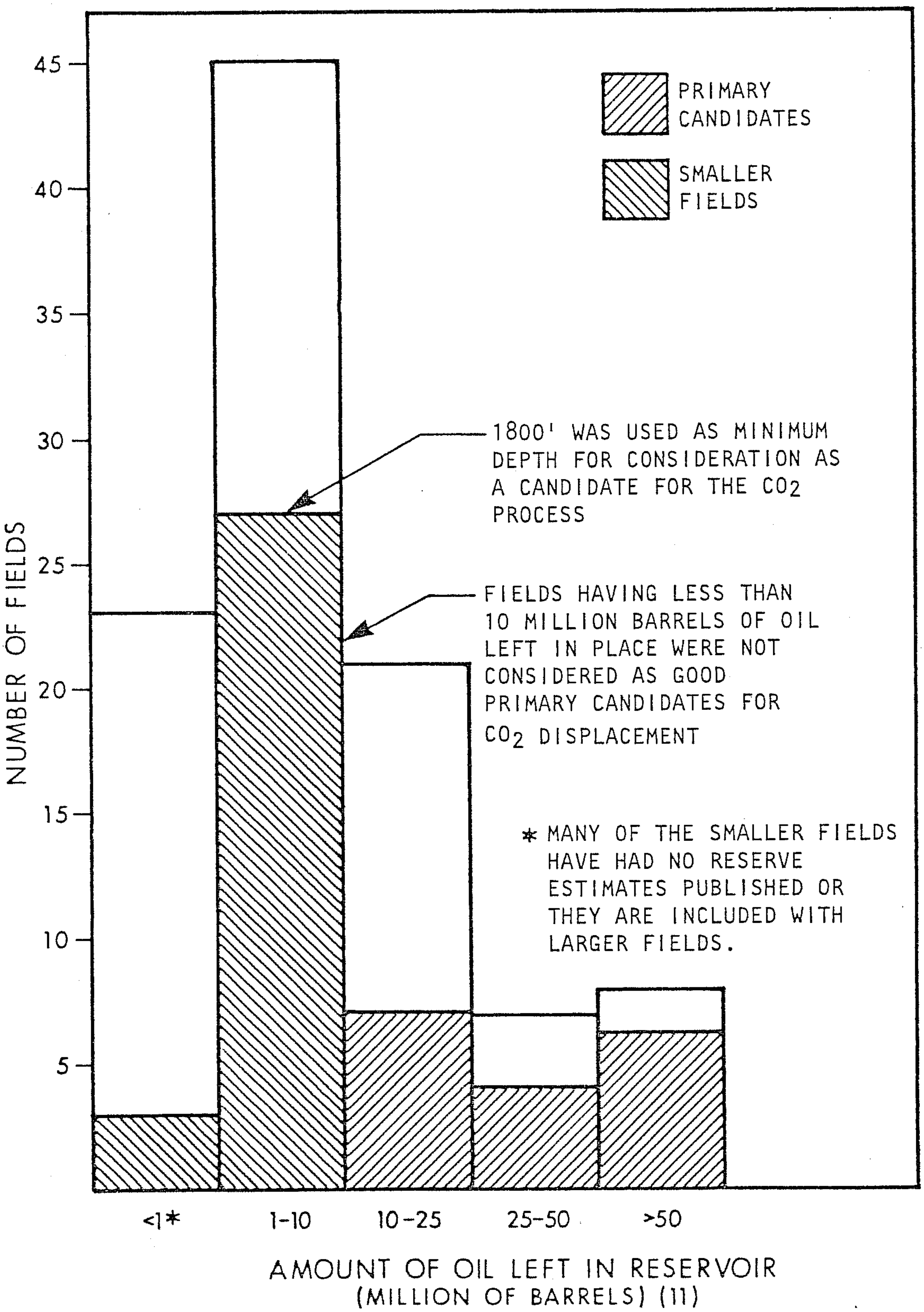


Fig. 5: Estimated Sizes and Number of Fields Suitable for CO_2 Enhanced Oil Recovery

WITH OIL AND GAS RESERVOIRS WEST VIRGINIA

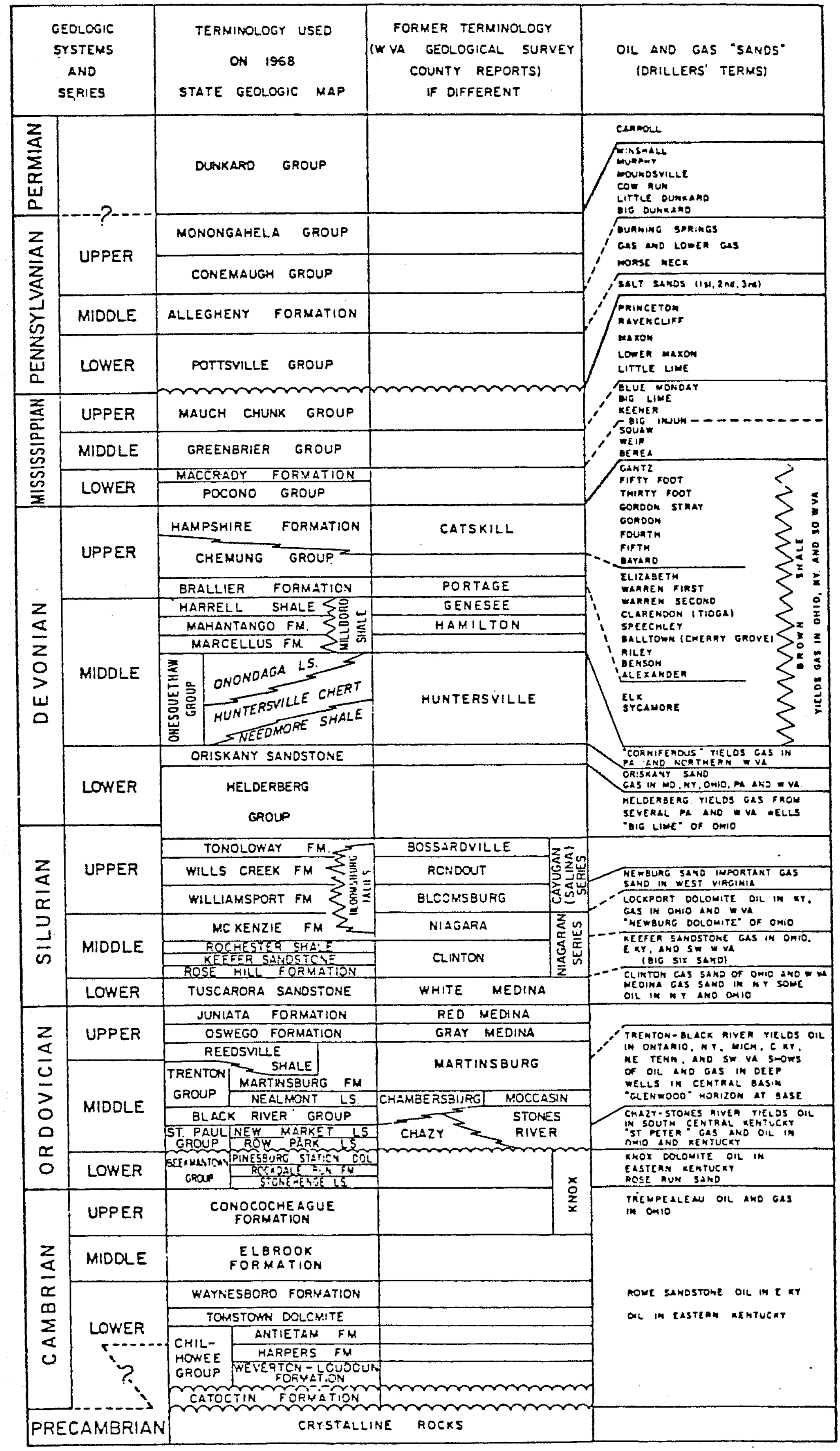
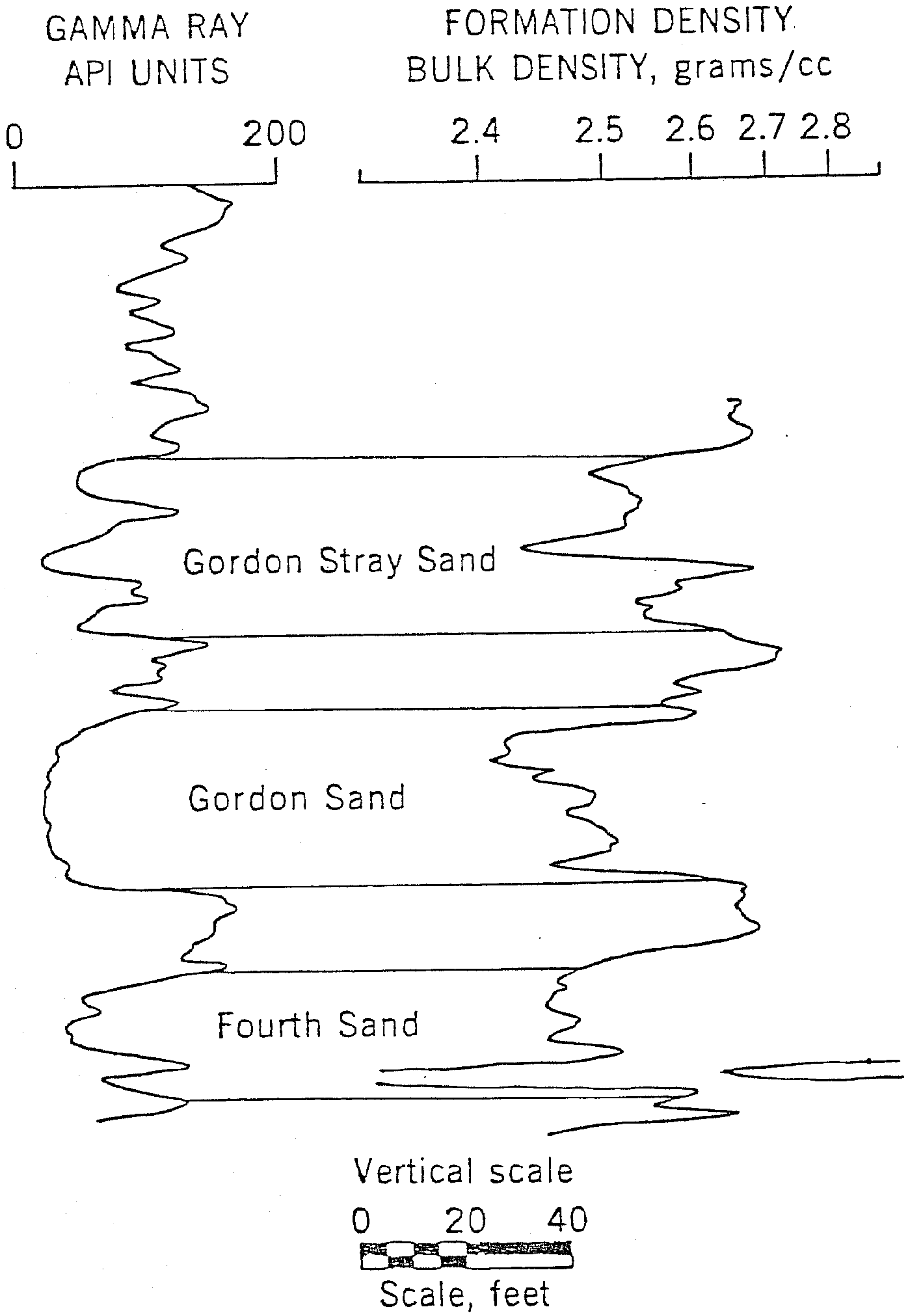


FIGURE 6



Gamma Ray and Formation Density Logs From Mannington Oil Field

FIGURE 7

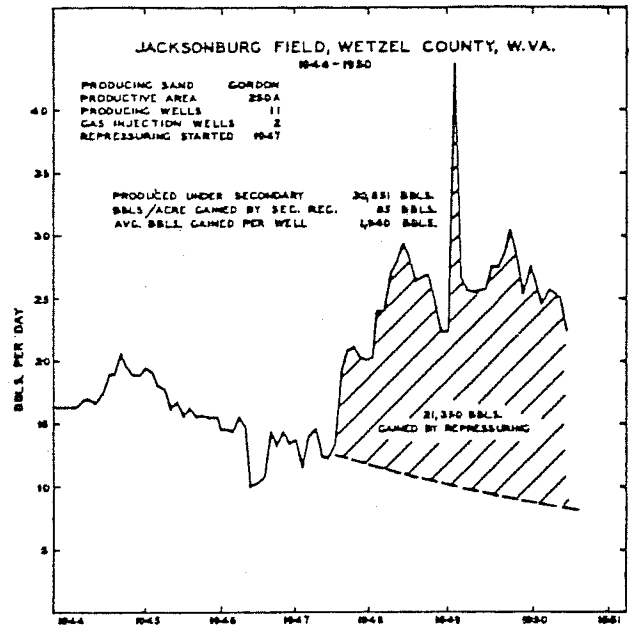


FIGURE 8

Decline Curve for a Gas Injection Project, Gordon Sand, Jacksonburg Field

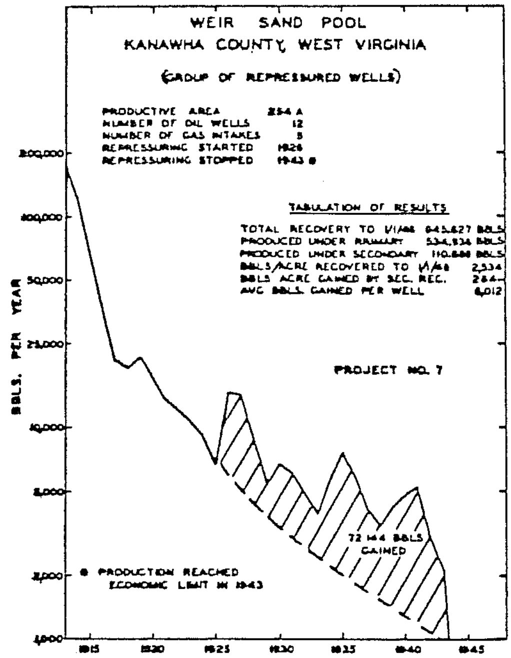


FIGURE 9

Decline Curve for a Gas Injection Project, Weir Sand, Blue Creek Field

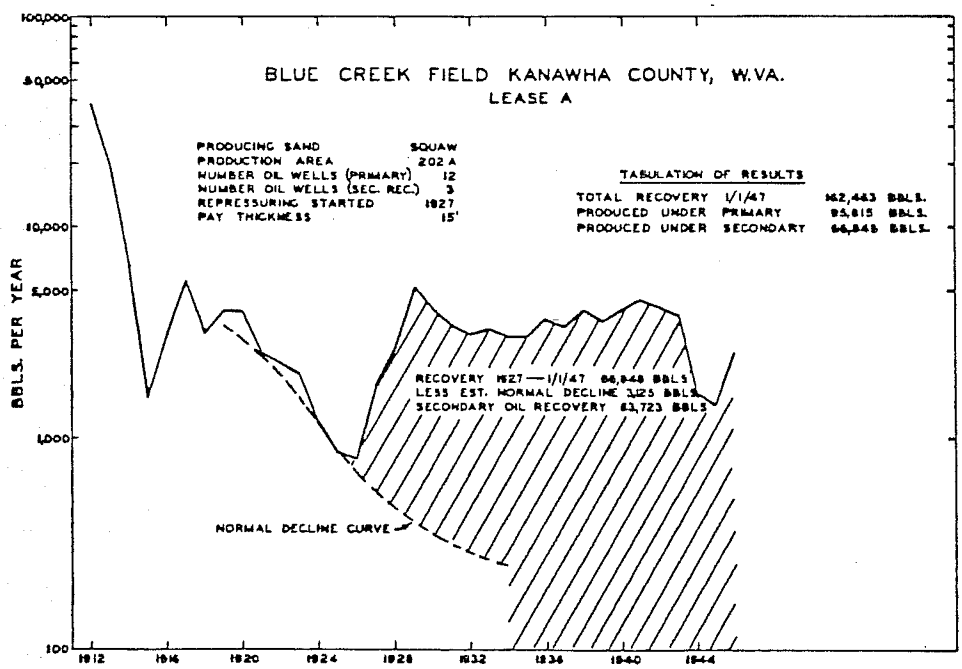


FIGURE 9a

Decline Curve for a Gas Injection Project, Squaw Sand, Blue Creek Field

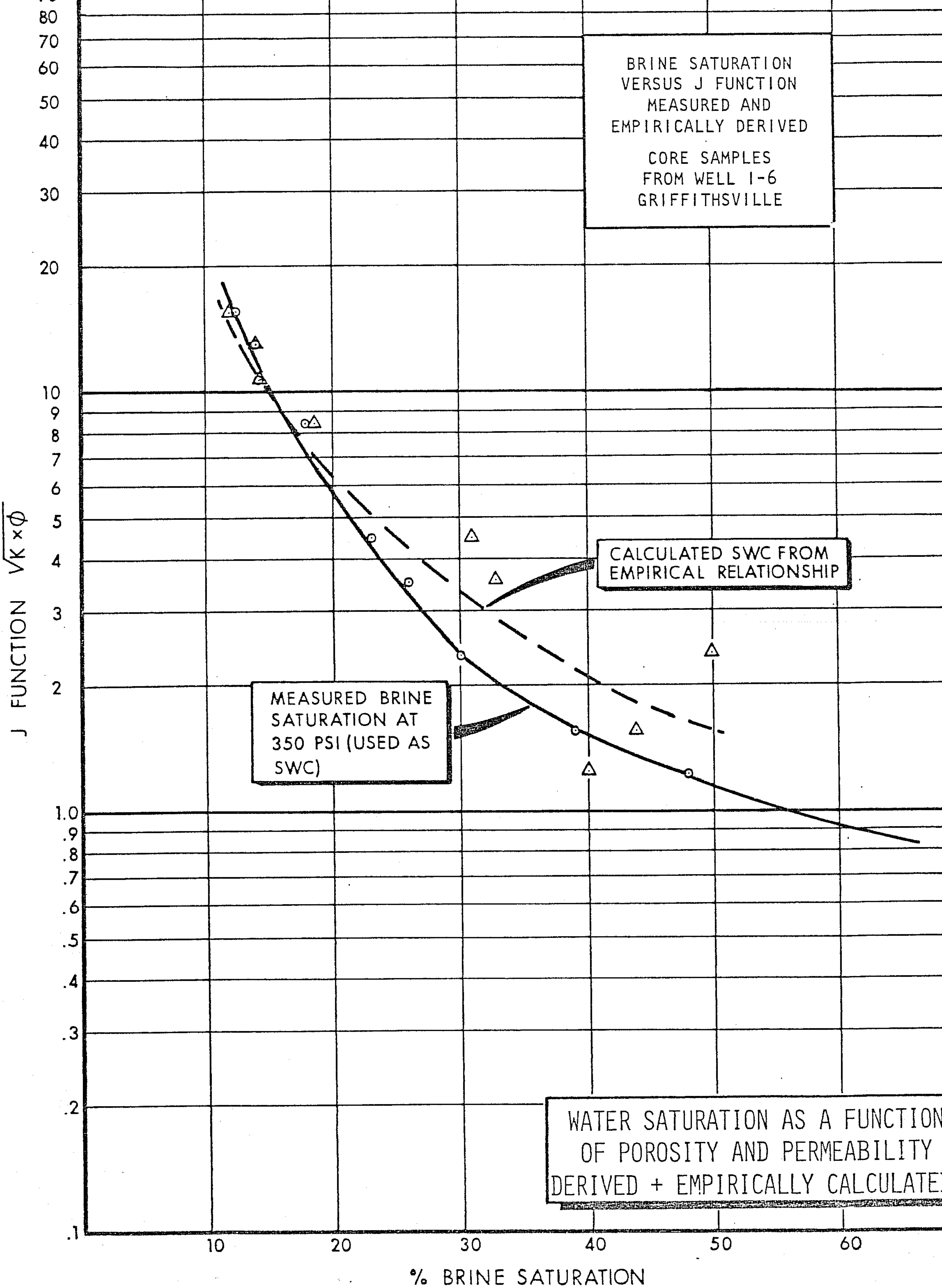

BRINE SATURATION
VERSUS J FUNCTION
MEASURED AND
EMPIRICALLY DERIVED
CORE SAMPLES
FROM WELL 1-6
GRIFFITHSVILLE
CALCULATED SWC FROM
EMPIRICAL RELATIONSHIP
MEASURED BRINE
SATURATION AT
350 PSI (USED AS
SWC)
WATER SATURATION AS A FUNCTION
OF POROSITY AND PERMEABILITY
DERIVED + EMPIRICALLY CALCULATE
J FUNCTION $\sqrt{K \times \phi}$
80
70
60
50
40
30
20
10
9
8
7
6
5
4
3
2
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
10
20
30
40
50
60
% BRINE SATURATION

Figure 10

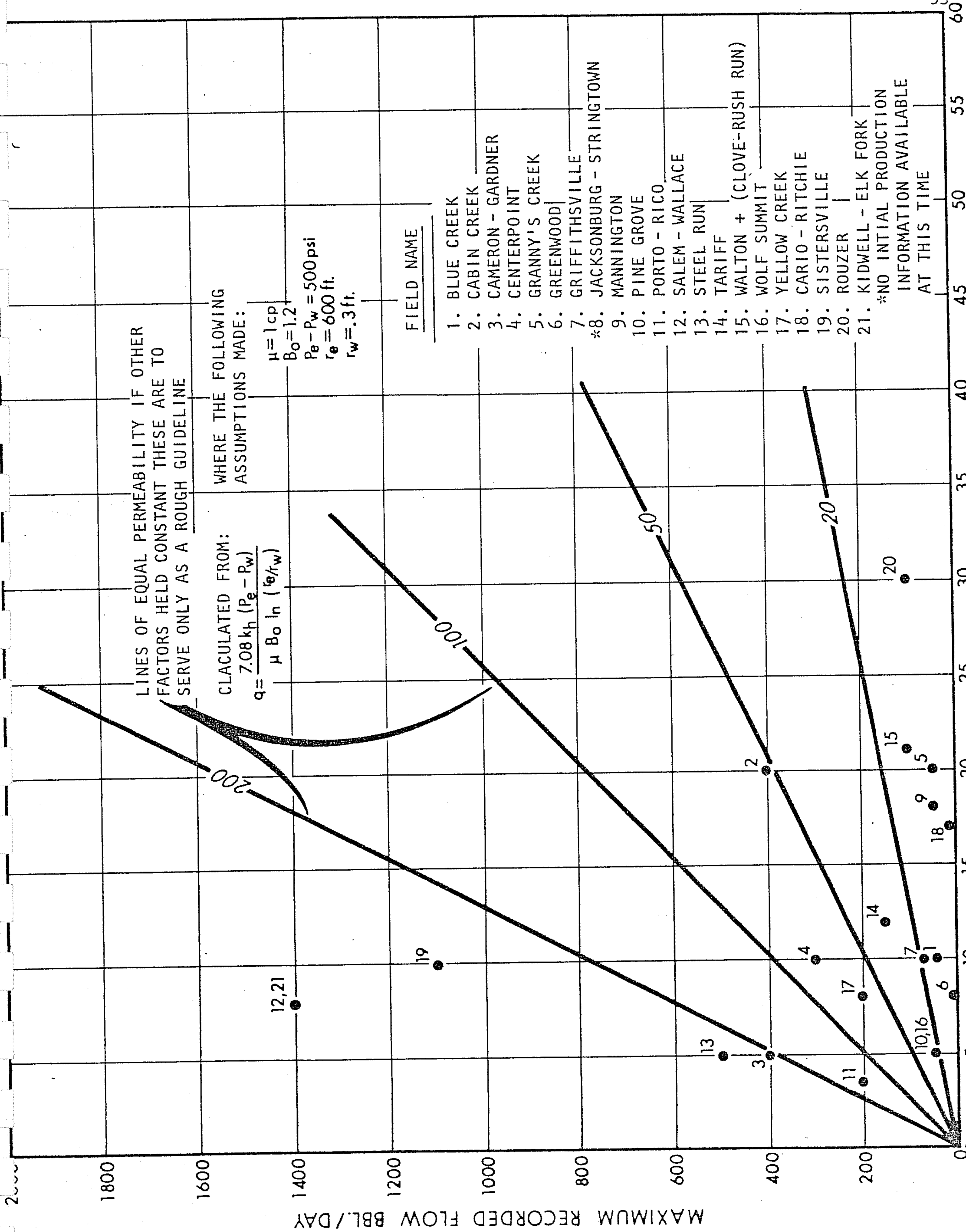


Fig. 11: Empirically Derived Permeability

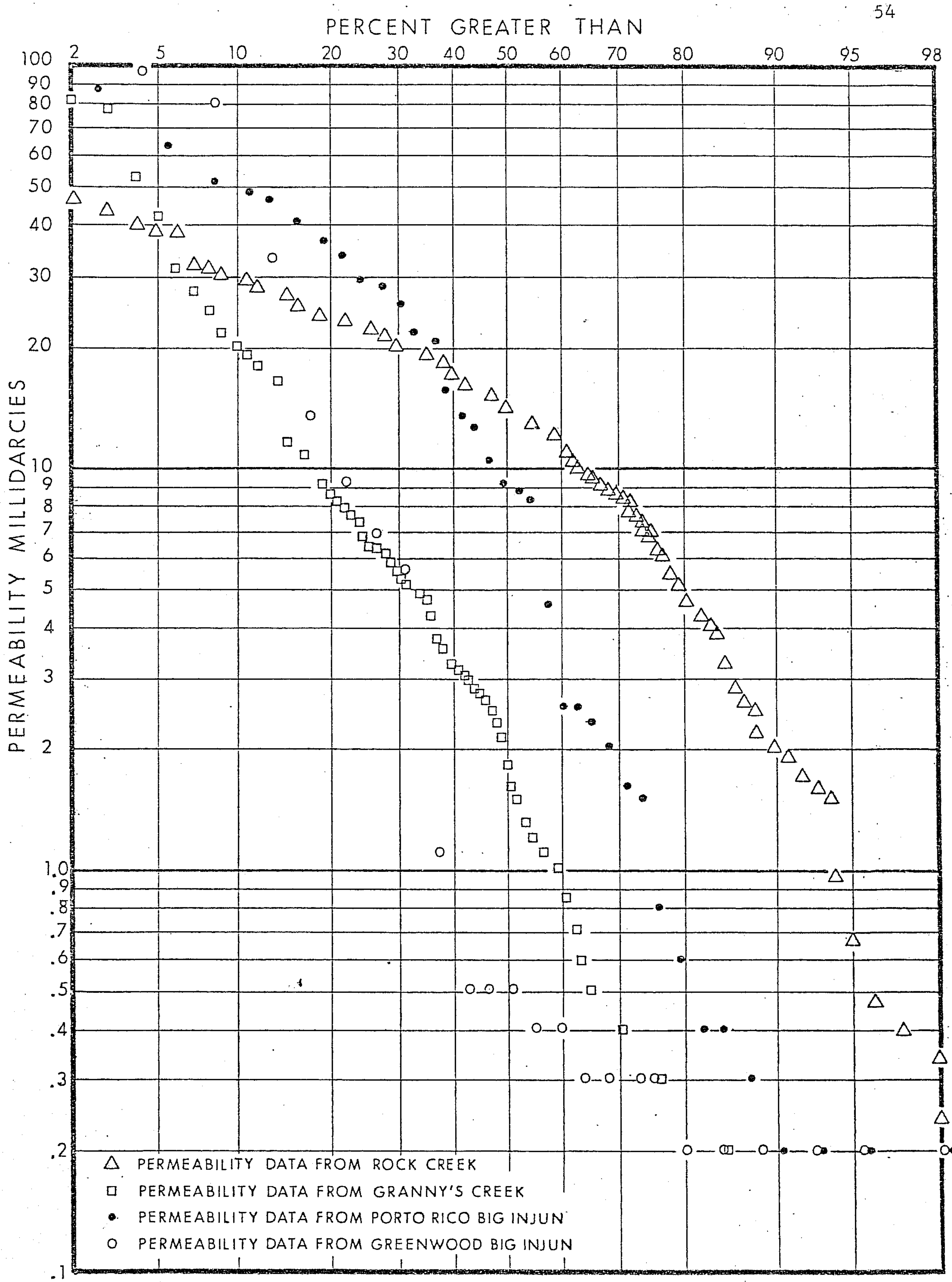


Fig. 12: Permeability Variation of Two Big Injun Sand Reservoirs in West Virginia

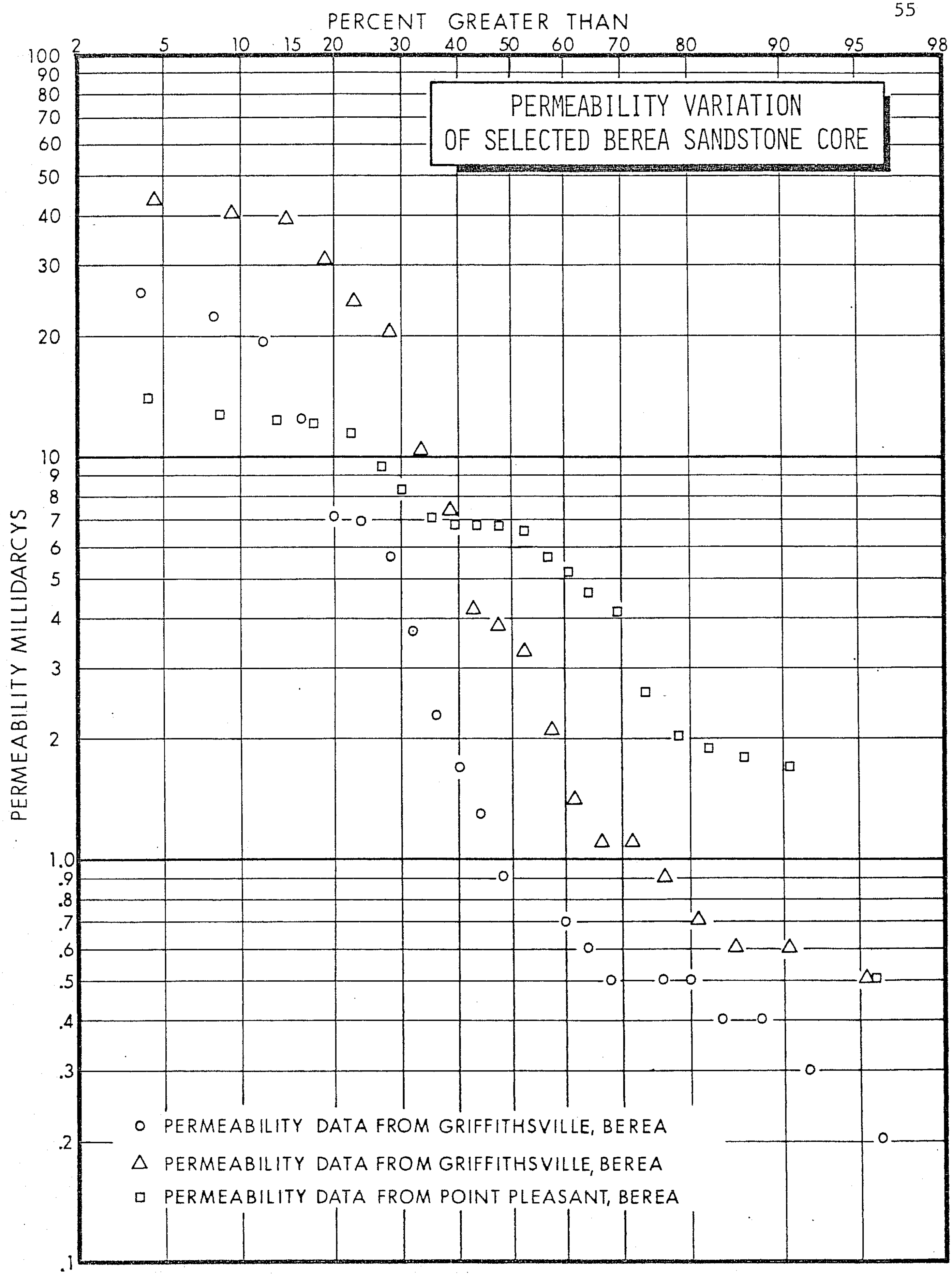

PERCENT GREATER THAN
2
5
10
15
20
30
40
50
60
70
80
90
95
98
PERMEABILITY VARIATION
OF SELECTED BEREA SANDSTONE CORE
PERMEABILITY MILLIDARCYS
100
90
80
70
60
50
40
30
20
10
9
8
7
6
5
4
3
2
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
PERMEABILITY DATA FROM GRIFFITHSVILLE, BEREA
PERMEABILITY DATA FROM GRIFFITHSVILLE, BEREA
PERMEABILITY DATA FROM POINT PLEASANT, BEREA

Figure 13

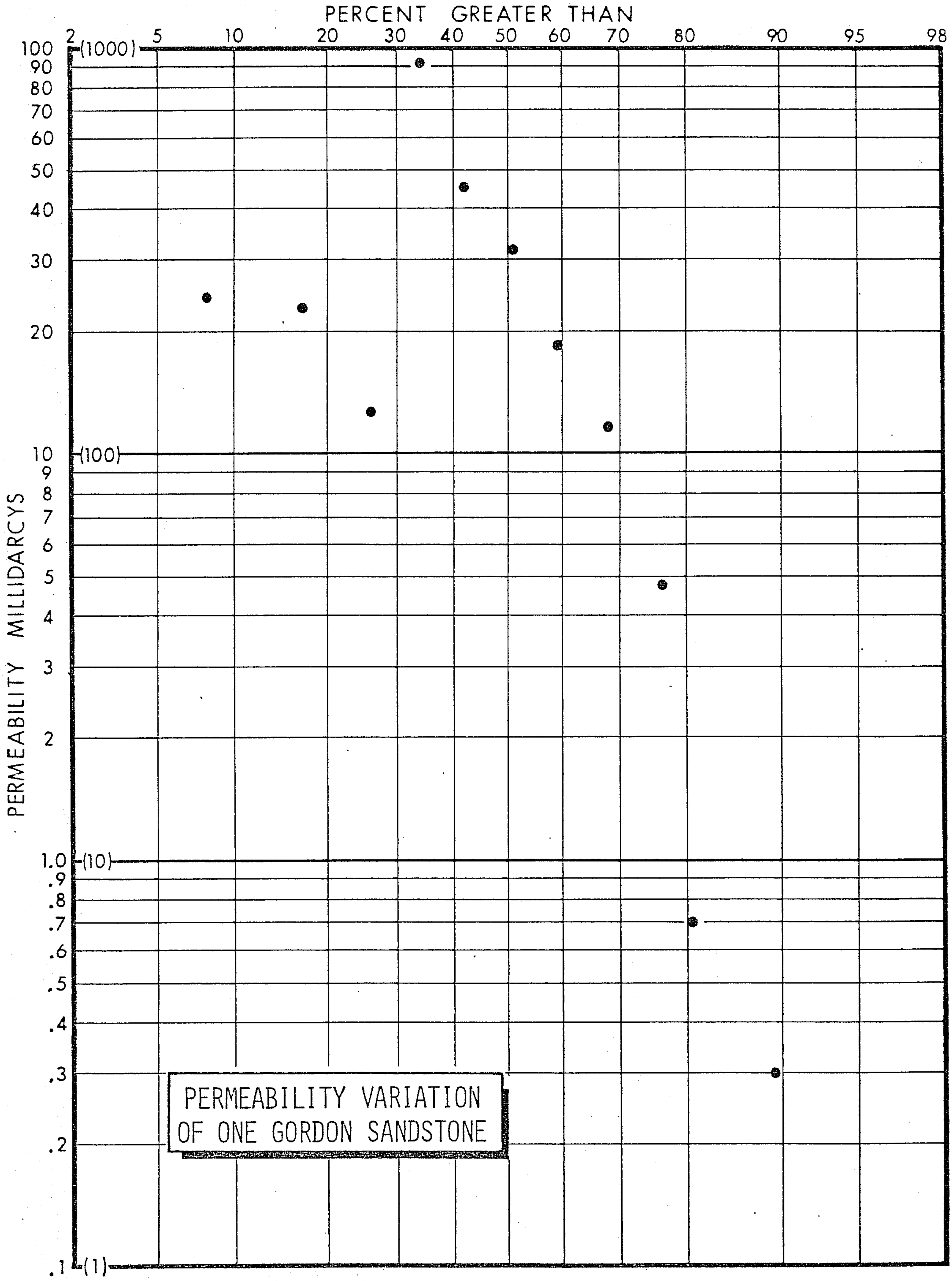

PERCENT GREATER THAN
2
5
10
20
30
40
50
60
70
80
90
95
98
PERMEABILITY MILLIDARCYS
100 (1000)
90
80
70
60
50
40
30
20
10 (100)
9
8
7
6
5
4
3
2
1.0 (10)
.9
.8
.7
.6
.5
.4
.3
.2
.1 (1)
PERMEABILITY VARIATION
OF ONE GORDON SANDSTONE

Figure 14

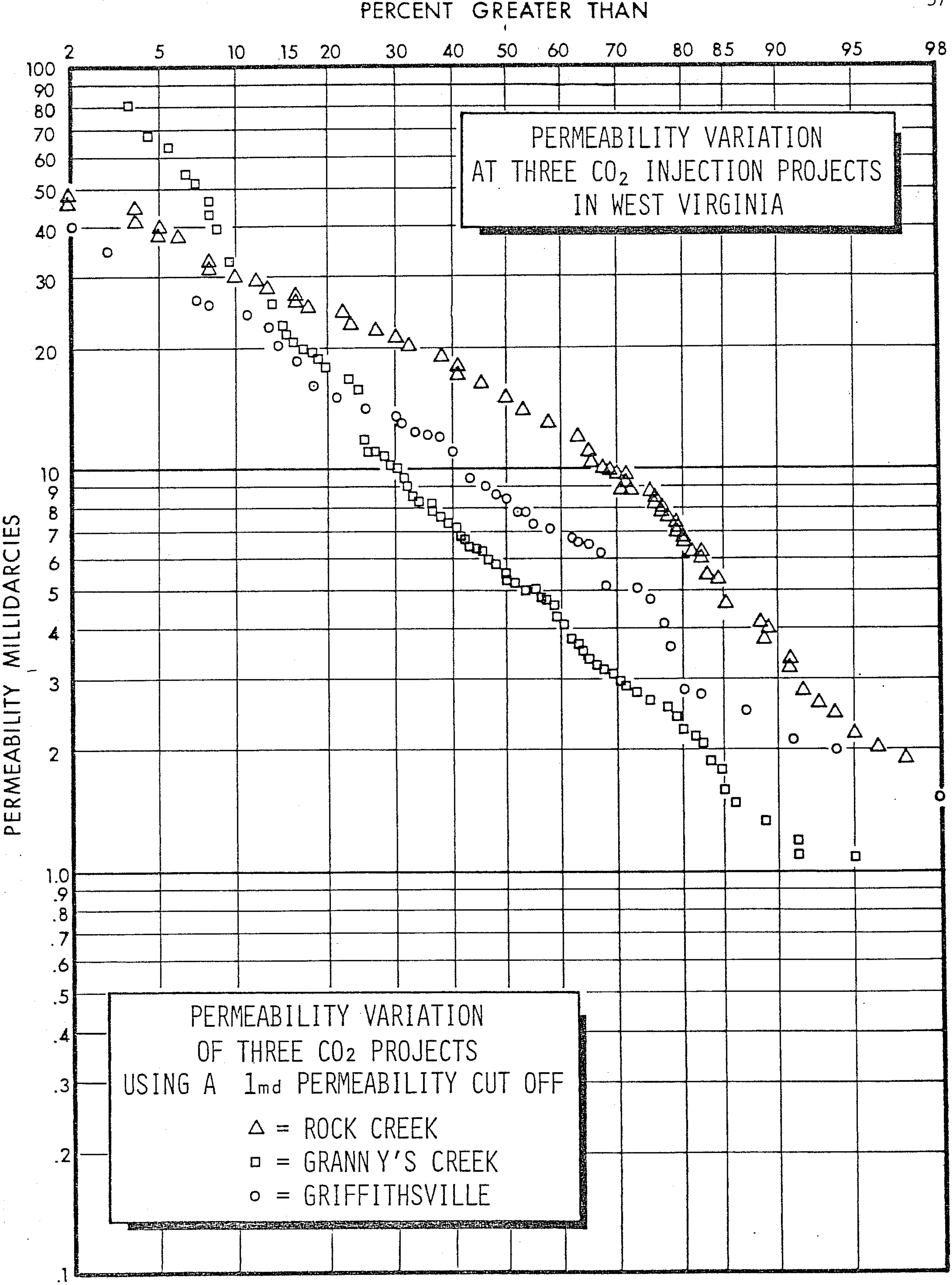

PERCENT GREATER THAN
2 5 10 15 20 30 40 50 60 70 80 85 90 95 98
PERMEABILITY MILLIDARCIES
100 90 80 70 60 50 40 30 20 10 9 8 7 6 5 4 3 2 1.0 .9 .8 .7 .6 .5 .4 .3 .2 .1
PERMEABILITY VARIATION
AT THREE CO_2 INJECTION PROJECTS
IN WEST VIRGINIA
PERMEABILITY VARIATION
OF THREE CO_2 PROJECTS
USING A 1md PERMEABILITY CUT OFF
△ = ROCK CREEK
□ = GRANNY'S CREEK
○ = GRIFFITHSVILLE

Figure 15

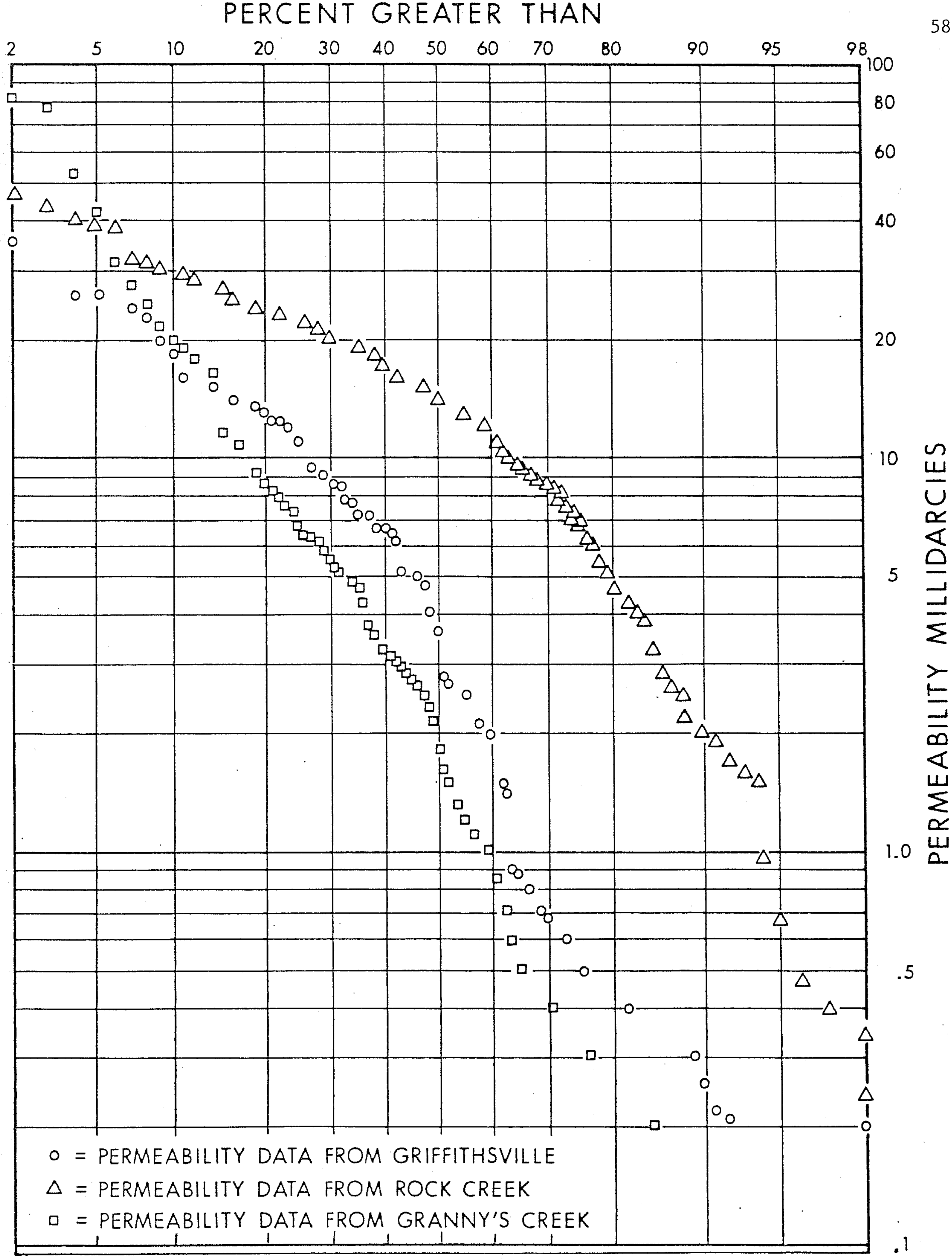


FIG. 16: PERMEABILITY VARIATION OF ALL THREE WEST VIRGINIA CO_2 INJECTION PROJECT AREAS USING 0.1-md CUTOFF.

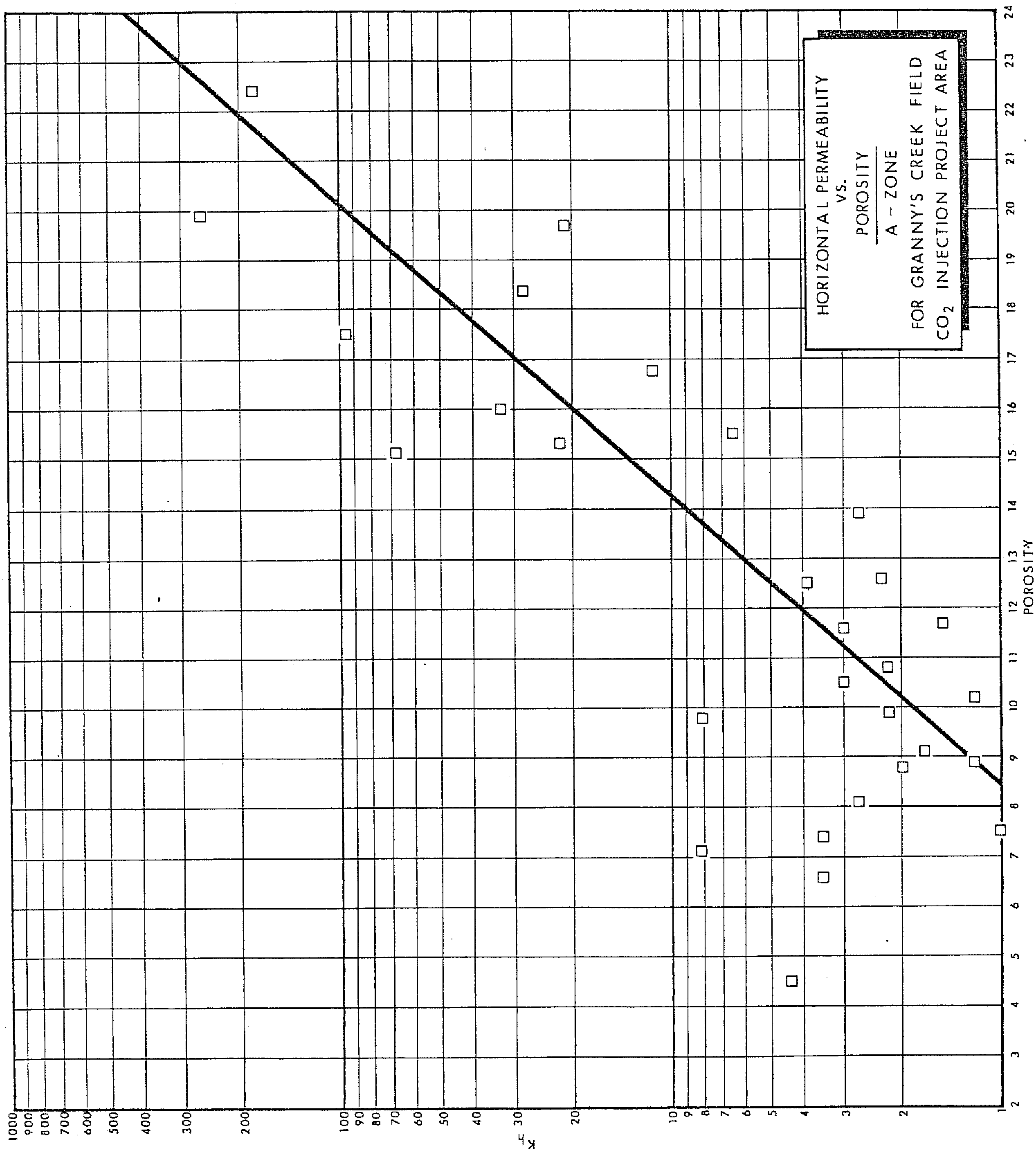


Fig.17: Permeability versus Porosity, A Zone, Granny's Creek Field

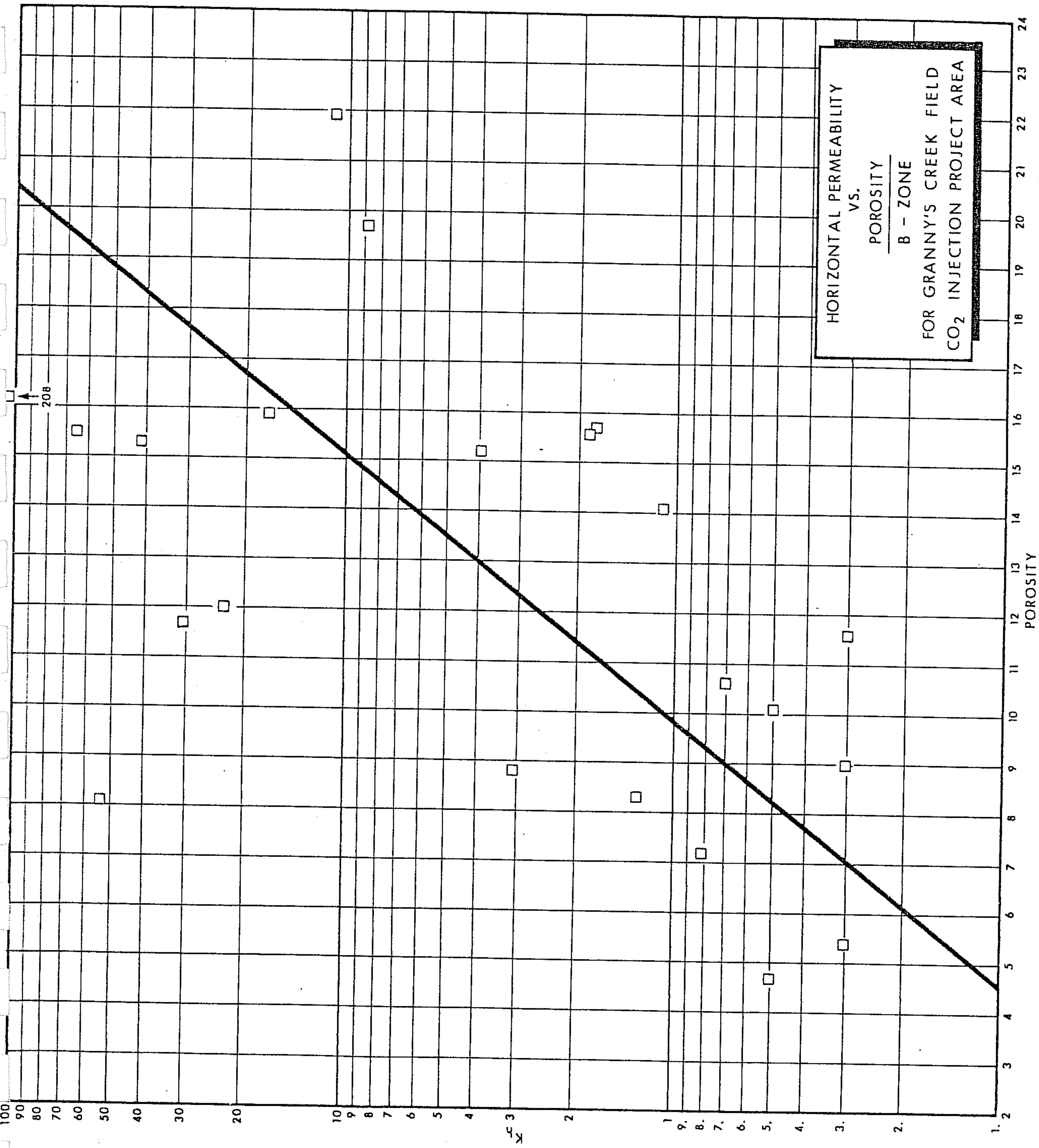


Fig. 18: Permeability versus Porosity, B Zone, Granny's Creek Field

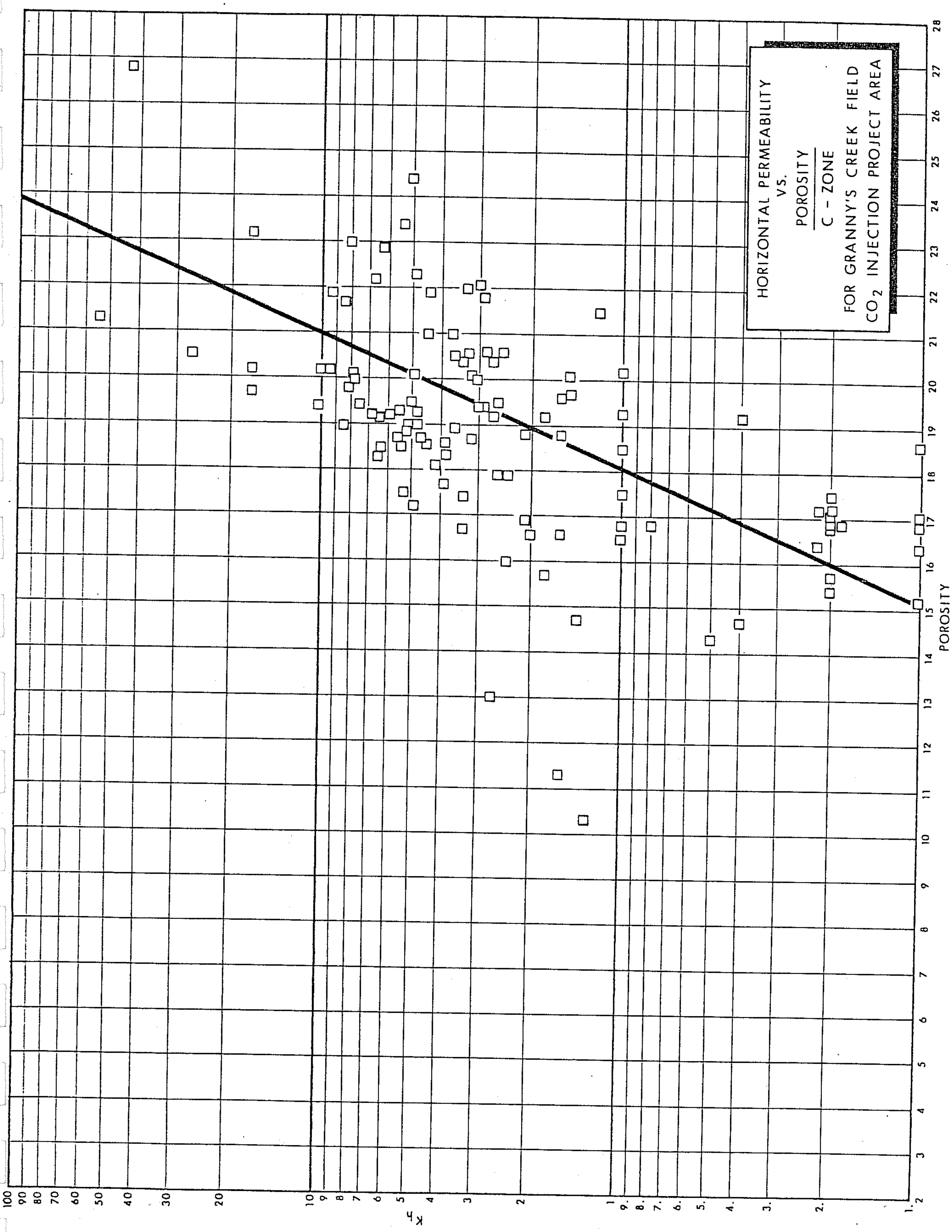
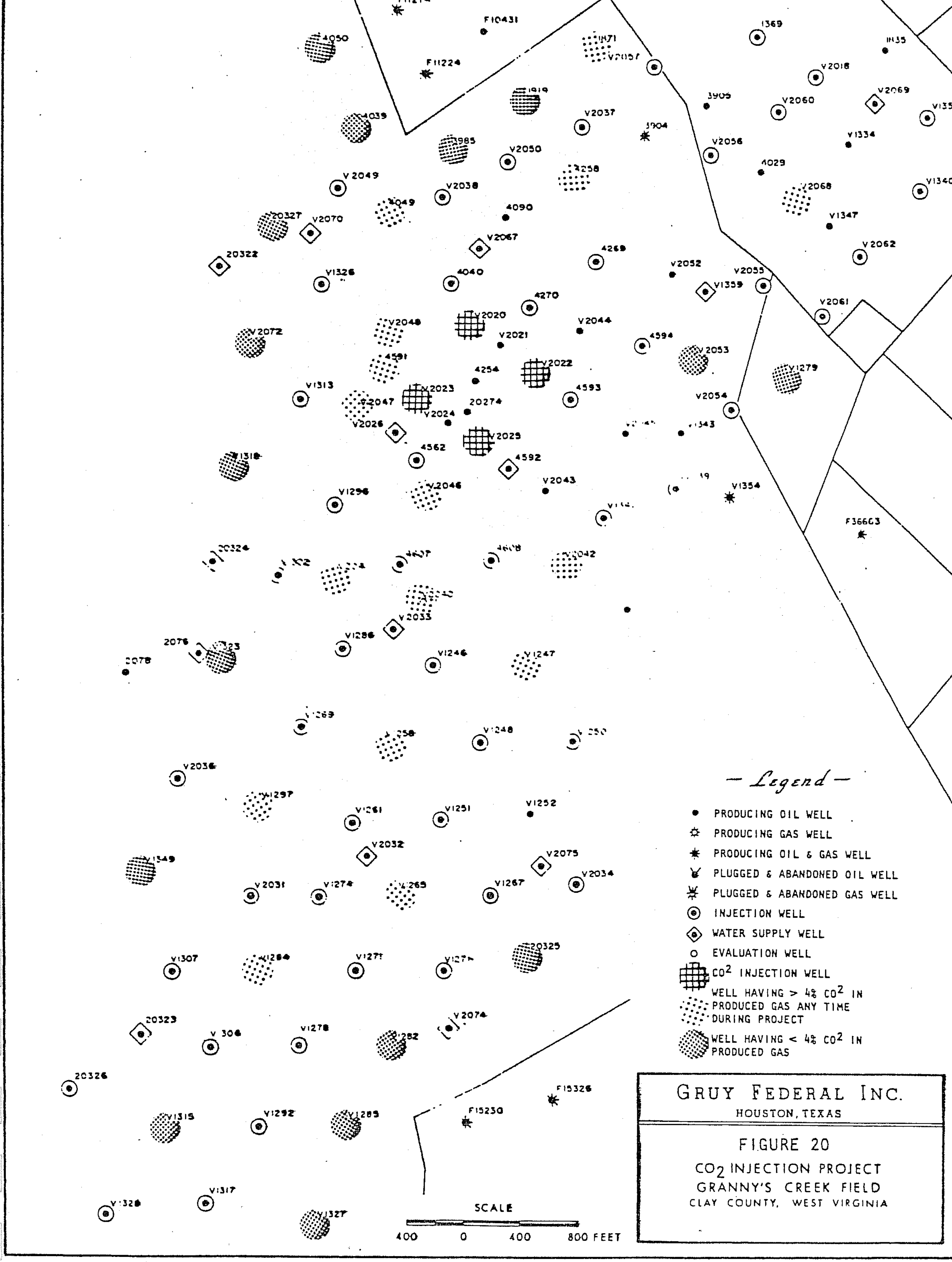


Fig. 19: Permeability versus Porosity, C Zone, Granny's Creek Field



- Legend -
PRODUCING OIL WELL
PRODUCING GAS WELL
PRODUCING OIL & GAS WELL
PLUGGED & ABANDONED OIL WELL
PLUGGED & ABANDONED GAS WELL
INJECTION WELL
WATER SUPPLY WELL
EVALUATION WELL
CO^2 INJECTION WELL
WELL HAVING > 4% CO^2 IN PRODUCED GAS ANY TIME DURING PROJECT
WELL HAVING < 4% CO^2 IN PRODUCED GAS
SCALE
400 0 400 800 FEET
GRUY FEDERAL INC.
HOUSTON, TEXAS
FIGURE 20
CO_2 INJECTION PROJECT
GRANNY'S CREEK FIELD
CLAY COUNTY, WEST VIRGINIA

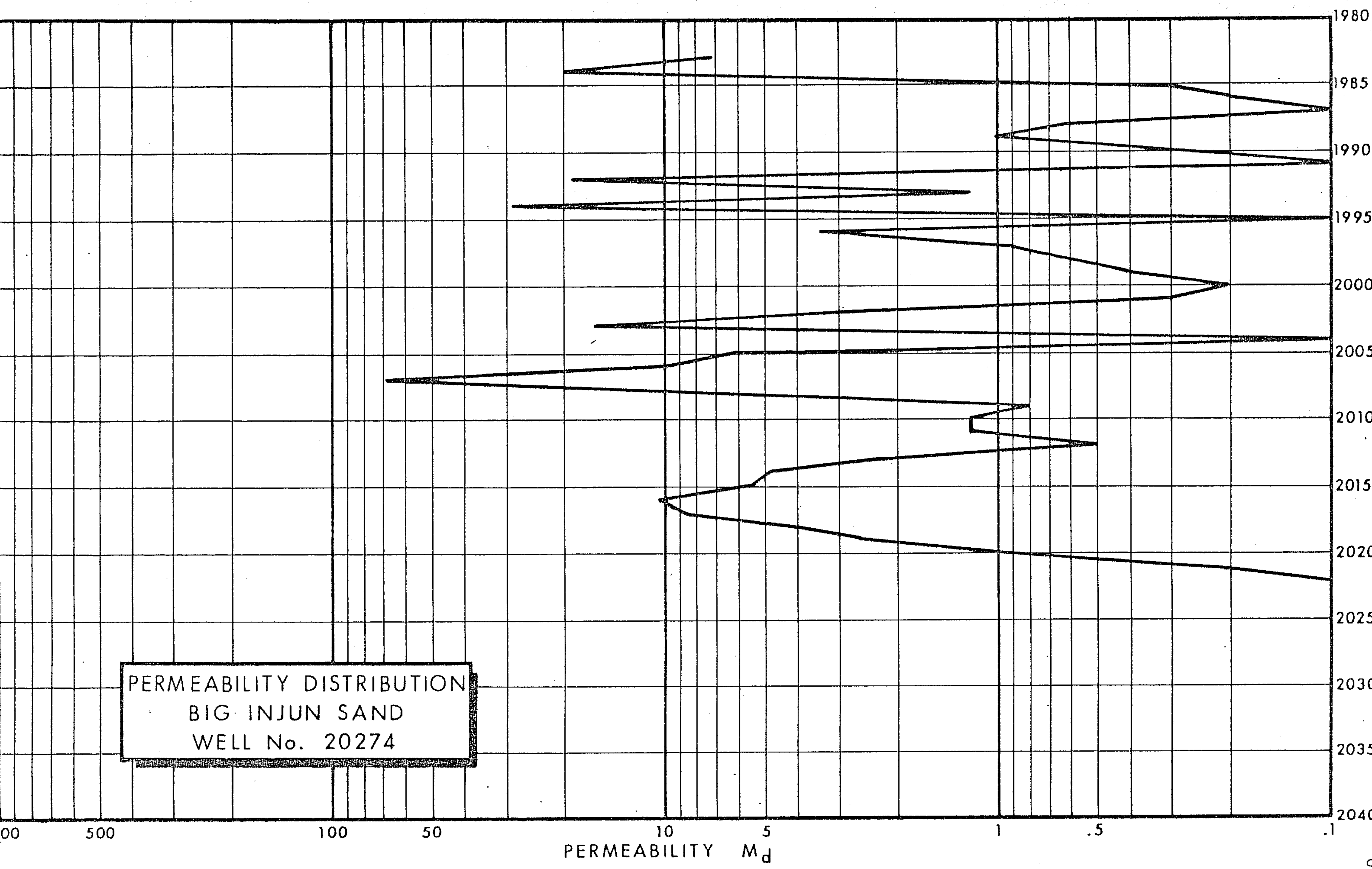
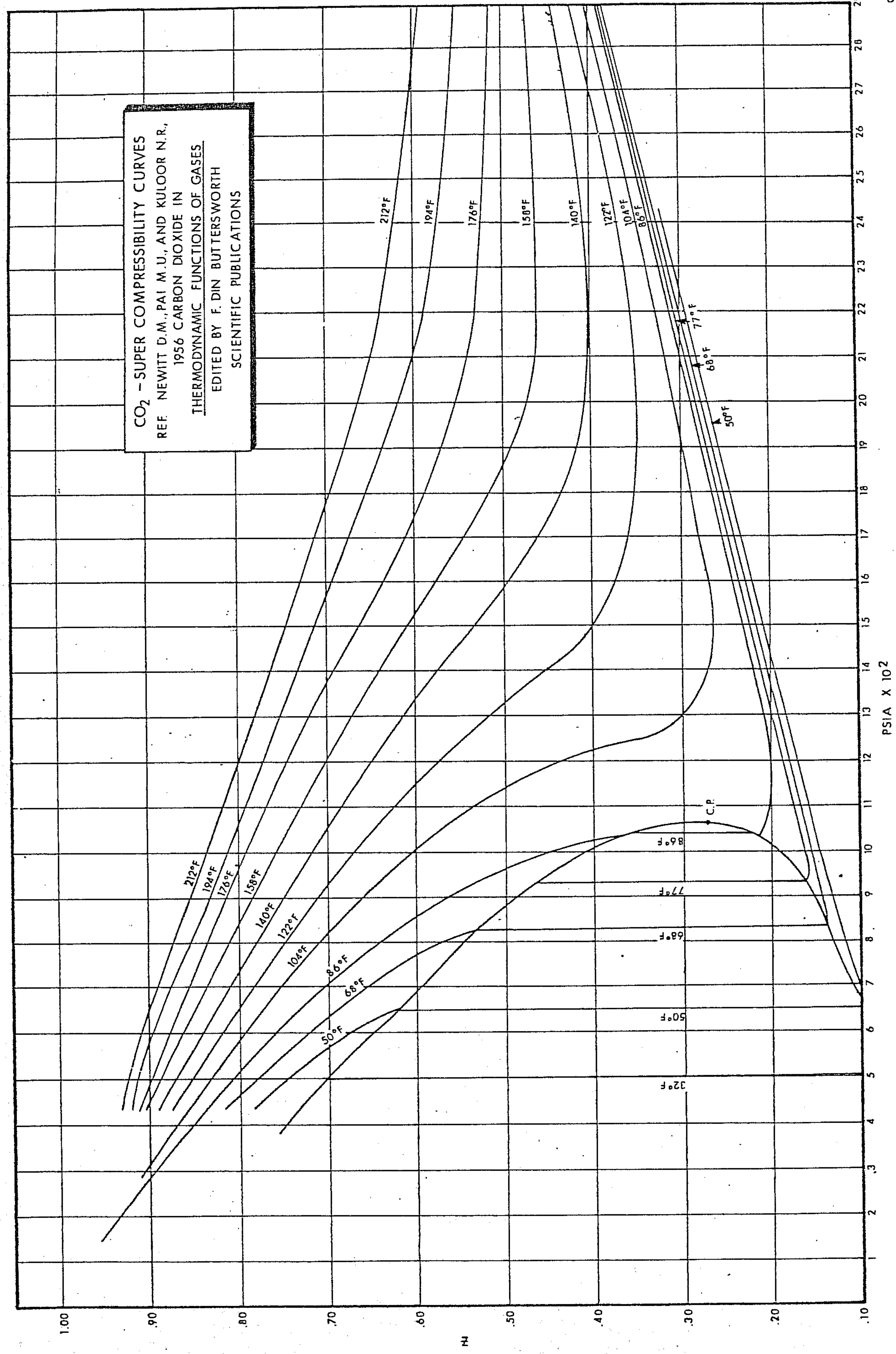

PERMEABILITY DISTRIBUTION
BIG INJUN SAND
WELL No. 20274
1980
1985
1990
1995
2000
2005
2010
2015
2020
2025
2030
2035
2040
500
100
50
10
5
1
.5
.1
PERMEABILITY M_d

Figure 21



CO_2 – SUPER COMPRESSIBILITY CURVES
REF. NEWITT D.M., PAI M.U., AND KULOOR N.R., 1956 CARBON DIOXIDE IN
THERMODYNAMIC FUNCTIONS OF GASES
EDITED BY F. DIN BUTTERSWORTH
SCIENTIFIC PUBLICATIONS
212°F
194°F
176°F
158°F
140°F
122°F
104°F
86°F
77°F
68°F
50°F
32°F
C.P.
PSIA X 10²
Z

Figure 22

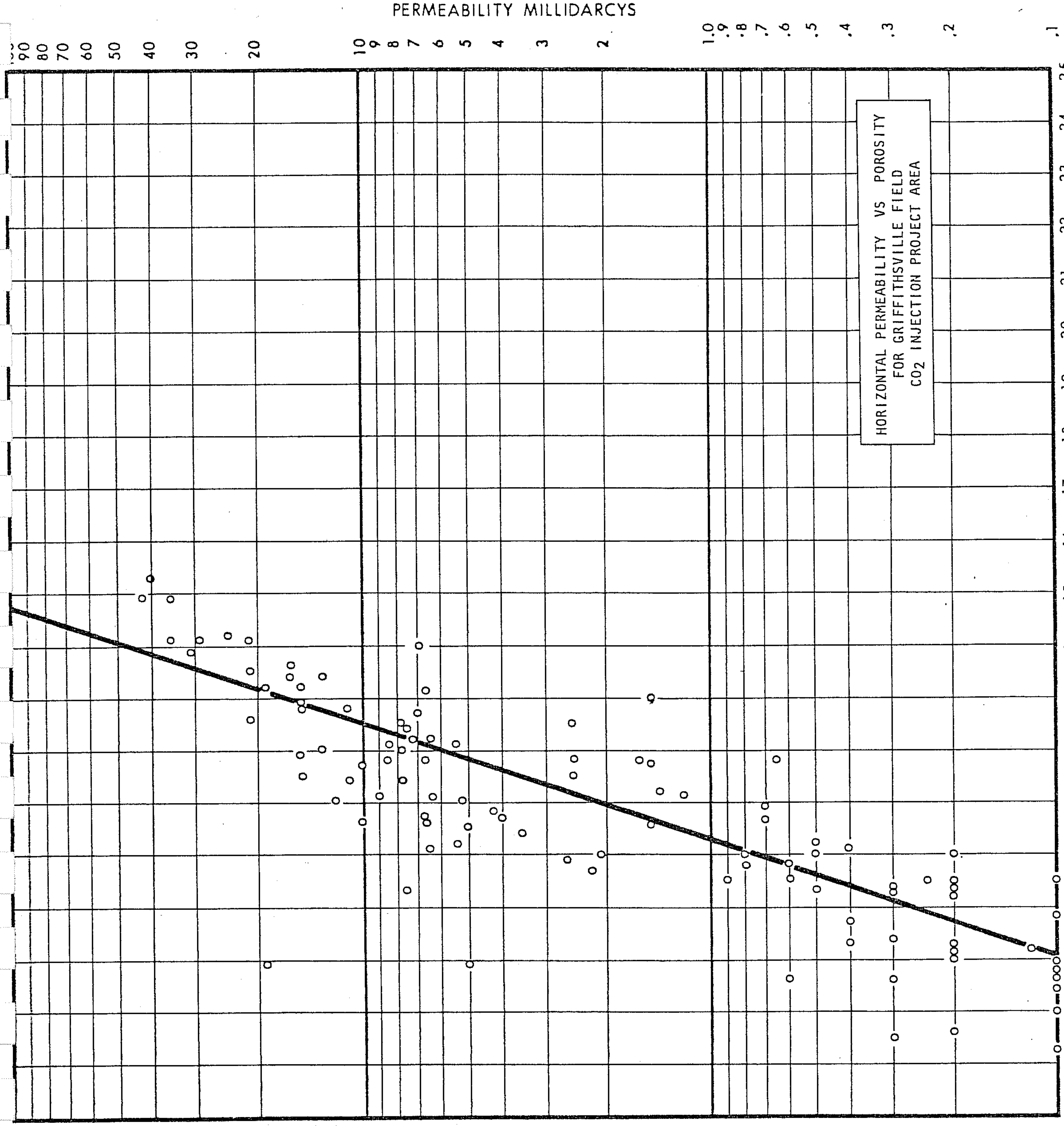

PERMEABILITY MILLIDARCYS
HORIZONTAL PERMEABILITY VS POROSITY
FOR GRIFFITHSVILLE FIELD
CO2 INJECTION PROJECT AREA

Figure 23

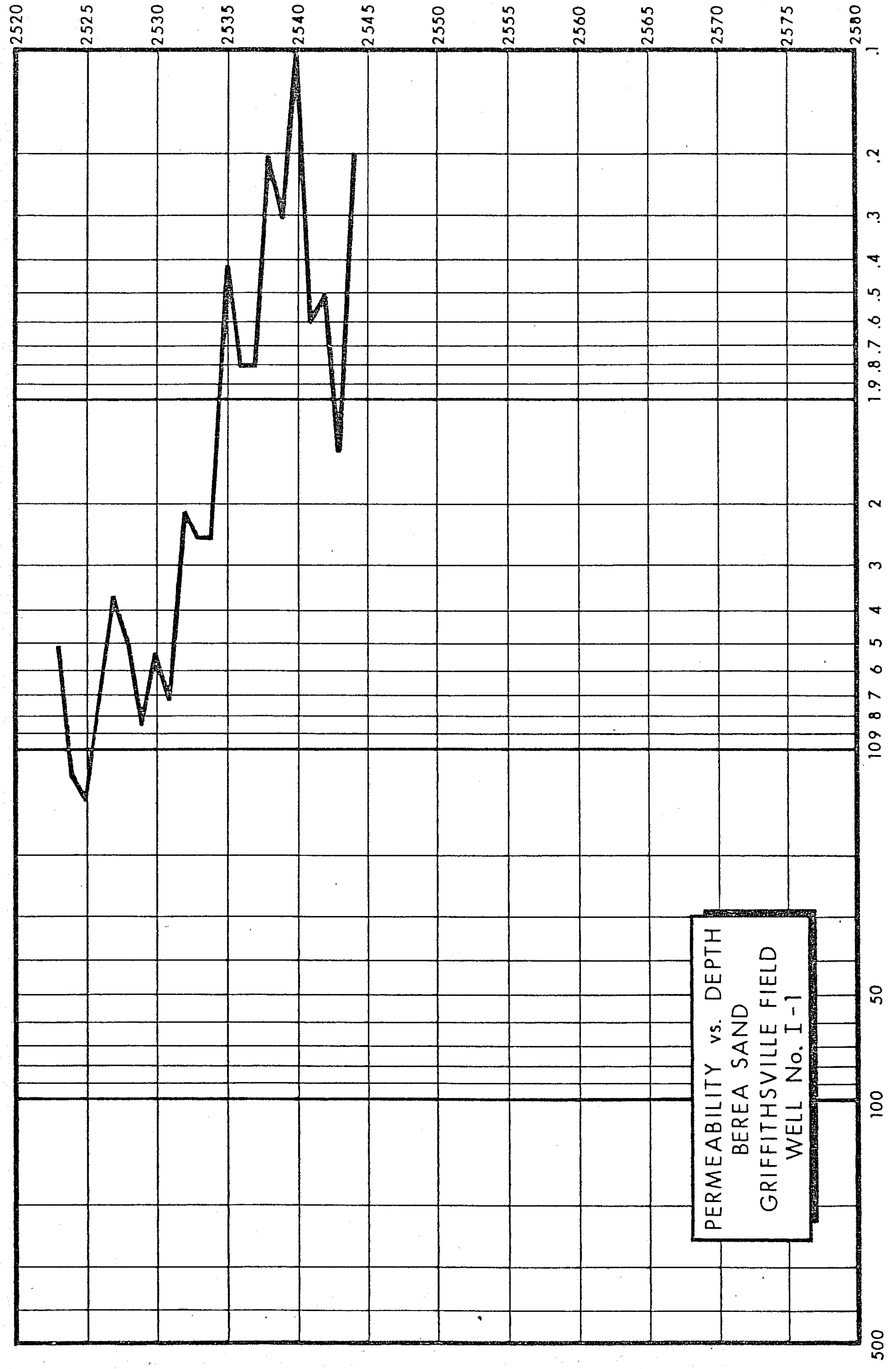

2520
2525
2530
2535
2540
2545
2550
2555
2560
2565
2570
2575
2580
.1
.2
.3
.4
.5
.6
.7
.8
.9
1
2
3
4
5
6
7
8
9
10
50
100
500
PERMEABILITY Md
PERMEABILITY vs. DEPTH
BEREA SAND
GRIFFITHSVILLE FIELD
WELL No. I-1

Fig. 24

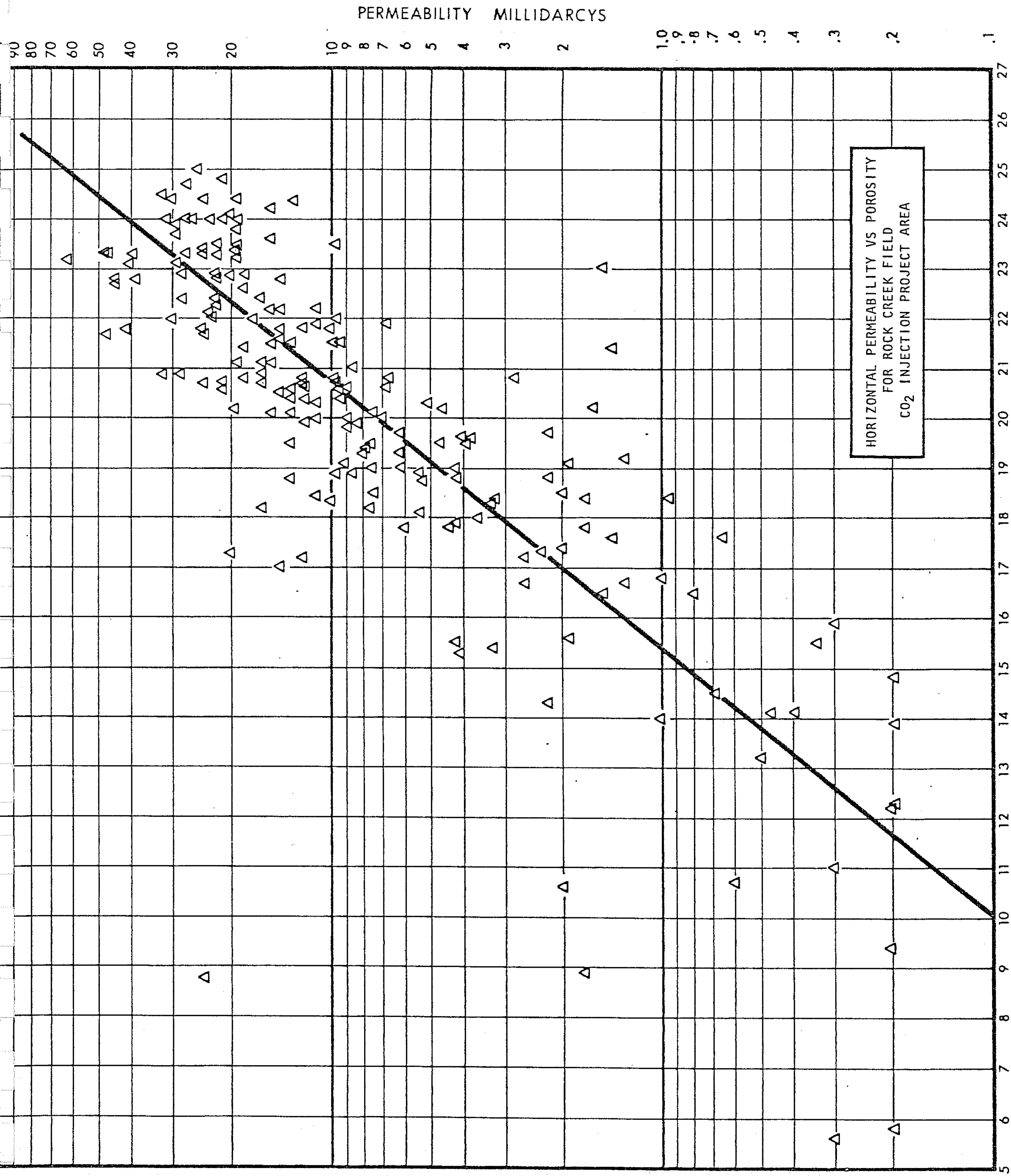

PERMEABILITY MILLIDARCYS
HORIZONTAL PERMEABILITY VS POROSITY
FOR ROCK CREEK FIELD
CO2 INJECTION PROJECT AREA

Figure 25

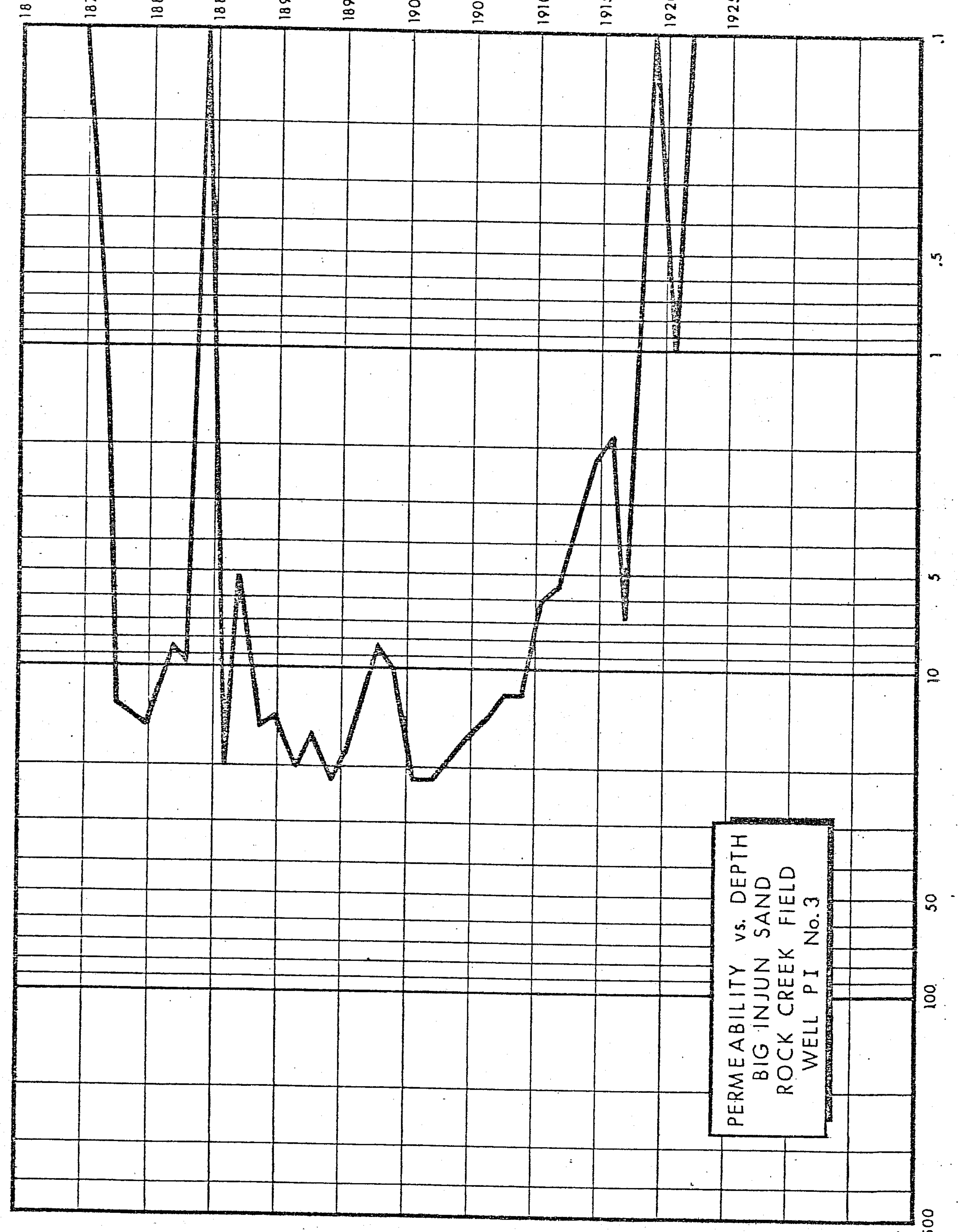

PERMEABILITY vs. DEPTH
BIG INJUN SAND
ROCK CREEK FIELD
WELL PI No.3
.1
.5
1
5
10
50
100
500
1925

Figure 26

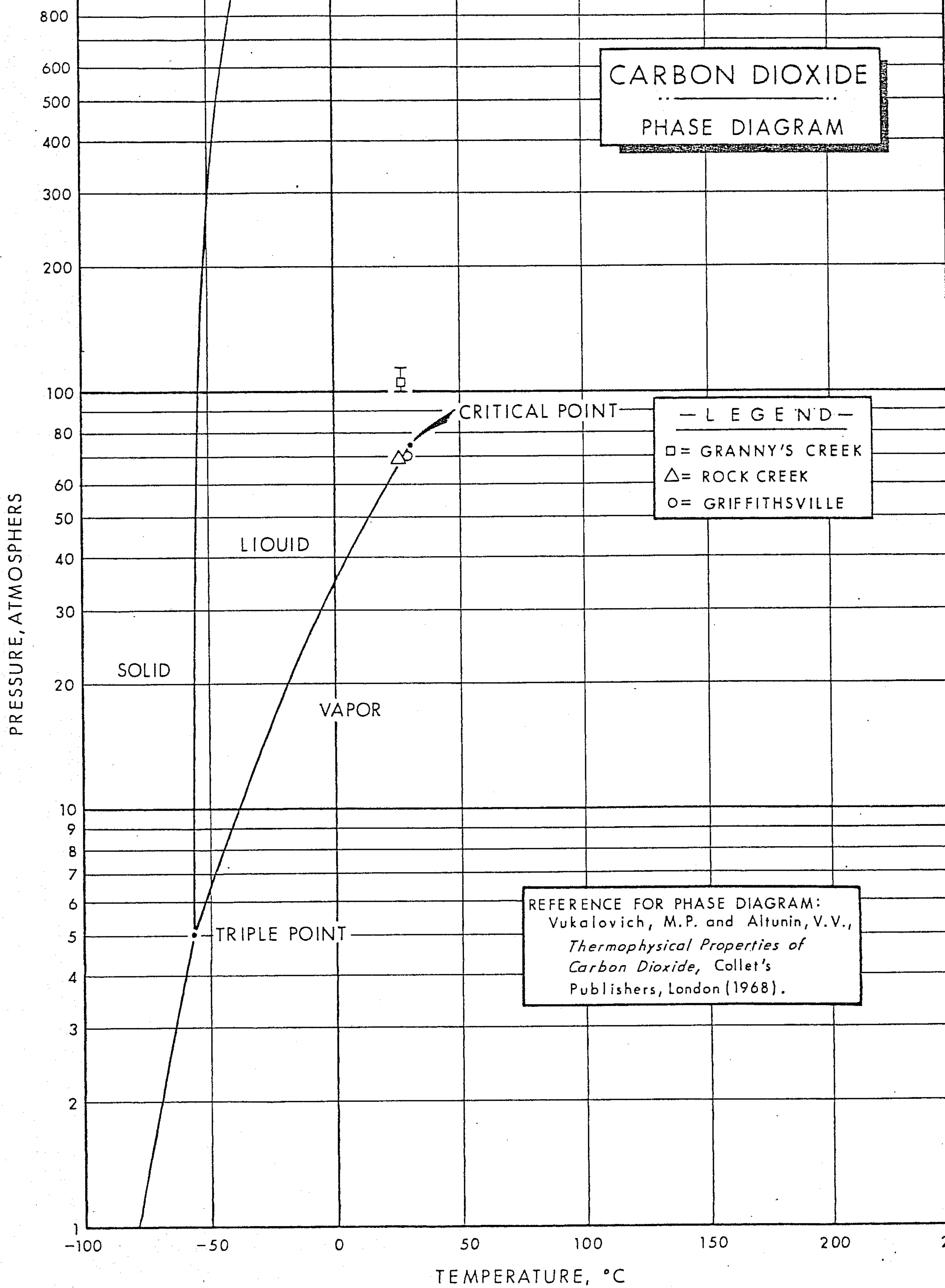

CARBON DIOXIDE
PHASE DIAGRAM
CRITICAL POINT
— L E G E N D —
□ = GRANNY'S CREEK
△ = ROCK CREEK
○ = GRIFFITHSVILLE
LIQUID
SOLID
VAPOR
TRIPLE POINT
REFERENCE FOR PHASE DIAGRAM:
Vukalovich, M.P. and Altunin, V.V.,
Thermophysical Properties of Carbon Dioxide, Collet's Publishers, London (1968).
PRESSURE, ATMOSPHERS
TEMPERATURE, °C
800
600
500
400
300
200
100
80
60
50
40
30
20
10
9
8
7
6
5
4
3
2
1
−100
−50
0
50
100
150
200

Fig. 27

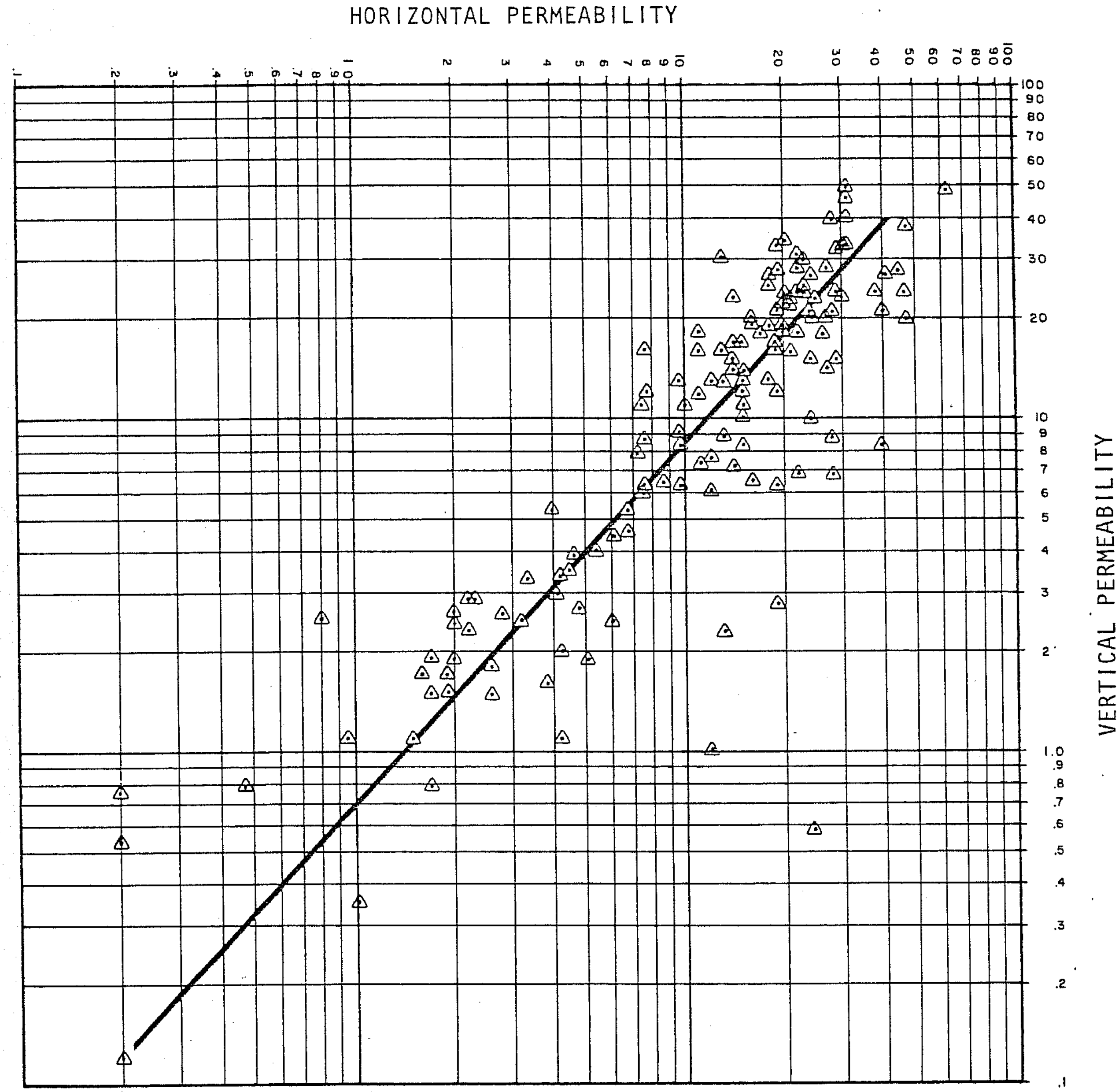


FIG. 28

HORIZONTAL PERMEABILITY VS VERTICAL PERMEABILITY

CO_2 INJECTION PROJECT AREA

ROCK CREEK FIELD WEST VIRGINIA

HORIZONTAL PERMEABILITY

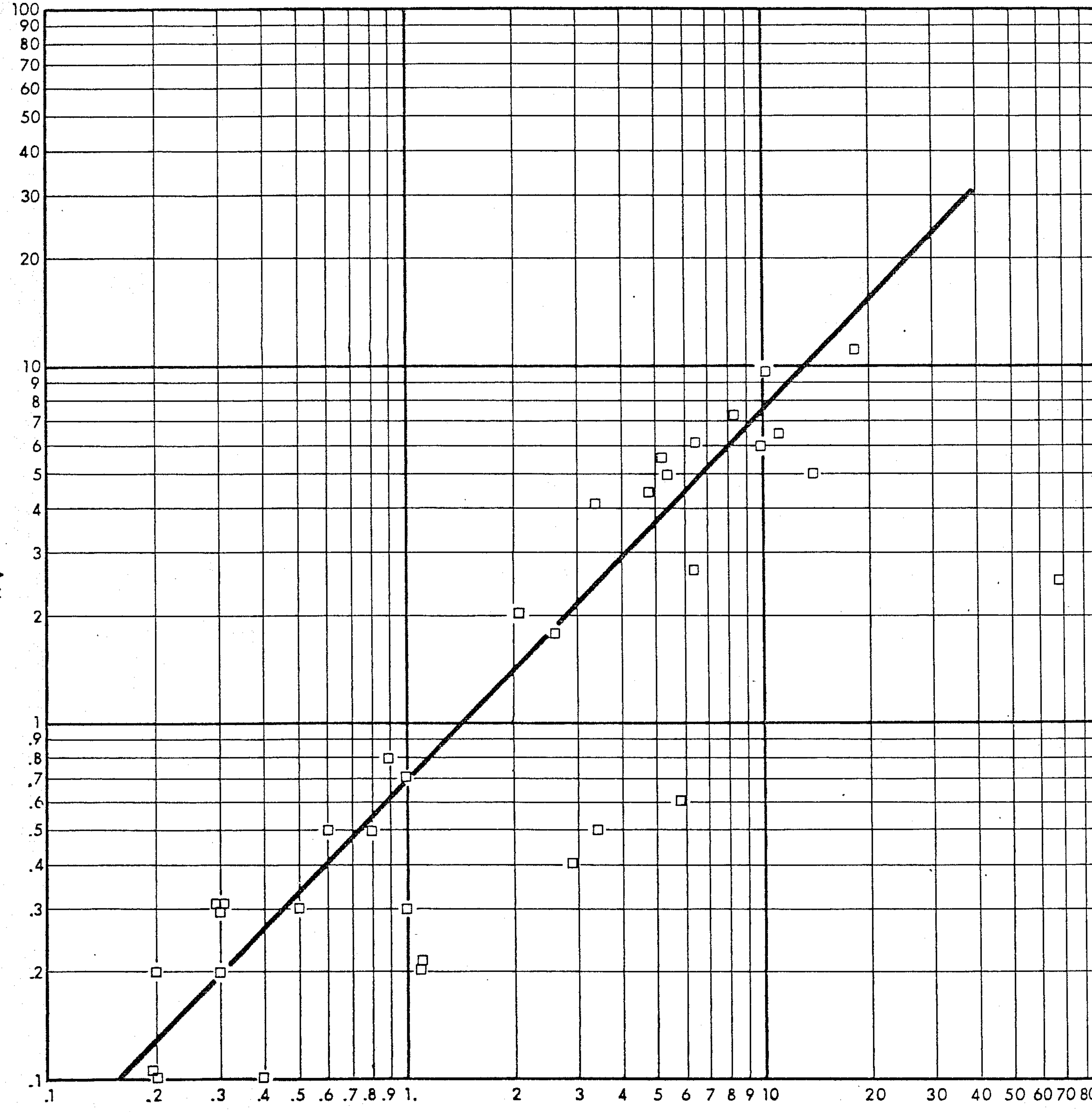


FIGURE 29

HORIZONTAL PERMEABILITY VS VERTICAL PERMEABILITY

CO_2 INJECTION PROJECT AREA

GRANNY'S CREEK FIELD

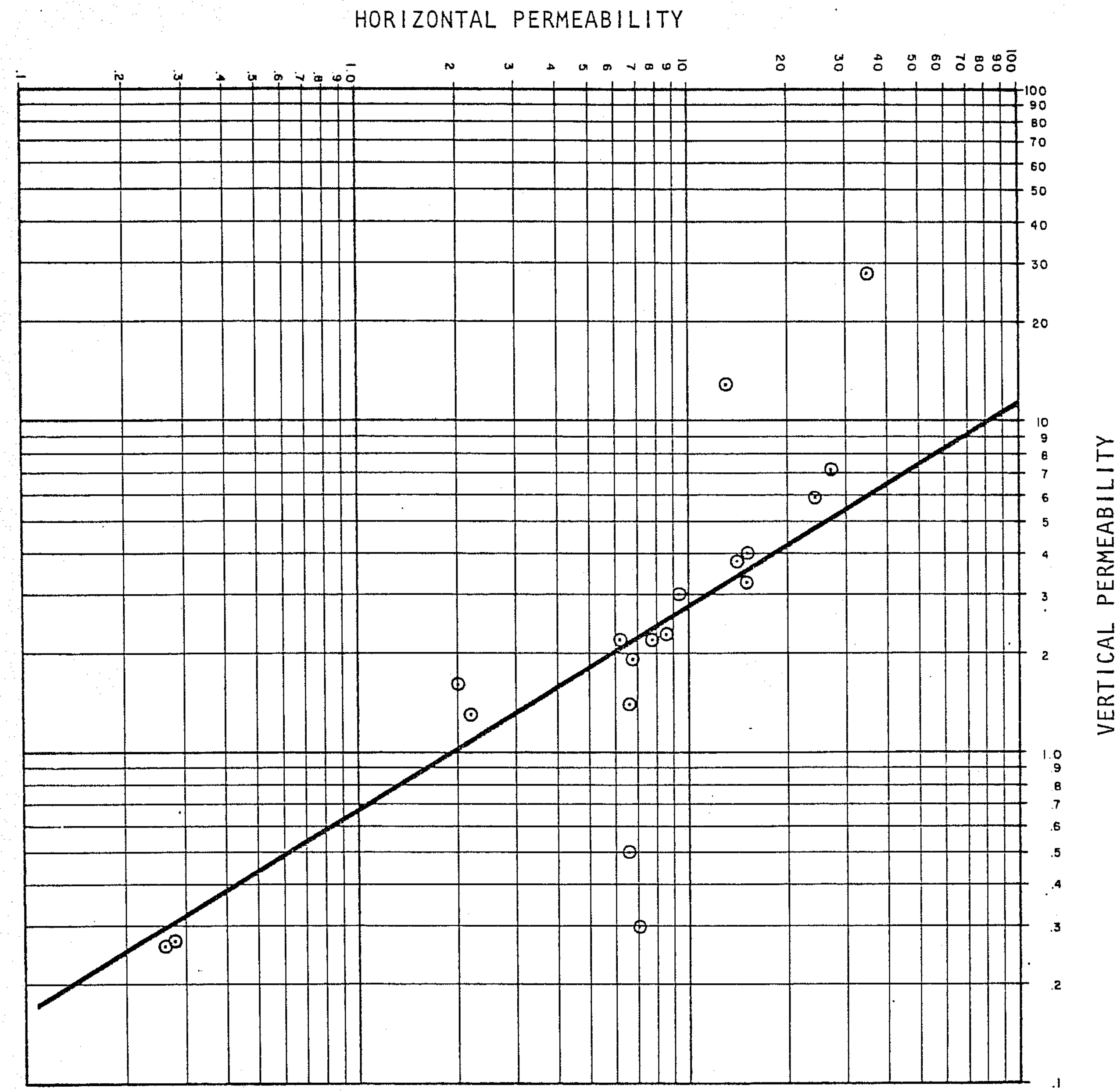
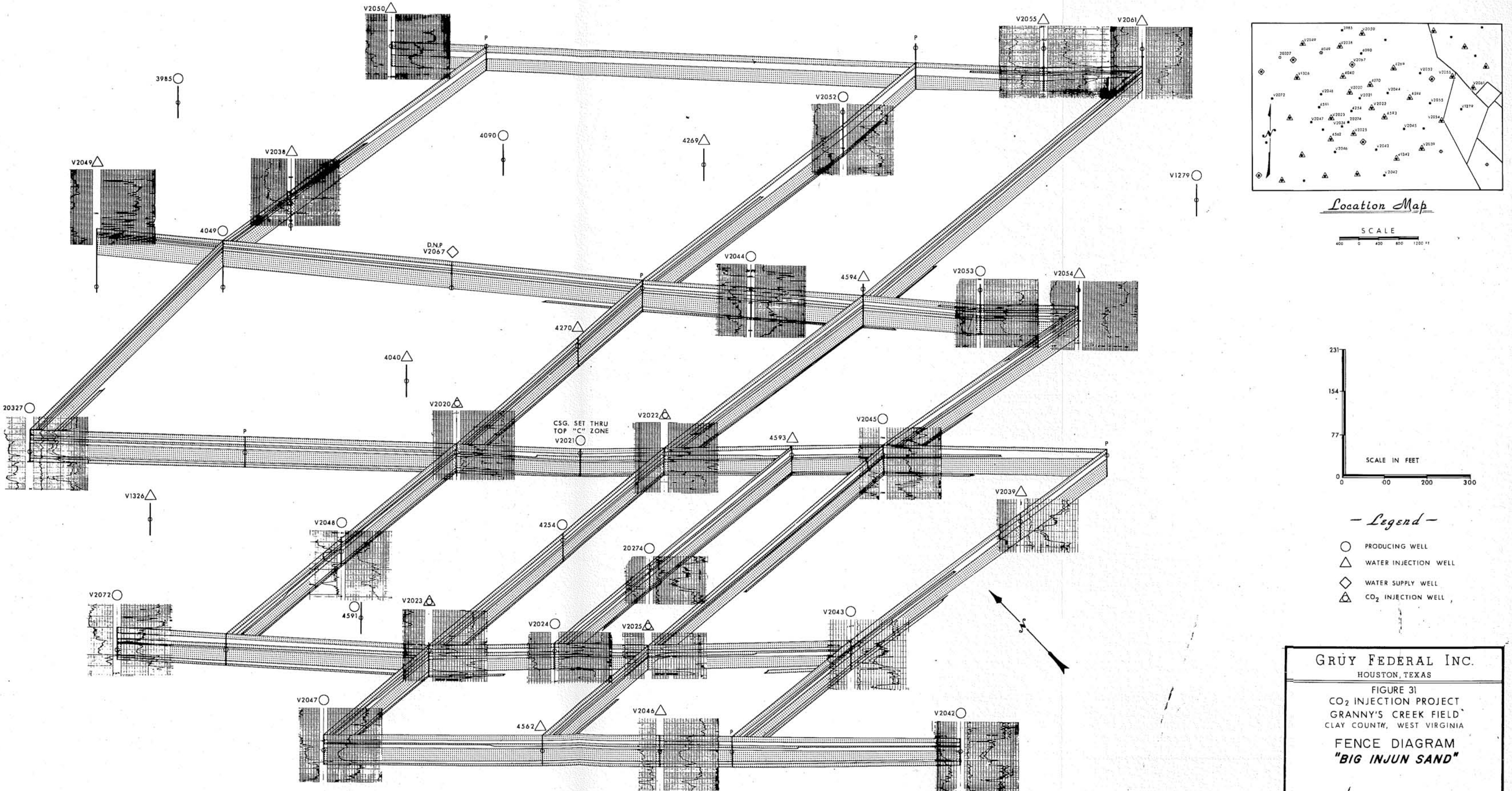


FIG. 30

HORIZONTAL PERMEABILITY VS VERTICAL PERMEABILITY

CO_2 INJECTION PROJECT AREA

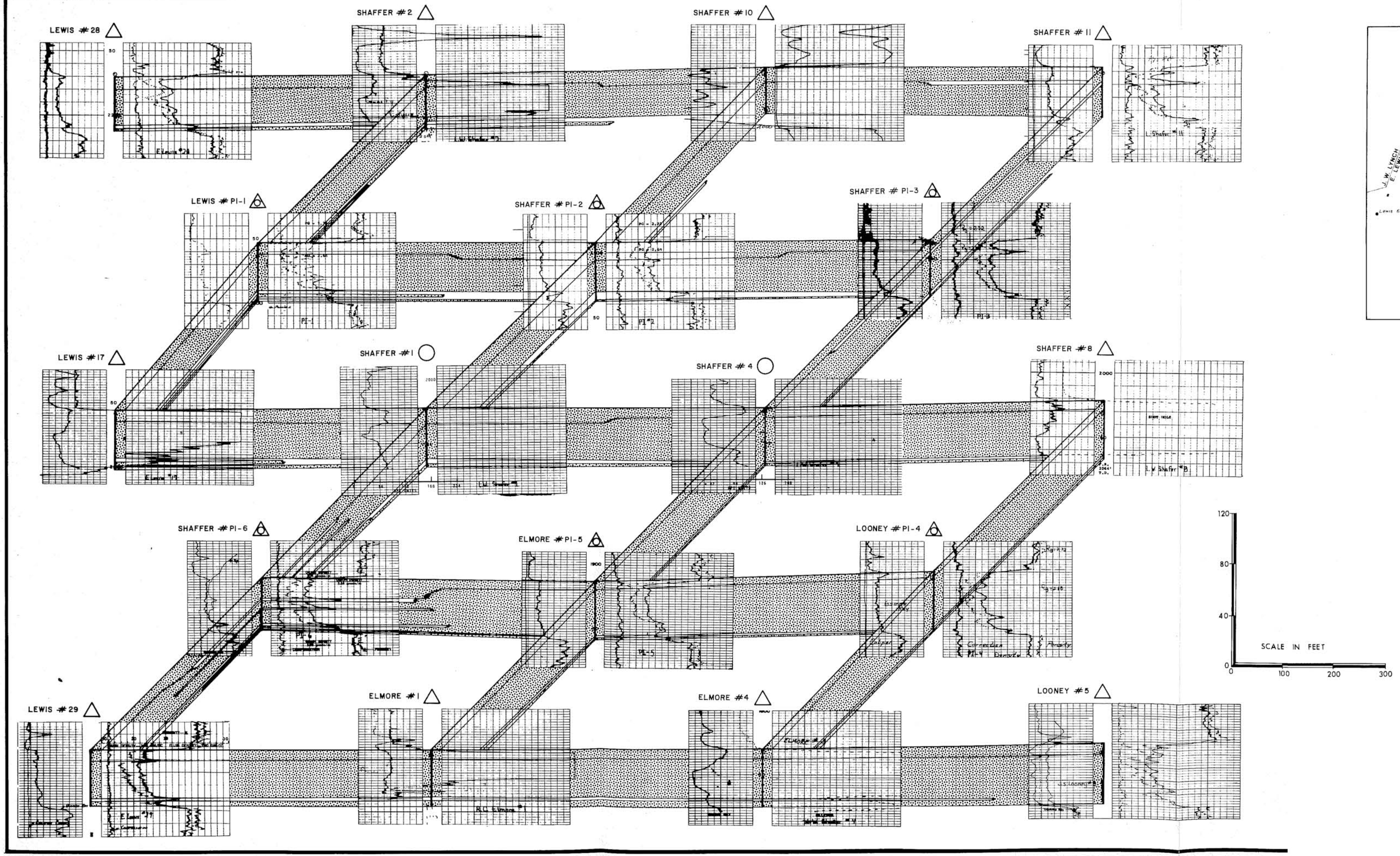
GRIFFITHSVILLE FIELD WEST VIRGINIA



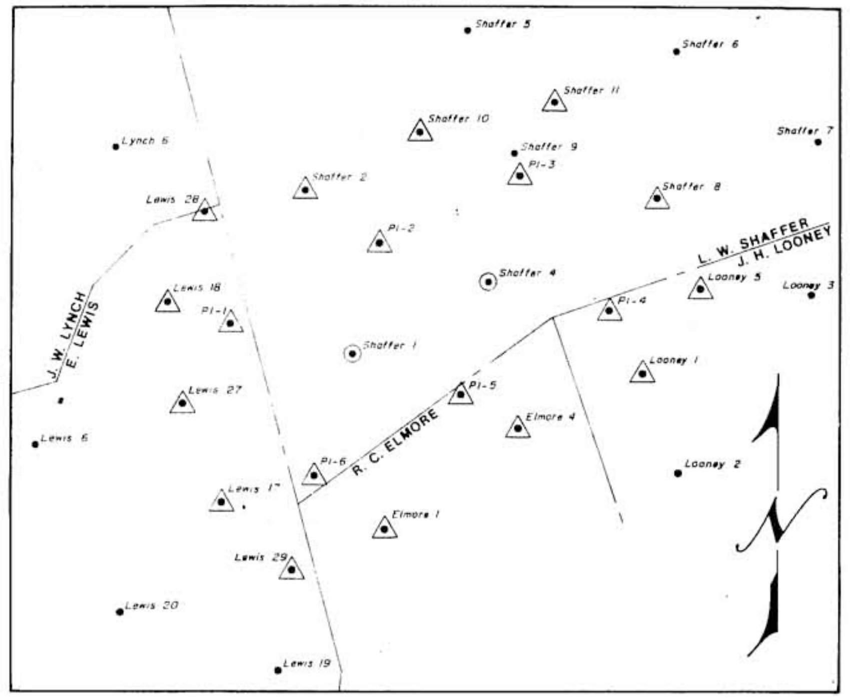
GRÜY FEDERAL INC.
HOUSTON, TEXAS

FIGURE 31
CO_2 INJECTION PROJECT
GRANNY'S CREEK FIELD
CLAY COUNTY, WEST VIRGINIA

FENCE DIAGRAM
"BIG INJUN SAND"



LOCATION MAP



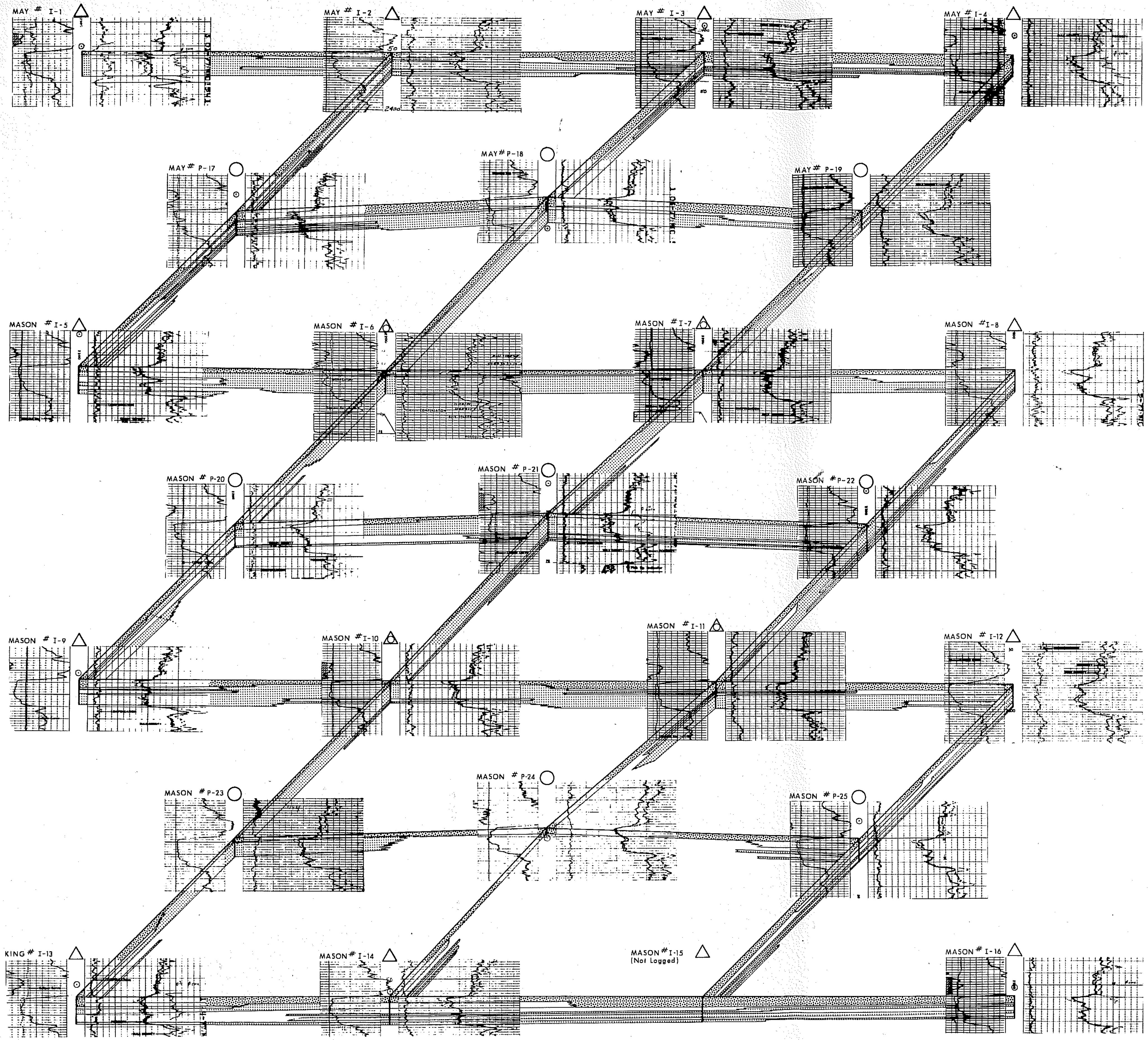
LEGEND

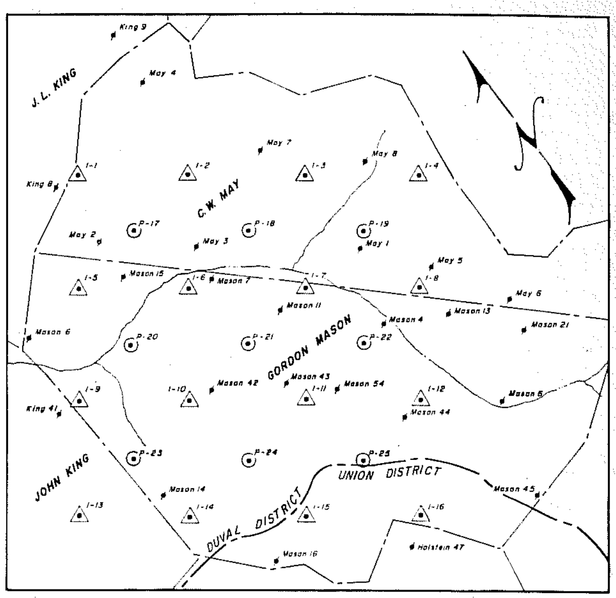
- ○ PRODUCING WELL
- △ WATER INJECTION WELL
- CO_2 INJECTION WELL

GRUY FEDERAL, INC.
HOUSTON, TEXAS

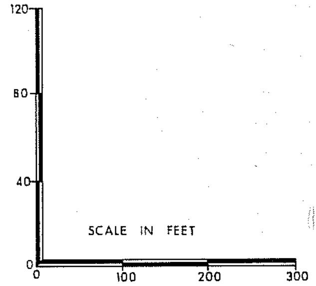
FIGURE 32
CO_2 INJECTION PROJECT
ROCK CREEK FIELD
ROANE COUNTY, WEST VIRGINIA

FENCE DIAGRAM
'BIG INJUN SAND'





Location Map



— Legend —

PRODUCING WELL

WATER INJECTION WELL

CO_2 INJECTION WELL

GRUY FEDERAL, INC.

HOUSTON, TEXAS

FIGURE 33

CO_2 INJECTION PROJECT

GRIFFITHSVILLE FIELD

LINCOLN COUNTY, WEST VIRGINIA

FENCE DIAGRAM

"BEREA SAND"

TABLE 1

PUBLISHED SCREENING CRITERIA FOR THE SELECTION OF ENHANCED OIL RECOVERY TECHNIQUES

	STEAM				IN SITU COMBUSTION					HYDROCARBON MISCIBLE (LPG SLUG)
	Lewin 1976	Geffen 1973	GURC #148	NPC 1976	Lewin 1976	Geffen 1973	GURC #148	NPC 1976	Poettman 1961	Geffen 1973
Viscosity, centipoises	NC				NC					<5
API Gravity (California crudes)	>10° (>10°)	>10°	10-25°		10-45° (10-45°)	$\ngtr$45°	10-35°		$\ngtr$40°	>30°
% of oil in area to be flooded before EOR	50				50					>25
Oil concentration, B/AF	>500	>780	>780	>500	>400	>390	>700	>500	>780	
Porosity x oil saturation	>0.065	>0.10	>0.10		>0.05	>0.05	>0.09		>0.10	NC
Depth, ft.	<5000	<4000	<3500	200-5000	>500	>500	>300	>500	>100	
Temperature, ^oF	NC	NC	NC		NC	NC	NC		>10	NC
BHP, original	NC				NC			>100		
Net pay, ft.	>20	>20	>25	>20	>10	>10	>10	>10		NC
Permeability, md	NC	NC	>500		NC	NC	>100			NC
Transmissibility (permeability x $\frac{\text{thickness}}{\text{viscosity}}$)	>100	>20		>100	>20	>100		>20		
Natural water drive	None to weak			None to weak	None to weak			None to weak		
Gas cap	None to minor			None to weak	None to minor			None to minor		
Fractures	NC unless extreme			None to minor						
Lithology	NC				NC				Uniform sand	
Salinity, ppm total dissolved solids	NC				NC					
Hardness, ppm Ca + Mg	NC				NC					
Operating pressure, psi		<2500			>250					>1300
k_{field}/k_{core}		NC			<5					<5
ϕh		high best				high best				low best
Sor										
Well spacing		$\le$10		$\le$10		$\le$40		$\le$20	$\le$20	NC

NC = not a criterion.

TABLE 1 (CONTINUED)

PUBLISHED SCREENING CRITERIA FOR THE SELECTION OF ENHANCED OIL RECOVERY TECHNIQUES

	CO_2 MISCIBLE				SURFACTANT POLYMER				POLYMER			CAUSTIC WATERFLOOD
	Lewin 1976	Geffen 1973	GURC #148	NPC 1976	Lewin 1976	Geffen 1973	GURC #148	NPC 1976	Lewin 1976	GURC #148	NPC 1976	NPC
Viscosity, centipoises	>12	>3		<10	<20	<10			≯200		<200 good	
API Gravity (California crudes)	>30° (>26°)	>30°	>30°		>28° (>25°)	NC	>25°	>10°	>18° (>16°)	>20°		15-25° good
% of oil in area to be flooded before EOR	25	>25	>25		25	>25			50		>25	>25 good
Oil concentration, B/AF					NC				NC			
Porosity x oil saturation	NC	NC	NC			NC						
Depth, ft.	>3000		>2000	3000	NC	NC			NC			
Temperature, °F	NC	NC	NC		<200	≤200	475	420	<200	>225	<200 good	175 good
BHP, original	>1500				NC				NC			
Net pay, ft.	NC	NC	>10		NC	NC	>10		NC	>5		
Permeability, md	NC	NC	NC		>20*	>20-50	>50	>20	>20	25-1500	30-5000 good	50-5000 good
Transmissibility (permeability x $\frac{\text{thickness}}{\text{viscosity}}$)	NC				NC				NC			
Natural water drive	none to weak			none to weak	none to weak			none	none to weak		none to weak	none to weak
Gas cap	none to minor			none to minor	none to minor			none	none to minor		none to minor	none to minor
Fractures	none to minor			none to minor	none to minor			none	none to minor		none to minor	none to minor
Lithology	NC			sandstone & carbonate	sandstone			sandstone	NC		sandstone good	sandstone go carbonate fa to poor
Salinity, ppm total dissolved solids	NC				<50,000			>2% by wt.	NC		NC	<2500 good
Hardness, ppm Ca + Mg	NC				<1,000			>2% by wt.	NC		NC	
Operating pressure, psi		>1100				NC						
k_{Field}/k_{core}		<5				<5						
ϕ_h		low best				high best						
Well spacing		NC				NC						

*with polymer drive.

TABLE 2

FRAC BREAKDOWN PRESSURES VS. DEPTH

WELL NO.	BREAKDOWN PRESSURE, PSI	DEPTH, FEET	APPROXIMATE BREAKDOWN GRADIENT, PSI/FT
Griffithsville Field - Berea Sandstone			
I-6	1900	2208	1.19
P-20	1400	2222	1.06
P-17	1600	2385	1.10
I-5	1600	2310	1.13
			Average 1.15
Rock Creek Field - Big Injun Sandstone			
PI-1	2200	2059	1.50
PI-2	1650	2098	1.22
PI-3	1550	1889	1.25
PI-4	1650	1937	1.28
PI-5	1450	1918	1.19
PI-6	1150	1973	1.02
			Average 1.24

TABLE 3

WEST VIRGINIA OIL FIELDS
HAVING SIGNIFICANT POTENTIAL FOR ENHANCED OIL RECOVERY
BY CO_2 INJECTION

FIELD NAME	ESTIMATED REMAINING OIL IN PLACE, MM BBL.	RESERVOIR
Primary Candidates		
Blue Creek	85	Squaw - Weir
Cabin Creek	65	Berea
Cameron - Gardner	16.5	Gordon
Centerpoint	67	Big Injun
Granny's Creek	27.5	Big Injun
Greenwood	11	Big Injun
Griffithsville	60	Berea
Jacksonburg - Stringtown	68	Gordon
Mannington	97-115* (97)†	Big Injun and Gordon
Pine Grove	15-31* (31)†	Gordon
Porto Rico	30-37* (30)†	Gordon
Salem-Wallace	201-218* (201)†	Gordon
Steel Run	12-23* (23)†	Gordon Stray
Tariff	19	Big Injun
Walton + Clover-Rush Run	158	Big Injun
Wolf Summit	47-56* (56)†	Fifth Sand
Yellow Creek	16-20* (16)†	Berea
TOTAL, PRIMARY CANDIDATES	1.0-1.1 Billion bbl.	
Secondary Candidates		
Cairo - Ritchie	90†	Salt Sand
Sistersville	45†	Big Injun
Rouzer	11†	Big Injun
Kidwell - Elk Fork	19	Keener
TOTAL, SECONDARY CANDIDATES	165 Million bbl.	

*Range of estimates because of lack of sufficient qualitative data to make a volumetric estimate. Reasonable data were used.

†1963 estimate.

TABLE 4

LITHOLOGIC DESCRIPTION OF GORDON SERIES´RESERVOIRS SELECTED IN THIS REPORT AS POTENTIAL EOR CANDIDATES

FIELD NAME	FORMATION	LITHOLOGIC DESCRIPTION	AVERAGE THICKNESS NET/GROSS
Cameron-Gardner	Gordon	Tightly cemented sandstone containing large pebbles	5/10-50
Jacksonburg-Stringtown	Gordon	Conglomeritic sandstone	4-5/10-35
Pine Grove	Gordon	Conglomeritic sandstone	5/10-70
Porto Rico	Gordon	Sandstone - variable thickness thins to the west	4/05-20
Salem Wallace	Gordon	Hard conglomeritic sandstone	8/05-50
Steel Run	Gordon Stray	Loosely cemented conglomeritic sandstone	5/10-40
Wolf Summit	Fifth	Coarse-grained well cemented sandstone	5'

TABLE 5

SUMMARY OF LOW-PRESSURE GAS INJECTION PROJECTS IN GORDON SERIES RESERVOIRS

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	FORMATION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/ INJECTION	INJECTION MCF/ WELLHEAD PRESSURE	DAILY PRODUCTION OIL, BBL.	GAS, MCF.	WATER. BBL.
1898	Pine Grove											
	(Wetzel Co.)	1954	1951	Gordon	2900	30	Hoyt-S ½	7/1	120/84	16	100	0
	(Grant Dist.)	1957						7/1	150/105	15	150	0
		1960						7/1	150/105	15	150	0
1898	Jacksonburg	1951	1947	Gordon	2800	30	Mills-Gordon	19/4	600/135	60	600	0
	(Wetzel Co.)	1954						19/4	600/135	40	600	0
	(Grant Dist.)	1957						19/4	800/135	40	800	0
		1960						19/4	850/135	40	800	0
1897	Stringtown	1951	1936	Gordon		18	Stringtown	12/1	57/145	9	-	14
	(Wetzel-Tyler Co.)	1954						23/2	170/145	20	-	7
	(McElroy-McClellan)	1957						37/3	310/135	26	-	15
		1960						36/3	342/135	26	-	12
1899	Wolf Summit	1951	1926	Fifth	2900	7	Lynch	72/8	375/81	67	-	2
	(Harrison Co.)	1954						77/11	800/81	80	-	5
	(Tenmile Dist.)	1957						77/11	910/100	77	-	4
		1960						75/11	1062/112	66	-	4

TABLE 6

SUMMARY OF SELECTED LOW-PRESSURE GAS CYCLING PROJECTS IN BIG INJUN SAND RESERVOIRS

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/ INJECTION	INJECTION MCF/ WELLHEAD PRESSURE	DAILY PRODUCTION OIL, BBL.	GAS, MCF.	WATER BBL.
1890	Sistersville		1933	1700	100	Sistersville					
	(Tyler Co.)	1951						403/3	65	3500	450?
	(Lincoln Dist.)	1954					36/6	365/3	62	3500	375
		1957					30/6	365/3	55	-	340
		1960					29/6	337/9	54	-	235
1890	Sistersville			1700	100	Sistersville					
	(Tyler Co.)	1951					61/9	403/3	65	3500	450
	(Lincoln Dist.)	1954					61/9		14.2	3000	500
		1957					61/9		14.2	3000	500*
		1960					-		-	-	-
1890	Mannington			2075	9.2/119	Blackshere					
	(Marion Co.)	1951					99/12	1003/126	101	-	60
	(Lincoln-Mannington Dist.)	1954					99/12	920/126	87	-	50
		1957					70/113	960/126	81	-	30
		1960					67/10	970/122	70	-	35
1889	Mannington		1926	1900	29/128	Mannington					
	(Marion Co.)	1951					12/3	275/100	30	40	-
		1954					12/3	160/240	12	30	7
		1957					12/3	65/255	10	700	4
		1960					12/3	65/255	10	700	4

TABLE 6 continued

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/ INJECTION	INJECTION MCF/ WELLHEAD PRESSURE	DAILY PRODUCTION OIL, BBL.	GAS, MCF.	WATER BBL.
1907	Rock Creek		1935	2025	30	Shaffer-Elewis					
	(Roane Co.)	1951					78/6	501/170	134	-	14
	(Walton Dist.)	1954					103/9	800/170	158	-	51
		1957					105/10	600/170	159	-	33
		1960					99/11	509/158	136	-	33
1909	Walton		1946	2000	30	Walton					
	(Roane Co.)	1951					15/2	325/350	30	-	-
	(Walton Dist.)	1954					15/5	400/350	85	425	-
							Discontinued				
1909	Walton		1946			Walton					
	(Walton Dist.)	1951					7/1	100/265	39	125	-
		1954					Discontinued				
1909	Clover										
		1951									
		1954									
		1957					33/4	135/275	25	-	10
		1960					37/5	274/328	29	-	6
1895	Elk Fork		1934	1850	12	Elk Fork					
	(Tyler Co.)	1951					47/6	310/32	51	-	14
	(Ellsworth Dist.)	1954					55/10	345/32	60	-	14
		1957					53/11	445/32	67	-	20
		1960					48/12	573/31	67	-	31

TABLE 6 continued

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/ INJECTION	INJECTION MCF/ WELLHEAD PRESSURE	DAILY PRODUCTION OIL, BBL.	GAS, MCF.	WATER BBL.
1898	Jacksonburg		1950	2100	40	Mills-Injun					
		1954					6/1	250/150	10	-	-
		1957					6/1	320/235	5	320	-
		1960					6/1	320/235	5	320	-
	Tariff		1951								
		1957					64/9	420/245	25	-	1
		1960					64/9	481/276	86	-	20
1924	Granny's Creek (Stockly)		1943								
		1951					75/7	1875/300	72	158	-
		1957					36/4	310/285	25	-	1
		1960					33/4	265/265	17	-	1

TABLE 6a

SUMMARY OF SELECTED LOW-PRESSURE GAS INJECTION PROJECTS IN BEREA SAND

	DATE OF FIRST INJECTION	NO. WELLS PRODUCTION/ INJECTION	INJECTION MCF/ WELLHEAD PRESSURE
Cabin Creek	1930	19/4	96/190
Cabin Creek	1932	244/27	732/50-200
Griffithsville	1926	/52	44/300

TABLE 7

SUMMARY OF SELECTED WATERFLOODS IN THE BEREA SAND

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICK-NESS, FT.	NO. WELLS PRODUCTION/ INJECTION	INJECTION B/D WELLHEAD PRESSURE, PSI	DAILY PRODUCTION OIL, BBL.	GAS, MCF	WATER, BBL.
1907	Griffithsville		1945	2300	22					
	(Lincoln Co.)	1951				/5	130/2000	-	-	-
	(Duval-Union Dist.)	1954				8/3	85/1400	6	-	4
		1957				/1	-	-	-	-
		1960				/3	-	-	-	-
1914	Cabin Creek		1947	2850	44					
	(Boone & Kanawha Co.)									
	(Cabin Creek & Sherman Dist.)	1951				5/19	600/1000	190	275	50
		1954				4/7	600/210	17	-	50
		1957				-	-	-	-	-
1914	Cabin Creek		1939	3000	30-55					
	(Boone & Kanawha Co.)									
	(Cabin Creek & Sherman Dist.)	1951				69/106	10000/2300	1360	-	-
		1954				62/130	15000/800	3218	-	1850
		1957				23/80	6650/800	535	-	200
		1960				15/51	3700/1200	325	-	125

TABLE 8

SUMMARY OF SELECTED WATER INJECTION PROJECTS OR TESTS IN BIG INJUN SAND RESERVOIRS

LOCATION	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	ACREAGE	NO. WELLS PRODUCTION/ INJECTION	B/D WATER INJECTED/WELLHEAD PRESSURE	DAILY PRODUCTION OIL, BBL.	DAILY PRODUCTION GAS, MCF.	DAILY PRODUCTION WATER, BBL.	TOTALS WATER INJECTED BBL.	TOTALS OIL RECOVERED BBL.
Clover - Rush Run		1955	1950	10 ?	42							
	1957					6/3	175/800	-	-	-		
	1960					6/3	-	-	-	-	152,624	2,589
Waterflood Inc.												
Walton		1954	2000	30	584	21/20						
Piedmont Oil Co.	1957					15/17	1642/1000	-	-	-		
	1960					5/7	-	-	-	-	2,762,442	14,667
Walton		1954	2025	30	7.5	1/4						
Ryan Oil	1957					1/4	223/1150	7	-	14		
	1960					1/4	-	-	-	-	280,000	19,721
Walton		1965	-	-	15	2/4	-	-	-	-	329,169	7,805
Cities Service												
Walton		1970	-	-	6.6	4/1	-	-	-	-	64,000	1,883
Pennzoil (Steam)												
Granny's Creek		1963 to present	-	-	350	19 five-spots	50 per injection well				4000 bbl. oil per acre recovered in pilot area	
Columbia												
(Preston)												
Granny's Creek		1971				2/6						
Pennzoil												

TABLE 9

SUMMARY OF SELECTED LOW-PRESSURE GAS INJECTION PROJECTS IN PENNSYLVANIAN SANDS

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/ INJECTION	INJECTION MCF/ WELLHEAD PRESSURE	DAILY PRODUCTION OIL, BBL.	GAS, MCF.	WATER, BBL.
1903	Hartley		1941	1800	94	Lemon-Haught					
	(Cairo-Mine)	1951				Lambert	43/4	279/244	24	-	80
	(Ritchie-Hartley)	1954					107/12	541/244	94	-	155
	(Ritchie Co.)	1957					107/12	588/244	86	-	197
	(Murphy Dist.)	1960					115/12	530/327	83	-	226

TABLE 10

SECONDARY RECOVERY PROJECTS IN BLUE CREEK, SQUAW, AND WEIR SAND FIELDS*

LOCATION, FLUID INJECTED, SAND	YEAR OF FIRST INJECTION	ACRES	NO. WELLS PRODUCTION/ INJECTION	PRODUCTION-INJECTION WELL DISTANCE, FT.	MCF OR BBL/DAY	PRESSURE RANGE/AVG.	DAILY PRODUCTION OIL, BBL.	GAS, MCF.	WATER, BBL.
Pinch (Blue Creek) (Bannster Heirs) Air Squaw	1932	175	5/2	595	206	25-67/46	8	-	7
Pinch (Gordon Creek) (Blue Creek) (Estep) Gas Squaw	-	-	14/2	700	66	135-159/147	8	-	0.5
Blue Creek (Pinch Block) Gas (Water in 1954?) Weir	1926	190 (202)	10/3	595	-	32-78	-	-	-
Blue Creek Blue Creek Gas Squaw	1925	646	33/4	600	75	/35	-	-	-
Blue Creek (Falling Rock) Gas Squaw	1939	200	18/2	1000	65	/115	-	-	-
Blue Creek (Skinner) (Water) Weir	1946	10	/1	600	100	/605			

*Summary as of 1951; all projects stopped reporting information in 1954.

TABLE 11

AVERAGE RECOVERY FROM WEST VIRGINIA RESERVOIRS

PRODUCING FORMATION	AVERAGE RECOVERY, B/AF PRIMARY, EST.	TOTAL	NO. OF RESERVOIRS
Berea	100	138	9
Big Injun	100	114	7
Gordon	180	195	4
Fourth	300	361	2
Fifth	150	197	1
Keener	150	198	1
		164*	

*Average recovery

TABLE 12

SUMMARY OF WELL DATA FROM WEST VIRGINIA GEOLOGICAL SURVEY
SHALLOW WELL FILE

FIELD	RESERVOIR	NO. OF WELLS	INITIAL POTENTIAL RANGE	INITIAL POTENTIAL AVG.	THICKNESS RANGE	THICKNESS AVG.
Blue Creek (Falling Rock)	Weir	8	0-8	2.89	19-198	94.13
	Squaw	1	0	0	28	28
Blue Creek (Hackberry Branch)	Weir	3	1-21	7.33	17-110	67.33
Yellow Creek (Big Spring)	Berea	4	0-3	2.25	ND	-
Walton (Johnson's Creek & Rock Creek)	Big Injun (undifferentiated)	19	0-25	6.95	29-48	39.64 (14)*
	Big Injun (Pocono)	1	0-25	6	ND	-
Wallace Folsom	Gordon	3	2-17	7.67	20-34	28.33
Tariff (Tallman)	Big Injun (Pocono)	1	20	20	44	44
	Big Injun (undiff.)	10	3-28	8.80	24-56	36.33 (3)*
Salem	Gordon	1	ND	-	14	14
Rouzer	Big Injun (Greenbrier)	21	2-125	41.24	19-86	45.71 (7)*
	Big Injun (Pocono)	7	10-160	46.14	28	28 (1)*
	Big Injun (undiff.)	23	0-50	18.52	36-78	54.95 (19)*
Porto Rico (Stout)	Gordon	5	1-10	6.20	4-16	9.50
Mannington	Big Injun (undiff.)	4	3-15	4.50	114-116	115 (2)*
Kidwell - Elk Fork Area	Keener	3	ND	-	-	-
Jacksonburg - Stringtown	Gordon	12	2-41	18.42	41-53	35.17
Griffithsville	Berea	205	1-25	30.74	10-46	10.11
Greenwood	Big Injun (Pocono)	63	0-400	26.90	ND	-
	Big Injun (undiff.)	2	12-15	13.50	ND	-
	Big Injun (Greenbrier)	1	4	4	ND	-
Granny's Creek	Big Injun (undiff.)	48	0-100	11	13-111	44 (43)*
Clover - Rush Run (Fisher)	Big Injun (undiff.)	47	1-207	26.51	11-64	23.33 (21)*
Centerpoint	Big Injun (Greenbrier)	1	1	1	ND	-
	Big Injun (undiff.)	3	3-4	3.33	101-128	111.33
Cairo - Ritchie Mine - Hartley	Salt Sands (general)	8	1-30	12.63	54	54 (1)*
Cabin Creek	Berea	58	0-136	12.33	4-54	38.64

ND = no data available

* [illegible] number of wells

TABLE 13

DERIVED ORIGINAL OIL SATURATION VALUES
FOR ALL FIELDS WHERE DATA PERMIT VOLUMETRIC CALCULATIONS*

FIELD	ϕ	h	ACREAGE	OIL ORIGINAL ESTIMATE	DERIVED S_o ESTIMATE
Blue Creek	0.12	10	17,254	69,016,000	0.52
Cabin Creek	0.16	20	4,480	32,704,000	0.36
Cameron Gardner	0.11	5	8,340	25,160,000	0.85
Centerpoint	0.17	10	12,980	51,920,000	0.36
Granny's Creek	0.17	20	2,803	16,818,000	0.17
Greenwood	0.06? 0.12?	8	2,253	13,518,000	1.93 0.815
Griffithsville	0.11	10	12,877	74,043,000	0.79
Jacksonburg Stringtown	0.125	4.5	16,000	88,469,000	1.52
Tariff	0.17	12	3,000	13,809,000	0.35
Walton	0.22	21	11,200	54,165,000	0.16

*B_o assumed to be 1.2 in all cases.

TABLE 14

STATE OF WEST VIRGINIA
RESERVOIR DIMENSIONS AND OIL SATURATIONS BY PRODUCING SANDS, JANUARY 1, 1954

SAND	NO. OF FIELDS	DEPTH	NO. WELLS PRO-DUCING	NO. WELLS ABAN-DONED	ORIGINAL PRODUCING ACREAGE	VISCOSITY STOCK TANK OIL CENTISTOKES AT RES. TEMP.	PAY, FT.	PORO-SITY	FORMATION VOLUME FACTOR	OIL SATURATIONS % OF PORE VOLUME ORIGINAL NATURAL	ORIGINAL STOCK TANK	1/1/54 STOCK TANK	NON-REC. RESIDUAL STOCK TANK	BBL/AC.-FT. ORIGINAL STOCK TANK
Cow Run	4	700-1100	1064	4046	10,200	4.9	20	15.9	1.05	54	51.4	43.4	27	634
Burning Springs	1	845	279	790	4,200	-	20*	15*	1.05	55*	52.4	43.2	28	610
Salt	4	360-1600	1028	4046	15,850	3.2	20*	12*	1.05	70*	66.7	53.5	35	621
Maxton	4	1200-2100	271	41	2,288	6.0	25	12.0	1.10	90	81.8	63.2	45	761.5
Big Lime	2	1235-1500	28	8	252	6.2	25*	16.0*	1.10	50*	45.4	37.4	25	564
Keener	4	1650-1860	530	658	6,120	3.7	16	10.5	1.13	64	56.6	48.6	32	461
Big Injun	24	1050-2100	3638	3321	54,423	4.3	25	17.6	1.14	52.5	46.1	38.9	26.2	629
Squaw	1	1800	327	142	3,020	3.2	16	11.0	1.13	74	65.5	54.1	37	559
Weir	2	1900	592	141	6,040	4.5	30*	11.3	1.14	73	64.0	50.0	37	561
Berea	16	1000-2800	2489	1911	31,944	5.2	13	15.0	1.17	80	68.4	53.8	40	796
Fifty Foot	1	2135	104	118	2,480	3.8	11*	9.0*	1.15	70*	60.9	47.9	35	425
Thirty Foot	1	2900	190	127	1,525	5.3	12	9.0	1.20	80	66.7	53.7	40	465
Gordon	16	2200-3200	1578	3939	73,800	5.2	17	10.1	1.20	76	63.3	53.2	38	496
Fourth	4	2240-3200	222	136	3,020	6.1	10	5.0	1.20	48	40.0	32.7	24	155
Fifth	6	2800-3100	798	784	19,300	5.6	10*	17.0*	1.20	60*	50.0	39.8	30	659
TOTALS	90		13138	20208	234,462									

*Estimated.

TABLE 15

VOLUMETRIC RESERVE ESTIMATES

SELECTED FIELDS IN WEST VIRGINIA

FIELD (FORMATION)	ϕ	h	ACREAGE	EST. ORIG. S_o †	ESTIMATED FORMATION VOLUME FACTOR, ORIG. †	B/AF	ESTIMATED ORIGINAL OIL IN PLACE, BBL.	PRODUCTION, BBL.	RECOVERY, PERCENT
Blue Creek (Weir)	0.12	10	17,254	0.73	1.14	596	102,833,840	18,185,000*	18
Cabin Creek (Berea)	0.16	20	4,480	0.80	1.17	849	76,070,400	11,077,000*	15
Cameron Gardner (Gordon)	0.11	5	8,340	0.76	1.20	540	22,518,000	5,975,000*	27
Centerpoint (Big Injun)	0.17	10	12,980	0.525	1.14	607	78,788,600	11,646,000	15
Granny's Creek (Big Injun)	0.17	20	2,803	0.525	1.14	607	34,028,420	6,466,000*	19
Greenwood (Big Injun)	0.06 ?	8	2,253	0.525	1.14	214 ?	135,070,000§	2,700,000	2
Griffithsville (Berea)	0.11	10	21,877	0.80	1.17	583	75,138,300	14,790,000*	20
Jacksonburg-Stringtown (Gordon)	0.125	4.5 ?	16,000 ?	0.76	1.20	614	88,500,000¶	20,458,000*	23
Tariff (Big Injun)	0.17	12	3,000	0.525	1.14	607	21,852,000	3,170,000*	15
Walton (Big Injun	0.22	20	11,200	0.525	1.14	786	176,064,000	18,097,000**	10
TOTAL							810.8 million	112.6 million	

NOTES: *1963 Estimate

**Probably higher - 1963 estimate

† From IOCC 1954

§ 1963 estimate is reasonable.

¶ 1963 estimate is more reasonable.

TABLE 16

AVERAGE POROSITY OF WEST VIRGINIA RESERVOIRS

FORMATION	THIS REPORT AVERAGE ϕ*	THIS REPORT NO. OF FIELDS WHERE AVERAGE ϕ IS KNOWN	IOCC REPORTS ** AVERAGE ϕ*	IOCC REPORTS ** NO. OF FIELDS WHERE AVERAGE ϕ IS KNOWN
Big Injun	0.16	14	0.176	14
Berea	0.14	5	0.15	16
Fifth	0.18	2	0.17*	6
Gordon	0.12	2	0.101	16
Keener	0.115	2	0.105	4
Fifty Foot	0.13	1	0.09	1

*Average value for fields where there is some production from the reservoir.

**Used some confidential core data from S. Penn Oil Co. files.

TABLE 17

AVERAGE FORMATION VOLUME FACTORS FOR

WEST VIRGINIA OIL RESERVOIRS

FIELD	FORMATION	VOLUME FACTOR fvf(correl.)	VOLUME FACTOR fvf (IOCC)
Blue Creek	Weir?	1.2	1.14
Cabin Creek	Berea	1.2	1.17
Cario	Salt		1.05
Griffithsville	Berea	1.2	1.17
Jacksonburg	Gordon	1.2	1.20
Mannington	Big Injun	1.2	1.14

TABLE 18

PERMEABILITY RANKING OF SELECTED CANDIDATE RESERVOIRS

	FIELD	RESERVOIR
High Permeability		
	Cameron-Gardner	Gordon
	Porto Rico	Gordon
	Steel Run	Gordon Stray
	Sistersville	Big Injun
	Kidwell Elk Fork	Keener
Medium Permeability		
	Cabin Creek	Berea
	Centerpoint	Big Injun
	Pine Grove	Gordon
	Tariff	Big Injun
	Wolf Summit	Fifth sand
	Yellow Creek	Berea
Low Permeability		
	Blue Creek	Wier
	Granny's Creek	Big Injun
	Greenwood	Big Injun
	Griffithsville	Berea
	Mannington	Big Injun
	Walton	Big Injun
	Cario Ritchie	Salt
	Rouzer	Big Injun

TABLE 19

SUMMARY OF SALIENT RESERVOIR FEATURES
OF RESERVOIRS SELECTED FOR EOR POTENTIAL

FIELD (FORMATION)	h	ϕ	EST. S_o, B/AF	ORIG. OIL IN PLACE EST., MMB	PERCENT RECOVERY	k	SECONDARY RECOVERY	WELLS DRILLED SINCE 1929	PRODUCING/ ABANDONED
Blue Creek (Weir)	10	0.12	596	103	18	low	No major projects	9	P
Cabin Creek (Berea)	20	0.16	849	76	15	med.	Waterflood	50	P
Cameron-Gardner (Gordon)	5	0.11	540	23	27	high	Current gas injection	0	A
Centerpoint (Big Injun)	10	0.17	607	79	15	med.	Gas injection (current?)	4	P
Granny's Creek (Big Injun)	20	0.17	607	34	15	low	Waterflood	48	P
Greenwood (Big Injun)	8	0.06	428	13	20	low	None	66	A?
Griffithsville (Berea)	10	0.11	583	75	12	low	3-well waterflood	205	P
Jacksonburg-Stringtown (Gordon)	4-5 ? (10)*	0.125	614	88	23	high?	Some (50-well) gas injection	12	A
Tariff (Big Injun)	12	0.17	607	22	15	med.	None	11	P
Walton (Big Injun)	20	0.22	786	176	10	low	Gas injection Waterflood project not expanded	20†	P

*4-5 is the value in the literature; 10 seems more reasonable.

†Actually much higher.

TABLE 20

CRUDE OIL PROPERTIES

OF THREE CURRENT CO_2 DISPLACEMENT PROJECT AREAS

AND ONE PROPOSED PROJECT AREA, FROM PREVIOUS REPORTS

FIELD NAME	API GRAVITY	VISCOSITY, CP	SURFACE TENSION	INTERFACIAL TENSION
Griffithsville	40.0	2.81	24.3	30.7
Granny's Creek	45.4	2.46	24.6	37.0
Rock Creek	46.5	3.11	25.1	30.8
Walton	43.5	3.97	25.1	30.8
Blue Creek	42.0	4.20	25.8	37.7
Blue Creek	45.8	2.15	24.0	41.7
Blue Creek	47.5	1.87		

TABLE 21

SOLUBILITY PRODUCT CONSTANTS OF SELECTED CARBONATE MINERALS

MINERAL	CHEMICAL FORMULA	K_{sp}
Calcite	$CaCO_3$	3.98×10^{-9}
Aragonite	$CaCO_3$	5.62×10^{-9}
Dolomite	$CaMg(CO_3)_2$	10^{-17}
Nesquehonite	$MgCO_3 \cdot 3H_2O$	10^{-5}
Magnesite	$MgCO_3$	7.9×10^{-9}
Hydromagnesite	$Mg_5(CO_3)_4(OH)_2 \cdot 4H_2O$	6.3×10^{-31}
Lansfordite	$MgCO_3 \cdot 5H_2O$	3.47×10^{-6}
Nahcolite	$NaHCO_3$	1.2×10^{-3}
Soda	$Na_2CO_3 \cdot 10H_2O$	0.752 mole/liter at 0°C
Trona	$Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$	0.58 mole/liter at 0°C

TABLE 22

COMPARISON OF THREE CO_2 OIL DISPLACEMENT PROJECTS IN WEST VIRGINIA

	GRANNY'S CREEK	GRIFFITHSVILLE	ROCK CREEK
Rock Properties (Formation)	(Big Injun)	(Berea)	(Big Injun)
Lithology	Sandstone, slightly limey silty near bottom	Sandstone, quartz, dolomitic	Sandstone, quartz, ankerite (dolomite)
Average ϕ	0.17	0.123	0.212
Average k_h	5, 5, 1.5 (3 zones)	8.2	15
Average k_v	$0.8 \times k_h$	$0.3 \times k_h$	$1.0 \times k_h$
Variation k_h/md cutoff	High/0.70	High/0.56	High/0.46
Stratification	At least three stratigraphically continuous layers	Impermeable zones not correlative between wells; high permeability zone at top	Nearly homogeneous
Ave. net/ave. gross	30/50	14/23	35/44
Fluid Saturations			
S_o original, est.	0.50	0.80	0.54
S_o present, est.	≈0.30-0.35	≈0.54-0.60	≈0.35-0.46
Est. original FVF	1.14	1.17	1.14
Reservoir Conditions			
Temperature	77-80°F	78-85°F	73-75°F
Depth	2000 ft	2300 ft	1900 ft
Production history	Primary, then waterflood	Primary, then accidental crossflow (dump flood)	Primary, then gas injection
Dip of reservoir	≈1°	<0.5°	<0.4°

TABLE 22 (continued)

COMPARISON OF THREE CO_2 OIL DISPLACEMENT PROJECTS IN WEST VIRGINIA

	GRANNY'S CREEK	GRIFFITHSVILLE	ROCK CREEK
Oil Properties			
Gravity, °API	45.4	40-43	46.5
Viscosity, cp	2.46	2.81-3.1 @ 85°	3.11
Miscible pressure/temp.	1000/75°	1100/85°	1000/73°
Surface tension	24.6	24.3	25.1
Interfacial tension	37.0	30.7	30.8
Design Features			
New or existing wells	Used all existing wells from previous waterflood pilot project	All new wells: 4 CO_2 injectors, 12 water injectors, 9 producers	6 new wells (CO_2 injectors), 2 inside producers, 13 backup injectors
Size (acres), design	6.5 - 1 skewed five-spot, 2 inside wells		
Injection pattern		1 confined five-spot 8 additional five-spots 10 acres/five-spot, 90 ac. total	2 confined 10-acre five-spots
CO_2			
Slug size	9888 tons	8000 tons for 4 injection wells	25,000 tons with 50% confined within pattern
Pressure range	1200-1700 psi	>1000 psi	>1000 psi
Injection procedure	Alternating water, CO_2	Alternating water, CO_2 planned	Alternating water, CO_2 planned
Recovery			
Bbl/Mcf CO_2 injected	1/20 overall*	no results yet	no results yet
Acres affected	>200	no results yet	no results yet

*If 6% of CO_2 assumed to enter pattern area, efficiency could have been 1/2.