GEOLOGICAL SURVEY CIRCULAR 828

Future Supply of Oil and Gas from the Permian Basin of West Texas and Southeastern New Mexico

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A report of the Interagency Oil and Gas Supply Project, U.S. Department of the Interior and U.S. Department of Energy

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PREFACE

In 1975, the U.S. Geological Survey issued its Circular 725, entitled "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States." Using advanced resource-appraisal techniques, the authors of that document presented new data on these resources. The results were essentially geological, and the economics of oil and gas recovery were not analyzed; instead, the analyses assumed the continuation of price/cost relationships and technological trends that prevailed before 1974. The study was not intended to produce schedules describing future oil and gas supply at different price levels and rates of return. Finally, the study specifically excluded shale oil, tar sands, heavy crude oil, gas from tight sandstone formations not already being produced, and oil and gas below waters that were more than 200 m deep.

Recognizing the need to add more of an economic perspective to the estimates, the Interagency Oil and Gas Supply Project was established in mid-1976 to: evaluate any changes in resource estimates that might result from the post-1974 price levels; incorporate subsequent geological and geophysical information; prepare basin-level marginal cost schedules reflecting both conventional and "enhanced" oil and gas recovery; and estimate costs for unconventional oil and gas sources.

The interagency agreement (p. 56) was prepared and signed in early 1977 by the Department of the Interior, which included the Office of Minerals Policy and Research Analysis (OMPRA), the Bureau of Mines (BOM), and U.S. Geological Survey (USGS), as lead agency; the Federal Energy Administration (FEA); the Federal Power Commission (FPC); and the Energy Research and Development Administration (ERDA). Subsequently, the involved offices in the BOM, the FEA, the FPC, and ERDA became part of the Department of Energy.

When the project was started, no up-to-date model was available that showed marginal-cost schedules of the full spectrum of possible sources on a disaggregated basis. Those who prepared such schedules had difficulties in separating oil and gas components and in dealing with inadequate data, and the biases introduced into historical data covering price-regulated commodities.

In spite of these difficulties, a rational effort has been made to estimate ultimate recovery and the associated costs. The project studies will contain estimates of ultimate recovery at various costs but will not contain predictions of the time of arrival of the supplies, because timing is determined by industry.

With respect to timing, additional recovery becomes progressively more costly as the size of newly discovered fields diminishes, as they become less accessible geographically, and as recovery requires more advanced technology. For the same reasons, progressively greater effort will be required for a given level of production, regardless of the volume of remaining resources. Ultimately, production must decline.

Although the areas were not defined in the agreement, the project leaders decided to limit the study to three areas: the Permian Basin (a mature producing area), the Gulf of Mexico offshore area (a partially developed area), and the Baltimore Canyon Basin (a frontier area). This report covers only the research on the Permian Basin.

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EXECUTIVE SUMMARY

In mid-1976, the Interagency Oil and Gas Supply Project was established, by agreement among several Federal agencies, to estimate how much oil and gas might be made available in the future at various price levels from all potential sources in the United States. The scope of investigation includes supplies of oil and gas from presently known fields through additional drilling and enhanced-recovery methods, from fields not yet discovered, and from a variety of sources categorized as "unconventional" (such as oil shale, tar sands, and gas from coal beds and geopressured brines). Liquid and gaseous fuels synthesized from coal or other substances are not considered.

The project, with the U.S. Geological Survey as lead agency, is designed to extend the analysis described in U.S. Geological Survey Circular 725 (Miller and others, 1975) by incorporating new geological and geophysical data, by supplying an economic perspective, and by addressing the outlook for enhanced recovery and unconventional sources not treated in the earlier study. As a prelude to a nationwide assessment, three areas were selected for study on a test basis: the Permian Basin of west Texas and southeastern New Mexico (a mature producing area), the Gulf of Mexico offshore (a partly developed basin), and the Baltimore Canyon Basin of the Atlantic Outer Continental Shelf (a frontier area). This report analyzes the oil and gas prospects of the Permian Basin. The basin is shown in figure 1 in relation to western Texas and eastern New Mexico, Region 5 in Circular 725. The Permian Basin covers roughly 50 percent of the 173,000 square-mile total area of Region 5.

The report begins with a survey of known resources of oil and gas in the Permian Basin[1] from which an estimate is made of the total amount of oil and gas discovered by the end of December 1974. Next, estimates are made of the amounts of undiscovered oil and gas thought to exist at various levels of probability; these data include the number of reservoirs estimated to exist in each of 20 size classes and in three successive depth intervals of 10,000 feet each. After this appraisal of the basin's original endowment of oil and gas, both discovered and undiscovered, a projection is made of the most likely sequence in which the undiscovered reservoirs may be found and the amount of exploratory drilling that will be required to find them. Exploration, development, and production costs are then introduced and are used to obtain estimates of the volumes of undiscovered oil and gas that will actually be found and produced at different assumed price levels and rates of return.

In addition to supply from new discoveries, relatively large amounts of oil and gas are expected to be produced from presently known fields, either through drilling that extends field limits or penetrates new pools within the field, or from new technologies that enable recovery of a greater fraction of the original oil or gas in the field than that which can now be recovered through conventional techniques. The volume of hydrocarbons obtained from such enhanced-recovery measures is estimated for different price levels and rates of return in the same manner that volumes of undiscovered oil and gas are estimated.

[1] The Permian Basin corresponds closely, but not exactly, to the area designated by the Texas Railroad Commission as Districts 7C, 8, and 8A, plus that designated as southeast New Mexico by the American Petroleum Institute and the American Gas Association. As a matter of convenience in this report, it is considered identical with these districts, unless otherwise specified.

PERMIAN BASIN HISTORY AND CHARACTERISTICS

The Permian Basin is a mature petroleum-producing province extending over about 80,000 square miles of west Texas and southeastern New Mexico; its sedimentary rocks are more than 25,000 feet thick in its deepest parts. The basin is characterized by arches, platforms, basins, and shelves formed during the later Paleozoic periods; the Midland, Delaware, and Val Verde Basins and the Central Basin Platform are of particular interest.

The Permian Basin has been a prolific source of petroleum hydrocarbons since the initial discoveries were made in 1921. Production to the end of 1976 amounted to 18.6 billion barrels of crude oil and 55.8 trillion cubic feet of natural gas; 5.5 billion barrels and 18.2 trillion cubic feet remained as proved reserves on that date. Virtually all the petroleum was found in Paleozoic sediments, most (71 percent) of the oil being in the relatively shallow Permian rocks and most of the nonassociated gas, in deeper strata of Devonian age and older. Oil has been produced from wells that are deeper than 14,000 feet, and gas has been produced from depths of more than 21,000 feet. Although carbonate reservoirs predominate in this province, large quantities of both oil and gas have been found in sandstone formations. Distribution of hydrocarbons is roughly equal in structural and in stratigraphic traps.

The oil and gas resources of the Permian Basin are for all practical purposes confined to those occurring as conventional accumulations, including those amounts requiring special recovery techniques to produce. Present data indicate that little, if any, oil and gas are available from oil shale, brown or black shale, rich in organic matter, tar sand, asphalt, heavy oil, and no methane is available in brines or hydrates; no supply from such sources is expected in the foreseeable future.

ORIGINAL OIL AND GAS IN PLACE

Discovered deposits as of December 31, 1974, were estimated to be 92 billion barrels of oil and 108 trillion cubic feet of natural gas, distributed as shown in figure 2. Of these volumes, about 26 percent of the oil and 75 percent of the gas are expected to be recovered under present economics and technology. Although these percentages may increase somewhat as anticipated improvements in recovery techniques are made, most of the oil and some of the gas will always be too difficult or too costly to produce and cannot be considered recoverable resources.

The amount of oil and gas remaining to be discovered in the Permian Basin has been appraised on the basis of (1) an intensive review of basin geology, (2) a statistical analysis of discovery experience, and (3) the application of professional judgment to obtain estimates of oil and gas in place at each of various levels of probability (95, 75, 25, and 5 percent), plus a

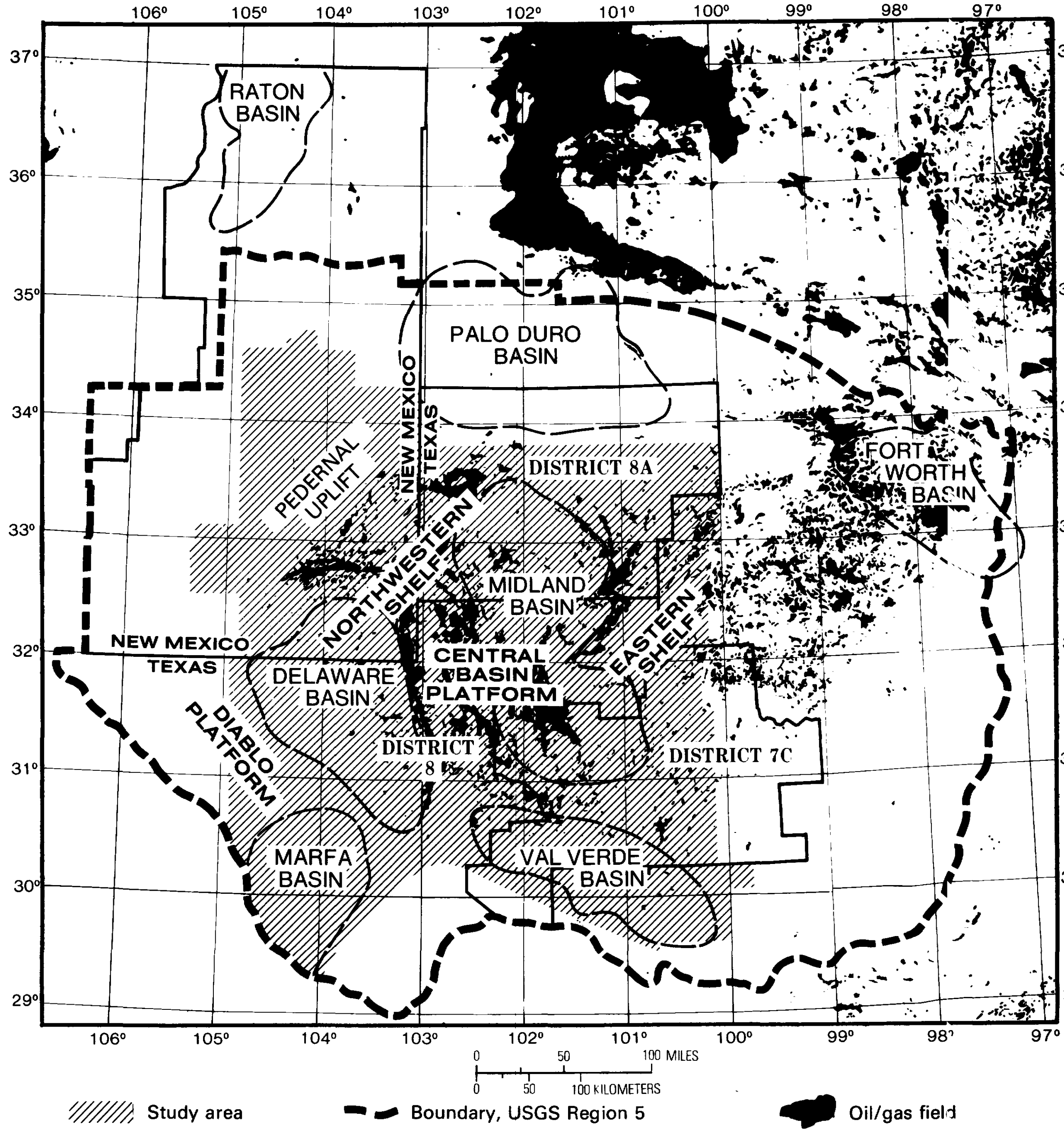

FIGURE 1.–Oil and gas fields in the Permian Basin.

modal estimate and a calculated statistical mean for each of three successive depth intervals of 10,000 feet. These estimates were then aggregated by means of Monte Carlo techniques into totals for the basin by depth interval. The mean values for each depth interval, plus the values estimated for the 95- and 5-percent probability levels are shown graphically in figure 3. A comparison of the mean values of undiscovered oil and gas with the discovered amounts (see fig. 2) suggests that almost 95 percent of the oil and 83 percent of the gas originally contained in the Permian Basin may already have been found.

FUTURE FIELD-SIZE DISTRIBUTION

The Permian Basin has long been the focus of an intensive search, which has resulted in the discovery of 4,036 oil and gas fields by 30,340 exploratory wells drilled from 1921 through 1974. The province shows a typical distribution pattern of fields by size and number. A very few very large fields are at one end of a spectrum that trends toward successively greater numbers of smaller and smaller fields, so that most of the basin's oil and gas is concentrated in a relatively few large fields. For example,

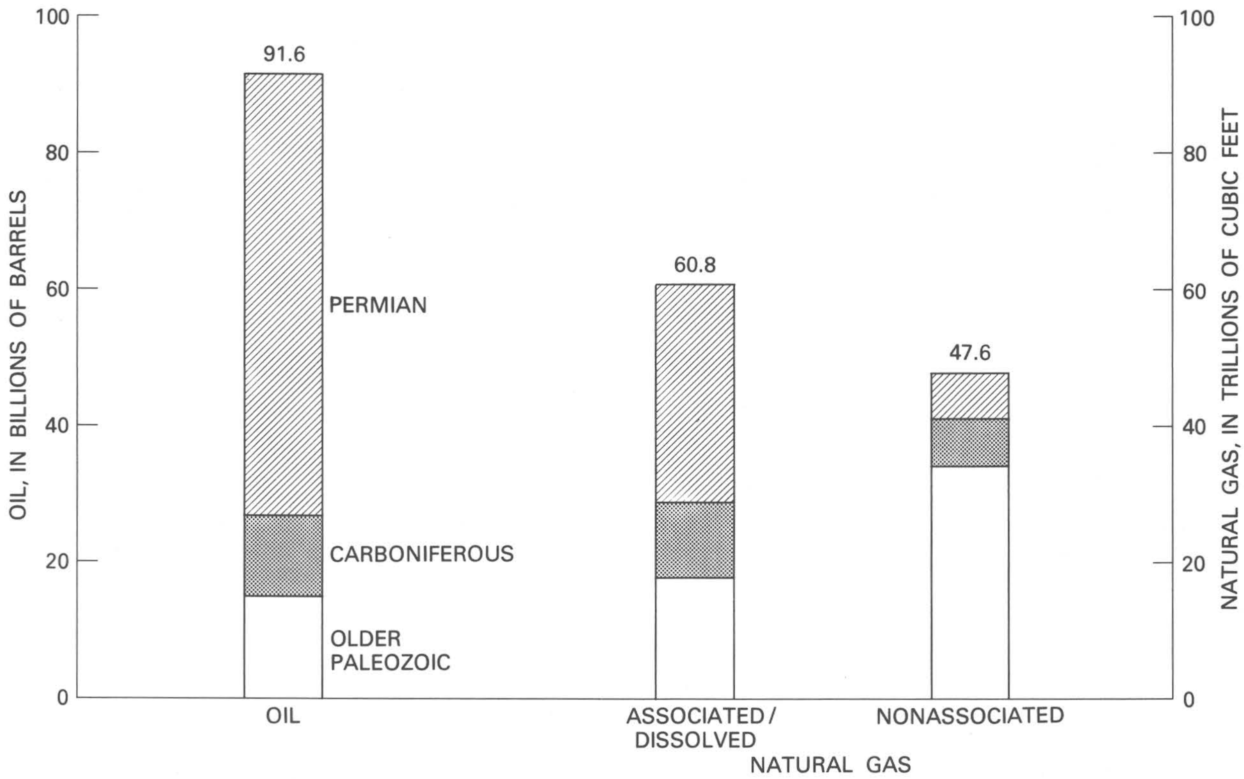

FIGURE 2.—Original oil and natural gas in place in the Permian Basin.

59 percent of the recoverable crude oil discovered in the Permian Basin has been found in 97 major fields.

This distribution, which is assumed to be characteristic of the total petroleum content of the basin, permits a calculation, by size class, of the number of fields that remain to be discovered.

These forecasts are made by means of a method proposed by Arps and Roberts (1958), which assumes that the probability of the next exploratory well finding a field of a given size is proportional to the ratio of the area of the field to the area of the basin. This assumes that the discovery of the larger fields will be made early in the search, so that as exploration proceeds, the average size of newly discovered fields diminishes. The Arps-Roberts model was modified to accommodate the features peculiar to the Permian Basin and was applied to estimate the number of remaining undiscovered fields in 20 size classes ranging from fields containing less than 6,000 barrels of oil equivalent (BOE) [2] to those containing from 1.6 to 3.1 billion BOE. Four successive 5,000-foot depth intervals from the surface down to 20,000 feet were considered.

When applied to the Permian Basin, this discovery-process model predicted that some 34,000 oil and gas fields remain to be discovered at depths of less than 20,000 feet, 98 percent of which are expected to contain less than 1.52 million recoverable BOE per field. Six-hundred eighty-two fields are expected to range in size from 1.52 to 12.14 million BOE, preponderantly at depths of less than 10,000 feet. Twenty-one fields ranging from 12.14 to 48.6 million BOE in size are thought to be distributed fairly evenly among the three deeper intervals (5,000–20,000 ft), and seven fields of more than 48.6 million BOE in size are predicted to be almost entirely in the 15,000–20,000-foot depth interval. In fact, no fields of as much as 100 million BOE are expected to be found at depths of less than 15,000 feet.

The model was also used to predict the number of fields by size class and depth interval that would be discovered by each of 20 successive drilling increments of 1,000 exploratory wells. In general, the discovery results confirmed the field-size distribution computed by means of the model in the earlier exercise: in the first 1,000-well drilling increment, no fields larger than 12.14 million BOE were expected to be found in the highly explored 0–5,000-foot interval; in the second and third intervals, fields to a maximum of 97.2 million BOE were expected to be found, and in the deepest (15,000–20,000-ft) interval, fields ranging in size classes from 97.2 to 388.6 million BOE were expected to be found. Analysis of the 19 other increments revealed similar patterns. Moreover, the total number of discoveries per increment was observed to decline, and larger discoveries became less frequent. Thus, both success ratio and average size of discoveries were projected to decline with each successive 1,000-well increment of exploratory drilling.

The results just described are the product of a purely statistical exercise to ascertain the numbers and sizes of fields that a 20,000-well exploratory drilling program could theoretically be expected to find among the remaining undiscovered oil and gas accumulations in the Permian Basin. Considered together with appropriate economic and engineering factors, these results can be useful in projecting how much oil and gas are likely to be found as the result of industry decisions to drill and produce.

[2] Includes crude oil, natural gas, or any combination of the two, counting wet natural gas and its entrained liquids; natural gas being assumed to contain 1.1 million Btu per 1,000 cubic feet and crude oil, 5.8 million Btu per barrel.

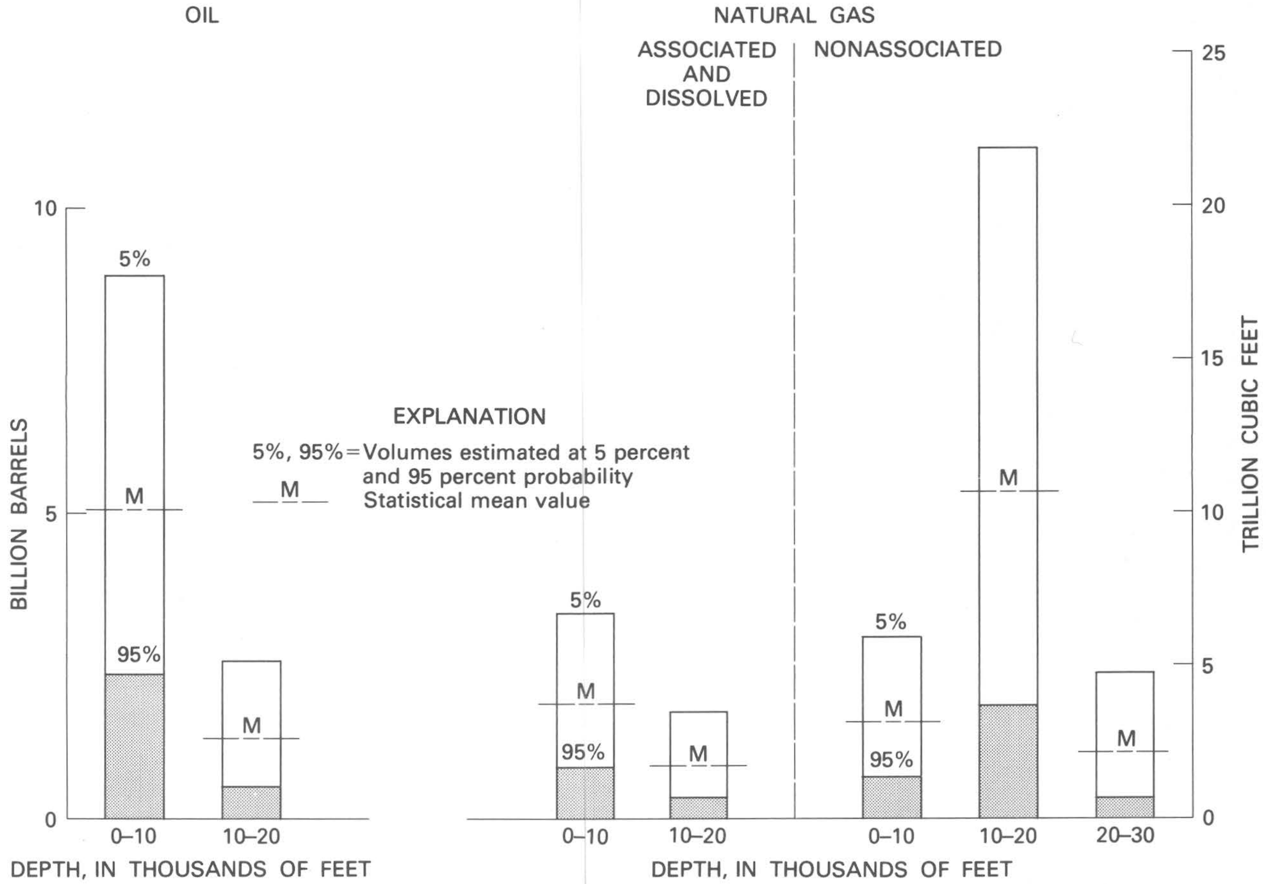

FIGURE 3. – Undiscovered oil and natural gas in place in the Permian Basin.

SUPPLY FROM NEWLY DISCOVERED FIELDS

Translating estimates of undiscovered oil and gas into producible reserves requires the introduction of economic considerations that determine whether the capital needed to bring those resources to market will, in fact, be invested. In the study, this was done in two steps. In the first step, field development and production costs were estimated. Then, in the second step, a discounted cash-flow analysis was used to estimate the amounts of undiscovered oil and gas that the oil industry would find and produce at different market prices and rates of return that were based on development and production costs. The results of the analysis are summarized in table 1 in terms of exploratory wells drilled and economically producible hydrocarbons discovered at each price level and rate of return.

The data presented in the tables indicate the mature stage of exploration in the Permian Basin and the response of supply, both to exploration effort and to price. The 30,000 exploratory wells projected to be drilled at $40 per BOE under a 25 percent rate of return are predicted to result in the discovery of 3.85 billion BOE, an amount approximately one-tenth of the volume of oil and gas found by the first 30,000 exploratory holes drilled in the basin. Table 1 also shows that, at all rates of return, discovery response to price diminishes sharply at prices greater than $25 per BOE. For example, in figure 4, which shows discoveries at a 15 percent rate of return, the first $15 increment above the base of $10 elicits a 185-percent increase in supply; the second increment of $15 yields an increase of less than 25 percent.

Another notable feature is the preponderance of natural gas, which constitutes approximately two-thirds of the energy value of the hydrocarbons projected to be discovered (see fig. 5). This distribution is almost the reverse of that shown by discovery experience through 1974, when crude oil constituted two-thirds of the total hydrocarbons found.

ADDITIONAL SUPPLY FROM EXISTING FIELDS

In addition to the oil and gas from future discoveries, substantial amounts of both are expected to be produced from already discovered fields, in addition to the amounts presently estimated to be recoverable. These "bonus" amounts result from (1) the fact that the larger oil and gas fields routinely "grow" from year to year as field limits are extended by drilling, new pools are found within fields, and additinal information about the field permits the upward revision of previous estimates; [3] and (2) technological improvements in recovery operations that permit a larger fraction of the total resources in the ground to be produced than that previously expected.

The fact has long been accepted that many fields are actually bigger than estimates have indicated. Accounting for proved reserves – oil and gas that can definitely be produced from a field on the basis of existing economics and technology – is necessarily conservative and includes only resources under acreage that can be drained by existing wells and in the

[3] However, such additional data may also result in a downward revision of previous estimates.

TABLE 1.—*Future exploration drilling and supply from undiscovered recoverable oil and gas resources in the Permian Basin*

[BOE, barrels of oil equivalent]

Output price ($/BOE)	Wells drilled (thousands)	BOE (billions)	Wells drilled (thousands)	BOE (billions)	Wells drilled (thousands)	BOE (billions)
	5 percent rate of return		15 percent rate of return		25 percent rate of return	
10	10	2.04	5	1.20	2	0.54
15	19	3.03	12	2.32	8	1.77
20	26	3.57	18	2.95	12	2.33
25	33	4.00	24	3.44	17	2.87
30	38	4.27	29	3.77	22	3.30
35	43	4.50	34	4.08	26	3.60
40	48	4.71	38	4.28	30	3.85

immediately adjoining undrilled parts that are judged to be productive on the basis of geologic and engineering data. In 1966, for example, the American Petroleum Institute (1967) estimated that the total amount of oil that might be recovered from all fields discovered by that date was 112 billion barrels. By 1976, the estimate for these fields had been raised to 129 billion barrels—a "growth" of 17 billion barrels that resulted chiefly from field extension and development over the intervening decade.

This "growth" phenomenon has resulted in efforts to predict the amounts of oil and gas that eventually may be found and produced from existing fields, beyond the proved reserves credited to them at any given date. These incremental amounts of oil and gas that are expected to become proved reserves at some future time are categorized as being either "indicated" or "inferred" reserves, depending largely upon the means by which they are expected to be converted into proved reserves.

Indicated reserves are those volumes of oil that are expected to be economically recoverable by means of improved conventional recovery techniques, such as fluid injection, where (1) an improved technique has been installed but its effect cannot yet be fully evaluated, or (2) an improved technique has not been installed but enough is known about its probably success to justify estimates of the volume of oil that might be made available by such means. According to the American Petroleum Institute (American Gas Associates and others, 1977, table 1), these "indicated additional" reserves in the four districts approximating the Permian Basin amounted to 1.6 billion barrels of recoverable crude oil as of December 31, 1976.

Inferred reserves are those that accrue through additional drilling and upward revisions of previous estimates justified by additional knowledge about existing fields. The process for estimating inferred reserves is more reliable for large areas such as the United States as a whole than for smaller, specific regions such as the Permian Basin. Nevertheless, estimates for inferred reserves, which were based on two separate approaches, suggest that an additional 7.1 trillion cubic feet of recoverable gas (1.35 billion BOE) and an additional 4.9 billion barrels of crude oil in place exist as inferred reserves in the Permian Basin. At the current recovery rate of 26 percent, an additional 1.3 billion barrels of recoverable oil may be derived from this source. This means that 2.65 billion BOE of petroleum hydrocarbons, which include the gas reserves, are estimated to exist as inferred reserves in the Permian Basin.

Enhanced recovery (that is, recovery techniques going beyond the conventional methods now in use) represents the other major opportunity for additional supply from existing fields. Enhanced Oil Recovery (EOR) has already resulted in some 300 million barrels that have been produced or proven in a few large reservoirs in the Permian Basin (such as the Scurry Area Canyon Reef Operators Committee (SACROC) carbon dioxide project in the Kelly-Snyder field). If, for example, the anticipated recoverable fraction of the Permian Basin's 92 billion barrels of original oil in place could be increased from the current average of 26 percent to 31 percent, an additional 4.6 billion barrels of oil would become available. Production of this oil will be neither easy nor cheap because many institutional, technical, and economic difficulties bar the way. Still, the oil is known to exist, most of the infrastructure needed to bring it to market is already in place, and sizeable commitments have been made by both the public and the private sectors toward the goal of moving it into the proved reserves category.

This study assumes that satisfactory solutions will eventually be found for the problems that presently beset the prospects for EOR. Estimates, therefore, were made of the amounts of oil that might become available, mainly through carbon dioxide flooding, at different price levels and rates of return, from 96 major reservoirs thought to be technically and economically amenable to EOR techniques. The results were extrapolated to obtain values for the total basin and are presented in table 2. For both the 15- and 25-percent rates of the return, supply response to price diminishes sharply when prices are more than $25 a barrel.

TABLE 2.—*Potential for enhanced recovery in the Permian Basin*

[BOE, barrels of oil equivalent]

1977 price ($/BOE)	Oil (billion barrels)		Gas (trillion cubic feet)	
	15 percent rate of return	25 percent rate of return	15 percent rate of return	25 percent rate of return
10	0.0	0.0	8.9	7.4
15	1.43	0.20	13.7	13.7
20	2.93	1.30	13.7	13.7
25	4.31	2.58	13.7	13.7
30	4.70	3.65	13.7	13.7
35	5.08	4.11	13.7	13.7
40	5.11	4.56	13.7	13.7

The prospects for enhanced gas recovery (EGR) offer the possibility for a significant contribution to future gas supply from the Permian Basin. The target is previously discovered nonassociated gas accumulations in rocks of low permeability that have thus far defied economic production by traditional methods. Rising gas prices and recent improvements in production technology may provide the means to convert part of these known but presently subeconomic resources into proved reserves.

The geographic focus for EGR in the Permian Basin is in its southeastern corner in three Texas counties. Within this area lie known gas accumulations that can be considered candidates for massive hydraulic fracturing (MHF), in which pressure is as much as 10 times greater than that used in conventional hydraulic fracturing that has long been used to introduce cracks in reservoir rock to facilitate the flow of oil and gas to the well bore.

Data were analyzed to ascertain the amounts of gas that these prospective gas fields might be expected to yield under MHF at two rates of return and several price levels (see table 2). The exercise shows that at a price of $15 or more per BOE, as much as 13.7 trillion cubic feet of gas might become available under currently available MHF technology.

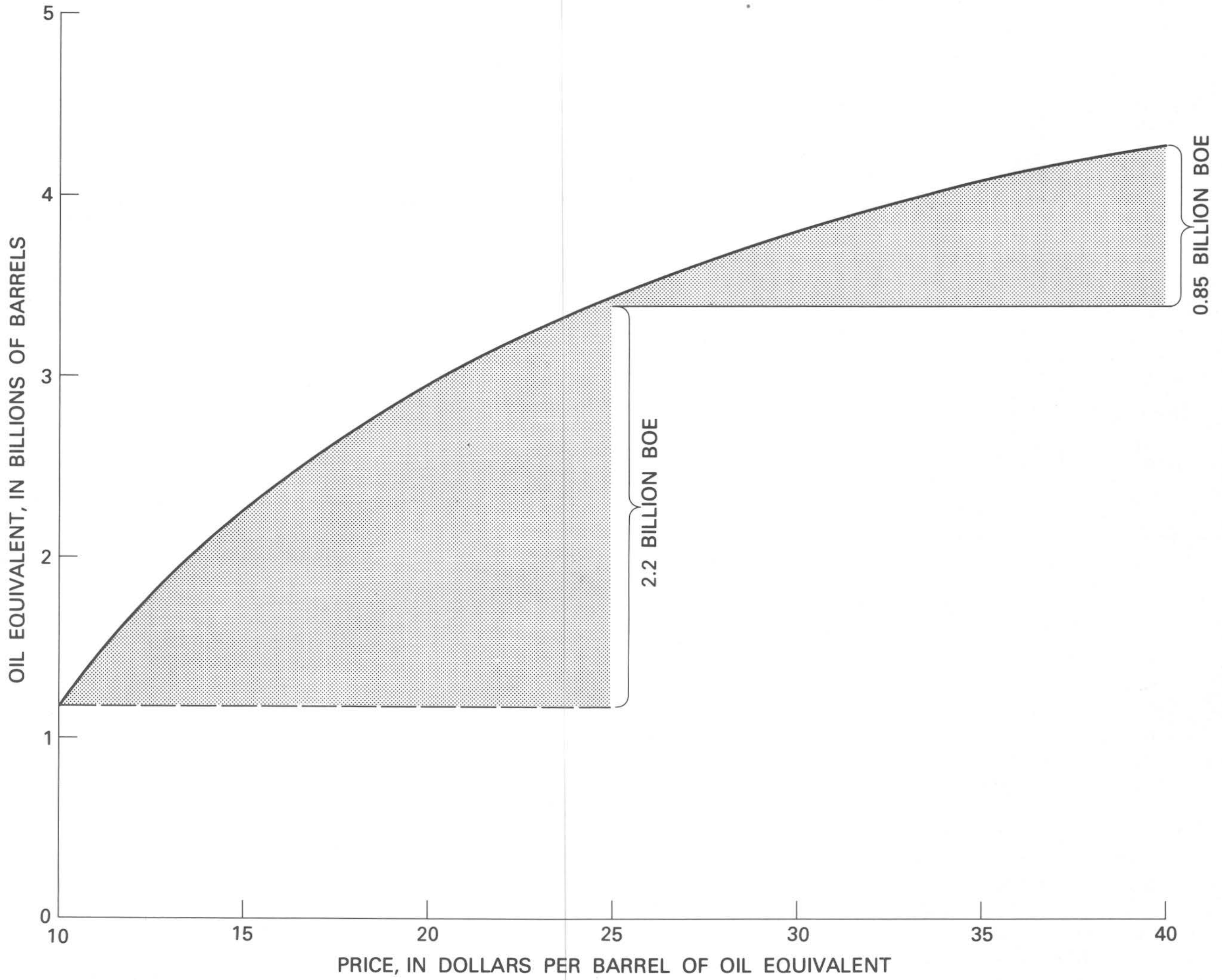

FIGURE 4.–Fuel supply from future discoveries in the Permian Basin.

PERMIAN BASIN SUPPLY—RETROSPECT AND PROSPECT

As the result of 6 decades of exploration and development, 24 billion barrels of recoverable crude oil and 74 trillion cubic feet of recoverable natural gas had been found in the Permian Basin as of December 31, 1974. By comparison, the analysis of data from this project indicates a potential future supply of 3 billion to 9 billion barrels of crude oil and 20 trillion to 37 trillion cubic feet of natural gas from all sources, a 15-percent rate of return and at a price range of $10 to $40 per BOE. At a 5-percent rate of return, these amounts would be somewhat higher, and at a 25-percent rate, somewhat lower. Supply responsiveness falls off quickly when prices are more than $25 per BOE for both oil and gas. Table 3 recapitulates the supply of oil and gas available from each source at prices of $10, $15, $25, and $40 per BOE at a 15-percent rate of return. Figure 6 represents these values graphically.

The prospect for additional oil from new discoveries is limited. Even at $40 a barrel, no more than 1.3 billion barrels is projected–about 17 percent of the amount expected to be recovered from existing fields and barely 5 percent of the 24 billion barrels discovered previously. By far, the greater part of future oil supply from the Permian Basin is expected to come from already discovered fields, primarily from indicated and inferred reserves at the lower price ranges, and from enhanced oil recovery at prices of $25 or more per BOE.

The outlook for new discoveries of natural gas is better than that for oil at all price levels, mainly because of the greater probabilities of finding large accumulations in those strata where gas is likely to be found, that is, below 15,000 feet in depth. Even so, however, new discoveries are expected to account for less than half the future supply of gas from the Permian Basin. Slightly more than 7 trillion cubic feet is expected from inferred reserves, and as much as almost 14 trillion cubic feet is optimistically projected from enhanced-gas-recovery projects in the tight sands of the basin at prices of $15 and more per BOE.

COMPARISON WITH EARLIER ASSESSMENTS

The results of the Permian Basin study cannot be directly compared with those of other assessments of the petroleum

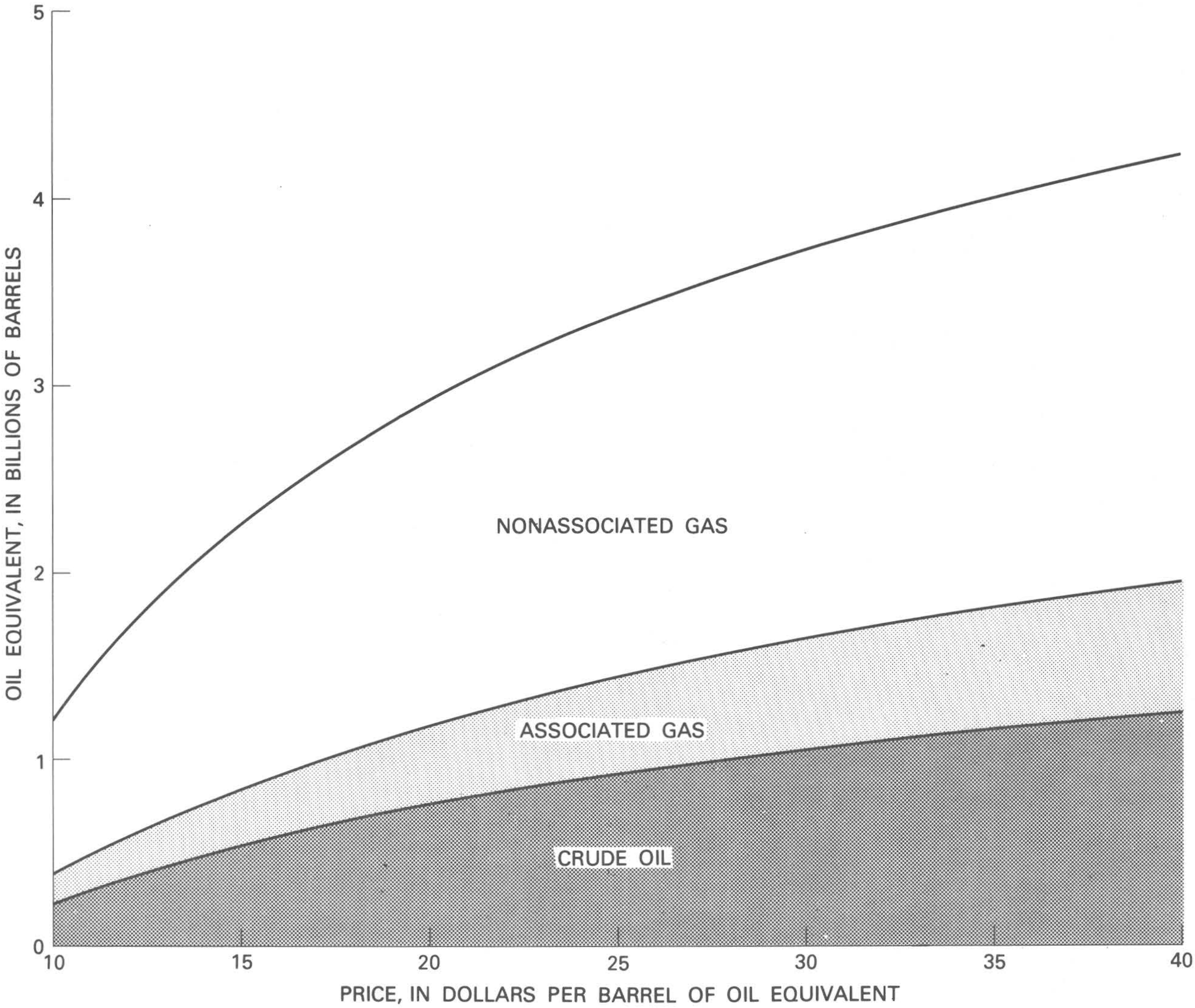

FIGURE 5.–Fuel supply from future discoveries in the Permian Basin by commodity.

potential of this general region because the areas considered are not identical. Nevertheless, the expectations from the current study are drastically lower than those indicated by previous estimates. Specifically, the estimate given in U.S. Geological Survey Circular 725 for Region 5's inferred and indicated reserves, plus the statistical mean for undiscovered recoverable resources is roughly five times the amount estimated in this study to be available from the Permian Basin at $25 per BOE and a 15-percent assumed rate of return. Although the Permian Basin constitutes only about half the area of Region 5, it has accounted for approximately 80 percent of all oil and gas discovered in that region to date. Therefore, only a small part of the large discrepancy between the two estimates can be attributed to geography; most of it has to be reckoned as a downward revision of resources ascribed to the Permian Basin in Circular 725.

The reasons for the differences are mostly due to the use of different data, different assessment methodologies, and a more thorough assessment of petroleum-exploration possibilities. In the Circular 725 assessment, only volumetric-yield or areal-yield

TABLE 3.–*Potential new recoverable supplies of oil and gas from the Permian Basin*

[At a 15 percent rate of return; BOE, barrels of oil equivalent; EOR, enhanced oil recovery; EGR, enhanced gas recovery]

1977 price ($/BOE)	Crude oil (billion barrels)					Natural gas (trillion cubic feet)				Total (billion BOE)				
	Indicated reserves	Inferred reserves	EOR	New discoveries	Total	Inferred reserves	EGR	New discoveries	Total	Indicated reserves	Inferred reserves	EOR plus EGR	New discoveries	Total
10	1.6	1.1	0.0	0.26	2.96	7.1	8.9	4.98	20.08	1.6	2.5	1.69	1.20	6.99
15	1.6	1.1	1.34	.58	4.62	7.1	13.7	9.17	29.97	1.6	2.5	3.94	2.32	10.36
25	1.6	1.1	4.31	.97	7.98	7.1	13.7	13.02	33.82	1.6	2.5	6.91	3.44	14.45
40	1.6	1.1	5.11	1.28	9.09	7.1	13.7	15.81	36.61	1.6	2.5	7.71	4.28	16.09

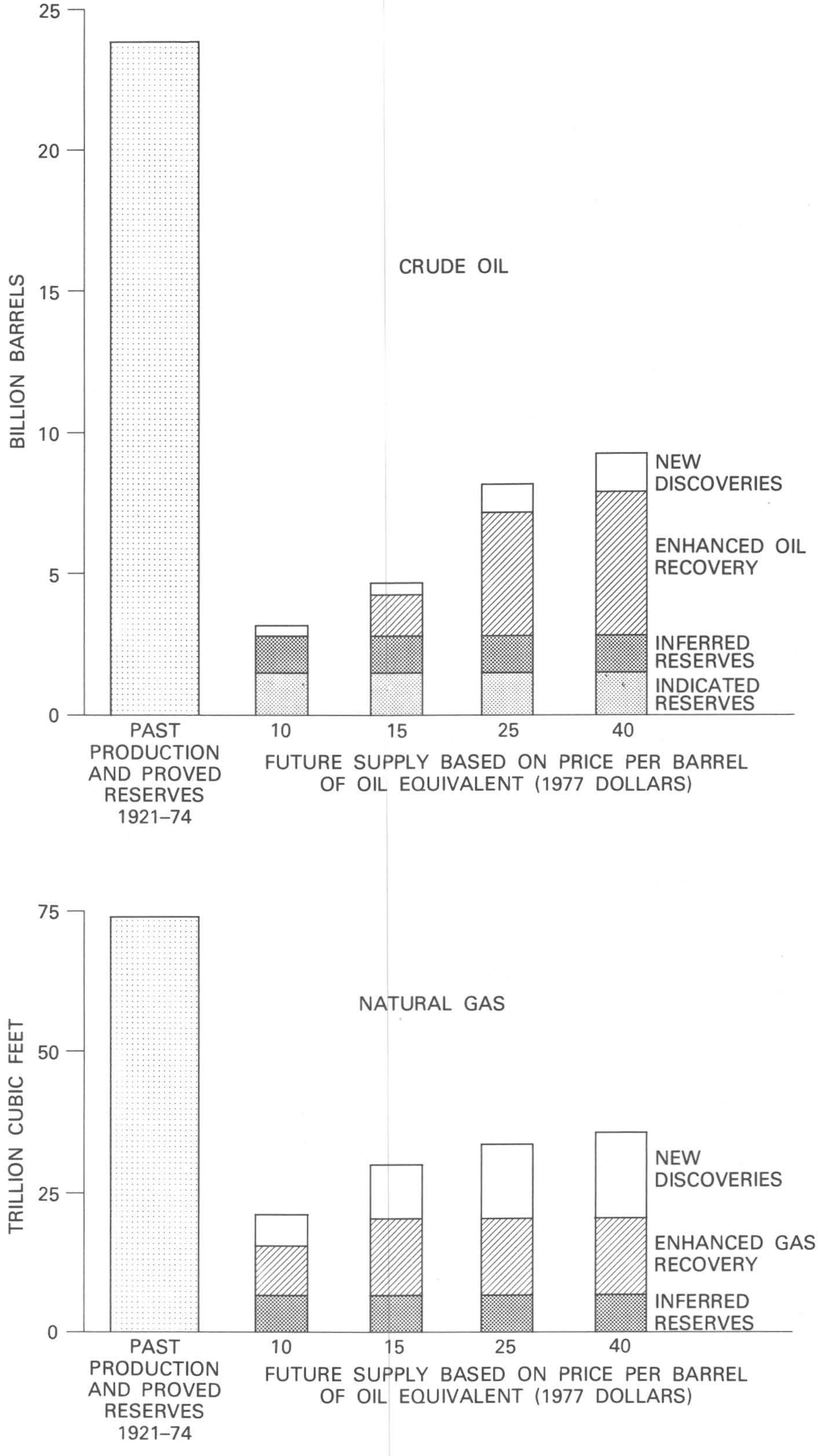

FIGURE 6. – Potential new supplies of oil and gas in the Permian Basin

analytical techniques were used. In the more recent assessment made here, a comprehensive field and pool data file was used, and abundant drilling and finding-rate studies were conducted along with a thorough review of the geology by stratigraphic units. The net result was a sharper perspective on the petroleum potential of this mature province and, possibly, a more reliable estimate. As has been illustrated by the differences between this study and Circular 725, reassessments can be expected to change over time as significant new data are acquired and new methods are used. These innovations, however, will not necessarily result in decreased assessments. Accordingly, to extrapolate a reduced expectation nationwide from the reduced assessment of the Permian Basin is not appropriate. The planned future assessments for other areas may be more optimistic than those offered previously as a result of new information or the application of different methodologies.

INTRODUCTION

This report is divided into two main parts to clearly distinguish between the methods used and the precision of the results attained. The first part deals exclusively with undiscovered oil and gas in conventional oil and gas reservoirs. Such petroleum, if found, is recoverable through primary- and secondary-recovery techniques. The second part assesses additional amounts of oil and gas that might be obtained from existing fields, either through enhanced-recovery techniques or additional drilling.

ABBREVIATIONS AND DEFINITIONS

The relationships between various resource terms defined below are illustrated in figure 7. Certain conventions used throughout the report are:

Barrel. Standard barrel of 42 U.S. gallons, used as an oil measure; abbreviated either as Bbl or B.

Basin. A large, bowl-shaped subsurface geologic feature formed by downwarping of the underlying basement rock and filled with sedimentary rocks. Large basins such as the Permian Basin may be divided after initial formation by uplifts and platforms, which in effect create other basins (such as the Midland and Delaware Basins) within the original structure.

BOE. Barrels of oil equivalent, that is, crude oil plus natural gas converted to crude oil equivalency on the basis of heat content measured in British thermal units (Btu). One barrel of crude oil is assumed to contain 5.8 million Btu, and 1 Mcf of natural gas (wet, that is, rich in condensate) is assumed to contain 1.1 million Btu (5.27 Mcf = 1 BOE).

MCF. 1,000 standard cubic feet of natural gas.

Oil or gas field. Any area underlain by one or more oil and (or) gas pools (reservoirs) that are recognized as being part of a common geologic or production unit. Where only one reservoir is present, the terms "field" and "pool" (or "reservoir") may be used interchangeably to designate the same unit.

Oil or gas in-place. The total amount of oil or gas contained in a reservoir, part of which will remain in the reservoir upon abandonment for economic or technological reasons.

Oil or gas pool (reservoir). A discrete unit of porous permeable rock containing oil and (or) gas and distinguished by a single pressure system, so that withdrawal of fluids from any part of the reservoir affects the pressure in all other parts. The terms "reservoir" and "pool" are synonymous and are used interchangeably.

Oil or gas supply. The quantity of oil or gas deliverable to market.

Province. A rather loosely defined term implying a region of common geologic character that contains one or more basins.

Tcf. 1 trillion standard cubic feet of natural gas.

Ultimate recovery. The total of cumulative past production plus proved reserves on a specific date (for example, ultimate recovery as estimated in 1976).

RESOURCE CLASSIFICATION

The principles set forth by the U.S. Bureau of Mines and the U.S. Geological Survey (1980) have been incorporated into a classification intended for oil and gas (U.S. Federal Power Commission, 1976). A modification of these two classifications is shown in figure 7 and is explained by the accompanying definitions.

Resource. A concentration of naturally occurring solid or liquid petroleum or petroleumlike material, or natural gas, in or on the Earth's crust, in such form that economic extraction is currently or potentially feasible. The resource includes all the material in place in a deposit.

Identified (Discovered) resources. Resources, and reasonable extensions thereof, whose location, quality, and quantity are known from drilling and geologic evidence, supported by engineering measurements.

Undiscovered resources—Resources surmised to exist on the basis of broad geologic knowledge and theory.

Reserve. That portion of the resource base from which a usable mineral and energy commodity can be economically extracted at the time of estimation. Such commodities include but are not necessarily restricted to petroleum, condensate,

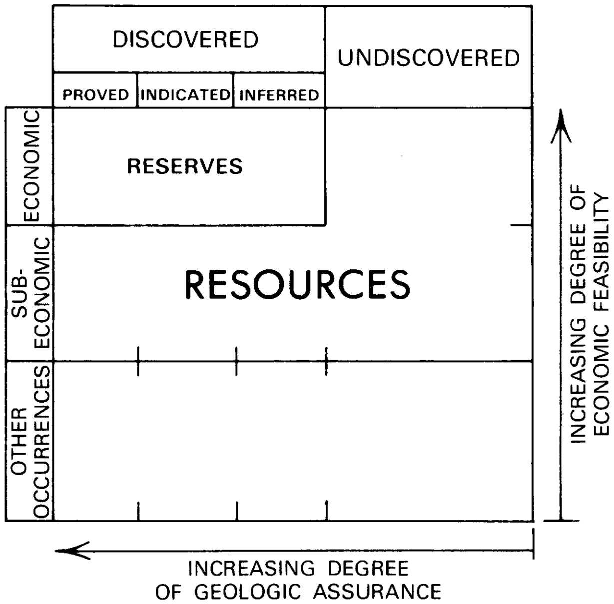

FIGURE 7.—Resource classification diagram, total resources.

natural gas, tar sands, and naturally occurring asphalt, without regard to mode of occurrence.

Proved reserves. Material for which estimates of the quality and quantity have been computed from analyses and measurements of closely spaced and geologically well-known sample sites.

Indicated reserves. Material that probably will be added in future years to proved reserves in discovered fields because of improved completion methods and increased recovery efficiency by secondary or enhanced methods. The American Petroleum Institute (American Gas Association and others, 1977, p. 14) category of "indicated additional reserves" is a part of indicated reserves; these are defined as "known productive reservoirs in existing fields expected to respond to improved recovery techniques such as fluid injection where (a) an improved recovery technique has been installed but its effect cannot yet be fully evaluated; or (b) an improved technique has not been installed but knowledge of reservoir characteristics and the results of a known technique installed in a similar situation are available for use in the estimating procedure."

Inferred reserves. Material that probably will be added in future years to proved reserves in discovered fields, estimated partly from drilling and production data and partly from extrapolation of geologic and engineering evidence over a reasonable area. This includes additions resulting from extension of producing areas and new reservoirs within known fields. Some shut-in or behind-the-pipe reservoirs not presently credited to proved reserves by some estimators are included in this category.

Discovered subeconomic resources. Known resources not economically producible on the date of estimation. Such resources include those that are too small or too remote; at depths too great, or under water depths too great to be economic; or those for which known producing technologies are not presently economic.

Hypothetical resources. Undiscovered material that may reasonably be expected to exist in a known producing basin under known geologic conditions. Exploration that confirms its existence and reveals the quantity and quality of this material will permit its reclassification to a discovered-resource category. This category is sometimes used to divide the "undiscovered" part of the resource diagram into "hypothetical" on the left and "speculative" on the right.

Speculative resources. Undiscovered material that reasonably may be expected to exist in presently nonproductive basins. Exploration that confirms its existence and reveals the quantity and quality of this material permits its reclassification to a discovered-resource category. This category is less geologically assured than hypothetical resources and, like that category, is infrequently used.

Undiscovered subeconomic resources. That material in hypothetical and speculative deposits which, if found, would not be economic to produce on the basis of existing technology at the time of estimation.

Other occurrences. Material not expected to become producible within a foreseeable period of time. For working purposes, this period may be defined as 25 years from the data of estimation. Among these materials are part or all of such unconventional deposits as gas occluded in coal, dissolved in water in geopressured reservoirs, or free in fractured shales; and oil in oil shale or tar sands.

EXPLANATORY NOTE

In the United States, data on cumulative production of crude oil are reasonably accurate, although no one pretends that every barrel has been counted. With respect to natural gas and natural-gas liquids (NGL), the story is otherwise. During most of the early oil-production years, the dissolved gas was vented to the atmosphere as an undesirable and dangerous annoyance. Only later was its importance recognized. Data on natural-gas liquids are nearly impossible to obtain, so most of the quantities are estimated in barrels obtained for each million cubic feet of gas produced. Likewise, quantities of gas produced in the past are commonly estimated by means of ratios to crude-oil production. Current gas production, where the gas is not associated with crude oil, is usually gauged accurately.

SENSITIVITY TO PRICES AND COSTS

As noted in U.S. Geological Circular 725, estimates of recoverable resources can be sensitive to assumptions about the future price of crude oil and the probable costs of finding and producing such oil. High prices relative to costs encourage the recovery of a greater proportion of the oil and gas in place and, thus, tend to raise estimates of recoverable resources; low prices discourage production and force estimates of recoverable resources down.

This study does not examine the timing of the discovery and development of resources as market conditions change. The actual effects of different price/cost levels on the timing of recovery can be complex. If producers believe that higher prices are likely to be short term, they may restrict their efforts to drilling and production on the intensive margin (that is, from already identified resources). For example, the price deregulation of crude production from stripper wells (those producing less than 10 barrels a day) increased the price of such oil from $5 per barrel to the current world price; this increase extended the productive lives of these wells. In this example, the higher price level moved identified subeconomic resources into the proved, indicated, and inferred catagories during this period. Estimates of identified recoverable resources would change rather than the estimates of undiscovered recoverable resources, which take longer to develop.

If producers expect prices to stabilize at a higher level relative to costs for a long period, they may accept the greater risk of drilling and producing on the extensive margin (that is, from presently undiscovered resources) as well as drill and produce on the intensive margin. Consequently, the higher price level would tend to increase any estimates of undiscovered recoverable resources until higher costs per barrel, owing to lower resource quality, reach the higher price level. Higher prices over the long run make economically feasible the use of enhanced recovery techniques. Consequently, such price increases have tended to increase activity on the intensive margin even more than perceived short-run price rises.

The events of the last 10 years have caused considerable uncertainty about the price and cost relationships likely to prevail in the future. This, in turn, has caused difficulties in assessing the effect of prices or costs in terms of future production on either the intensive or the extensive margin, over time.

Events have indicated the possibility that long-term changes in prices and costs may be taking place. From 1960 to 1970, the cost index maintained by the Independent Petroleum Association of America (IPAA) indicated a drop in the ratio of prices to costs. Such a trend might reduce estimates of ultimately recoverable resources. However, this trend was reversed after 1970.

Since 1970, the trend toward higher prices for new oil in nominal dollar terms has been clear. Until 1973, prices were relatively constant in nominal dollars, or declining in real dollars (that is, after the effects of inflation were removed). In 1974, the U.S. price of new oil averaged $10.13 per barrel in nominal dollars, and by 1977, the average upper-tier oil price was $11.32 per barrel. Since then, prices have risen still further in nominal dollars. Currently, although the real-dollar price of upper-tier oil is falling, it is still above 1973 prices. Long-term higher prices have encouraged producers to expand exploratory drilling on the extensive margin, and ultimately they will make the recovery of a greater portion of presently undiscovered resources economically feasible.

Costs of oil production (in nominal dollars) more than doubled from 1970 to 1977 for an oil field at a depth of 4,000 feet in the Permian Basin. In general, during this period, direct operating costs increased 104 percent; lease equipment costs, 169 percent; and drilling and equipment costs, 107 percent. If such trends continue, the effects of higher prices could be offset solely by the increased costs of doing business.

To avoid the problem of forecasting inflation rates, for this analysis, we held costs at 1977 levels (in real-dollar terms) and considered a range of prices (in real-dollar terms) from $5 per barrel to $40 per barrel. In this way, we have tried to indicate the sensitivity of the estimates of undiscovered recoverable resources to different price/cost levels. Although the price responsiveness of inferred reserves was not explored, the effect of higher prices on extending the lives of wells in new fields is incorporated. Because the Permian Basin has been extensively explored, exploration has covered the area to such an extent that it has no true extensive margin; it has only an intensive margin.

THE PERMIAN BASIN PILOT AREA

Accomplishing the project's objectives required new analytical techniques and a considerable expenditure of time, money, and labor. Prudence dictated a development and testing period to perfect the new methods.

The Permian Basin was selected for a variety of reasons, two of which were paramount. First, the basin has a long history of development for which good historical records exist. It has been a productive source of oil and gas since 1921. Second, the production in the basin is from geologically varied sources: from reservoirs at depths as great as 22,000 feet, from stratigraphic as well as structural traps, from both carbonate and clastic rocks, and from rocks as old as Cambrian and as young as Cretaceous.

Consequently, the Permian Basin presented an ideal pilot area for the study of a "mature" basin. Large in areal extent and having a thick sedimentary section, the basin has been explored exhaustively and is not likely to yield major surprises in terms of future discoveries or production. Most of the known fields have been fully drilled, many secondary-recovery projects have been installed, and the best prospects for additional future recovery of petroleum appear to be in the realm of enhanced recovery. An example of enhanced oil recovery is the major carbon dioxide injection program at the SACROC unit in the Kelly-Snyder reef field.

In choosing the Permian Basin, we recognized that this first project report would not be of interest to those eager to learn of opportunities for major new discoveries. Such opportunities are not present in a basin as "mature" as the Permian Basin. A mature basin does, however, provide a proper setting to devise and evaluate methodologies. It provides the opportunity:

(1) To evaluate the basic methodological approaches before proceeding to study a partly developed basin;

(2) To gain more understanding of the relationship of oil- and gas-resource availability to cost of finding and developing it in a typical basin; and

(3) To estimate the cost of analysis versus the value of the knowledge to be gained.

APPROACH AND GENERAL METHODOLOGY

At the outset, the work was divided into tasks, only some of which required new methodologies. These tasks concerned geologic appraisal, exploration productivity, growth of known reserves after discovery, future improved recovery from known fields, unconventional occurrences of oil and gas, and the estimated marginal costs of the additional reserves to be obtained from these various categories of effort.

This project differs from other published oil and gas appraisals in that the analysis of conventional oil and gas is based upon individual fields or pools, rather than upon broad regional aggregations. Therefore, both the number and the size of expected discoveries are significant in the analyses. In addition, oil and gas resources from extension drilling, secondary and enhanced recovery, and unconventional sources—all of which have been excluded previously—are included in these appraisals.

UNDISCOVERED RESOURCE APPRAISAL

The first task was to establish a framework for classifying all known occurrences of conventional oil and gas in the basin according to the size distribution of the reservoirs already discovered and the depths at which they were found. Next, judgments were made concerning quantities of oil and gas that still might be discovered in the basin through additional exploratory drilling for new fields and reservoirs. In this stage of the work, the fundamental methodology described in U.S. Geological Survey Circular 725 was used. Although no major changes were made in this subjective probability approach, it has been modified and improved for this project. As a result, the kinds of details required in the data about undiscovered oil and gas resources are different. The appraisal task group used historical data as well as its knowledge of the geologic setting of the basin not only to estimate the range of quantities of oil and gas that might be present, but also to present these data in terms of the numbers of reservoirs to be found in each of several field-size classes and in three depth classes. A minimum size of occurrence to be estimated was set explicitly to avoid the necessity of estimating all the oil and gas that might exist in nature. Finally, the geologic task group was asked to report on an oil-and-gas-in-place basis rather than on a recoverable basis. This permitted subsequent analyses to deal with variations in costs, prices, and recovery factors, and provided a clear separation between economic and geologic analysis.

DISCOVERY—PROCESS MODEL

After the geologic appraisal of undiscovered oil and gas was made, the next task group formulated a discovery model. The model was used to determine the most likely sequence in which the undiscovered reservoirs will be discovered and to estimate the amount of drilling that will be required to find progressively more of the remaining oil and gas. The geologic appraisal and the discovery model can be used independently or jointly. By extrapolating the past history of drilling in terms of the number of holes drilled and the oil and gas found as a result, the discovery model projects the number and sizes of fields to be discovered and the quantity of oil and gas contained in these fields. The discovery model also shows how many dry holes and producing wells would be required to detect various proportions of the remaining targets, given the areal dimensions of these targets and their numbers. The geologic appraisal and discovery model produced different but comparable estimates of remaining resources and indicated a new avenue for future research.

ENGINEERING AND COST ANAYSIS FOR FUTURE FIELDS

After the appraisal of in-place conventional resources and of the discovery of new reservoirs through exploratory drilling, the task group translated the oil and gas discovered into recoverable oil and gas by estimating the numbers of production wells required, the rate at which the oil and gas may be produced, and the point at which the reservoirs are abandoned (that is, the proportion of the oil and gas originally in place that is left unrecovered). This required establishing standard drilling density and production patterns based on customary practices reflecting depth, reservoir size, amenability to secondary recovery, and other factors. From these patterns, the entire sequence of development and production of the basin was estimated.

THE INTEGRATING ECONOMIC MODEL

The task group completed the conventional oil and gas analysis by using an integrating economic model that combined physical processes and economic considerations. The amount of oil and gas that is actually discovered and produced is a reflection of the economic motivation to drill exploratory and development wells, of the broader goals of the oil and gas industry, and of the effects of Government policies and regulations. The model represents recovery of discovered oil and gas as a function of the recovery of costs under a range of returns on investment and assumed prices. A discounted cash-flow computation is used where production is the only source of revenue, and all future production receives the assumed price. In this simplified representation, neither the industry's broader goals nor current Federal regulations are modeled. All calculations are based on the size and depth of fields predicted by the discovery model as a function of exploratory wells drilled. All discounted cash flows are based on production profiles from engineering analysis, as described in "Engineering and Cost Analysis for Future Fields."

ADDITIONAL OIL FROM KNOWN FIELDS

So far, the analysis has accounted only for the future oil and gas to be recovered from undiscovered oil and gas reservoirs. In addition, the analysis takes into account:

(1) The oil and gas which may be produced from known reservoirs but which is not now included in proved reserves; and
(2) The additional oil and gas to be recovered by means of enhanced-recovery technologies not included in the conventional model.

INDICATED AND INFERRED RESERVES

The amount of additional oil and gas from indicated and inferred reserves is related to those reserves added to the proved category through extension drilling, revisions resulting from new information, and the added recovery resulting from the installation of secondary-recovery projects. The methodology used in this task basically involved a statistical analysis of change in ultimate recovery over time.

ENHANCED OIL AND GAS RECOVERY

The enhanced oil recovery (EOR) methodology projects enhanced production potential by using a data base that describes specific reservoirs selected from the major producing fields in the region. This data is believed to cover a substantial percentage of the remaining oil in place in the Permian Basin and a much higher percentage of the best EOR prospects.

Economic criteria are used in the model to evaluate five EOR methods: steam drive, in situ combustion, gas miscible flooding, surfactant polymer flooding, and polymer-augmented waterflooding. The evaluation involves three steps:

(1) Screening reservoirs according to geologic and economic factors, and assigning EOR techniques to the most attractive prospects;
(2) Identifying minimum acceptable prices and reservoir-specific production profiles over a period of time, on the basis of prices and rates of return; and
(3) Extrapolating production data to regional levels and accumulating reserves.

Potential production from EOR is estimated only for known fields. New fields are treated in the discovery model.

The methodology of enhanced gas recovery (EGR) is analogous to that of EOR. A detailed geological description of potential EGR targets and an economic evaluation of alternative recovery methods are used to determine the economically attractive projects. The development and production schedules over a period of time are then projected for these projects, and reserve estimates are accumulated.

OTHER OCCURRENCES

The assignment to the remaining task group was to determine whether the basin has a geologic potential for providing commercially significant hydrocarbons from unconventional sources, such as oil shale, brown and black shale rich in organic matter, coal, tar sand or other heavy oils, geopressured brines, or hydrates. This group found that little oil and gas was available from all these so-called unconventional sources, and, therefore, no discussion of them appears in this report.

The end product of this analytical process constitutes a complete review of the oil and gas resource and supply potential of the basin. The oil and gas resources in place are fully accounted for, and the associated range of probabilities are shown. These estimated resources are translated into recoverable quantities at assumed cost and at various rates of return and price settings.

We do not suggest that by means of this methodology, we have produced a wholly accurate assessment of Permian Basin hydrocarbon resources, but the assessment does reasonably approximate the amount of oil and gas that might ultimately be recovered at a given price and at a given rate of return. This methodology does not enable us to predict the time that various oil and gas quantities will be produced, but it does provide a means to grade the resource base economically and to approximate the amounts of oil and gas left to be discovered and produced in the Permian Basin by relating some sense of the effort, both physical and economic, that will be required to actually transform resources into producible oil and gas.

FUTURE PRODUCTION OF UNDISCOVERED OIL AND GAS FROM THE PERMIAN BASIN

PERMIAN BASIN RESOURCE APPRAISAL

The Permian Basin, which has been one of the most prolific sources of petroleum in North America, is now in an advanced stage of exploration and development. Very large quantities of oil and natural gas have been found there in rocks of Paleozoic age (those 225–570 million years old), and minor amounts have been found in younger reservoirs (table 4). Reservoirs produce oil from depths of less than 500 feet to slightly more than 14,000 feet and natural gas from depths of less than 500 feet to more than 21,000 feet. Most of the oil (71 percent) has been found in the relatively shallow Permian rocks, and most of the nonassociated gas (71 percent), in the deeper, older Paleozoic rocks (table 4).

GEOLOGY

The Permian Basin is a large asymmetric structural depression in the Precambrian basement, filled primarily with Paleozoic sediments. It had essentially acquired its present structural form by Early Permian time, although that form has been modified by subsequent tectonic activity. Rocks of all Paleozoic systems are present and have a maximum combined thickness of more than 25,000 feet. The location and major structural elements in the Permian Basin are shown in figure 8.

From Cambrian through Mississippian time, the area was relatively stable; from a broad marine shelf, it evolved into a marine basin with associated shelves. This basin was the site of extensive carbonate and subordinate fine clastic sedimentation. Its deepest part was in the approximate vicinity of the present Delaware Basin. Only mild structural movement and deformation took place during this early period, producing local unconformities and structural anomalies of low and broad relief. The

TABLE 4.—*Discovered oil and gas in place, Permian Basin (1921 to December 31, 1974)*

Geologic subdivision	Oil in place[1] (10^9 bbls)	Natural gas in place[1] (in trillion cubic feet)		
		Associated	Dissolved	Nonassociated
post-Permian	0.184	0.000	0.006	trace
Permian	65.070	2.414	30.323	6.268
Carboniferous	11.926	.352	10.228	7.721
older Paleozoic	14.368	1.167	16.284	[2] 33.636
undifferentiated Paleozoic	.003	.000	.001	.000
Total	91.551	3.933	56.842	[2] 47.625

[1] Discovered quantities cited here are estimates of initial oil or gas in place and do not include quantities that may accrue to known fields through future growth by extension, new pays, or new pools (hence, they exclude inferred reserves but include cumulative past production and proved reserves).
[2] Includes 2.2 trillion cubic feet of CO_2.

deeper parts accumulated fine clastic sediments and some interbeded limestone in Mississippian time.

The dolomite of the Ordovician Ellenburger Group and Devonian limestones and dolomites are the principal reservoirs of the older Paleozoic and Mississippian sequence, although other productive reservoirs are found throughout. Traps in the older Paleozoic rocks are primarily in faulted anticlines, some of large size; truncation of strata below unconformities also produced significant stratigraphic and combination traps.

From Early Pennsylvanian into Early Permian time, the region was subjected to intense structural deformation and orogenic movement that culminated in the formation of the present tectonic elements (fig. 8) and provided a depositional setting totally different from the relatively stable basin that existed earlier. The tectonic elements include the Diablo and Central Basin Platforms, the deep Delaware, Val Verde, and Midland Basins, and their surrounding shelves (Northwestern and Eastern). Sedimentation in Pennsylvanian time varied according to the tectonic setting. Coarse clastic sediments were deposited near the shorelines of basins and limestones seaward of the clastic deposits. Reefs built at that time constitute a large percentage of the limestone. In Late Pennsylvanian time, the deeper basins were sediment starved, and only thin marine shales were deposited. Pennsylvanian rocks are absent in many localities because of erosion or nondeposition, particularly along the trend of the Central Basin Platform. Among the types of traps present, reefs are common.

In Permian time, sediments continued to build on the tectonic setting formed in Pennsylvanian time. Reef building increased; the great Permian reefs are the most striking feature of the entire Permian Basin. The reefs generally formed at the basin hingelines and separated the clastic and thin limestone deposits of the basins from the backreef lagoonal deposits of sandstone, mudstone, carbonate, and anhydrite interfingering layers.

The growth of the great reefs and the lagoons behind them led to the dominance of Permian rocks in the production of oil and gas. Most of the Permian oil and gas traps are related to the reefs and backreef rocks and their varied porosities. Many well-known reservoirs are found in this setting, including the San Andres Limestone, the dolomite of the Grayburg Formation, the reef of Abo Sandstone, and the Glorieta Sandstone. Many other reservoirs, including some from other settings such as the "Spraberry" fractured siltstone, contribute to the dominance of the Permian section in hydrocarbon production in the Permian Basin.

ANALYSIS AND ASSESSMENT

The assessments of undiscovered oil and gas in place reported here fall in the right-hand column of the resource classification diagram (fig. 7). Not all in place resources will be recovered because of economic and technological limitations.

Some deposits of hydrocarbons are too small, too dispersed, or too remote to be classified as resources. The smallest size class used in this study is that of a reservoir containing 1,000 barrels of oil in place or 1 million cubic feet of nonassociated gas in place. Resources assessed here are for the most part conventional oil and gas and exclude tight gas sands, tar sands, and heavy oil deposits.

The Paleozoic section of the Permian Basin was divided into three identifiable major stratigraphic units for purposes of assessment of undiscovered hydrocarbons. These three units are separated in many places by natural boundaries within the stratigraphic column and consist, respectively, of rocks of the Permian, the Carboniferous, and the

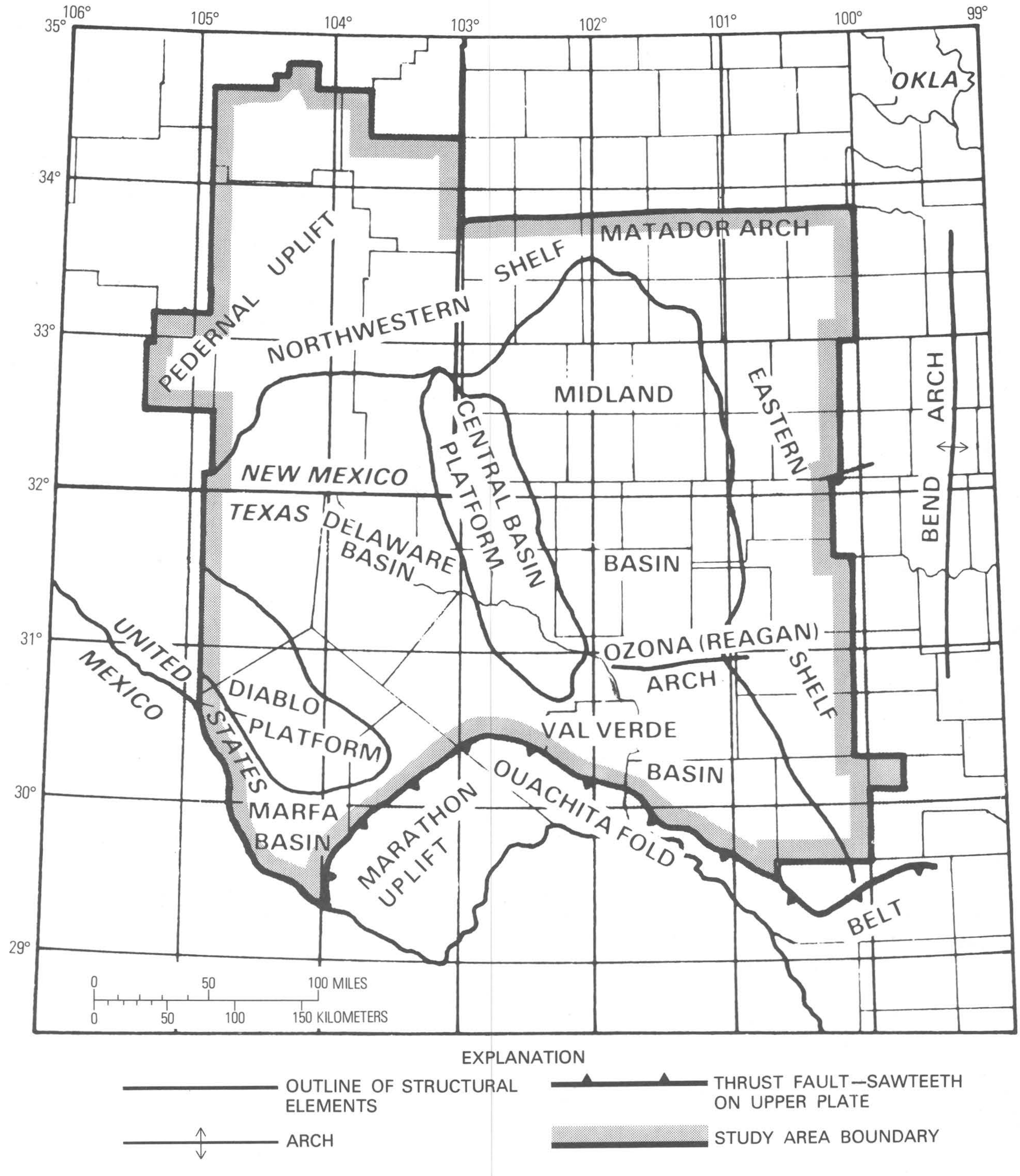

FIGURE 8.—Structural elements in the Permian Basin.

remaining older Paleozoic systems. Each major stratigraphic unit (such as the Permian, Carboniferous, and older Paleozoic) was analyzed independently by a team of geologists. Because of restrictions imposed by physical characteristics of each unit, specific methods of data preparation and treatment in each unit vary to a certain degree. However, the objective of the analysis – to assess undiscovered in place hydrocarbons, and the probability distributions for pool sizes containing these hydrocarbons – dictated similar methods of approach for all three units. The separate assessments were combined into the totals reported here.

The procedure for estimating the undiscovered oil and natural gas in the Permian Basin involved an intensive review of the geology and analysis of historical data, and ultimately the application of subjective probability methods for the actual assessment.

GEOLOGIC ANALYSES

All available geologic, drilling, reservoir-engineering, and related data were compiled for the three major stratigraphic units. The Dallas Field Office of the Energy Information Administration, U.S. Department of Energy (at that time part of the U.S. Bureau of Mines) supplied data concerning total known oil and gas reserves of the Permian Basin, initial oil and gas in place, estimates of ultimate recovery, amounts of associated and dissolved gas, field and pool sizes, discovery dates, age of productive units, depths of production, and general reservoir characteristics. Basic drilling information, derived from the Petroleum Information Corp. "Well History Control System" (unpub. proprietary commercial data file) was used to establish the well density, penetration depths, identification of stratigraphic units, and historical success records of exploratory wells. Publicly available literature provided information on porosities, permeabilities, reservoir lithologies, amounts of net pay sections, gas/oil ratios, hydrocarbon properties, trapping mechanisms, and types of reservoir seals. Literature on the Permian Basin, USGS files, and unpublished maps also provided isopach, lithofacies, and some structural maps. Studies on geophysical investigations were not available.

Subsurface geologic maps were prepared for 5,000-foot depth intervals and were used, together with isopach maps, to calculate the total area and volume of the three major stratigraphic units. Volumes of sediment in each of the three major stratigraphic units were partitioned into the depth intervals of 0–10,000, 10,000–20,000, and 20,000–30,000 feet.

Drilling-density maps were prepared and provided the basis for outlining maturely drilled areas, immaturely drilled areas, and totally undrilled areas. Maturely drilled areas are defined as having 12 or more wells per 25 square miles, and immaturely drilled areas as having less than 12, and more than 0, wells per 25 square miles. Combined with rock distributions, these maps provided volumes and areas of maturely drilled, immaturely drilled, and undrilled rock in each major stratigraphic unit and in each depth interval. The drilling-density maps were based on maps of new-field wildcats drilled through or into specific stratigraphic units and were derived from Petroleum Information Corp. "Well History Control System" (unpubl. proprietary commercial data file). To these maps, the locations of oil and gas fields producing from the same or older stratigraphic units were added. The resulting combined maps were contoured on the basis of well density.

To gain some idea of the possible range of undiscovered oil and gas in place, we applied yield [4] factors to the volumes or areas of immaturely drilled and undrilled rock. These yield factors were derived from maturely drilled areas of the basin and were applied to sedimentary-rock volumes or areas within individual tectonic elements or on a gross regional scale or trend basis. To calculate a possible "high" amount of undiscovered oil or gas for any one area, we assumed that geologic and reservoir conditions in the immaturely drilled or undrilled areas were similar to those existing in the maturely drilled producing area. Such conditions include lithologic and reservoir variables, trap types, sealing mechanisms, and source rocks. We calculated "low" amounts by: (1) reducing the total area or volume of sedimentary rock in immaturely drilled areas by a quantity assumed tested by the exploratory wells in the area, (2) discounting undrilled or immaturely drilled sedimentary-rock volume in direct proportion to the success ratio established in maturely drilled producing areas before applying the yield factor, or (3) discounting either the undrilled sedimentary-rock volumes or historic-yield factors, assuming particularly unfavorable geologic conditions. Yield factors were directly lowered in some places to reflect a reduced

[4] Yield, as used here, applies to in place rather than recoverable quantities.

probability of occurrence of additional giant fields.

We also applied analog models to major tectonic elements within the Permian Basin by using known hydrocarbon yield factors from other major elements, such as the highly productive Midland Basin and Central Basin Platform.

STATISTICAL ANALYSIS

We analyzed historic finding rates by plotting discovered volumes of hydrocarbons against units of exploratory effort for each of the three major stratigraphic units and for several pool-size classes. The amount of oil discovered as drilling effort increased has declined dramatically (fig. 9). However, such a decline is not apparent for nonassociated natural gas (fig. 10). Finding rates for pool-size categories, not shown here, indicate that oil is no longer being found in the larger pool-size classes, which historically have contributed the major quantities of discovered resources. Even the larger components of the smallest size class are being found in decreasing numbers. In terms of natural gas pool sizes, no clear finding-rate trend can be identified.

SUBJECTIVE PROBABILITY PROCEDURES

Subjective probability procedures were used in the final assessments. These procedures were similar to those described by Miller and others (1975), except that associated dissolved-gas estimates were derived from oil estimates through the use of historic depth-dependent gas/oil ratios. Estimates of the least quantity of oil or gas expected at 95, 75, 25, and 5 percent probability and a modal estimate describing the highest probability of occurrence were produced separately for the major stratigraphic units within the basin for the depth increments 0–10,000, 10,000–20,000, and 20,000–30,000 feet. These were then aggregated by means of Monte Carlo techniques into the Permian Basin totals shown in table 5 and into the depth intervals shown in table 6.

METHODS FOR POOL-SIZE ASSESSMENT

Data for pool-size assessments of future discoveries were compiled as an integral part of the overall data collection and analysis. The

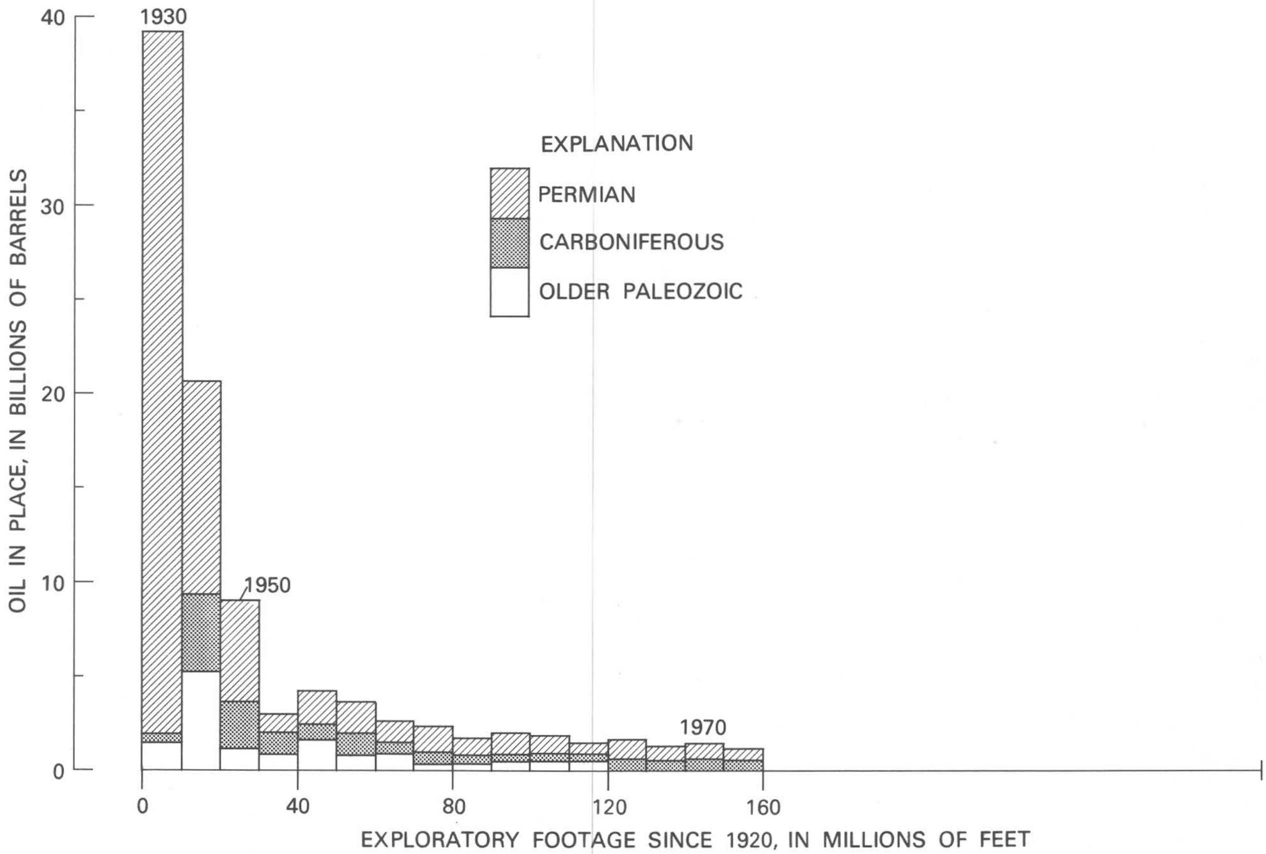

FIGURE 9.–Historic finding rate for oil, 1920–1974, Permian Basin.

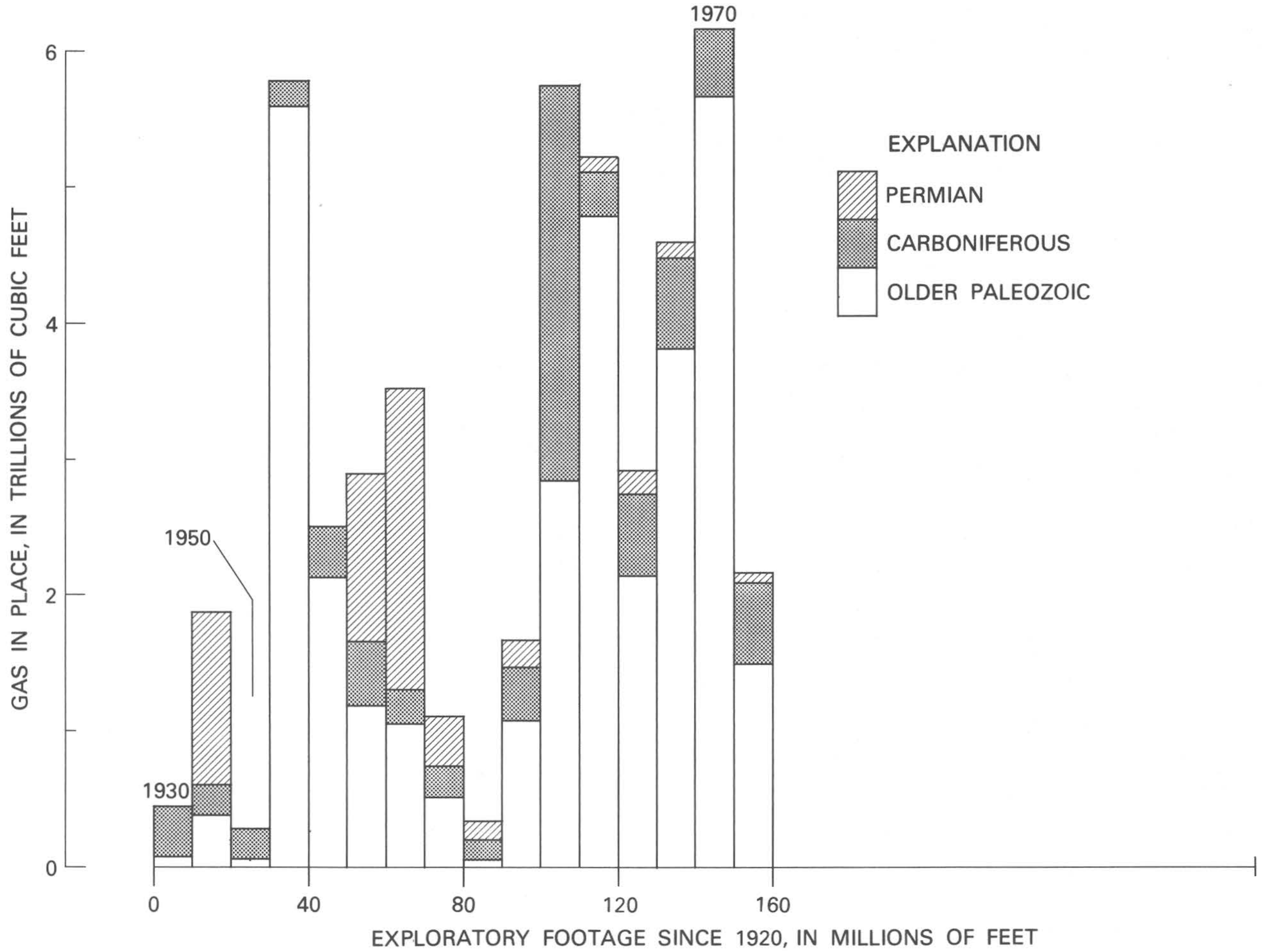

FIGURE 10. – Historic finding rate for nonassociated natural gas, 1920–74, Permian Basin.

historic pool-discovery data were subjected to several analyses with each major stratigraphic unit.

(1) Histograms were prepared for all pool-size classes by depth intervals and by equal units of exploratory effort.
(2) Cumulative frequency distributions were calculated for the entire historic period and for the last two 40-million-foot units of exploratory effort.
(3) A linear regression was fitted to the historic cumulative frequency distributions in an attempt to project numbers and frequencies of pools in the very small classes.
(4) Finding-rate curves were calculated for various field-size classes.

Probability estimates of the pool sizes in which the assessed undiscovered oil and nonassociated gas in place occur were produced by subject probability procedures for each of the major stratigraphic units and depth intervals. Pool sizes were estimated as in place quantities. Dissolved and associated gas occurrences were not included in size estimates of those pools.

The evaluators provided estimates of the minimum pool size corresponding to the 95, 75, 25, and 5 percentile probabilities and also of a modal ("most likely") value. Attempts were made to fit several functions to these subjective estimates. Although no totally satisfactory fit was found, a lognormal curve was used. As a result of the lognormal curve, the calcuated mean pool sizes appear unduly large, and the reported distributions should be viewed only as approximations of the assessed distributions of undiscovered pool sizes. Pool-size assessments were made by stratigraphic interval. Aggregations of the pool-size distributions into a basin total are not currently available.

SUMMARY RESULTS

Assessed total undiscovered oil and gas in place are summarized in table 5 and shown by depth

TABLE 5.—*Estimates of total undiscovered hydrocarbons in place*

[The values shown are the estimates corresponding to the probability that there is at least that amount. Values shown are derived from lognormal curve fits at the 0.95 and 0.05 probability levels]

	0.95 probability	0.75 probability	0.25 probability	0.05 probability	Mean	Standard deviation
Oil in place (10^9 bbls)	3.32	4.53	7.22	10.43	6.35	2.29
Gas in place (in trillion cubic feet)						
Dissolved and associated	2.99	4.06	6.31	8.83	5.57	1.85
Nonassociated	8.24	11.38	18.80	28.27	16.30	6.58
Total	12.89	16.50	24.29	33.80	21.87	6.74

TABLE 6.—*Estimates of total undiscovered hydrocarbons in place by depth interval*

[The values shown are the estimates corresponding to the probability that there is at least that amount. Values shown are derived from lognormal curve fits at the 0.95 and 0.05 probability levels]

Depth interval (thousand feet)	0.95 probability	0.75 probability	0.25 probability	0.05 probability	Mean	Standard deviation
Undiscovered oil in place (10^9 bbls)						
0–10	2.31	3.37	5.91	8.87	5.05	2.18
10–20	.51	.79	1.52	2.56	1.30	.69
Undiscovered associated dissolved gas in place (trillion cubic feet)						
0–10	1.76	2.58	4.42	6.70	3.80	1.56
10–20	.68	1.07	2.08	3.53	1.77	.97
Undiscovered nonassociated gas in place (trillion cubic feet)						
0–10	1.43	2.16	3.83	5.98	3.31	1.52
10–20	3.73	6.17	12.74	21.90	10.70	6.15
20–30	.75	1.28	2.73	4.86	2.29	1.38

interval in table 6. Probability distributions for the data in table 5 are given in figures 11 through 14. Table 7 shows the estimated mean depths of occurrence for undiscovered hydrocarbons in place by depth intervals for all Paleozoic systems, of 10,000 feet. Examples of the fit of lognormal curves for a few of the pool-size probability distributions, along with dots representing the numerical average of original estimates to which the curves have been fitted, are given in figures 15 through 17.

TABLE 7.—*Estimates of mean depths of occurrence of undiscovered hydrocarbons in place—all Paleozoic systems*

[n.a., not applicable]

Depth interval (thousand feet)	Mean depth of occurrence (ft) Oil	Mean depth of occurrence (ft) Nonassociated gas
0–10	6,100	7,600
10–20	11,800	15,400
20–30	n.a.	21,500
0–30	7,300	14,700

THE DISCOVERY—PROCESS MODEL

Through discovery and production-cost analyses, the number, size, and depth of occurrence of future oil and gas discoveries in the Permian Basin can be estimated. Because the Permian Basin has a long exploration history, the pattern of future discoveries may be forecast by extrapolating the past drilling and discovery record.

The method used here to forecast the size distribution of future discoveries is based upon a well-documented and not surprising characteristic of the petroleum-discovery process; the large deposits tend to be discovered early in the exploration of an area (Ryan, 1973; Barouch and Kaufman, 1978; Drew and others, 1978, 1979; and Arps and Roberts, 1958). Any reasonable quantitative model of the discovery process must incorporate this characteristic. The model described here was proposed by Arps and Roberts (1958) and assumes that the probability of the next exploratory well finding a field of a given area is proportional to the ratio of the area of the field to the area of the basin. Thus, a field having a large surface area has a higher probability of being discovered early than does a field having a small surface area. For this

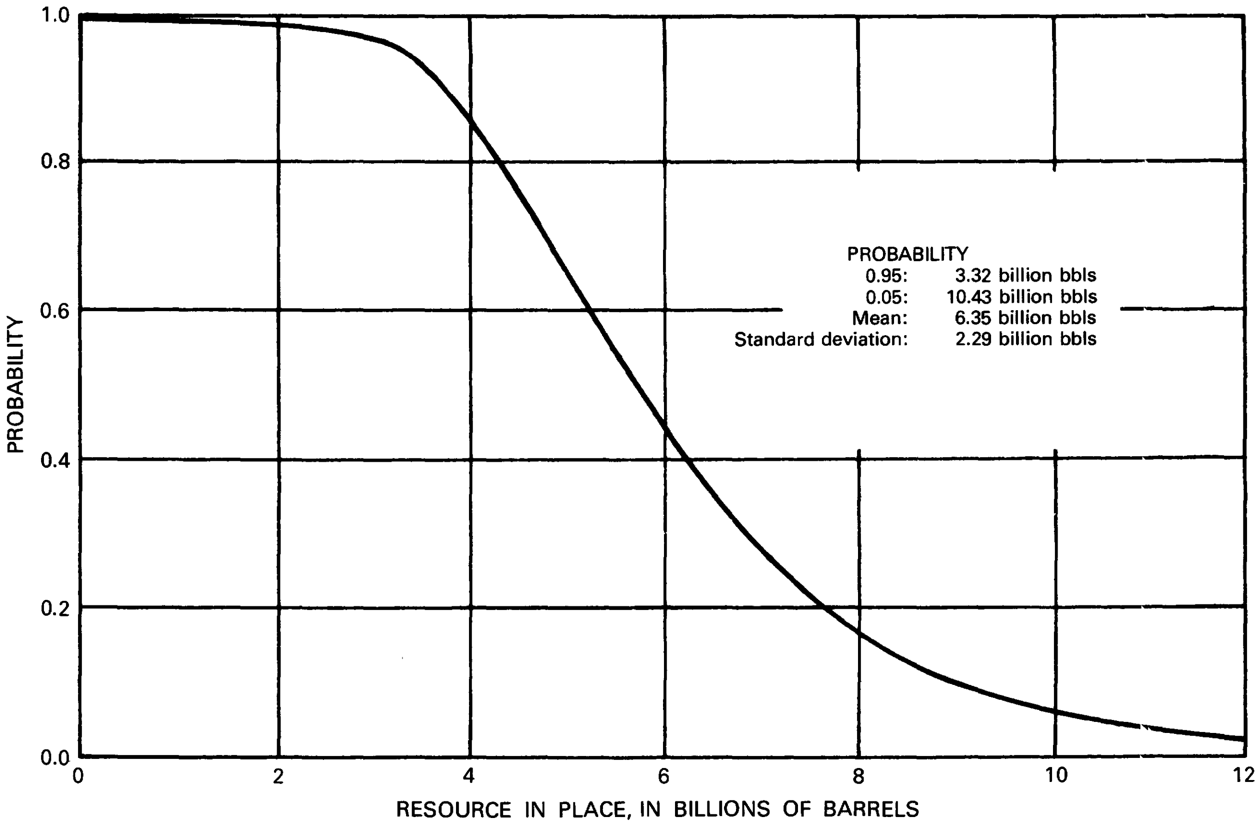

FIGURE 11.–Probability distribution of the total Paleozoic undiscovered oil in place, aggregated for depths of 0–20,000 feet.

reason, the model initially projects a distribution of the areal sizes of future discoveries. This distribution is then converted into a distribution of the volumes of predicted future recoverable petroleum by relating the average areal size of fields to the average volume of recoverable petroleum that they contain.

This approach was originally devised to forecast future discoveries in a basin having only a single productive horizon without large structural relief. The approach had to be modified before it could be used in a basin, characterized by many productive strata at varying depths and modes of geologic occurrence (for example, the Permian Basin). To apply the model to the Permian Basin, we divided the basin into four layers, each 5,000 feet thick. Forecasts of future discovery rates were then made independently for each layer.

Two types of information were required for the analysis: (1) detailed information on the exploratory drilling history of the basin, obtained from the Petroleum Information Corp. "Well History Control System" (proprietary unpub. commercial data file) which gives the completion date and total depth of each exploratory well drilled before January 1, 1975; and (2) information on the known oil and gas fields in the Permian Basin; including the volume of recoverable oil and gas, the discovery, and the depth and surface projection area of each field, prepared by the Dallas Field Office of the Energy Information Administration, DOE (unpub. data, 1977–78.)

EXPRESSING THE DATA IN DEPTH INTERVALS

The oil and gas fields were divided into four depth-class intervals: 0–5,000, 5,000–10,000, 10,000–15,000, and 15,000–20,000 feet. Few data were available for depths greater than 15,000 feet. No estimates were made for fields deeper than 20,000 feet because of insufficient data as of December 31, 1974. A field was assigned to the interval that contained its largest reservoir. Within each interval, the fields were partitioned into 20 size classes based upon quantities of recoverable oil and gas (table 8). "Oil equivalent" expressed as BOE (barrels of oil equivalent) represents total

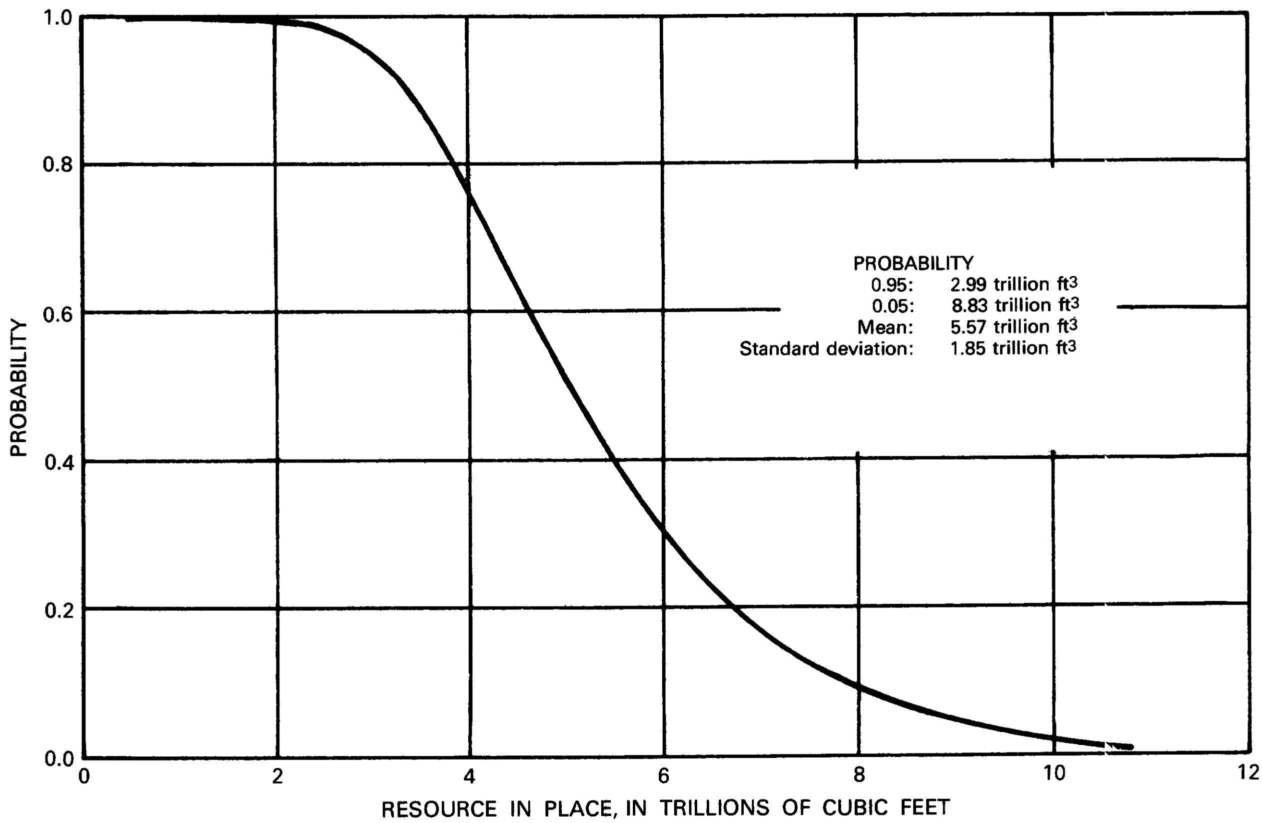

FIGURE 12. – Probability distribution of total Paleozoic undiscovered dissolved and associated gas in place, aggregated for depths of 0–20,000 feet. Pool sizes in trillions of cubic feet (ft^3).

volatile hydrocarbon fluids. It includes barrels of oil, barrels of lease condensate, and thousands of cubic feet of wet natural gas converted to BOE. The average volume of recoverable oil equivalent and average areal extent of the fields in each size class and depth interval combination were also computed.

TABLE 8. – *Field-size classes*

[BOE, barrels of oil equivalent]

Size clsss	Size range (million BOE recoverable oil and gas)
1	0.0 to 0.006
2	.006 to .012
3	.012 to .024
4	.024 to .047
5	.047 to .095
6	.095 to .19
7	.19 to .38
8	.38 to .76
9	.76 to 1.52
10	1.52 to 3.04
11	3.04 to 6.07
12	6.07 to 12.14
13	12.14 to 24.3
14	24.3 to 48.6
15	48.6 to 97.2
16	97.2 to 194.3
17	194.3 to 388.6
18	388.6 to 777.2
19	777.2 to 1,554.4
20	1,554.5 to 3,109.0

The number of exploratory wells drilled each year was converted into the number of net wells per year within each depth interval. For example, an exploratory well drilled to a total depth of 7,500 feet was counted as one well in the 0–5,000-foot interval and as half a well in the 5,000–10,000-foot interval. A well drilled to a total depth of 20,000 feet was counted as one well in each of the four depth intervals.

FORM OF THE MODEL

The discovery-process model selected to predict future rates of discovery in the Permian Basin has the following analytic form for relating discoveries to exploratory wells:

$$F_a(w) = F_a(\infty) * (1 - e^{-CAw/B})$$

where:

$F_a(w)$ = the cumulative number of discoveries estimated to be made in size class a by the drilling of w exploratory wells,

$F_a(\infty)$ = the ultimate number of fields in size class A that occur within the basin,

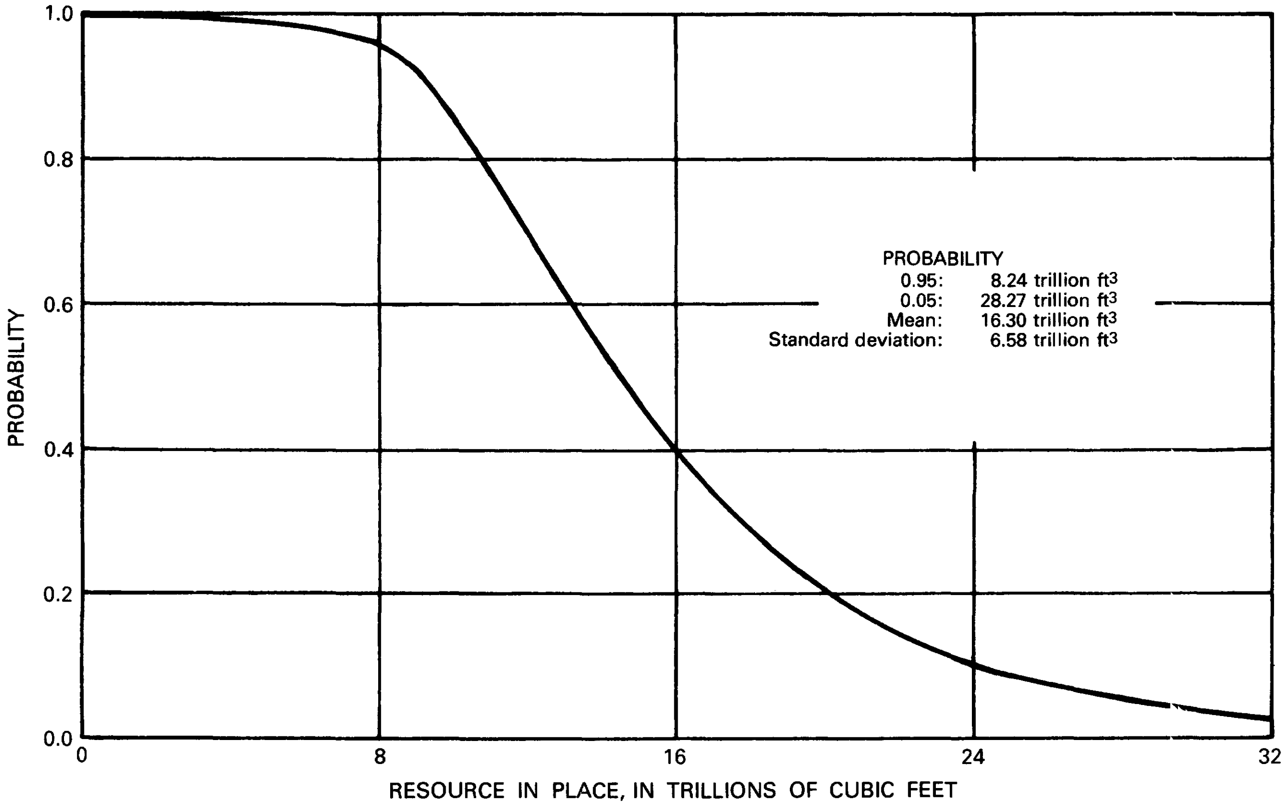

FIGURE 13. – Probability distribution of total Paleozoic undiscovered nonassociated gas in place, aggregated for depths of 0–30,000 feet. Pool sizes in trillions of cubic feet (ft^3).

B = area of the basin,
A = average areal extent of the fields in the given size class and depth interval,
w = cumulative number of net exploratory wells for the depth interval, and
C = the efficiency of exploration. For random drilling, $C=1$; if the exploration is twice as effective as random, $C=2$.

The ultimate number of fields expected in the class, $F_a(\infty)$, was estimated from the model and the discovery record, after a value for C had been estimated.[5] The value of $F_a(\infty)$ was calculated for each size class of fields within each depth interval by solving the discovery-process model equation. A sample calculation for field-size class 10 in the 0–5,000-foot interval is given below:

Input data for size-class 10, depth interval 0–5,000 feet

Average areal extent of fields =	2.2 mi^2
Permian Basin size =	100,000 mi^2
Efficiency of exploration =	2.0
Cumulative exploratory wells through 1960 =	14,243
Number of discoveries in size-class 10, in the 0–5,000 foot interval through 1960 =	59

Solution for ultimate number of fields

$$F_{10}(\infty)=\frac{F_{10}(w)}{1-e^{-CAw/B}}$$

$$=\frac{59}{1-e^{-2.0*2.2*14,243/100,000}}$$

$$=126.7 \text{ fields}$$

Given the number of discoveries in this size class through 1960 and the cumulative net wells in the interval, the model estimates that 126.7 − 59 = 67.7 fields of this size (1.52 to 3.04 million BOE) remaining to be discovered after 1960 in this depth interval. Of course, we do not discover a fraction of a field any more than we throw 1.5 heads in 3 tosses of a coin. The statistical expectation in 3 coin tosses, however, is 1.5 heads, just as the statistical expectation for class 10 fields is 126.7.

[5] For each value of C it is possible to use the pre-1961 discovery data and the model to forecast the 1961–1974 discoveries in each size class in a given depth interval. The criterion for selecting a value for C for a particular interval was that the total oil in the forecasted 1961–1974 discoveries be equal to the total oil in the actual 1961–74 discoveries. The value of C selected for a particular interval was then used to forecast the post-1974 discoveries in each size class for that depth interval.

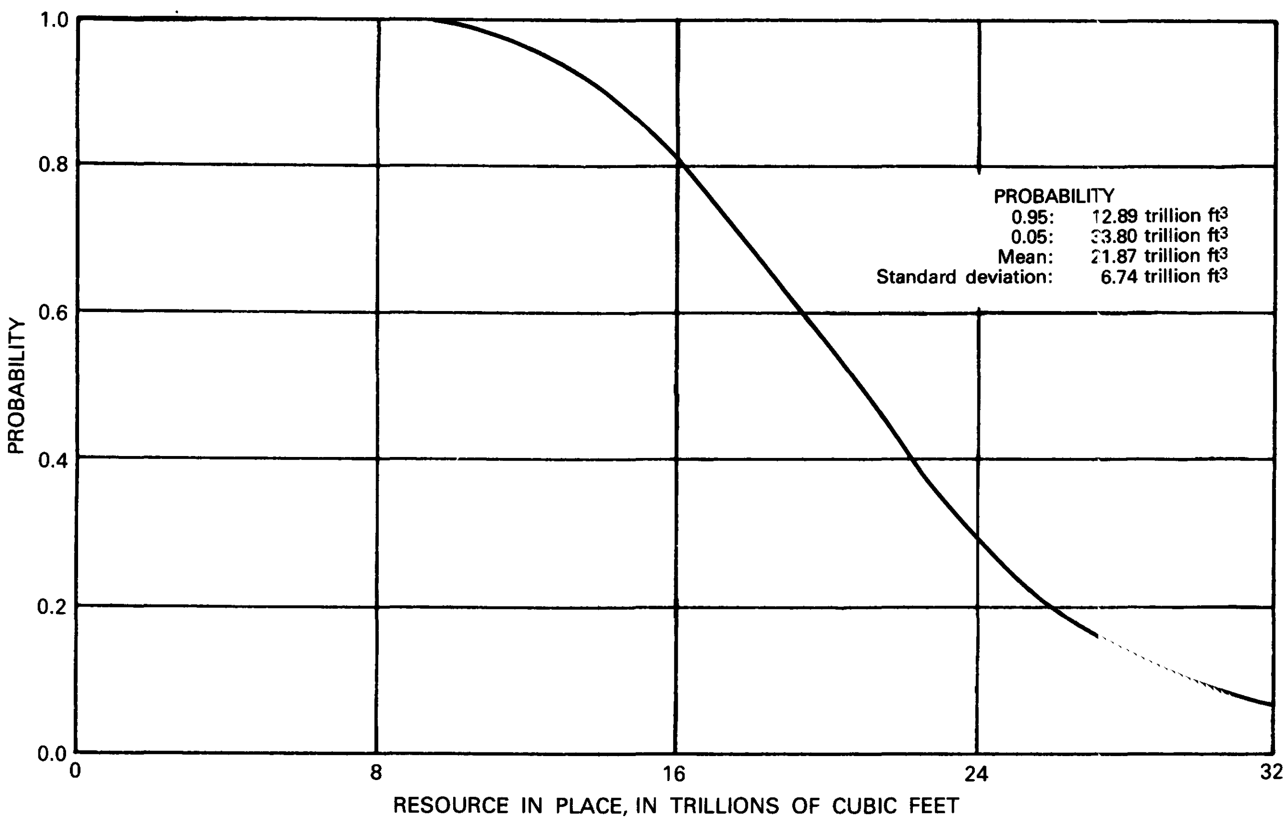

FIGURE 14.—Probability distribution of total Paleozoic undiscovered gas (dissolved, associated, nonassociated) in place, aggregated for depths of 0–30,000 feet. Pool sizes in trillions of cubic feet (ft^3).

TABLE 9.—*Comparison of the numbers of discoveries through 1974 with the number forecast, keyed on the pre-1961 discovery and exploratory drilling data in the 0–5,000-foot depth interval*

Size class	Area (square miles)	Discoveries		
		Actual	Estimated	Difference
1	0.13	211	200.1	10.9
2	.14	84	66.0	18.0
3	.16	84	84.7	- .7
4	.22	92	67.0	25.0
5	.25	127	109.6	17.4
6	.39	135	114.8	20.2
7	.49	129	125.3	3.7
8	.94	104	92.8	11.2
9	1.23	111	107.4	3.6
10	2.21	84	84.5	- .5
11	4.24	75	82.9	-7.9
12	5.40	49	52.2	-3.2
13	8.30	35	33.3	1.7
14	18.19	19	18.2	.8
15	40.42	14	14.0	.0
16	49.19	16	16.0	.0
17	67.20	9	9.0	.0
18	81.75	6	6.0	.0
19	129.88	2	2.0	.0
20	40.25	1	1.0	.0
Total		1,387	1,286.8	100.2

We can determine whether an estimate arrived at by means of this method is reasonable by making an historical forecast from 1960 to some subsequent year before 1979. The forecast can then be checked against the actual number of discoveries made in the field-size class from 1960 to that particular year. The forecast shown below projects discoveries for size-class 10. On the basis of 25,055 wells drilled in the 0–5,000-foot interval from the start of exploration through 1974,

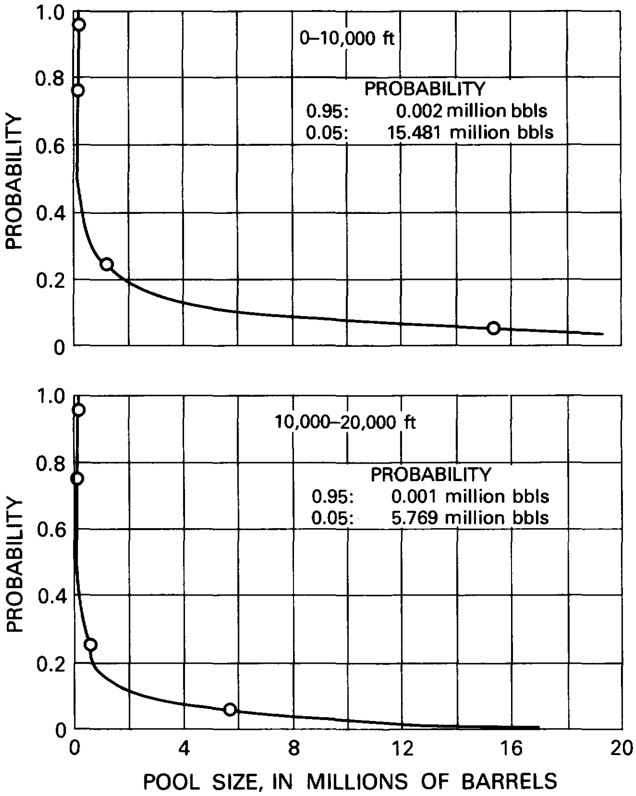

FIGURE 15.–Lognormal-probability size distribution of undiscovered Permian oil pools in depths of 0–10,000 and 10,000–20,000 feet.

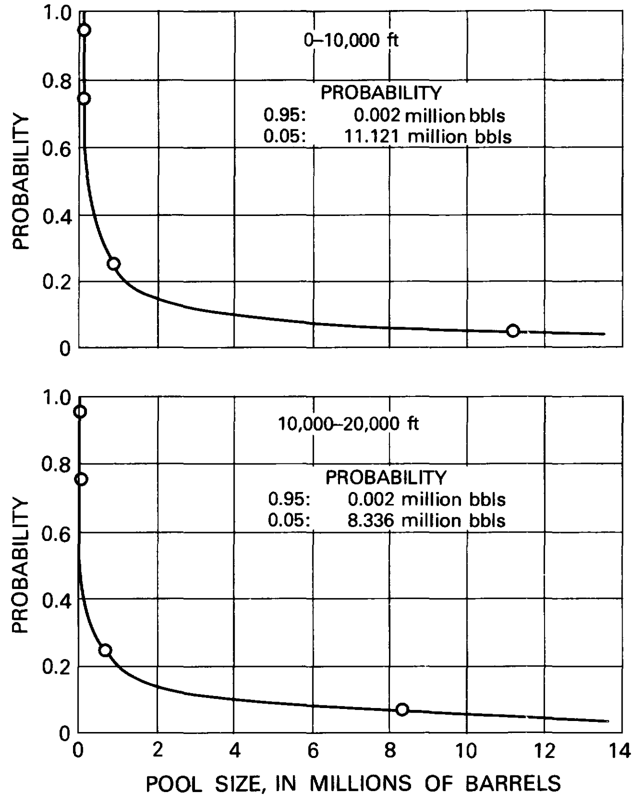

FIGURE 16.–Lognormal-probability size distribution of undiscovered Carboniferous oil pools in depths of 0–10,000 and 10,000–20,000 feet.

$$F_{10}(25055) = 126.7 * (1 - e^{-2.0 \cdot 2.2 \cdot 25055/100000})$$
$$= 84.5 \text{ deposits to be discovered by } 12/31/74$$

As 59 discoveries in this size class had been made by 1960, the model is forecasting an additional 84.5 – 59.0 = 25.5 fields in class 10 to be discovered between 1960 and 1974. In fact, 25 discoveries were made in the size class during the 15-year period, so the model produced a remarkably accurate forecast. The results of analogous calculations for other classes are presented in table 9. The level of accuracy varies among the field-size classes and also across the depth intervals. In general, however, acceptable agreement was found between the predicted and the acutal levels of discoveries.

The major differences between the actual and predicted number of discoveries in the 0–5,000-foot depth interval were found in six of the eight smallest size classes (table 9). In each of these six size classes, the model underpredicted the actual level of discovery. These underpredictions occurred because the rate of discovery in these small size classes accelerated during the 1961–74 time period in comparison with the pre-1961 rates of discovery. The consequence of these underpredictions is small, however, because most of the fields involved contain relatively small amounts of petroleum.

FORECASTING FUTURE RATES OF RECOVERY

Forecasts of the number of discoveries within each field-size class and depth interval were made for 20 increments of drilling, each consisting of 1,000 exploratory wells at the surface. Within each of these drilling increments, a portion of the wells on a net-well basis was applied against the expected size distribution of fields remaining to be discovered at the start of each drilling increment. The assignments of the net wells to be drilled in each drilling increment were taken from extrapolations of the historical trends in the net-well penetration in each depth interval versus the cumulative wells drilled at the surface through 1974. A mathematical function was fitted to each of these net-well curves and then extrapolated for

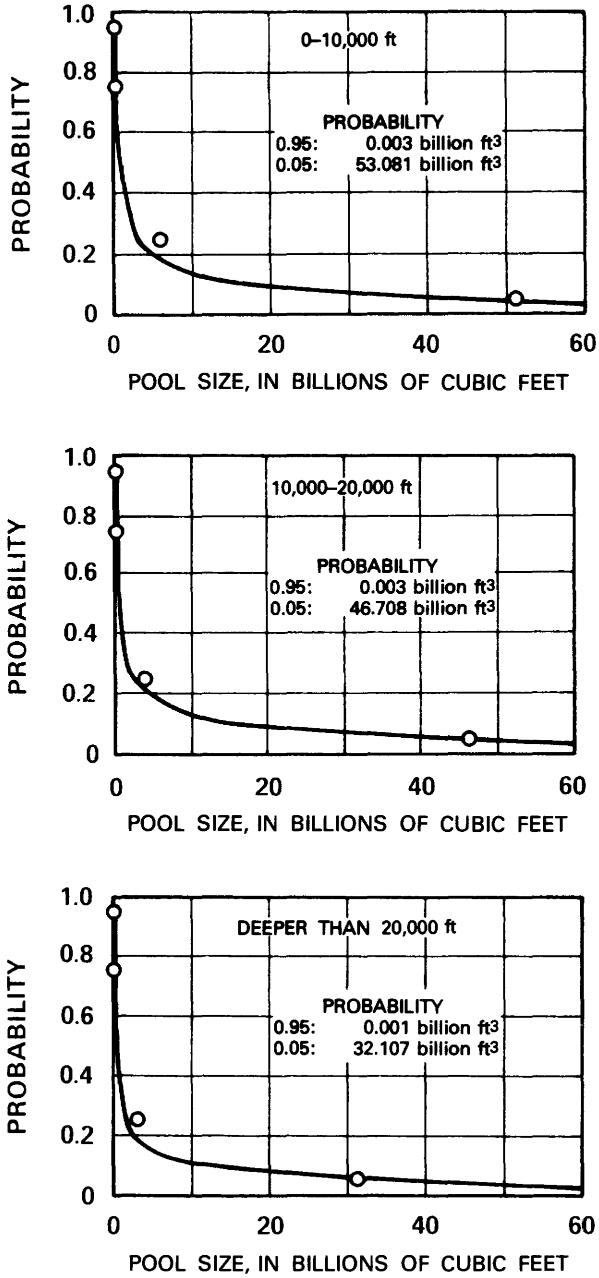

FIGURE 17.–Lognormal-probability size distribution of undiscovered nonassociated Carboniferous gas pools in depths of 0–10,000, 10,000–20,000, and deeper than 20,000 feet.

an additional 20,000 exploratory wells to be drilled in the future.

The number of deposits expected to be discovered within each field-size class for any future increment of exploratory drilling can be determined by aggregating the expected number of discoveries to be made within each depth interval. The first increment of 1,000 exploratory wells drilled at the surface results in 900 net wells in the 0–5,000-foot interval, 500 net wells in the 5,000–10,000-foot interval, 130 net wells in the 10,000–15,000-foot interval, and 35 net wells in the 15,000–20,000-foot interval. The expected size distribution of fields remaining to be discovered at the start of the first drilling increment within each of the four depth intervals is shown in tables 10 through 13.

The number of discoveries (150.9) forecast within the first 1,000-well increment is given in table 14. The largest discovery is predicted in class 17 (194.3 to 388.6 million BOE). This discovery (in expectation, 0.1 fields) is predicted to be in the 15,000–20,000-foot depth interval. With the exception of class 1, the largest number of discovered fields within a single field-size class is expected to occur with class 7 (0.19 to 0.38 million BOE), where a total of 16.7 discoveries are expected to be made within all four of the depth intervals.

Comparing the expected number of discoveries across the depth intervals reveals a trend in the forecast sizes of discoveries. In the shallowest, most highly explored depth interval, no discoveries are expected to be larger than field-size class 12 (6.07 to 12.14 million BOE); in the second and third depth intervals, discoveries are expected to be made to size class 15; and in the deepest interval, discoveries are expected in size classes 16 and 17 during the first drilling increment.

A similar table can be made for each of the increments of exploratory drilling. A comparison made across the successive drilling increments indicates that the total number of discoveries per increment is projected to decline gradually and that the larger discoveries are projected to become less frequent. Thus, both the success ratio and average size of the discoveries are projected to decline with each successive increment of exploratory drilling.

CONCLUSIONS

The discovery-process model predicts that a large number of oil and gas fields remains to be discovered–approximately 34,000 fields in the basin at depths shallower than 20,000 feet–but that most of these fields individually contain very small volumes of oil and gas, as the following tabulation shows:

Field size (millions of barrels of oil equivalent)	Number	Percentage of total remaining fields
48.6 and larger	6.6	0.02
12.14 to 48.6	20.7	0.06
1.52 to 12.14	681.6	2.00

TABLE 10.—*Expected ultimate number of fields remaining to be discovered after 1974 in the 0–5,000-foot depth interval*

Size class	Area (square miles)	Expected number of fields remaining	Number of fields found by 1974
1	0.13	4,106.1	211
2	.14	1,355.3	84
3	.16	1,006.3	84
4	.22	789.4	92
5	.25	951.6	127
6	.39	625.5	135
7	.49	463.5	129
8	.94	175.2	104
9	1.23	130.3	111
10	2.21	41.4	84
11	4.24	10.2	75
12	5.40	2.5	49
13	8.30	.1	35
14+	46.18	.0	67

TABLE 11.—*Expected ultimate number of fields remaining to be discovered after 1974 in the 5,000–10,000-foot depth interval*

Size class	Area (square miles)	Expected number of fields remaining	Number of fields found by 1974
1	0.12	5,462.9	215
2	.12	2,922.0	115
3	.13	2,856.8	122
4	.19	2,189.6	138
5	.20	2,468.0	164
6	.29	1,718.2	168
7	.42	1,382.6	200
8	.47	751.6	160
9	.76	570.5	158
10	1.28	245.4	125
11	2.21	94.6	98
12	3.76	26.6	76
13	5.40	5.9	50
14	10.86	1.5	47
15	20.30	.2	27
16+	72.14	.0	27

TABLE 12.—*Expected ultimate number of fields remaining to be discovered after 1974 in the 10,000–15,000-foot depth interval*

Size class	Area (square miles)	Expected number of fields remaining	Number of fields found by 1974
1	0.21	511.0	49
2	.22	307.9	31
3	.33	277.2	36
4	.25	400.7	56
5	.31	320.6	48
6	.37	302.7	53
7	.31	325.4	62
8	.43	249.1	54
9	.63	196.1	62
10	1.30	97.8	47
11	1.20	93.1	64
12	1.90	34.5	49
13	3.89	6.3	28
14	4.77	1.6	21
15	7.53	.3	18
16+	12.67	.0	9

TABLE 13.—*Expected ultimate number of fields remaining to be discovered after 1974 in the 15,000–20,000 foot depth interval* [1]

Size class	Area (square miles)	Expected number of fields remaining	Number of fields found by 1974
1	1.00	17.6	2
2	1.00	17.6	2
3	.00	.0	0
4	1.00	26.5	3
5	1.00	17.6	2
6	.78	35.3	4
7	1.00	17.6	2
8	.25	8.8	1
9	1.00	8.8	1
10	2.25	22.9	4
11	3.67	10.7	3
12	4.00	1.9	1
13	4.50	2.7	2
14	9.00	2.6	3
15	10.50	5.5	9
16	9.00	.3	1
17	21.00	.2	1
18	14.00	.1	1

[1] The USGS resource appraisal group estimated that no oil, and a mean value of 2.29 trillion cubic feet of gas in place, exists below 20,000 feet.

TABLE 14.—*Number of discoveries expected to be made in each size class with the first increment of 1,000 exploratory holes drilled in the Permian Basin after 1974*

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth	15,000–20,000-foot depth	Total
1	7.5	10.1	2.8	0.3	20.7
2	3.0	5.4	1.7	.3	10.4
3	2.9	5.7	2.0	.0	10.6
4	3.2	6.4	3.1	.4	13.1
5	4.3	7.6	2.6	.3	14.8
6	4.4	7.7	2.9	.5	15.5
7	4.1	8.9	3.4	.3	16.7
8	3.0	6.9	2.9	.1	12.9
9	2.9	6.6	3.2	.1	12.8
10	1.6	4.8	2.3	.5	9.2
11	.8	3.2	2.8	.4	7.2
12	.3	1.7	1.7	.1	3.8
13	.0	.6	.6	.2	1.4
14	.0	.2	.2	.3	.7
15	.0	.1	.1	.7	.9
16	.0	.0	.0	.0	.1
17+	.0	.0	.0	.1	.1
Total	38.0	75.9	32.3	4.7	150.9

The model, thus, predicts that 97.9 percent of the oil and gas fields remaining to be discovered in the Permian Basin individually contain less than 1.52 million BOE.

Furthermore, the model predicts that nearly all the expected fields remaining to be discovered that contain more than 48.6 million BOE each are expected to be in the 15,000–20,000-foot depth interval. In contrast, the 20.7 fields remaining to be discovered that individually contain between 12.14 and 48.6 million BOE are expected to occur in approximately equal numbers in the 5,000–10,000-foot, 10,000–15,000-foot, and 15,000–20,000-foot depth intervals. The bulk of the smaller oil and gas fields expected to remain in the basin are predicted by the model to be at depths shallower than 10,000 feet.

A prediction of the rate at which these oil and gas fields will be discovered in the future was made for 20 successive future 1,000-well increments of exploratory drilling. The predicted size distribution of discoveries to be made in each of these drilling increments forms one of the basic inputs into the economic analysis discussed in "Engineering and Cost Analysis for Future Fields", and "The Integrating Economic Model."

ENGINEERING AND COST ANALYSIS FOR FUTURE FIELDS

The costs of oil and gas reserves from undiscovered fields were estimated by an engineering and cost-analysis model. The model estimated the exploration, development, and production costs for the distribution of fields found per 1,000 exploratory wells drilled. The analysis depended on the predicted size and depth of undiscovered fields provided by the discovery process model discussed in "The Discovery-Process Model."

EXPLORATION COSTS

For each increment of 1,000 exploratory wells, we predicted the average depth by using a function estimated from historical data where average depth of exploratory wells was specified as a function of the cumulative number drilled since 1956 in the Permian Basin (see fig. 18).

To obtain the average cost for drilling and equipping future exploratory wells, we fitted a function of average costs versus average depth (see fig. 19) and used extrapolations of this function. Data used for estimating this function were published in the "Joint Association Survey of the U.S. Oil and Gas Producing Industry" (American Petroleum Institute, 1975). These costs were inflated to the appropriate 1977 values.

We obtained total exploration cost per exploratory well, exclusive of the land acquisition cost, by using a fitted function (see fig. 20) that specified total exploratory cost per well versus the cost of drilling and equipping exploratory wells, from 1966 through 1975 (American Petroleum Institute, 1967–78). For all results presented here, land acquisition costs were assumed to be zero.

FIELD DESIGN AND INVESTMENT COSTS

The discovery-process model categorized fields to be discovered by depth interval and BOE size class. Because of the differences involved in the economics of oil production and gas production, the fields discovered were separated into oil and gas fields. Ratios of oil fields to total fields were projected from a fitted function that specified the ratio as a function of depth interval and size class (see table 15).

Field Design. – For oil and gas fields, the number of required development wells was determined by dividing nominal field recovery by nominal

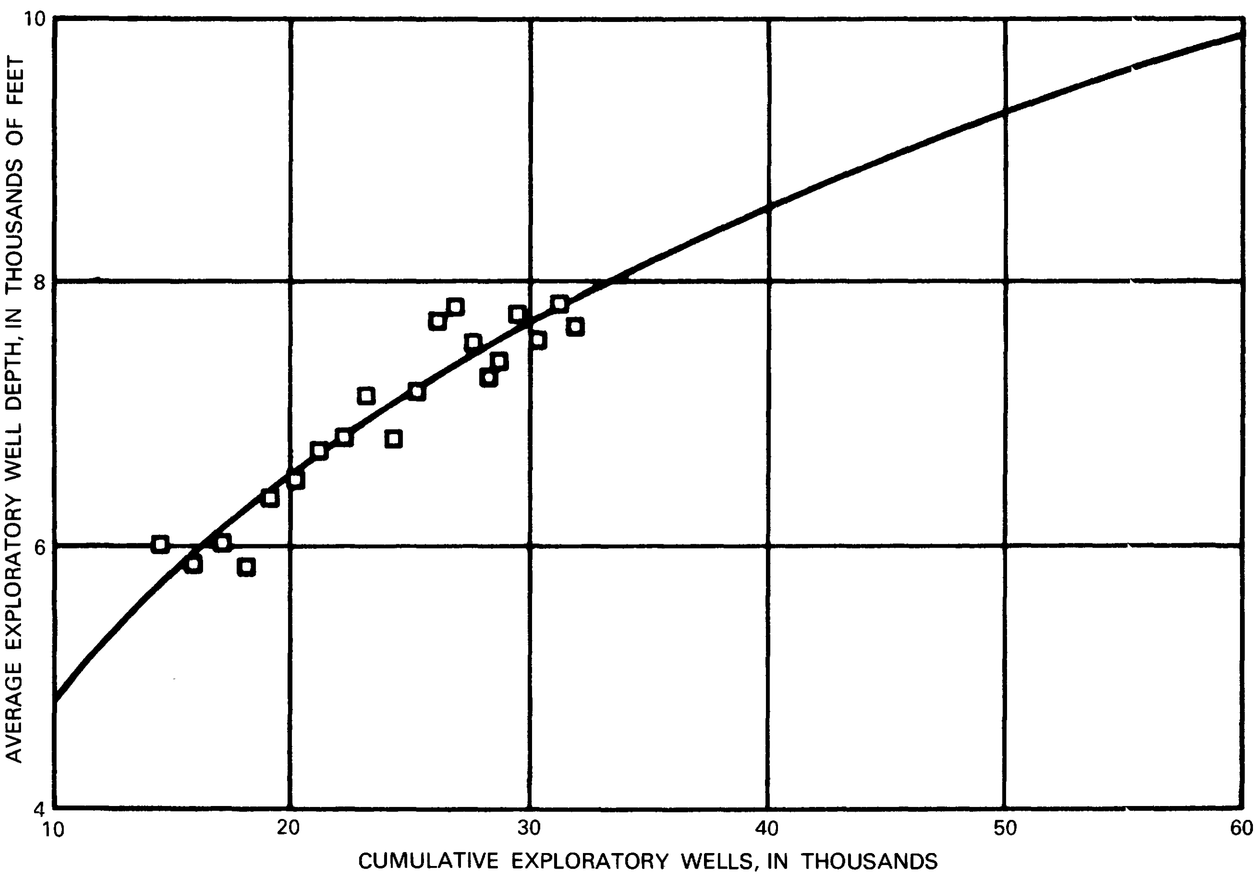

FIGURE 18. – Average depth of exploratory wells as a function of cumulative exploratory wells drilled in the Permian Basin.

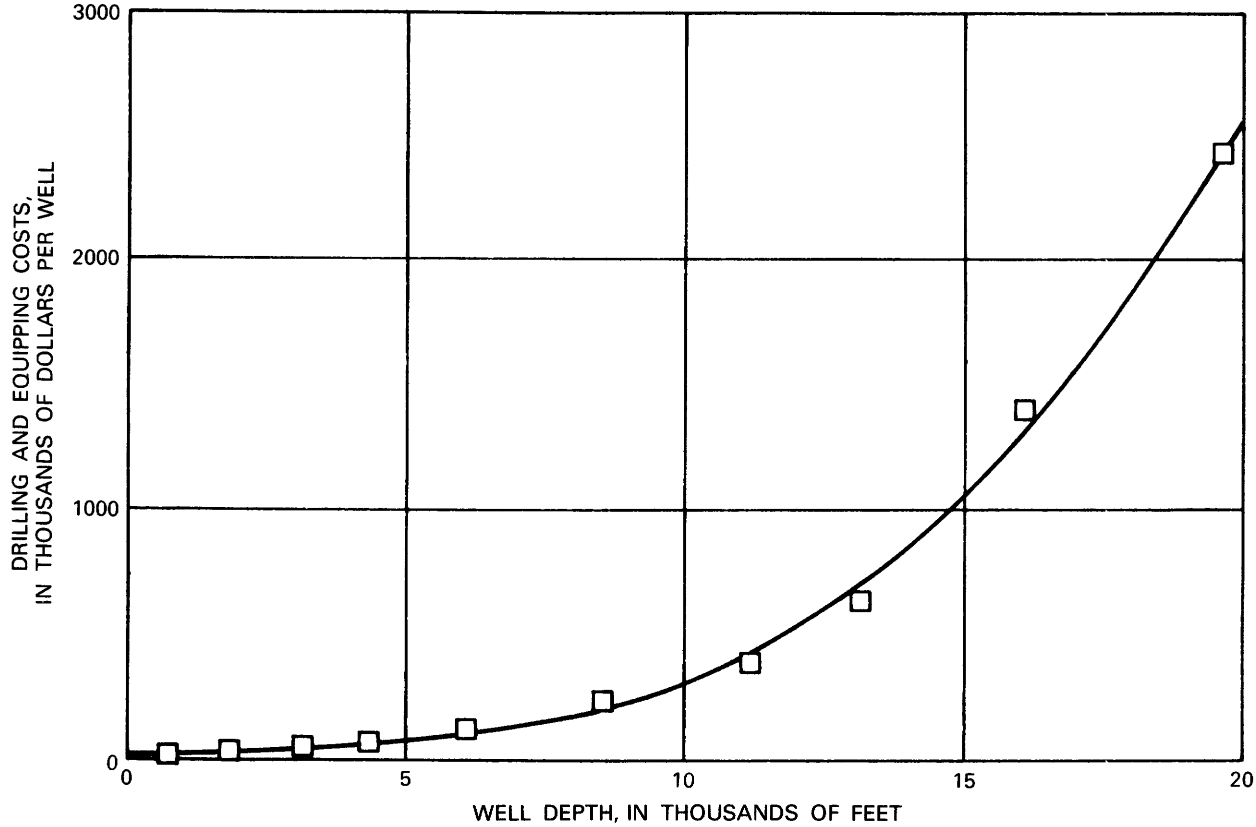

FIGURE 19.—Exploratory well drilling and equipping costs as a function of well depth in the Permian Basin in 1975 (1977 costs can be obtained by increasing by 18.9 percent).

TABLE 15.—*Ratio of oil fields to total fields in the Permian Basin*

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth
1	0.86	0.84	0.54
2	.78	.78	.51
3	.72	.73	.49
4	.68	.69	.47
5	.65	.67	.45
6	.65	.66	.43
7	.65	.66	.41
8	.67	.67	.40
9	.70	.69	.39
10	.73	.71	.37
11	.77	.73	.36
12	.81	.76	.36
13	.86	.79	.35
14	.90	.82	.35
15	.94	.85	.35
16	.97	.87	.34
17	1.0	.89	.35
18	1.0	.90	.35
19	1.0	.91	.35
20	1.0	.90	.36

reserves per well. We estimated the nominal values for fields under primary recovery only by extrapolating fitted curves (reserves versus size class), which we estimated by using historical values from those fields that have undergone primary production only. We used a similar procedure for determining reserves per producing

TABLE 16.—*Expected ultimate oil recovery per field in the Permian Basin*

[Million barrels]

Size class	0–5,000-foot depth	5,000–10,000 foot depth	10,000–15,000-foot depth
1	0.002	0.002	0.002
2	.007	.005	.005
3	.013	.011	.011
4	.027	.022	.021
5	.054	.044	.042
6	.108	.090	.084
7	.216	.181	.166
8	.433	.367	.330
9	.868	.741	.656
10	1.740	1.500	1.300
11	3.500	3.030	2.590
12	7.010	6.130	5.150
13	14.100	12.400	10.200
14	28.200	25.000	20.300
15	56.700	50.600	40.400
16	114.000	102.000	80.300
17	228.000	207.000	160.000
18	458.000	418.000	317.000
19	918.000	846.000	630.000
20	1,840.000	1,710.000	1,250.000

well and ultimate recovery for (1) oil fields susceptible to secondary recovery and (2) nonassociated gas fields. These basic data are presented in tables 16–22. For completeness, values were included for oil fields deeper than 15,000 feet where no historical oil fields existed. Ultimate oil recovery

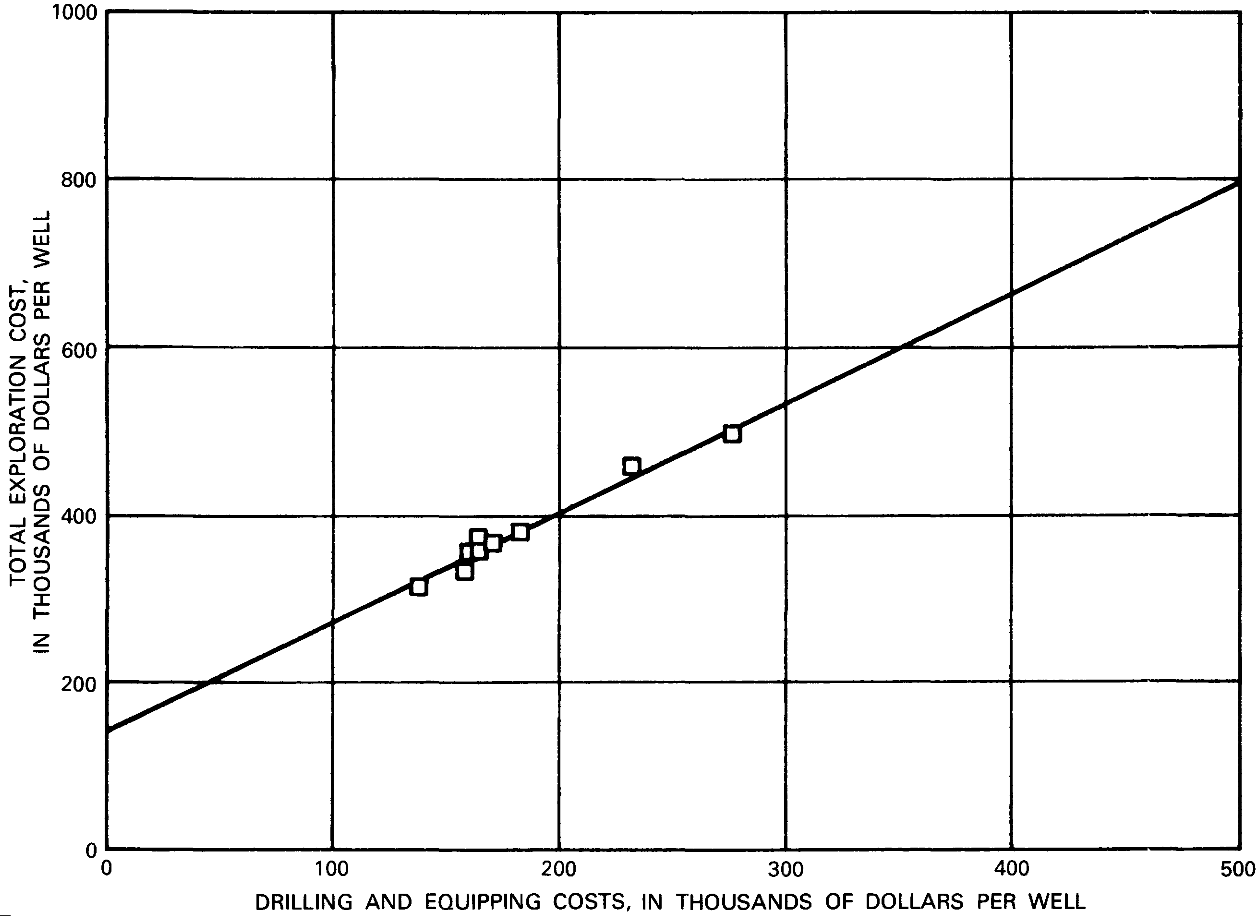

FIGURE 20. – Total exploration cost per exploratory well (minus cost of acquiring undeveloped acreage) as a function of drilling cost per well in 1977.

TABLE 17. – *Expected ultimate oil recovery per well from primary oil fields in the Permian Basin*

[Thousand barrels]

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth
1	1.490	1.930	2.160
2	4.280	4.070	4.170
3	7.580	8.670	9.590
4	11.800	15.900	18.900
5	17.300	25.900	32.400
6	24.500	39.000	50.700
7	33.800	55.100	74.100
8	45.700	74.600	103.000
9	53.300	82.900	136.000
10	54.900	118.000	198.000
11	68.900	132.000	261.000
12	95.600	140.000	333.000
13	135.000	154.000	419.000
14	188.000	189.000	526.000
15	254.000	258.000	662.000
16	334.000	374.000	834.000
17	428.000	550.000	1,050.000
18	536.000	802.000	1,310.000
19	658.000	1,140.000	1,630.000
20	794.000	1,580.000	2,010.000

per field and ultimate gas recovery per well were projected, and ultimate oil recovery per well was set equal to the same value as the 10,000–15,000-foot interval values.

TABLE 18. – *Expected ultimate associated-dissolved gas recovery per oil well from primary fields in the Permian Basin*

[Million cubic feet at 14.73 psia (pounds per square inch absolute) and 60° F]

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth
1	1.490	4.320	7.470
2	4.740	9.210	14.400
3	9.050	20.100	32.000
4	15.200	38.400	63.000
5	24.100	65.700	110.000
6	36.500	103.000	175.000
7	53.200	153.000	261.000
8	75.100	216.000	371.000
9	81.900	266.000	506.000
10	117.000	327.000	657.000
11	164.000	389.000	806.000
12	223.000	453.000	1.070.000
13	293.000	518.000	1.460.000
14	374.000	584.000	1.960.000
15	467.000	652.000	2,580.000
16	572.000	721.000	3 320.000
17	688.000	1,080.000	4.170.000
18	816.000	1,570.000	5 150.000
19	955.000	2,240.000	6 240.000
20	1,110.000	3,100.000	7,450.000

For technical reasons, secondary-recovery techniques are not applicable to some oil fields. A ratio of primary oil fields to total oil fields was derived for each size and depth class of oil field.

TABLE 19.—*Expected ultimate oil recovery per well from secondary and pressure maintenance fields in the Permian Basin*

[Thousand barrels]

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth
1	–	–	–
2	–	–	–
3	–	–	–
4	–	–	–
5	–	–	–
6	12.500	41.500	–
7	20.300	49.100	–
8	28.500	58.400	–
9	37.200	69.500	107.000
10	46.300	82.300	131.000
11	55.800	96.900	154.000
12	65.800	161.000	178.000
13	76.300	176.000	202.000
14	87.200	186.000	336.000
15	99.600	219.000	484.000
16	129.000	304.000	648.000
17	195.000	456.000	828.000
18	298.000	624.000	1,020.000
19	438.000	831.000	1,230.000
20	614.000	1,070.000	1,460.000

TABLE 20.—*Expected ultimate gas recovery per oil well from secondary and pressure maintenance fields in the Permian Basin*

[Million cubic feet at 14.73 psia (pounds per square inch absolute) and 60° F]

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth
1	–	–	–
2	–	–	–
3	–	–	–
4	–	–	–
5	–	–	–
6	12.000	93.500	–
7	23.400	111.000	–
8	34.900	136.000	–
9	46.300	168.000	348.000
10	57.800	208.000	464.000
11	69.200	254.000	580.000
12	80.600	374.000	695.000
13	92.100	400.000	811.000
14	104.000	420.000	1,360.000
15	122.000	452.000	1,910.000
16	145.000	514.000	2,470.000
17	185.000	622.000	3,020.000
18	242.000	796.000	3,580.000
19	315.000	1,050.000	4,100.000
20	405.000	1,410.000	4,680.000

TABLE 21.—*Expected ultimate nonassociated gas recovery per field in the Permian Basin*

[Million cubic feet at 14.73 psia (pounds per square inch absolute) and 60° F]

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth	Greater than 15,000-foot depth
1–4	86	102	95	102
5	366	347	334	286
6	704	720	756	839
7	1,364	1,412	1,412	1,269
8	2,670	2,991	2,836	3,234
9	5,544	5,418	5,130	5,562
10	11,206	11,368	10,773	10,989
11	20,760	21,690	20,560	26,528
12	47,355	48,735	46,554	43,860
13	95,245	85,407	86,184	96,964
14	185,319	186,912	180,455	160,376
15	361,284	390,010	400,842	359,114
16	714,015	554,960	713,600	852,826
17	1,490,688	1,452,192	1,278,025	1,935,413
18	2,889,936	2,634,969	2,645,554	3,341,724
19	6,140,000	6,140,000	6,140,000	6,140,000
20	12,300,000	12,300,000	12,300,000	12,300,000

TABLE 22.—*Expected ultimate nonassociated gas recovery per well in the Permian Basin*

[Million cubic feet at 14.73 psia (pounds per square inch absolute) and 60° F]

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15 000-foot depth	Greater than 15,000-foot depth
1–4	86	51	95	102
5	183	347	334	286
6	352	360	756	839
7	341	706	706	1,269
8	445	997	1,418	1,617
9	504	1,357	2,565	2,781
10	862	1,624	3,591	3,663
11	1,038	2,169	5,140	6,632
12	1,155	2,565	7,759	10,965
13	2,215	4,067	12,312	13,852
14	3,141	5,841	16,405	20,047
15	4,301	9,070	22,269	25,651
16	5,805	13,874	28,544	32,801
17	7,764	25,932	36,515	41,179
18	10,248	28,333	45,613	49,143
19	10,248	28,333	45,613	49,143
20	10,248	28,333	45,613	49,143

This ratio was used to apportion oil fields to be discovered into: (1) fields susceptible to primary recovery alone, and (2) fields susceptible to both primary and secondary recovery. These ratios are presented in table 23.

TABLE 23.—*Ratio of primary oil fields to total oil fields in the Permian Basin*

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth
1	1.000	1.000	1.000
2	1.000	1.000	1.000
3	1.000	1.000	1.000
4	1.000	1.000	1.000
5	1.000	1.000	1.000
6	.984	.986	1.000
7	.958	.983	1.000
8	.891	.972	1.000
9	.781	.940	.981
10	.636	.881	.962
11	.474	.792	.938
12	.318	.679	.895
13	.188	.554	.818
14	.097	.429	.693
15	.048	.315	.515
16	.030	.213	.307
17	.025	.119	.116
18	.013	.032	.001
19	.000	.000	.000
20	.000	.000	.000

Depth intervals were: (1) 0–5,000 feet, (2) 5,000–10,000 feet, (3) 10,000–15,000 feet, and (4) greater than 15,000 feet. Average depths (based on historical data) for oil fields corresponding to each interval were: (1) 3,400, (2) 7,200, (3) 11,400, and (4) 16,000 feet (no historical fields). The average depths for nonassociated gas fields were: (1) 3,400, (2) 7,200, (3) 12,200, and (4) 17,700 feet.

For those fields susceptible to secondary-recovery methods, the design and assumptions of the recovery program depended on the field's depth interval.

(1) In the 0–5,000-foot interval, the primary producing wells were assumed to constitute 70 percent of all the wells that produced oil. In the secondary-recovery program, the remaining 30 percent of the producing wells were drilled, and a sufficient number of primary producing wells were converted to injection wells so that there was one injection well for each producing well.

(2) For the interval between 5,000 and 10,000 feet, the number of newly drilled injection wells is given by the relationship:

$$WNI = ((PH)^{1/2} - 1)^2$$

where WNI is the number of newly drilled injection wells and PH is the number of primary producing wells. This relationship provides the number of wells needed to infill drill the centers of a square array of wells that produced during the primary stage. The number of primary producers that must be converted to injection wells is such that there is a one-to-one ratio of producing to injection wells during secondary recovery.

(3) In the two intervals deeper than 10,000 feet, it is assumed that a pressure maintenance program was carried out from the initial stage of development. For each set of four primary producing wells, an injection well was drilled.

Investment Costs.—We estimated drilling and equipping costs for production wells, and dry-hole costs, using data taken from the "Joint Association Survey of the U.S. Oil and Gas Producing Industry" (American Petroleum Institute, 1975). Drilling costs were inflated to attain mid-1977 cost levels. The drilling and equipping costs were expressed as a fitted function of depth. Figures 21 and 22 present the estimated functions.

Costs of dry development wells for all fields were included by increasing costs of each producing well by 19 percent of the cost of a dry hole. Using the U.S. data from 1971 through 1975, we found that the ratio of dry to successful development wells did not depend strongly on depth; therefore, the average ratio for all depths was used.

Cost estimates for field lease equipment were based on data from Dietzman, Pierce, Funk, and Anderson (1978). Costs of oil-field lease equipment were expressed as a function of well depth (see fig. 23). The cost curve shown in figure 23 is derived from a combination of rod-pumped operations to a maximum of 8,000 feet, and hydraulically pumped operations from 8,000 to 12,000 feet. Costs of nonassociated gas-field equipment were expressed as a function of well depth and field size (see table 24).

PRODUCTION SCHEDULES AND PRODUCTION COSTS

Production Schedules.—Size classes for all fields were based on a BOE scale. The classes ranged from the smallest at 0 to 5,930 BOE to the largest at 1,554.5 million to 3,109.0 million BOE. The upper limit of each class is double the upper limit of the next smaller class. The nominal field size estimated for each class base is based upon averages of known fields, as mentioned earlier.

For each oil field, the primary production schedule for representative producing oil wells was prepared by using representative exponential oil well decline rates (see table 25) and a calculated initial producing rate (depending upon the oil recovery per well) limited by the Texas allowable yardstick. Three examples of primary oil-

TABLE 24.—*Cost of lease equipment per nonassociated gas development well in the Permian Basin in 1977 dollars*

[Surface producing equipment from wellhead to flange on meter run]

Size class	Ultimate recoverable range (thousand cubic feet)	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth	Greater than 15,000-foot depth
1–4	0 to 0.25	$13,000	$14,000	$16,000	$16,000
5	0.25 to 0.5	13,000	14,000	16,000	16,000
6	.5 to 1	13,000	14,000	16,000	16,000
7	1 to 2	13,000	14,000	16,000	16,000
8	2 to 4	13,000	14,000	16,000	16,000
9	4 to 8	13,000	14,000	16,000	16,000
10	8 to 16	13,000	14,000	23,500	23,500
11	16 to 32	13,000	14,000	23,500	23,500
12	32 to 64	13,000	14,000	23,500	23,500
13	64 to 128	13,000	21,500	23,500	23,500
14	128 to 256	13,000	21,500	23,500	24,500
15	256 to 512	13,000	21,500	24,500	24,500
16	512 to 1,024	13,000	21,500	30,500	30,500
17	1,024 to 2,048	13,000	27,000	43,500	43,500
18	2,048 to 4,096	20,500	27,000	45,000	45,000
19	4,096 to 8,192	20,500	27,000	45,000	45,000
20	8,192 to 16,380	20,500	27,000	45,000	45,000

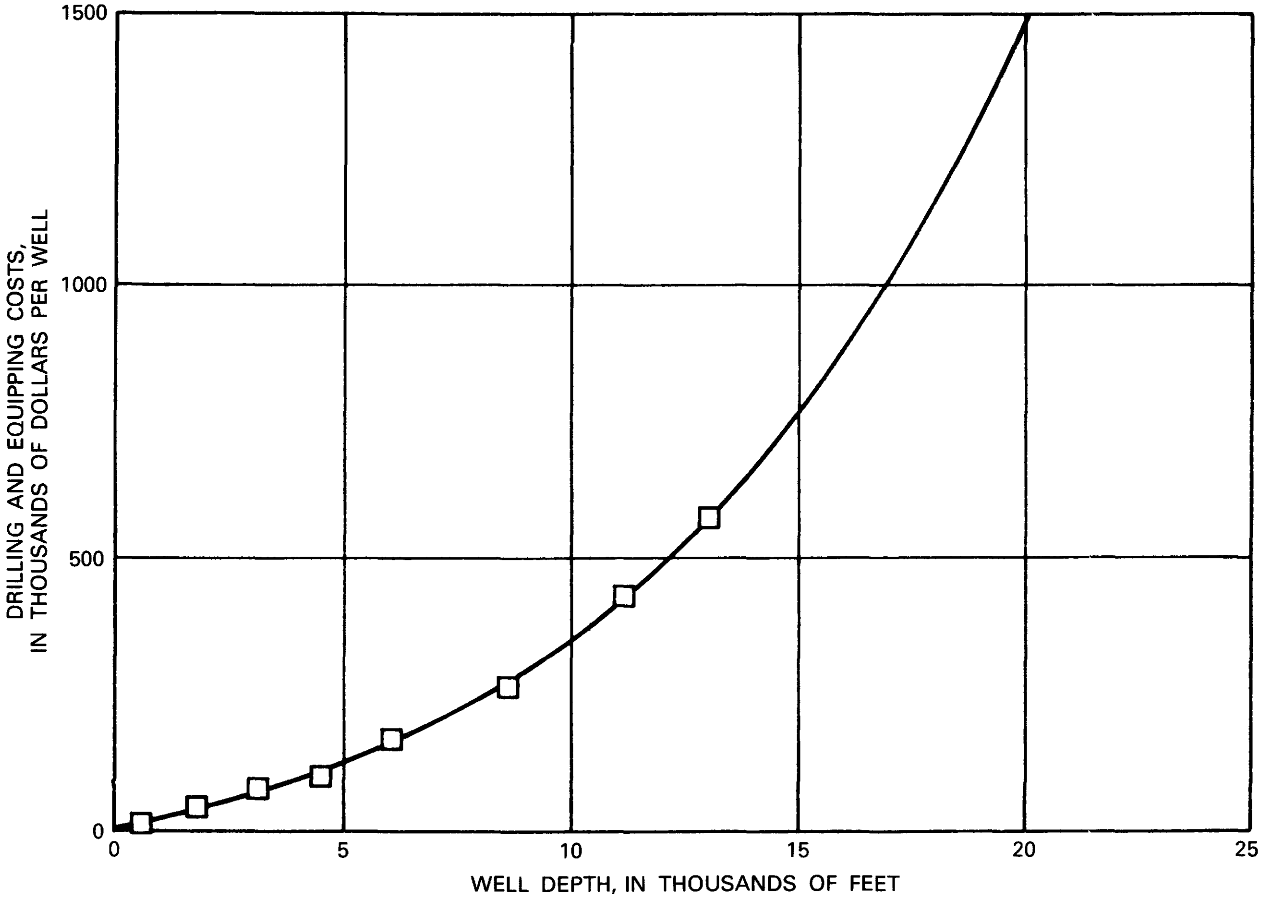

FIGURE 21.–Drilling and equipping cost per development well versus depth in the Permian Basin in 1975 (1977 costs can be obtained by increasing by 18.9 percent).

production schedules are shown in figure 24. For oil fields undergoing secondary recovery, we calculated the well-production schedule during the secondary-recovery phase by using a percentage of remaining ultimate well recovery each year, on the basis of a nominal 10-year waterflood life.

TABLE 25.–*Exponential oil-well decline rates per year in the Permian Basin*

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth
1	1.50	1.50	1.50
2	1.00	1.10	1.10
3	.90	1.00	1.00
4	.35	.51	.61
5	.29	.38	.40
6	.24	.34	.35
7	.22	.32	.35
8	.22	.32	.29
9	.22	.32	.29
10	.22	.24	.29
11	.22	.24	.29
12	.20	.21	.20
13	.20	.21	.20
14	.20	.21	.20
15	.20	.20	.20
16	.20	.20	.20
17	.20	.20	.20
18	.20	.20	.20
19	.20	.20	.20
20	.20	.20	.20

Production streams for associated/dissolved gas from all oil fields were based on the percent of cumulative oil production to the percent of cumulative gas production, a relationship that was derived from an engineering material balance approximating a depletion drive reservoir (see fig. 25).

Production schedules for nonassociated gas wells were assumed to initially show constant production based on a daily contract quantity of 1 million standard cubic feet per 3 billion cubic feet of nominal reserves per well. The period of constant production was based upon the calculated deliverability characteristics for a well of a field of a given size and depth class (Hicks, 1978). An exponential decline was used to describe production after the production decline began (see fig. 26).

Production Costs.–For oil wells and for nonassociated gas wells, direct operating costs were expressed as a function of both depth and output. Basic cost data were taken from Dietzman and others (1978) and inflated by 14 percent (see fig. 27 and 28 and table 26).

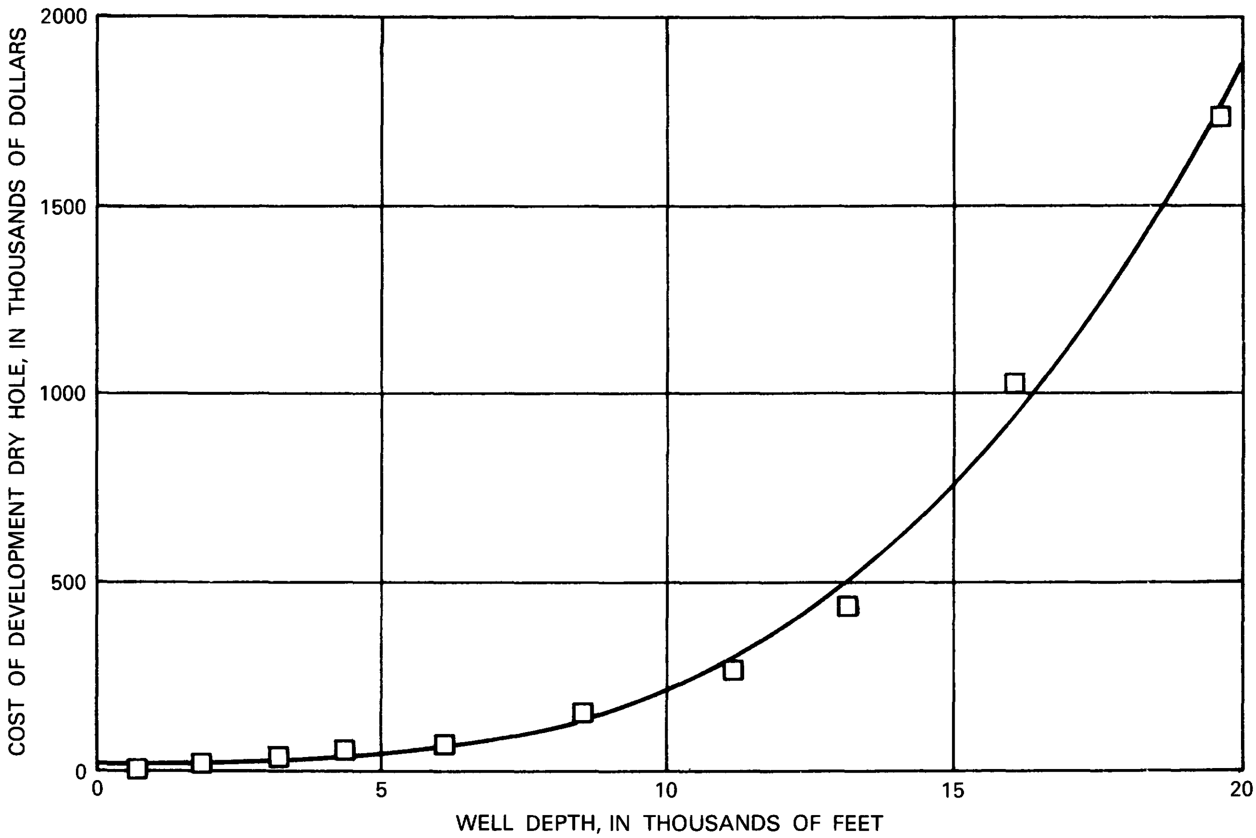

FIGURE 22.—Cost of development of dry hole versus depth in the Permian Basin in 1975 (1977 costs can be obtained by increasing by 18.9 percent).

TABLE 26.—*Annual direct operating expenses for nonassociated gas wells in the Permian Basin in 1977 dollars*

Size class	0–5,000-foot depth	5,000–10,000-foot depth	10,000–15,000-foot depth	More than 15,000-foot depth
1-4	$3,600	$4,200	$5,800	$8,800
5	3,600	4,300	5,900	8,800
6	3,600	4,300	5,900	8,900
7	3,600	4,300	5,900	8,900
8	3,600	4,300	6,000	8,900
9	3,600	4,300	6,100	9,000
10	3,600	4,400	6,200	9,100
11	3,700	4,400	6,300	9,400
12	3,700	4,500	6,600	9,800
13	3,800	4,600	7,000	10,100
14	3,800	4,800	7,400	10,700
15	4,000	5,100	8,000	11,300
16	4,100	5,500	8,600	12,000
17	4,300	6,800	9,500	13,000
18	4,500	7,000	10,500	13,800
19	4,500	7,000	10,500	13,800
20	4,500	7,000	10,500	13,800

Indirect operating expenses include general and administrative overhead costs and certain property taxes. These costs are expressed on a per unit output basis and were set as $0.229 per barrel of oil and $0.0435 per 1,000 cubic feet of gas.

We calculated recovery per well for each price and return by accumulating annual production and assuming that production stops when the economic limit rate is reached. The economic limit is reached when the sum of operating costs and production-related taxes exceeds the operator's revenue.

ASSUMPTIONS FOR PRESENT VALUE CALCULATIONS

The following assumptions were used in the calculations of present values:

(1) A 5-year limit on the carryover of losses for income tax purposes.
(2) Operators' working interest was 87.5 percent.
(3) State, county, and school property taxes and wellhead severance taxes are rolled into a royalty type tax of 6.4 percent of gross income for oil and 9.3 percent of gross income for gas.
(4) Federal income tax rate was 48 percent.
(5) Depreciation method was unit of production method.

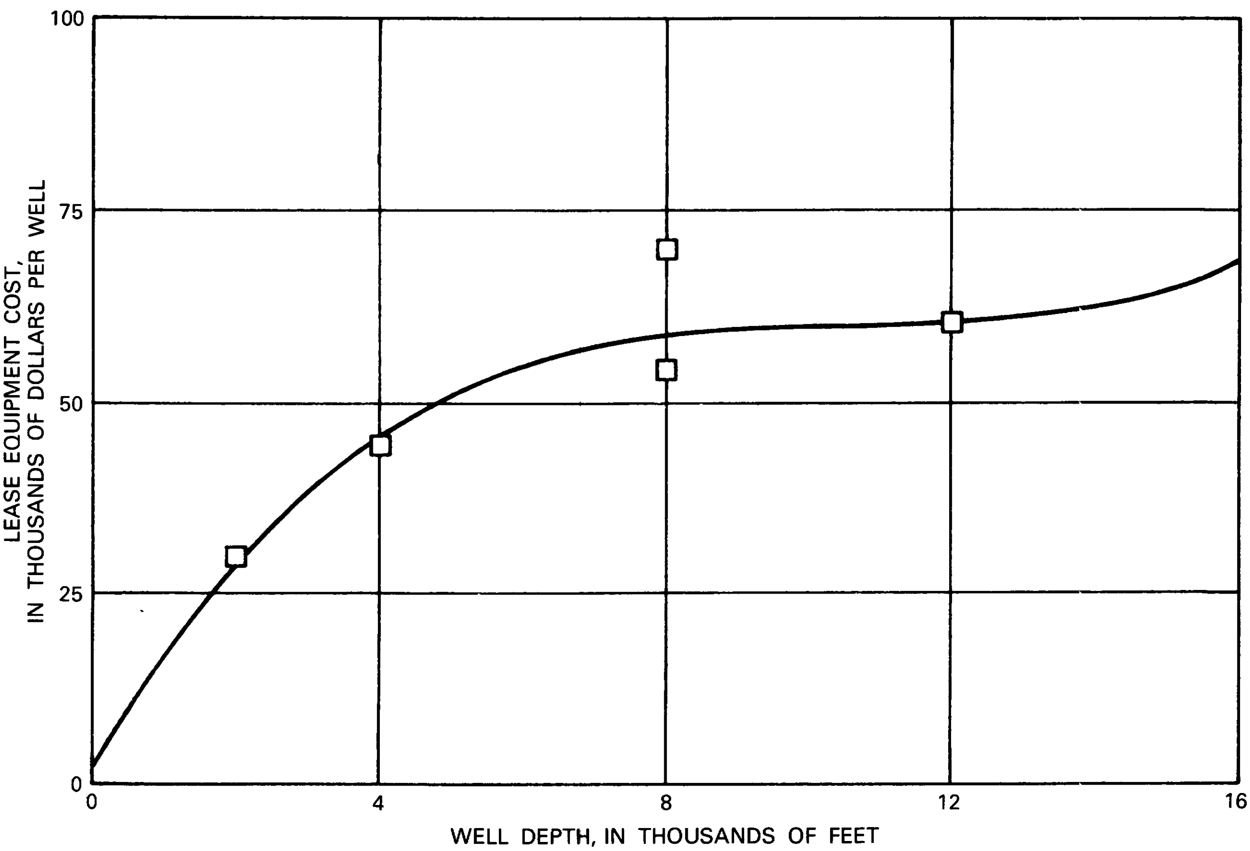

FIGURE 23.—Lease equipment cost per well versus depth for primary oil production in the Permian Basin in 1976 (1977 costs can be obtained by increasing by 9.0 percent).

(6) Cost depletion was applied when determining taxable income.
(7) Costs were based on mid-1977 prices, and the entire analysis assumed constant 1977 dollars.
(8) 70 percent of drilling costs for successful development wells along with dry-hole costs were expensed, and the remaining field-development costs were capitalized.
(9) Natural-gas prices were tied to the price of oil on a Btu basis.

ESTIMATED MARGINAL COST FUNCTIONS FOR UNDISCOVERED RECOVERABLE OIL AND GAS RESOURCES IN THE PERMIAN BASIN

Economic analysis of the exploration process begins with the relationship between incremental units of exploration effort and the number and size of fields discovered as a consequence of these units of effort.

The portion of the resource base that is physically discoverable is restricted by the state-of-the-art of exploration technology. That portion always represents less than 100 percent of the undiscovered fields that may actually exist. Within this "effective upper limit" of a region's discoverable oil and gas, we expect the amounts found per unit effort to decrease as cumulative exploration increases. However, a technical breakthrough in exploration can change the upper limit of what is discoverable and can increase the amounts discovered per unit of effort.

Given a discovery, the analysis shifts to the function that describes physical relationships involved in the recovery of in-place resources. Again the

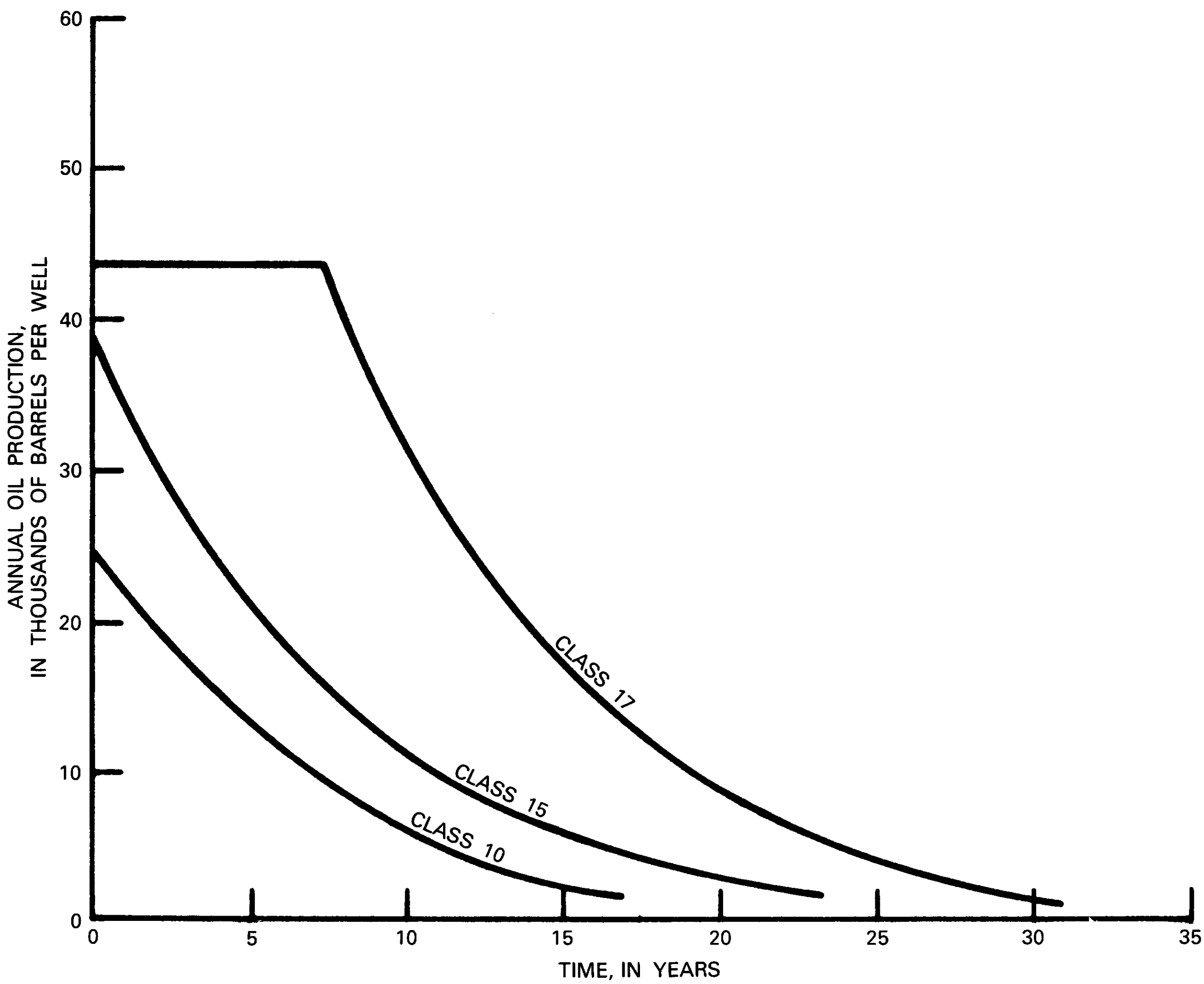

FIGURE 24.—Oil-production-decline curves for primary recovery at 7,200 feet in the Permian Basin.

state-of-the-art in production technology places an upper limit on the portion of oil and gas that can be physically recovered and produced. Even when the analysis includes future tertiary-recovery technology, less than 100 percent of the oil and gas in place is recovered.

In "Permian Basin Undiscovered Resources Appraisal," we discussed in detail subjective appraisals of the undiscovered oil and gas in place in the Permian Basin. In "The Discovery-Process Model," we described exploration and provided direct estimates of the number of fields that might be discovered with incremental units of exploratory effort. Estimates of what is recoverable from these future "discoveries" were then determined by using the field-development information, production-decline curves, and cost data described in "Engineering and Cost Analysis for Future Fields."

The Permian Basin resource estimates and the discovery-process model were prepared by separate task groups working concurrently, rather than sequentially. As a consequence, work remains to be done in integrating more fully the subjective resource estimates and the historic discovery data projected by the discovery-process model.

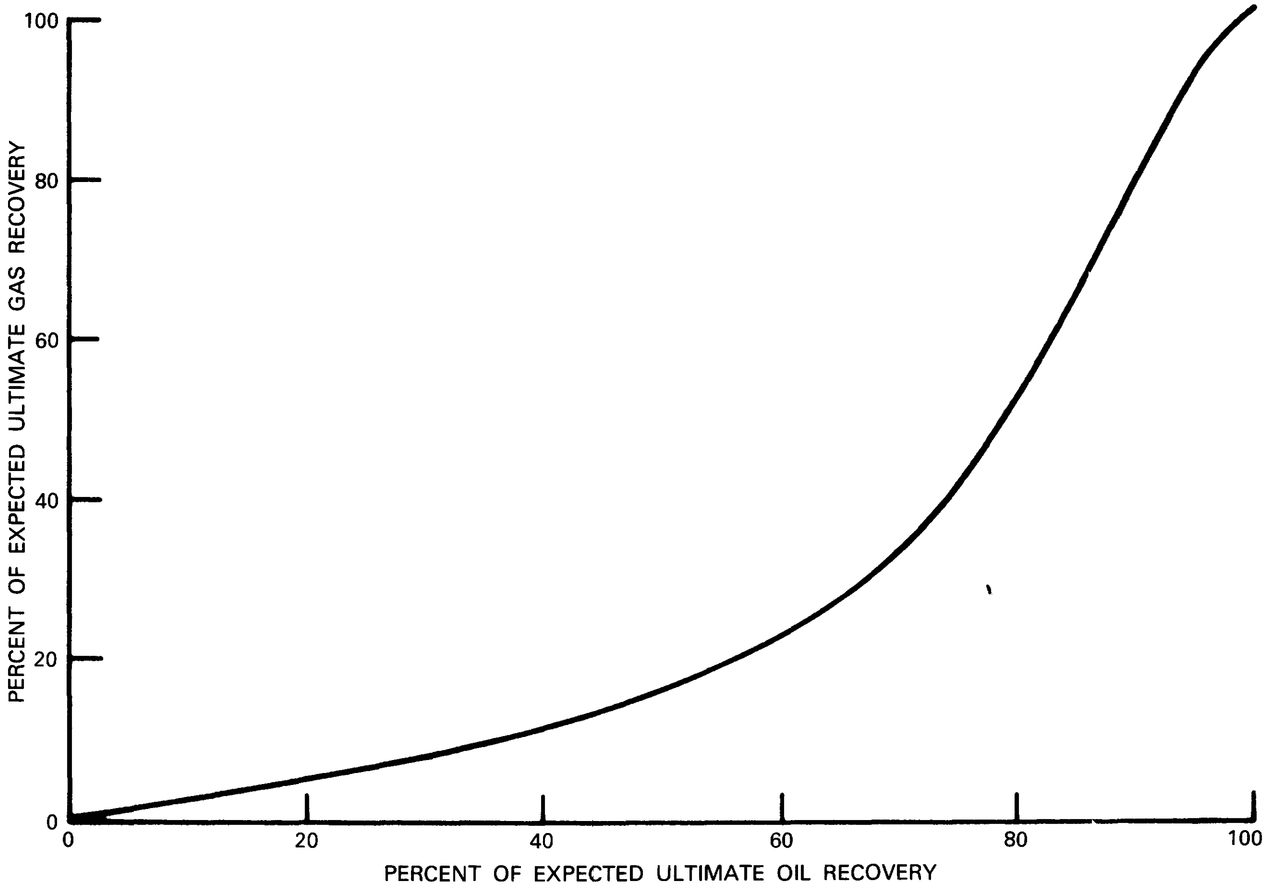

FIGURE 25.—Percent of expected ultimate gas recovery as a function of percent of expected ultimate oil recovery in the Permian Basin.

METHODOLOGY

This section is concerned with estimates of marginal cost functions for undiscovered recoverable oil and gas resources in the Permian Basin. We constructed the marginal cost curves by using the methods described in "The Discovery-Process Model" and "Engineering and Cost Analysis for Future Fields" and considering a return on investment and market prices of oil and gas.

The return and price considerations assume that incremental units of exploration, development, and production effort will not take place unless the expected revenues received for eventual production sufficiently cover the incremental costs, including a normal rate of return on investment. The costs per barrel of oil or per 1,000 cubic feet of gas discovered, developed, and produced in the Permian Basin increase as additional units of effort increase. The marginal cost functions presented here show how much of the theoretically discoverable oil and gas, identified in "Permian Basin Undiscovered Resource Appraisal" and "The Discovery-Process Model," would be classified as recoverable at alternative prices and rates of return.

The output of the discovery-process model for a given increment of exploration is a frequency distribution of the expected number of fields found for a particular size and depth category, where the size is expressed in BOE. To estimate the marginal costs of finding and developing these undiscovered fields, the fields must be categorized as:

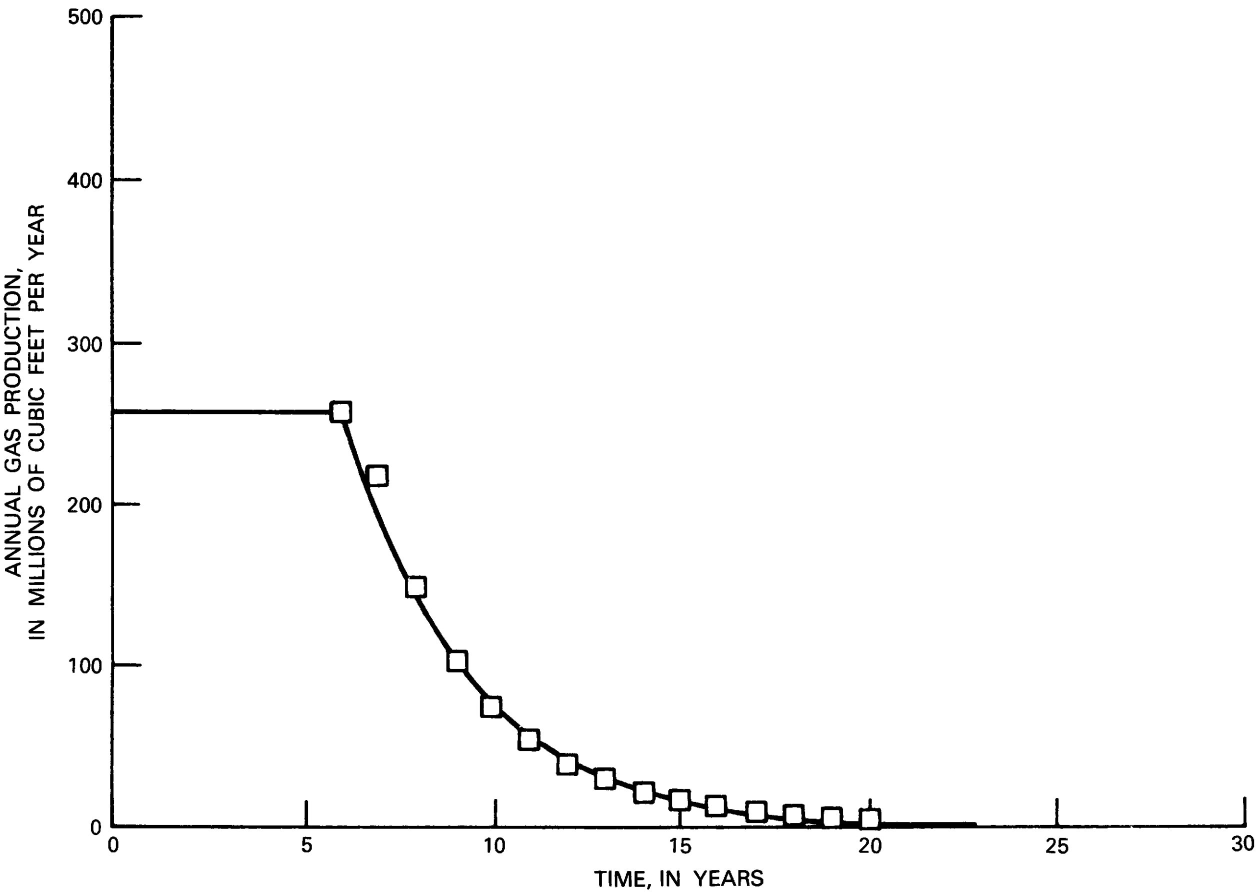

FIGURE 26.—Nonassociated gas-well-production curve for a class–13 field in the depth bracket of 0–5,000 feet in the Permian Basin.

(1) crude oil and associated-dissolved gas and (2) nonassociated gas. The deposits in the "crude oil and associated-dissolved gas" category are then classified as: (1) technically susceptible to primary-recovery techniques alone, and (2) susceptible to both primary and secondary techniques. These categories are necessary for a more accurate identification of the appropriate production processes and their related costs.

The economic analysis of the deposit is a standard application of discounted cash flows (DCF). The net after-tax cash flow for a representative producing well is calculated and then discounted at various rates of return. The cash flows are obtained by subtracting operating costs, capital costs, and taxes from product revenues. If the calculations indicate that the DCF at an assumed price level and rate of return is negative, that deposit is considered uneconomic and will not be produced.

The model can be applied in a straightforward manner to determine which deposits will be produced after discovery and how much oil and gas will be recovered under specific price and cost conditions. Determining how many additional exploratory wells will be drilled is more difficult. The dynamics of the exploration process are not well understood, and probably no model can simulate actual practice realistically. However, it is possible to assume classical economic behavior under conditions of perfect knowledge. Then, the number of exploratory wells drilled can be determined on the basis of the present value of future exploration cost being equivalent to the present value of develop-

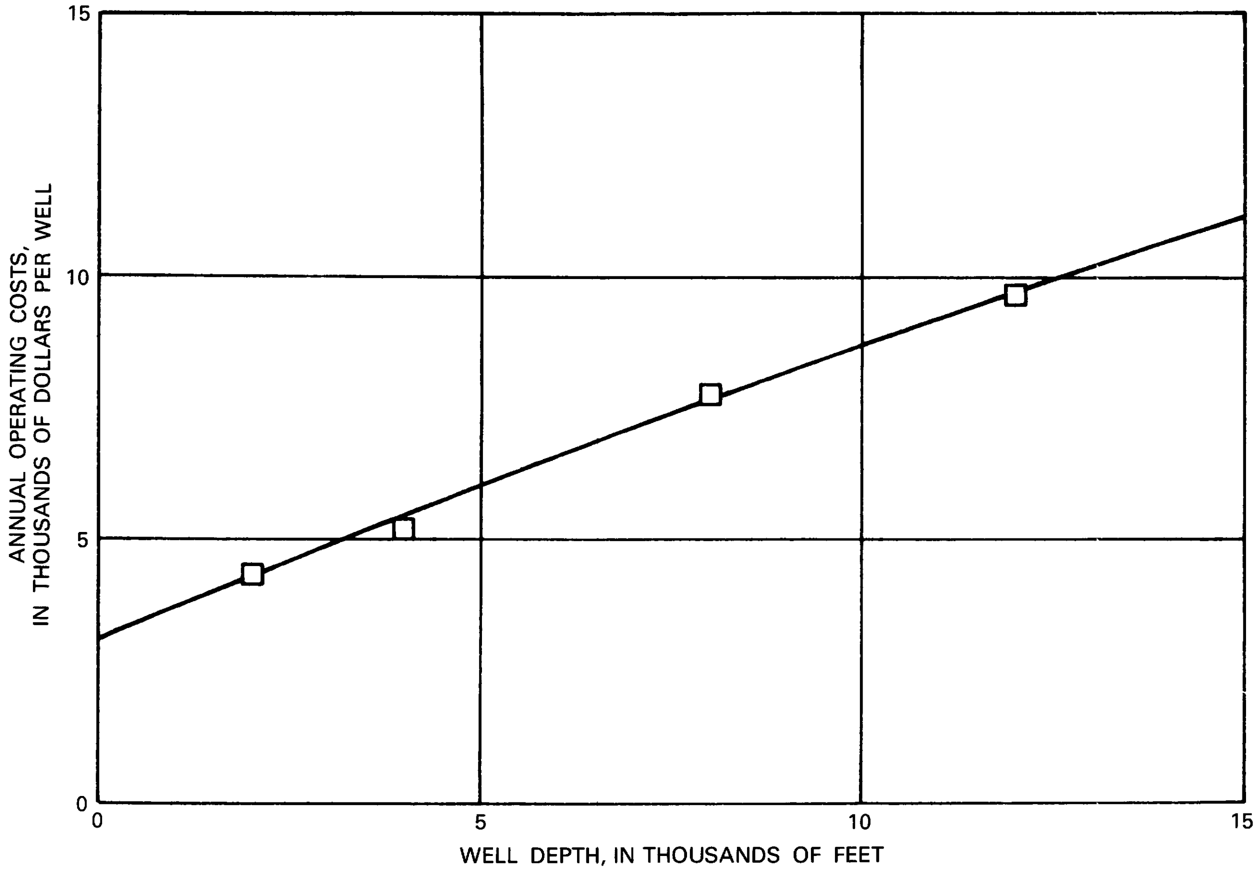

FIGURE 27.—Annual direct operating cost per producing oil well versus depth for primary recovery in the Permian Basin in 1976 (1977 costs can be obtained by increasing by 14 percent).

ment (exclusive of exploration cost). In other words, the positive surplus of present value obtained through developing the various fields must eventually provide a cash flow adequate to pay for the number of exploratory wells drilled. Recognizing the narrowness of these assumptions, the study group estimated the number of exploratory wells that could be drilled (in increments of 1,000 wells) until the incremental cost of drilling exploratory wells was equal to or greater than the present value of the developed deposits discovered by the last 1,000 exploratory-well increment. This point varied with the price and rate of return assumed.

SUMMARY OF RESULTS

Table 27 provides estimates of the oil and gas resources that could be found and produced from the Permian Basin as a function of price, finding cost, and production cost. The prices, rates of return, and number of exploratory wells that would be justified under the assumptions made are indicated. If the price is assumed to be $40 per BOE, the economically recoverable oil equivalent attains a maximum of 4.7 billion BOE at a 5 percent rate of return, 4.3 billion BOE at a 15 percent rate of return, and 3.9 billion BOE at a 25 percent rate of return. These quantities can be compared with the 38.2 billion BOE already discovered in the Permian Basin by the end of 1974.

Between 30,000 (at 25 percent rate of return) and 48,000 (at 5 percent rate of return) exploratory wells were estimated to be economically viable at the $40 price level. Figure 29 shows how the exploratory effort varies as price and rate of return

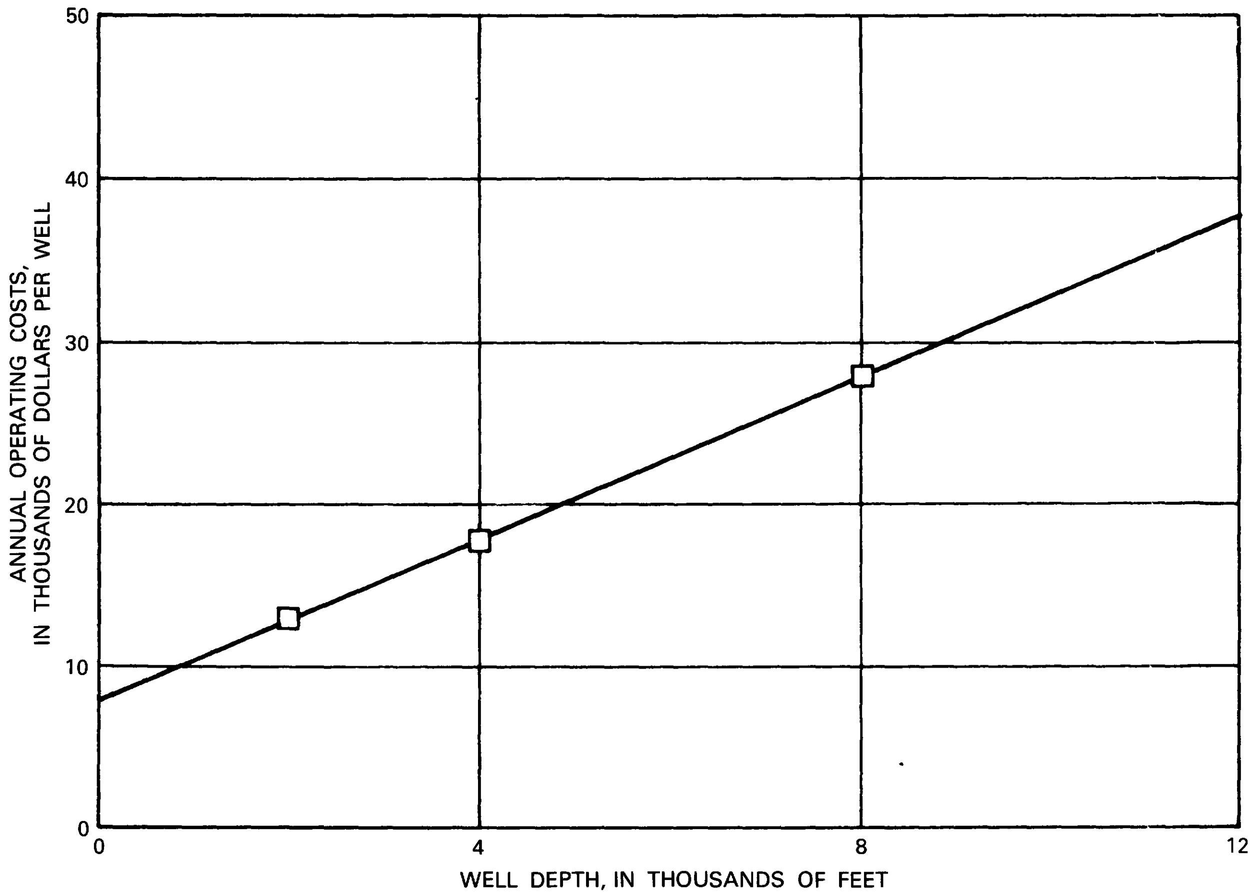

FIGURE 28. – Annual direct operating cost per producing oil well versus depth for secondary recovery in the Permian Basin in 1976 (1977 costs can be obtained by increasing by 14 percent).

vary. This can be compared with the slightly more than 30,000 exploratory wells which were drilled in the Permian Basin through December 31, 1974, in which approximately 10 times more BOE were discovered than the BOE projected for the next 30,000–48,000 wells.

At $15 a barrel and a 15 percent rate of return, only 12,000 exploratory wells would be drilled and 2.3 billion BOE reserves added. The model can be used to answer two questions: (1) what price and rate of return are required to stimulate a certain level of exploration to find a given amount of oil and gas in BOE's?; or, (2) what amount of oil and gas can be anticipated from the Permian Basin at the present or some future price and rate of return?

The output of the model can be examined in terms of associated-dissolved gas, nonassociated gas, and oil resulting from various price levels and rates of return. The graphs shown in figures 30–32 reveal the declining size of the targets discovered as a result of additional exploratory effort. As the marginal cost curves turn sharply upward, oil- and gas-reserve additions to be gained at costs of $10 to $25 per barrel are considerably greater than those at $25 to $40 per barrel.

Another interesting result shown in the analysis is the dominance of nonassociated gas in the remaining resources in the Permian Basin. This dominance is true under all price and rate-of-return assumptions. When nonassociated gas is added to the associated-dissolved gas, crude oil represents only about one-quarter of the future potential.

TABLE 27.—*Potential recoverable oil and gas resources from future discoveries in the Permian Basin as a function of output price, marginal finding cost, marginal production cost, exploratory wells, and return on investment (ROI)*

[BOE, barrels of oil equivalent; Tcf, trillions of standard cubic feet of natural gas]

Output price ($/BOE)	ROI (percent)	Cumulative exploration wells[1] (in thousands)	Marginal costs[2]		CUMULATIVE POTENTIAL RESOURCES					Total BOE (in billions)
						Associated gas		Nonassociated gas		
			Finding ($/BOE)	Production ($/BOE)	Oil BOE (in billions)	Tcf	BOE (in billions)	Tcf	BOE (in billions)	
10	5	10	$ 2.64	$ 7.36	0.489	1.371	0.260	6.803	1.291	2.040
	15	5	1.67	8.33	.264	.750	.142	4.234	.803	1.209
	25	2	1.26	8.74	.108	.304	.058	1.948	.370	.536
15	5	19	4.58	10.42	.813	2.273	.431	9.384	1.781	3.025
	15	12	3.00	12.00	.578	1.614	.306	7.559	1.434	2.318
	25	8	2.15	12.85	.417	1.164	.221	5.982	1.135	1.773
20	5	26	6.40	13.60	1.013	2.822	.535	10.654	2.022	3.570
	15	18	4.30	15.70	.792	2.205	.419	9.170	1.740	2.951
	25	12	2.97	17.03	.582	1.621	.308	7.586	1.436	2.326
25	5	33	8.49	16.51	1.178	3.276	.622	11.610	2.203	4.003
	15	24	5.79	19.21	.965	2.684	.509	10.332	1.961	3.435
	25	17	4.03	20.97	.763	2.121	.393	8.954	1.699	2.865
30	5	38	10.30	19.70	1.278	3.536	.670	12.220	2.319	4.268
	15	29	7.14	22.86	1.094	3.014	.572	11.110	2.108	3.774
	25	22	5.19	24.81	.918	2.547	.483	9.996	1.897	3.298
35	5	43	12.27	22.63	1.366	3.788	.719	12.741	2.418	4.503
	15	34	8.65	26.35	1.202	3.334	.632	11.803	2.240	4.075
	25	26	6.19	28.81	1.024	2.839	.539	10.712	2.033	3.596
40	5	48	14.59	25.41	1.488	4.006	.760	13.162	2.498	4.706
	15	38	10.05	29.95	1.284	3.557	.675	12.253	2.325	4.284
	25	30	7.31	32.69	1.119	3.100	.588	11.294	2.143	3.850

[1] Exploratory wells assumed to be drilled since December 31, 1974. The stopping rule for exploratory wells drilled does not take into account the tax benefit of charging the cost of exploratory wells against current income. Therefore, these figures overestimate the effective cost of exploratory drilling.

[2] At the margin, the sum of the marginal finding cost and the marginal production cost is equal to the output price (column 1).

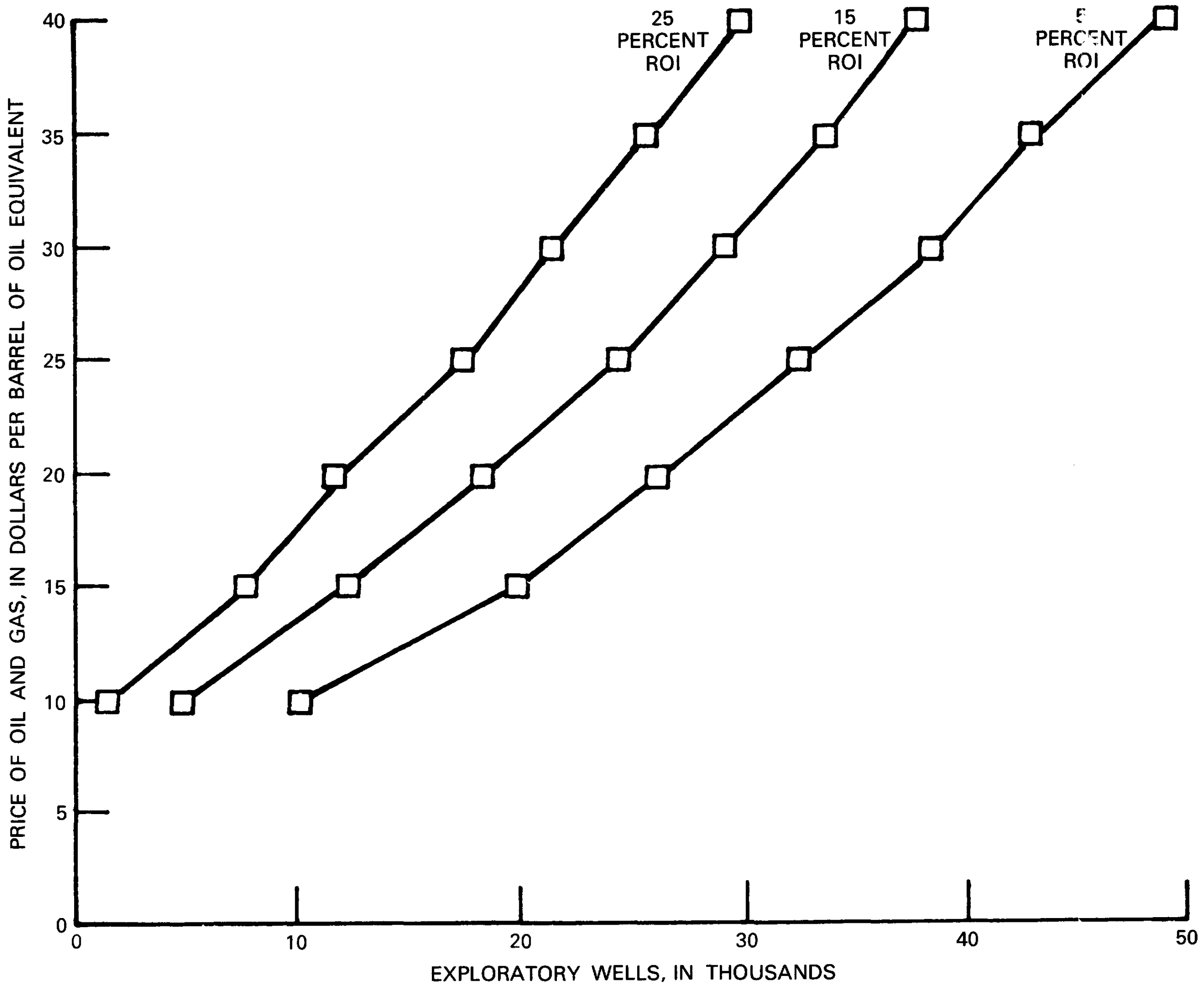

FIGURE 29. – Exploratory wells projected to be drilled in the Permian Basin as a function of price of oil and gas and rate of return on investment (ROI).

CONCLUSION

Estimates of undiscovered recoverable oil and gas, made using assumptions of $15 per BOE and 15 percent rate of return, indicate that oil and gas discoveries after January 1, 1975, will be 2.3 billion BOE, or less than 7 percent of the estimated ultimate recovery from fields discovered before 1975. The production of oil and gas in 1974 from the Permian Basin was approximately 1.4 billion BOE. Thus, the amount produced in 1 year is 60.3 percent of the total estimated potential recoverable resources from future discoveries in the Permian Basin at a price of $15 per BOE and a 15 percent aftertax real rate on investment. Given the highest price ($40 BOE) and lowest required rate of return (5 percent) shown in table 27, the 1974 production equals 29.7 percent of the total potential recoverable resources from future discoveries. Even in this most favorable example, the results indicate that estimated potential recoverable resources from future discoveries are little more than 3 years of production at the 1974 levels.

ADDITIONAL SUPPLIES FROM KNOWN FIELDS

ESTIMATES OF INDICATED AND INFERRED RESERVES

The second part of this study shifts from undiscovered oil and gas resources to the resources remaining in the fields discovered in the past. The most common measure of the production potential of known fields is proved reserves. The definition of proved reserves is intentionally conservative. It

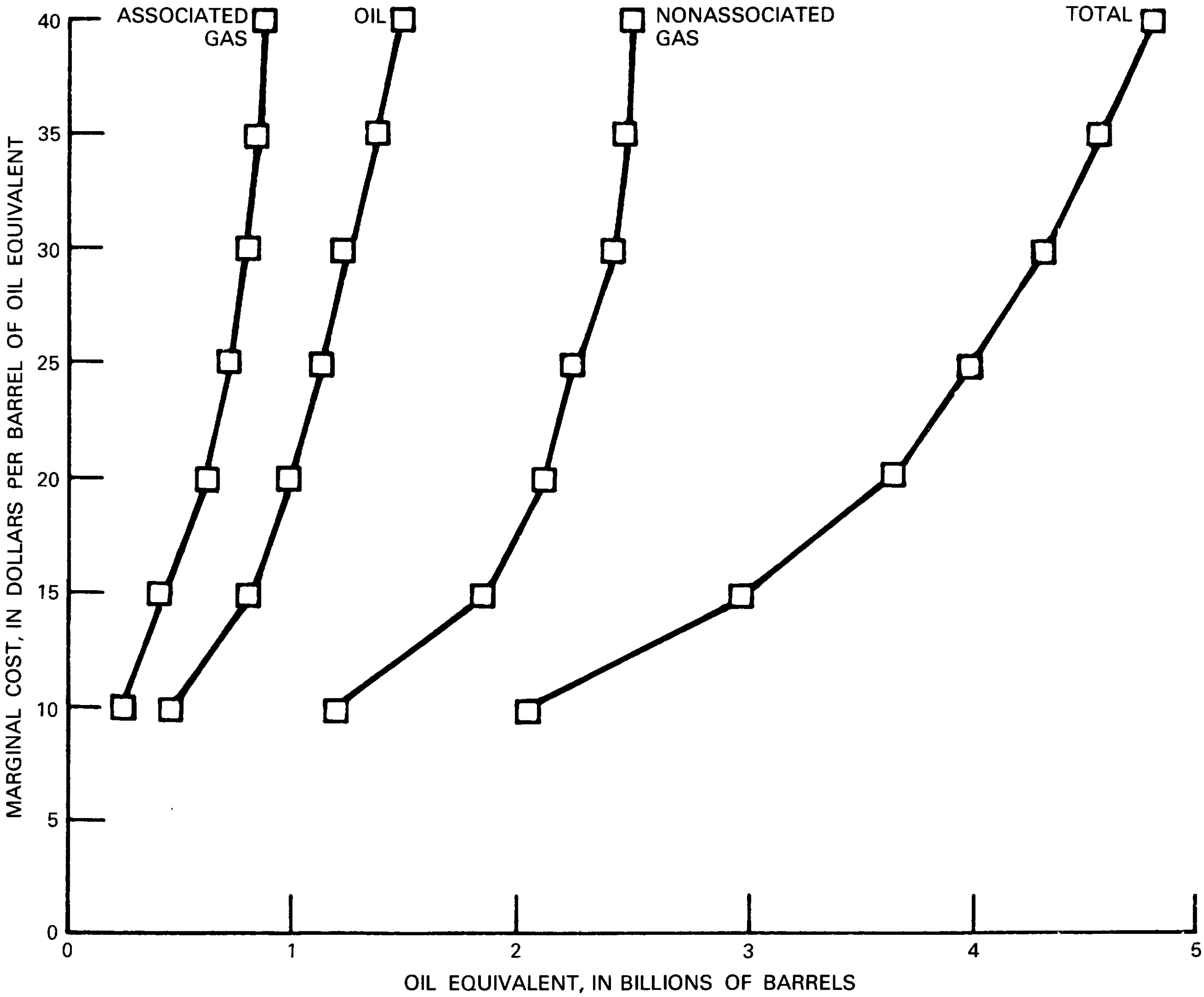

FIGURE 30.—Marginal cost of recoverable oil and gas resources from undiscovered deposits in the Permian Basin—5 percent discounted cash-flow rate of return.

reflects the measurements, estimates, and historical production data for the field and provides a projection that is unlikely to overstate what can be produced in the future at current prices and technology.

The proved reserves of the Permian Basin reported by the industry as of December 31, 1976, were: 5.5 billion barrels of oil and 18.2 trillion cubic feet of natural gas,[6] as compared with past production from the Permian Basin of 18.6 billion barrels of oil and 55.8 trillion cubic feet of natural gas. A judgment can be made concerning how much oil and gas was originally in place in the parts of known fields that provided this past production and that contain the remaining proved reserves. These amounts are approximately 90.4 billion barrels of oil and 108.4 trillion cubic feet of natural gas. The combination of past production and proved reserves indicates that 26.0 percent of the oil will ultimately be recovered in the Permian Basin.

As additional production experience is gained and as more development and extension wells are drilled in known fields, additional quantities of oil and gas may be projected with sufficient confidence to include these quantities in the proved category. Subsequent production must be subtracted from earlier proved estimates, and new information may cause upward or downward revisions in previous

[6] These figures represent the sum of proved reserves reported by the American Petroleum Institute and the American Gas Association for the Southeast New Mexico District and Texas Railroad Commission Districts, 7C, 8, and 8A. The four districts, although not identical to the Permian Basin as defined in this report, closely approximate it and are considered identical for the purpose of counting reserves and original oil in place.

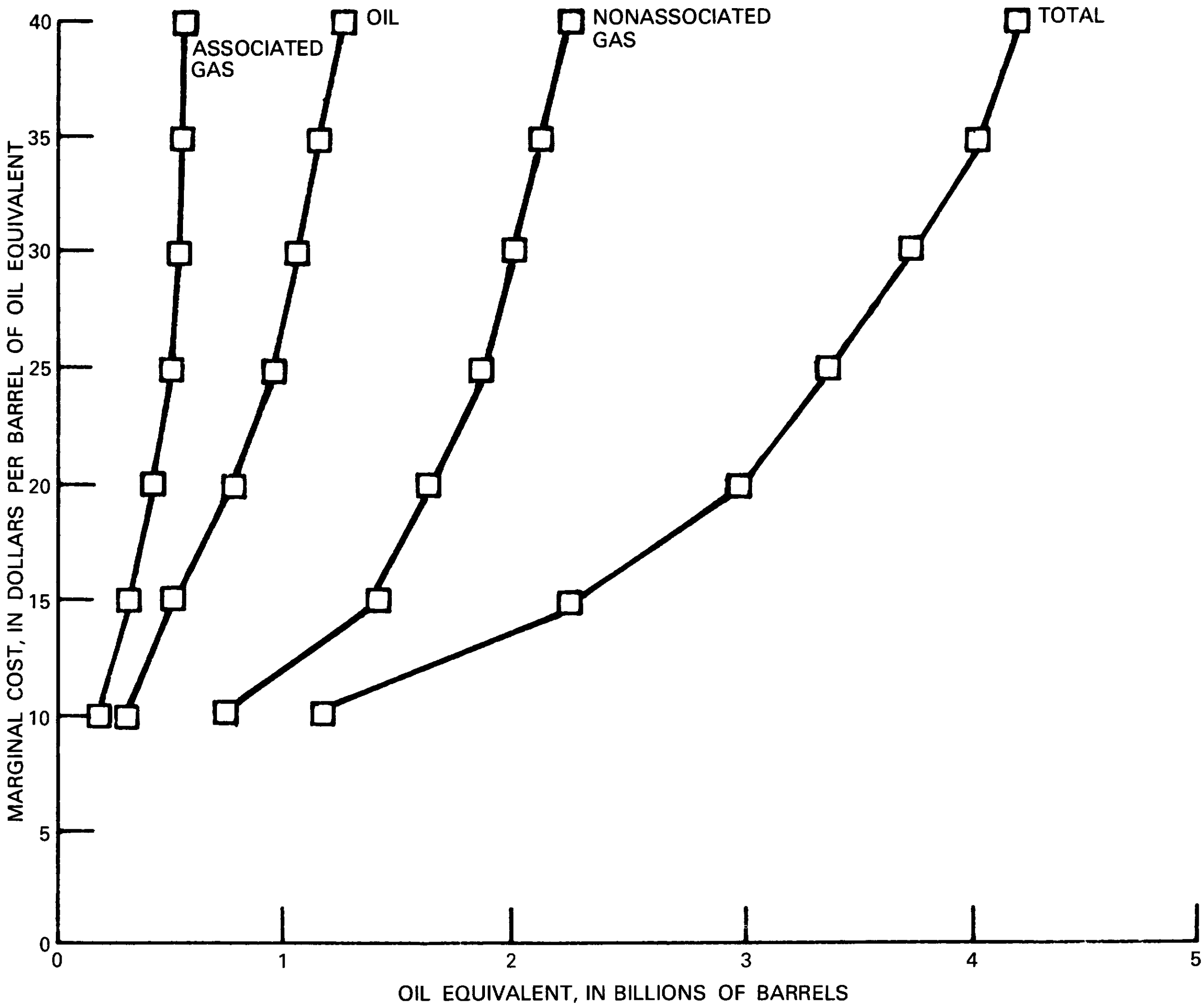

FIGURE 31.—Marginal cost of recoverable oil and gas resources from undiscovered deposits in the Permian Basin—15 percent discounted cash-flow rate of return.

estimates. History indicates also that the recovery factor does not remain constant over time because new secondary projects are introduced into fields and economic conditions change. As a consequence, the estimate of ultimate recovery, as well as perceptions of the amount of oil and gas originally in place, changes gradually over time.

INDICATED RESERVES

The initial step in accounting for the known oil and gas resources of the Permian Basin is, therefore, to estimate how much oil and gas may be produced from known fields, in addition to that included in proved reserves. Included in the first of these additional amounts are the quantities of oil expected to be recovered from projects that will improve recovery in active fields—projects where secondary recovery operations have begun, but are too new to evaluate; and proposed projects, which must be evaluated according to experience gained in other fields. According to the American Petroleum Institute (American Gas Association and others, 1977, table 1) these "indicated additional reserves" amounted to 1.6 billion barrels of recoverable oil as of December 31, 1976.

INFERRED RESERVES

The combination of proved reserves plus any indicated additional reserves does not fully account for the potential of the known fields. The discovered reserves of oil and gas also include inferred reserves, which are hydrocarbons whose

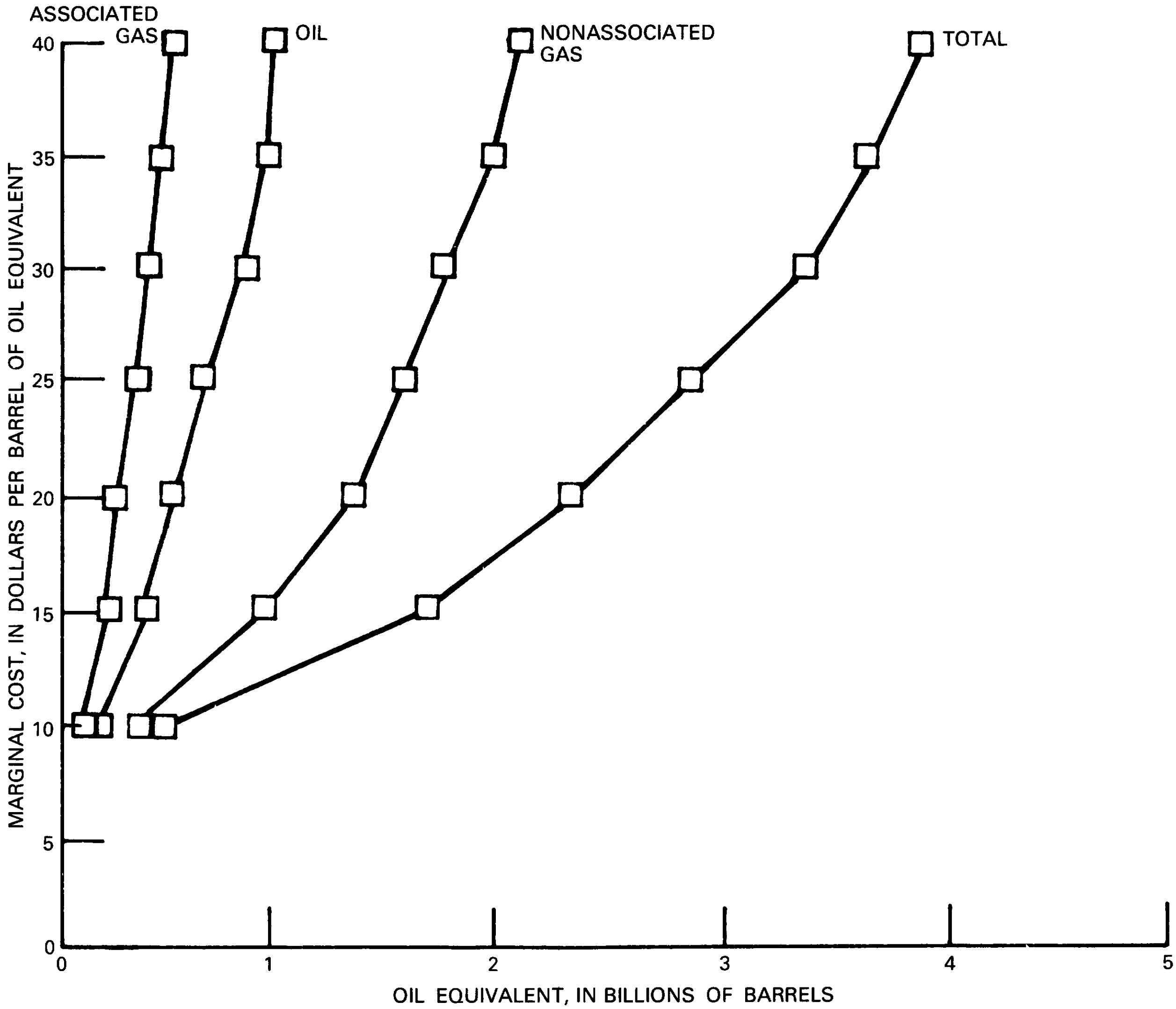

FIGURE 32. – Marginal cost of recoverable oil and gas resources from undiscovered deposits in the Permian Basin – 25 percent discounted cash-flow rate of return.

quantity cannot be precisely determined. Nevertheless, this additional oil and gas probably will be recovered eventually, and its recovery will not require the exploratory drilling needed for a new field discovery.

For all fields discovered in a given year, the American Gas Association (AGA), the American Petroleum Institute (API) and the Canadian Petroleum Association (CPA) have published through 1978 (American Gas Association and others, 1967–79) annual estimates of ultimate recovery. Changes in estimates of the quantity in place plus the recoverable quantities (proved reserves plus production) provide some basis for estimating the degree to which reserve and recovery figures may change over time for individual fields, an entire basin, or the United States as a whole. Estimates of ultimate recovery eventually stabilize for mature fields and become good projections of the actual recoverable quantity, if we assume that no changes in price or technology take place.

GENERAL OUTLINE OF DATA AND METHODS

Proved reserves of crude oil and natural gas are defined by the API and AGA. These definitions include only the part of the oil and gas resource base that is known to be technically and economically producible. Because the estimate of proved reserves in a field depends on the degree of development and production in each field, the estimates are updated each year. On the average, estimates of ultimate recovery (past production plus proved reserves) increase with time; the changes in estimates are due to extensions, revisions, and new reservoir discoveries in old fields (referred to as "new pools" in subsequent discussion). Extensions and new pools are proved reserve additions warranted by increases in the perceived physical dimensions of the field as a result of additional drilling. Revisions are all other changes (either positive or negative). Generally, estimates of a field's ultimate production grow more rapidly in the first few years after discovery; most fields are well-defined after 6 years of development and production.

Data on ultimate recovery can be used to estimate how much oil will actually be produced from fields that are not yet fully developed, if we assume that the estimates of their ultimate recovery grow in the same way that such estimates grew in the past. Briefly, an estimate of ultimate recovery for each year of age is made as the fields pass through that year of age. For example, the amount of growth as the fields advance from their fifteenth to their sixteenth year would be indicated by the changes in estimates for December 31, 1966, and December 31, 1967, for fields discovered in 1951. The percentage changes between successive estimates for all years for which data are available can then be calculated. The mean percentage change is the average growth that can be expected as fields age from their fifteenth to their sixteenth year.

Such expected growth was calculated for each year. The estimated ultimate recovery for fields discovered in a given year was multiplied by the growth factors for each year beyond the age of the fields. The same method of analysis was also applied to original oil in place and to recoverable natural gas for the Permian Basin. Results are presented in tables 28 and 29.

TABLE 28.—*Growth in estimates of original oil in place for the Permian Basin*

[In this table, Permian Basin comprises Southeastern New Mexico and Texas Railroad Commission Districts 7C, 8, and 8A]

Discovery year	Estimate 12/31/76 (billion bbl.)	Age of estimate in yrs (t)	$1/f(t)$	Corrected estimate (billion bbl.)
1975	0.0472	0.5	5.84	0.2755
1974	.0416	1.5	2.89	.1201
1973	.1610	2.5	1.95	.3142
1972	.0997	3.5	1.76	.1753
1971	.0857	4.5	1.58	.1353
1970	.2359	5.5	1.42	.3347
1969	.2511	6.5	1.36	.3409
1968	.1041	7.5	1.32	.1372
1967	.1893	8.5	1.29	.2446
1966	.6271	9.5	1.27	.7939
1965	.5114	10.5	1.25	.6387
1964	.4189	11.5	1.22	.5109
1963	.2555	12.5	1.23	.3136
1962	.7279	13.5	1.23	.8932
1961	.3888	14.5	1.22	.4735
1960	.7398	15.5	1.21	.8936
1959	.6283	16.5	1.21	.7595
1958	.4246	17.5	1.20	.5105
1957	1.6167	18.5	1.15	1.8528
1956	1.5509	19.5	1.14	1.7676
1955	1.0706	20.5	1.14	1.2171
1954	2.7785	21.5	1.12	3.1193
1953	2.8443	22.5	1.11	3.1439
1952	1.0497	23.5	1.10	1.1542
1951	1.2816	24.5	1.07	1.3707
1950	2.4700	25.5	1.04	2.5806
1949	12.4150	26.5	1.01	12.5650
1948	4.0569	27.5	1.04	4.2146
1947	2.0158	28.5	1.03	2.0856
1946	.8728	29.5	1.03	.8975
1945	3.5591	30.5	1.05	3.7296
1944	2.4933	31.5	1.02	2.5443
1943	1.4396	32.5	1.02	1.4716
1942	.8482	33.5	1.04	.8818
1941	2.2130	34.5	1.02	2.2491
1940	1.9322	35.5	1.02	1.9704
1939	1.4757	36.5	1.01	1.4868
1938	.8560	37.5	1.02	.8733
1937	.7615	38.5	1.02	.7766
1936	6.8011	39.5	1.02	6.9313
1935	2.2127	40.5	1.02	2.2520
1934	2.6043	41.5	1.01	2.6344
1933	.2241	42.5	1.01	.2266
1932	.5565	43.5	1.02	.5695
1931	.0082	44.5	1.03	.0084
1930	3.3113	45.5	1.01	3.3519
1929	5.1144	46.5	1.01	5.1639
1928	1.4529	47.5	1.00	1.4575
1927	.6538	48.5	1.00	.6558
1926	8.5027	49.5	1.00	8.5027
1925	2.0742	50.5	1.00	2.0742
1924	.1249	51.5	1.00	.1249
1923	.5842	52.5	1.00	.5842
1922	0	53.5	1.00	0
1921	.1658	54.5	1.00	.1658
1920	0	55.5	--	0
Pre-1920	0	--	--	0
Total	89.9300			94.5200

METHOD OF ANALYSIS

Let $Q_e(u,v)$ be the estimate of ultimate recovery made at the end of year v for all fields discovered during the year u. Let $Q(u)$ be the actual, but unknown, amount of oil discovered in year u. We assume that:

$$Q_e(u, v) = Q(u) f(v-u) + Q(u) E(u, v) \qquad (1)$$

where $f(v-u)$ is a fraction which increases to 1.0 as the age of the fields, $v-u$, increases to infinity.

The error term, $Q(u)\,E(u,v)$, is assumed to be proportional to $Q(u)$. Taking logarithms gives:

$$\ln Q_e(u,v) = \ln Q(u) + \ln(f(v-u) + E(u,v)).$$

We now fix u and regard both sides as functions of v only and ignore the error term, $E(u,v)$.

Taking the difference betwen successive estimates of the amount of oil or gas discovered in a year u gives equation (2):

$$\ln Q_e(u,v+1) - \ln Q_e(u,v) = \ln f(v+1-u) - \ln f(v-u) \qquad (2)$$

TABLE 29.—*Growth in estimates of recoverable natural gas for the Permian Basin*

[In this table, Permian Basin comprises Southeastern New Mexico and Texas Railroad Commission Districts 7C, 8, and 8A]

Discovery year	Estimate 12/31/76 (trillion cubic feet)	Age of estimate in yrs (t)	$1/f(t)$	Corrected estimate (trillion cubic feet)
1976	0.0965	0.5	4.748	0.4582
1975	.2377	1.5	2.311	.5493
1974	.3787	2.5	1.673	.6336
1973	.9057	3.5	1.499	1.3578
1972	.4966	4.5	1.462	.7260
1971	.5044	5.5	1.360	.6860
1970	.6070	6.5	1.326	.8051
1969	1.587	7.5	1.326	2.105
1968	1.962	8.5	1.250	2.452
1967	0.9316	9.5	1.201	1.119
1966	1.347	10.5	1.195	1.6091
1965	1.004	11.5	1.176	1.181
1964	.7197	12.5	1.177	.8470
1963	5.951	13.5	1.186	7.060
1962	2.653	14.5	1.189	3.154
1961	1.301	15.5	1.238	1.611
1960	.8093	16.5	1.176	.9514
1959	.2894	17.5	1.1027	.3191
1958	.8278	18.5	1.134	.9386
1957	1.466	19.5	1.085	1.590
1956	1.371	20.5	1.063	1.458
1955	.6345	21.5	1.018	.6460
1954	2.596	22.5	1.012	2.628
1953	1.574	23.5	1.014	1.596
1952	2.815	24.5	1	2.815
1951	.4043	25.5	1	.4043
1950	2.77	26.5	1	2.777
1949	2.452	27.5	1	2.452
1948	.8001	28.5	1	.8001
1947	.8041	29.5	1	.8041
1946	.7491	30.5	1	.7491
1945	3.048	31.5	1	3.048
1944	2.016	32.5	1	2.016
1943	.4739	33.5	1	.4738
1942	.3197	34.5	1	.3197
1941	1.241	35.5	1	1.241
1940	.2037	36.5	1	.2037
1939	1.432	37.5	1	1.432
1938	.3360	38.5	1	.3360
1937	.1426	39.5	1	.1426
1936	3.295	40.5	1	3.295
1935	1.435	41.5	1	1.435
1934	2.257	42.5	1	2.257
1933	.0497	43.5	1	.0497
1932	.1268	44.5	1	.1268
1931	.0	45.5	1	.0
1930	2.692	46.5	1	2.692
1929	10.55	47.5	1	10.55
1928	1.075	48.5	1	1.075
1927	.1751	49.5	1	.1751
1926	1.284	50.5	1	1.284
1925	.2503	51.5	1	.2503
1924	.2806	52.5	1	.2806
1923	.1989	53.5	1	.1989
1922	.0	54.5	1	.0
1921	.0026	55.5	1	.0026
1920	.0	56.5	1	.0
Pre-1920	.0	≥57.5	1	--
Total	73.937			81.167

The left-hand side of equation (2) may be computed from the data. For a given time lag s, suppose we have the data $\ln Q_e(u,u+s)-\ln Q_e(u,u+s-1)$ for n different values of u, then define:

$$h(s)=\sum_u (\ln Q_e(u,\ u+s)-\ln Q_e(u,\ u+s-1)*a(u,\ s)$$

where the weighting factors $a(u,s)$ are chosen so that for a fixed $s, \sum_u a(u,s)=1$ and $a(u,s)$ is proportional to $Q_e(u,u+s)$. The reason for using weighting factors, rather than a simple average, is to reduce the effect of changes in estimates for years in which very little oil was discovered. Then define: $H(s)=\sum_{i=1}^{s} h(i)$. The two functions $H(s)$ and $\ln f(s)$ differ by an unknown constant, that is independent of s:

$$\ln f(s)=H(s)+C.$$

The constant C can be estimated from the fact that $\ln f(s)$ increases as s increases and it approaches zero as s approaches infinity. By examining the graph of $H(s)$, one can estimate when $H(s)$ will be close to its asymptotic value. This value is the negative of the estimate of C. Another way of estimating C is to choose, by any method, an age of fields beyond which growth is negligible. If this age is "a" then take C to be $-H(a)$ and set $f(s)=1$ for $s \geq a$. This method is particularly useful if the discovery dates of older oil fields are being changed so that substantial quantities of crude oil are being shifted from one discovery year to another.

The analysis was applied to estimates of recoverable natural gas and original oil in place. Statistical irregularities made choosing the asymptotic values for $H(s)$ difficult, especially for natural gas.

The discovery year assigned to a particular field often changes. When the data for a small region such as the Permian Basin are analyzed, shifting the discovery year of a field can introduce large variations in the ultimate production of all the fields discovered in a given year; such variations have nothing to do with additions to reserves through extensions and revisions. This problem was resolved by grouping the fields according to the decade of discovery to determine to within 10 years the age at which the growth of the fields is virtually over.

In the Permian Basin, the 1973 estimate of ultimate gas production from fields discovered between January 1, 1950, and January 1, 1960, was 51.1 trillion cubic feet. The 1976 estimate for the same fields was 51.3 trillion cubic feet. This stability indicated that estimated sizes of Permian Basin gas fields discovered between January 1, 1950, and January 1, 1960, were not likely to grow significantly beyond the December 31, 1976, estimates.

The projection of historical growth rates into the future will probably led to an overestimate of the amount of growth that can be expected from known fields, because fields are now developed more rapidly than they were in the past and are smaller on the average.

A VARIATION ON THE METHOD OF ANALYSIS

The delay between the discovery of a field and the estimate of its size can be measured by an index of industrial activity, rather than time. The mathematics of the analysis is the same when some other index is used.

Pelto (1973) considered the problem of growth in estimates of field size, specifically estimates of original oil in place in the conterminous 48 states. His method differed from that described above, in four respects. First, instead of using a geometric mean of ratios of successive estimates, he used an arithmetic mean. Second, he omitted certain discovery years (pre-1920, 1921, 1923, 1924, 1934, and 1935) from his calculations because irregularities in the data for those years were probably caused by changes in the discovery years assigned to some fields. Third, he omitted the first three estimates (1966, 1967, and 1968) because they were subject to significant startup errors. Last, he used a smoothing function. Later, Pelto applied his method to recoverable natural gas. The discovery years omitted from the natural-gas calculations were 1941, 1957, 1959, and 1965. When Pelto's method and the method described above were applied to the entire conterminous 48 States, the two methods produced similar results, and results given here for the Permian Basin are also similar.

SUMMARY

The estimate of original oil in place in the Permian Basin decreased during the period from December 31, 1974, to December 31, 1975, by 0.285 percent. Application of the growth factors indicates that the December 31, 1975, estimate can be expected ultimately to increase by 5.1 percent for a predicted combined increase of 4.8 percent over the December 31, 1974, estimate. This would mean an increase of 4.4 billion barrels of oil, of which, at a 26 percent recovery factor, 1.1 billion barrels would be recoverable.

The estimate of recoverable natural gas increased by 0.899 percent during the period from December 31, 1974, to December 31, 1976. The growth factors indicate that the December 31, 1976, estimate can be expected ultimately to increase by 8.9 percent. Thus, the overall increase in recoverable natural gas from the December 31, 1974, estimate is 9.8 percent. This percentage of growth applied to the Permian Basin's December 31, 1974, estimate of recoverable natural gas, 71.7 trillion cubic feet, means that an additional 7.1 Tcf would be produced from known fields.

The inferred reserves of the Permian Basin, therefore, are calculated to be 1.1 billion barrels of crude oil and 7.1 Tcf of natural gas. However, projection of the growth of fields under the assumption that fields discovered in the 1960's and 1970's will show the same growth as fields discovered in the 1950's and before, will almost surely lead to an overestimate, because the more recently discovered fields are smaller.

ENHANCED OIL AND GAS RECOVERY

The previous section accounts for the oil and gas yet to be produced from known fields in the Permian Basin through normal drilling, development, and the addition of secondary-recovery projects. However, advanced production techniques may be used to recover additional oil and gas from known fields, although such oil and gas is generally not now included in the various reserve estimates (see fig. 33). These techniques go beyond injecting water or gas as a routine part of pressure maintenance, and most are either experimental or only marginally economic. The possibilities for such enhanced recovery in the Permian Basin are discussed here.

ENHANCED OIL RECOVERY

Enhanced oil recovery (EOR) already makes a significant contribution in the Permian Basin. As shown below, about 0.3 billion barrels of oil has been produced or proven to date by EOR, the bulk of this results from the application of hydrocarbon gas miscible flooding in addition to the major carbon dioxide flood at the Kelly-Snyder field (SACROC unit).

	Number of reservoirs having substantial EOR[1] production	Cumulative EOR[1] production	Proved reserves	Indicated reserves
		(as of December 31, 1977) (million barrels)		
Hydrocarbon gas miscible	5	187.1	24.6	0.0
CO_2 flooding	2	75.6	14.0	9.5
Other	1	.1	.0	.0
Total	8	262.8	38.6	9.5

[1] Enhanced oil recovery.

In the Permian Basin, the further use of EOR techniques could conceivably increase ultimate recovery by an additional 10 billion barrels. This would raise ultimate recovery from roughly 26 percent to about 37 percent of the original oil in

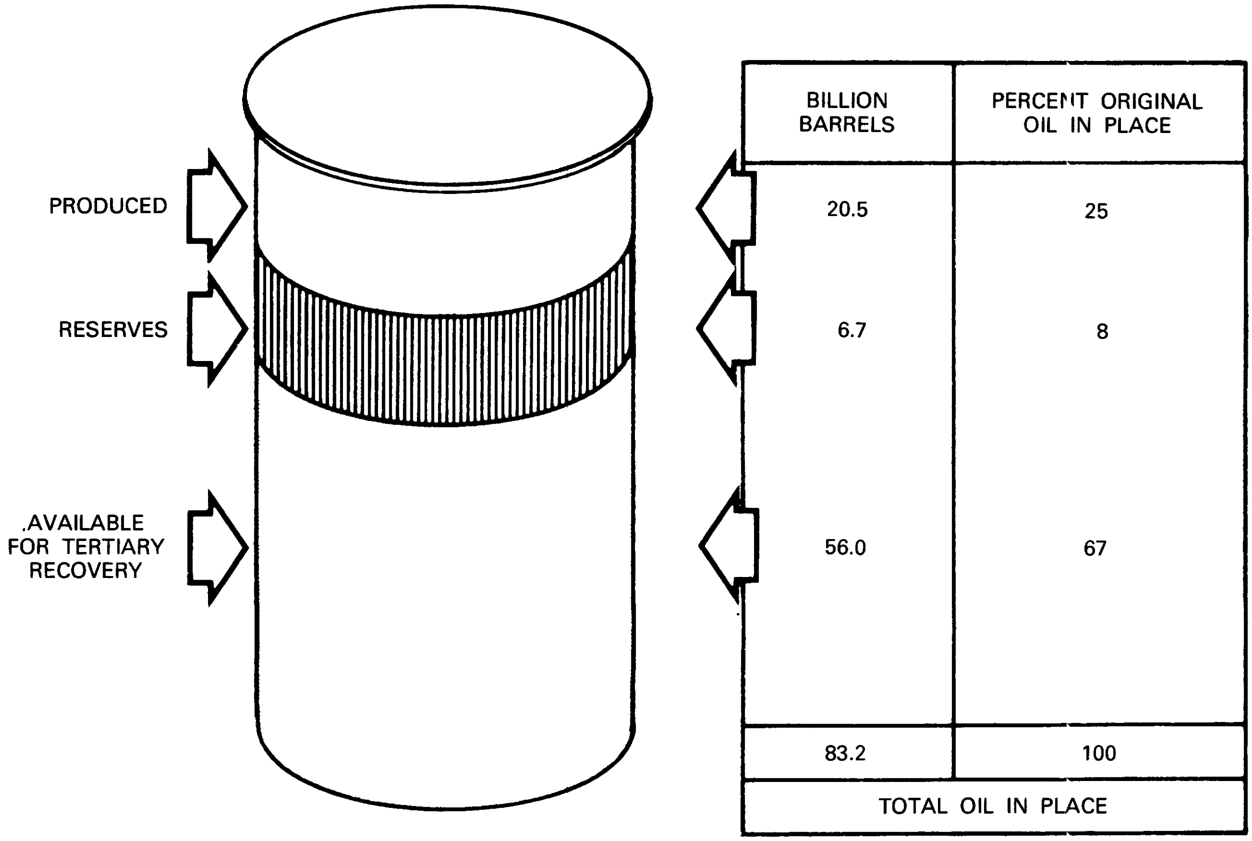

FIGURE 33.—Production, reserves, and residual oil in place in the Permian Basin, exclusive of "Spraberry" Trend, December 31, 1977.

place.[7] However, recovering such additional amounts of oil will probably be limited by economic and major technological problems.

METHODOLOGY

The EOR potential of the Permian Basin is based upon projections for major reservoirs for which the use of EOR techniques appears feasible. For those fields that already have EOR projects, expansion of the projects was assumed where economic. We extrapolated the results to the level of the entire basin using the oil-in-place data by depth and lithology. The EOR supply possibilities were determined for two rates of return on investment and seven price levels.

The EOR model used in this study was originally prepared by Lewin and Associates, Inc. (1976), and the Federal Energy Administration. Currently, the model has been updated and documented (Lewin and Associates, Inc., 1978) and is operated by the Energy Information Administration of the Department of Energy. The model is reservoir-specific and performs individual project evaluations on a sample of large candidate reservoirs from the Permian Basin. This sample is believed to cover more than 50 percent of the oil in place in the basin and a much higher percentage of the best EOR prospects. The model uses economic criteria to evaluate the possible use of EOR methods in these reservoirs. Each recovery method has its own engineering efficiencies, costs, and other data specified. The evaluation involves a three-step process:

(1) Screening reservoirs according to geologic and economic factors, and assigning EOR techniques to the most attractive prospects.[8]

(2) Identifying minimum acceptable prices and reservior-specific production profiles over a

[7] These figures exclude the "Spraberry" Trend, a very large formation of shale and siltstone that is economically producible only because of a system of naturally occurring, closely spaced vertical fractures, which permit an ultimate recovery currently estimated at no more than 7 percent of the original oil in place.

[8] This screening process permits a choice, based upon fluid and reservoir characteristics, among steam drive, in situ combustion, gas miscible flooding, surfactant/polymer injection, and polymer-augmented waterflooding.

period of time, on the basis of projected market prices and rates of return.

(3) Extrapolating production data to regional levels and accumulating reserves.

The study was conducted separately for sandstone and carbonate reservoirs, which then were classified by reservoir depth. Ninety-six reservoirs were included in the sample studied. The distribution of the reservoirs within these categories is given in table 30. The sample was extrapolated to obtain estimated values for the entire basin for both sandstone and carbonate formations and for various reservoir depths. The extrapolation factors used and the results obtained are shown below:

Reservoir type	<5,000 ft	5,000–10,000 ft	>10,000 ft
Sandstone:			
Sample OOIP [1], billion bbls	1.65	0.22	–
Total OOIP, billion bbls	10.81	4.94	.0.40
Extrapolation factor	.153	.045	–
Carbonate:			
Sample OOIP, billion bbls	25.17	15.64	2.94
Total OOIP, billion bbls	32.50	26.87	7.68
Extrapolation factor	.774	.582	.383

[1] Original ore in place.

TABLE 30.—*Classification of sample reservoirs selected for enhanced oil recovery in the Permian Basin*

	<5,000		5,000–10,000 ft		>10,000 ft	
	No.	OOIP [1] (10^9B) [2]	No.	OOIP (10^9B)	No.	OOIP (10^9B)
Technically feasible for EOR [3]						
Sandstone	2	1.65	2	0.22	–	–
Carbonate	34	19.88	29	14.31	9	2.44
Infeasible for EOR:						
Sandstone	–	–	–	–	–	–
Carbonate	5	5.29	5	1.33	10	.50
Total	41	26.8	36	15.9	19	2.9

[1] Original oil in place.
[2] B, barrel.
[3] Enhanced oil recovery.

The technology assumed was the best of the currently tested and applied carbon dioxide processes. More specifically, the model includes assumptions that:

(1) Oil saturation is uniformly distributed within the part of the reservoir being developed at the time the project is initiated (this assumption may lead to an underestimate of drilling costs and, hence, an overestimate of recovery).

(2) The effective sweep efficiency for the carbon dioxide varies according to the performance of the waterflood previously used and the reservoir lithology (that is, carbonate or sandstone); the carbon dioxide sweep efficiency used by the model is a function of ultimate primary/secondary sweep, as follows:

CO_2 *sweep efficiency*

[Percent of waterflood sweep]

Reservoir suitability [1]	Sandstone reservoirs	Carbonate reservoirs
Good	50	45
Fair	40	40
Poor	30	35

[1] As determined by the National Petroleum Council (1976).

(3) Residual oil saturation in the swept zone after carbon dioxide flooding is 60 percent of the residual after waterflooding.

(4) Residual oil saturation in the unswept zone remains unchanged.

(5) World oil prices remain at the mid-1977 level in constant dollar terms.

Potential EOR production ranges from zero production at $10 per barrel to 5.1 billion and 4.6 billion barrels at $40 per barrel for rates of return at 15 percent and 25 percent, respectively, as shown in table 31.

TABLE 31.—*Enhanced oil recovery potential of the Permian Basin*

[In billions of barrels; BOE, barrels of oil equivalent]

Output price ($/BOE)	15 percent rate of return	25 percent rate of return
10	0.0	0.0
15	1.34	.20
20	2.93	1.30
25	4.31	2.58
30	4.70	3.65
35	5.08	4.11
40	5.11	4.56

ENHANCED GAS RECOVERY

Conventional gas production ordinarily recovers a large fraction of the original gas in place, 70 percent or more in the Permian Basin; the remaining gas is generally not an attractive target for enhanced gas recovery (EGR) techniques.

The usual targets for EGR, instead, are discovered gas accumulations that have never been produced because conventional production methods are uneconomic. The gas in these fields is classified as a discovered subeconomic resource and is frequently designated "near-conventional" or "unconventional" gas, to indicate the subeconomic response to conventional production methods.

Within the Permian Basin, interest in EGR centers on the southern part, Sutton, Crockett,

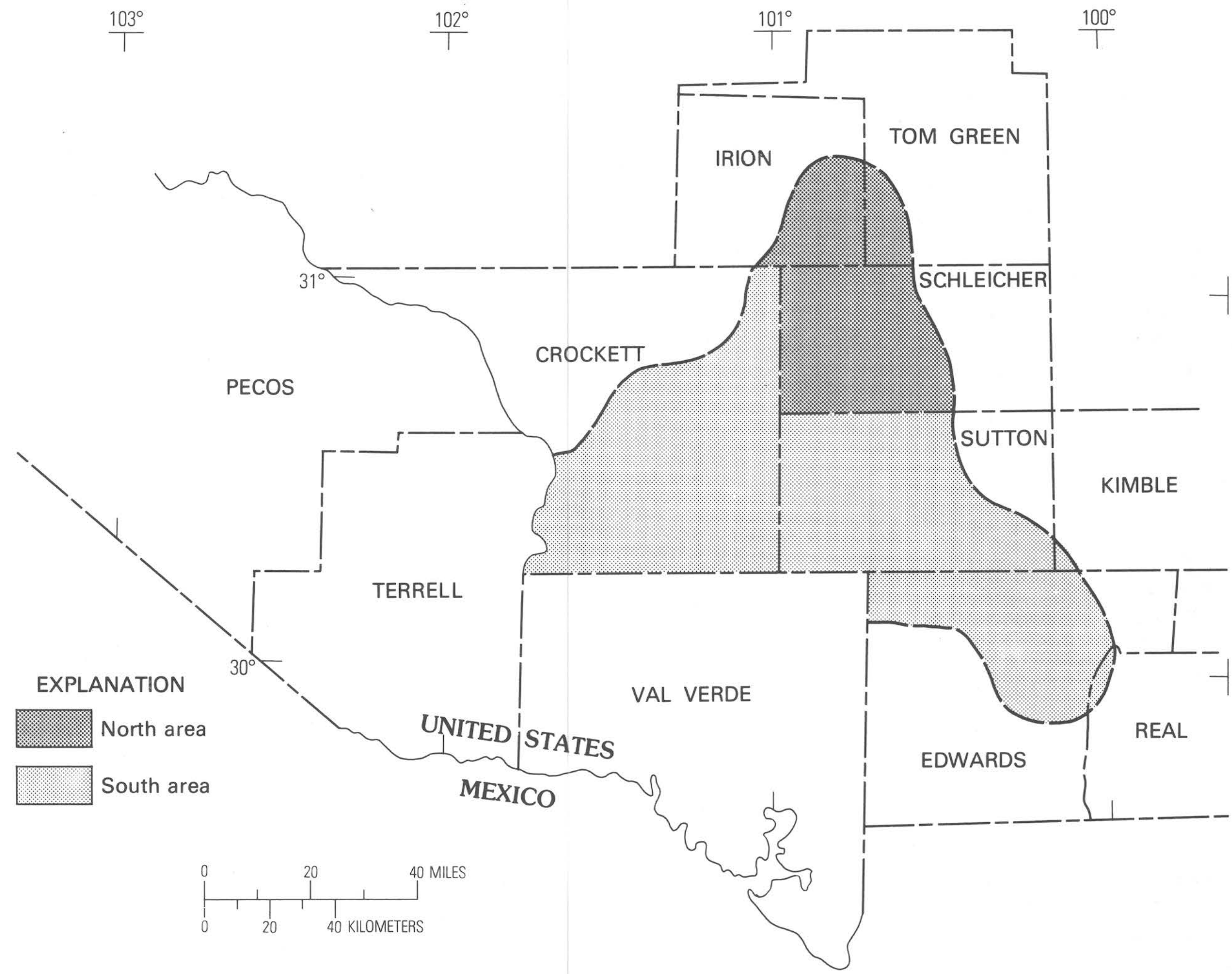

FIGURE 34.—Areas of the Permian Basin for enhanced gas recovery.

and Schleicher Counties in Texas (see fig. 34). About 4,500 square miles of this subbasin may be responsive to massive hydraulic fracturing (MHF) at some future time under the economic conditions assumed in this study.

MHF now has advanced sufficiently to become standard production practice in many fields of low permeability. However, the economic and subeconomic resources of the area are difficult to identify separately. This report, therefore, assumes that all such resources are presently subeconomic and that exploiting this area will require future technological advances.

EGR using MHF was analyzed at two rates of return and at a wide range of price levels (see table 32). The methodology was similar to that for EOR. The response ranges from 7.4 trillion cubic feet at $10 per BOE and 25 percent rate of return to 13.7 trillion cubic feet at $40 per BOE and either 15 or 25 percent rate of return.

TABLE 32.—*Enhanced gas recovery potential of the Permian Basin*

[In trillion cubic feet; BOE, barrels of oil equivalent]

Output price ($/BOE)	15 percent rate of return	25 percent rate of return
5	8.9	7.4
10	13.7	13.7
15	13.7	13.7
20	13.7	13.7
25	13.7	13.7
30	13.7	13.7
35	13.7	13.7
40	13.7	13.7

EXPANDED PRODUCTION FROM KNOWN FIELDS: AN APPRAISAL OF RESULTS

Although the undiscovered oil and gas resources of the Permian Basin have been discussed in "The Integrating Economic Model," the second part of this study, which addresses future supply from known fields and analyzes separate problems, required different approaches. The statistical outputs given in "Estimates of Indicated and Inferred Reserves" and "Enhanced Oil and Gas Recovery" are less uniform in character than those in "Future Production of Undiscovered Oil and Gas from the Permian Basin," and, consequently, are difficult to aggregate. Therefore, a formal integrating model to show the potential for future recovery of oil and gas from known reservoirs has not been attempted.

Using one set of assumptions (such as $15 per BOE and 15 percent rate of return), we can itemize (see following table) the current outlook in the Permian Basin for recovering additional oil and gas from discovered fields. In a general way, this table provides a concept of the relative magnitude of future supply.

Reserves as of December 31, 1976	Oil (billion barrels)	Natural gas (trillion cubic feet)
Proved	5.5	18.2
Indicated additional	1.6	–
Inferred	1.1	7.1
From enhanced-recovery techniques	1.3	13.7
From unconventional sources	none	none

The estimation of proved, indicated, and inferred reserves in the Permian Basin involves no formal economic analysis; reserves are quantities considered economic under the price and technological conditions specified at the time of estimation. As a result, the indicated and inferred reserves data found in "Estimates of Indicated and Inferred Reserves" are not shown in terms of price ranges or rate-of-return alternatives. Although the question of economics is avoided by definition as an explicit variable in the reserve estimation at one specific time, the passage of time will require that these prior estimates be changed to reflect the subtraction of production, subsequent changes in price and technological conditions, and changes in classification as indicated, and inferred reserves are moved into the proved reserves category.

Realistically, if upward price trends persist, a continuing transfer of current subeconomic Permian Basin oil and gas volumes into the reserves category will take place. In the Permian Basin, this transfer may prove to be a more important quantitative adjustment in the longer term than is the refinement of past reserves estimates. The estimation of subeconomic resources in known oil and gas fields involves the simultaneous consideration of technological and economic change, which can alter both the producibility and the ultimate recovery over time, under various price and rate of return expectations. This step in the appraisal process is limited by a lack of knowledge about the quantity of oil and gas remaining in place. In addition, the appraisal problem is complicated because the hydrocarbon mix includes varying proportions of crude oil, nonassociated gas, associated and dissolved gas, and natural-gas liquids.

In examining the marginal cost functions of undiscovered oil and gas in "Future Production of Undiscovered Oil and Gas from the Permian Basin," we recognized that the economic model attempts to simulate the industry's exploration-decision process. Any discovery model, however, has difficulty in adjusting to geologic probability data as well as in properly capturing the true nature of the corporate decision process. Once a discovery has been made, development is most likely to be based upon engineering estimates and calculations. Unlike the exploration process, an oil and gas production model can be considered an assessment of development costs and risks versus the potential rewards to be gained. It involves reasonable estimates of the specific quantity of money needed as an initial investment, provides for certain operating costs, and forecasts an expected income from production within a relatively narrow range of future circumstances. This is sufficient for the private decisionmaker as a basis for making his choices among alternative investments, when conventional reservoirs and technology are involved. The risk reflects the uncertainty of price and the accuracy of the development design.

NOTES ON METHODOLOGY

This study of the Permian Basin was undertaken as an experimental effort to: (1) devise methodologies generally applicable for estimating future oil and gas possibilities in a geologic basin; (2) test these methodologies in a mature basin for which available data are abundant and of good quality; and (3) extend the methodology of earlier resource appraisals by introducing economic considerations. In general, the methodologies used to inventory the remaining recoverable oil and natural gas resources of a single basin appear sound and should provide useful information and an opportunity for further refinement.

Some concern must be expressed about the extremely high level of effort that has been invested in studying a single basin. However, a learning process has been involved, and future efforts should show the benefits of streamlining, because the early stages of the project need not be repeated. Thus, the time and expense of studying the two additional proposed regions should be reduced.

The Permian Basin was selected as the first study because it is a mature producing basin. The second study concerns the Gulf of Mexico offshore and will have to deal with new economic and technological considerations as it applies its methodology to marine operations. The final pilot study will be the Baltimore Canyon basin of the Atlantic Ocean, which is largely a frontier area. Little exploration and drilling has taken place, and little "hard" information is available. Consequently, this last pilot project will involve a severe test of the methodology.

In future work, several aspects of the approach must be refined. One question will concern the distribution of resources by depth category, the fineness of depth classifications being an important consideration. Further examination of the rationale behind a reservoir-size cutoff should also be made.

Because estimates of reserve-cost functions must begin with an appraisal of the undiscovered oil and gas resources in place, the subjective resource-appraisal techniques developed and applied in "Future Production of Undiscovered Oil and Gas from the Permian Basin" must be related to discovery, perhaps by using mature regions as analogs.

The engineering model used to project production profiles for future oil and gas discoveries in a basin should be examined carefully to determine how uncertainty can be estimated. Also, in using engineering or process calculations, the model may lose considerable economic sensitivity. The cost analysis also fails to reflect uncertainty.

In examining the future potential of the known reserves and resources of a basin, this report reveals the difficulty of using a purely statistical approach to estimating inferred reserves. Such estimation seems more suitable at a national level than at that of a single basin level.

Projection of the possible recovery rates by means of advanced technology is a relatively recent endeavor and needs additional work. We found two special problems in analyzing the Permian Basin. First, some of the oil and gas included in the enhanced-recovery analysis perhaps should have been a part of the proved or indicated-reserves estimates. Conversely, the growth of oil and gas-reserves estimates in part reflects past changes in technology, so that some of the quantities counted as inferred reserves may have been double-counted as the products of enhanced-recovery techniques.

Second, the analysis of oil and gas supply from undiscovered resources considered only primary and secondary forms of recovery; that is, the enhanced-recovery analysis dealt only with known fields. As a result, the supply estimates probably understate potential recovery under various price and rate-of-return assumptions for undiscovered recoverable oil. To be sure, there is some justification for this approach with respect to the Permian Basin. In the Permian Basin, the undiscovered resources are in small fields, whereas the major potential for EOR and EGR is found in the larger, known fields. Therefore, applying enhanced-recovery calculations only to known areas probably does not create major errors. Nevertheless, in a less well-developed basin, such calculations should be applied to both known and unknown areas. This is very difficult because the EOR and EGR models depend on microgeologic information.

Finally, a complete basin analysis would include two aspects not included in this study. The absence of any important unconventional resources eliminated the need to devise a methodology for examining the quantities, technologies, and costs of such resources. Also, an integrating model to combine the various estimates of discovered oil and gas resources, comparable with that used for the undiscovered resources, was not constructed. This model is an objective for future work.

Despite the problems and limits mentioned, the study group believes that the methodology leads to an improved understanding of the physical potential and economic characteristics of Permian Basin oil and gas resources.

INTERAGENCY AGREEMENT FOR AN OIL AND GAS SUPPLY PROJECT

1. *Participating Agencies*

This Interagency Agreement is made and entered into this 13th day of December, 1976, between the following participating agencies of the United States Government: Department of the Interior (DOI), represented by the Office of Minerals Policy and Research Analysis (OMPRA), Geological Survey (GS), and Bureau of Mines (BM); Federal Energy Administration (FEA); Federal Power Commission (FPC); and Energy Research and Development Administration (ERDA).

2. *Purpose*

The purpose of this Interagency Agreement (the Agreement) is to delineate certain understandings between the participating agencies set forth in Paragraph 1 above, with respect to the execution, performance, and financing of the subject Project.

3. *Lead Agency*

The participating agencies, OMPRA, BM, FEA, FPC, and ERDA, hereby agree that GS will be the lead agency in achieving the purpose of the Agreement set forth in Paragraph 2 above.

4. *Steering Committee*

The Participating agencies shall plan and guide the Project through a Steering Committee, which shall be composed of the following members, their representatives, designated alternates, or successors:

Richard F. Meyer, GS, Project Coordinator
Robert L. Adams, OMPRA
Robert R. Aitken, FEA
Allen L. Clark, Jr., GS
Jerry D. Ham, ERDA
Gary W. Horton, GS
Richard F. Mast, GS
Ira Mayfield, FEA
L.P. White, OMPRA
Richard F. Zaffarano, BOM
Gordon K. Zareski, FPC

The Steering Committee, which may include Advisors and Conferees from outside the U.S. Government, shall make technical decisions with respect to the Project, assist in planning the work of the Project and in naming personnel to perform the Tasks named in Paragraph 5, and review the final report.

5. *Task Groups*

The work of the Project shall be divided into seven Tasks, each with a Leader and personnel designated by the Steering Committee:

Task 1. Conventional Oil and Gas Resource Appraisal and Field Size Distribution
Task 2. The Exploration/Production Function
Task 3. Future Conventional Oil and Gas Supply from Extension Drilling
Task 4. Future Oil and Gas Supply from Improved Recovery
Task 5. Future Oil and Gas Supply from Nonconventional Sources
Task 6. Econometrics and Supply
Task 7. Annual Report

6. *Purpose of Project*

The purpose of the Interagency Oil and Gas Supply Project (Project) is (1) the preparation of curves showing supply of undiscovered recoverable oil and gas resources from all sources at various cost levels, and (2) the determination of possible changes, if any, in the levels of estimated recoverable oil and gas resources at varying price/cost ratios.

To accomplish this will require examination of potentially recoverable hydrocarbon resources from such sources as oil shale, black organic shale, coal seams, heavy-oil reservoirs, tar sands, tight gas sands, geopressured reservoirs, abandoned oil fields, strippable oil fields, and water depths of more than 200 m; from enhanced oil-recovery methods in both known and undiscovered fields; and from extension drilling. Models must be prepared to include exhaustion, risk analysis, and field-size distribution with respect to future exploration.

7. *Duration of Agreement*

This Agreement is to cover work to be performed through September 30, 1977. With the concurrence of the signatory agencies, it will be extended as required to complete the Project.

8. *Financial Provisions*

Each Agency is responsible for funding its own personnel, with respect to salary and travel. GS will assume responsibility for grants, contracts, and similar funding arrangements, except as may be agreed upon in the future among one or more of the Participating Agencies.

9. *Reports*

The GS shall be responsible for publication and distribution of Annual Report(s) and completion of study preparation and publication of results.

10. *Revisions and Amendments*

From time to time GS, BM, OMPRA, FEA, FPC and ERDA mutually may consider it desirable to supplement, revise, or amend this Agreement in certain respects.

11. *Approval and Accepted*

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Title: Director
Date: December 10, 1976

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By: H. Enzer
Title: Chief
Date: (Undated)

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Title: Director
Date: January 19, 1977

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FEDERAL POWER COMMISSION
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