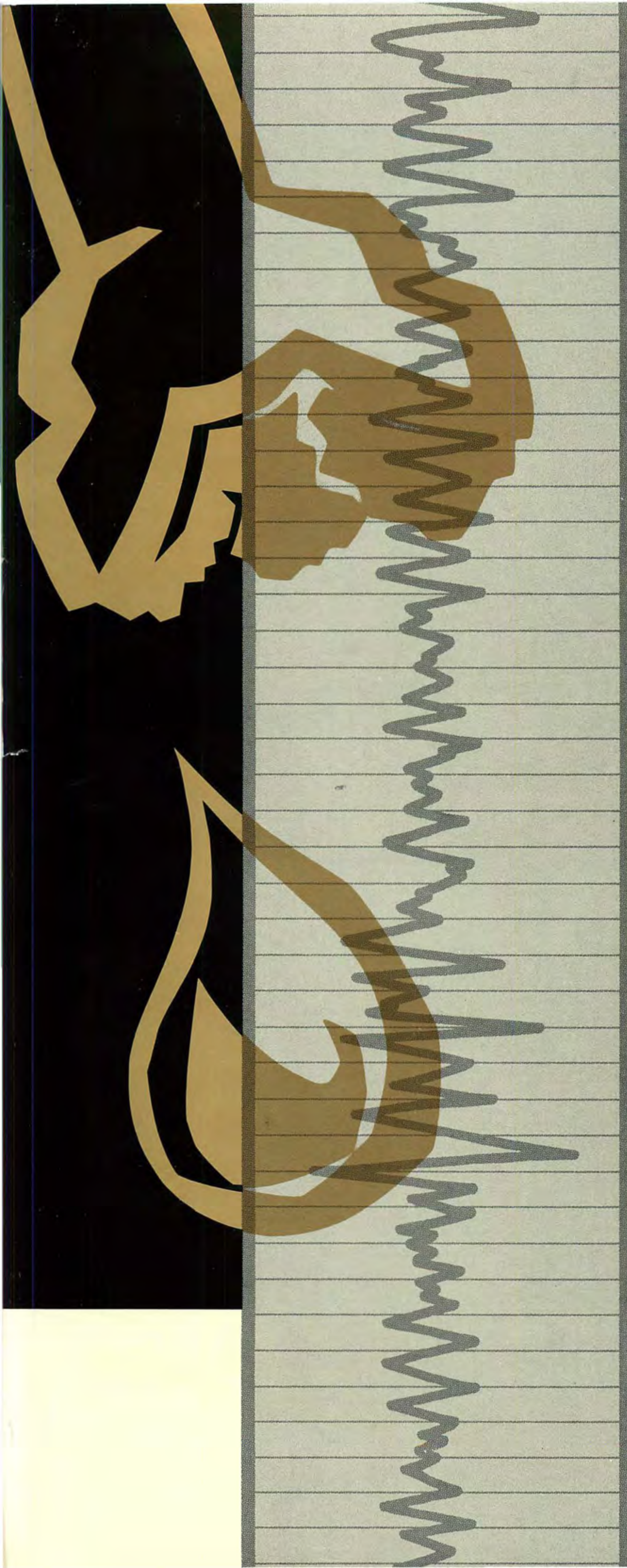

IMPACT
OF NEW TECHNOLOGY
ON THE U.S. PETROLEUM INDUSTRY 1946-1965

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IMPACT

OF NEW TECHNOLOGY ON THE U. S. PETROLEUM INDUSTRY 1946-1965

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Prepared by the
National Petroleum Council
in response to a request of the Department of the Interior

IMPACT

OF NEW TECHNOLOGY

ON THE

U.S. PETROLEUM INDUSTRY

1946 - 1965

Prepared by
the National Petroleum Council's Committee
on Effects of New Technology on the Petroleum Industry
Richard C. McCurdy, Chairman

with the assistance of the
Subcommittee for New Production Technology
Lloyd E. Elkins, Chairman
and the
Subcommittee for New Refining Technology
Donald G. Stevens, Chairman

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FOREWORD

Since World War II many rapid advances in technology have been taking place which have had a marked influence upon the exploration, production, refining and transportation operations of the petroleum industry. Because these petroleum industry activities have an important impact on the overall economy and well-being of the United States, the Government needs to be adequately informed about the significant advances being made by scientists and engineers, particularly as they relate to industry operations.

With this in mind, officials of the Department of the Interior asked the National Petroleum Council, in 1965, to study this highly specialized field to evaluate the impact of the new knowledge and procedures upon petroleum productive capacity, recovery factors in oil fields; yields of petroleum products at refineries and upon their related product quality changes. Such conclusions and expert industry opinions as to future technologic trends as would seem appropriate and helpful were requested.

Responsive to the request of the Department of the Interior, the study was undertaken by the Council and completed in the Summer of 1967. The report was made by the Council's Committee on Effects of New Technology on the Petroleum Industry, under the Chairmanship of Richard C. McCurdy, President of Shell Oil Company, and the Co-Chairmanship of Onnie P. Lattu, Director of the Office of Oil and Gas, U.S. Department of the Interior.

The overall task was divided into two major parts —production technology (Part I) and refining technology (Part II). Vice Chairman for the production technology phase of this study was E. H. McCollough, Chairman of the Board of Amerada Petroleum Corporation. The Subcommittee for New Production Technology was headed by Lloyd E. Elkins, Production Research Director of Pan American Petroleum Corporation as Chairman, and R. F. Meyer, Office of Oil and Gas, as Government Co-Chairman. The material contained in Part I was developed by this Subcommittee.

Vice Chairman for the refining technology part of this study was Charles E. Spahr, President of The Standard Oil Company (Ohio). The Subcommittee for New Refining Technology was headed by Donald G. Stevens, Vice President of The Standard Oil Company (Ohio) as Chairman, and W. D. Luening, Office of Oil and Gas, as Government Co-Chairman. The material contained in Part II is the result of that group's efforts.

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PART I

IMPACT OF NEW TECHNOLOGY ON U. S. PETROLEUM EXPLORATION AND PRODUCTION

Contents of PART I

IMPACT OF NEW TECHNOLOGY ON U.S. PETROLEUM EXPLORATION AND PRODUCTION

CHAPTER ONE

CONCLUSIONS AND SUMMARY

SECTION 1—Introduction

The effects of the developing technology of the twenty-year period 1946-1965 upon crude oil exploration and production in the United States are presented in Part I of this volume, together with an assessment of the performance by the industry that will be required in these areas to meet the estimates of future crude oil demands made in 1965 by the Bureau of Mines, U.S. Department of the Interior.

These technological improvements are related, as quantitatively as is possible, to their effect on current U.S. crude oil productive capacity and recovery. The twenty-year history of an improving technology and its impact on the crude oil picture serves as a basis of judgment as to the effect of possible or anticipated technological advances on productive capacity and even better recovery efficiency through the next decade.

It is important to recognize that the operations of the petroleum industry are influenced, not only by advances in technology, but also by geological conditions and economic and government policy factors. These factors are so interrelated that their influence cannot be measured separately. Part I treats, in some depth, specific technological advances made since World War II in exploration, drilling, production and reservoir recovery. It also attempts to measure the influence the advances have had on the overall operations of the industry. A separate study, undertaken by the National Petroleum Council simultaneously with this one, and issued in January, 1967, entitled "Factors Affecting U.S. Exploration, Development and Production," presents an effort to analyze all the major factors including economic, government policy, geological and technological, that have affected exploration, development and production since 1945. The treatment of technology in that report appears in context with the purpose of that study and is based on the far greater detailed study of technology contained in Part I of this book.

Chapter One contains conclusions and summary material based upon an analysis and interpretation of the facts and detailed data contained in the other chapters of Part I. These chapters (Two to Seven) and sections thereof were prepared by recognized authorities in each applicable field. The individually authored portions of Part I are basically the effort of those individuals whose names appear at the beginning of the separate chapters or sections. However, these individual efforts also reflect the advisory assistance of all the Subcommittee members, as well as general concurrence with the content of the overall report by the members of the parent Committee on Effects of New Technology on the Petroleum Industry.

The Summary in Chapter One highlights the major technological developments covered in Chapters Two to Seven and their impact on five crude oil supply factors. It also contains a discussion of the performance needed by industry to meet U.S. Bureau of Mines estimated crude oil demands through the 1970's.

The Sections of the Summary are as follows:

A. The Impact of New Technology on Crude Oil Discovery
B. The Impact of New Technology on Crude Oil Recovery
C. The Impact of New Technology on Crude Oil Productive Capacity
D. The Impact of New Technology on Cost Reduction
E. The Impact of New Technology on Transportation
F. Some Guidelines of Discovery and Recovery Performance Needed Through the 1970's to Meet U.S. Bureau of Mines Estimated Production of Domestic Crude Oil

Each of the six sections is supported by charts indicating the impact of new technology on crude oil supply, as reflected in certain industry performance trends. To correlate important new specific technological advances with general industry performance these have been profiled chronologically as "time-lines" which show their evolving development during the period 1946-1965. The time-lines start with the introduction of a particular idea or practice, and progress through *experimental—field testing (or infancy),* into *semiproven—gaining acceptance (or youthful),* and finally to *accepted in general practice (or mature).* In some cases, a technological development will die out before reaching general acceptance. In others, a practice considered *mature* may yet be far short of its maximum application.

SECTION 2—Conclusions

During the twenty-year period following World War II—1946 to 1965—the development and use of both new and improved technology, as well as the more effective application of previously known technology, rapidly accelerated in the exploration and production phases of the petroleum industry. Through extensive research new tools, techniques and procedures were discovered, and widespread testing was undertaken to determine their practical effectiveness. The full impact of many of these developments has not yet been attained.

These technological developments had a major impact on inland and offshore exploration for oil, on drilling rates and depths, on the amounts of crude oil obtainable from previously discovered fields, on the rates of production under sound conservation practices, and on the costs of drilling, development, production and transportation. From this experience and in the light of more recent technological developments a momentum has been achieved that can be expected to result in additional developments and continued favorable impact on these areas of operations well past the 1970's.

A. Exploration

New technology had a growing favorable impact on discovery efficiency by providing tools and methods for improved selectivity in choosing drilling prospects, even though remaining geological opportunities in the United States were somewhat reduced in the well-explored areas during the latter part of the twenty-year postwar era. While the actual number of wildcat wells (rank exploratory) drilled each year has been declining since 1956, the total volume of new oil found per new field wildcat drilled has apparently been sustained at a constant level since 1955. This occurred following a severe decline in oil found per new field wildcat in the period 1946 to 1955, when the number of wildcats was increasing rapidly. The trend in total new oil in place discovered per year has declined since 1948, although new technology during the past five years should be credited with contributing to the leveling off of this trend.

The evolution of technological improvements for offshore exploration and development in progressively deeper waters on the Continental Shelf of the United States has opened vast new geographical areas for exploration. Improved geophysical techniques, advanced geological concepts and application of new methods for deeper drilling have all permitted exploration down to depths not possible a few years ago, which opened new sedimentary basins for exploration. Formation fracturing and commercialization of thermal recovery methods have broadened the spectrum of exploration opportunities in formations which could not be efficiently or profitably produced prior to the development of these methods.

Through the 1970's, in order to meet the demands for U.S. crude oil estimated by the U.S. Bureau of Mines, it would be necessary for the industry's exploration efforts to result in the discovery of an average of about 6 billion barrels of total oil in place per year, if import controls are continued as at present and the current reserves to production ratio (18.3 to 1)* is maintained. This is about 25 percent a year more than the experience of the last seven years. The extent to which these increased demands will be met in the future will be highly dependent on technology not yet developed and improved technology not fully applied.

* Based on primary and fluid injection reserves estimated by the Interstate Oil Compact Commission (rather than API reserve estimates). See Appendix Table 3, page 25; Table 2, page 24; and pages 28 and 43.

B. Producing Previously Discovered Fields

An estimate of the impact of technology since World War II on both exploration effectiveness and recovery efficiency requires as a base an estimate of the history of the cumulative total oil in place discovered in the United States. Such an estimate would represent the aggregate production from all oil-bearing reservoirs since their discovery plus estimates of the total remaining oil within those reservoirs. The analysis made in this study indicates that by 1965 about 350 billion barrels of oil in place had been discovered in the United States.

The amount of oil which can be recovered economically is dependent on physical properties of the hydrocarbons, reservoir and rock characteristics, and prevailing technology at any point in time. Of the estimated 350 billion barrels of oil in place discovered in the United States, it is estimated in this study that about 36 percent or about 128 billion barrels of oil has been or will be recovered under 1965 economic and technological conditions.

It is further estimated in this study that cumulative oil recovery effectiveness, which includes oil added by revisions in reserve estimates during the period, has increased from 26 percent of the oil in place in 1945 to about 36 percent in 1965. There is good reason to expect continued improvement in oil recovery efficiency through the 1970's. The magnitude of the increase will be largely dependent upon the timing and degree of utilization of developed, developing and new technology, as well as the demand for and price of crude oil. If conditions are favorable, it is not unreasonable to anticipate increases at rates approaching those of the past twenty years. However, the rate of improvement of recovery efficiency may be expected to decline as higher total recovery is attained. An ultimate economic recovery efficiency of at least 50 to 60 percent of the oil discovered appears within reason. Recoverable reserves from oil in place already discovered will continue to be increased by improvements in production technology.

While methods for increasing recovery of oil in place by injection of water and gas into oil pools have been known for many years, such procedures became particularly important during the twenty-year period under review. This was due to development and application of new or improved fluid injection technology, together with advanced reservoir engineering knowledge. Such injection procedures have been principally responsible for improvement in oil recovery efficiency. The injection of water in conjunction with heat, chemical additives and polymers, and water which is foamed, emulsified, or solubilized in oil are new developments now on the threshold of application and merit optimism for continued improvement in recovery efficiency.

C. Productive Capacity

Productive capacity for oil is the maximum daily rate that can be produced from existing wells with the condition that such rates do not cause loss of recoverable reserves. Of course productive capacity is contingent first upon the finding or discovery of new oil and then on recovery capability.

It is significant that the ratio of productive capacity to actual production of domestic crude oil has steadily increased since the early 1950's. Improved well completion, fluid injection, formation fracturing, and operating technology have sustained or increased productive capacity in many older fields and augmented productive capacity from more recent discoveries.

D. Cost Savings

The application of new or improved technology in the past twenty years has resulted in substantial cost savings, thus in turn making a significant contribution toward the generation of funds from production operations. Evolving new technology combined with direct cost reduction efforts since 1946-1950 have resulted in an estimated annual cost savings equivalent to between eighty-five cents and a dollar per barrel of oil produced in 1965. Wider well spacing, faster drilling rates, fluid injection, extensive use of automation and conservation of materials represent the main contributing factors to this accomplishment. Application of new technology in the future, as well as continued management effectiveness, give promise of additional cost savings. However, the magnitude of savings which can be ultimately realized through known technology has practical maximum limitations.

E. Transportation

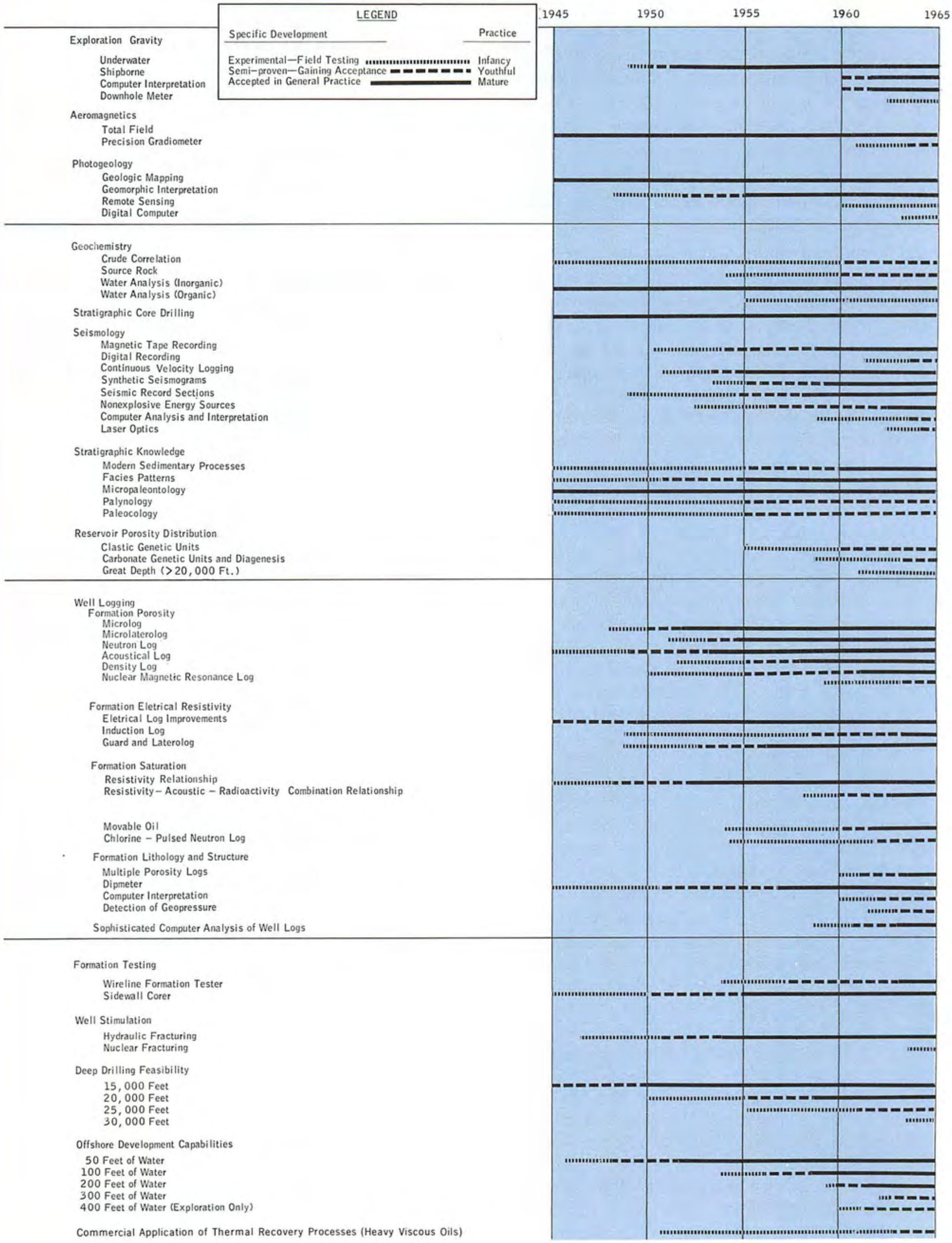
Crude oil and liquid products are transported by pipeline, tanker, barge, rail and truck. New technology in the past two decades has been extensively applied to all these forms of transportation. The result is significant particularly in the case of pipelines, through which the bulk of crude oil movements to refineries are made. In this area the developments include highly automated large-diameter thin-walled (high-strength steel) pipeline systems. Unit pipeline tariff costs have declined about 15 percent during the past fifteen years. In this same period wage and basic materials costs almost doubled. In the case of water transportation some cost reductions have been made in coastwise shipping through the use of larger tankers. As even larger vessels are put into service, unit cost reductions of as much as 50 percent may be attained.

F. Outlook For The Future

The Bureau of Mines has estimated that the 1965 annual crude oil production rate of 2.7 billion barrels would increase to a level of 3.8 billion barrels in 1980. This estimate of growth was predicated on the assumption that crude oil would retain approxi-

CHART **IA**

The Impact of Technology on Crude Oil Discovery



mately the same share of the energy market it held in 1965, and that the 1965 ratio of imported oil to domestic production would be generally constant.

The industry's capability, with continued application of technological improvements, to find new oil and to recover an increasingly higher percentage of discovered oil are such as to indicate that the Bureau of Mines estimates through the 1970's are within the range of attainment. Meeting these estimated future requirements will, however, require an increasingly aggressive program of exploration and development, and the continuing intensified application of current and developing technology, as well as accelerated research, development and utilization of new technology.

SECTION 3—Summary

The following summary represents an effort to correlate, to the extent possible, a wide range of specific technological improvements (indicated by the several time-line charts) with general industry operational performance trends (depicted by the statistical curves) for the various areas of operation discussed in the Conclusions.

A. Impact of New Technology on Crude Oil Discovery

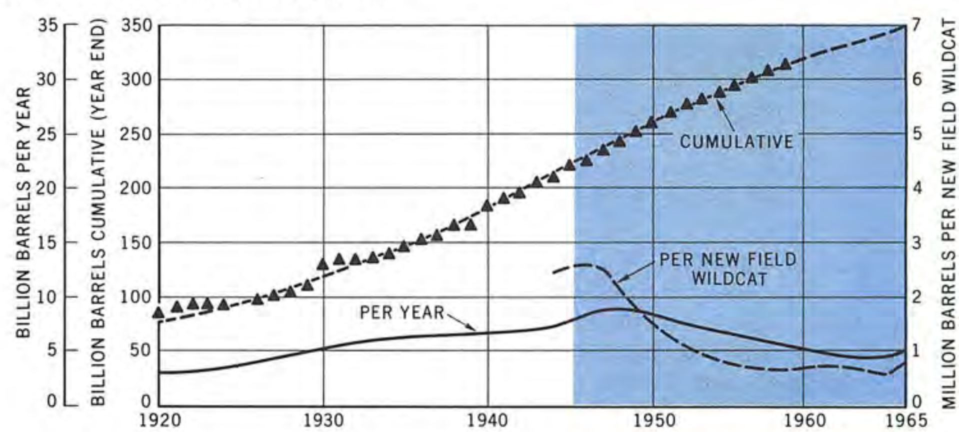
Both the maintenance and potential expansion of the petroleum industry's domestic crude oil producing capability depends first on a continuing program of exploration for, and discovery of new oil reserves. Once new oil is discovered, then technology relating to reservoir performance and production operations becomes the major element in developing producing capacity and obtaining the maximum oil recovery.

Perhaps the best yardstick that can be used to measure the effectiveness of the oil exploration efforts is a series of estimates of total oil in place discovered. This study includes such a series of estimates. The data and the method employed in arriving at them are discussed fully in the Appendix to this Chapter.

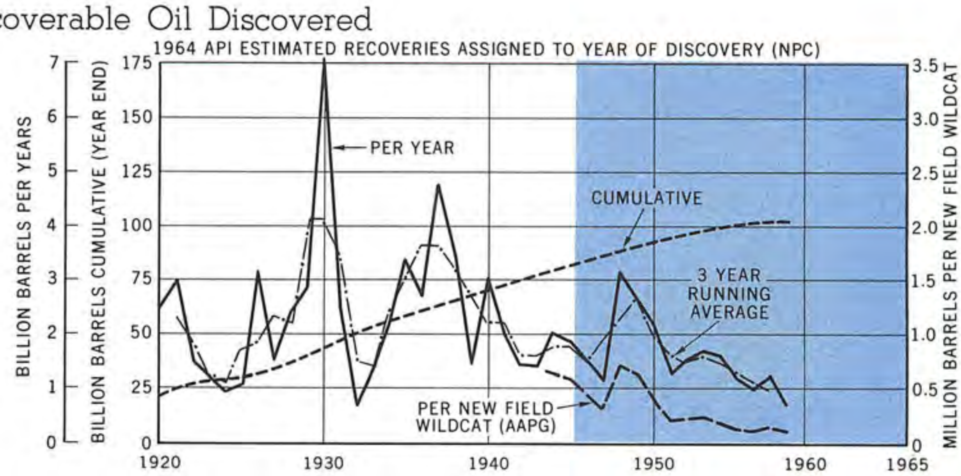
On Chart I is a constructed history, since 1920, of the estimated (as of 1965) cumulative total oil in place discovered in the United States in all oil fields commercially developed. There is also indicated on Chart I the total oil in place discovered per year over

CHART I

Total Oil in Place Discovered



Recoverable Oil Discovered



this 45-year period, as well as per new field wildcat since 1944. Discovery trends of the recoverable oil from such oil in place discovered are shown utilizing previous National Petroleum Council studies on this subject. Both the oil in place and recoverable oil estimates have been credited back to the year in which the oil fields were initially discovered.

The latest Council study on proved discoveries (issued in 1965) provides a recast of already known reserves estimates for crude oil, as of December 31, 1963, as made by the American Petroleum Institute, arranging these estimates according to the discovery years of the fields to which the reserves are attributed. The tabulations were carried only through the year 1958. The discovery estimates given in the Council's 1965 report represented the total expected recoveries of crude oil, including both past production and remaining proved reserves, based upon field size and past performance *as such factors were known on December 31, 1963*. As suggested by that study, comparisons of those estimates of proved discoveries with prior estimates made by the NPC and others show that the estimated recovery from the average field usually increases severalfold over the estimate made at the end of the discovery year, and continues to increase from various causes for a great many years. Such tabulations are useful, therefore, in providing through such comparisons insight into the magnitude and rate of increase of recovery estimates.

Based on the above information, and using current technology and knowledge of the types of reservoirs in the geological regions that were being explored or discovered during the decades prior to and after 1920, this study assigned an estimated cumulative recovery efficiency factor to each decade from 1919 up through 1958.

The trend of cumulative total oil in place discovered was established by taking the estimates of proved discoveries at the conclusion of each decade (cumulative production plus known reserves under 1964 conditions) and dividing these figures by the assigned currently estimated cumulative recovery efficiency factor.

These estimates indicate that about 350 billion barrels of crude oil in place had been discovered in the United States as of 1965. Over one-third of this oil is estimated in this study to be economically recoverable by application of existing technology. An enormous inventory of discovered oil remains to be recovered by improved technology.

Nevertheless, it should be emphasized that no matter how much improved technology may increase the yield from oil fields that are discovered, new inventories of oil can only be supplied by the discovery of additional fields. An indication as to the increasing difficulty in discovering new domestic crude oil deposits is shown by the falloff in the number of giant oil fields discovered in recent years (see following table).

DISCOVERY HISTORY [a]

DECADE	GIANT FIELDS DISCOVERED (Over 100 MM Bbls.) [b]
1870 to 1910 (4 decades)	21
1910 to 1920	32
1920 to 1930	65
1930 to 1940	70
1940 to 1950	43
1950 to 1960	25
1960 to 1966 (6 years)	5
Total	261

a—Walter C. Link, *Oil and Gas Journal,* August 22, 1966.
b—Recoverable Oil, 1965 Conditions.

From the late 1940's to the late 1950's, the trend in new oil in place discovered, per year, was downward, but leveled off thereafter, as shown on Chart I. There is little question that new technology is playing a major role in this trend, and that it has been responsible for considerable volumes of newly discovered oil. Technology has an impact on the exploration for new oil in three ways: by providing tools and methods for improving discovery efficiency; by opening new oil environments (i.e., offshore, greater depths); and by providing cost reduction.

Developments in exploration technology have been largely evolutionary over the past twenty-year period. While a number of new tools have been developed, the mainstays of exploration are still seismology and subsurface structural mapping, with the use of stratigraphic methods growing rapidly. The following chart illustrates the use of these and other methods since 1920.

Relative Efforts on Major Exploration Methods in the U.S., 1920-1965

The various tools used by the oil explorationist, and their present stage of development, are shown on Chart IA. No attempt has been made to indicate their relative importance. Many of these are still developing and will be proved only by the test of time and usage. Notable among the tools and methods employed in the exploration field are the following:

1. GRAVITY SURVEYS, AEROMAGNETIC, AND PHOTOGEOLOGY—These are principally tools of reconnaissance developed many years ago. As indicated in the time-lines on Chart IA, some new developments in the application of these old tools are essentially in their infancy or youth but may prove important in the next few years.

2. GEOCHEMISTRY—This is partially a reconnaissance tool and assists in subsurface and modern stratigraphic studies. Crude oil correlation, organic water and source rock studies have a bright future as they reach for maturity.

3. SEISMOLOGY—There have been a number of important developments in seismology with magnetic tape recording, continuous velocity logging, seismic record sections and nonexplosive energy sources having the greatest impact. Computer analysis and interpretation of seismic data is fast maturing. Laser optics, while still essentially experimental, may very well prove to be a most desirable optical system for processing seismic data. The full impact of these new developments may well be realized in the next few years.

4. STRATIGRAPHIC KNOWLEDGE—Through the study of recent sedimentary processes stratigraphic knowledge has been acquired. Knowledge of factors controlling porosity development and distribution is increasing. Through studies of facies patterns, palynology, and paleoecology, the geologist has become more intimately familiar with the geologic history of basins where petroleum might be found.

5. WELL LOGGING—A number of significant improvements in well logging have been valuable to oil exploration activities. Of particular importance are the microlatero, the induction and the acoustical logs. A number of developments within the last five years show considerable promise.

6. COMPUTERS—In both the fields of geophysics and geology, the computer has provided considerable assistance by supplying and analyzing information and revealing relationships that heretofore were impractical to develop. While utilization of the computer is an excellent supplemental tool in the hands of the explorationist, it of course cannot be substituted for an intimate knowledge of geologic history. Successful oil finding has always relied heavily on imaginative analysis by the explorationist.

A number of notable technological developments outside of the strictly exploration field have had a marked effect on oil discovery efficiency rates during the past twenty years. Among these are:

1. HYDRAULIC FRACTURING—The introduction of hydraulic fracturing techniques in this period stimulated the flow of oil from "tight" or low permeability formations. These new techniques made feasible the development of many formations not previously commercial. Since its inception it is estimated that this process has resulted in the addition of 5.7 billion barrels of recoverable reserves from new reservoirs.

2. DEEPER DRILLING—The industry's ability to drill wells to greater depths at faster penetration

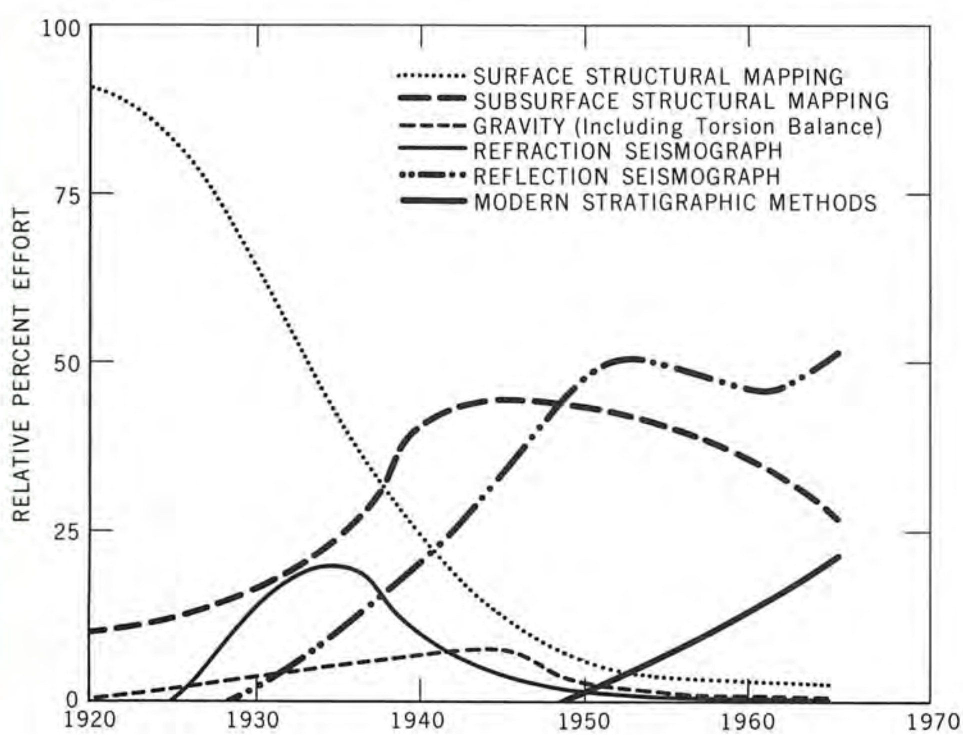
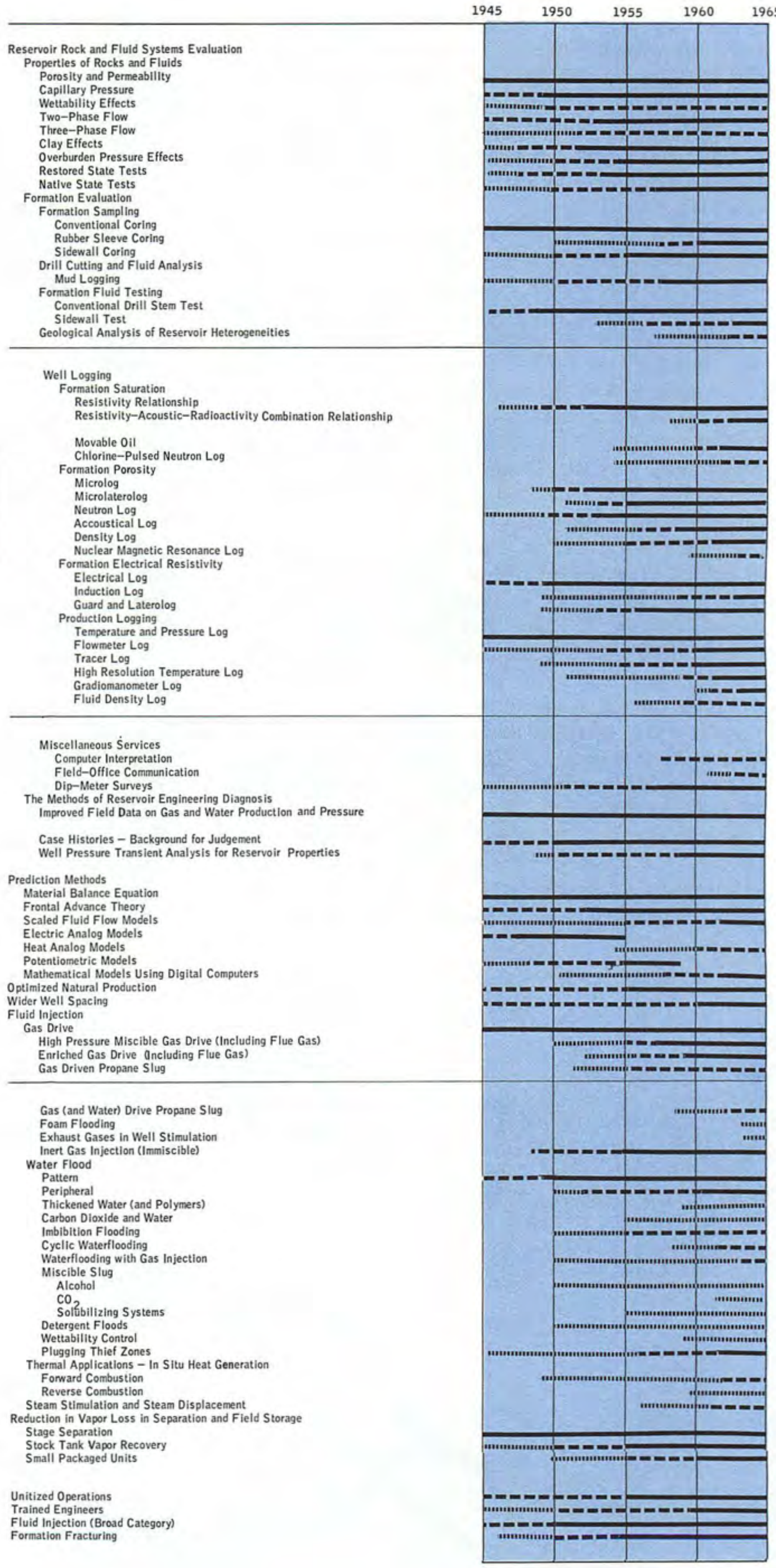


CHART IIA
The Impact of New Technology on Crude Oil Recovery

LEGEND

Specific Development		Broad Practice
Experimental–Field Testing	··········	Infancy
Semi–proven–Gaining Acceptance	– – – –	Youthful
Accepted in General Practice	———	Mature



rates has opened up deeper horizons to exploration. Before 1945 only two wells had been drilled as deep as 15,000 feet, but over 330 were drilled below this depth in 1965. Depths of 20,000 feet are now becoming common. However, such deeper drilling generally comes at a high cost, and in many cases lower porosity and higher oil shrinkage make the deeper formations less attractive prospects than shallower reservoirs. These factors, on the other hand, are frequently more than offset by wider well spacing patterns.

3. OFFSHORE EXPLORATION CAPABILITIES—Practical methods for drilling and producing oil in offshore waters of the United States have been developed entirely since 1946. This offshore development capability has opened for exploration the Continental Shelf of the United States including Alaska. Exploration and drilling activities are now feasible in deeper waters than are producing operations. The time-lines on Chart IA indicate that development capabilities in water 300 feet deep are in the youthful stage.

4. THERMAL RECOVERY—The commercial application of thermal recovery processes to heavy viscous oil broadens incentives for exploration for this type of oil. Exploration will be required to define and lay out the estimated 50 billion barrels of heavy oil in place in the U.S.* in the better prospects. This amount of oil can be added to the inventory of total oil in place if it can be produced profitably. The development of thermal processes which will make this possible appears close at hand. Some of this oil has already been included in the most recent estimates of original oil in place made by the Interstate Oil Compact Commission.

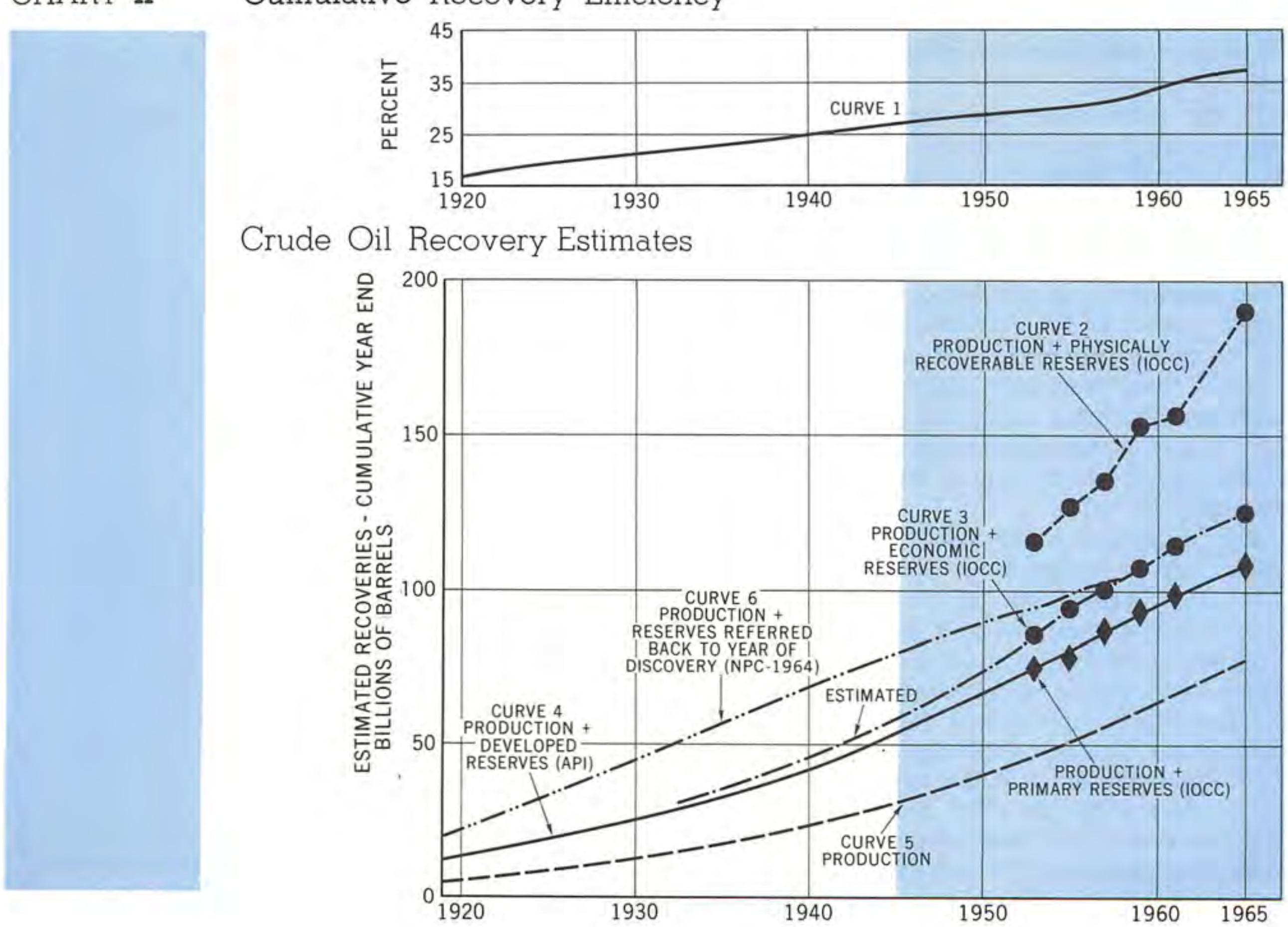
B. Impact of New Technology on Crude Oil Recovery

No precise estimate can be made of the improvement in average oil recovery efficiency rates over the past twenty-year period. Such estimates are subject to many indeterminable variables. That substantial improvement in recovery efficiency has actually occurred is certain.

Through the analysis herein an attempt was made to derive a trend for estimated cumulative recovery efficiency which prevailed at any time back to 1920 (see *Curve 1* on Chart II). This was done to provide

* U.S. Bureau of Mines, *Information Circular* 8263 (1965).

CHART **II** Cumulative Recovery Efficiency



some measure or "order of magnitude" of improvement in oil recovery rates, so as to use these indicated gains as a basis for judging what might be reasonable to expect in the near future. The methods employed in this study in developing these estimates are explained in detail in the Appendix to this Chapter. In essence, the estimates were arrived at by taking the total proved discoveries, i.e., total recoverable oil (cumulative production plus known reserves) at any one time and dividing by the estimated cumulative total oil in place discovered at that same time. This reflects the level of recovery capability either *real* or *recognized at that time*. These same elements are described in the preceding section in the discussion concerning development of estimates of cumulative total oil in place discovered by decades.

The trend thus developed in this study indicates that the estimated cumulative recovery efficiency for the total crude oil in place discovered, which includes oil added by revisions in reserve estimates, increased from about 26 percent in 1945 to about 36 percent in 1965 (see Chart II). This incremental percentage increase in recovery efficiency (i.e., 10 percent) is equivalent to about 35 billion barrels of additional recoverable oil (or 10 percent of 350 billion barrels of oil in place discovered). Carefully selected and engineered fluid injection processes and optimum use of primary recovery techniques presently being employed frequently recover 60 to 70 percent of the oil in place from some types of reservoirs, but unfortunately the recovery is as low as 10 to 20 percent in others.

In the same twenty-year period, the estimated total increase in recoverable oil—which estimate reflects not only improved technology, but also new recoverable oil found and revisions of reserve estimates—was around 70 billion barrels (see *Curve 3* on Chart II). According to these estimates, then, about one-half of the 70 billion barrel increase in recoverable oil in the 1946-1965 period is attributable to this improvement of technology applied to recovery from previously discovered reservoirs or reservoirs discovered during this period. Part of this is, of course, attributable to better methods for predicting recovery from some of the older water-drive reservoirs.

Several factors which have had an important effect on recovery efficiency are:

1. The development of reservoir engineering principles, confirmed by field performance experience, has enabled the petroleum engineer to predict confidently reservoir performance and design effective fluid injection programs for various types of oil reservoirs. This has resulted in the early initiation of such programs in new fields, as well as widespread use in older fields. In 1965 over one-third of the oil production in the United States came from fields under fluid injection. The growth of these projects is shown in the following table:

YEAR	ANNUAL OIL PRODUCTION FROM FIELDS UNDER FLUID INJECTION * (Million Barrels)
1946	250
1950	315
1955	485
1960	730
1965	980

* IOCC Report (December 1966).

2. The number of petroleum engineers trained in reservoir science increased from about 250 in 1945 to approximately 5,000 in 1965.

3. The optimized control of natural production from reservoirs operating under primary energy sources has become accepted practice.

4. Unitized operations which rapidly evolved during this twenty-year period, permit the most efficient use of fluid injection techniques as well as other important benefits.

5. Enabling legislation in many states has permitted more efficient production practices and encouraged unitized operations.

6. Formation fracturing has permitted the recovery of an estimated 7.3 billion barrels of oil otherwise unrecoverable, 5.7 billion of which was from new wells made commercial by fracturing and 1.6 billion from wells previously completed.

The time-lines on Chart IIA indicate the many significant improvements in the tools of the petroleum engineer. They relate to measurement of reservoir rock and fluid systems properties, including physical testing and logging, and to engineering methods for analyzing and predicting performance of a variety of recovery processes. These tools are being effectively applied.

These time-lines also indicate the excellent future potential for fluid injection. Many improvements are expected in gas injection, water injection, and thermal recovery processes. Many of these are still in the experimental or infancy state, and provide a basis for anticipating major improvements in the next decade.

Recovery estimates are cumulative and apply to the total amount of oil in place discovered in the United States at any given time. The characteristics of some reservoirs and oils are such that the maximum economic recovery efficiency anticipated is 10 to 20 percent. In achieving the estimated current average recovery efficiency of approximately 36 percent, it has been necessary to operate many reservoirs at a much higher recovery efficiency. A significant volume of oil previously discovered is in reservoirs from which the recovery has been or will be 50, 60 and 70 percent. But in many other reservoirs, some of which have already been abandoned, recovery is considerably less. If the cumulative recovery efficiency continues to advance at the indicated past rate in the range of one-half percent a year, it will be necessary to develop new technology as well as fully apply present technology. Nevertheless, past accomplishments and present research provide reason to believe that technology will be developed which will ultimately enable the recovery of at least 50 to 60 percent of the total oil in place discovered.

The rate of improvement of recovery efficiency will expectedly taper off as the ultimate level of 50 to 60 percent is approached. The likelihood of major recovery improvements from water flood additives and thermal processes should have a significant impact on recovery efficiency through the 1970's; thus, any serious "tapering off" should be delayed for a decade or two.

C. Impact of New Technology on Crude Oil Productive Capacity

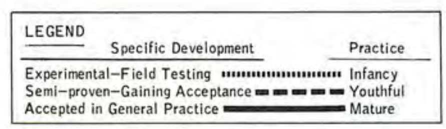
The productive capacity in the U.S. for crude oil is the amount of oil that could be produced on any given date from all then existing oil wells without the loss of recoverable reserves. The amount of productive capacity is basically controlled by the volume of new oil in place discovered and by the efficient development and production of the reservoirs.

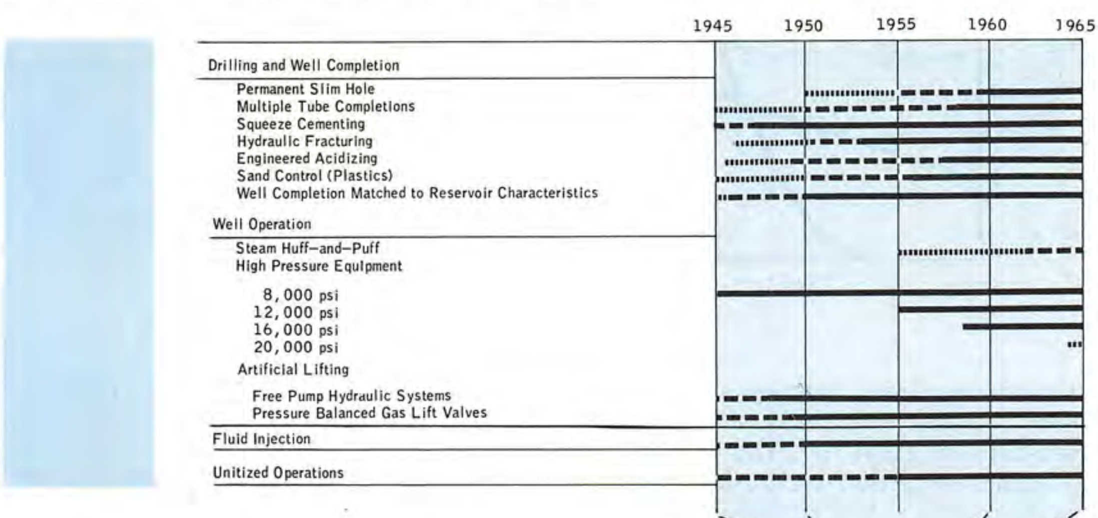
It is significant that the productive capacity for crude oil in the U.S., as estimated by the National Petroleum Council, increased from 6.7 million barrels daily on January 1, 1951 to 12.1 million barrels daily as of January 1, 1965 (see Chart III). During the same period domestic crude oil production increased from 6 to 7.4 million barrels per day.

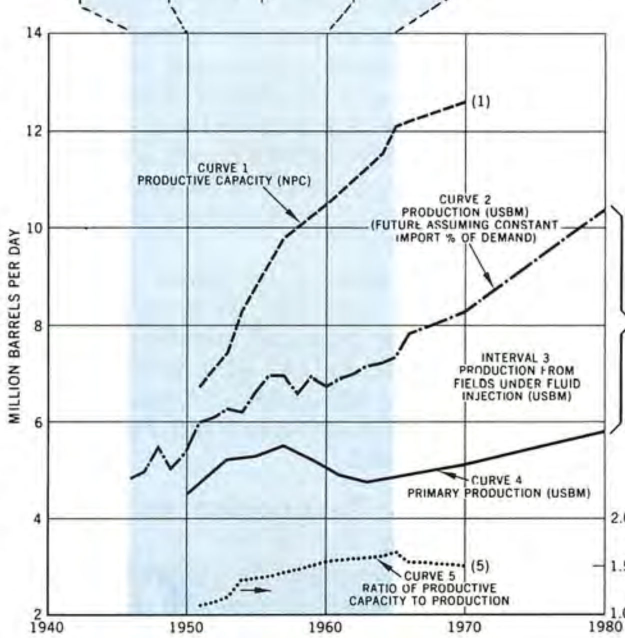
In a study published by the Department of the Interior in 1965, the U.S. Bureau of Mines made estimates of demand for domestic crude oil to 1980. It was assumed in these estimates that oil and gas would supply its 1965 share of the energy market through the 1970's, and that the existing import policy would remain essentially unchanged. The need

CHART **III**

Crude Oil Production and Productive Capacity





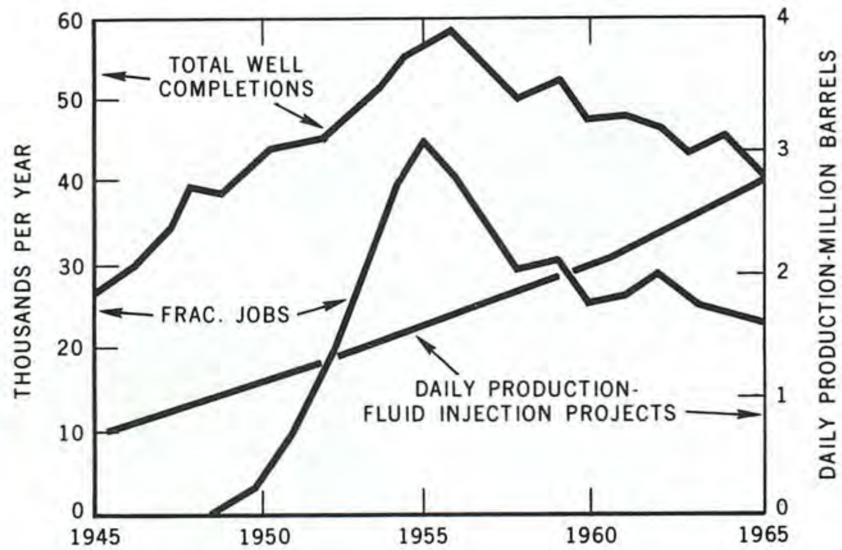


for a growing productive capacity to meet this demand is shown on Chart III. These estimates recognize the importance of fluid injection in past growth of productive capacity and expect it to contribute significantly in the future.

The major technological factors which have favorably affected productive capacity since 1950 have been hydraulic fracturing and the accelerated application of fluid injection. Their usage is indicated on the graph below.

cost savings in drilling, production and transportation. Although it is difficult to measure these cost savings quantitatively, it is generally recognized that petroleum product prices to the consumer are much lower than would have been feasible without the technological advances.

It is virtually impossible to ascertain the true cost of finding and developing a barrel of crude oil at any point of time. While there are many reasons for this, basic in such cost analyses is the determination



of the amount of oil discovered in a given reservoir. This estimate is subject to even greater than usual question when made soon after discovery since minimum information is available as to the size and character of the reservoir. In drilling and producing operations it is difficult to make cost comparisons for similar activities at different times. It is not possible to separate accurately, cost savings attributable to advanced technology from those due to good management and the high degree of competition prevalent in the petroleum industry.

The matching of well completion techniques to reservoir characteristics also contributed to improved productivity (see time-lines on Chart III). This has become significant during the period under study and is a result of improvements in logging methods, and better understanding of reservoir technology, as well as of improved specific well completion techniques. The time-lines show that a number of techniques in the areas of drilling and well completion have become mature during the period.

Steam stimulation has markedly increased productive capacity in old heavy oil fields, especially in California.

Another important factor is the advent and extensive use of unitized operations. With unitization, wells which cannot be produced without wasting reservoir energy are shut in, and wells with greater capacity are produced efficiently at higher rates. Thus, reservoir energy is conserved and maximum productivity is maintained.

D. Impact of New Technology on Cost Reduction

New and improved technology in the 1946-1965 period, in addition to providing better oil discovery and recovery efficiency, also provided substantial

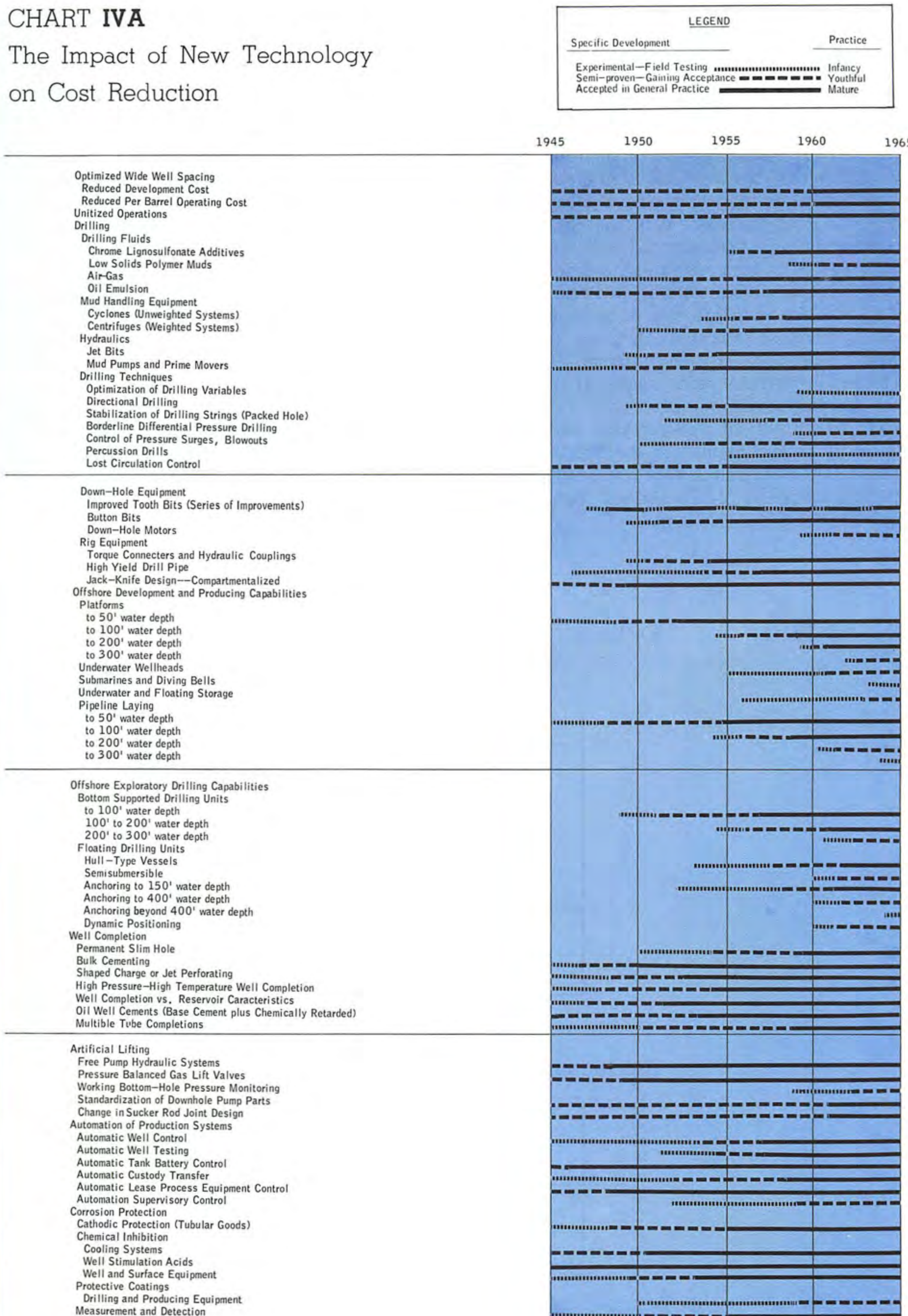
Certain published cost information is available, however, which this study analyzed in an attempt to develop an "order of magnitude" of cost savings during the period. Drilling and production costs are compared with relevant cost indices. These analyses are presented in more detail in the Appendix to this Chapter.

1. DRILLING—Cost reductions, through better technology, for drilling operations can be approximated by analyzing trends in the drilling rate per rig, and by comparing surveys of drilling costs with trends of accepted relevant cost indices.

Based upon the different estimating methods employed, it is indicated that in 1965 average costs were $13 per foot of hole drilled. This is estimated

CHART **IVA**

The Impact of New Technology on Cost Reduction



to be $6 to $7.50 per foot less than it would have cost had 1950 drilling practices been used (see Chart IV). An average savings of $7 per foot applied to the 136 million feet of oil drilling in 1965, is equivalent to a savings of $0.35 per barrel of oil produced in 1965.

2. PRODUCTION—Information on crude oil production costs are available from the Joint Association Surveys for most years covering the period 1955 to 1963. Applying cost index analysis, the annual production costs per operated well in 1963, had 1955 practices been employed, would have been $4,345 as compared to an estimated actual 1963 cost of $3,500. An annual savings of $845 per operating well is therefore indicated. Had this same rate of improvement been experienced from 1950 to 1965 (16 years instead of 9 years examined), it is estimated that the cost savings in 1965 over 1950 practices would be $1,500 per well per year (see Chart IV). This cost savings applied to the 580,000 oil wells operated in 1965, and in turn related to 1965 crude oil production of 2,686 million barrels, is the equivalent of $0.32 per barrel.

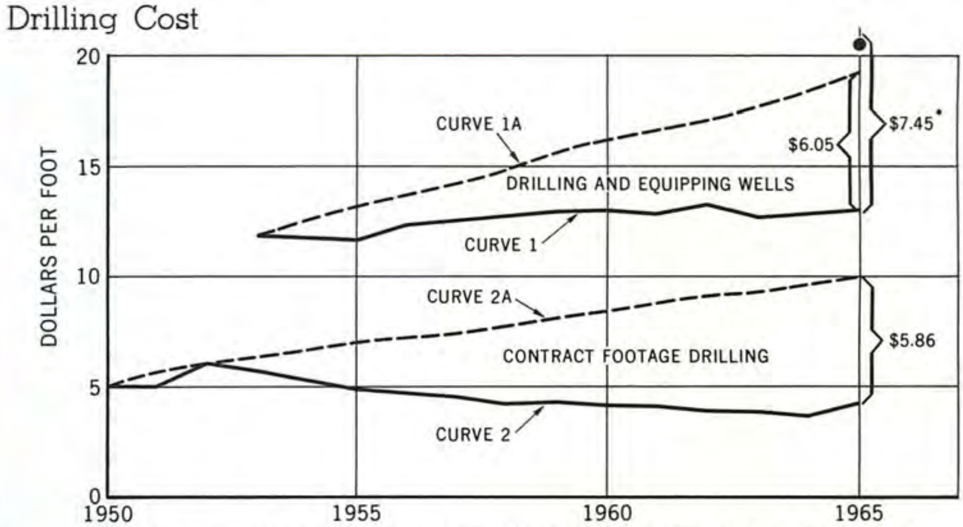
3. CORROSION CONTROL—During the last two decades technological advances in minimizing corrosion contributed to significant cost savings. Cathodic protection and chemical inhibition minimize corrosion in oil well casing, tubular goods, and operating equipment. This, of course, reduces repair and workover costs attendant to a tremendous investment accumulated over several decades. While corrosion has still not been completely eliminated, the cost reduction from corrosion prevention is estimated to be at least $0.09 per barrel of oil produced.* This, for the most part, is in addition to the savings in production cost discussed above.

4. WELL SPACING—The trend to wider well spacing is an outgrowth of reservoir engineering experience which proved that wells can efficiently recover oil over much wider surface areas than previously thought. As a consequence, fewer wells are now drilled in the development of a given oil reservoir than were drilled even a few years ago. This in turn has resulted in major savings in de-

* NACE—API Training Manual, 1958.

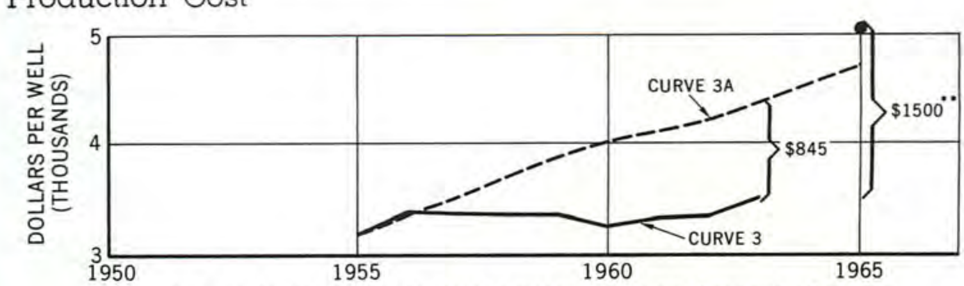
CHART **IV**

Drilling Cost



*Estimated 1965 Savings From Costs With 1950 Rather Than 1953 Practices. See Appendix.

Production Cost



Curve 1A, 2A, 3A, Costs if Followed Engineering News Record Construction Cost Index
Curve 1,3 Joint Association Survey
Curve 2 American Association of Oil Well Drilling Contractors

**Estimated 1965 Savings From Costs With 1950 Rather Than 1955 Practices. See Appendix.

velopment costs, and in many cases has permitted development of otherwise uneconomic fields.

Although comparative data are unavailable on well spacing practices over the twenty-year period under study, the following table shows the increasing number of state spacing orders and the trend from 20 acres or less per well in 1940-1950, to 40, 80 and 160 acres by 1962.

REPORTED OIL SPACING ORDERS ISSUED

	20 ACRES OR LESS	40 ACRES	80 ACRES	160 ACRES OR MORE
1940	25	6	0	0
1950	63	70	8	1
1955	159	136	46	4
1960	76	185	106	16
1961	113	259	207	15
1962	78	248	222	23

Over 18,000 oil wells were completed in 1965. It is reasonable to assume that if 1946 spacing practices were still in effect, then 50 to 100 percent more oil wells would have been completed in 1965 on closer spacing. A range of savings in costs due to wider spacing practices is thus indicated, as shown below:

	ACTUAL WELLS	NUMBER OF WELLS IF DRILLED ON CLOSER SPACING: 50% MORE WELLS	100% MORE WELLS
No. Oil Wells Completed—1965	18,000	27,000	36,000
Cost of Drilling and Completion MM$ (Avg. cost/well $52,000) [a]	935	1,405	1,870
Savings in Cost MM$	—	470	935
Oil Produced in 1965—MM Bbl.	2,686	2,686	2,686
Savings in Cost/Bbl.—1965	—	$0.175	$0.35

a-Joint Association Survey for 1963.

Based on the above four analyses, indications are that had 1950 practices been applied in 1965 to perform the same drilling and production operations, the estimated cost per barrel of oil produced would have been the equivalent of $0.76 per barrel higher (i.e., drilling—$0.35; production—$0.32; corrosion control—$0.09). In addition, the elimination of unnecessary drilling in 1965 through the use of wider well spacing practices provided estimated cost savings ranging from $0.175 to $0.35 per barrel of oil produced. The estimates indicate a total cost savings equivalent to about $1.00 per barrel of crude oil produced in 1965 has been attained through evolving new technology, interwoven with intensified cost reduction efforts.

On Chart IVA there are presented time-lines indicating the major technological developments that have had a bearing on cost reduction.

Optimized wide well spacing and unitized operations tend to increase production rate per well and consequently reduce the per-barrel operating costs.

A major part of cost reduction is attributable to the application of the latest technology to drilling. Drilling fluids that contribute to faster drilling, better hydraulics, better bits, better rig equipment and improved techniques that more effectively apply energy to rock removal have been combined to reduce drilling costs substantially. The greatest impact in future drilling technology will probably come through optimization of drilling variables, and perhaps the perfection of liquid-operated percussion drills, downhole motors, and other developments that will permit more drilling and less round-trip time.

Offshore drilling and producing are considerably more expensive than comparable onshore operations, but the cost without new technological developments would be virtually prohibitive. Exploration drilling capability is edging out beyond water depths of 400 feet. Improvements in anchoring and/or dynamic positioning of drilling vessels together with improved riser pipe technology will extend these capabilities to progressively deeper waters. Development in water depths beyond 300 feet will probably see above-surface, bottom-supported platforms replaced by various types of underwater installations. As operations go underwater, new technology will be needed for remote control of wells; collection, separation, storage and transportation of well production; and radically new well servicing systems.

Well completion practices have contributed to cost reduction and have also made it possible to sustain productive capacity. Major developments of this type are reflected in the time-lines on Chart IVA. This listing includes only those principally directed toward cost reduction.

In well operations, artificial lifting has advanced steadily. The free pump in hydraulic systems and pressure-balanced gas lift valves are noteworthy. Automation in all phases of producing operations is contributing greatly to cost reduction. Automation has progressed from automatic control of tank batteries, to lease process control, to well testing and operations, and then to lease automatic custody transfer (LACT). Automation is now moving into supervisory control.

Protection against corrosion is being engineered into most production systems, while twenty years ago the emphasis was on the repair or replacement of corroded items.

E. Impact of New Technology on Transportation

The application of new or advanced technology to the handling and transportation of oil since World War II has resulted in major improvements. The time-lines on Chart V indicate some of these developments.

The technical success in constructing large diameter, thin-wall, high-strength pipe long-distance line systems has been established. The tremendous growth of the pipeline industry in the twenty-year period has forced rapid developments in the technology of making and laying line pipe of steadily increasing diameter and strength. Automation of pipeline pumping stations, with appreciable cost savings, has, at the same time, become accepted practice. The result has had a major impact on the cost and capacity of liquid petroleum pipelines.

Similar to the pipelines, the trend in other forms of transportation—barge, tanker, truck, and rail—has been to larger facilities with increased efficiency and capacity. For example, trends to larger oil tankers, and remote loading and unloading facilities, point to reduced costs in the future for ocean and coastwise shipping.

Underground storage of volatile products, which reduces storage costs, has become a common practice. Surface refrigerated storage of volatile products is moving into the semiproven category and is gaining acceptance.

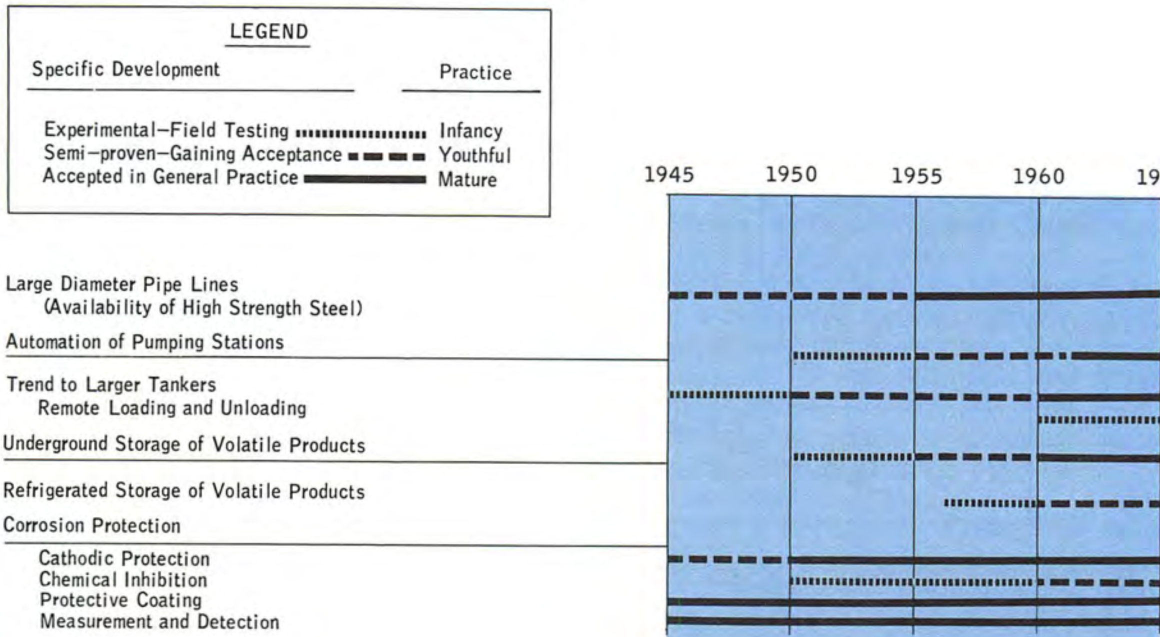
Corrosion prevention by cathodic protection and protective coatings, and corrosion measurement and detection, have been utilized by the pipeline industry throughout most of this period. The use of chemical inhibitors under certain conditions is gaining acceptance and may add to cost reduction in the future.

The significance of these developments is that the actual cost of moving a barrel of oil has declined, while operations costs increased (see *Curves 1* and *2*, Chart V). Technology has been an important contributing factor in accomplishing this result.

F. Future Oil Discovery and Recovery Guidelines

No forecast is offered in this study as to the level of new discoveries and additions to recovery of crude oil that will or should be achieved through the 1970's. However, based on estimates in this study

CHART **V**
The Impact of
New Technology
on Transportation



Pipe Line Operations—U.S.

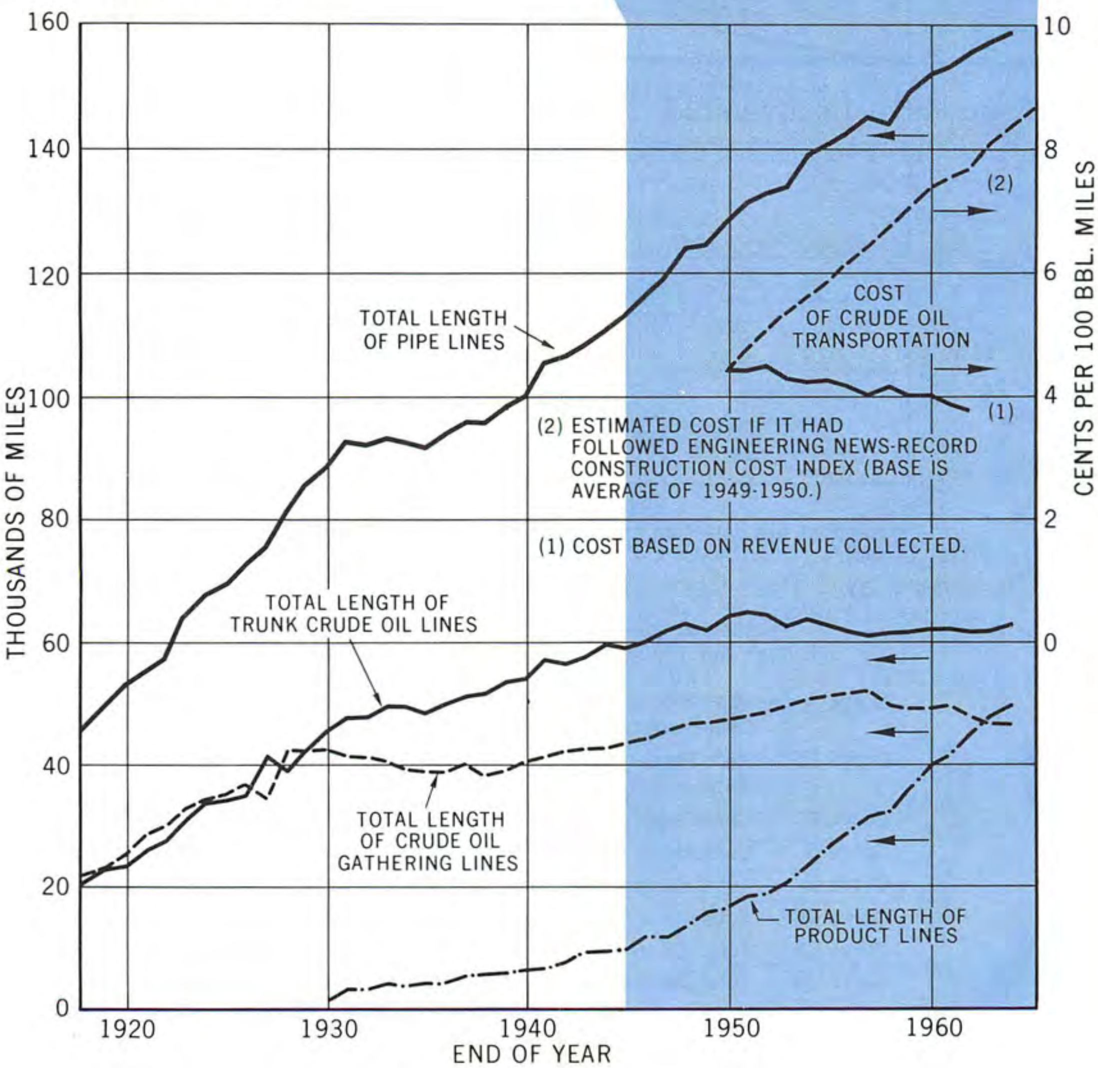
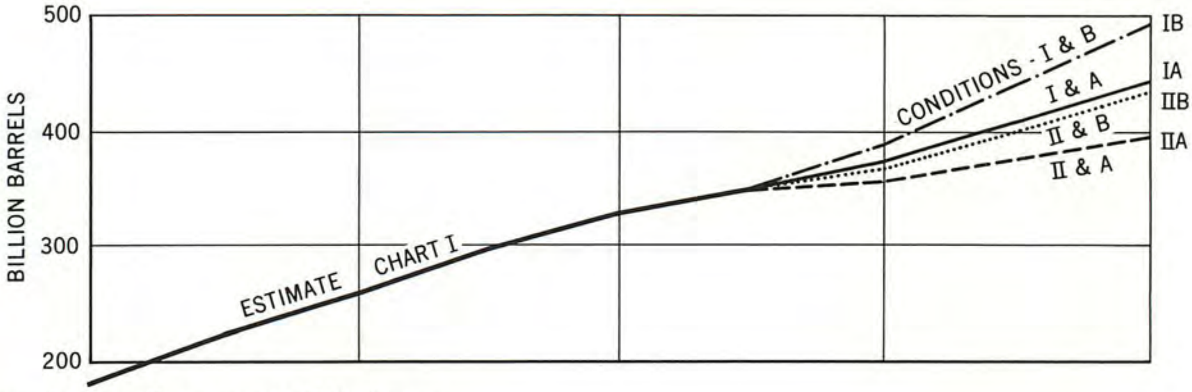
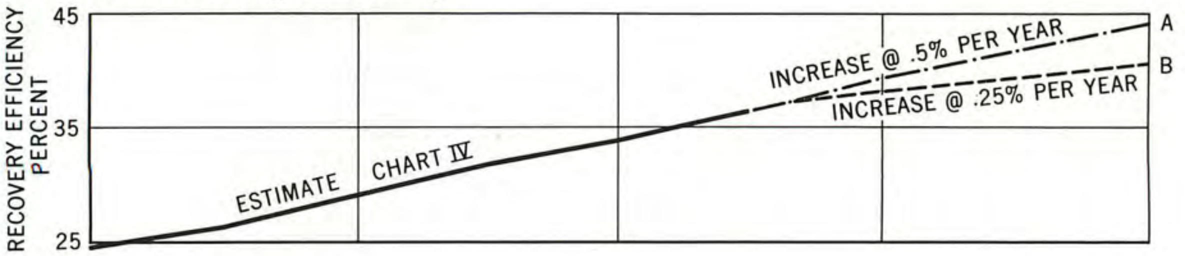


CHART **VI**

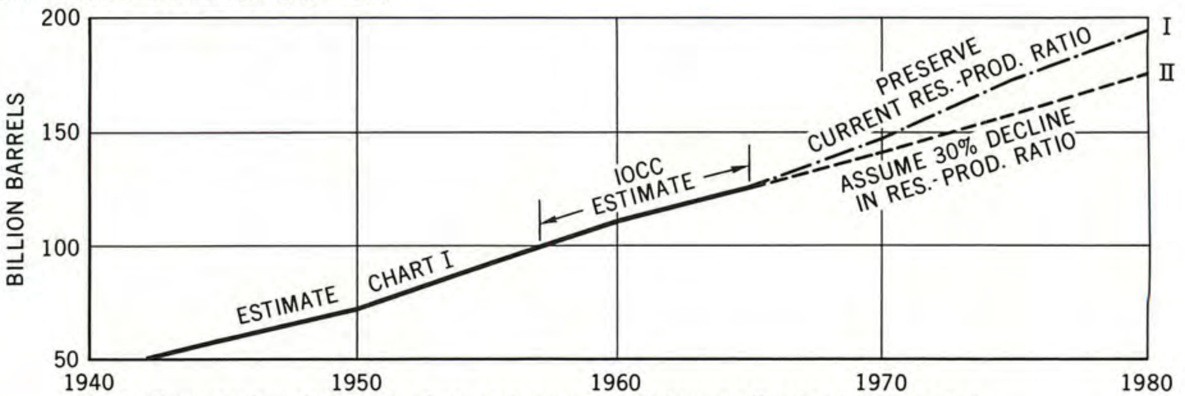
Cumulative Oil in Place Discovered



Cumulative Recovery Efficiency



Cumulative Recoverable Oil



Projections are based on oil-in-place and recovery efficiency estimated in this report.

Discovery and Recovery Guidelines

These Guidelines Indicate Discovery and Recovery Performance Needed Through the 1970's to Meet USBM Estimated Production of Domestic Crude Oil

- Curve I — Past Production Plus Reserves (IOCC Basis), Projected to Preserve Current Reserve-Production Ratio
- Curve II — Past Production Plus Reserves (IOCC Basis), Except That Reserve-Production Ratio is Allowed to Decline by 30 Percent
- Curve A — Cumulative Recovery Efficiency Increasing at ½ of 1% Additional Per Year
- Curve B — Cumulative Recovery Efficiency Increasing at ¼ of 1% Additional Per Year
- Curve IA — Total Oil in Place Necessary to be Discovered to Satisfy Conditions of I and A
- Curve IB — Total Oil in Place Necessary to be Discovered to Satisfy Conditions of I and B
- Curve IIA — Total Oil in Place Necessary to be Discovered to Satisfy Conditions of II and A
- Curve IIB — Total Oil in Place Necessary to be Discovered to Satisfy Conditions of II and B

through 1965, of cumulative oil in place discovered (Section A) and cumulative recovery efficiency (Section B), it is possible to bracket or encompass the general range of discovery and recovery activity that appears indicated in order to meet demands for domestic crude oil through the 1970's. This demand is based upon a forecast made by the Bureau of Mines* of the growth in U.S. crude oil production up to 1980 which assumes continuation of the present oil import program.

1. CUMULATIVE PRODUCTION PLUS RESERVES—A curve on Chart VI shows total proved oil discoveries, i.e., cumulative crude oil production plus known reserves. From 1965 to 1980 two different "trends" have been plotted as follows:

a. Trend I reflects the cumulative proved discovery levels required to meet the forecasted production rates *if the existing ratio of reserves to production is maintained at 18.3 to 1.* **

b. Trend II reflects the cumulative proved discovery levels required to meet the forecasted production rates *if the ratio of reserves to production gradually declines from the current 18.3 to 1 (1965) to a ratio of 13 to 1 in 1980.*

2. CUMULATIVE RECOVERY EFFICIENCY—As discussed in Section B, cumulative oil recovery efficiency is an extremely important factor and must be considered in estimates of requirements up to 1980. This appears in the second curve on Chart VI, which also shows two separate "trends" for the period 1965 to 1980 as follows:

a. Trend A reflects the continuation up to 1980 of a cumulative recovery efficiency improvement rate of *one-half percent a year,* the rate previously estimated to have occurred over the past twenty-year period.

b. Trend B reflects a cumulative recovery efficiency improvement rate of *one-quarter of a percent per year.*

3. CUMULATIVE DISCOVERIES OF OIL IN PLACE—Based on the forecasted crude oil production, and estimated cumulative additions to recovery needed to provide this oil and maintain one of the indicated reserves to production ratios (Trends I and II), it is then possible to bracket necessary levels of cumulative discoveries of oil in place with the two different recovery efficiency trends (Trends A and B). This exercise is best shown by the following table:

*An Appraisal of the Petroleum Industry of the U.S., U.S. Department of the Interior, January 1965, Table 28.

**Based on primary and fluid injection reserves estimated by the Interstate Oil Compact Commission (rather than API reserve estimates). See Appendix Table 3, page 25; Table 2, page 24; and pages 28 and 43

MAINTAIN PRESENT RESERVE-PRODUCTION RATIO

	RECOVERY EFFICIENCY IMPROVES ½%/YEAR (CURVE IA) (BILLION BARRELS)	RECOVERY EFFICIENCY IMPROVES ¼%/YEAR (CURVE IB) (BILLION BARRELS)
Crude Oil Production	48.3	48.3
Avg/Year	3.22	3.22
Additions to Recovery[a]	68.5	68.5
Avg/Year	4.57	4.57
Needed Oil in Place Discovered	96.0	137.0
Avg/Year	6.4	9.1

ALLOW RESERVE-PRODUCTION RATIO TO DECLINE ABOUT 30%

	RECOVERY EFFICIENCY IMPROVES ½%/YEAR (CURVE IIA) (BILLION BARRELS)	RECOVERY EFFICIENCY IMPROVES ¼%/YEAR (CURVE IIB) (BILLION BARRELS)
Crude Oil Production	48.3	48.3
Avg/Year	3.22	3.22
Additions to Recovery	48.3	48.3
Avg/Year	3.22	3.22
Needed Oil in Place Discovered	51.0	87.0
Avg/Year	3.4	5.8

a-The volume of recoverable oil added during the interval (difference between cumulative production plus reserves at one time and cumulative production plus reserves at another time).

It will be noted that the conditions indicated by *Curve IB* (present reserve/production ratio, but lower rate recovery efficiency improvement) would require an annual oil in place discovery rate of 9.1 billion barrels, significantly higher than the 4.5 to 5 billion barrel annual rate estimated for the years 1960-1965.

In the situation indicated by *Curve IIA* (present rate recovery efficiency improvement, but lower reserve/production ratio) 3.4 billion barrels per year of oil in place discovered would be required. Should this be achieved then supplemental crude supplies would be required by not later than 1980.

The estimated domestic crude production requirement through the 1970's would be met if the situations under *Curve IA* or *IIB* are achieved. Under *Curve IA* conditions (continuation of both present reserve/production ratio and recovery efficiency rate of improvement) an average of 6.4 billion barrels of oil in place would have to be discovered annually. Under *Curve IIB* (both lower reserve/production ratio and recovery efficiency improvement rate) an average of 5.8 billion barrels of oil in place would be required annually. The attainment of the situations in both *Curves IA* and *IIB*, however, would depend heavily upon continued development and effective utilization of technology. Should the trend of new oil discovery improve, the recovery efficiency rate can be less, without causing a decline in the reserve to production ratio. On the other hand, if the new oil discovery effectiveness falls off, the recovery efficiency rate would have to increase in order to sustain the reserve to production ratio.

A close study of the bracketing curves leads to the conclusion that the petroleum industry must intensify application of current and developing technology, as well as accelerate utilization of new technology in order to supply requirements for crude oil through the 1970's.

Appendix to Chapter One

ESTIMATED TOTAL OIL IN PLACE DISCOVERED USING NPC PROVED DISCOVERIES AS A BASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	NPC RECAST OF API RESERVES TO YEAR OF FIELD DISCOVERY				TOTAL ORIGINAL OIL IN PLACE DISCOVERED				YEARLY ORIGINAL OIL IN PLACE DISCOVERED PER NFWC MB
					CUMULATIVE				
YEAR	PER YEAR	3-YEAR RUNNING AVERAGE	CUMULATIVE MB	RECOVERY EFFICENCY (RETROSPECT)	COMPUTED	SMOOTHED	PER YEAR	NUMBER OF NEW FIELD WILDCATS	
1919			18,591,298	0.25	74.4	74.4			
1920	2,463,946		21,055,244	0.26	81.0		3.0		
1921	3,036,197	2,329,573	24,091,441	0.27	89.3	80.0	3.1		
1922	1,488,576	1,922,121	25,580,017	0.28	91.3		3.2		
1923	1,241,591	1,223,804	26,824,608	0.29	92.5	87.5	3.6		
1924	941,245	1,071,349	27,762,853	0.30	92.5		3.8		
1925	1,031,212	1,737,373	28,794,065	0.31	92.8	95.0	4.0		
1926	3,239,661	1,912,475	32,033,726	0.32	100.0		4.2		
1927	1,466,551	2,380,088	33,500,277	0.33	101.4	104.0	4.8		
1928	2,434,051	2,252,382	35,934,328	0.34	105.6		5.0		
1929	2,856,545	4,132,622	38,790,873	0.35	110.7	114.0	5.2		
1930	7,107,271	4,132,736	45,898,144	0.355	129.3		5.4		
1931	2,434,393	3,416,373	48,332,537	0.36	134.2	125.0	5.6		
1932	707,454	1,503,656	49,039,991	0.365	134.4		5.7		
1933	1,369,120	1,434,764	50,409,111	0.37	136.3	136.0	6.0		
1934	2,227,719	2,345,410	52,636,830	0.375	140.2		6.1		
1935	3,439,390	2,779,121	56,076,220	0.38	147.5	148.0	6.2		
1936	2,670,254	3,646,777	58,746,474	0.385	152.6		6.4		
1937	4,830,686	3,651,510	63,577,160	0.39	163.0	162.0	6.6		
1938	3,453,589	3,232,384	67,030,749	0.395	169.6		6.6		
1939	1,412,877	2,671,712	68,443,626	0.40	171.0	175.0	6.7		
1940	3,148,669	2,248,116	71,592,295	0.395	181.3		6.7		
1941	2,182,803	2,261,977	73,775,098	0.39	189.3	189.0	6.7		
1942	1,454,458	1,693,080	75,229,556	0.385	195.3		6.8		
1943	1,441,979	1,653,393	76,671,535	0.38	201.7	202.5	6.9		
1944	2,063,743	1,809,390	78,735,278	0.375	210.0		7.2	3,094	2,320
1945	1,922,447	1,841,101	80,657,725	0.37	218.0	218.0	7.9	3,037	2,600
1946	1,537,114	1,540,963	82,194,829	0.365	225.0		8.4	3,133	2,680
1947	1,163,329	1,969,312	83,358,168	0.36	231.3	236.0	9.0	3,480	2,580
1948	3,207,493	2,365,153	86,565,661	0.355	243.8		9.2	4,296	2,140
1949	2,724,638	2,723,156	89,290,299	0.35	255.0	254.0	8.8	4,449	1,980
1950	2,237,336	2,080,806	91,527,635	0.3475	263.3		8.4	5,290	1,590
1951	1,280,443	1,686,013	92,808,078	0.345	268.7	270.0	7.7	6,189	1,240
1952	1,540,259	1,515,809	94,348,337	0.3425	275.3		7.2	6,698	1,070
1953	1,726,725	1,636,008	96,075,062	0.34	282.5	285.5	6.9	6,925	1,000
1954	1,641,039	1,526,887	97,716,101	0.3375	289.5		6.7	7,380	910
1955	1,212,896	1,297,343	98,928,917	0.335	295.0	297.5	6.3	8,104	780
1956	1,038,094	1,170,492	99,967,011	0.3325	300.7		6.1	8,709	700
1957	1,260,485	1,019,035	101,207,757	0.33	306.7	310.0	5.8	8,014	720
1958	758,527		101,986,103				5.5	6,950	790
1959						320.0	5.2	6,473	800
1960							4.9	7,320	670
1961						329.6	4.7	6,909	680
1962						334.2	4.6	6,795	680
1963						338.7	4.5	6,570	680
1964						343.0	4.4	6,632	660
1965						348.0	5.0	6,182	810

Col. 2 — From Table 1, NPC *"Proved Discoveries and Productive Capacity"* (1965).
Col. 3 — Obtained from Col. 2.
Col. 4 — Accumulated Col. 2.
Col. 5 — Values for ends of years 1919, 1929, 1939, 1949, and 1957 assigned by judgment; intervening years linearly interpolated.
Col. 6 — Col. 4 divided by Col. 5.
Col. 7 — Obtained graphically, trend through Col. 6 values. Projections beyond 1957 guided by API New Field Discovery Trends (See App. Table 4).
Col. 8 — Obtained graphically, measuring tangent to curve of Col. 7.
Col. 9 — AAPG data cited, *Twentieth Century Petroleum Statistics* (1966), p. 26.
Col. 10 — Col. 8 divided by Col. 9.

This Appendix amplifies and supports the six basic sections of the Summary in Chapter One with supplementary discussion of the methodology and data used in arriving at the various estimates or conclusions. All curves appearing in the Summary are included in the Appendix together with supporting statistical tables.

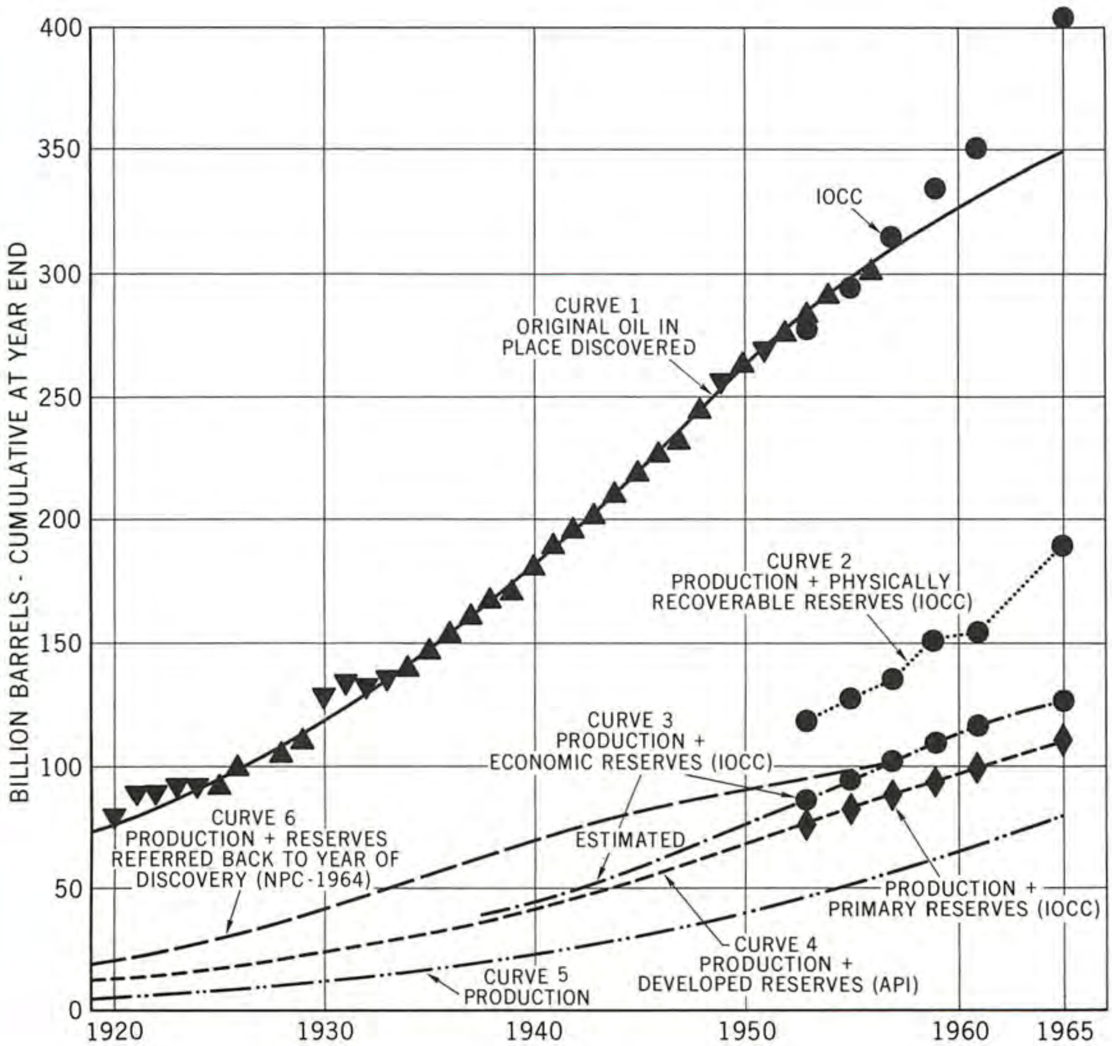
A. Crude Oil Discovery

As suggested in the Summary, perhaps the best yardstick for measurement of the effectiveness of the oil exploration (discovery) effort, as well as the improvement in recovery efficiency, is a series of estimates of total oil in place discovered and economically recoverable oil. If these can be reasonably developed, then the impact of technology on both activities can be also estimated.

An estimated history of the cumulative oil in place discovered in the United States appears as *Curve 1* on Appendix Chart 1, supported by columns 6 and 7, Table 1, which was made as follows:

Step 1—The curve is based on the estimated proved discoveries of crude oil (past production plus remaining proved reserves), or the total expected recoveries of crude oil, as made by the National Petroleum Council and published in 1965 (see column 2, Table 1). These estimates were based upon field size and past performance as they were known on December 31, 1963. The cumulative production

APPENDIX CHART **1**
Original Oil
in Place Discovered,
Recovery Estimates,
and Production



and remaining reserves (API reserve estimates) were credited back to the year in which the oil fields were initially discovered.

The above NPC study allows 5 years production history, revisions and extensions before assigning any proved discoveries to a field. For this reason the 1964 NPC study credits back all cumulative production plus reserves only up to 1958. For example, the NPC proved discoveries for the year 1950 is the sum of crude oil production plus reserves of the fields discovered that year determined as of December 31, 1963. Accordingly, the total proved discoveries in the U.S. for the year 1950 are judged with 1964 technology and actual production history up to December 31, 1963. This is illustrated by *Curve 6* on Appendix Chart 1.

Step 2—This next step in developing an estimated history of cumulative total oil in place discovered is admittedly based solely on sound engineering judgment. It is necessary to assign an estimated cumulative oil recovery efficiency realized in 1964 to the types of reservoirs that were actually discovered up through 1958. This engineering judgment is based upon a long history of production performance and reservoir engineering technology known at this time. The estimates are as follows (see also column 2, Table 2):

END OF YEAR	CURRENT CUMULATIVE RECOVERY EFFICIENCY FACTOR
1919	25%
1929	35%
1939	40%
1949	35%
1957	33%

From the above it is apparent that all fields discovered through 1919 were estimated to have a combined production and remaining reserve as of December 31, 1963, equivalent to 25 percent of the total oil in place discovered. This includes not only

Appendix Table 2

CUMULATIVE CRUDE OIL RECOVERY EFFICIENCY ESTIMATES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				CUMULATIVE PRODUCTION PLUS ECONOMIC RESERVES			
				IOCC		API	
END OF YEAR	CURRENT CUMULATIVE RECOVERY EFFICIENCY %	NPC CUMULATIVE DISCOVERY TREND SMOOTHED CURVE (MOORE)[a] M^3B	ESTIMATED CUMULATIVE ORIGINAL OIL IN PLACE M^3B	M^3B	% RECOVERY EFFICIENCY	M^3B	% RECOVERY EFFICIENCY
1919	25	18.6	74.4	11.7[b]	15.7	11.7	15.7
1929	35	40.7	114.0	25.4	22.3	25.4	22.3
1939	40	65.6	175.0	43.0	24.5	40.9	23.4
1949	35	87.9	254.0	70.8	27.9	63.6	25.0
1957	33	102.2	310.0	101.5	32.7	87.7	28.3
1959			320.0	108.4	33.9	94.0	29.3
1964			343.0	122.6	35.7	106.0	30.9
1965			348.0	127.5	36.6	109.1	31.4

Col. 2 — Values estimated; current recovery efficiency realized by 1964 technology applied to cumulative oil in place discovered at date indicated.
Col. 3 — Computed cumulative discoveries, Moore (1966), p. 35.
Col. 4 — Col. 3 divided by Col. 2. Projection beyond 1957 based on API New Field Discoveries (see App. Table 4).
Col. 5 — Figures for ends of years 1957, 1959, and 1965 from IOCC evaluations, 1964 interpolated; earlier years from trend converging back to API statistics for end of 1929.
Col. 6 — Col. 5 divided by Col. 4; recovery efficiency estimated that would have prevailed at the time indicated with the existing technology applied at that time.
Col. 7 — Cumulative production plus year end reserves — American Petroleum Institute.
Col. 8 — Col. 7 divided by Col. 4.

a — Moore, C. L. *Analyses and Projections of the Historic Patterns of U.S. Domestic Supply of Crude Oil, Natural Gas, and Natural Gas Liquids*, Department of the Interior, Office of Oil and Gas (May 1966).

b — Estimated by API in retrospect. (Annual estimates began for 1938, Moore's computed trend values do not go back of 1938.)

primary production from the oil fields, but also a secondary recovery completed or under way. This judgment also takes into account the fact that a significant volume of original oil in place in these early fields was abandoned following cessation of primary flush production.

By the end of 1929, ten years later, the engineering judgment is that cumulative recovery efficiency for all oil fields discovered as of that time, based upon 1964 conditions, had increased to 35 percent. By the end of 1939 the cumulative efficiency had further increased to 40 percent. These particular judgments are based primarily upon the discovery of a growing number of major water-drive reservoirs between 1920 and 1940. The performance of these reservoirs by 1964 offsets lower recovery efficiency of fields discovered prior to 1920, thus accounting for the estimated buildup in cumulative oil recovery efficiency by 1940.

During the next twenty years (1940-1960) the types of reservoirs discovered were not, as of 1964, capable of yielding as high a recovery efficiency as those discovered from 1920-40. Therefore, the engineering judgment made here is that the cumulative recovery efficiency applied to all total oil in place discovered fell off to 35 percent by the end of 1949 and further to 33 percent by the end of 1957.

The 33 percent cumulative recovery efficiency figure as of January 1, 1958, based upon the foregoing engineering judgment as applied to NPC estimated cumulative proved discoveries, corresponds quite closely to the IOCC estimate of 32.15 percent for the same date (see Table 3). NPC estimates of cumulative proved discoveries as of January 1, 1958, based upon 1964 conditions and estimated at that time (102 billion barrels) are about the same as those of the IOCC (101.5 billion barrels). This is illustrated by the intersection of *Curves 3 and 6* on Appendix Chart 1. While this could be coincidental, there is good reason to accept the conclusion that the two separate estimates at this one time could be expected to be similar. The NPC waits for the actual application of improved recovery technology and 5 years for extensions to be proven before they first list discovered recoverable oil for any one year. IOCC reserve estimates, by definition, attempt to determine initially the ultimate productive area and the effect of the use of known technology. So the two estimates should tend to converge at the date of first NPC allocation. Thus, these two estimates of recoverable oil, compared with the IOCC estimated total oil in place discovered, support a 32 to 33 percent cumulative recovery efficiency as of January 1, 1958.

Step 3—Utilizing the series of estimated cumulative recovery efficiency rates under 1964 conditions, as described in Step 2 above, the estimated cumulative original oil in place discovered was then calculated by dividing the NPC cumulative proved

Appendix Table 3

EVALUATION OF UNITED STATES OIL RESOURCES
INTERSTATE OIL COMPACT COMMISSION
SECONDARY AND RECOVERY MAINTENANCE COMMITTEE

		MILLIONS BARRELS CRUDE OIL						
DATE OF STATISTICS		JAN. 1 1954	JAN. 1 1956	JAN. 1 1958	JAN. 1 1960	JAN. 1 1962	JAN. 1 1966	LINE NO.
Original Oil Content of Reservoir								
Original Oil In Place previously reported		(271,933)	(288,523)	(309,907)	(328,407)	(346,195)		1
Original Oil In Place revised Dec. 1966		277,247	295,372	315,719	334,261	352,051	404,368	2
Cumulative Past Oil Production		47,817	52,687	57,818	62,636	67,657	78,057	3
Primary Oil Reserves		27,786	29,670	30,580	30,970	31,399	31,689	4
Economic Reserves by Fluid Injection		11,527	11,979	13,095	14,822	16,332	17,734	5
Total Economic Reserves	(A)	39,313	41,649	43,675	45,792	47,731	49,423	6
Cumulative Production Plus Economic Reserves	(B)	87,130	94,336	101,493	108,428	115,388	127,480	7
Cumulative Recovery Efficiency, % (IOCC)	(C)	31.43	31.94	32.15	32.44	32.78	31.53	8
Physically Recoverable Potential Reserves by Fluid Injection in Addition to Economic Reserves by Fluid Injection		29,137	32,830	34,483	44,013	40,183	61,480	9
Cumulative Total Physically Recoverable Oil in Place by Known Methods	(D)	116,367	127,166	135,976	152,441	155,571	188,960	10

(A) Lines 4 + 5 (C) Line 7 ÷ 2
(B) Lines 3 + 6 (D) Lines 7 + 9

Source: *Evaluation of United States Oil Resources as of January 1, 1966*, by Paul D. Torrey, Chairman of the Committee, presented to the IOCC, Decembei 1966; Table 3.

discoveries (see column 4, Table 1) by the assigned oil recovery efficiency by years, the interpolation within the decades having been made (see column 5, Table 1). The result, by years, appears in columns 6 and 7, Table 1, and is also illustrated by *Curve 1* on Appendix Chart 1. Along *Curve 1,* the circle points at the end of years 1953, 1955, 1957, 1959, 1961, and 1965 represent the IOCC estimates of the original oil content of reservoirs (Table 3). The triangular points spotted along the smooth *Curve 1* are those using year-to-year cumulative proved discoveries reported by the NPC (see column 4, Table 1) and estimated by the method described above.

This method permits the use of 1964 knowledge of technology and reservoir performance to estimate the original oil in place in fields discovered by 1958. The application of this technique to the thousands of individual oil fields would provide a more accurate estimate of total oil in place discovered. However, it is believed that the above estimate is reasonable.

Step 4—Since NPC estimates do not cover the period 1958 through 1965, the projected trend of original oil in place discovered for this period was controlled by the trend in ratio of API annual new

Appendix Table 4

COMPARISON ANNUAL RATE OF API DISCOVERED RESERVES WITH ESTIMATED TOTAL OIL IN PLACE DISCOVERED

(1)	(2)	(3)	(4)	(5)	(6)
	API RESERVES DISCOVERED NEW FIELDS & POOLS (API) MB				
YEAR	ANNUAL	3-YEAR RUNNING AVERAGE	ESTIMATED TOTAL ORIGINAL OIL IN PLACE DISCOVERED M^3B	RATIO COL. 4 TO COL. 3	TOTAL API RESERVES ADDED MB
1937	928,742	—	6.6	—	3,721,532
1938	810,493	693,301	6.6	9.5	3,054,064
1939	340,667	479,166	6.7	14.0	2,399,122
1940	286,338	352,326	6.7	19.0	1,893,350
1941	429,974	325,454	6.7	20.6	1,968,963
1942	260,051	324,148	6.8	20.9	1,878,976
1943	282,418	351,259	6.9	19.6	1,484,786
1944	511,308	404,570	7.2	17.8	2,067,500
1945	419,984	391,909	7.9	20.1	2,110,299
1946	244,434	369,949	8.4	22.7	2,658,062
1947	445,430	362,115	9.0	24.8	2,464,570
1948	396,481	577,443	9.2	15.9	3,795,207
1949	890,417	617,271	8.8	14.2	3,187,845
1950	564,916	612,863	8.4	13.7	2,562,685
1951	389,256	483,533	7.7	15.9	4,413,954
1952	496,428	492,455	7.2	14.6	2,749,288
1953	591,680	557,971	6.9	12.4	3,296,130
1954	585,806	551,481	6.7	12.1 Avg. 13.65	2,873,037
1955	476,957	509,995	6.3	12.3	2,870,724
1956	467,222	453,459	6.1	13.5	2,974,336
1957	416,197	399,383	5.8	14.5	2,424,800
1958	314,729	366,763	5.5	15.0	2,608,242
1959	369,362	312,649	5.2	16.6	3,666,745
1960	253,856	328,197	4.9	14.9	2,365,328
1961	361,374	331,939	4.7	14.2	2,657,567
1962	380,586	363,950	4.6	12.6 Avg. 13.7	2,180,896
1963	349,891	358,923	4.5	12.9	2,174,110
1964	346,293	389,377	4.4	11.3	2,664,767
1965	471,947	376,221	5.0	13.3	3,048,079
1966	310,422	—	4.8	—	2,963,978

Columns 2 and 6:
Years 1937-1958—*API Petroleum Facts and Figures* (1959), p. 63.
Years 1959-1964—*API Petroleum Facts and Figures* (1965), p. 57.
Years 1965-1966—*Oil and Gas Journal,* March 28, 1966, p. 107; April 3, 1967, p. 128, resp.
Column 4 from Appendix Table 1 this report.

field reserves discovered to annual original oil in place discovered estimated in the manner described on Table 4. This trend is illustrated on Appendix Chart 2. The extrapolation of total oil in place discovered after 1958 is projected to follow approximately the same ratio to API new field reserves discovered as experienced from 1950 to 1958.

It is recognized that this projection falls below the oil in place discovered estimates of the IOCC after 1958 (see Appendix Chart 1). In this study the total oil in place is estimated only for fields being commercially developed or operated. Known heavy oil deposits which have not yet been drilled or are not being commercially produced are not included in the oil in place estimate made in this study. Some of these heavy oil deposits appear to be included in recent IOCC estimates.

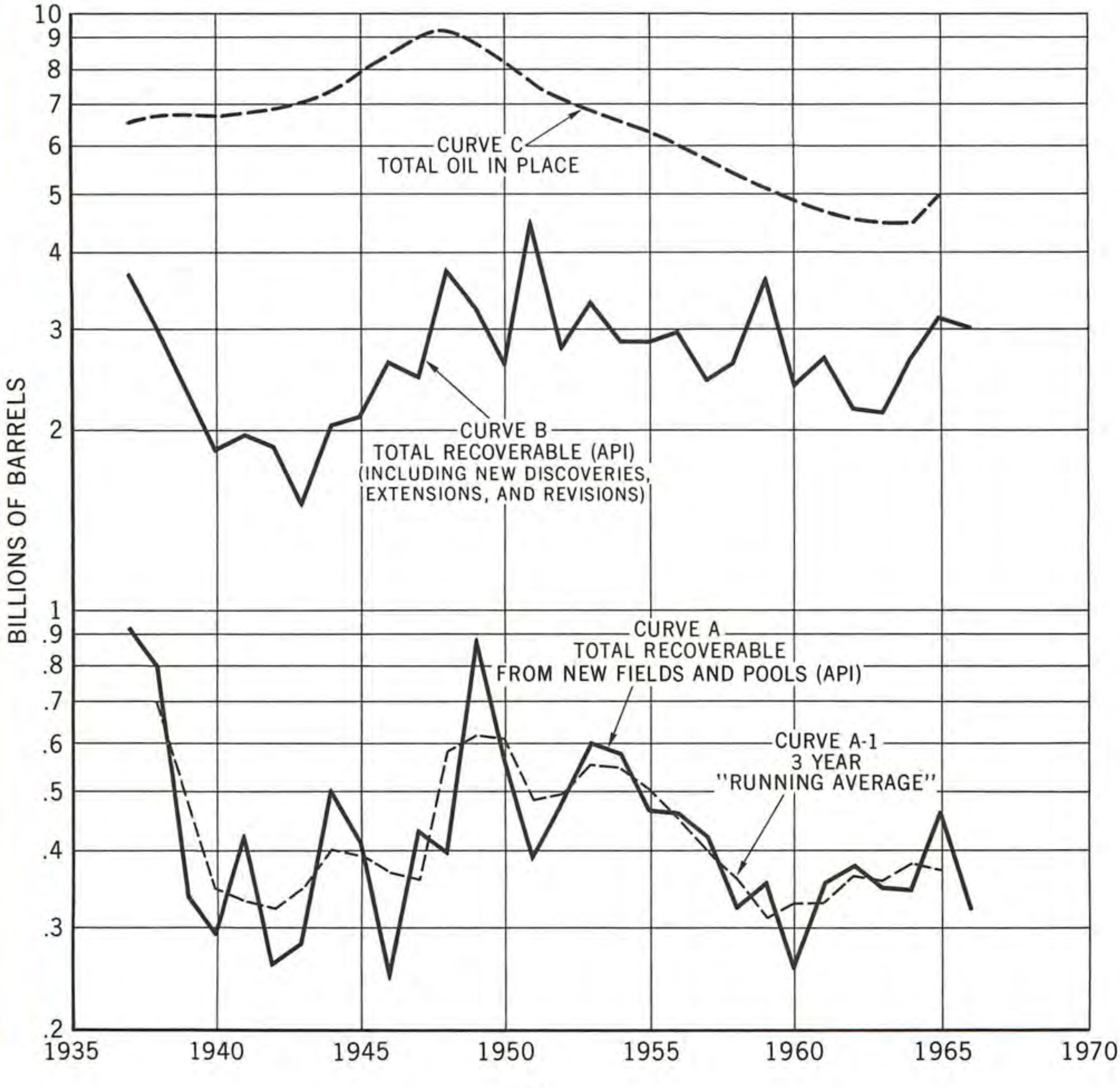
Conclusion—Based on the above four steps, this study concludes that at the end of 1965 the total oil in place discovered was approximately 350 billion barrels. The American Petroleum Institute recently released an estimate of original oil in place discovered, as of January 1, 1967, at 381 billion barrels. This estimate was a year later and very likely includes some heavy oil deposits recently proved commercial as well as oil discovered during 1966.

APPENDIX CHART **2**

Estimated Annual

Crude Oil

Discovered



On Chart I of the Summary (appearing here as Appendix Chart 3), the original oil in place discovered *per year* and per new field wildcat well are shown (see Tables 1 and 5). The number of new field wildcats drilled per year is taken from information published by the American Association of Petroleum Geologists, and is recapitulated on Table 1.

B. Crude Oil Recovery

As stated in the Summary, an estimate of improvement in oil recovery efficiency during the past twenty years is subject to so many indeterminable variables that it cannot be made with precision.

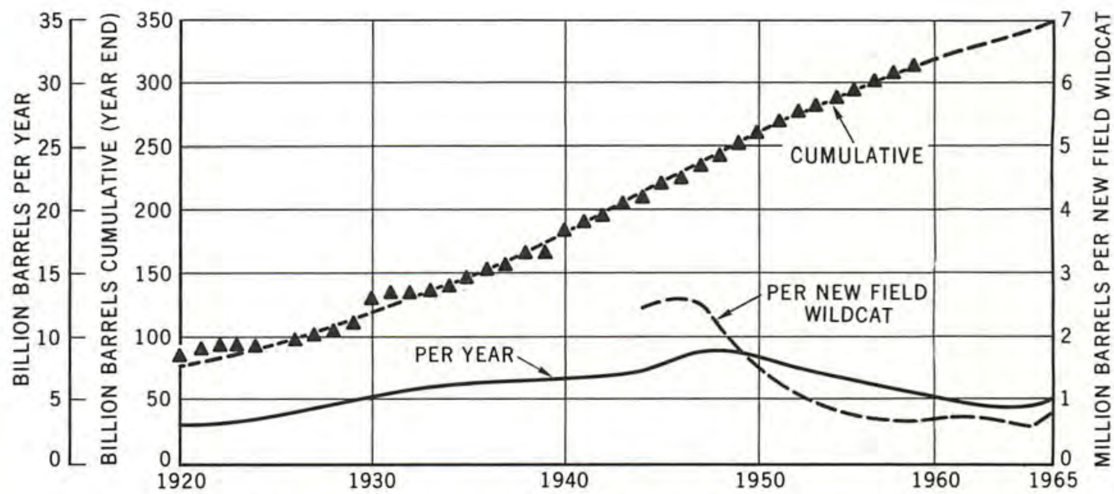
The study did attempt to derive a trend for estimated cumulative recovery efficiency at any one time back to 1920. This is illustrated by *Curve 1* on Appendix Chart 4. This trend was developed by dividing the total proved discoveries (cumulative production plus known recoverable reserves) as of any year by the estimated cumulative total oil in place discovered as of the same year (see Appendix Table 2, column 6). Another way of expressing this can be visualized by referring to Appendix Chart 1. Recovery efficiency is calculated by dividing *Curve 4* (from 1920 to 1937) and then *Curve 3* (from 1937 through 1965) by *Curve 1*. This is cumulative recovery efficiency. It is past production plus recoverable reserves at any one time divided by total oil in place discovered at the same time. In this study the IOCC type of reserve estimate is used.

There are four different estimates of total proved discoveries (total recoverable oil) which can be examined. These appear as *Curves 2, 3, 4 and 6* on Appendix Chart 4. The six data points on *Curve 2* are from published reports of the Interstate Oil Compact Commission (see Table 3). This represents the IOCC estimate of cumulative total *physically* recoverable oil in place by known methods without regard to economics.

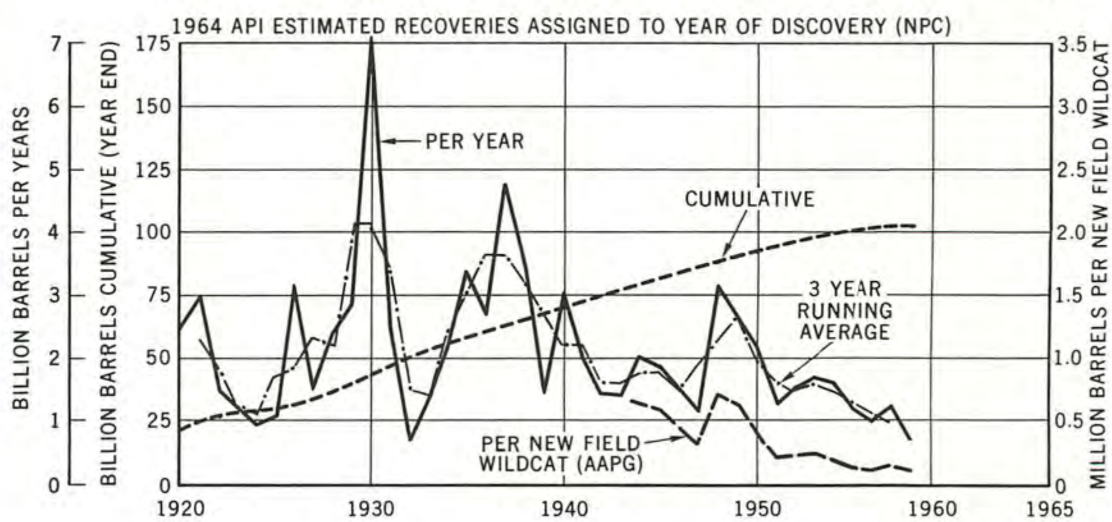
Curve 3 represents an extension of IOCC estimates of cumulative recoverable oil. In these estimates the IOCC includes cumulative past oil production, primary oil reserves, and conventional fluid injection reserves with existing technology and economics. The six control points (circles) on *Curve 3* are data published by the IOCC covering the period from the end of 1953 to the end of 1965 (see Table 3). The probable trend from 1954 back to 1930 is estimated.

APPENDIX CHART 3

Total Oil in Place Discovered



Recoverable Oil Discovered



The projection is guided by the historic API estimates reflected in *Curve 4*. *Curve 3* represents that which is believed to be the best estimate of the total recoverable oil which reflects the results of an improving technology. Oil which is not yet under fluid injection operations, but which can be economically recovered by conventional methods, is included in this category. On the other hand the API reserve estimates (prior to estimates for 1966) include only primary oil proven and that secondary oil recovery expected from established fluid injection operations. While these reserves serve a very useful purpose it is recognized, because of rules and definitions used by the API in preparing reserve estimates, they tend to be conservative. However, for measuring the impact of technology on crude oil recovery it is the opinion of this study group that the IOCC reserve estimates are, at this time, more meaningful.

Curve 4 shows two trends practically superimposed upon each other. The curve shows estimates of cumulative discoveries, i.e., cumulative past production plus reserves taken from API reserve statistics (see Table 6). The square points, appearing from the end of 1953 to the end of 1965, represent the estimates of the IOCC primary reserves only. The information taken from the API reserve estimates includes both primary and those secondary reserves which are under actual operation. It is a coincidence that these two sets of reserve estimates, different by definition, practically coincide with each other. Here again, it should be noted that the API reserves prior to 1966 include only proven primary and secondary under operation. The primary reserves estimated by the IOCC include oil that is reasonably proven but not yet drilled.

Curve 5 reflects the cumulative total oil production as listed in API statistics (see Table 6). Estimated reserves are added to this base to provide estimates of total recoverable oil.

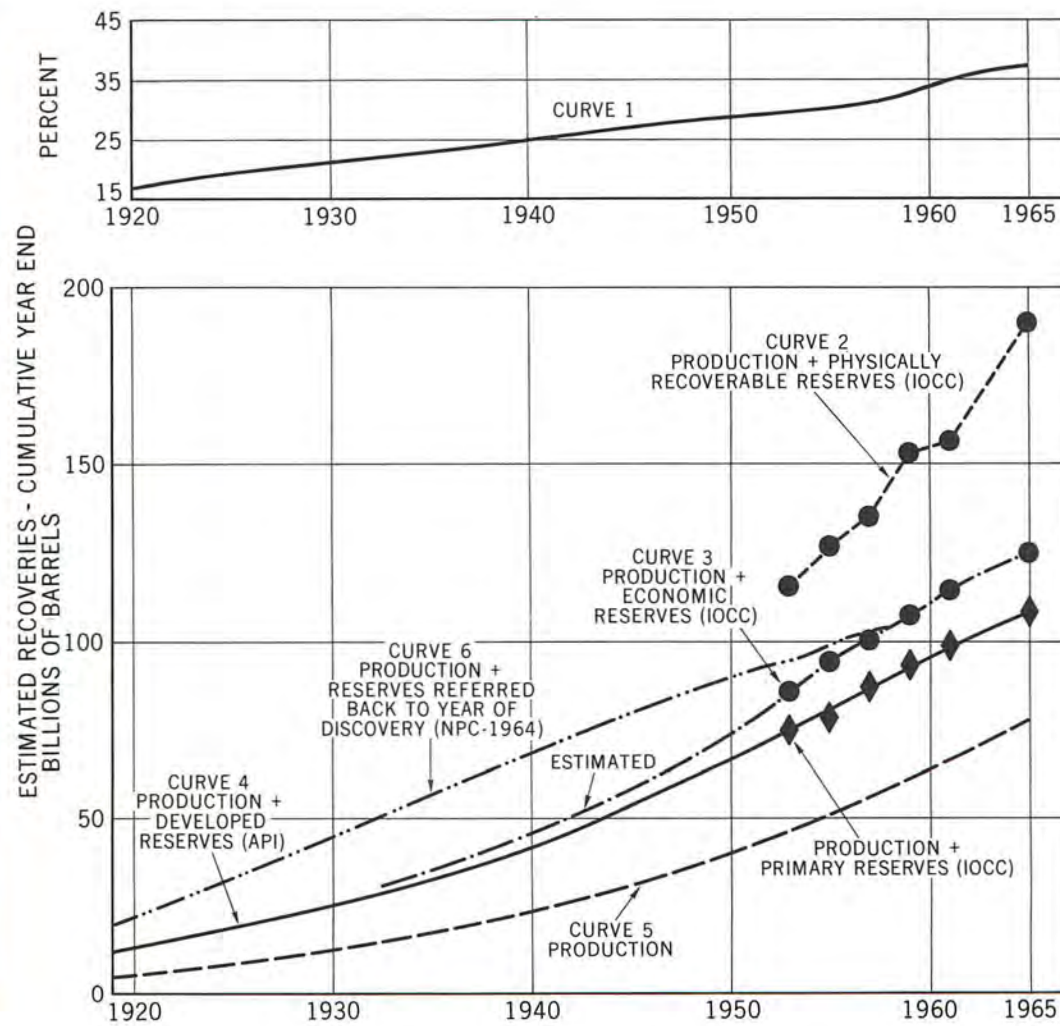
Curve 6, as previously indicated, reflects the NPC estimates of cumulative proved discoveries, or recoverable oil (cumulative past production, plus API reserves estimated at 1964 conditions, but referred back to discovery date). As described in Section A of the Appendix, the information is developed only through 1958.

It should be explained here that the spread between *Curve 6* on the one hand, and *Curves 3 and 4*

APPENDIX
CHART 4

Cumulative Recovery Efficiency

Crude Oil Recovery Estimates



on the other hand, is caused by two major factors: One, field extensions which were not anticipated in estimates of the IOCC or the API; and two, the application of current technology to fields that were discovered years earlier. The major portion of the spread between *Curve 6* and the other two curves is caused by the impact of technology. Much of this technology has been developed in the last twenty years and has been applied to fields that are much older. As time goes on, therefore, *Curve 6* will gradually swing to a higher level as new technology is applied which either has not now been developed or adequately proven, or is not economical under existing conditions. New technology and improved economics could cause *Curve 6* to swing up toward *Curve 2*.

Appendix Table 5

RECOVERABLE OIL DISCOVERED—1964 CONDITIONS REFERRED TO DATE DISCOVERED (NPC)

(1)	(2)	(3)	(4)	(5)
	NPC DISCOVERY ALLOCATION		NUMBER OF NEW FIELD WILDCATS	YEARLY NPC DISCOVERY PER NEW FIELD WILDCATS, MB/W
YEAR	PER YEAR MB	CUMULATIVE MB		
1919		18,591,298		
1920	2,463,946	21,055,244		
1921	3,036,197	24,091,441		
1922	1,488,576	25,580,017		
1923	1,241,591	26,824,608		
1924	941,245	27,762,853		
1925	1,031,212	28,794,065		
1926	3,239,661	32,033,726		
1927	1,466,551	33,500,277		
1928	2,434,051	35,934,328		
1929	2,856,545	38,790,873		
1930	7,107,271	45,898,144		
1931	2,434,393	48,332,537		
1932	707,454	49,039,991		
1933	1,369,120	50,409,111		
1934	2,227,719	52,636,830		
1935	3,439,390	56,076,220		
1936	2,670,254	58,746,474		
1937	4,830,686	63,577,160		
1938	3,453,589	67,030,749		
1939	1,412,877	68,443,626		
1940	3,148,669	71,592,295		
1941	2,182,803	73,775,098		
1942	1,454,458	75,229,556		
1943	1,441,979	76,671,535		
1944	2,063,743	78,735,278	3,094	667
1945	1,922,447	80,657,725	3,037	633
1946	1,537,114	82,194,829	3,133	490
1947	1,163,329	83,358,168	3,480	334
1948	3,207,493	86,565,661	4,296	747
1949	2,724,638	89,290,299	4,449	613
1950	2,237,336	91,527,635	5,290	423
1951	1,280,443	92,808,078	6,189	207
1952	1,540,259	94,348,337	6,698	230
1953	1,726,225	96,075,062	6,925	249
1954	1,641,039	97,716,101	7,380	223
1955	1,212,896	98,928,917	8,104	150
1956	1,038,094	99,967,011	8,709	119
1957	1,260,485	101,207,757	8,014	157
1958	758,527	101,986,103	6,950	109

Col. 2— From Table I, NPC *Proved Discoveries and Productive Capacity* (1965).
Col. 3 — Accumulated Col. 2.
Col. 4 — AAPG data cited on p. 26, *Twentieth Century Petroleum Statistics* (1966).
Col. 5 — Col. 2 divided by Col. 4.

CRUDE OIL DISCOVERIES, PRODUCTION AND RESERVES IN THE UNITED STATES, 1920-1966

(THOUSANDS OF BARRELS)

YEAR (AS OF DEC. 31)	RECOVERABLE OIL ADDED [a] ANNUAL	RECOVERABLE OIL ADDED [a] CUMULATIVE [b]	PRODUCTION ANNUAL	PRODUCTION CUMULATIVE	REMAINING RECOVERABLE RESERVES [c]
1920	942,929	12,629,868	442,929	5,429,868	7,200,000
1921	·1,072,183	13,702,051	472,183	5,902,051	7,800,000
1922	357,531	14,059,582	557,531	6,459,582	7,600,000
1923	732,407	14,791,989	732,407	7,191,989	7,600,000
1924	613,940	15,405,929	713,940	7,905,929	7,500,000
1925	1,763,743	17,169,672	763,743	8,669,672	8,500,000
1926	1,070,874	18,240,546	770,874	9,440,546	8,800,000
1927	2,601,129	20,841,675	901,129	10,341,675	10,500,000
1928	1,401,474	22,243,149	901,474	11,243,149	11,000,000
1929	3,207,323	25,450,472	1,007,323	12,250,472	13,200,000
1930	1,298,011	26,748,483	898,011	13,148,483	13,600,000
1931	251,081	26,999,564	851,081	13,999,564	13,000,000
1932	85,159	27,084,723	785,159	14,784,723	12,300,000
1933	605,656	27,690,379	905,656	15,690,379	12,000,000
1934	1,085,065	28,775,444	908,065	16,598,444	12,177,000
1935	1,219,596	29,995,040	996,596	17,595,040	12,400,000
1936	1,763,087	31,758,127	1,099,687 [d]	18,694,727	13,063,400
1937	3,721,532	35,479,659	1,277,664	19,972,391	15,507,268
1938	3,054,064	38,533,723	1,213,186	21,185,577	17,348,146
1939	2,399,122	40,932,845	1,264,256	22,449,833	18,483,012
1940	1,893,350	42,826,195	1,351,847	23,801,680	19,024,515
1941	1,968,963	44,795,158	1,404,182	25,205,862	19,589,296
1942	1,878,976	46,674,134	1,385,479	26,591,341	20,082,793
1943	1,484,786	48,158,920	1,503,427	28,094,768	20,064,152
1944	2,067,500	50,226,420	1,678,421	29,773,189	20,453,231
1945	2,110,299	52,336,719	1,736,717	31,509,906	20,826,813
1945 [e]	....	51,451,752	....	....	19,941,846
1946	2,658,062	54,109,814	1,726,348	33,236,254	20,873,560
1947	2,464,570	56,574,384	1,850,445	35,086,699	21,487,685
1948	3,795,207	60,369,591	2,002,448	37,089,147	23,280,444
1949	3,187,845	63,557,436	1,818,800	38,907,947	24,649,489
1950	2,562,685	66,120,121	1,943,776	40,851,723	25,268,398
1951	4,413,954	70,534,075	2,214,321	43,066,044	27,468,031
1952	2,749,288	73,283,363	2,256,765	45,322,809	27,960,554
1953	3,296,130	76,579,493	2,311,856	47,634,665	28,944,828
1954	2,873,037	79,452,530	2,257,119	49,891,784	29,560,746
1955	2,870,724	82,323,254	2,419,300	52,311,084	30,012,170
1956	2,974,336	85,297,590	2,551,857	54,862,941	30,434,649
1957	2,424,800	87,722,390	2,559,044	57,421,985	30,300,405
1958	2,608,242	90,330,632	2,372,730	59,794,715	30,535,917
1959	3,666,745	93,997,377	2,483,315	62,278,030	31,719,347
1960	2,365,328	96,362,705	2,471,464	64,749,494	33,613,211
1961	2,657,567	99,020,272	2,512,273	67,261,767	31,758,505
1962	2,180,896	101,201,168	2,550,178	69,811,945	31,389,223
1963	2,174,110	103,375,278	2,593,343	72,405,288	30,969,990
1964	2,664,767	106,040,045	2,644,247	75,049,535	30,990,510
1965	3,048,079	109,088,124	2,686,198	77,735,733	31,352,391
1966	2,963,978	112,052,102	2,864,242	80,599,975	31,452,127

a— Includes reserves added through discoveries of new fields and of new pools in old fields as well as revisions of previous estimates and extensions to known fields.

b— Cumulative production plus developed reserves.

c— Equivalent to cumulative discoveries less cumulative production.

d—Prior to 1937, production data are from the Bureau of Mines.

e— Beginning with 1946, reserves include crude oil only. These are comparable 1945 data on this new basis. Prior to 1945 some condensate was included.

Source: American Petroleum Institute

C. Crude Oil Productive Capacity

In this section the study group has relied upon the estimates of productive capacity made by previous committees of the National Petroleum Council. The latest such study, published in July, 1966, estimated productive capacity on January 1, 1965, and also projected productive capacities for crude oil as of January 1 of each year, 1966 to 1970 inclusive (see Table 7, and *Curve 1* of Appendix Chart 5).

The NPC defined productive capacity for crude oil as the maximum daily rate that could be produced from existing wells with the condition that such rates would not cause loss of recoverable reserves. In predicting future producing capabilities it was necessary for the NPC to estimate wells to be drilled and improved recovery projects to be initiated in the future. The effects of those estimates are included in the projections of productive capacity.

Curve 2, interval No. 3, and *Curve 4* are based on the data contained in Table 28 of the U.S. Department of the Interior's "Appraisal of the Petroleum Industry of the U.S." published in January, 1965 (see Tables 7 and 8).

The estimates of future crude oil production, to 1980, made in this report by the Bureau of Mines, assumes that oil and gas will serve about the same

Appendix Table 7

U.S. CRUDE OIL PRODUCTION AND PRODUCTIVE CAPACITY

YEAR	(1) CRUDE AND CONDENSATE PRODUCTION MBD	(2) CONDENSATE PRODUCTION MBD	(3) CRUDE OIL PRODUCTION MBD	(4) PRODUCTIVE CAPACITY CRUDE OIL MBD	RATIO OF CAPACITY TO PRODUCTION
1945	4,695		4,695		
1946	4,751		4,751		
1947	5,085		5,085		
1948	5,520		5,520		
1949	5,046		5,046		
1950	5,407	111	5,296		
1951	6,158	124	6,034	6,727	1.11
1952	6,256	139	6,117		
1953	6,458	156	6,302	7,465	1.18
1954	6,343	158	6,185	8,331	1.35
1955	6,806	171	6,635		
1956	7,151	187	6,964		
1957	7,170	210	6,960	9,867	1.42
1958	6,710	232	6,578		
1959	7,053	266	6,987		
1960	7,035	294	6,741	10,585	1.57
1961	7,183	322	6,861		
1962	7,332	341	6,991		
1963	7,542	365	7,177		
1964	7,614	389	7,225	11,590	1.60
1965	7,804	445	7,359	12,107	1.64
1966	8,337	490	7,847	12,232	1.57
1970	8,832	579	8,253	12,613	1.53
1975	10,031	716	9,315		
1980	11,290	892	10,398		

Col. 1 —Figures for 1945-1949 from API *Petroleum Facts and Figures* (1959), p. 41. Authority: API, Bureau of Mines; "Petroleum in the U.S. and Possessions."
Figures for 1950-1963 from *"An Appraisal of the Petroleum Industry of the U.S.,"* by U.S. Department of the Interior (January 1965), Table 10; Bureau of Mines basis.
Figures for 1964, 1965 and 1966 from Annual Review and Forecast issues (Feb. 15) *World Oil;* Source: Bureau of Mines.
Figures for 1970, 1975 and 1980 from *"An Appraisal of the Petroleum Industry of the U.S.,"* Table 28.

Col. 2 —Figures for 1950-1963 from *"An Appraisal of the Petroleum Industry of the U.S.,"* Table 13.
Figures for 1964, 1965 and 1966 by difference between adjoining columns.
Figures for 1970, 1975 and 1980 from *"An Apprasial of the Petroleum Industry of the U.S.,"* Table 28.

Col. 3 —Figures for 1945-1949 same as in second preceding column.
Figures for 1950-1963 and 1970, 1975 and 1980 difference between two preceding columns.
Figures for 1964, 1965 and 1966 American Petroleum Institute data as reported in *The Oil and Gas Journal,* Mar. 29, 1965, Mar. 28, 1966, and April 3, 1967.

Col. 4 —Figures through 1965 from *"Estimated Productive Capacities,"* NPC (July 19, 1966), Table 2.
Figures for 1966 and 1970 from *"Estimated Productive Capacities,"* Table 5.

Appendix Table 8

U.S. PRODUCTION ASSOCIATED WITH FLUID INJECTION AND PRIMARY

YEAR	FLUID INJECTION PRODUCTION MBD	PRIMARY PRODUCTION MBD
1950	898	4,442
1953	1,113	5,242
1955	1,359	5,294
1957	1,468	5,550
1959	1,563	5,267
1961	2,009	4,867
1962	2,192	4,830
1963	2,357	4,764
1965	2,534	4,854
1970	3,160	5,093
1975	3,908	5,407
1980	4,604	5,790

Figures from *An Appraisal of the Petroleum Industry of the United States*, U.S. Department of the Interior, January 1965, Table 28.

fraction of the energy market through 1980 as it did in 1965, and that the present import program will be continued. The oil production associated with fluid injection processes constitutes total production from those fields in which fluid injection is operating. A comparison of the Bureau of Mines estimates and those of the IOCC, published in December, 1966 follows:

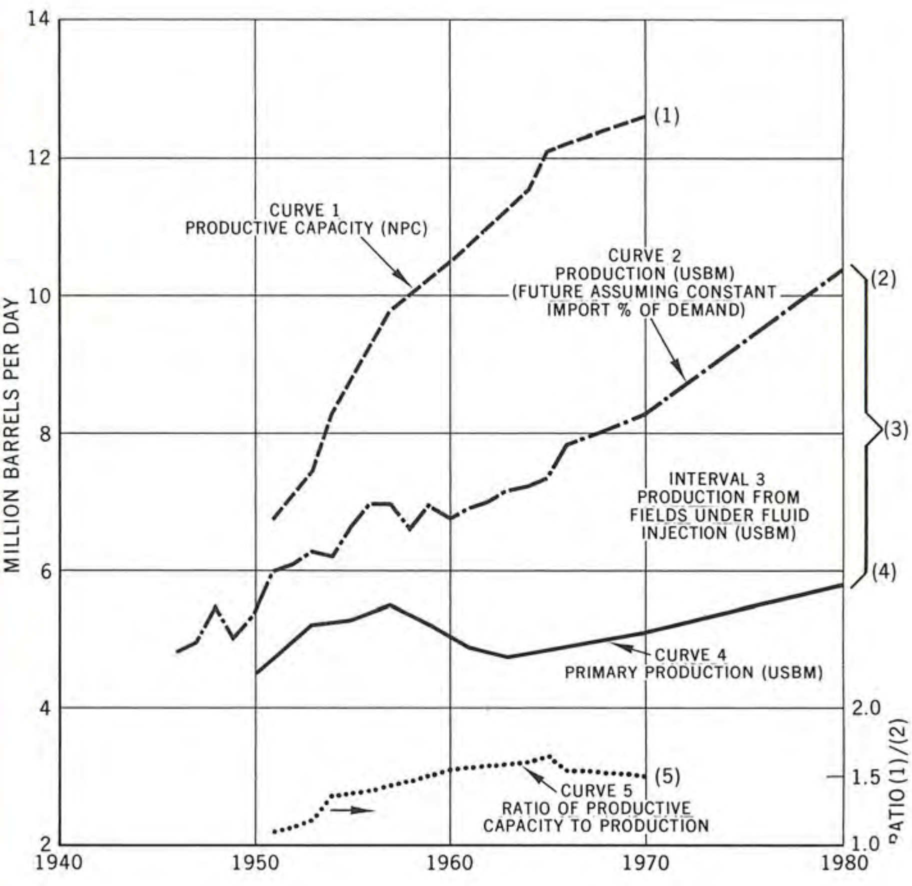
DAILY AVERAGE CRUDE OIL PRODUCTION FROM FIELDS IN WHICH FLUID INJECTION IS OPERATING 1000 BARRELS

YEAR	BUREAU OF MINES	IOCC
1950	898	865
1955	1,359	1,330
1961	2,009	2,240
1965	2,534	2,685

Curve 5 depicts the ratio of the NPC estimated productive capacity rates to the projected need for domestic crude oil production estimated by the Bureau of Mines. The productive capacity estimates only go to 1970, while the estimated production of domestic crude oil is projected to 1980 (see Table 7).

APPENDIX CHART **5**

U.S. Crude Oil Production and Productive Capacity



D. Cost Reduction

While it is impossible to determine what overall cost reductions have been realized through the application of advanced technology, this study has presented, in the Summary, an analysis of probable savings in four areas of operations—drilling, production, corrosion prevention, and well spacing. Two of these are explained sufficiently in the Summary, viz., corrosion prevention and well spacing. The methods employed in arriving at the other two estimates are described below:

1. DRILLING—Two different methods were used to determine, within reason, the order of magnitude of cost savings in drilling during the twenty-year postwar period.

a. First method—This method requires estimating the money savings attributable to faster drilling rates. During the period 1946 to 1965 improvement in drilling rate is indicated as follows:

CHANGES IN ROTARY RIG ACTIVITY[a]

	TOTAL WELLS	MILLION FEET	AVERAGE DEPTH	AVG. NO. RIGS MAKING HOLE	ANNUAL FOOTAGE RATE PER RIG
1946	20,500	80	3,900	1,557	51,000
1955	48,400	210	4,300	2,686	78,200
1965	33,000	165	5,000	1,388	118,900

a-NPC report *Factors Affecting U.S. Exploration, Development and Production 1946-1965*, 1967.

Ratios of 1965 rate:
to 1946 = 2.33
to 1955 = 1.53

In 1965 the annual footage rate per rig was 2.33 times greater than the 1946 rate; and 1.53 times more than the 1955 rate.

Approximately 50 percent of intangible well drilling costs are directly attributable to the drilling rates, and 81 percent* of the total cost of drilling (including dry holes) is intangible.

In 1965, based on an estimated $13 per foot total cost, the average intangible cost was $10.50 a foot (81% × $13). Half of this, or $5.25 per foot, was then affected by the drilling rate.

Had there been no improvement in drilling rates in 1965, the intangible cost would have been as follows:

If drilled at the 1946 rate:

$5.25 × 2.33	=	$12.25/foot
Less 1965 Cost		—5.25
Estimated Savings		$ 7.00/foot

If drilled at the 1955 rate:

$5.25 × 1.53	=	$ 8.00/foot
Less 1965 Cost		—5.25
Estimated Savings		$ 2.75/foot

b. Second method—This method compares actual drilling cost experience with cost which could have prevailed if the actual costs had followed what is believed to be a relevant cost index.

The cost index selected was the Engineering News-Record Construction Cost Index. The value of the index numbers used to escalate costs for the periods of time investigated are developed on Table 9. It should be noted that the authors of this index recognize that application of technology, excellent management, and strong competitive conditions could cause better actual performance than this index would suggest. The Engineering News-Record prepares two cost indexes. They point out "both indexes have proven, over the years, to be infallible as to

*Derived from Joint Association Survey, 1963.

direction and, in normal times, accurate as to the degree." Basic material costs are included in both indexes. A labor cost using skilled labor is included in the Building Index, while common labor is predominant in the Construction Cost Index. The extensive common oil-field labor segment in drilling, well servicing, etc., indicates that the Construction Cost Index is probably more closely related to oil field operations than the Building Index. Therefore it is used in this analysis.

The following comparison is made of the two EN-R indexes with other cost performance trends:

	BASE PERIOD	1965 % INCREASE OVER BASE PERIOD
EN-R Building Cost Index	1949-50 avg.	74
EN-R Construction Cost Index	1949-50 avg.	98
Oil Field Wages	1950	77[a]
Casing	1950	72[a]
Machinery	1950	48[a]

a-Bureau of Labor Statistics.

Two drilling cost surveys are available for comparison with this index. One is directed toward footage contract costs; the other concerns total cost per foot for drilling and equipping all wells.

Appendix Table 9

ENGINEERING NEWS-RECORD CONSTRUCTION COST INDEX

		BASE PERIOD		
YEAR	INDEX	1949-50 RATIO OF INDEX TO 487	1953 RATIO OF INDEX TO 596	1955 RATIO OF INDEX TO 650
1949-50 (Avg)	487	1.00		
1951	535	1.09		
1952	565	1.16		
1953	596	1.22	1.00	
1954	625	1.28	1.05	
1955	650	1.33	1.09	1.00
1956	685	1.40	1.15	1.05
1957	715	1.46	1.20	1.10
1958	752	1.54	1.26	1.16
1959	792	1.62	1.33	1.22
1960	818	1.67	1.37	1.26
1961	835	1.71	1.40	1.29
1962	860	1.76	1.44	1.32
1963	892	1.83	1.50	1.37
1964	925	1.89	1.55	1.42
1965	965	1.98	1.62	1.48

Established costs at time of base period are projected to later years by multiplying the base cost by the appropriate index ratio.

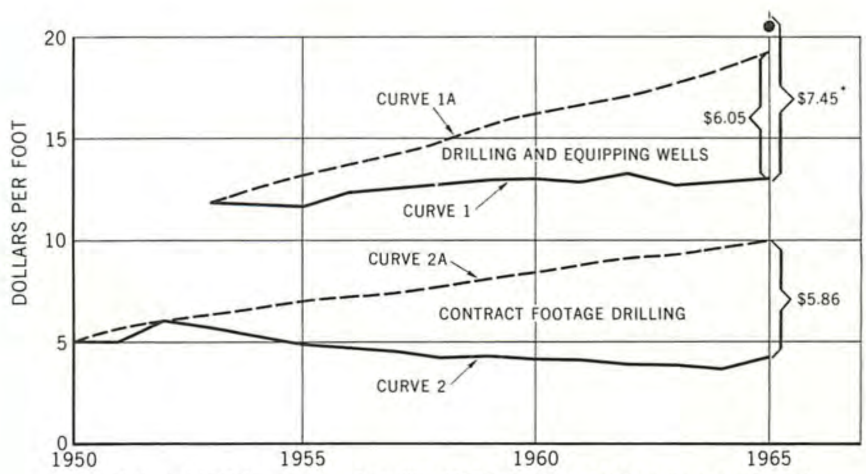
WELL DRILLING COST ANALYSIS

	FOOTAGE CONTRACT COST		DRILLING AND EQUIPPING COST	
YEAR	ACTUAL COST $/FT [a]	COST IF IT FOLLOWED ENGINEERING NEWS-RECORD CONSTRUCTION COST INDEX $/FT	ACTUAL COST $/FT	COST IF IT FOLLOWED ENGINEERING NEWS-RECORD CONSTRUCTION COST INDEX $/FT
1950	5.00	5.00		
1951	5.00	5.45		
1952	5.85	5.80		
1953	5.60	6.10	11.76 [c]	11.76
1954	5.10	6.40	—	12.35
1955	4.90	6.65	11.55 [d]	12.82
1956	4.75	7.00	12.35 [d]	13.52
1957	4.51	7.30	—	14.11
1958	4.27	7.70	—	14.82
1959	4.33	8.10	12.90 [e]	15.64
1960	4.11	8.35	13.01 [e]	16.11
1961	4.11	8.55	12.85 [e]	16.46
1962	3.97	8.80	13.31 [e]	16.93
1963	3.88	9.15	12.69 [e]	17.64
1964	3.68	9.45	—	18.23
1965	4.04 [b]	9.90	13.00 [f]	19.05

Note: Above sources are from annual survey by American Association of Oil Well Drilling Contractors.
a— Years 1950 through 1964 — *The Drilling Contractor,* March-April, 1965, p. 44.
b— Year 1965 — *The Drilling Contractor,* March-April 1966, p. 39.
c— "Reappraisal of 1953 Joint Association Survey of Industry Drilling Costs," published April 1961, p. 4.
d— API *Petroleum Facts and Figures* (1959), p. 27; Source — API; Mid-Continent Oil and Gas Association; IPAA.
e— Joint Association Survey of Industry Drilling Costs (Section 1), 1963, p. 4.
f— Estimated.

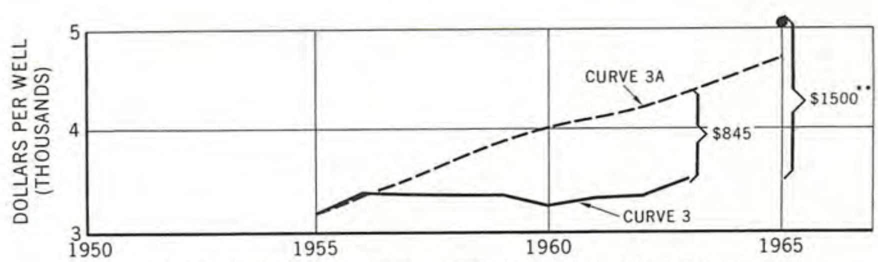
APPENDIX
CHART 6

Drilling
Cost



*Estimated 1965 Savings From Costs With 1950 Rather Than 1953 Practices. See Appendix.

Production
Cost



Curve 1A, 2A, 3A, Costs if Followed Engineering News Record Construction Cost Index
Curve 1,3 Joint Association Survey
Curve 2 American Association of Oil Well Drilling Contractors
**Estimated 1965 Savings From Costs With 1950 Rather Than 1955 Practices. See Appendix.

Footage Contract Costs: Information on this type of drilling cost information is available since 1950 and is shown in Table 10 and as *Curve 2* on Chart 6. These costs represent basically what is paid to a contractor for drilling hole. The costs of equipping the well and other costs which are not related to making hole are not included. Actual costs per foot for the most part have trended downward during the 15-year period 1950-1965, while materials and labor costs have steadily increased. If footage contract costs had followed the EN-R Index, the actual cost of $4.04 per foot in 1965 would have been $9.90. This cost trend is plotted on *Curve 2A* of Chart 6.

This type of drilling is highly competitive and constitutes about one-half of the total effort. It is, in general, routine, and drilling conditions are well enough established to justify bidding costs on a footage basis.

Total Cost of Drilling and Equipping Wells: This cost information, prepared in Joint Association Surveys, was first available for the year 1953. The results from these surveys are listed in Table 10 and shown as *Curve 1* on Chart 6. These costs include all charges for drilling and completing all wells, including dry holes. The trend of these costs has been between just under $12 and up to just over $13 per foot, despite considerably greater escalation of the materials and labor costs involved.

The $13 per foot cost for 1965 is estimated and not yet confirmed by surveys. Had the actual cost for drilling and equipping wells followed the EN-R Index from 1953 through 1965, the cost would have been about $19 per foot. This trend is plotted as *Curve 1A* on Chart 6.

Neither of these two methods of estimating savings in cost for drilling encompasses all the factors involved. The estimates are recapped and compared as follows:

	BASE PERIOD	SAVINGS PER FOOT IN 1965
Faster Drilling Rate:	1946	$7.00
	1955	$2.75
EN-R Index Escalation:		
Footage Contract Costs	1950	$5.86
Total Drilling and Equipping Cost	1953	$6.05
Total Drilling and Equipping Cost (Adjusted to 1950*)	1950	$7.45

* Assumes linear extrapolation from 13 to 16 years thus: $\$6.05 \times \frac{16}{13} = \$7.45$

Based on the foregoing, it is estimated that $7.00 per foot in 1965 is a reasonable cost reduction from costs that would have prevailed if 1965 drilling had been performed under 1946-1950 conditions.

2. PRODUCTION—The difference in cost for production operations has also been estimated by employing the EN-R Construction Cost Index. This is developed on Table 11. Annual costs for production for the industry have also been estimated in the Joint Association Surveys. These have been converted to annual costs per operated well as indicated

Appendix Table 11

ANALYSIS OF PRODUCTION COST TRENDS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
YEAR	PRODUCTION [a] EXPENDITURE CURRENT $ MILLIONS	PRODUCING [b] OIL WELLS END OF YEAR M	PRODUCING [b] GAS WELLS END OF YEAR M	TOTAL OIL AND GAS PRODUCING WELLS END OF YEAR	AVERAGE PRODUCING OIL AND GAS WELLS DURING YEAR M	ANNUAL PRODUCTION COST/WELL, $ (COL. 2/COL. 6)	RATIO OF ENGINEERING NEWS-RECORD COST INDEX FROM APPENDIX TABLE 9	ANNUAL PRODUCTION COST/WELL IF IT HAD FOLLOWED ENGINEERING NEWS-RECORD COST INDEX
1955	1,864	524	71	595	588	3,170	1.00	3,170
1956	2,056	551	74	625	610	3,370	1.05	3,329
1957							1.10	3,487
1958							1.16	3,677
1959	2,223	583	83	666	661	3,363	1.22	3,867
1960	2,182	591	91	682	674	3,237	1.26	3,994
1961	2,270	595	97	692	687	3,304	1.29	4,089
1962	2,378	588	103	691	692	3,436	1.32	4,184
1963	2,434	588	112	700	695	3,502	1.37	4,343
1964							1.42	4,501
1965							1.48	4,692

a — Joint Association Surveys.
b — *Twentieth Century Petroleum Statistics* (1966), p. 25—Source: *World Oil.*

PIPELINE OPERATIONS IN U.S. AS INDICATED BY NUMBER OF MILES OF PIPELINE IN OPERATION (THOSE REPORTING TO ICC—END OF YEAR)

	CRUDE OIL LINES		PRODUCT LINES	
YEAR	TRUNK	GATHERING	TRUNK	TOTAL
1918	22,157	23,415	....	45,572
1919	24,435	24,867	....	49,302
1920	25,330	27,663	....	52,993
1921	26,292	28,968	....	55,260
1922	27,325	30,024	....	57,349
1923	31,322	33,438	....	64,760
1924	34,072	34,113	....	68,185
1925	34,801	35,208	....	70,009
1926	35,515	37,331	....	72,846
1927	41,610	34,460	....	76,070
1928	39,422	42,254	....	81,676
1929	43,564	42,232	....	85,796
1930	45,388	42,806	534	88,728
1931	48,014	41,803	3,273	93,090
1932	48,133	41,378	3,271	92,782
1933	49,468	40,859	3,397	93,724
1934	49,837	39,665	3,568	93,070
1935	48,641	39,380	4,016	92,037
1936	50,263	39,600	4,148	94,011
1937	51,369	40,062	5,181	96,612
1938	51,781	38,874	5,283	95,938
1939	53,641	39,573	5,467	98,681
1940	54,084	40,300	5,772	100,156
1941	57,502	41,858	6,075	105,435
1942	56,762	42,318	7,405	106,485
1943	57,586	42,471	8,726	108,783
1944	59,259	43,276	9,080	111,615
1945	59,576	43,994	9,781	113,351
1946	60,120	44,862	11,562	116,544
1947	61,561	45,909	11,828	119,298
1948	63,364	47,036	13,692	124,092
1949	62,272	47,212	15,500	124,984
1950	64,622	47,593	16,374	128,589
1951	64,922	47,629	18,836	131,387
1952	64,888	48,522	19,305	132,715
1953	63,408	50,030	20,462	133,900
1954	64,145	50,689	24,128	138,962
1955	63,347	50,645	26,832	140,374
1956	61,885	51,336	29,465	142,686
1957	61,379	52,077	31,780	145,236
1958	61,702	49,787	32,865	144,354
1959	61,860	49,567	37,732	149,159
1960	62,059	49,401	40,508	151,968
1961	62,251	49,656	41,830	153,737
1962	61,702	48,063	45,288	155,053
1963	61,832 (est)	47,125 (est)	47,855 (est)	156,812 (est)
1964	63,139 (est)	46,777 (est)	49,667 (est)	159,583 (est)

Authority: Interstate Commerce Commission.

Source: *Twentieth Century Petroleum Statistics* (1966), p. 60.

on Table 11. *Curve 3* on Chart 6 shows these annual well operation costs. *Curve 3A* projects such costs from 1955 to 1963 had they followed the EN-R trend.

This comparison indicates that if technology and related operating practices had remained as employed in 1955, the annual per-well operating cost in 1963 would have been approximately \$4,345 as compared with an actual cost of \$3,500. Thus, a savings of \$845 per well is indicated. This is for the nine-year period 1955-1963. It is estimated that the same annual rate of cost improvement prevailed over the 16-year period from. 1950 to 1965, inclusive. Thus the indicated savings in 1965 are approximately \$1,500 per well over that employing 1950 practices ($\$845 \times \frac{16}{9} = \$1,500$).

3. CONCLUSION—Based upon the above cost trend comparison, the savings by the industry in oil well drilling and production costs in 1965 when related to actual crude oil production, were the equivalent of \$0.67 per barrel of oil produced in that year. This is estimated as follows:

DRILLING COST REDUCTION (1965)

1. \$7.00 per foot × 181,427,000 total feet drilled × 75%*=\$951,000,000

2. \$951,000,000 ÷ 2,686,000,000 barrels produced=\$0.35 per barrel cost savings

PRODUCTION REDUCTION (1965)

1. \$1,500 per well × 580,000 operating oil wells**=\$870,000,000

2. \$870,000,000 ÷ 2,686,000,000 barrels produced=\$0.32 per barrel cost savings

* Percent of drilled footage allocable to oil drilling. Estimated from Joint Association Surveys of Oil and Gas Drilling Activities for 1963.

** *Twentieth Century Petroleum Statistics* (1966), p. 25.

E. Transportation

Technological advancements applied to transportation facilities and operations have been significant in the period 1946 to 1965, resulting in the decline in the actual cost of transporting a barrel of oil, although overall operational costs have increased.

Some statistics on pipeline operations are contained in Tables 12 and 13, and are depicted by

Appendix Table 13

ANALYSIS OF CRUDE OIL TRANSPORTATION COSTS

YEAR	COST OF CRUDE OIL TRANSPORTATION BASED UPON REVENUE COLLECTED CENTS/100 BBL. MILES [a]	RATIO OF INDEX TO 487 (AVERAGE 1949-1950)	ESTIMATED CRUDE OIL TRANSPORTATION COST IF IT HAD FOLLOWED ENGINEERING NEWS-RECORD CONSTRUCTION COST INDEX (BASE IS AVERAGE OF 1949-1950) [b]
1950	4.4	1.00	4.4
1951	4.4	1.09	4.8
1952	4.5	1.16	5.1
1953	4.3	1.22	5.4
1954	4.2	1.28	5.6
1955	4.2	1.33	5.9
1956	4.1	1.40	6.2
1957	4.0	1.46	6.4
1958	4.1	1.54	6.8
1959	4.0	1.62	7.1
1960	4.0	1.67	7.4
1961	3.9	1.71	7.5
1962	3.8	1.76	7.7
1963		1.83	8.1
1964		1.89	8.3
1965		1.98	8.7

a-*An Appraisal of the Petroleum Industry of the United States*, U.S. Department of the Interior, (Jan. 1965), Table 61 (no figures earlier than 1950 or later than 1962).

b-Figures obtained in similar manner to those described on App. Table 9. The figure for 1950 (4.4 cents/100 bbl. miles) was multiplied by the average Engineering News-Record Construction Cost Index for the particular year divided by the average cost index for 1949 and 1950 (487).

several curves on Appendix Chart 7. Reflected here are the pipeline construction and operation activities for crude oil and liquid products transportation.

Curve 1 on Chart 7 shows the trend in the cost of crude or pipeline transportation based upon revenue collected (see Table 13). *Curve 2* represents an estimate of what this cost would have been had it followed the Engineering News-Record Construction Cost Index (see also Table 13).

The other curves on Chart 7 depict the miles of gathering, crude oil trunk, and product trunk pipelines in operation. The total mileage of line in operation rose from 116,544 miles in 1946 to approximately 160,000 miles in 1964 or an increase of 37 percent. Most significant in this overall increase in lines built is the rapid increase in product pipeline construction.

F. Some Guidelines of Discovery and Recovery Performance Needed Through the 1970's to Meet U.S. Bureau of Mines Estimated Production of Domestic Crude Oil

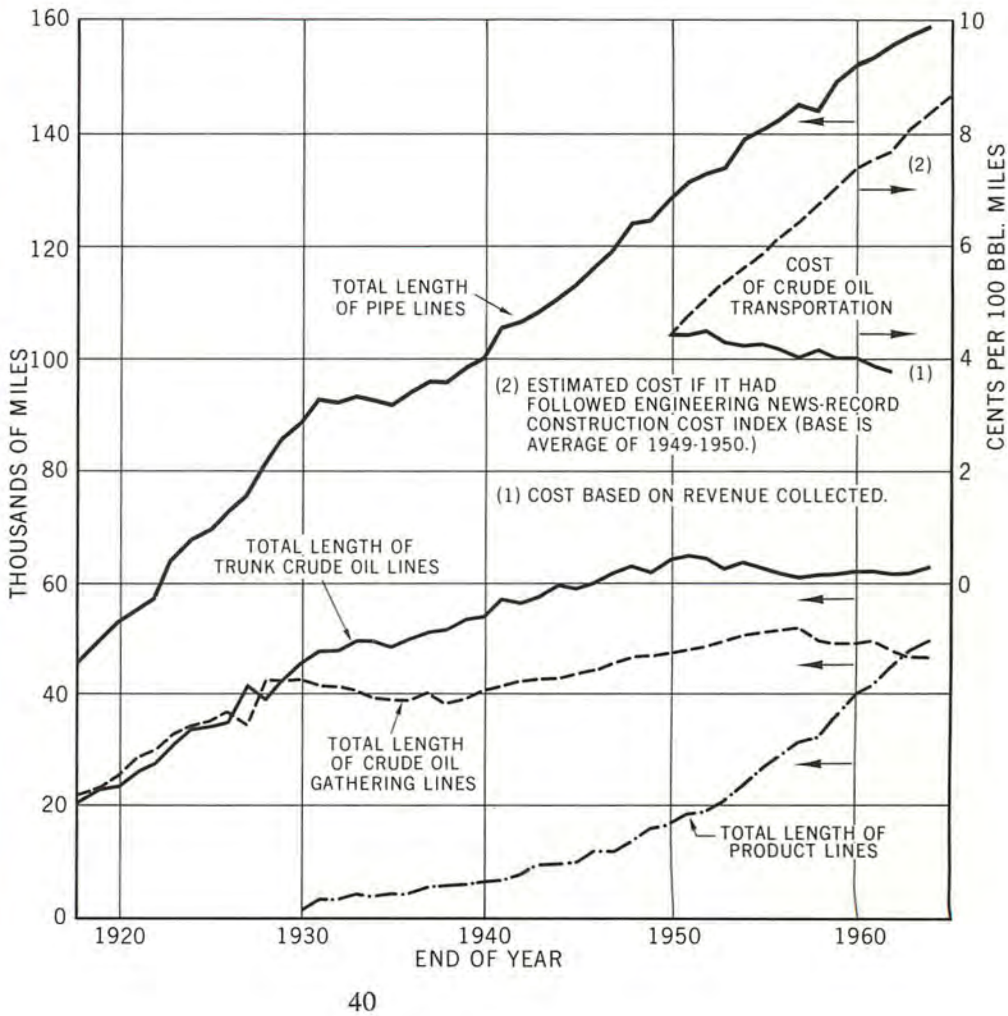
The projected curves on Chart VI of the Summary, reproduced here as Appendix Chart 8, bracket, but are not intended to forecast, additions to recovery, recovery efficiency and discoveries of oil in place that would be necessary to produce the needed domestic crude oil, through the 1970's, as forecast by the Bureau of Mines.*

The source data used in preparing these guidelines are as follows:

1. The information prior to and up through 1965 is taken directly from Charts I and II in the Summary.

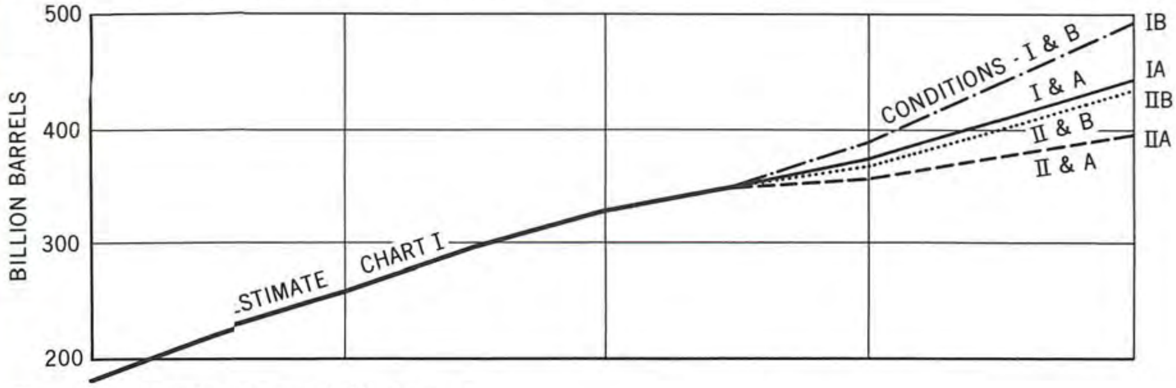
* *An Appraisal of the Petroleum Industry of the U.S.*, U.S. Department of the Interior, January 1965, Table 28.

APPENDIX
CHART **7**
Pipeline Operations—U.S.

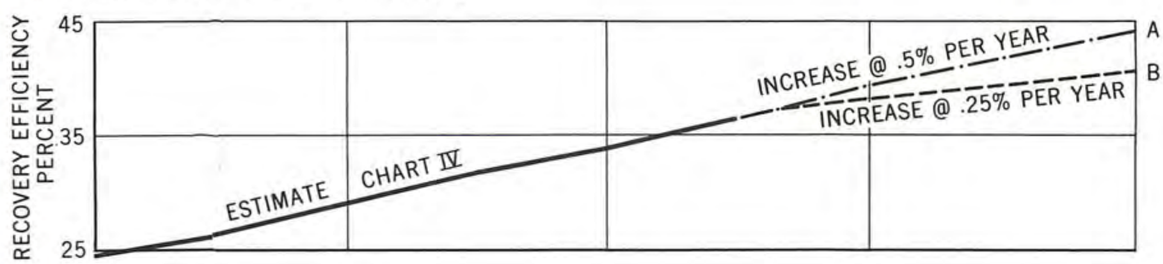


APPENDIX CHART 8

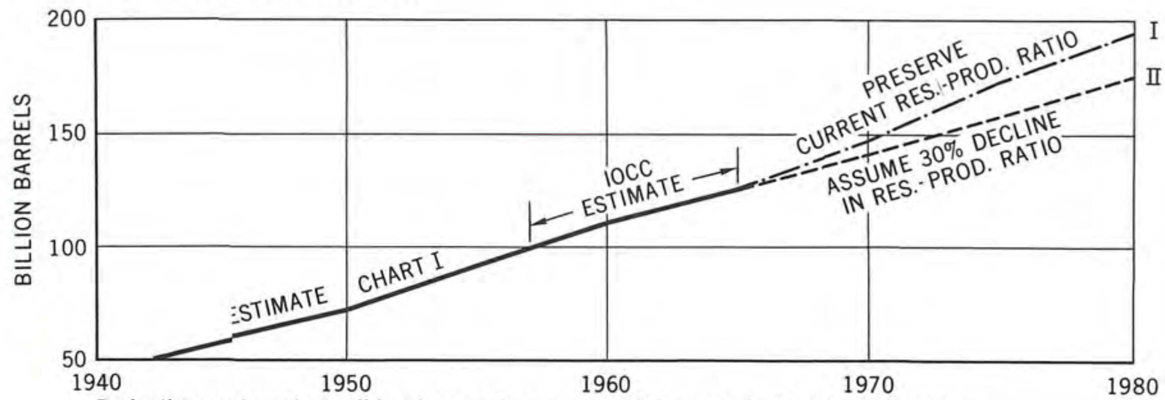
Cumulative Oil in Place Discovered



Cumulative Recovery Efficiency



Cumulative Recoverable Oil



Projections are based on oil-in-place and recovery efficiency estimated in this report.

Discovery and Recovery Guidelines

These Guidelines Indicate Discovery and Recovery Performance Needed
Through the 1970's to Meet USBM Estimated Production of Domestic Crude Oil

Curve I —Past Production Plus Reserves (IOCC Basis), Projected to Preserve Current Reserve-Production Ratio

Curve II —Past Production Plus Reserves (IOCC Basis), Except That Reserve-Production Ratio is Allowed to Decline by 30 Percent

Curve A —Cumulative Recovery Efficiency Increasing at ½ of 1% Additional Per Year

Curve B —Cumulative Recovery Efficiency Increasing at ¼ of 1% Additional Per Year

Curve IA —Total Oil in Place Necessary to be Discovered to Satisfy Conditions of I and A

Curve IB —Total Oil in Place Necessary to be Discovered to Satisfy Conditions of I and B

Curve IIA —Total Oil in Place Necessary to be Discovered to Satisfy Conditions of II and A

Curve IIB —Total Oil in Place Necessary to be Discovered to Satisfy Conditions of II and B

2. The bracketing guideline statistics for the projection through 1980 are developed on Table 14.

The following important factors used in projecting the bracketing guidelines should be carefully considered in their use:

1. Crude oil production through 1980 is based upon a forecast prepared by the Bureau of Mines and included in the Department of the Interior's appraisal of the U.S. petroleum industry (previously cited). The assumptions used in that study were that oil and gas through 1980 would retain approximately a constant fraction of the energy market and that the present import program would continue.

2. It is believed that the most representative statistics on economically recoverable crude oil reserves as of January 1, 1966, are those developed by the IOCC. API statistics of the past more closely reflect *active or early availability* of reserves, while IOCC reserves would generally require additional development and further application of existing technology to make all reserves *actively available.*

3. It is believed that the past history of cumulative oil in place discovered through 1965, as developed in this study, is reasonable both in direction (trend vs. time) and in absolute values. Perhaps the trend is most relevant in judging the impact of technology on both past and future crude oil supply.

4. Lease condensate is classified as natural gas liquids and is not included in these bracketing guidelines. (This is true throughout the report unless otherwise designated). Its contribution to reserves will follow natural gas exploration, development, and marketing programs more closely than it will the

GUIDELINES AS TO DISCOVERY AND RECOVERY PERFORMANCE NEEDED THROUGH THE 1970'S TO MEET USBM ESTIMATED PRODUCTION OF DOMESTIC CRUDE OIL

YEAR	CRUDE OIL PRODUCTION DAILY AVERAGE MB	CRUDE OIL PRODUCTION PER YEAR M^3B	CRUDE OIL PRODUCTION PREVIOUS 5 YEARS M^3B	CRUDE OIL PRODUCTION CUMULATIVE M^3B	RESERVE PRODUCTION RATIO YEAR'S SUPPLY (AT ANNUAL RATE)	RESERVE MAINTAINED (IOCC BASIS) M^3B
I. Assuming Current Reserve: Production Ratio to be Maintained at 18.3:1						
1965	7,384	2.70[b]		78.1[b]	18.3	49.4[b]
1970	8,253[a]	3.01	14.3	92.4	18.3	55.1
1975	9,315[a]	3.40	16.0	108.4	18.3	62.3
1980	10,398[a]	3.80	18.0	126.4	18.3	69.6
Increment 1966-80, Incl.				48.3		
II. Assuming Reserve: Production Ratio to Decrease to 13.0:1						
1965	7,384	2.70		78.1	18.3	49.4
1970	8,253	3.01	14.3	92.4	16.25	48.9
1975	9,315	3.40	16.0	108.4	14.5	49.3
1980	10,398	3.80	18.0	126.4	13.0	49.4
Increment 1966-80, Incl.				48.3		

a — *An Appraisal of the Petroleum Industry of the U.S.*, by U.S. Department of the Interior (January 1965), Table 28.
b — *Evaluation of United States Oil Resources as of January 1, 1966,* by Paul D. Torrey, presented to the IOCC December 1966, Table No. 1.
c — From App. Table 2 this report.

technological factors controlling crude oil discovery and recovery.

5. The current reserve production ratio (1965) of 18.3:1, using IOCC reserves, is higher than the commonly used numbers of 11:1 to 12:1. The latter ratios are related to API reserve statistics which, as previously explained, have not reflected the full potential economic recovery of oil in place discovered.

In one case developed on Table 14 the reserves to production ratio is maintained, and in the other it is allowed to decline from 18.3:1 to 13:1. This is in no way to suggest that this degree of decline is desirable; it indicates one possible factor that could, by its variation, materially influence the need for accelerated discovery and/or recovery efforts.

Appendix Table 14

		ORIGINAL OIL IN PLACE NECESSARY TO BE DISCOVERED WITH ½% PER YEAR RECOVERY EFFICIENCY INCREASE			ORIGINAL OIL IN PLACE NECESSARY TO BE DISCOVERED WITH ¼% PER YEAR RECOVERY EFFICIENCY INCREASE	
CUMULATIVE PRODUCTION PLUS RESERVES M^3B	(A) RECOVERY EFFICIENCY PERCENT ESCALATED AT ½% PER YEAR	CUMULATIVE M^3B	AVG/YEAR PREVIOUS 5 YEARS M^3B	(B) RECOVERY EFFICIENCY PERCENT ESCALATED AT ¼% PER YEAR	CUMULATIVE M^3B	AVG/YEAR PREVIOUS 5 YEARS M^3B
127.5[b]	36.6[c]	348[c]		36.6[c]	348[c]	
147.5	39.1	377	5.8	37.8	390	8.4
170.7	41.6	410	6.6	39.1	437	9.4
196.0	44.1	444	6.8	40.4	485	9.6
68.5		96	6.4 (avg/yr)		137	9.1 (avg/yr)
127.5	36.6	348		36.6	348	
141.3	39.1	362	2.8	37.8	374	5.2
157.7	41.6	379	3.4	39.1	404	6.0
175.8	44.1	399	4.0	40.4	435	6.2
48.3		51	3.4 (avg/yr)		87	5.8 (avg/yr)

Note: Crude oil production estimated for 1970, 1975 and 1980 by USBM assumes that oil and gas will serve about the same fraction of the energy market as they did in 1965 and that the present import program will continue.

I, II, A, and B key this information to Curves on Appendix Chart 8.

CHAPTER TWO

EXPLORATION

SECTION 1—The Evolution of Exploration Technology

R. Dana Russell

A. Creekology and the Anticlinal Theory

The application of scientific methods to the search for hydrocarbons did not fully develop until more than half a century after the drilling of the Drake well in 1859. This was not for lack of knowledge. The anticlinal theory of oil accumulation[1] was developed between 1842 and 1861 by Sir William Logan, Henry D. Rogers, and T. Sterry Hunt, but it was not widely known or applied. Even after it was "rediscovered" and successfully applied to the discovery of several oil and gas fields by Professor I. C. White of West Virginia in the 1880's, it was largely ignored by the oil industry.[2]

There are several reasons for this neglect. Chief among them is the fact that supply exceeded demand during most of the early years of the industry. Enough oil was found at shallow depths by random drilling to flood the market periodically. And wildcat locations were not entirely random; there was some logical basis for many of the apparently unscientific methods used. The Drake well and some of its immediate successors were drilled in creek bottoms, so "creekology" was the popular method until some brave soul drilled a successful well on the uplands. But in the Appalachians of Pennsylvania, the trellis drainage follows the strike of the beds and major creek valleys follow anticline crests, so there is some

1. An explanation of the early observation that oil and gas accumulations commonly occur on the crests of upfolds (anticlines) is obvious when one realizes that most rocks are saturated with water, that oil is lighter than water, and hence that it tends to migrate to the highest point in permeable rocks. If, then, a permeable bed such as sand is overlain by an impervious shale which acts as a seal against migration, oil and/or gas will accumulate at the high part of an upward fold, and we have an *anticlinal trap*.
2. Landes, K. K., *Petroleum Geology*, John Wiley & Sons, New York, 1951, pp. 3-17.
Howell, J. V., "Historical Development of Structural Theory of Accumulation of Oil and Gas," *Problems of Petroleum Geology*, Am. Assoc. Pet. Geol., Tulsa, 1934, pp. 1-23.

sense in following the creeks. The Appalachian oil pools were also markedly elongate, trending NNE (again, parallel to the strike of the rocks); this observation led to the development of "trendology"—still a useful guide where traps tend to be elongated and aligned. The discovery of the giant Spindletop oil field on the Texas Gulf Coast led to the drilling of other topographic mounds over shallow piercement salt domes. Drilling in the vicinity of oil seeps and "paraffin dirt" deposits has proved successful, especially where the rocks are rather steeply dipping.

But these rules of thumb proved inadequate as demand increased with the invention of the automobile and the airplane, and the shallow deposits became exhausted. The pioneer teaching of Professor I. C. White, and of Professor Orton of Ohio, began to pay off. Whereas only two oil companies, both in California, regularly employed geologists in 1898, by 1908 a number of oil companies were "cautiously following geologic advice."[3] And only eight years later, in 1916, there were 60 "petroleum" geologists present at the first meeting, in Norman, Oklahoma, of what was to become the American Association of Petroleum Geologists—now the largest geological society in the world.[4] This review is thus being written on the semicentennial of the founding of the Association; petroleum exploration is indeed a young technology.

The greatly expanded demand for oil and gasoline during and following World War I led to intensified exploration and to the rapid development of more scientific methods. The Association played an important role in this development by sponsoring the exchange of ideas and techniques through symposia and technical meetings, and the publication of facts and theories in the *Bulletin* and in special publications. In the 'teens, the dominant—in fact, almost the only—exploration method was surface geologic mapping to delimit anticlines and other favorable structural traps. Subsurface methods for locating buried structures came next; core drilling, to provide geologic data in areas of inadequate outcrops, started in 1919 and reached a peak in the 1920's. The first "subsurface" laboratory was established in 1919, and micropaleontology was introduced as a means of correlating geological horizons in 1920. By the late '20's, almost every oil company of any size had a laboratory where cuttings were examined and lithologic logs prepared to supplement the driller's log. Many also had "paleo labs," providing micropaleontologic information to determine "tops"—the first appearance of successive geologic horizons as the drill sank deeper.

The size of this subsurface geologic effort on samples and cores dwindled rapidly after the invention in France of the electric log by the Schlumberger brothers in 1927.[5] The electric log identified common rock types (shale, sandstone, limestone), gave some indication of their pore fluids (oil, gas, or water), and by the variation of log response provided a means of correlating geologic horizons from one well to another by matching the squiggles on logs of each well. The need for careful examination and interpretation of rocks on outcrop and the study of well cuttings for correlation diminished considerably. Meanwhile, the parallel development of geophysical techniques for outlining buried structure accelerated the decline of the "sample geologist." Gravity methods were introduced with the development of the torsion balance in 1920, and seismic methods in 1923. The discovery of five salt dome oil fields by torsion balance and refraction seismology in 1924-25 triggered an explosive expansion of geophysical research and application.

B. The Transcendence of Structure

Throughout these early developmental years, all of the exploration emphasis was on the location of suitable structural traps—usually anticlines, and the more "closure," the better. The seismic refraction method and the torsion balance were very successful in locating salt domes and choosing drilling locations on them, but they were not adapted to the location of buried structure in more normal sedimentary sequences. The reflection method was needed for this application.

The reflection seismograph grew from the Fessenden acoustic sounder developed during World War I to measure water depths and locate icebergs. Between 1919 and 1921, J. C. Karcher developed reflection seismic equipment and used it successfully to detail the flank of a known dome in Oklahoma; but commercial exploitation did not come until 1927, when the Geophysical Research Corporation discovered the Maud Field in Oklahoma. By the early 1930's the reflection seismic method was the most widely used of all geophysical techniques—and it still is.[6]

So successful was the reflection seismograph in revealing buried structure that it quickly supplanted older methods, even where the latter were cheaper and more effective.[7]

In the last thirty-some years (Figure 1), it has almost worked itself out of a job several times—all of the presumably prospective areas having been covered. But in each case, an increase in demand

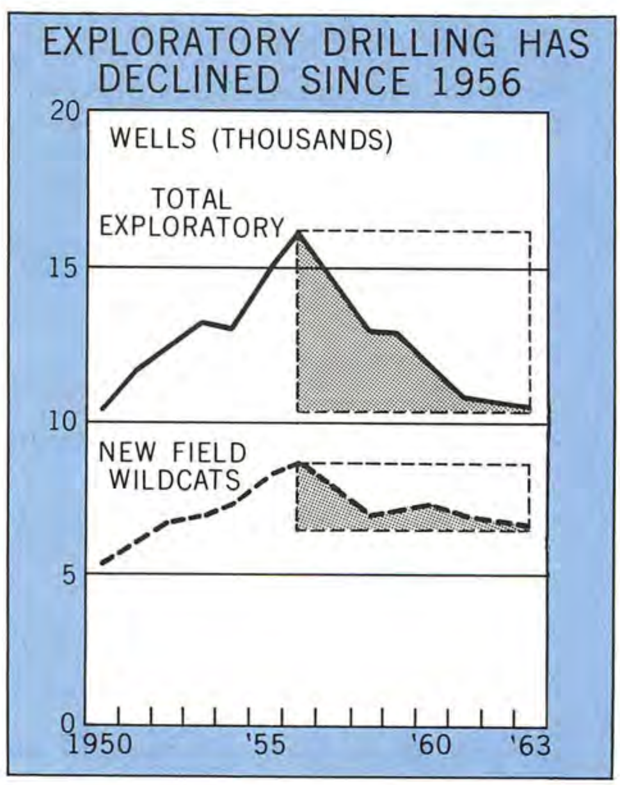
3. Price, P. H., "Evolution of Geologic Thought in Prospecting for Oil and Natural Gas," *Bull.*, Am. Assoc. Pet. Geol., April 1947, vol. 31, No. 4, p. 685.
4. Morley, H. T., "A History of the American Association of Petroleum Geologists: First Fifty Years," *Bull.*, Am. Assoc. Pet. Geol., April 1966, vol. 50, No. 4.
5. Clark, J. A., *The Chronological History of the Petroleum and Natural Gas Industries*, Clark Book Co., Houston, 1963.
6. Dobrin, M. B., *Introduction to Geophysical Prospecting*, McGraw-Hill, New York, 1960, p. 13.
7. Russell, R. Dana, "Future of Field Geology," *Bull.*, Am. Assoc. Pet. Geol., Feb. 1941, vol. 25, No. 2, p. 324.

FIGURE **1.** Reflection Seismograph Crew-Months in the United States (After Eckhardt[8a] and Smith[9])

(as in World War II and the Korean War), or the opening of new areas (as the development of offshore prospecting), or improvements in equipment or techniques, sparked a new advance—until 1952. The almost continuous decline from a peak of 719 crew-months in 1952 to less than 300 in 1962 was caused by several conditions, including the fact that most of the shallower, easy-to-find structures had been located, resulting in increased shooting costs in the more difficult areas, while the opening of foreign areas after World War II and the discovery of abundant foreign oil made foreign exploration economically more attractive. Also, very successful exploration in the early 1950's required more funds for development, relative to exploration. All of these and many other factors[8] caused domestic exploration budgets to shrink which was reflected in decreased exploratory drilling in the United States after 1956 (Figure 2).

FIGURE **2**

Exploratory Drilling in the United States Since 1950[10]



C. Stratigraphic Geology in Exploration

The discovery of the giant East Texas Field, largest in the western hemisphere, by random drilling in 1930, drew the attention of many thoughtful explorationists to the problem of finding stratigraphic, as contrasted with structural, traps. East Texas could

8. *Factors Affecting U.S. Exploration, Development and Production 1946-1965,* National Petroleum Council, 1967.
8a. Eckhardt, E. A., *Geophysics,* Oct. 1948, XIII, 4, p. 530.
9. Smith, N. J., *Geophysics,* Oct. 1965, XXX, 5, p. 909.
10. Lattu, O. P., et al., *An Appraisal of the Petroleum Industry of the United States,* U. S. Dept. of the Interior, Office of Oil & Gas, Jan. 1965.
Dillon, E. L., and Van Dyke, L. H., "Exploratory Drilling in 1965," *Bull.,* Am. Assoc. Pet. Geol., June 1966, vol. 50, pp. 1114-1138.

not have been found by the reflection seismograph or any other geophysical technique of the '30's, and it is at least debatable whether it could have been found by any of today's geophysical methods. A much better understanding of the geology of the area was needed, acquired by improved methods of geological interpretation of the stratigraphy—not just the structure. The American Association of Petroleum Geologists recognized this need, and sponsored a series of symposia on this subject in the early forties.[11] A study of research needs by the Association's Research Committee followed.[12] These reviews pointed out the requirement for more information on the characteristics of sediments deposited in different environments, so that the environments of deposition of ancient rocks could be recognized and environmental patterns used in exploring for reservoir rocks. The establishment of API Project 51, a ten-year study of modern sediments of the northwest Gulf of Mexico,[13] pioneered a series of studies of Pleistocene and Recent sediments. The discovery of big carbonate (limestone and dolomite) "reef" fields in West Texas and Canada in the late '40's indicated the need for a better understanding of carbonate-rock reservoirs as well, so modern environments of carbonate deposition also began to receive attention.

Meanwhile, better techniques for the interpretation of ancient sediments were being developed, particularly in the universities. Sedimentary rocks were being examined more closely for clues to their environments of deposition. In addition to mineralogy, texture, and fossil content, primary sedimentary structures began to be studied. Statistical and other mathematical techniques were applied to the analysis of sedimentary rock types or "facies," and the elucidation and mapping of facies patterns. But the industry was not ready for detailed stratigraphic work as long as new fields could be found by existing geophysical methods. Only with the declining success ratios of the fifties, and the discovery of several large stratigraphic trap fields in areas that had already been examined with the seismograph, was the stage set for the development and application of modern exploration methods.

D. Summary

Figure 3 summarizes diagrammatically my concept of the development and present relative status of the more important scientific techniques used in petroleum exploration to date. It is based on estimates of relative effort as measured by dollars (percent of total annual expenditures on these six methods), so it does not reflect variations from year to year in the total budget as does an absolute measure such as the "crew-months" of Figure 1. Moreover, since it is based on dollars, it accentuates the more costly methods at the expense of the cheaper ones; i.e., reflection seismograph compared to gravity and to geologic methods. For the same reason, the decline shown by Figure 1 in reflection seismic work between 1952 and 1962 is partly offset by the rising cost of more sophisticated techniques—the same number of dollars buys fewer crew-months.

Since records of exploration costs are not generally available, these curves are necessarily subjective estimates, and no two people would draw them in exactly the same way. But this is a *trend* graph, and I think that all explorationists would agree on the general trends. Note that surface mapping for structure, and gravity and the refraction seismograph, have long since passed their peaks and are only used today for special purposes or in newly opened areas such as Alaska. The reflection seismograph became the dominant method in the late '30's and remains so. There is some indication that its decline has been arrested and that an upturn is in prospect as a result of the major technical advances of the last few years. Subsurface structural mapping continues to be a major geological technique, but is gradually declining as "modern stratigraphic methods" increase in importance. The former is here interpreted to include all subsurface work using information from samples, cores, or logs to locate structural prospects; the latter to include all work, surface or subsurface, aimed at working out detailed stratigraphy.

The rising curve of modern stratigraphic methods represents the response of the industry to the dual challenge of the search for stratigraphic traps and offshore exploration. The expensive testing of offshore structures requires delineation of stratigraphically promising prospective areas and more detailed information on potential reservoirs. Hence more stratigraphic information is needed in these relatively "virgin" areas, as well as in "mature" areas of exploration where stratigraphic and combination traps are important objectives. We have reached the stage "where most of the oil being found, especially the large fields, is in 'the obscure and subtle trap.' Another way of stating the change is that . . . exploration formerly was structure-oriented; now it is reservoir-oriented."[14]

These new developments in exploration will be the chief topics of the succeeding sections of this Chapter.

11. Levorsen, A. I., Fitzgerald, P. E. Millikan, C. V., Eckhardt, E. A., Lahee, F. H., and DeGolyer, E., "Symposium on New Ideas in Petroleum Exploration," *Bull.*, Am. Assoc. Pet. Geol., Aug. 1940, vol. 24, No. 8, pp. 1355-1399.
Levorsen, A. I., et al., *Stratigraphic Type Oil Fields*, Am. Assoc. Pet. Geol., Tulsa, 1941.
12. Lowman, S. W., et al., "Final Reports on a Reconnaissance Survey of Research Needs in Petroleum Geology . . . . ," *Bull.*, Am. Assoc. Pet. Geol., 1946-47; vol. 30, No. 12, pp. 2043-2063; vol. 31, No. 1, pp. 161-181, 375-393; vol. 31, No. 3, pp. 501-512.
13. Shepard, F. P., Phleger, F. B., van Andel, Tj. H., et al., *Recent Sediments, Northwest Gulf of Mexico*, Am. Assoc. Pet. Geol., Tulsa, 1960.
14. McGookey, D. P., "Truth About Typical Rocky Mountain Oil Traps—Introduction," *Bull.*, Am. Assoc. Pet. Geol., 1966, vol. 50, No. 10, p. 2056.
Levorsen, A. I., "The Obscure and Subtle Trap," *ibid.*, pp. 2058-2067.

SECTION 2—Geophysics

Frank J. McDonal

A. Introduction—The Geophysical Methods Employed in Oil Exploration

The gravity and seismic refraction methods were of prime importance in the first phase of geophysics during the 1920's and early 1930's. Seismic refraction proved very efficient in the location of high velocity piercement salt domes surrounded by the lower velocity sands and shales. Altogether, some forty salt domes were located by the refraction method, but many of these did not yield oil until years later. Although the refraction method was very successful in locating salt domes, it did not provide the detailed information needed for selecting well locations. Gravity measurements with the torsion balance were extensively used for this purpose.

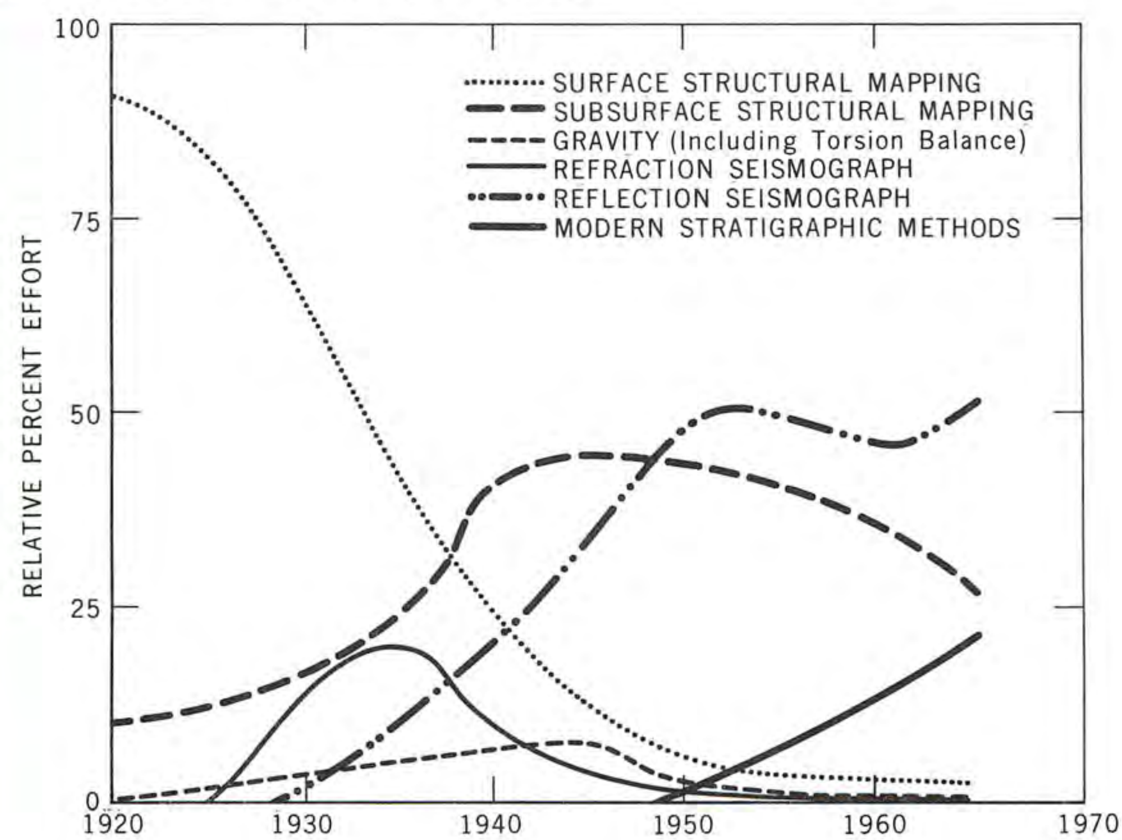
The seismic reflection method rose to prominence during the early 1930's and has dominated the geophysics picture since that time. By 1937 stable and sensitive electronic amplifiers were available. Automatic gain control and filters had been developed. Six- to ten-track oscillographic recordings on photographic paper were standard.

During the twenty-year period from 1935 to 1955 the geophysical community continued to use the seismic reflection method as the primary tool for detailed information with the gravity method as the primary reconnaissance tool. Seismic instrumentation and interpretation proceeded through a period of gradual but steady improvement in technology. By 1935 the gravity meter had replaced the slower and more cumbersome torsion balance. The fluxgate magnetometer, which was developed during the war for submarine detection, was adapted for oil exploration and has been widely used as an aerial reconnaissance method.

Starting in the mid-1950's geophysics entered a period of rapid technological growth that has produced magnetic tape recording, the continuous velocity log, the synthetic seismogram, the seismic record section, nonexplosive seismic sources, and new methods of analysis and interpretation of data. Digital recording and computer analysis of seismic data are the most recent advances of this period. This section will be concerned primarily with these developments.

Gravity has continued as the foremost reconnaissance method, but the lower cost of aeromagnetics has led to extensive use of this method also. The seismic refraction method has been widely used as a reconnaissance tool, particularly in areas where the

FIGURE 3. Relative Effort on Major Exploration Methods in the U.S., 1920-1965



reflection method has given poor results. Electrical and electromagnetic methods have received attention from time to time by the major oil companies, but these methods have not played any significant role in oil exploration to date in the United States and Canada. Recent technological developments indicate that electromagnetic methods could be useful for reconnaissance, but the ultimate use of these methods will probably depend upon economic as well as technical factors.

B. The Seismic Reflection Method

1. THE NEW BASIC CONCEPTS

a. The Synthetic Seismogram

The seismic method of 1950 was based on the concept of a sedimentary section composed of a small number of layers of varying thickness. The prevailing view at that time was that seismic reflections were produced only at the top and bottom of thick beds, beds at least several hundred feet thick. Each of these beds was associated with an average velocity, and the amplitude of the seismic reflection produced at the boundary between two of these beds was determined by the standard relation:

$$\text{seismic reflection coefficient} = \frac{\text{velocity in the lower bed} - \text{velocity in the upper bed}}{\text{velocity in the lower bed} + \text{velocity in the upper bed}}$$

In this model, the seismogram consisted of about fifteen reflections, plus various types of noise. Reflections from the thicker beds would be isolated, but reflections from the top and bottom of beds only a few hundred feet thick would overlap to some extent.

With the appearance of the continuous velocity log in the early 1950's it became apparent that a new model of the seismic process was needed. Some of the strongest reflections on the seismogram occurred at times that did not correspond with boundaries between thick beds. The basis for this new model was presented in a paper by R. A. Peterson in 1954. This paper showed that the seismogram, in the absence of noise, was a continuous function rather than a series of isolated reflections. This relation is expressed

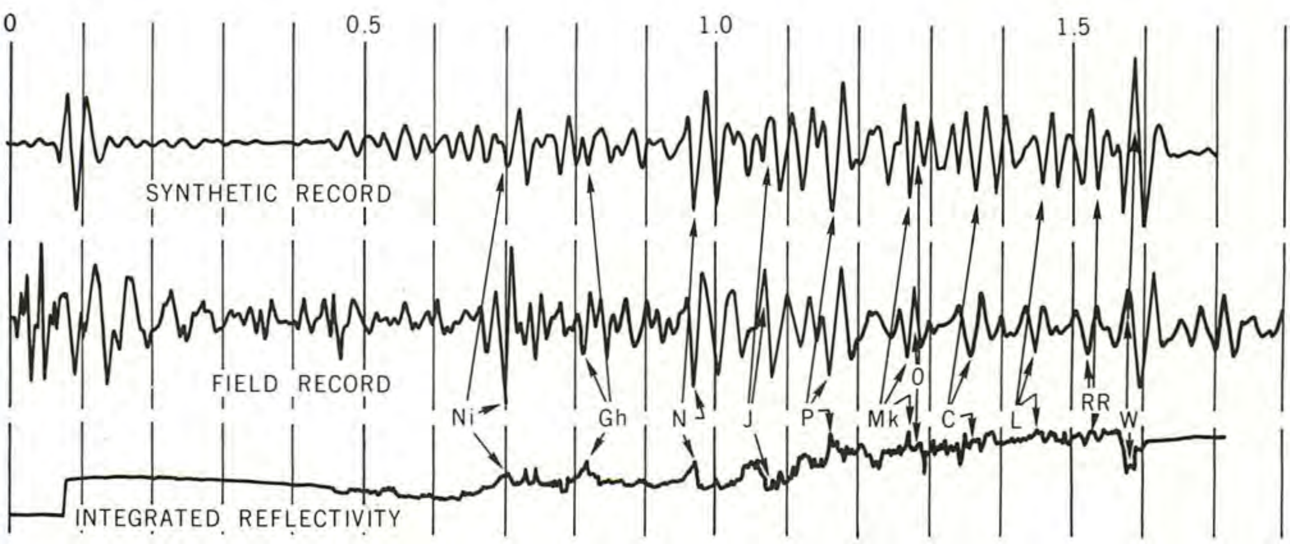
$$R = \tfrac{1}{2}\,\frac{d \log v(t)}{dt}$$

where R is the unfiltered, primary reflection seismogram and v is acoustic velocity expressed as a function of seismic time rather than depth.[15]

In Figure 4 the synthetic record has been obtained by passing the integrated reflectivity function through a conventional seismic filter, and the field record is a composite of four field traces recorded adjacent to the well. The notations on the velocity trace refer to geologic formations, the Niobrara, the Greenhorn,

15. For the sake of simplicity, we have omitted any reference to density in the above. Since variations in density are small compared to velocity changes, density can be omitted in most cases without any observable effects in the comparison of theoretical and field seismograms.

FIGURE **4.** Comparison of a Velocity Function (Integrated Reflectivity) With the Synthetic Seismogram and the Field Record



Piper, etc. The immediate effect of the synthetic seismogram was that it made possible a detailed comparison of velocity and electric logs with the field seismogram.

b. The Linear Filter Model

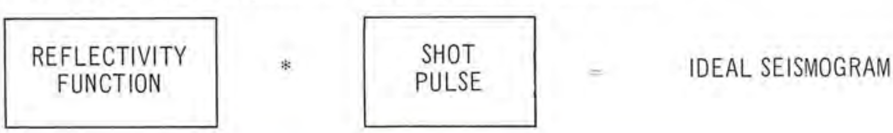
The synthetic seismogram was the first step in the development of a linear filter model of the seismic process. A seismic pulse generated by the detonation of a charge of dynamite is filtered as it travels through the earth. This filtering action has two components. One part is the attenuation of high frequencies as the pulse changes from a sharp spike near the shot to a broad low-frequency pulse at the detector. The second part of the filtering action is a generation of reflections as the shot pulse travels downward through the earth. A third filter is that of the recording instruments. Since the order of a linear process is immaterial, we may consider the velocity function as the input, filtered by the shot pulse, the attenuation filter of the earth, and the recording instruments.

FIGURE **5.** Linear Filter Model of the Primary Reflection Process

(The symbol * indicates that the function at the left is filtered by the function on the right. Filtering implies a change in frequency response in the same sense that the bass control on a radio or sound system varies the amplitude of the low frequencies and the treble control varies the amplitude of the high frequencies.)

Since we are not able to measure separately the frequency response of the shot pulse itself, the attenuation of the earth, and the recording instruments, it is convenient to lump these three items into one filter which we will label "shot pulse." Thus, the ideal seismogram can be shown by a simple block diagram indicating the velocity function as an input filtered by one composite filter, the shot pulse.

FIGURE **5a.** Simplified Linear Filter Model



Distortions produced by multiple reflections, ghosts, and water reverberations also behave as a linear filter; noise is simply added to the final output. Thus, the complete seismic process can be represented by a reflectivity function that is filtered by a shot pulse and one or more distortion operators, with additive noise.

FIGURE **5b.** Linear Filter Model With Noise and Distortion

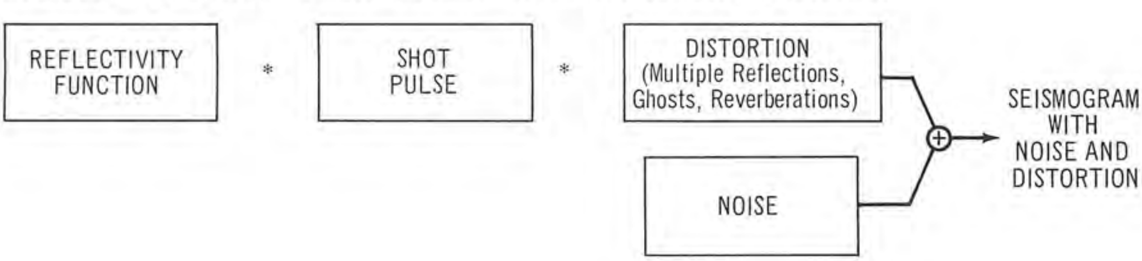


FIGURE **6**

Examples of

First Order Surface

Multiple Reflection Paths

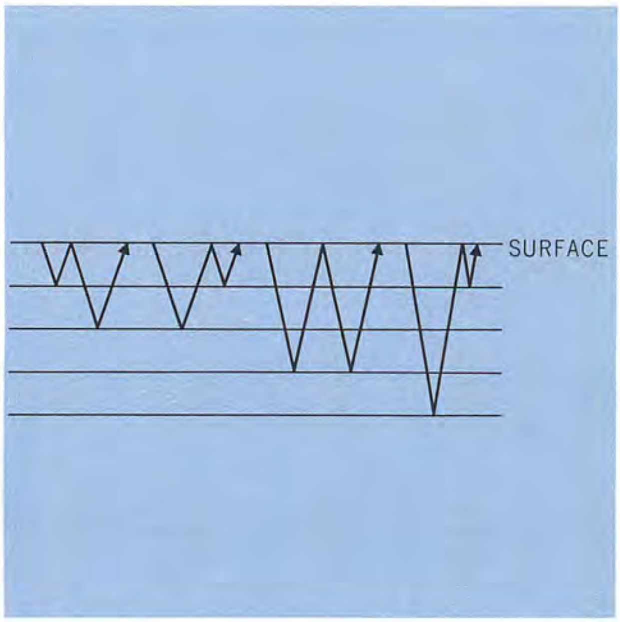
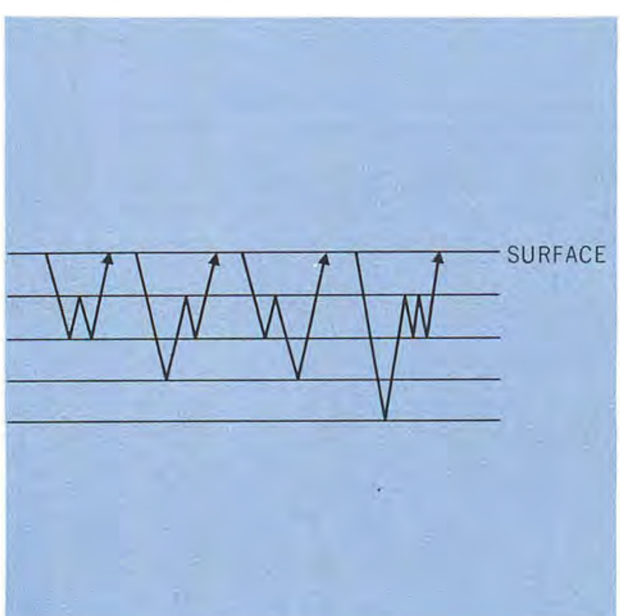


FIGURE **7**

Examples of

Internal Multiple

Reflection Paths



The linear filter model was a significant development because it provided a better understanding of the basic seismic reflection process, and because it provided a basis for the application of modern communication theory and information theory to seismic data analysis. Examples of these applications are given in the pages that follow.

c. Multiple Reflections

The field seismogram shown in Figure 4 is a very good approximation to the velocity layering of the earth, but in many areas of the world multiple reflections are superimposed on the primary reflection record. A seismic pulse traveling downward from the shot is partially reflected wherever it encounters a change in the velocity of the earth. If the reflected part of this wave encounters a change in velocity on its way back to the surface, part of the energy is reflected back down into the earth again. Thus, a seismic pulse traveling through the earth experiences a series of partial reflections until its energy is finally dissipated. Pulses that return to the surface after only one reflection are called primary reflections, and it is these that provide the basic seismic information. Pulses that have been reflected more than once within the earth are called multiple reflections. Figure 6 shows examples of multiple reflection paths in which the surface of the earth is one of the reflecting layers. This type of multiple reflection is responsible for most of the interference observed on field seismograms.

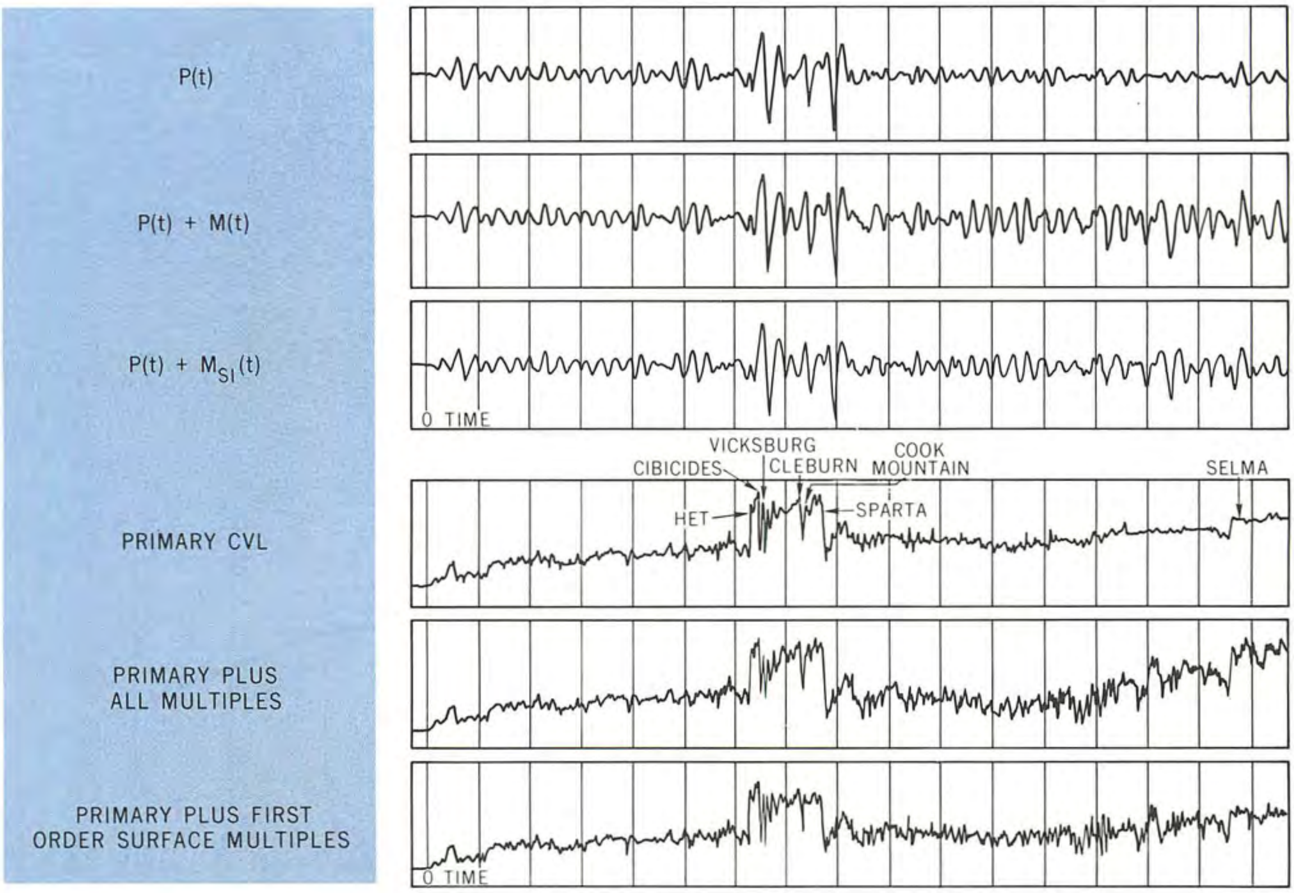
Figure 7 shows examples of internal multiple reflection paths. The internal multiple is more difficult to recognize and more difficult to eliminate from the field record.

It is now standard practice to compute synthetic seismograms showing both primary and multiple reflections (Figure 8). The multiple reflection synthetic seismograms assist the seismic interpreter in the identification of primary and multiple reflections, and they provide the basis for the development of new methods of analysis for the elimination of multiple reflections from field seismograms.

d. New Methods for the Analysis and Elimination of Distortion

The synthetic seismogram provided a better understanding of the true nature of the seismic reflection process, and the linear filter model provided the framework for a mathematical analysis of distortion. Multiple reflections, ghosts, and reverberations can be treated as linear filters operating on the primary reflection seismogram. Another way of stating this is that the earth is an acoustic delay-line filter with characteristics that are sometimes undesirable. These undesirable characteristics can be minimized by linear filtering methods.

FIGURE **8.** Primary-Multiple Synthetic Seismograms
Southern Mississippi



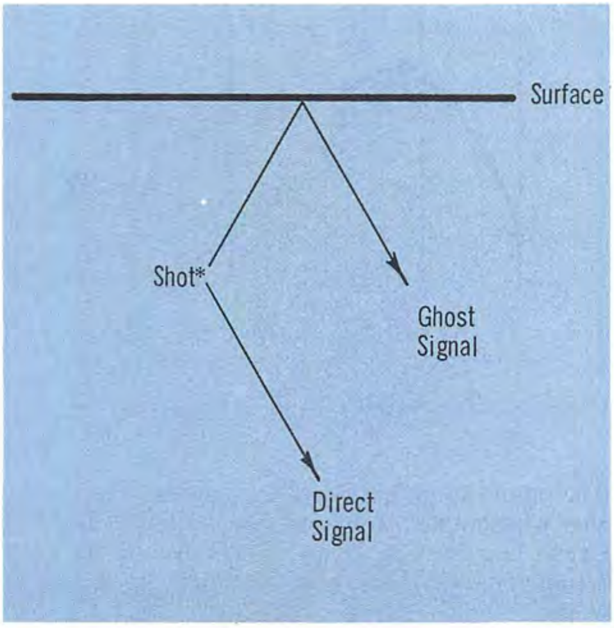
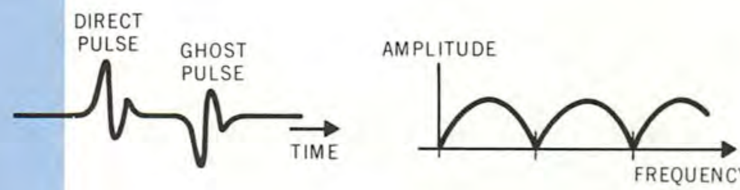


FIGURE **9**
The Ghost Effect

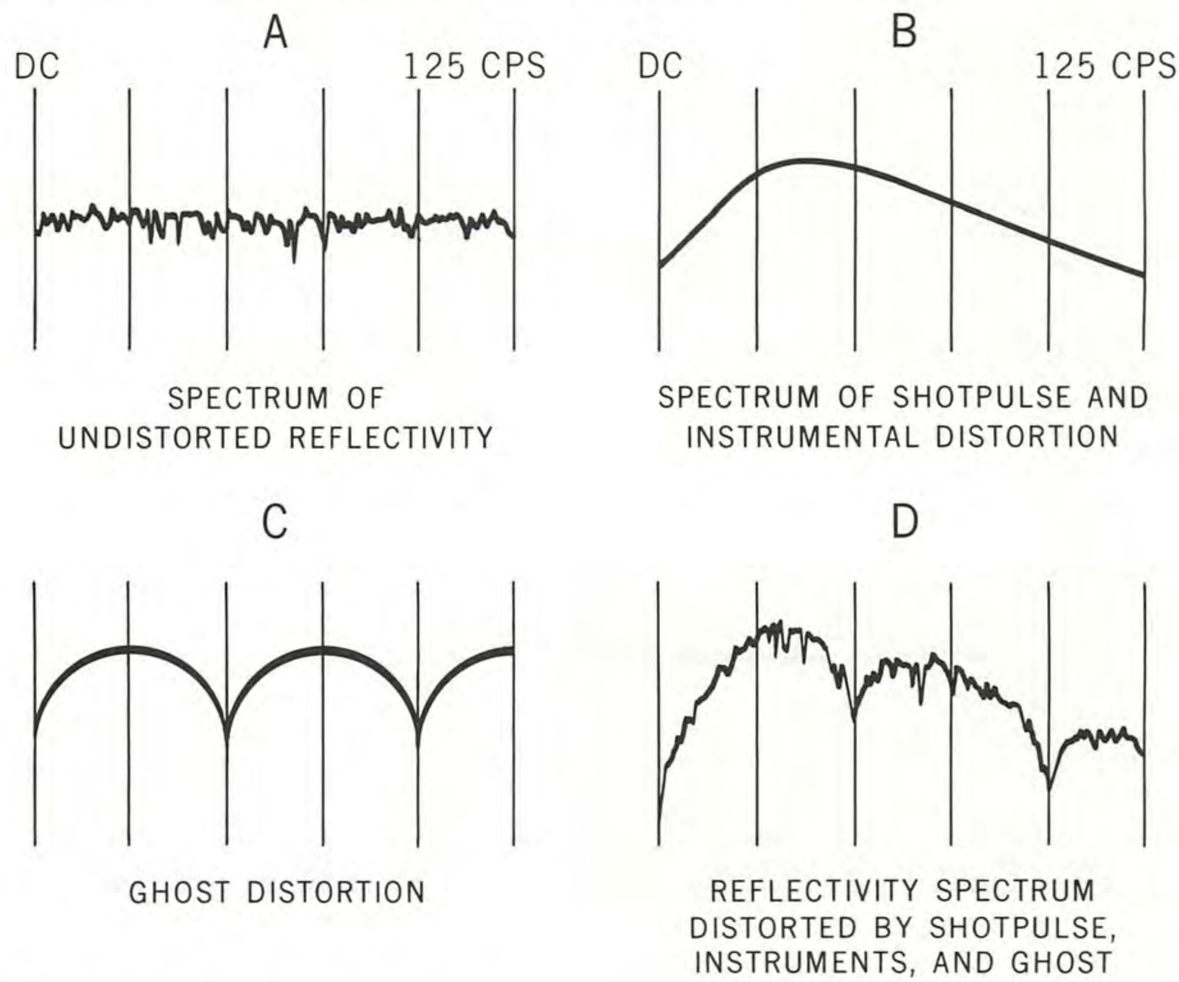
The simplest example of distortion is the ghost effect (Figure 9). Ghosts are produced when a shot is detonated beneath the earth's surface. One pulse travels downward from the shot. A second pulse travels upward from the shot, and is reflected downward by the surface of the earth. The net effect is that the simple shot pulse is replaced by a double pulse. Thus, the earth has in this case performed as a two-channel acoustic delay line. Figure 10 shows the distorted double pulse and the corresponding frequency distribution.

FIGURE **10.** Distortion Produced by the Ghost Effect



Now consider the manner in which ghost distortion modifies the spectrum of the seismogram. Figure 11 shows four spectra with amplitude plotted as a function of frequency over the complete seismic frequency range from zero to 125 cycles per second.

FIGURE **11.** Description of Distortion in Frequency Domain



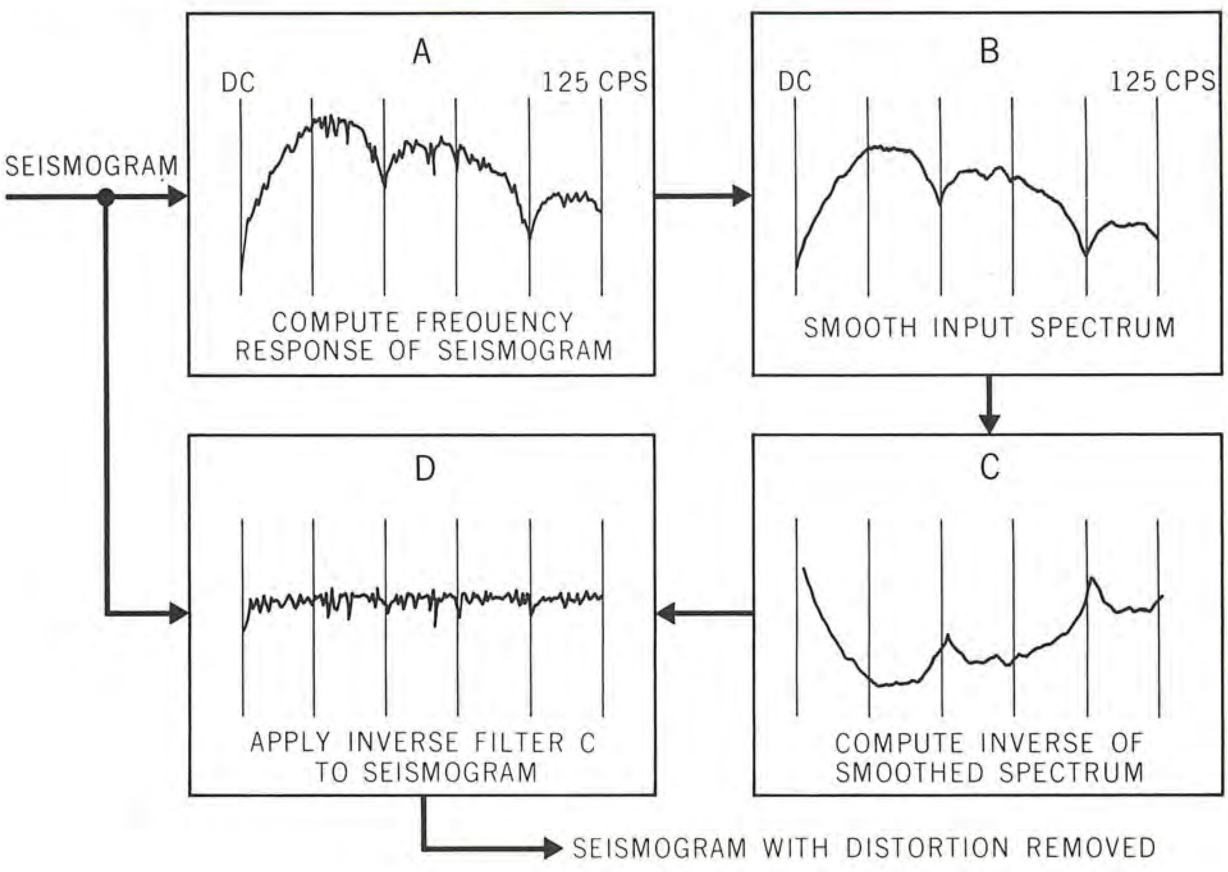
Graph A shows the frequency response of a typical reflectivity function. Graph B shows the combined response of a shot pulse and wide band recording instruments. Graph C shows the frequency response of a typical ghost distortion. The input at A is filtered through filter B and filter C to produce an output D..

The output of graph D is the product of the spectra shown in graphs A, B, and C; $D = A \times B \times C$. Graph D is then the frequency spectrum of an ideal seismogram that has been distorted by the ghost effect.

Distortion removal through inverse filtering is illustrated in Figure 12. In the first step, shown as A, the frequency response of the seismogram is computed. The spectrum shown in A is passed through a smoothing operator to produce a smooth representation B of the frequency response of the seismic trace. An inverse filter is then computed that has the exact inverse of the spectrum shown in B. Graph C shows the frequency response of the inverse filter. Then, the inverse filter whose frequency response is shown in graph C is applied to the seismogram whose frequency response is shown in graph A. The output is the undistorted seismogram whose frequency response is shown in graph D.

Inverse filtering, or deconvolution as it is often called, is a very powerful method for the removal of water reverberations. An example is shown in Figure 13. A conventional record section is displayed on the left-hand side and the right-hand side shows the same basic data after inverse filtering. Inverse filtering is also effective for removing ghosts in areas where the signal-to-noise ratio is average or better, but the method is not effective where the noise level is high. Under special circumstances multiple reflections can be highly attenuated, but in general, inverse filtering has not been effective in this application.

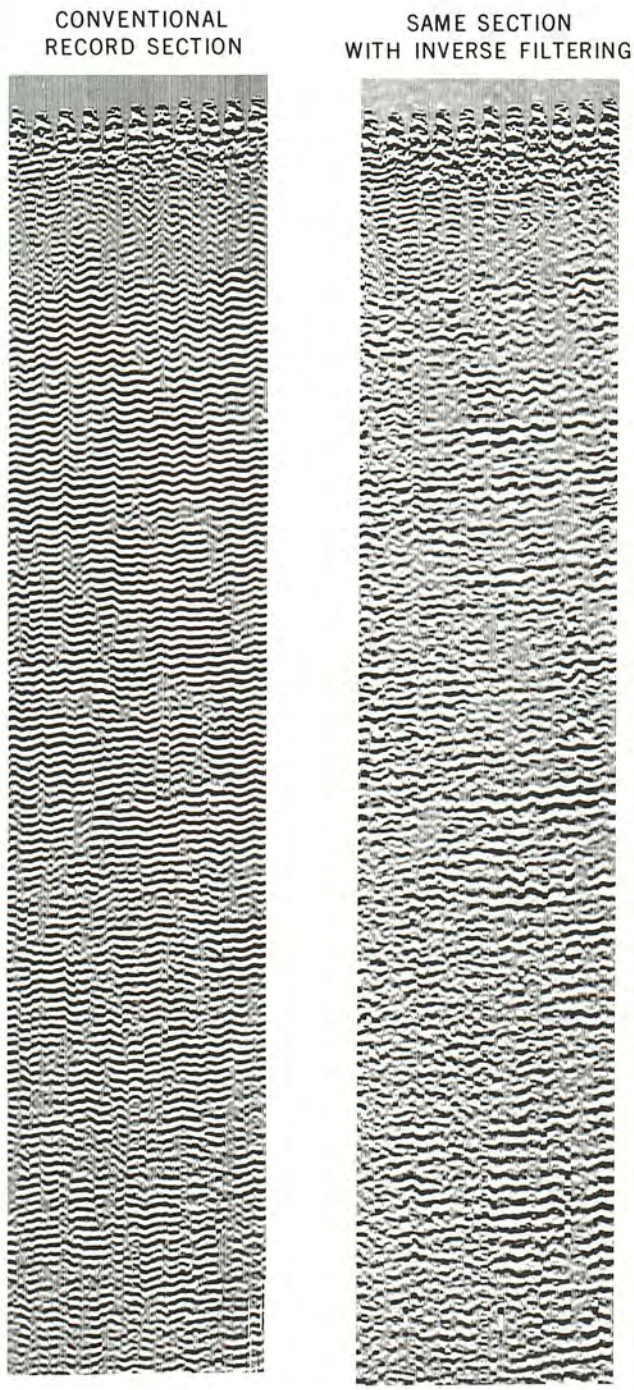
FIGURE **12.** Distortion Removal by Inverse Filtering



e. Progress in the Reduction of Noise

The basic concepts of optimum filtering were described by Norbert Wiener in 1949, but Wiener's work received very little practical use until it was

FIGURE **13**
Reverberation Elimination



applied in the seismic field in 1963 and 1964. One example of optimum filter theory is the rejection of horizontally traveling noise on the seismogram. In this method (generally referred to as velocity filtering) signal and noise are separated on the basis of differences in apparent velocity. In Figure 14 the reflection wave front is almost horizontal as it approaches the surface. As this reflection wave front strikes the array of detectors on the surface, there will be a small difference in the arrival time Δt from one detector to the next. The apparent velocity of the wave as observed along the array is then $v_a = \dfrac{\Delta x}{\Delta t}$, where Δx is the spacing between detectors.

FIGURE **15.** Multitrace
Processing System
for Velocity Filtering

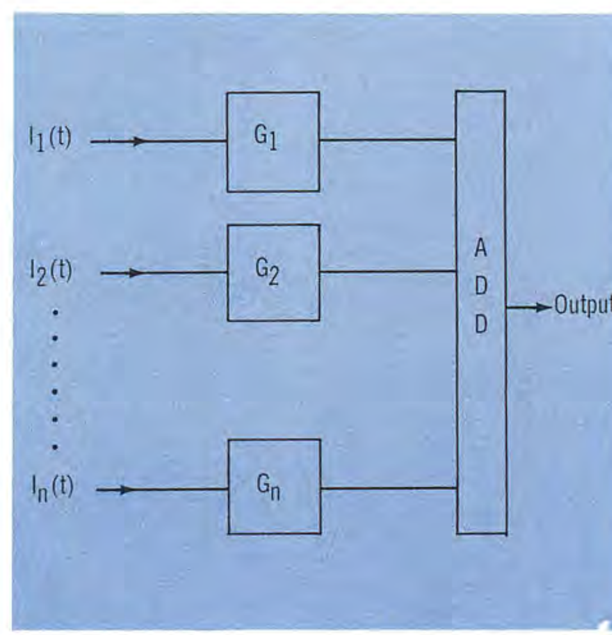
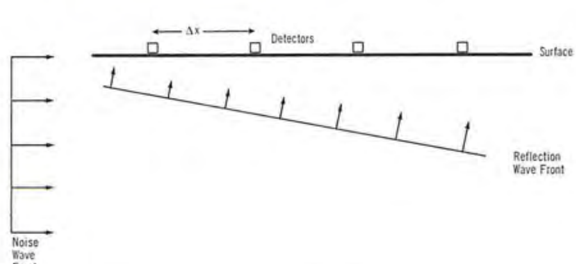


FIGURE **14**
Apparent Velocity
for Signal
and Noise



Now consider a noise wave sweeping across the array of detectors with a vertical wave front. The apparent velocity of the noise wave as observed along the line of detectors will be $V_a = \frac{\Delta x}{\Delta T}$, where ΔT is the time required for the wave front to move from one detector to the next, and Δx is again the distance between detectors. Since ΔT will in general be larger than Δt, there is a physical basis for the separation of signal and noise. Indeed, geophone and shot patterns have been designed for years to take advantage of the difference in apparent velocity of signal and noise.

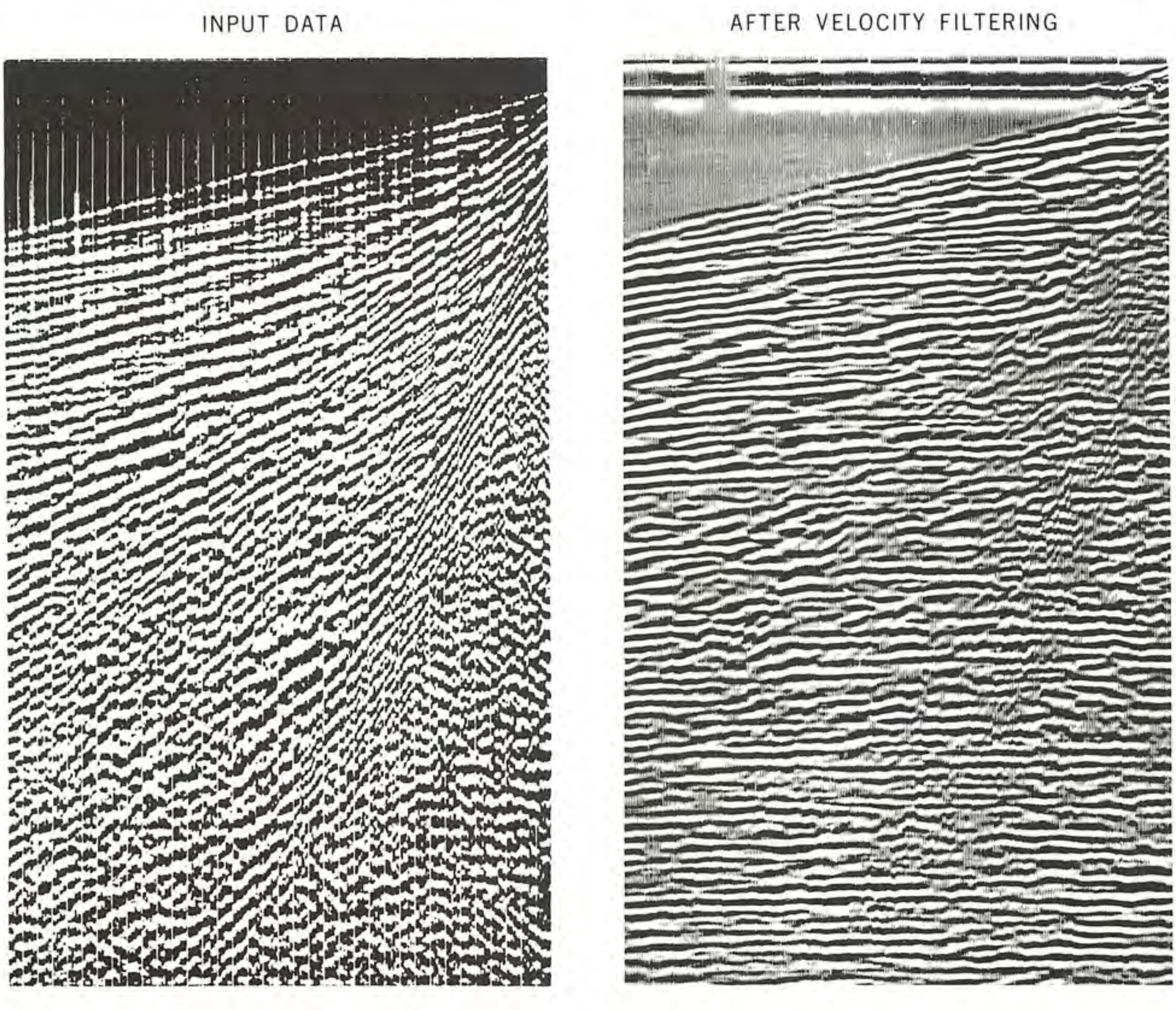
Velocity filters seek to obtain the maximum rejection of noise through the method of Wiener optimum filtering. The procedure is to design a series of filters $G_1, G_2, \ldots G_n$, one filter for each of the seismic traces recorded by detectors in the array. The outputs of the "G" filters are summed to produce an output of one trace from inputs $I_1, I_2, \ldots I_n$. Statistical communication theory is employed to design the G filters such that the output is the best statistical estimate of the true signal with maximum rejection of noise. Figure 15 is a diagram of this procedure.

Velocity filtering can be employed to distinguish one signal from another if they have different apparent velocities along a line of seismic detectors. The method is being used successfully in the rejection of various types of seismic noise and multiple reflections, and a variation of the method has been very successful in the suppression of ghosts. Figure 16 is an example of the suppression of seismic noise by the velocity filter. Surface waves and other types of noise almost completely obscure reflections on the original field data shown at the left; after velocity filtering, the standout of reflections is adequate for conventional structural mapping.

f. The Impact of Mathematics on Seismic Data Processing

The linear filter model of the seismic process was borrowed from the technology of electrical engi-

FIGURE **16.** Velocity Filter Comparison



neering. During the past four years geophysics has made extensive use of statistical communication theory, but this use has gone beyond the mere borrowing of another technology. Geophysics has developed and advanced optimum filter theory and methods of inverse filtering. Crosscorrelation techniques have been developed for making optimum static time corrections and for determining the amplitude and time of seismic reflections. Decision theory and parameter estimation are being used in the identification and analysis of primary and multiple reflections. Present indications are that mathematical analysis and high-speed digital computers will continue to play a major role in the processing and interpreting of all forms of geophysical data.

2. NEW SEISMIC INSTRUMENTS

The period from the mid-1930's to mid-1950's is known in some quarters as the paper record era. During this period substantial improvements were made in the accuracy and reliability of the recording equipment, and interpreters developed a high degree of skill in the recognition of the continuity of reflections in the presence of noise and in the procedures for preparing cross sections and contour maps. The seismic method of 1950 was characterized by:

(1) One to 100 detectors per trace, depending upon the local noise problem.
(2) One to 50 shots, depending upon the noise.
(3) A standard 24-trace oscillographic recording on photographic paper.
(4) Filtering performed in the recording truck.
(5) Depth sections prepared from the paper oscillographic records.
(6) Contour maps of seismic structures prepared from the records and depth sections.

Looking back over this period, it must be said that success of geophysics was due more to the skill and enthusiasm of people than it was to the sophistication of equipment and data processing methods. The 24-trace oscillographic record required that the interpreter mentally visualize the wave shape of key reflections as he observed them from record to record. The output of interpretation was a record section prepared by plotting the record times observed for reflections identified on the 24-trace oscillographic records.

a. Magnetic Tape Recording

With the introduction of magnetic tape recording and the variable-area and variable-density record sections during the late 1950's, the interpreter had at his disposal a flexible system for the interpretation of data. Filters could be changed on playback to enhance the signal-to-noise ratio, time corrections could be introduced to compensate for near-surface velocity variations and elevation changes, and the effect of normal moveout could be removed. Previously, the interpreter had been forced to interpret the seismic data one reflection at a time, one trace at a time, perhaps one record at a time. Now he could, within the field of view of the eye, examine an entire line. Geologists and geophysicists were able to correlate reflections over miles of line at a glance, a process that previously would have required hours of painstaking work. More important, the record section enhanced the ability of the interpreter to visualize structural and stratigraphic features that would have been difficult to observe on the older paper records. Despite early opposition, the variable-area and variable-density record sections are now widely accepted, and in many exploration offices this is the only form of seismic recording that is used.

b. Digital Recording

As research on methods for eliminating multiple reflections, ghosts, reverberations, and noise progressed during the late 1950's, it became apparent that digital computers and digital recording would be necessary to implement new developments. In 1958 three companies entered into a joint program for the development of digital equipment. Each of these companies had several digital recorders in routine operation in the field by 1962, and by 1965 digital recording and data processing had made a strong impact on the entire geophysical industry. The greater accuracy and dynamic range of digital recorders has contributed to better processing of seismic data, particularly in the compositing of large numbers of seismograms for noise elimination and the treatment of severe cases of water reverberations. Digital systems have also made possible true amplitude recording which allows the interpreter to employ both reflection amplitude and reflection time in the study of structural and stratigraphic problems. While these engineering improvements in the accuracy of recording are important, the primary reason for digital recording in the field is that it provides a practical method for processing seismograms in digital computers.

c. Digital Computers in Seismic Data Processing

Digital computers are now used on a routine basis for removal of water reverberations and ghosts, the removal of multiple reflections, optimum velocity filtering for noise rejection, multitrace and multirecord compositing, and the preparation of time-corrected record sections. Both costs and effectiveness of digital data processing depend upon the efficiency and practicality of the computer programs and the capabilities and rental cost of the particular computer employed at a given data processing center. The cost per record for small computers is prohibitive. However, as the volume of data processed increases, the use of large digital computers is feasible, and the cost per record can be reduced to a reasonable level.

d. Laser Optics

Optical data processing under the trade name "LaserScan" has received wide interest as a method

Table I

RELATIVE COSTS OF COMPUTER DATA PROCESSING

COMPUTER	SPEED	COST PER HOUR	COST PER RECORD
IBM 360/30	1.0	1.0	1.0
IBM 360/75	150	7.6	.050
CDC 6800	1,600	13.5	.008

of seismic data processing. Optical systems perform both conventional frequency filtering and spatial filtering. (Spatial filtering is equivalent to velocity filtering described earlier in this report.) While these operations can be performed more accurately in a digital computer, the optical systems have the advantage that the entire record section is processed as a unit rather than on a trace-by-trace basis. The method is fast and costs are moderate.

e. A Laser Optical System for Processing Seismic Data (Figure 17)

A variable-area or variable-density seismic record section is reproduced as a transparency on 35 mm film as input to the optical system. For coherent (laser) light incident on the input plane, a diffraction pattern of the input transparency is formed at the transform plane and a reconstruction of the input is formed at the output plane. Stated mathematically, the amplitude distribution in the transform plane is approximately equal to the two-dimensional Fourier transform of the amplitude distribution at the input plane due to the input transparency. Additionally, the amplitude distribution in the output plane is a Fourier transform of the amplitude distribution in the transform plane and is thus a reconstruction of the input transparency. It is useful to think of the Fourier transform of the input as the two-dimensional Fourier spectrum of the input data. Filter masks can be placed in the transform plane to reduce certain parts of the spectrum with respect to other parts. When this is done, the reconstruction is a filtered copy of the input.

Optical data processing holds good promise for the future in the processing of geophysical data, particularly in the area of pattern recognition. At present, most of the information concerning equipment and methods of pattern recognition is classified, and is not available to the petroleum industry.

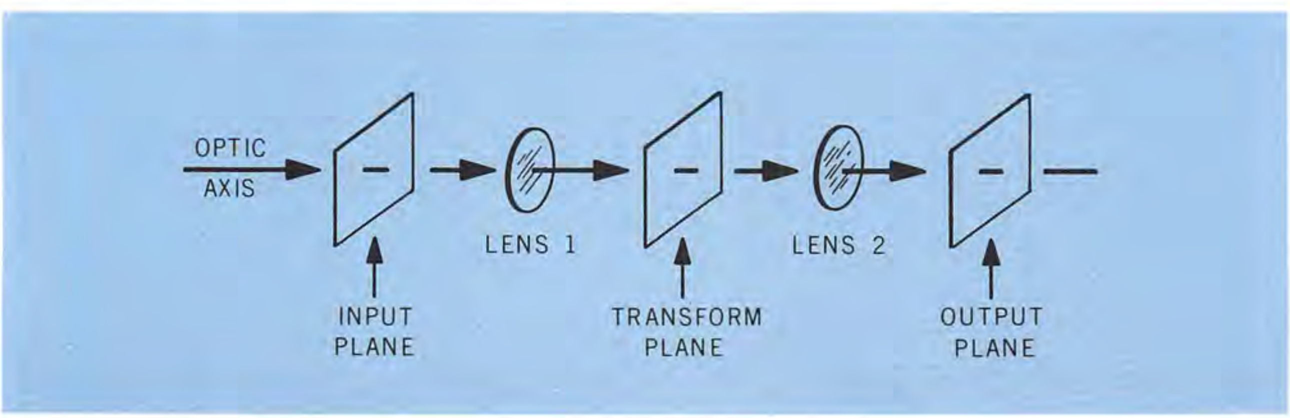
3. NEW FIELD PROCEDURES

a. Common Depth Point Method

The common depth point method is at present the most effective procedure for minimizing multiple reflections. In this method the single shot, 24-trace record is replaced by six shots, each of 24 traces (3, 4, 6, and 12 shot composites are used; 6-fold compositing is probably used most frequently). The six 24-trace records are then summed to produce one 24-trace final record. The geometry of this method is such that for each set of six traces that are summed, the subsurface is represented by a common reflection point. Shot-to-detector distances range from 200 to 10,000 feet. As each of the traces is given the appropriate normal moveout correction

FIGURE **17**

Lens 1 Focal Length = Lens 2 Focal Length



for primary reflections before compositing, and as multiple reflections usually have different normal moveout corrections, primaries will be added in phase and multiple reflections will be out of phase in the final composite section. Figures 18 and 19 demonstrate this reduction of multiple reflections.

b. Seismic Sources

In areas where surface waves produce a serious noise problem, a large number of traces must be composited to produce a useful signal-to-noise ratio. It is common practice to employ as many as 50 to 100 detectors per trace and 50 to 100 complete records may be composited to produce one final 12- or 24-trace record. Drilling of 50 to 100 shot holes per record is not economically feasible. The Thumper, Vibroseis, Dinoseis, and other nondynamite sources have been developed to meet the need for an economical seismic source for prospecting in poor record areas. Nondynamite sources are also receiving attention at this time for use in water-covered areas. Again, the objective is economy through the elimination of costs associated with explosives and the handling and supplying of explosives. The energy output of nonexplosive seismic sources is not adequate for those applications where compositing is not required. However, the extensive use of the common depth point and other compositing methods for the reduction of multiple reflections and noise has necessitated the use of a larger number of sources and receivers. Thus, the expanding use of nonexplosive sources is related to noise and multiple reflection problems rather than to any inherent superiority of these sources over explosive sources.

FIGURE **18.** Conventional Single-Fold Recording

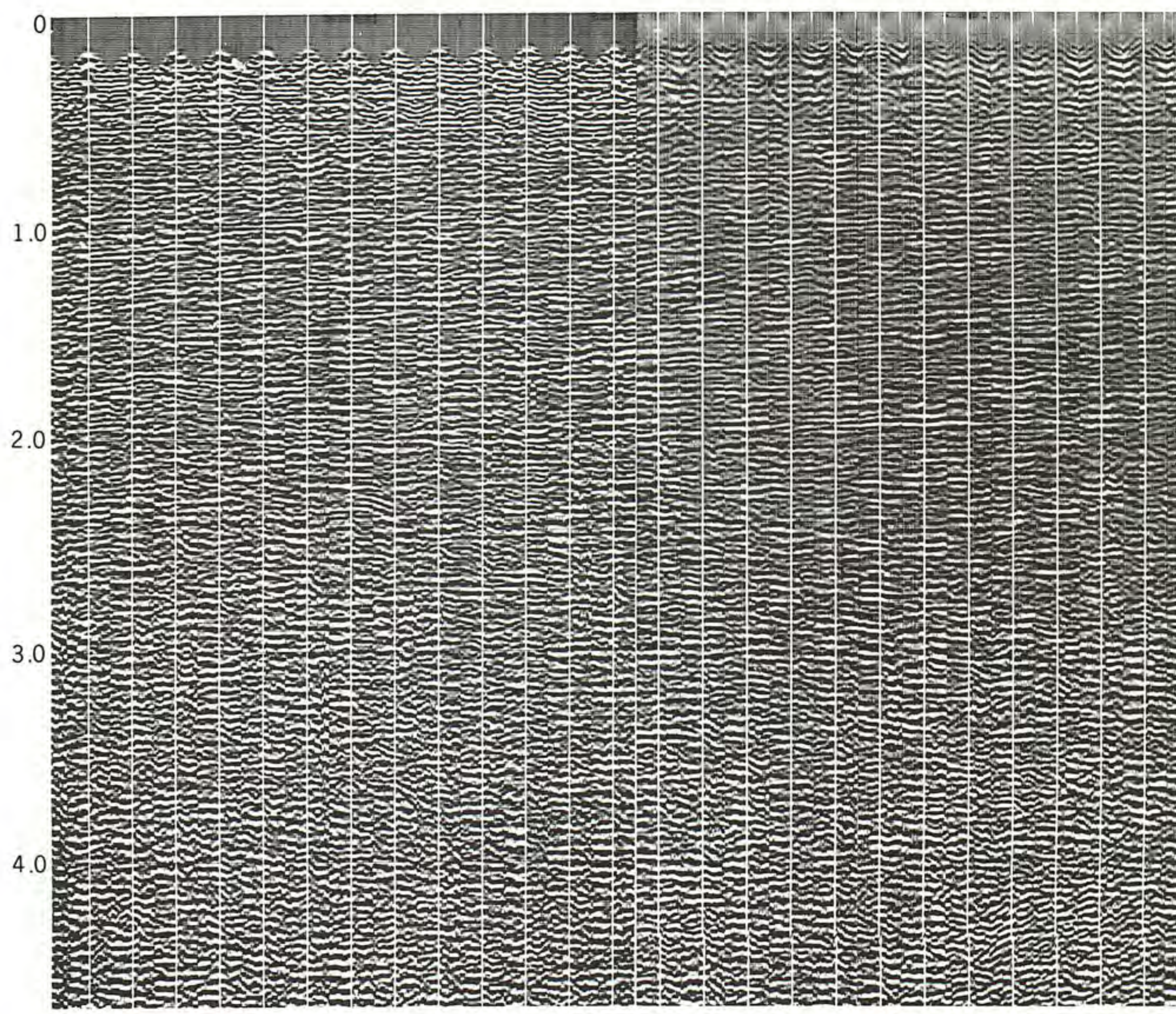
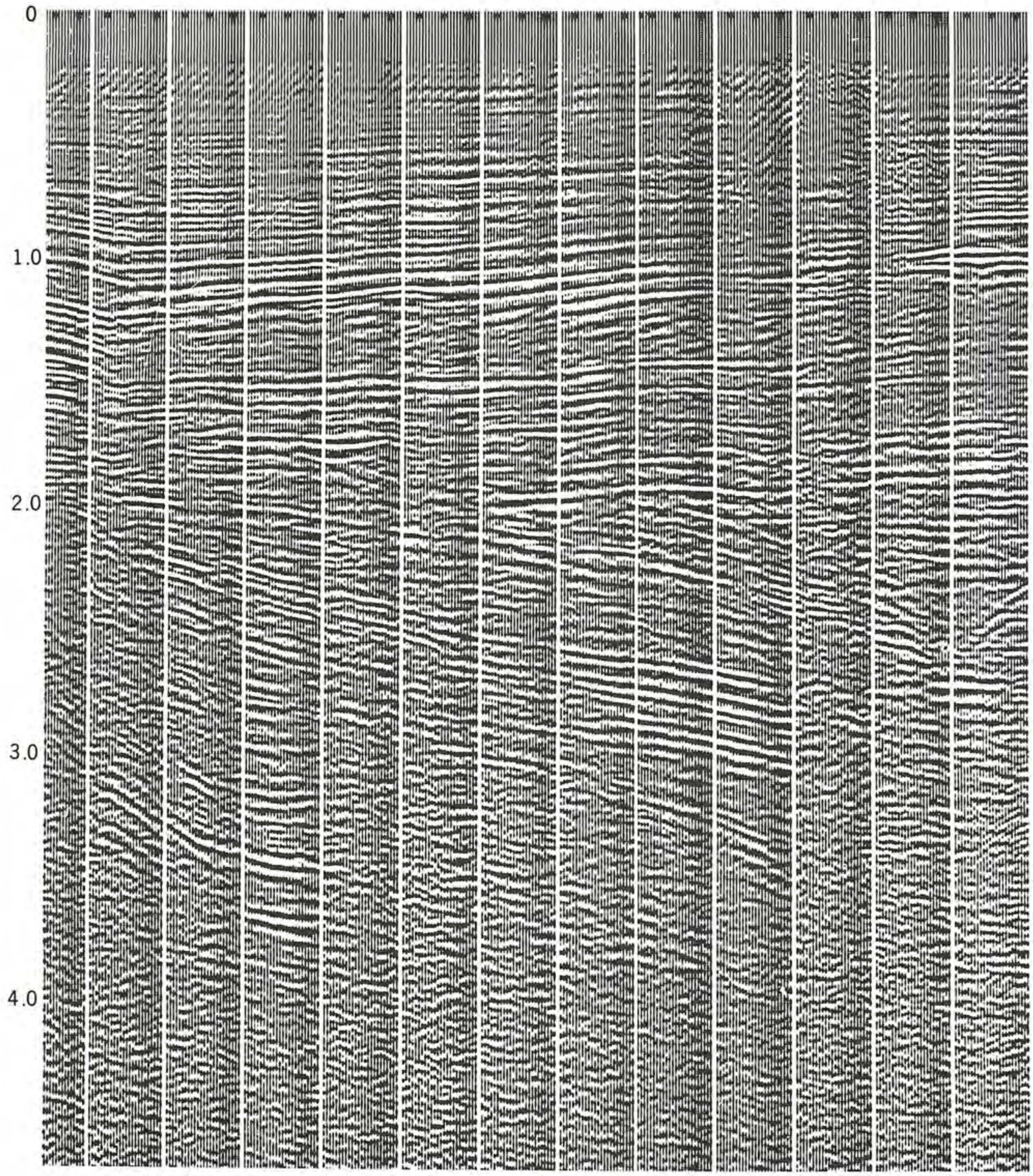


FIGURE **19.** Sixfold Common Depth Point Recording



(Same Linear Coverage as Fig. 18).

C. Gravities

1. GRAVITY INSTRUMENTATION

Although the pendulum and torsion balance were instrumental in the discovery of a number of oil fields in the 1920's and 1930's, it was not until the advent of the modern gravimeter (Mott-Smith, LaCoste-Romberg, Worden, etc.) in the late 1930's and 1940's that gravity surveys could be conducted economically on a large scale. Gravimeters now in use are capable of measuring the earth's gravitational field to one part in 100 million (0.01 milligal), which is more than adequate for most exploration work.

The resolution of shipborne gravimeters is severely limited by the motion of the ship, which cannot be separated from the gravitational force because of the fundamental relationship between the acceleration due to motion and the acceleration of gravity. A further limitation is that the position of the ship, its velocity, and the water depth must be known accurately for accurate gravity determinations. All of these factors combine to limit the resolution of the shipborne gravimeter to about 3.0 milligals, whereas approximately 0.1 milligal is required for normal exploration work. There is reasonable expectation that improved towing devices and improved navigation will increase the useful sensitivity by a factor of ten, which, although marginal, would provide useful reconnaissance information. Airborne gravimeters are now limited to a resolution of approximately 10 milligals. It is unlikely that the stability of flight and navigation can be improved sufficiently to provide a useful exploration tool within the next five to ten years.

During the past year two borehole gravity meters have been described that appear capable of determining the earth's gravitational field in a borehole to an accuracy of 0.01 to 0.02 milligals, which is sufficient to determine density to within 0.02 grams per cubic centimeter. While these instruments may eventually be employed as logging tools for porosity determinations, the immediate use is that of determining density for gravity interpretation. The availability of accurate density values in any given area would substantially improve the capabilities of the gravity method.

2. GRAVITY INTERPRETATION

Large-scale variations of the earth's gravitational field are associated with ocean basins, the continents, mountain ranges, and other large physical features of the earth. Small-scale changes in the gravitational field extending over a few thousand feet or a few miles are associated with density changes of basement rocks and rocks of the sedimentary section. The objective in exploration is to relate these small-scale variations to structures favorable for the accumulation of oil.

Once the basic corrections have been made to the field data, gravity interpretation is concerned with (1) the separation of local anomalies of exploration interest from the broad regional changes in the earth's gravitational field, and (2) the determination of the geological significance of the gravity anomaly. One common procedure is to estimate the regional field, either graphically or by a digital filtering program, and subtract this regional from the total observed field to obtain a residual map of local anomalies. The preparation of a second vertical derivative contour map is also used to emphasize local anomalies. A variety of graphical and digital computer procedures are available for perfoming both of these operations.

The second phase of gravity interpretation is that of relating a residual gravity map to geology. A fundamental difficulty here is that an infinite number of density distributions could have produced the observed gravity anomaly. Broad density anomalies at shallow depth cannot be distinguished from deeper anomalies of smaller dimensions. Much of the present gravity research in the oil industry is directed toward developing methods for introducing known density and structural information in an attempt to minimize this ambiguity of gravity interpretation. A standard procedure is that of comparing the calculated gravitational fields for buried spheres, cylinders, and other shapes of specified sizes and density distributions. An attempt is then made to select a model that agrees with the observed gravity, and one that is geologically plausible. With the development of computer programs capable of calculating the gravitational field for a body of arbitrary shape, the procedure for comparing the observed field with that of models has reached a high level of sophistication.

Where the density and structure of the upper part of the sedimentary section is known, a procedure known as "stripping" can be applied in which the gravitational effects of the upper part of the section are removed, leaving the field that would be observed due to the lower part of the section. After stripping, the relation between the gravitational field and deep structure can be determined with greater clarity.

Future gravity research will undoubtedly employ the techniques of modern filter theory and information theory, together with information from density logs, seismic data, and other sources, to provide more detailed and more reliable gravity interpretations. This research will emphasize the use of gravity as a reconnaissance tool and the use of gravity in combination with information from other sources as a geophysical tool to provide detail not available from other sources.

D. Aeromagnetics

1. AEROMAGNETIC INSTRUMENTATION

With the introduction of the fluxgate magnetometer for airborne use following World War II, aeromagnetics came to the forefront as an inexpensive but useful reconnaissance method. Present fluxgate magnetometers have a sensitivity of 0.5 to 2.0 gamma, which is sufficient for reconnaissance in oil exploration. The proton aeromagnetometer, developed by Varian in 1955, has led to the development of magnetometers of extreme sensitivity. The rubidium-vapor and helium magnetometers are capable of measuring fields down to 0.01 gamma. With this sensitivity it is now possible to employ two magnetometers separated by a fixed distance of 10 to 100 feet to provide a measurement of the vertical gradient of the earth's magnetic field. The gradient measurement has the advantage of eliminating the necessity for making corrections for diurnal changes of the earth's field and provides both the total and gradient field for use in interpretation.

Improvements in magnetometer instrumentation have also included means for providing data for digital computer processing. Magnetometer data are recorded on punched or magnetic tape and electronic navigation systems record location information simultaneously with the magnetic measurements. Digital recording and processing of magnetometer data makes possible a wider variety of computing methods and quicker access to the final interpretation. The general trend is toward the production of a greater variety of maps as an aid to improve interpretation of data.

2. AEROMAGNETIC INTERPRETATION

In many areas the airborne magnetometer provides good estimates of the depth to basement, the major tectonic features, and possible faults and basement relief that can be checked by other methods. The static magnetic field as measured in conventional aeromagnetics is due almost entirely to variations in the concentration of magnetite in basement rocks. Except for local ore deposits and igneous flows, the sedimentary section is only weakly magnetic and does not contribute significantly to the total observed field. Determinations of the depth to basement are based on the observation that the breadth of the magnetic anomaly as observed at the surface of the earth is related to the depth of the feature producing the anomaly. A sharp, narrow anomaly can only be produced by magnetic material at shallow depth, whereas a broad, smooth anomaly is more likely to be associated with a feature at great depth. In areas where there is a sufficient number of anomalies, depth estimates are accurate to about ten percent.

In the interpretation of magnetic data, residual and second derivative maps are computed in the same manner as for gravity, and downward and upward continuation are employed to further enhance the interpretation. While the processing of gravity and magnetic data is similar in many respects, magnetic interpretation is complicated by the fact that anomalies change their shape as the inclination of the earth's magnetic field changes. Thus, the magnetic field for a given magnetic anomaly at high latitudes will appear very different from the field observed for the same anomaly in the vicinity of the equator. Baranov has developed a method which transforms the magnetic data to the form that it would have had for a vertical magnetic field such as would be observed at the magnetic poles. This method, called "reduction to the pole," produces a map showing magnetic maxima directly over the anomalous bodies. A magnetic map processed by this method has much the same appearance as a gravity map.

The impact of digital computers and mathematical analyses on magnetic interpretation is not greatly different from the corresponding discussion on gravity interpretation. However, as the sediments are only very weakly magnetic, it is unlikely that the same integration of magnetic data with other geophysical information can be achieved as can be in a case of gravity. The availability of new magnetometers which can measure anomalies as small as 0.01 gamma may open a new field for possible study of magnetic anomalies associated with the sedimentary section.

E. Electrical and Electromagnetic Methods[16]

There has been a forty-year history of electrical measurements being applied to actual geophysical problems in the petroleum industry. The level of activity, as measured by technical publications and number of workers in electromagnetic methods, has fluctuated markedly with sharp decreases in effort in the early 1940's and also in the early 1950's. Those methods which have been touted as "direct oil-finding schemes" have always been viewed with considerable suspicion, a suspicion which has been well founded. The parameter which most directly influences measurements by all methods is electrical resistivity, a bulk property of rocks and minerals which can range in value over many decades. There has been only the vaguest and most highly variable relationship between bulk electrical resistivity and occurrence of petroleum in geologic formations constituting oil reservoirs.

Depth of penetration of electromagnetic energy increases as (1) the frequency decreases, (2) the resistivity of the propagating medium increases, or (3) the size and/or strength of the energy source increases. However, there exists a conflicting requirement that resolution (i.e., ability to delineate accurately the interface between two media of slight resistivity contrast) improves as frequency increases or as the size of energy source and/or detector decreases.

The requirements and compromises suggested above which govern penetration and resolution for electrical methods apply as well to other geophysical

16. Grant, F. S., and West, G. F., *Interpretation Theory in Applied Geophysics*, McGraw-Hill, New York, 1965.

methods. Topography and near-surface conditions, however, exert more influence on interpretation of electrical surveys than perhaps any other geophysical method. Because of some of these limitations which have been encountered in applying electrical methods to real field problems, effort in the United States in the petroleum industry has been confined to applying electrical methods to well logging.

1. D-C CONDUCTION METHOD

The simplest and oldest electric method used in petroleum exploration can be classified as a direct current conduction method. Electrodes or probes are used to inject current from a battery or generator into the earth; the potentials appearing at the surface of this conducting medium are detected by other electrodes connected to a high-impedance voltmeter. Figure 20 illustrates a particular in-line configuration referred to as a "Wenner Spread."

Figure 21 illustrates the simplest theoretical model which might be used to roughly approximate and interpret measurements made in the field.[17] The earth is considered to be a semi-infinite medium of resistivity ρ_2 overlain by a layer of uniform thickness h and constant isotropic resistance ρ_1. By expanding the electrode separations (or scale factor a) successive values of apparent resistivity may be measured. To the extent that measured values can be "fitted" to one of the family of theoretical curves, the three parameters h, ρ_1, and ρ_2 may be determined. As more parameters are introduced into a theoretical model of the earth at a particular site, the curve-fitting becomes more difficult and near-surface layers tend to obscure deep layer determinations.

In addition to the perversity of nature which makes any theoretical model an inexact representation of the actual earth, electrode polarizations, power limitations, and noise caused by telluric currents (currents induced by the fluctuating geomagnetic field), as well as man-made sources of noise, are practical problems which have been attacked with considerable effort.

The D-C conduction method ("dipole-dipole sounding") and several variations of this method are currently being employed by over 100 field crews in the U.S.S.R. in petroleum exploration programs.[18] Experience in the U.S.A. before 1953 indicated that sufficient detail at significant depths was not obtainable with the various dipole-dipole sounding methods and that correlations with known geologic structures were often poor. Recently, contractors for the U.S. Government[19] have employed dipole-dipole sounding methods in a search for buried layers with relatively high resistivities which might support deep strata communications for defense purposes.

2. MAGNETO-TELLURIC DEPTH SOUNDING

Micropulsations, or small amplitude temporal variations in the earth's magnetic field, and the resultant

FIGURE **20.** A "Wenner" Electrode Array for Resistivity Surveying

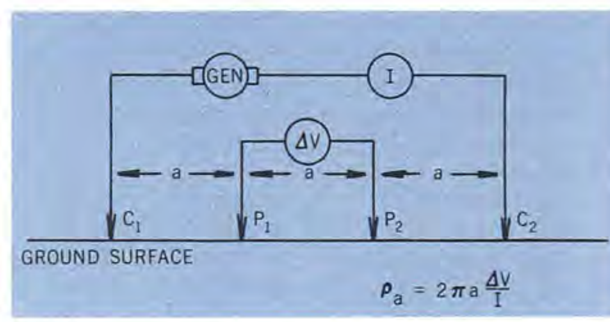
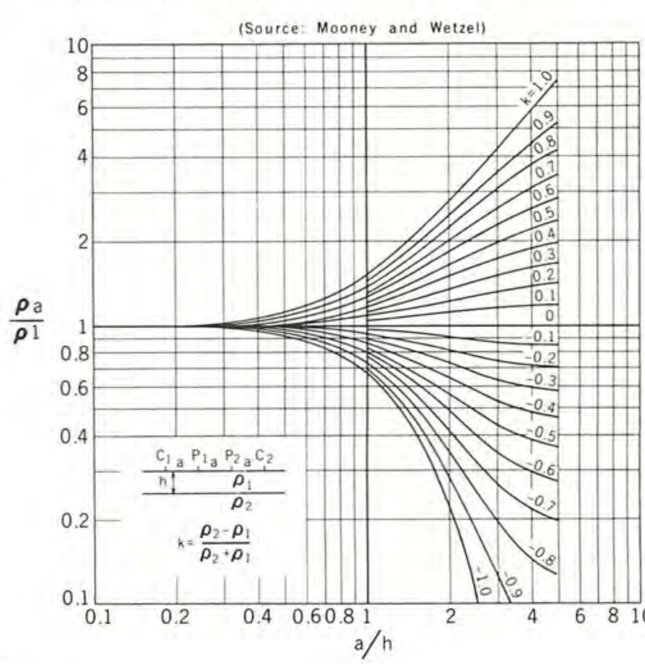


FIGURE **21.** Apparent Resistivity Curves for the Single-Layer Model Using the Wenner Method



17. Mooney, H., and Wetzel, G., *The Potentials About a Point Prove in a Two-, Three-, and Four-Layered Earth,* University of Minnesota, 1957.
18. Keller, G. V., Caldwell, R. L., et al., "Tour of Petroleum Geophysics Activities in the U.S.S.R.," *Geophysics,* 1966, vol. 31, pp. 630-638.
19. Lahman, H. S., Orange, A., and Vozoff, K., "Results of Deep Resistivity Measurements in Six PreCambrian Areas of the Western United States," 1965, Contract AF 19 (628)-2351, Project No. 4600, Task No. 460008, Scientific Report No. 7, AD 628 695.
Jackson, D. B., "Deep Resistivity Probes in the Southwestern United States," U. S. Geol. Surv., Washington, D. C., March 19, 1965, Technical Letter Crustal Studies-29, ARPA Order No. 193-61.

telluric currents which are induced in the earth's crust, constitute a source of noise in many electrical methods. Cagniard[20] proposed a method wherein the micropulsations are envisioned as a signal source. With sensitive instruments continuous recordings can be made of the components of both the electric and magnetic field variations at a point on the earth's surface. A spectral analysis can be made of these "noise-like" recordings and amplitudes of harmonic components in the frequency range from 0.001 to 100 cycles per second obtained. The ratio of the electric field amplitude to its orthogonal magnetic field amplitude at a given frequency is the "wave impedance" at the earth's surface for that frequency. A conversion of this wave impedance to an "apparent resistivity" can be made at each frequency. This apparent resistivity ρ_a is a function not only of frequency but of the resistivity distribution beneath the earth's surface. At the higher frequencies only the near-surface resistivities of the earth affect the measurements, but at lower frequencies the influence of resistivity variations at greater depth can be seen in the apparent resistivity.

Theoretical magneto-telluric sounding curves can be computed for relatively simple models of the earth. Figure 22 is a set of the "master" curves for the simple model discussed earlier in Figure 21. The similarity in general appearance between the two figures is striking even though entirely different methods are analyzed. The correspondence between long periods (low frequencies) in the magneto-telluric analysis and long spread distances in the D-C conduction analysis is intuitively understandable by physical reasoning.

20. Cagniard, L., "Basic Theory of the Magneto-Telluric Method of Geophysical Prospecting," *Geophysics*, 1953, vol. 18, pp. 605-635.

21. Yungel, S. H., "Magneto-Telluric Sounding Three-Layer Interpretation Curves," *Geophysics*, 1961, vol. 26, pp. 465-473.

FIGURE **22.** Master Curves for the Apparent Resistivity of a Single-Layered Ground Measured by the Magneto-Telluric Method[21]

(Source: Yungel)[21]

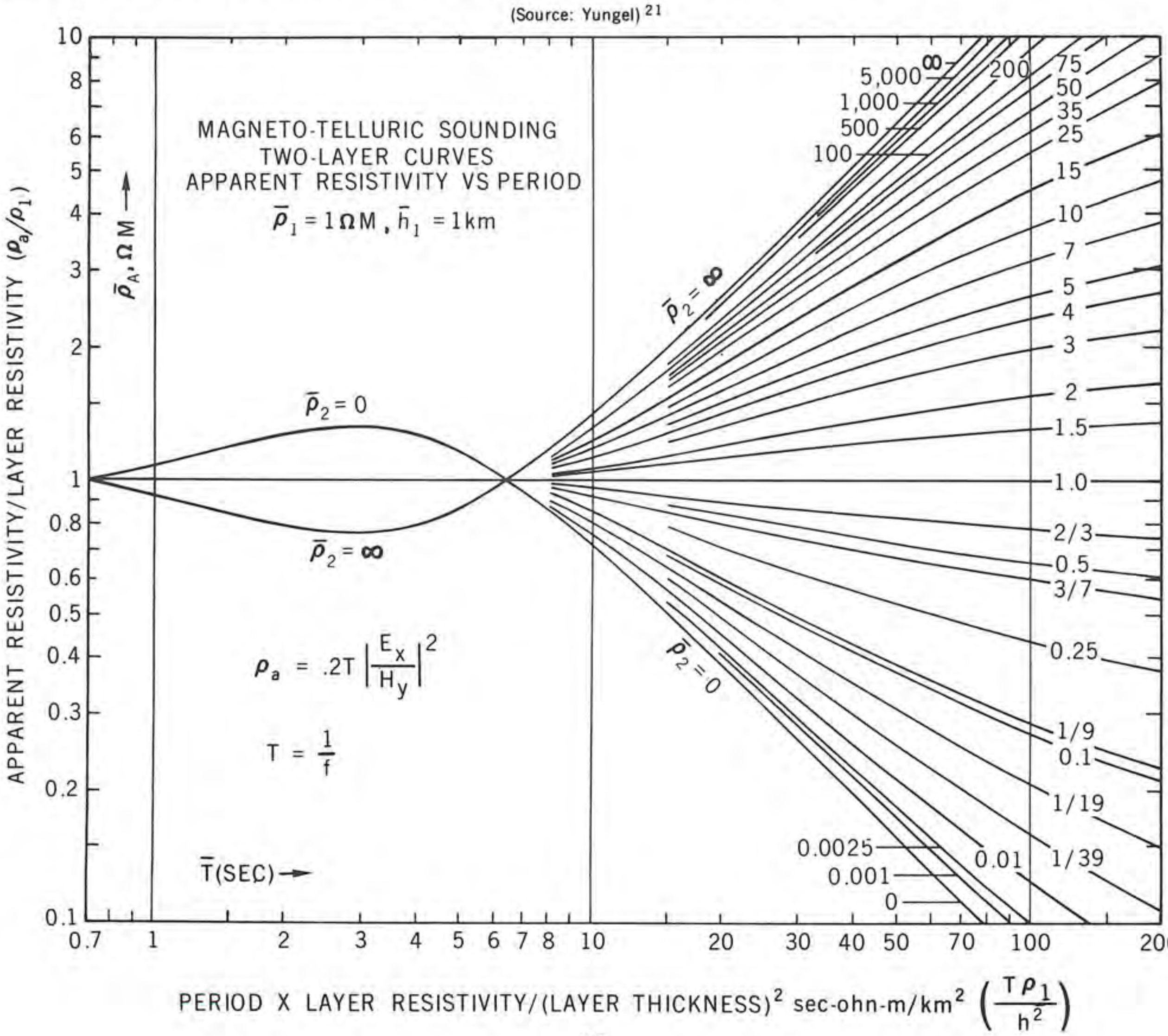


FIGURE **23**

Apparent Resistivity Vs. Period at Littleton, Mass. The Resistivity of the Layer Was Assigned the Value 8,000 ohm-m According to Earlier D-C Conduction Measurements [22]

(Source: Cantwell and Madden).

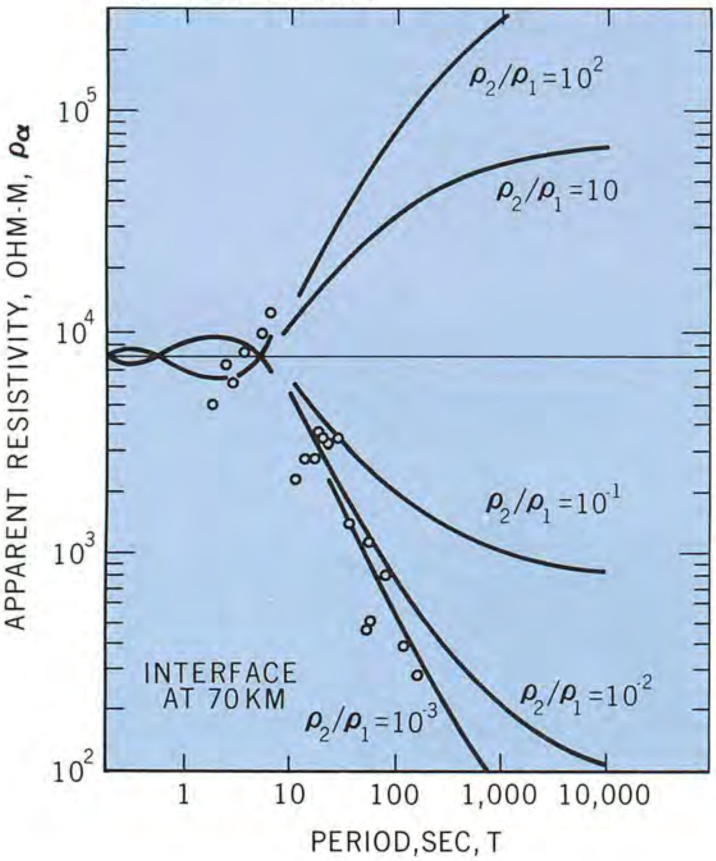


Figure 23 shows an application of the magneto-telluric method to actual field measurements in Massachusetts where the interpretation is in terms of the simple theoretical model of Figure 22.

Currently there is extensive theoretical and field evaluation work on the magneto-telluric method in the U.S.A. This method can become a useful adjunct to reconnaissance methods such as gravity and air-borne magnetic surveys by U.S. petroleum companies in a manner similar to current practice in the Soviet Union.[23] Additionally, however, because of more extensive and powerful digital computer facilities in the U.S., there is promise of applying magneto-telluric methods to more complicated geologic and geophysical problems than reconnaissance and basement mapping.

F. Seismic Refraction

In the first refraction work conducted during the 1920's, a technique known as "fan shooting" was employed to detect piercement salt domes surrounded by low-velocity sand and shale sediments. In the fan method a measurement was made of the time required for sound to travel from the shot to a series of detectors spaced along an arc at equal distances from the shot. Any decrease in the travel time from the shot to detector was indicative of the presence of high-velocity salt along part of the travel path. While variations of this method are still employed on occasion, most refraction work today employs a refraction line in which detectors are spaced in a straight line at distances from a few hundred feet to a few miles from the shotpoint. For detectors near the shot, the first arrival represents a travel path through the top layer of the earth. The first arrivals for detectors at greater distances will represent layers at greater depths. On the basis of the known distances from the shot to the several detectors and the observed travel times for first arrivals, the depth to one or more high-velocity layers may be computed with good accuracy. Large faults which produce a significant vertical displacement of a high-velocity layer will produce an anomaly in the record of travel times, and hence, can be located both with regard to depth and horizontal position. The refraction method does not determine the depth or velocity of low-velocity layers sandwiched between higher velocity beds. Specific applications of the refraction method may be listed as follows:

1. DETERMINATION OF VELOCITY FOR NEAR-SURFACE LAYERS

Short refraction lines, a few hundred to a few thousand feet long, are often employed in conjunction with seismic reflection work to determine the seismic velocity of near-surface layers. Velocities measured in this manner are employed to compensate seismic reflection records for variations in reflection times due to changes in near-surface velocity.

2. RECONNAISSANCE SURVEY

Long refraction lines (5,000 to 100,000 feet long) may be employed as a reconnaissance method to determine the depth and velocity of one or more high-velocity layers, and to locate faults and major structures. In areas where the reflection seismic method is not effective, refraction can be employed

22. Cantwell, T., and Madden, T. R., "Preliminary Report on Crustal Magneto-Telluric Measurements," *Jour. of Geophys. Research*, 1960, vol. 65, No. 12, pp. 4202-4205.

23. Keller, Caldwell, et al., *Geophysics*, vol. 31, pp. 630-638.

as a reconnaissance tool. The method does not have the resolution for locating structures of small relief, but many large structures have been found, some of which are among the world's large oil fields. The refraction method is most effective in areas where the section is composed of thick limestone, evaporite, sand and shale layers that differ in velocity from layer to layer; the method is not effective in sand-shale basins where the velocity changes from layer to layer are small. The presence of a thick, high-velocity bed above the zone of interest also precludes the use of the refraction method if the shallow, high-velocity bed has a higher velocity than beds in the zone of interest.

3. DETERMINATION OF SALT DOME BOUNDARIES

A detailed refraction program conducted in the vicinity of a salt dome is capable of outlining the boundaries of the dome in three dimensions to an accuracy of a few hundred feet. More accurate data are obtained when shots are detonated in a well located within the salt mass, but procedures have been developed for accurate profiling of salt domes with shallow shots. Similar procedures have been employed to outline the positon of large shale masses, but the low velocity of the shale precludes the accurate determination of boundaries that is achieved for salt domes.

Technological developments described previously with regard to the seismic reflection method have also led to the improvement of seismic refraction. Magnetic tape recording and digital recording have supplied more accurate field data and have provided a means for further processing of the basic data. Variable-area and variable-density record sections assist the interpreter in the recognition of second and third arrivals that may be employed in refraction calculations, and time corrections and velocity filtering also are employed to enhance the recognition and measurement of secondary arrivals. While this has not been demonstrated in the literature, there is every reason to expect that techniques now employed in the analysis of reflection data will yield more accurate determination of arrival times of both primary and secondary refraction signals.

G. Well Logging

In the exploration for oil much of the basic geophysical and geological information comes from well logging methods. Practically every well drilled in the earth in the search for oil is logged with tools lowered into the hole to measure properties of the rocks surrounding the hole. The primary purpose of drilling the wells is to find and produce commercial quantities of oil or gas, but in addition, geophysical information is obtained by means of logs. Meeting the major objective requires the location and evaluation of potentially productive zones which the wells penetrate. To provide accurate measurement of rock properties electrical, acoustical and nuclear radiations are used since they have substantial penetrations in rocks, and the data obtained can be interpreted to give a definitive evaluation and accurate depth location of productive formations. To guide the interpretation of the field logs, cores obtained from selected sections in key wells are examined and analyzed in the laboratory.

Historically, the primary logging method has been the electrical survey. The electrical log method of locating oil or gas zones in a well depends upon the resistivity contrast between a porous zone in the well containing water and a similar porous zone containing oil or gas. The assumption is usually made that the rock itself is non-conductive. Thus, although the presence of oil is not measured directly by the electrical resistivity log, it can be inferred from the combination of high resistivity and good porosity of the rock.

Interpretation of logs for formation evaluation is complicated by the drilling fluid in the borehole and by the invasion of drilling fluid into the formation, displacing the oil from the porous rock near the borehole. The invaded zone around the wellbore tends to shield the logging tool from the virgin formation whose properties are desired. Invasion affects the resistivity measurement more than the porosity measurement. To obtain a meaningful evaluation of the formation, the true resistivity of the uninvaded formation must be measured. If the filtrate invasion is too deep, there is no way to measure the true resistivity; the apparent resistivity recorded on the log is primarily that of the invaded zone. By proper control of the properties of the drilling field to reduce filtrate invasion, meaningful electrical resistivity logs can usually be obtained.

Specific logging objectives generally fall into the following categories:

(1) Location of porous-permeable zones in the well, quantitative determination of oil and water saturation within these zones, measurement of porosity, and estimation of net feet of productive intervals.

(2) Study of lithology. This includes identification of various rock types, location of boundaries and determination of thickness of various strata, and determination of physical and chemical characteristics of each rock type.

(3) Correlation of rock strata between adjacent wells—a procedure which requires accurate identification of marker beds selected for the study.

(4) Special surveys, such as density log, dipmeter, and acoustic velocity which are run to obtain both geophysical and geological information.

(5) Miscellaneous information, such as hole size, temperature, deviation of borehole from vertical, and the like.

LOGGING DEVICES AND USES [24]

(Several of the Devices Listed Here are Obsolescent)

DEVICES \ USES	CORRELATION	LITHOLOGY	BED THICKNESS	DEPTH CONTROL	FLUSHED ZONE RESISTIVITY-RXO	INVADED ZONE RESISTIVITY-RI	UNCONTAMINATED ZONE-RT	DOWNHOLE MUD RESISTIVITY-RM	WATER SALINITY & RW	PERCENT POROSITY	OIL & WATER SATURATIONS	DETECTION OF GAS	PERMEABILITY STUDIES	INVASION STUDIES	HOLE DIAMETER & VOLUME	MUD CAKE THICKNESS	CAVES & FRACTURES	HOLE INCLINATION & DEVIATION	DIP & STRIKE OF BEDS	LOCATING CEMENT	LOCATING CASING COLLARS	LOCATING WATER SOURCE	DETECTING CHLORINE CONTENT	DETECTING OXYGEN CONTENT	DETECTION OF HYDROCARBONS	SALINITY OF MUD	DRILLING TIME	FORMATION PRESSURE	NATURE OF FORMATION FLUID	SAMPLE OF FORMATION	PICTURE OF ROCKS & FRACTURES
S.P. LOG	★	★	★	★					★				★	★					★			★				★					
STATIC S.P.									★				★																		
SHORT NORMALS	★	★	★	★		★				★			★	★											★						
LONG NORMALS	★	★				★	★				★		★	★											★						
SHORT LATERALS		★				★	★				★		★	★											★						
LONG LATERALS		★					★				★		★	★											★						
LIMESTONE						★	★			★				★											★	★					
POINT RESISTANCE	★	★	★	★		★																			★						
INDUCTION 5,6	★	★	★	★			★				★		★	★											★						
LATEROLOG 3,7	★	★	★	★		★	★				★		★	★											★						
GUARD	★	★	★	★		★	★				★		★	★											★						
LATEROLOG 8	★	★	★	★	★	★					★	★	★	★											★						
MICROLOG		★	★	★	★			★		★			★	★			★								★	★					
MICROLATEROLOG		★	★	★	★			★		★			★	★			★								★	★					
PROXIMITY	★	★	★	★	★					★			★	★			★								★						
ACOUSTIC	★	★								★		★		★			★								★						
GAMMA RAY	★	★	★	★									★																		
NEUTRON	★	★	★	★						★		★	★	★											★						
CHLORINE														★									★		★						
OXYGEN																								★	★						
DENSITY	★	★		★						★							★			★											
TRACER													★									★									
SPACED NEUTRON													★	★								★			★						
NUCLEAR MAGNETISM													★																		
DRILLING TIME	★	★																									★				
DIRECTIONAL																		★													
DIPMETER																			★												
CALIPER	★	★												★	★	★	★														
SONAR CALIPER														★			★														
MUD												★													★	★					
SIDEWALL CORES		★								★	★		★												★				★	★	★
FLUID TESTER											★	★	★									★			★	★		★	★		
CASING COLLAR				★																	★										
MAGNETIC SUSCEPTIBILITY													★	★			★														
TEMPERATURES	★	★										★		★						★		★									
DOWNWELL CAMERA																															★
PHOTOELECTRIC																						★							★		

24. From Hamilton, R. G., "The Revolution in Well Logging," printed by permission of the *Oil & Gas Jour.*

Table II lists logging devices and uses. Logs are selected on the basis of objectives to be met. For example, in the study of lithology each log makes a different contribution. A combination of logs (gamma ray, density, neutron, and acoustic velocity will usually suffice) can give a definite answer as to type of lithology. It is the job of the log analyst to recommend which logs will yield the desired information. In selecting logs it must be remembered that some logs lack vertical resolution, and hence, if thin beds are encountered, the measurements will not be accurate.

I. HISTORICAL

Well logging in 1945 was in its infancy. The basic concepts of quantitative interpretation had been introduced by Archie [25] in 1942, but little quantitative analysis had been done due to the lack of adequate well logs. The logs available at that time were the electrical log, which was usable only in thick reservoirs; natural gamma ray, caliper and temperature logs; and a very crude short interval dipmeter log. The neutron log had just been discovered but little was known about the variables involved or the art of obtaining a good nuclear log.

The progress in well logging between 1945 and 1960 was nothing short of phenomenal. The most drastic changes were in instrumentation with interpretation following at a slower speed. The generally unpredicted improvements in downhole cables, surface recorders and surface equipment in general, played a very significant part in the technological progress of well logging. It was during this period that most of the concepts which are now considered important were developed, although not always successfully exploited.

The first significant development during this era was the induction log [26] for use in oil-base muds. The initial tool was not so important in itself, but was the beginning of a new generation of focused resistivity logs. In 1950, the microlog [27] was introduced as a means of obtaining porosity, which would thereby permit quantitative interpretation of well logs. However, the microlog in use did not provide a reliable measurement of porosity. Quickly following the microlog were the guard log [28] in 1951 and the continuous velocity log [29] in 1952. Initially, the velocity log was developed as a geophysical tool to give formation velocities needed for the interpretation of seismic surveys. From the velocity log synthetic seismograms are made for comparison with surface seismic records. Use of the velocity log for formation evaluation soon showed it to be a useful porosity device. Although the velocity is not a direct measurement of porosity, there is an empirical correlation between velocity and porosity. The acoustic velocity log soon became the most important porosity log for quantitative analysis.

In 1953 a combination of the guard and microlog principles was introduced, called the microlaterolog.[30] These logs were particularly useful for logging wells drilled with salt-base muds. During the 1950's many other technological advancements, such as the first density log [31] and the continuous dipmeter,[32] were made, but these were not commercially successful in their original form.

The second major development to occur in this era was the induction electrical log in 1956.[33] This tool combined the self-potential (SP) and short normal curves from the old electrical log with the induction type resistivity measurement. Tool acceptance was rapid and soon this was the prime resistivity log, a position it still maintains.

As of 1960, the induction electric log and the acoustic velocity log were the principal wireline formation evaluation tools. The continuous dipmeter became an accepted log, supplemented by other wireline services.

During the rapid tool development period of 1945 to 1960, an equally significant development occurred in quantitative analysis. The first of these developments was the relating of the SP deflection to mud and formation water resistivities [34] by equations which today are widely used. The other variable needed to utilize these equations for quantitative analysis was porosity, which was supplied first in a very poor manner by the microlog and later by the microlaterolog and the continuous velocity log. It was during this time that the disturbing effects of shaly type sands were observed.[35] The presence of shale in sand and carbonate reservoirs makes the rock matrix appear to be conductive. Thus, the quantitative determination of oil saturation in a shaly sand or shaly carbonate is not reliable. Shale also tends to influence adversely the porosity measurement of reservoir rock, affecting the velocity, density and neutron log responses in such a manner as to indicate too high a porosity. The shaly reservoir rock

25. Archie, G. E., "The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics," *Trans.*, AIME, 1942, vol. 146, p. 54.
26. Doll, H. G., "Introduction to Induction Logging and Application to Logging of Wells Drilled with Oil-Base Mud," *Trans.*, AIME, 1949, vol. 186, p. 148.
27. Doll, H. G., "The Microlog," *Trans.*, AIME, 1950, vol. 186, p. 155.
28. Owen, J. E., and Greer, "The Guard Electrode Logging System," *Trans.*, AIME, 1951, vol. 192, p. 47.
29. Summers, G. C., and Broding, R. A., "Continuous Velocity Logging," *Geophysics*, 1952, vol. 17, p. 598.
30. Doll, H. G., "The Microlaterolog," *Trans.*, AIME, 1953, vol. 198, p. 17.
31. Newton, G. R., et al., "Subsurface Formation Density Logging," *Geophysics*, 1959, vol. 19, p. 636.
32. De Chambier, P., "Microlog Continuous Dipmeter," *Geophysics*, 1953, vol. 18, No. 4.
33. Dumanoir, J. L., et al., "Interpretation of the Induction Electrical Log in Fresh Mud," *Jour. Pet. Tech.*, July 1957.
34. Doll, H. G., "The SP Log," *Trans.*, AIME, 1948, vol. 146. Wyllie, M. R. J., "Quantitative Analysis of Electrochemical Component of the SP Curve," *Trans.*, AIME, 1949, vol. 186, p. 17.
35. Poupon, A., et al., "A Contribution to Electrical Log Interpretation in Shaly Sands," *Jour. Pet. Tech.*, June 1954.

problem has not been solved and we are today using concepts developed during the 1945-1960 era. One of the important techniques developed in this period was the cross-plotting of resistivity and the reciprocal of acoustic velocity. This technique was extended to all porosity type logs because of its simplicity and ease of interpretation, and because it reduced the amount of data needed for an interpretation. Throughout this era there was a tremendous buildup of information that carried over into the following decade and contributed much to instrumentation as well as to interpretation developments.

2. RECENT DEVELOPMENTS

The period from 1960 to 1966 saw important advancements in instrumentation for borehole measurements and in interpretation of logging data. We will discuss first the improvements in well logging tools, and then the resulting interpretation advances. The major development in resistivity logging was the dual induction-laterolog-8 log introduced in 1960.[36] This did not replace the induction electric log but became a special-purpose log to be used when invasion is a problem or an unknown factor. The three resistivity curves present a limited profile of the resistivity of the formations extending horizontally from the wellbore. Other developments were basically combinations of existing devices and improvements in tool resolution.

The 1960's might easily be called the nuclear age of well logging. The significant tool developments were all nuclear devices. The older steady-state (capsule source) neutron logs were improved and advantage was taken of their weakness of being influenced by chlorine. The resulting chlorine log[37] was used to detect the absence of chlorine or the presence of oil. This tool has been largely replaced by a new concept, the pulsed neutron log.[38] This log measures the thermal neutron die-away time and is called "neutron lifetime" and "thermal decay time" log by the different service companies. This log is probably the most significant development ever made for cased hole logging and has the potential of providing information comparable to that given by the electric log for open holes. The pulsed neutron log responds to the formation porosity, fluid content and mineral composition of the rock.

Other nuclear developments during this era were the dual spaced density log,[39] which compensates for mud cake and borehole influences that severely influenced the earlier tools, and the pad-type epithermal neutron log,[40] which almost completely eliminates the borehole influence that was severe on the older type steady-state neutron logs.

Acoustic logging expanded to the use of amplitude logs to determine the quality of the cement bond to the casing,[41] and later to measurement of shear wave velocity and amplitude in open hole logging in an attempt to locate fractures in reservoir rocks.[42] Along with this evolved the borehole compensated velocity log which largely eliminates the influence of changes in borehole diameter.

Paralleling the hardware developments were the great strides taken in the interpretation of well logs. Of particular note is the "grand slam" type analysis which not only compensated for effects of invasion but also permitted identification of different invasion profiles. This technique, along with a less comprehensive analysis called the "little slam," used the new dual induction-laterolog-8 device. These systems resulted in a much better "true" formation resistivity in all except very severe cases of invasion. With the widespread use of the three complementary "porosity" logs (acoustic velocity, density, neutron), better porosities could be obtained as well as estimations of mineral composition or rock chemistry.[43] The major reason for this type of analysis becoming practical was increased knowledge of the variables influencing neutron measurements. Neutron logs became useful "porosity" logs because the count rates could be converted to porosity knowing the mineral composition of the rock.

The 1960's saw many other new interpretation techniques. One of the simplest and most effective was the detection of induced fractures using the temperature log. The evaluation of well problems became more important as new oil became harder to find, and production well logging came into prominence.

Digital computers are having a noticeable influence on log interpretation. One example is the computing of dip from logs recorded in digital form in the field. Another example is the use of the computer to provide a "quick look" interpretation of two or more logs to find oil or gas shows.[44] The present trend is toward the development of more sophisticated computer programs for both special-purpose and conventional log analysis.[45]

36. Doll, H. G., et al., "Suggestions for Better Electric Log Combinations and Improved Interpretations," *Geophysics*, 1960, vol. 25, p. 854.
37. Rabson, W. R., "Chlorine Detection by the Spectral Log," *Petr. Engr.*, 1959, vol. 21, No. 3, p. 131-132.
38. Youmans, et al., "Neutron Lifetime, A New Nuclear Log," *Jour. Pet. Tech.*, 1964, vol. 26, p. 319.
39. Wahl, J. S., et al., "The Dual Spacing Formation Density Log," *Jour. Pet. Tech.*, 1964, vol. 26, No. 12, p. 1411.
40. Tittman, J., et al., "The Sidewall Epithermal Neutron Porosity Log," Presented Oct. 1965, Meeting of SPE of AIME, Denver, Colo.
41. Grosmangin, M., et al., "Sonic Method of Analyzing the Quality of Cementation of Borehole Casings," *Jour. Pet. Tech.*, 1961, vol. 13, No. 2, p. 165.
42. Kokesh, F. P., et al., "A New Approach to Sonic Logging and Other Acoustic Measurements," *Jour. Pet. Tech.*, 1965, vol. 17, No. 3, p. 282.
43. Savre, W. L., "Determination of a More Accurate Porosity and Mineral Composition in Complex Lithologies with the Use of the Sonic, Neutron and Density Surveys," *Jour. Pet. Tech.*, 1963, vol. 15, No. 9, p. 945.
44. Davis, C. R., "Now They're Using Computers to Help Find Oil," *Oil & Gas Jour.*, 1963, vol. 61, No. 41, p. 222. Millican, M. L., et al., "Well-Site Recording of Movable Oil PLOT," *Soc. Prof. Well Log Ann.*, 5th Ann. Logging Symposium, Midland, May 1964.
45. Horn, H. K., and Slack, H. A., "COMLOG, A Comprehensive Computer System for Log Interpretation," *Jour. Pet. Tech.*, 1962, vol. 14, No. 10, p. 1109.

3. FUTURE DEVELOPMENTS

There are a number of problem areas in well logging that will require major advancements in both open hole and cased hole logging. The cost of drilling a well is so substantial that much research has gone into improving drilling fluids. The different types of drilling fluids affect the logging methods in different ways. For example, electrical conductivity logs cannot be used in oil-base muds or in salt-base muds to obtain true formation resistivity; also, a dipmeter log cannot be obtained since it depends on measurement of electrical conductivity. To prevent loss of mud in very permeable formations, plugging agents such as cottonseed hulls and other fibrous materials are added to the mud; these materials are such good acoustic absorbers that frequently acoustic logs cannot be obtained. Close collaboration is needed between logging research and drilling mud engineers to achieve the economics of drilling with special muds without loss of the information provided by well logs.

In general, the depth of investigation of all logs needs to be increased without sacrificing the detailed vertical resolution needed to evaluate thin formations. This is a twofold problem in that one must eliminate borehole influences that bother us today when the holes are large and also overcome the influence of invasion, fluid damage and stress relief without making the measurements too influenced by adjacent beds. If sufficient depth of investigation can be attained, well logs may become an even more effective exploration tool.

The measurement of porosity has been difficult because: (1) acoustical methods are based on empirical correlations which may be difficult to select in a specific area, (2) density methods require assuming values for rock matrix and fluid densities to obtain porosity, and (3) electrical methods require assumptions as to the resistivity of the fluid within the pores of the rock. Further research is needed on these methods to improve porosity determination from logs.

A major problem in open hole logging is the determination of permeability. The recently introduced nuclear magnetic resonance log should aid in providing permeability information in open holes. However, a new approach to permeability measurement is needed.

The location of fractures and the evaluation of fractured reservoirs is an important need. Acoustic amplitude and shear velocity logs fall far short of providing the desired information.

The cased hole problem is even more severe in that primarily only nuclear logs can be used because of the shielding effect of the iron casing and the cement between casing and rock formation. Neutron logs have only a shallow depth of investigation, and there is little prospect of improving this substantially. On the other hand, there is also a need for improving neutron log determination of porosity and differentiation of oil or gas from water. The prospects are good for major improvements along both these lines.

As mentioned previously, the problem of shale in sand and carbonate reservoir rocks is unsolved. Research on both logging methods and interpretation techniques is needed to try to solve this very serious problem, which is present for both open hole and cased hole logs.

Finally, computers will help by taking over much of the manual work required for log analysis and by providing a means of applying statistics and information theory to log analysis. Computer analysis of log data should help to determine which logs are most useful in providing answers to the major objectives of logging, whether for use by the geologist, geophysicist or reservoir engineer. Compilation of log data from hundreds and even thousands of wells by a computer can provide subsurface geological and geophysical information over a broad area for use in exploration, such as the compiling of isopach maps, areas of porosity development and productive intervals.

SECTION 3—Geology and Geochemistry

R. Dana Russell

A. Introduction

As noted in Section 1 on the evolution of exploration technology, petroleum exploration twenty years ago depended primarily upon the reflection seismograph and subsurface structural geology, as was the case ten years earlier. Only in the last ten years has there been more general adoption of a philosophy of thorough geologic interpretation of a prospective area. This evolution in geologic interpretation has consisted primarily of the development of much more sophisticated stratigraphic methods, aided by new knowledge in paleontology and geochemistry, and the development of photogeology, principally for reconnaissance. We are now entering a phase in which integration of all available information—geophysical, geochemical, stratigraphic, structural, and economic—is greatly facilitated by the development of modern high-speed computers.

B. Stratigraphy

In the late thirties and forties, recognition of the problems of exploring for stratigraphic traps brought the realization that exploration staffs were not equipped, either by training or by fundamental knowledge, to undertake the kind of detailed geologic interpretation required; nor was the fundamental knowledge available. Stimulation of research in universities by the American Association of Petroleum Geologists and the American Petroleum

Institute was very helpful, but results were slow in coming and often were not directly applicable to exploration. Much of the research on modern sediments, for example, was done by marine geologists and oceanographers with little knowledge of the problems of interpreting ancient rocks, or of the kinds of information applicable to such problems.

The result was that many oil companies established their own research groups to investigate the factors involved in stratigraphic entrapment. Some also undertook studies of the characteristics of both modern and ancient sediments, and tried to winnow out the information most useful to their exploration staffs. As knowledge of the stratigraphic factors influencing entrapment grew, explorationists found that better regional geological knowledge and interpretation were also required. The depositional history of the prospective area had to be worked out, the possibility of adequate source rocks investigated, time-lines established, the distribution of rock types and the environments of deposition of prospective formations deciphered, and ages of folding and periods of fluid migration determined. "Exploration Research," which from the mid-twenties to the late forties had been concerned almost exclusively with geophysical instruments and methods, suddenly expanded into many aspects of geology and geochemistry as well.

1. A CLOSER LOOK AT THE ROCKS

Many postwar petroleum geologists had pretty well forgotten what rocks look like. Their primary tools were the "electric" log, other types of logs as they became available, and the reflection seismograph. Today they are again looking at cores and cuttings with the hand lens, binocular microscope, and even the petrographic 'scope. They are not, however, just looking for diagnostic features of specific geologic horizons to enable them to correlate between wells, and hence to draw structural contour maps, but for indications of environments of deposition. They look for variations in mineralogy, in textures, in fossil content, and in sedimentary structures such as cross-stratification, ripple-stratification, animal borings, and plastic deformation.

Since cores are obviously better than cuttings for these types of analyses, more cores need to be cut to provide material for this work. Outcrops are still more informative; so, where possible, petroleum geologists are back in the field—not to map structure, but to measure stratigraphic sections, examine the rocks carefully, sample them for paleontologic and other analyses, and determine environmental patterns of deposition. These can then be projected into the adjacent subsurface or used to establish "models" for use in interpretation elsewhere.

2. MODERN METHODS OF CORRELATION

Modern approaches to exploration in many areas require reconstruction of past environmental patterns—the making of detailed paleogeographic maps. But this can be done only if rocks can be closely correlated from one well to the next. To establish trends of barrier island sands at a particular point in geologic time, for example, it is essential to know whether or not the sand at 7,560 feet in Well A is the same sand found at 7,500 feet in Well B, a mile away. Logs often will not tell you, and radiometric determinations of absolute age, though helpful, are not close enough. Paleontology is still the most useful tool.

But establishment of time equivalence at about 500- to 1,000-foot intervals may not be adequate for matching individual sands, whereas "tops" every 500-1,000 feet were considered very good paleo control twenty years ago. Today, more detailed paleontologic data, plus computer analysis of the data, can help establish zonation at closer intervals.

Paleontologic research continues to discover new forms, many of them ultramicroscopic and hence potentially abundant in cuttings. These forms help zone sedimentary sequences where the well-known "conventional" microfossils, particularly foraminifers and ostracods, are rare or absent. The most important of these discovered to date are the fossil pollen and spores from land plants. Because these tiny organic bodies were widely distributed by both wind and water, they are found in a variety of depositional environments, both marine and nonmarine ("forams" are pretty well limited to marine sediments). "Palynology" is the new branch of paleontology dealing with these and other "organic microfossils"—ultramicroscopic forms composed of resistant organic matter. Today, almost every major oil company has palynologists on its staff.

Many other properties of rocks have been used to characterize and to correlate them, including various aspects of their mineralogy, their radioactivity, and their remanent magnetism. When these properties can be measured with a downhole tool, a new logging device has usually been developed to exploit this determination. Perhaps the ultimate gadgetry in the application of mineralogic determination so far is a device (a laboratory one, not downhole) that automatically determines by X-ray the percentages of common minerals in powdered rock samples and feeds this information to a computer. The computer can then transmit the information to a plotter, which will plot logs of mineral abundances or maps of the areal distribution of individual minerals, groups of minerals, or mineral ratios.[46]

3. PALEOECOLOGY

Generations of paleontologists have devoted their lives to the taxonomic side of paleontology—describ-

46. Earley, J. W., "Automatic Acquisition, Processing, and Interpretation of Geologic Data," *Bull.*, Am. Assoc. Pet. Geol., Feb. 1962, vol. 46, No. 2, p. 264.

ing, classifying, and naming fossils. Good taxonomy is essential to any systematic work (including paleoecology) and is, of course, required for the correlation of rock units using fossils. But taxonomic paleontology by itself helps little in determining the environments of deposition of sedimentary rocks; here we need paleoecology—the determination of ancient environments from fossils, through an understanding of the relationships between fossil groups and the habitat in which they lived. Paleoecology is now in a period of rapid growth as a result of the demands of modern stratigraphy.

API Project 51, on sediments of the northwest Gulf of Mexico,[47] provided a major stimulus to the study of environmental assemblages of foraminifers, ostracods, and larger marine invertebrates. Similar studies of the same and other animal and plant groups in a variety of modern environments have added to our knowledge, and much of this is directly applicable to the younger rocks of the geologic column—Cretaceous and Tertiary. But as we go farther back in time, inferences from living forms become less valid, and we are forced to draw conclusions from evidence furnished by the fossil itself—the characteristics of its shell or other preserved parts (its "functional morphology"), and its fossil associations and enclosing sediment properties. This is an active area of research, with contributions from trace element analysis, isotope analysis, and other fields of geochemistry.

4. TRACE ELEMENTS AND STABLE ISOTOPES

Spectroscopic analysis for elements present only in trace quantities, and mass spectrometric determination of the ratios of stable isotopes of certain elements (notably carbon, oxygen, hydrogen-deuterium, and sulfur) have proved to be powerful tools in tackling certain geochemical problems. It has also been suggested that these, and other sophisticated analytical techniques, may provide valuable stratigraphic data. The trace element boron, as one example, is supposed to be more abundant in marine than in nonmarine sediments,[48] providing some indication of environment of deposition. These methods show some future promise for this application, but the results so far are too general to be very useful and too costly to be generally applicable.

5. LITHOFACIES[49] ANALYSIS AND MAPPING

A variety of techniques have been developed in the past 10 to 15 years for analyzing and presenting stratigraphic data, such as those discussed above, in maps of various sorts. Among the more useful of these are systems in which the essential features are quantitative "lithofacies" contours, analogous to the more familier isopach (thickness) and structure contours. Dozens of systems have been described, many of them flexible enough to be adaptable to many kinds of situations.[50]

Lithofacies analysis and mapping is greatly facilitated by computer processing of the stratigraphic data used in compiling the maps, and by machine plotting of the results, as discussed in the next section.

6. GEOLOGIC DATA AND THE COMPUTER

The last ten years, and particularly the last five, have seen an almost explosive development of the computer processing of geologic data. A dozen or more service companies have, at one time or another during this period, attempted to get oil companies to sponsor them in supplying comprehensive listings of geologic, engineering, and production data from wells on computer cards or magnetic tape. At the end of 1965, only five or six of these companies were still active.

These "well data storage systems" are based, for the most part, on "scout ticket" information, and suffer from all the inaccuracies of their source. Users of well data computer storage systems are thus faced with a major job of data evaluation and correction before the well data file can be very useful. Some companies have done this on their own, adding in proprietary information; others have joined cooperative groups, with further complications in some cases. Another difficulty has been the lack of a uniform system of specifying well location. Eventually all locations probably will be converted to a latitude-longitude system, even though conversion involves a number of problems. Thus there are ancillary benefits coming from this confusion; a uniform location system and better data recording and reporting will almost certainly result, and the next few years will probably see all useful well data (at least from all wells drilled in the past 40 years) recorded in well data storage systems.

The most obvious and immediate uses for these well data files are: (1) Rapid and precise retrieval of very specific items of information. (Which wells drilled in the Denver Basin had gas shows in the top

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47. Shepard, F. P., Phleger, F. B., van Andel, Tj. H., et al., *Recent Sediments, Northwest Gulf of Mexico,* Am. Assoc. Pet. Geol., Tulsa, 1960.
48. Degens, E. T., Williams, E. G., and Keith, J. L., "Environmental Studies of Carboniferous Sediments": Pt. I, "Geochemical Criteria for Differentiating Marine and Fresh-Water Shales," *Bull.,* Am. Assoc. Pet. Geol., 1958, vol. 42, pp. 272-309; Pt. II, "Application of Geochemical Criteria," *Bull.,* Am. Assoc. Pet. Geol., 1958, vol. 42, pp. 981-997.
49. Litho = rock, facies = "aspect" or characteristics. Lithofacies maps show areal variations in one or more overall aspects of the lithology of a stratigraphic unit.
50. Forgotson, J. M., Jr., "Review and Classification of Quantitative Mapping Techniques," *Bull.,* Am. Assoc. Pet. Geol., 1960, vol. 44, pp. 83-100.
Levorsen, A. I., *Paleogeologic Maps,* W. H. Freeman & Co., San Francisco, 1960.
Krumbein, W. C., and Sloss, L. L., *Stratigraphy and Sedimentation,* 2nd Ed., W. H. Freeman & Co., San Francisco, 1963, pp. 448-500.

ten feet of the Dakota Formation? You could have the answer in about two minutes.) (2) Plotting and contouring of formation tops and thicknesses (subsurface structure and isopach maps). But the more valuable potential applications are in the field of modern stratigraphy. Once stratigraphic data are placed in machine storage, they can be analyzed and presented in many different ways; for example, they may be selectively analyzed to present the most significant information for solution of a given problem.

To perform these functions requires specific computer "programs," and it is in the preparation of these programs that a great deal of specialized knowledge, ingenuity, and imagination is essential. But once a program is written and "debugged," anyone can use it. A geologist can treat his data with a variety of sophisticated statistical techniques without having to be a statistician; he can have maps of various log parameters plotted and contoured without having to examine the logs and compute the values contoured. In fact, once the basic data are in the machine, the plotter associated with it will print out graphs of data, or plot data and contour them, almost as fast as specific instructions can be fed to the computer. The explorationist can literally be buried in geophysical, structural, isopach, and various kinds of lithofacies maps without having to draw a single one himself.

Several important implications result. First, the explorationist is relieved of a mass of routine and detail, and can devote most of his time to analyzing the significance of his data. Second, the rapidity and variety of analysis tempts one to feed in all sorts of data, and to dream up all sorts of "programs" to analyze them, without regard to whether the results will be valid or significant to exploration. These are but growing pains, however, and the future of the computer in geologic data processing is assured—if we use it intelligently. It is well to remember that the computer only does what a good geologist has always done: select and recall data, synthesize it, regroup it, and present it for interpretation. The human brain does this and much more—it also does the interpreting. The power of the computer lies primarily in its ability to do the routine aspects of the job completely, accurately, repeatedly, and ever so much more quickly.

C. Structural Geology

In the past, the almost routine search for anticlines and other simple structural traps has not encouraged the development of improved understanding of rock mechanics or tectonics. Such understanding may be unnecessary where structures can be mapped directly or readily detected by geophysical methods. But the greater the amount of geologic inference involved, the greater the need for fundamental theories that can be used in prediction.

Classical elastic theory, the core of structural geology, has severe limitations when applied to the deformation of rock masses. There is no generally valid stress-strain theory for large deformations of rocks. During the past decade, particularly, considerable experimental research effort has gone into an attempt to develop valid stress-strain laws for rock deformation, with only partial success. Some progress has been made in relating strain response to rock properties, and rock fabrics to stress directions. There has also been increasing recognition of the importance of anisotropy (elastic theory assumes a uniform, isotropic body; both experimental and field studies have shown that rock stratification, fabric, or fractures can be completely overriding). Perhaps the greatest advance has come from recognition of the importance of pore fluid pressures, from work both in the laboratory and in the field.[51] This work has resolved some of the problems of moving thin sheets of rock strata large distances over very low slopes by gravity forces to produce overthrust and folded mountain belts.

But most of the developments in structural geology research in the past 20 years, both from experiments and field studies, have resulted in almost as many contradictions as advances in understanding. This is not to say that we have not learned much about structural geology in the past 20 years—we have. We know a great deal more about the composition and deformational history of the continental and oceanic crusts, for example, including recognition and definition of the major wrench faults. But most of our increased knowledge has not helped much in solving the practical problems of predicting structural configurations, particularly at the scale involved in petroleum exploration. We can hope that the next two decades will show a major improvement in our prediction capability.

D. Reconnaissance Geological and Geochemical Methods

1. PHOTOGEOLOGY [52]

Since World War II, photogeology has been the most important geological reconnaissance method. Although geologic mapping on aerial photos as a base was common prior to World War II, the explosive growth of photogeology occurred chiefly after the war, largely as a result of the great strides made in aerial photographic interpretation in the photoreconnaissance programs of the armed services during the war. Many of the wartime "photo interpreters" were geologists, and a number of them continued to work in this field after the war; as teachers, as consulting geologists, and as founders or members of photogeologic service companies.

Photogeology, as a supplement or complement to field geology, was initially limited to structural map-

51. Hubbert, M. K., and Rubey, W. W., "Role of Fluid Pressure in Mechanics of Overthrust Faulting," *Bull.*, Geol. Soc. Am., Feb. 1959, vol. 70, No. 2, pp. 115-205.
52. Colwell, R. N., ed., *Manual of Photographic Interpretation*, Am. Soc. of Photogrammetry, 1960.

ping in areas of good outcrops and relatively steeply dipping beds. As such areas became mapped more attention was devoted to sedimentary basins where the surface geology consists of limited outcrops and gentle dips. Geomorphic analysis became an essential tool of the photogeologist—the analysis of land forms, of major drainage anomalies and detailed drainage patterns, of plant cover, and of the tonal patterns of soils. Comprehensive photogeologic mapping now includes an integrated use of all of these tools, plus the accurate determination of geologic parameters by the use of stereo plotters and other sophisticated equipment of the photogrammetrist. Modern digital computer techniques now enable the photogrammetrist to extend his measurements to areas of very low dips (less than one degree), in areas of relatively poor outcrops, by averaging elevation readings from as many as 50 points on a single bed within a limited area.

2. GEOCHEMICAL METHODS

Most geochemical prospecting methods are based on direct or indirect detection of anomalous quantities of hydrocarbons in soils or formation waters. In this respect they differ from the other exploration methods discussed, which are aimed at finding the conditions favorable for entrapment of hydrocarbons. But even the most ideal trap will be barren if no hydrocarbons migrate into it, or if they are flushed out; many dry holes have been drilled on beautiful structures. Geochemical prospecting is a direct method; you look for an actual accumulation, rather than a potential one.

A very good theoretical case can be made for the validity of geochemical soil-analysis methods.[53] Soil samples are analyzed for hydrocarbon gas, hydrocarbon residue, or for bacteria living on hydrocarbons in the soil, and the results shown on a map of the area. Halos or other local anomalies presumably indicate the presence of an accumulation below. First tried by the Russians in the early '30's (and still used by them to some degree),[54] these methods were extensively investigated by several major oil companies in the '40's and early '50's. Almost all have abandoned them. The complexity of natural diffusion processes in such a complicated layered medium as the earth, and the fact that economically insignificant shallow hydrocarbon accumulations effectively mask large ones at depth, are the principal reasons why these methods are not successful.[55]

There is more hope for the analysis of formation waters, from a well near a major hydrocarbon accumulation. Here the disturbing effects of long migration and the masking effect of nearer minor accumulations would be minimized. Anomalous quantities of benzene or other light hydrocarbons dissolved in formation waters from dry holes may be valid "proximity indicators." The Russians so consider them,[54] and some research in this country tends to confirm the possibility.[56] The difficulty in applying the method is that great care must be taken in sampling formation waters to avoid contamination and to preserve dissolved gases, yet the results are still somewhat ambiguous. The amount of hydrocarbon present will vary with distance to the source, size of the source, aquifer conditions, and degree of dilution by addition of waters along the migration path; not a very satisfactory direct oil-finding method, but possibly a useful indicator of a prospective area.

The chemistry of formation waters has also been studied from the standpoints of logging, of formation correlation, and of petroleum migration and hydrodynamics. Accurate knowledge of formation water chemistry is essential to quantitative log interpretation, and where individual formations have distinctive formation waters, this factor can be used to correlate them. Distinctive chemistry can also be used to trace the movement of formation waters, providing evidence on possible migration paths and on hydrodynamic gradients.

Another phase of geochemical research has proved quite useful in evaluating relatively unexplored areas —source rock analysis. Based on the analysis of non-reservoir rocks (especially shales) for their organic carbon and hydrocarbon content, this method was first announced by Shell at the International Geological Congress in 1956.[57] The ratio of extractable hydrocarbons to total organic carbon determines whether the hydrocarbons are indigenous or migrated; if indigenous, the source-rock quality is given by the following table:

Table III

SOURCE ROCK QUALITY	INDIGENOUS HYDROCARBON CONTENT IN PARTS PER MILLION OF DRY SEDIMENT	INDIGENOUS HYDROCARBON CONTENT IN BARRELS PER ACRE-FOOT *
Excellent	5,000	120
Very Good	1,500–5,000	35–120
Good	500–1,500	12–35
Fair	150–500	3.5–12
Poor (Marginal Commercial)	50–150	1.2–3.5
Very Poor (Noncommercial)	0–50	0–1.2

* In the conversion of parts per million into barrels per acre-foot hyrocarbon density is assumed to be 0.9, and the rock density, 2.7 (from Philippi [57]).

53. Rosaire, E. E., "Geochemical Prospecting for Petroleum," *Bull.*, Am. Assoc. Pet. Geol., 1940, vol. 24, No. 8, pp. 1400-1433.
54. Kartsev, Tabasaranskii, Subbota, and Mogilevskii, *Geochemical Methods of Prospecting for Petroleum and Natural Gas*, 1954; English Translation, Witherspoon and Romey, eds., Univ. Calif. Press, 1959.
55. *Proceedings of the Seminar on Geochemical Prospecting Methods and Techniques*, Mineral Res. Dev. Series, No. 21, United Nations, New York, 1963, pp. 11-12.
56. Zarella, W. M., Mousseau, N. D., Coggeshall, N. D., Norris, M. S., and Schrayer, G. J., "Analysis and Interpretation of Hydrocarbons in Subsurface Brines," Preprints, Am. Chem. Soc., Div. Pet. Chem., April 1963, vol. 8, No. 2, pp. A-7-16.
57. Philippi, G. T., "Identification of Source Beds by Chemical Means," *International Geol. Congress*, Session XX, Mexico City, (1956); Section III, 1957, pp. 24-38.

A related aspect of the organic geochemistry of sediments is the correlation of a specific crude oil with its source-rock section (i.e., determination of what group of rocks the oil came from). Much research has been done on this problem but little published; it is probable, however, that most major oil companies can do this with varying degrees of success.

These are only two aspects of the whole problem of petroleum evolution—its origin, migration, and accumulation. This is the oldest research problem in petroleum geology and geochemistry and one of the most difficult. The American Association of Petroleum Geologists and the American Petroleum Institute have sponsored research on this general problem since their inception, and most major oil companies have had research programs underway for many years. The literature is now far too large to review here. In spite of the amount of effort, however, relatively few definitive results have been obtained until recently, when new analytical techniques such as infrared and ultraviolet spectroscopy, gas-liquid chromatography, and stable isotope analysis began to yield more detailed, and perhaps more meaningful, results.

3. HYDRODYNAMICS

Under hydrostatic conditions, a petroleum accumulation occupies the highest structural position beneath an impermeable barrier and the oil-water contact is horizontal. Theoretically, however, if the formation water is in motion (hydrodynamic conditions), the accumulation is displaced and the oil-water contact is tilted. And in a stratigraphic trap, the amount of oil column that can be held behind a permeability barrier theoretically depends upon the direction of flow of the formation water: the greater the component of flow down dip, the greater the height of the oil column trapped.

At least some of these general principles have been known since 1909, but were first thoroughly expounded and demonstrated mathematically by Hubbert in 1953.[58] Almost immediately many explorationists became concerned about hydrodynamics, and one service company was established to provide training in hydrodynamic analysis and to furnish potentiometric maps (pressure-difference maps showing direction and amount of formation water flow) to the industry. These maps were touted as major reconnaissance aids that would indicate the areas within a sedimentary basin where petroleum accumulations could be expected. Hydrodynamics was advertised as being the third important requirement for petroleum entrapment, equal in importance to structure and stratigraphy.

These claims proved to be extravagant. Hydrodynamic effects certainly exist and may be critical under certain conditions, so they should be considered in evaluating traps. But they are not as important in most cases as stratigraphy and structure, and have not proved very useful as a general reconnaissance tool.

58. Hubbert, M. K., "Entrapment of Petroleum under Hydrodynamic Conditions," *Bull.*, Am. Assoc. Pet. Geol., 1953, vol. 37, pp. 1954-2026.

4. STRATIGRAPHIC CORE DRILLING

Shallow core or "strat-test" drilling has been used since 1919 or before to provide information on rocks below the surface, particularly in undrilled areas of poor outcrops. When most sedimentary basins in the continental United States had been tested by the drill, the need for this type of information decreased, while at the same time drilling costs rose. The amount of information obtained per dollar expended decreased until strat-test drilling was no longer economically attractive except in special areas or on special problems.

Recently, offshore exploration has changed this picture. The continental shelves were largely virgin areas with little known about the stratigraphy, so strat-tests were drilled to provide information on at least the upper part of the sedimentary section. Strat-testing on the continental shelves has been done chiefly by groups of companies to reduce costs, just as offshore seismic survey costs have been shared. Both seismic and strat-test reconnaissance surveys have usually been made in advance of lease sales to provide the participating companies with information for evaluating the potential of the areas offered for lease, and hence have been limited to offshore California and some off the Gulf Coast. Recently the JOIDES (Joint Oceanographic Institutions Deep Earth Sampling) program drilled the first deep (up to 320 meters) core tests on the Atlantic continental shelf, off the east coast of Florida.

SECTION 4—Exploration Costs

R. Dana Russell

Table IV presents currently available figures on exploration costs for the past 22 years. Although a number of sources were examined for these data, only the three shown were considered adequate and they provide data for only 11 of the 22 years. Nor are the figures from different sources directly comparable. They do reveal some trends, however, especially if plotted as curves (Figure 24). Between 1945 and 1955, total exploration costs increased at a fairly uniform rate, about $125 million per year.

Marked fluctuations after 1955 reflect periods when offshore acreage was offered for lease, but the only general trend seems to be a flattening off. This is confirmed by the figures on dry hole costs and geological-geophysical (G & G) costs, available for

EXPLORATION COSTS—UNITED STATES

SOURCE	1944 [a]	1948 [a]	1951 [b]	1953 [a]	1955 [c]	1956 [c]	1959 [c]	1960 [c]	1961 [c]	1962 [c]	1963 [c]
	MILLIONS OF DOLLARS										
Dry Hole Costs	274	462	650	797	774	909	821	774	774	874	790
Lease Acquisition					651	561	554	626	428	815	376
Geological &	327	570	824	987							
Geophysical					306	360	320	277	280	299	300
Lease Rentals							193	193	189	197	193
Land, Leasing & Scouting Expenses								104	115	108	117
Overhead	44	79	127	172							
Other					263	287	124	71	65	58	69
Total	645	1,111	1,601	1,956	1,994	2,117	2,012	2,045	1,851	2,324	1,845

a—API, *Petroleum Facts & Figures,* 12th Ed., New York, 1956, p. 133.
b—Anderson, C. C., *Petroleum and Natural Gas in the U.S.—Relation of Economic and Technological Trends,* World Power Conference, Montreal, Sept. 7-11, 1958, p. 6.
c—API, Ind. Producers Assoc. of Am., and Mid-Continent Oil & Gas Assoc., *Joint Association Survey of Industry and Drilling Costs.* API, New York, 1959 and 1963.

FIGURE **24** Exploration Costs in the United States, 1944-1963

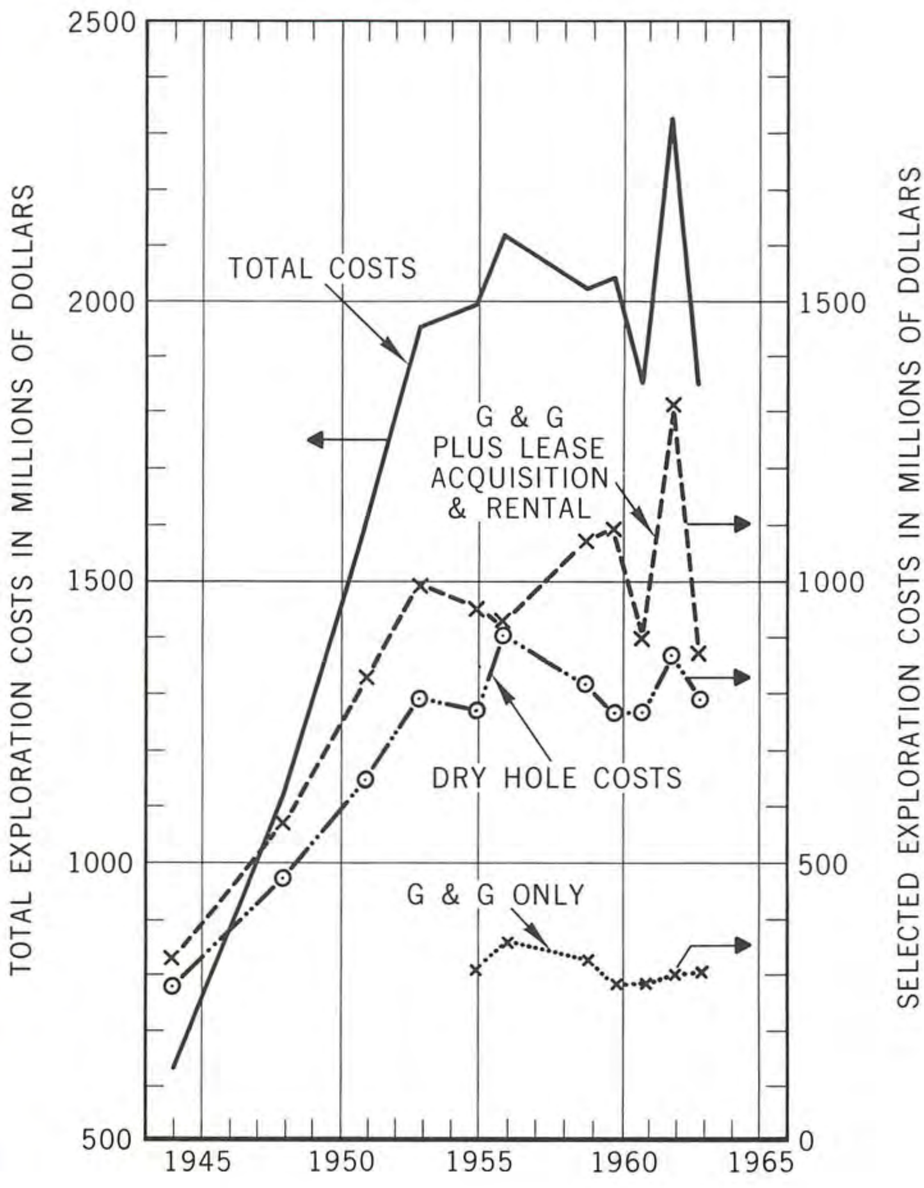
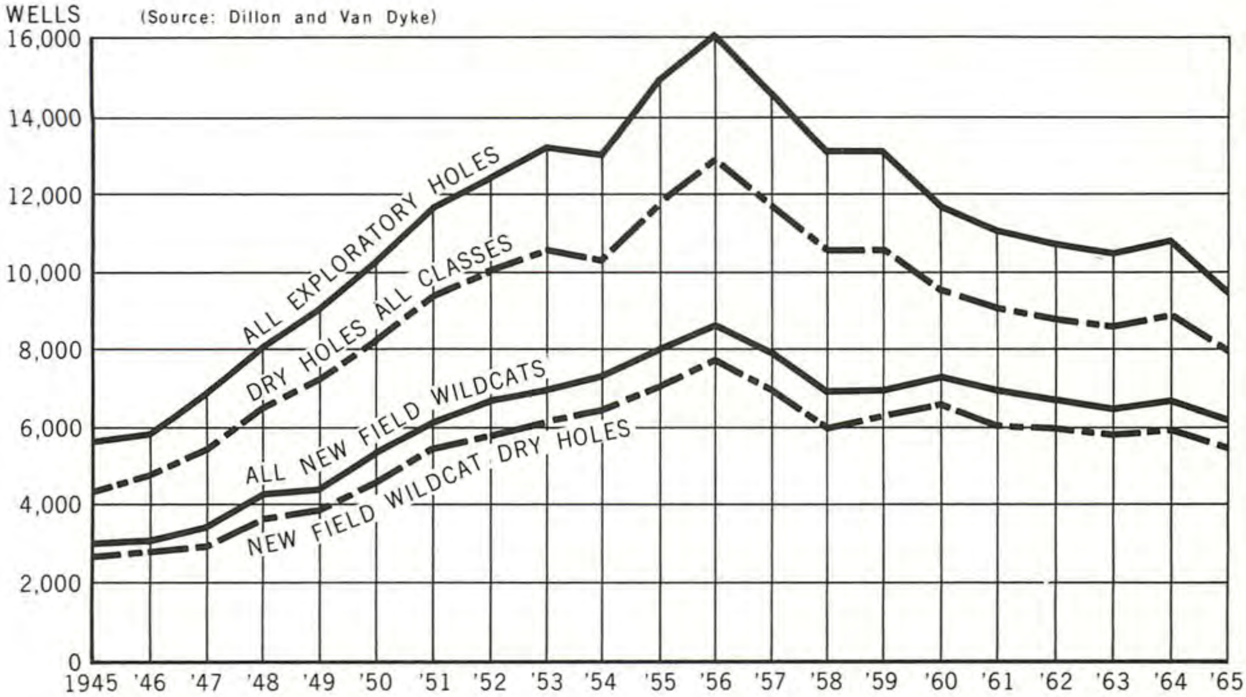
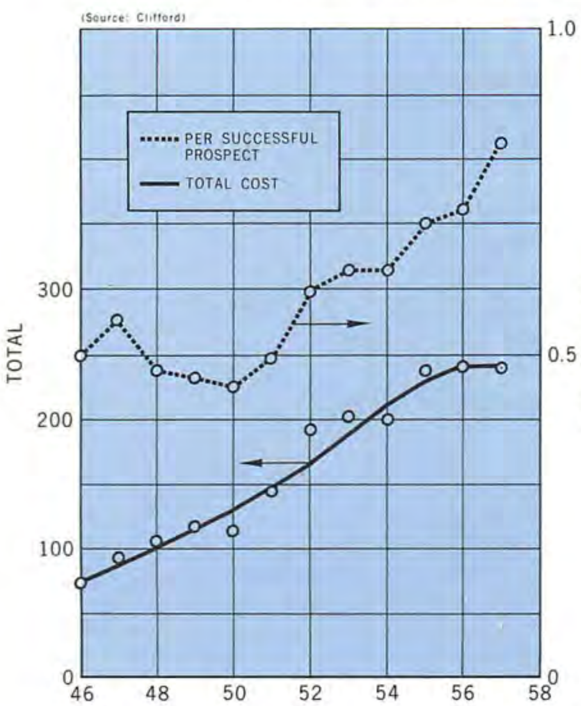


FIGURE **25.** Exploratory Drilling in the United States, 1945-1965 [59]



59. Dillon, E. L., and Van Dyke, L. H., "Exploratory Drilling in 1965," *Bull.*, Am. Assoc. Pet. Geol., June 1966, vol. 50, pp. 1114-1138.

FIGURE **26.** Geophysical Costs in Millions of Dollars, 1946-1958 [60]



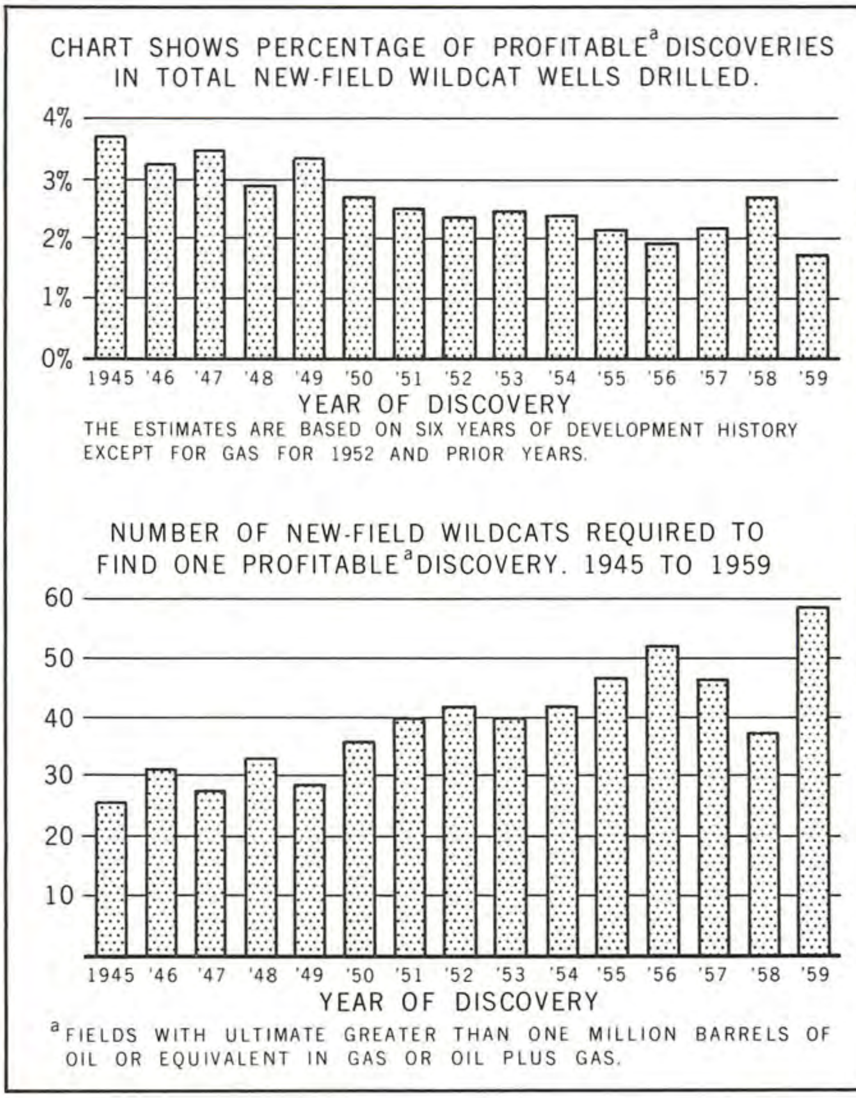
60. Clifford, O. C., Jr., "An Oil-Finder Looks at his Profession," *Oil & Gas Jour.*, May 26, 1958, pp. 156-160.

1955, 1956, and for 1959 through 1963; these remained about the same during this 10-year period. Dry hole costs averaged a little over \$800 million per year and G & G about \$300 million.

But these dollars bought less exploration each year because of rising exploration costs. New field wildcat wells dropped from 8,742 in 1956 to 6,182 in 1965 (Figure 25). The total geophysics cost per year has increased from \$74 million in 1946 to \$240 million in 1956 (Figure 26), with the cost per successful prospect going up from about a half million dollars to nearly three-quarters of a million in this period. Costs for 1965 are not yet available, but probably are over a million dollars per new field discovery in the United States, by geophysical or combined geological-geophysical methods. Meanwhile, although our success ratio has remained about the same over 20 years (between 11 and 13 percent), the number of wildcats needed to find a "profitable" discovery (greater than one million barrels of oil or gas equivalent) has steadily increased from about 25 in 1945 to about 50 in 1960 (Figure 27). The fields we are finding are smaller and less valuable.

In summary, our improved technology has enabled us to continue to find new reserves, even though they

FIGURE **27**
Profitable Discoveries After Six Year History as a Percentage of Total New Field Wildcats[61]



61. From Dillon and Van Dyke, *loc. cit.*

are increasingly difficult to find because only the hard-to-find accumulations are left in the continental United States. But we continue to increase our reserves by new discoveries only at increasing costs.

SECTION 5—The Future of Exploration

R. Dana Russell
With contributions by Frank J. McDonal

The last section ended on rather a gloomy note. As the Red Queen told Alice: "Now here, you see, it takes all the running you can do, to stay in the same place." From 1955 through 1964 we were not even doing that; we were losing ground. What does this imply as to the future of exploration in the United States? Part of the answer, at least, depends upon how much oil remains to be found.

A. Domestic Reserves

No one knows how much oil and gas remain to be discovered and produced in the United States, but many people have tried their hands at guesstimating the amount. Three recent and quite thorough studies, from different points of view, probably bracket the true figure. Hubbert[62] figures ultimate U. S. production at 175 billion barrels of crude oil, 30 billion

62. Hubbert, M. K., *Energy Resources*, A Report to the Committee on Natural Resources of the National Academy of Sciences—National Research Council. Nat. Acad. Sci.—Nat. Res. Council Publ. 1000-D, Washington, D. C., 1962, pp. 42-86.

barrels of natural gas liquids, and 1,000 trillion cubic feet of natural gas; Hendricks of the U.S. Geological Survey [63] calculated 400 billion barrels of crude oil, 60 billion barrels of natural gas liquids, and 2,000 trillion cubic feet of natural gas as economically recoverable. Both estimates include the continental shelves, but Hubbert's does not include Alaska. The most recent estimate, by Moore,[64] is even higher than Hendricks' but includes reserves that Hendricks considers submarginal and uneconomic. All these are estimates of ultimate production in terms of recovery practices at the time of estimate; the amounts of oil and gas originally in place are variously estimated as two to four times as great.

There is quite a difference between these estimates, but all are large enough to provide exploration incentive for a long time, especially since less than 90 billion barrels of petroleum liquids have been produced to date. Furthermore, as many explorationists have pointed out, we have scarcely touched two of our greatest prospective areas—the continental shelves and Alaska. Lewis Weeks recently analyzed the potential of the shelf areas of the world.[65] Of the 10.763,000 square miles of shelf under less than 1,000 feet of water, over half (6,170,000 sq. mi.) are underlain by a thick enough sedimentary section to make them prospective. Weeks rates 188,000 square miles of shelf as "excellent potential," 1,657,000 as "fair," and 4,325,000 as "poor," but possible. He estimates the ultimate recoverable reserves (petroleum liquids plus gas equivalents) from only the first two categories at 1,000 billion barrels; about 20% of this area and reserve potential is on the continental shelves of North America. More recent estimates by Nelson and Burk [66] are considerably smaller but still substantial. We are only now beginning to look at our Atlantic shelf, and large areas of both the Gulf and Pacific shelves remain untested by the drill.

The controlling factors, then, are technical ability and economics. Let's look at our technical ability first.

B. New Tools in Prospect

1. DIRECT METHODS

Exploration management perennially hopes that research (or "someone") will come up with a "breakthrough"—a radically new method of oil finding that will drastically improve success ratios. Preferably, it should be a direct oil-finding method that would detect oil or gas accumulations, not just traps that might contain petroleum. Unfortunately, there is little prospect of this hope ever being realized short of the development of extrasensory perception. The transmissibilities of various forms of energy in the earth are now well enough known for us to say with some confidence that there is no special band of frequencies, in either the acoustic or electromagnetic spectrums, that will let us "see" oil underground.

There is. however, some slight hope in the "force" field. Development of sensitive high-precision gravimeters by Esso Production Research [67] and by McCulloh of the U. S. Geological Survey [68] show promise of being able to detect large accumulations of petroleum by the gravity difference produced by the replacement of pore water by hydrocarbons. Calculations indicate that at least one hundred feet of oil or gas saturation would be required in a highly porous reservoir (30% porosity) at a depth of 1500 feet or less to produce a detectable negative anomaly at the surface. The deeper the reservoir, the larger the accumulation would have to be to be detectable. So this tool, also, does not seem to be the answer for a direct, surface-operated, oil-finding method. It has more promise, however, as a proximity indicator in a borehole.

2. REMOTE SENSORS AND OTHER NEW TOOLS

If a direct oil-finding tool seems unlikely, we are at least getting a number of new tools that improve our ability to do conventional geophysics, geochemistry, and geology. For example, research in connection with military and space requirements has produced greatly improved "remote sensors" [69] that can be used from orbiting spacecraft for studies of the earth. These include devices sensitive to force fields, such as gravity gradient systems, and a range of devices that record reflections of electromagnetic energy through a wide part of the spectrum. Color photography from satellites promises new developments in photogeology. And a new terrain profiler, using a gas-laser ranging device, has a capability of accurately profiling the surface over which an aircraft is being flown to better than one foot at 1,000 feet above the ground surface.

The potential of the laser principle is so great in so many fields of application as to almost defy imagination. We will, for example, soon have an offshore location system, using lasers, that will increase location accuracy manyfold and solve one of the principal problems of offshore surveys and site location. Ana-

63. Hendricks, T. A., "Resources of Oil, Gas, and Natural-Gas Liquids in the United States and the World," *Circular 522*, U. S. Geol. Surv., Washington, D. C., 1965, p. 12.
64. Moore, C. L., *Analyses and Projections of the Historic Patterns of the U. S. Domestic Supply of Crude Oil, Natural Gas, and Natural Gas Liquids*, U. S. Dept. of the Interior, Office of Oil & Gas, May 1966.
65. Weeks, Lewis G., "World Offshore Petroleum Resources," *Bull.*, Am. Assoc. Pet. Geol., 1965, vol. 49, pp. 1680-1693.
66. Nelson, T. W., and Burk, C. A., "Petroleum Resources of the Continental Margins of the United States," *Trans.*, 2nd Ann. Conf., Marine Tech. Soc., June 1966, pp. 116-133.
67. "Esso Licenses Down-Hole Gravity Meter," *Oil & Gas Jour.*, June 27, 1966, pp. 101-102.
68. McCulloh, T. H., "Gravimetric Effects of Petroleum Accumulations—A Preliminary Survey," *Circular 530*, U. S. Geol. Surv., Washington, D.C., 1966.
69. Feder, A. M., "Let's Use More of the Electromagnetic Spectrum," *Trans.*, Gulf Coast Geol. Soc., 1964, vol. 14, pp. 35-49.
Badgley, P. C., Fischer, W., and Lyon, R. J. P., "Geologic Exploration from Orbital Altitudes," *Geotimes*, Sept. 1965, vol. 10, No. 2, pp. 11-14.

lytical applications of lasers are just beginning to appear and other new analytical techniques and devices are constantly expanding our capabilities to learn more about the rocks that make up the earth.

C. Improved Existing Tools

1. GEOPHYSICS

The outstanding recent developments in the field of geophysics have resulted from the adaptation of new developments in physics, mathematics, and engineering to the specific problems of oil exploration. This trend will continue. More accurate and more reliable seismic digital recorders, magnetometers, gravimeters, and well logging equipment will become available. Each of these improvements will make a specific contribution to improved oil finding, but the major improvements will be in the area of computer technology. Large, high-speed digital computers make possible analyses that were heretofore impossible. For example, the application of pattern recognition to seismic data would, in a typical example, require one billion multiplications. These calculations on a medium-speed computer such as the CDC 1604 would theoretically require about 2,000 hours and cost $400,000. On the CDC 6800 computer the same calculations will require approximately 30 minutes at a cost of $400. A theoretical time of 2,000 hours for pattern recognition simply means that this method of analysis cannot be applied at the present time; but with the advent of computers in the 6800 class, such analyses will become feasible.

2. GEOCHEMISTRY

Modern geochemistry is a rapidly growing earth science that owes its renaissance to the development of new analytical tools such as precision emission spectroscopy, mass spectrometry, gas-liquid chromatography, the electron and laser microprobes, and most recently, atomic absorption spectroscopy. These are powerful tools that are providing new data on the chemical history of minerals, rocks, and rock-contained fluids. As mentioned in the preceding section, these new tools have resulted in more progress on the difficult problems of petroleum genesis in the past five to ten years than in the preceding fifty. Equally rapid progress is occurring in inorganic geochemistry, though few results so far have been of direct application to exploration. The chemistry of formation waters is a relatively untouched area of research that looks particularly promising. Certainly geochemistry will contribute significantly to our exploration capabilities in the next decade or so.

3. GEOLOGY

As a primarily synthesizing and interpretive science, the greatest contribution that geology will make to improved exploration capability is in greatly improved geologic interpretation. This is being achieved by expanded research on the characteristics of modern sediments deposited in different environments, on distributional patterns of rock types in ancient sediments and their significance and relationships to depositional patterns, on the imaginative adaptation of laboratory experiments to field interpretation, and by the synthesis of all available geophysical, geochemical and geological information into a consistent geologic picture. This is the "modern stratigraphy" discussed in the preceding chapter, and it is just getting underway. There have been major changes in exploration methods in the past five years, but they are likely to be minor compared to what we can look forward to in the next five to ten years.

4. COMPUTER APPLICATIONS

Computers are essential in handling the more technical and far more complex exploration technology of the future. At this point it is difficult to predict the full impact of computer technology, but there are some indications evident from the present state of the art.

The major gains achieved in the last few years in the computer processing of seismic records and in interpreting gravity and magnetic data can be expected to continue, as noted above. In processing geologic data, several possibilities seem likely. The present method of contouring data consists of interpolating between known data points to provide a value for each intersection of a rectangular grid pattern, then contouring the grid values. The process is entirely objective and mechanical. A geologist, on the other hand, in contouring known data points, usually does so in terms of a specific geological model—his contouring involves subjective interpretation. How good his interpretation is depends, of course, on how good a geological interpreter he is—a composite result of his training, his experience, and his imagination and degree of intuitive perception. There are, of course, advantages and disadvantages to each system.

We will soon be able to provide an intermediate method by programming a computer to contour known data points in terms of a specific geologic model; i.e., according to predetermined geologic assumptions or known environmental patterns of facies distributions. We could then vary the model (or assumptions) and compare the results. A further development would instruct the computer to examine the data in terms of various models, select the one that best fits the data, then contour according to that model. Another possibility is extrapolation (present methods only interpolate). The computer could be instructed to examine the data for internal consistency and where consistent trends exist, project the trend for a specified distance. The possibilities seem almost limitless.

But perhaps the most significant advance in the effectiveness of oil exploration will be a more effective combination of geological and geophysical information. Digital computers have made possible the evaluation, comparison, and correlation of larger volumes of geophysical and geological data. All steps in the planning and execution of geophysical programs are based upon geological information, and on the other hand, geological studies are often planned and executed on the basis of the results available from geophysics. The interrelationship of geophysics and geology is complex, but the standard practice is to execute these programs more or less independently. Computer systems now in the breadboard stage will greatly facilitate the integration of geophysical and geological programs from the early stages of basin evaluation to final prospect evaluation.

The logical next step is the complete integration of of all geophysical, geochemical, and geological information into the optimum interpretation of the geology of a specific area or sedimentary basin. Again, if the data are relatively few and far between (early stage of development) many models and assumptions can be tried and the geologically most plausible interpretation selected for interim decisions. As more wells are drilled and more data become available, the computer may be able to tell us which interpretation is most likely (if we have fed in the criteria)—and even calculate the probability of it being the correct one.

The final step would be calculation of the productive potential of a sedimentary basin and, by the use of operations research techniques, determination of exploration and production tactics. These might well vary from company to company, depending upon corporate objectives and fiscal policies. Initial steps have already been taken along this path; some companies are using these techniques to determine their bidding strategy and maximum bids at lease sales.

5. THE NEW EXPLORATIONIST

Perhaps the greatest challenge of the future is to the individual exploration geologist (or better, explorationist, since he must be far more than the exploration geologist of the past). He must adapt to a much more technical and much more complex profession or become obsolete. He must be sufficiently conversant with modern developments in geophysics, geochemistry, and geology to be able to talk to specialists in these fields and evaluate the application of their results to his exploration problems. To some degree, at least, he must keep up with computer technology, and he must become an economist of sorts—today's high, and tomorrow's higher, costs—for technology, acreage, deep drilling, and production—and make the exploration group acutely aware of the economic impact of all their actions and decisions. For most prospects, the group must calculate far more than potential reserves—they must estimate possible rates of return, profit before and after taxes, profit to investment ratio, profit to risk ratio, payout time, discount rates, and the effect on profit of a delay in production. In remote or difficult accessibility regions, feasibility studies of operating problems must often be conducted as a part of the exploration program, or in advance of it, to determine whether any new discovery could be profitably brought to market.

The major petroleum companies are well aware of these demands of the new exploration technology and of the problems of obsolescence, as is the American Association of Petroleum Geologists. The Association has recently added a "Continuing Education" program of short courses to its long-standing "Distinguished Lecture Series." And most major companies have established technical seminars and special training courses that run from a week to as much as nine months. There will be even more need for efforts of this sort in the future.

CHAPTER THREE—DRILLING AND PRODUCTION PRACTICES

SECTION 1—Drilling—Fluids, Hydraulics, Drilling Methods and Techniques

Walter Rogers and W. C. Goins

A. Drilling Efficiency Improvements

The purpose of this Section is to outline the technical improvements in drilling muds, hydraulics, drilling techniques, etc., which occurred in the oil well drilling industry over the years 1945-1965 and were of sufficient importance to improve drilling efficiency. Numerous statistics on drilling are compiled annually; from these, evidence can be found as to whether drilling efficiency has been improved at all and, if so, to what extent.

One method of doing this is to determine whether the footage per rig has increased over the period in question. Table V gives some evidence on this score. It shows the number of rigs in use and the footage drilled per rig year. The data show the footage per rig increased between 1950 and 1965 from 35,263 feet per year to 65,191 feet per year. This would be truly an achievement if the same rigs were the only ones in use. During this period the average well depth increased as shown by Table VI. These data show an increase between 1950 and 1965 from 3,680 to 4,380 feet.

The best evidence as to whether rig efficiency increased is believed given by a comparison of the drilling cost per foot of hole in constant dollars over the period in question. This is given in Table VII and shows by year from 1950 to 1965 the average contract price per foot reported to the American Association of Oil Well Drilling Contractors, the U. S. Bureau of Labor price index with 1958 as 100 percent, and the adjusted contract cost per foot in terms of adjusted or constant dollars. This table shows that the real cost per foot of hole decreased from $5.00 to $3.25 per foot. For the past three years the cost has been about the same, with perhaps a slight increase in 1965.

These data show unquestionably that even though most rig replacements are at increased price and labor and materials have advanced in cost, the true drilling costs have been markedly decreased since 1952. Having established this fact, the remainder of this Section will be devoted to discussing those technical improvements which are believed to have been responsible for at least a portion of this increased efficiency.

B. Drilling Fluids

1. MUD IMPROVEMENTS

In the drilling of wells there are necessarily numerous factors relating directly to the ability to drill and rate of making hole. These include the mechanical equipment above and below ground, the physical and chemical properties of the formations, the drilling fluid, and the technique by which the mechanical equipment and drilling fluids are handled in order to perform the drilling operation. Improvements in muds over the period 1945-1965 were many and of a varied nature.

At the beginning of 1945 drilling fluids in principal use were of the freshwater-clay type where viscosity and gel strength control were obtained with phosphates or quebracho, lime-treated muds had been in use about two years, saltwater-starch muds had been developed, and oil-base muds were used in special cases for completion in low permeability,

Table V

U. S. ANNUAL RIG ACTIVITY AND RATES PER RIG

YEAR	AVERAGE NUMBER RIGS IN USE: ROTARY MAKING HOLE	AVERAGE NUMBER RIGS IN USE: TOTAL ROTARY AND CABLE	AVERAGE ANNUAL DRILLING RATES PER TOTAL RIG: WELLS	AVERAGE ANNUAL DRILLING RATES PER TOTAL RIG: FOOTAGE
1950	2,154	4,517	9.6	35,263
1951	2,596	4,844	9.2	35,576
1952	2,642	4,857	9.4	38,540
1953	2,614	4,784	10.3	41,578
1954	2,508	4,635	11.6	46,984
1955	2,683	4,867	11.6	46,491
1956	2,619	4,845	12.0	48,279
1957	2,429	4,791	11.2	46,316
1958	1,923	4,114	11.9	47,978
1959	2,074	3,991	12.8	52,179
1960	1,745	3,543	13.2	53,825
1961	1,763	3,464	13.5	55,301
1962	1,637	3,089	14.9	64,279
1963	1,501	2,952	14.8	62,452
1964	1,502	3,066	14.8	61,945
1965	1,384	2,783	14.9	65,191

Rotary Rigs Making Hole from Hughes Tool Company, excludes rigs testing, fishing, logging, cementing.
Total Rotary and Cable Rigs from World Oil, includes both rotary and cable rigs logging, testing, cementing, or fishing in addition to rigs drilling.
Drilling Rates Per Rig calculated by dividing Total Wells and Total Footage (Table VI) by Total Rotary and Cable Rigs in Use.
(Courtesy *The Drilling Contractor,* Jan., Feb. 1966)

easily damaged reservoirs. While some of these muds represented real developments over the previous 16 years, or since the advent of the first technical development of modern muds, they were still lacking in the variation of characteristics and inertness desired.

In 1945 the average well depth was 3,425 feet and less than 500 were drilled as deep as 10,000 feet. While partially solved, more adequate measures were necessary to eliminate the problems of abnormal viscosity and gel strength developed by freshwater muds, the most frequently used type, when salt, gypsum, salt water or high temperatures were encountered. Detrimental effects of these factors were particularly costly when weighted muds of 14-17 ppg were used. Improved techniques and better knowledge of the cause of the problems were also necessary in the handling of abnormal pressures, caving shales, hole washouts and the like.

Lime-treated muds became quite popular just before 1945 for use in drilling deep wells in country where extensive beds of tertiary shales were present and high weights and advanced temperatures were encountered. Quoting from Rogers:

> "Lime mud has many advantages over freshwater mud. One is a high resistance to contamination by saltwater flows. Where the effect of such a flow is to severely gel a freshwater mud, the lime-treated mud will often take up to 5 percent salt without excessive thickening. It is generally conceded that this has resulted in less stuck pipe when high-pressure flows are encountered. Another advantage is the low gel strength, frequently zero initial and zero 10 minute, and low yield value. This results in low swabbing and spudding pressures when moving drill pipe. It also means that a lower mud density may be used, since excessive swabbing pressures do not have to be overcome. Lime muds are also not affected when drilling cement, and are affected to only a small degree when drilling anhydrite and gypsum.
>
> "Because of the filtrate calcium the shales dispersed during drilling do not build viscosity as rapidly as in freshwater muds. As a result, high total solids difficulties are lessened. This is particularly valuable in high-density muds where it is usually necessary to water back the concentration of shale solids dispersed into the mud during drilling. Under these conditions barite additions result. However, the filtrate calcium concentrations of lime-treated muds usually being in the range of 80 to 150 ppm indicate that the inhibition of hydration is not all that it would be if the concentration were in excess of 300 ppm.
>
> "The high alkalinity of lime-treated muds also offers a ready means of preserving starch from fermentation when low filtration rate muds are

Table VI

TOTAL U. S. DRILLING ACTIVITY

YEAR	TOTAL NEW WELLS DRILLED	TOTAL FOOTAGE DRILLED	AVERAGE DEPTH PER WELL
1950	43,279	159,288,000	3,680
1951	44,516	172,331,000	3,871
1952	45,821	187,190,000	4,085
1953	49,279	198,839,000	4,035
1954	53,930	218,986,000	4,061
1955	56,682	226,270,000	3,992
1956	58,160	233,902,000	4,022
1957	53,838	221,900,000	4,122
1958	49,111	197,384,000	4,019
1959	50,893	208,249,000	4,092
1960	46,751	190,703,000	4,079
1961	46,962	192,116,114	4,088
1962	46,179	198,588,641	4,297
1963	43,653	184,357,230	4,223
1964	45,236	189,921,870	4,198
1965	41,423	181,427,015	4,380

Source: *Oil & Gas Journal*
The Drilling Contractor, Jan. Feb. 1966

Table VII

FOOTAGE PRICES RECEIVED BY ROTARY DRILLING CONTRACTORS

YEAR	AVERAGE CONTRACT [a] PRICE/FOOT, $	COST INDEX 1957-59 = 100%	AVG. CONTRACT PRICE PER FOOT IN CONSTANT DOLLARS
1950	5.00	88.8	5.00
1951	5.50	90.0	5.35
1952	5.85	91.2	5.67
1953	5.60	92.4	5.30
1954	5.10	93.6	4.80
1955	4.90	95.2	4.65
1956	4.75	96.8	4.35
1957	4.51	98.4	4.08
1958	4.27	100.0	3.80
1959	4.33	101.5	3.81
1960	4.11	102.8	3.50
1961	4.11	104.1	3.48
1962	3.67	105.4	3.33
1963	3.88	106.8	3.20
1964	3.68	108.1	3.00
1965	4.04	109.5	3.25

a—*An Appraisal of the Petroleum Industry of the United States,* U. S. Department of the Interior, Jan. 1965, Table 36.

required. Heaving shale difficulties have been substantially reduced as a result of low filtration rates and effect on hydration common to lime muds. It is believed that the filtrates have an advantageous effect on producing formations in that hydratable clays present will not swell as much as with freshwater muds."[1]

Lime-treated muds remained popular and advantageous in use until wells began to consistently reach depths with temperatures of 265°F and over. Depending upon the earth temperature gradient, this meant depths of 13,000 to 16,000 feet. At this temperature reactions in the mud between lime and clays resulted in cementitious materials developing solidification requiring a search for muds free of this property. Extensive investigation by oil company and service company research departments ranging from about 1952 to 1959 resulted in a number of modifications of the lime-treated system; but in spite of some improvements in susceptibility of high temperatures, as long as lime treatment remained so did the susceptibility in proportion to the amount of lime and caustic used. The developments included low-lime mud; the M-1 mud;[2] a calcium chloride-lime-calcium lignosulfonate mud; and gypsum or salt surfactant mud.

In late 1945 or early 1946 a different type of development resulted in marked improvements in muds. This was the development of oil emulsion muds, consisting simply of adding 5 to 20 percent oil plus emulsifier to form an oil-in-water emulsion. Usually diesel oil is used, although low-volatility field crudes can be substituted. Such oil emulsion muds were not a new mud system in themselves since the oil addition can be made beneficially to any and all water-base systems: i.e., fresh water, calcium treated, high pH, low pH, surfactant, gypsum, chrome lignosulfonate, or any other. The addition of oil was found to result in many advantages over nonoiled muds, such as:

(1) Increased drilling rate.
(2) Longer bit life—fewer round trips.
(3) Holes drilled more nearly to gauge size.
(4) Less torque on pipe.
(5) Less drag on pipe.
(6) Reduction of balling of bit and drill collars.
(7) Improved hole conditions, sometimes better control of sloughing shales.
(8) Lightened mud weight.

Studies of improvements in drilling from the addition of oil occurred over the interval 1946 to 1957, resulting in oil additions becoming routine practice. Weichert and Van Dyke,[3] Wilson,[4] Perkins,[5] Cunningham and Goins,[6] and others have reported details on this subject.

One of the more important developments occurred in 1955 with the advent of the chrome lignosulfonates (CLS) as dispersants. These followed the extensive use of calcium lignosulfonates, one of the prime components of lime-treated muds. It was long known that gypsum-treated muds, which were operated at only slightly alkaline pH values, were immune to high temperature solidification but their gel strengths were too high for use in deep wells requiring high weights. The use of chrome lignosulfonate dispersants resulted in workable gel strengths and viscosities and even low fluid losses without the addition of special fluid loss agents. With this development, the previously advantageous 265°F lime-treated system rapidly disappeared from the scene. In its place first came the use of gypsum-CLS-CMC systems of 8.5-10.5 pH onshore and gypsum-CLS-CMC seawater muds for offshore. Gypsum was used in each case to prevent hydration of drilled shale particles and otherwise confer inertness to salt, cement, etc., if encountered. Further studies showed that the use of the chrome lignosulfonates alone by virtue of their adsorption on clay particles resulted in the development of inertness to salts and cements and the gypsum could be eliminated. The pH is usually carried at 8.5 to 9.5 and the muds can be weighted with barium sulfate to the usual maximum of about 18 pounds per gallon (ppg). Where the CLS additions are utilized for fluid loss as well, the muds can be successfully used to temperatures of 300-350°F. At and above these temperatures mined or processed lignins are added to help maintain low fluid loss. Currently the CLS dispersant in 8.5-10.5 pH muds is the most popular in use. It is limited only by temperatures of 300-350°F, which permits use for the vast majority of wells drilled. Above 350°F, lignites or other materials can be added to improve mud properties.

For wells which are adaptable to its use, low-solids muds were found about 1953 to speed drilling compared to weighted muds. Low-solids muds are composed principally of water, usually containing salt up to saturation at 10.1 ppg. Heavier brine muds can be made to 11.5 ppg, using singly or in combination sodium chloride, sodium carbonate and calcium chloride. Such muds must be low in suspended solids, not over 2 percent by volume clays or other solids being preferable, with 5 to 7 percent being the absolute upper limit for increased drilling rate.

Inasmuch as the mud must be maintained essentially as clear water, its use is restricted to areas

1. Rogers, W. F., *Composition and Properties of Oil Well Drilling Fluids*, 3rd Ed., Gulf Publishing Company, 1963.
2. Coffer, H. J., and Clark, R. C., "An Inexpensive Mud for Deep Wells," AIME, Petroleum Branch, Dallas, Texas, Oct. 19-21, 1953.
3. Van Dyke, O., and Weichert, J. P., "The Effect of Oil Emulsion Mud on Drilling," 10th Ann. Meeting, AAODC, Tulsa, Okla., Oct. 9-10, 1950.
4. Wilson, D. L., "Emulsion Drilling Fluids," *Proc.* 3rd World Pet. Congress, Sec. II, The Hague, Holland, 1951.
5. Perkins, H. W., *A Report on Oil Emulsion Drilling Fluids*, API, Southwest Dist., Div. of Production, Beaumont, Texas, March 1951.
6. Cunningham, R. A., and Goins, W. C., Jr., "Laboratory Drilling of Gulf Coast Shales," *Drill. & Prod. Prac.*, API, 1967, p. 75.

where soft mud-making shales are not encountered. This restricts them to areas where:

(1) Mud weights of 8.4 to 11.6 ppg are sufficient. Usually for low mud cost the weight must be restricted to a maximum of 10.1 ppg.
(2) Hard shale, dolomite, limestone, sandstone, etc., are drilled and the formations are not mud-making.
(3) High fluid losses, i.e., at or above 15 cc, are sufficient.
(4) Circulating rates are sufficiently high that the low mud viscosity will bring cuttings from the hole.

McGhee [7] in 1956 discussed the use of an oil emulsion, low-solids mud to promote fast drilling. Lummus, et al.,[8] in 1961 discussed the use of polymers as an important element in maintaining low-solids muds. Collings and Griffin [9] in 1960 discussed the use of a saltwater, low-solids mud in West Texas. The mud contained about 2 percent solids by volume and weight ranged from 8.6 to 10 ppg, utilizing salt water to adjust weight upwards. For the wells in question the reduction in drilling time ranged from 30-41 percent, the number of bits decreased from 24-50 percent, and the well mud costs ranged from a 27 percent increase to a 50 percent decrease. While, unfortunately, the use of low solids is severely limited to hard rock drilling, wherever it can be used reduced drilling costs have been found to result. Figure 28 is typical of drilling depth-time curves for low-solids muds and is taken from Collings and Griffin.

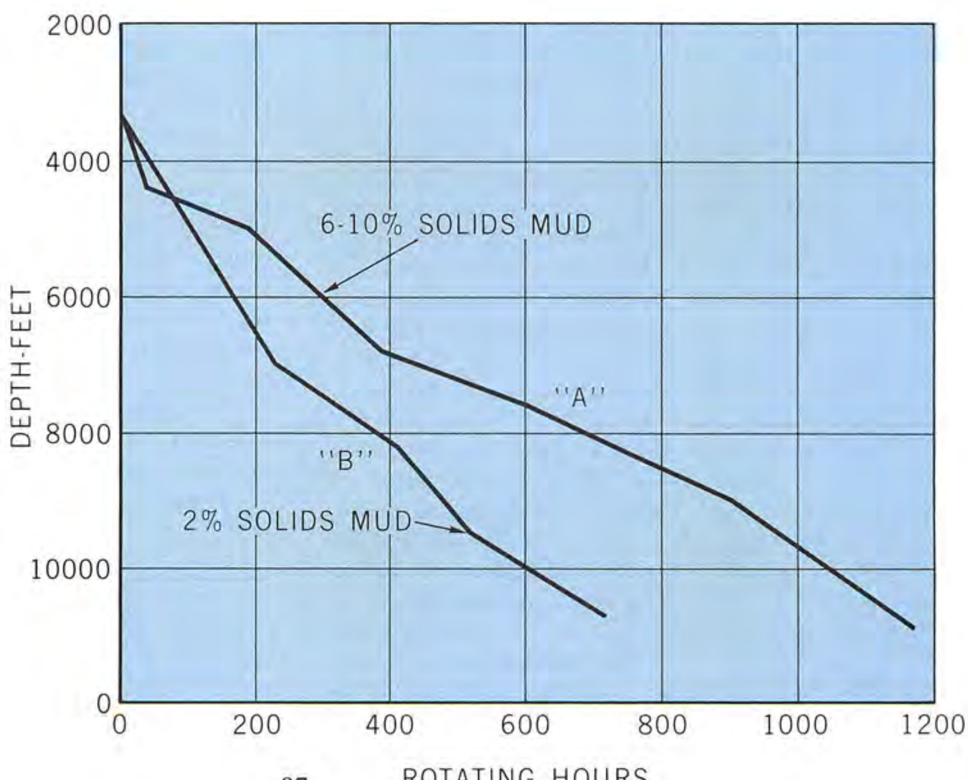
Oil-base muds probably received their start in California about 1939 and were relatively well developed by 1945. Such muds are frequently utilized where deep, high-temperature wells are drilled and long sections of soft-to-medium hard shales are encountered. Technical changes in oil-base muds in the period 1953-1960 largely revolved around the development of invert emulsions; i.e., muds of oil exterior-water interior phases, of sufficient stability to be worthy of use. Such muds are compounded containing from 20-60 percent water and are stable at temperatures from 100-350°F. The invert emulsions generally are compounded differently from the oil-base muds which do not tolerate the high water content of inverts. These muds drill at about the same rate as water-base muds but permit lower cost drilling in some wells having surface formations of soft, easily hydratable, clastic shales.

2. MUD-HANDLING EQUIPMENT

New items of mud-handling equipment were developed in the late 1950's to play an important part in improving properties and reducing costs. These improvements were not related to new chemical systems with special properties but to the ability mechanically to impart improved properties by discarding unwanted cuttings, sand, and other mud contaminants while maintaining costly necessary mud

7. McGhee, E., "New Oil Emulsion Speeds West Texas Drilling," *Oil & Gas Jour.* Aug. 13, 1956.
8. Lummus, J. L., Fox, J. E., Jr., and Anderson, D. B., "New Low Solids Polymer Mud Cuts Drilling Costs for Pan American," *Oil & Gas Jour.*, Dec. 11, 1961.
9. Collings, B. J., and Griffin, R. R., "Clay-Free Salt Water Muds Save Rig Time and Bits," *Oil & Gas Jour.*, April 18, 1960.

FIGURE **28**
Effects of Mud Solids of West Texas Permian Basin Drilling



constituents. The improved mud-handling equipment includes centrifuges and cyclones for discarding sand, unwanted cuttings, and unwanted clay particles which build in mud to give increased viscosity and gel strengths, while recovering costly barium sulfate weighting agents.

Cyclones are principally used to remove sand and sometimes larger silt particles from muds weighing to approximately 12.5 ppg. They can also be used to remove total solids where low-solids muds are desired and only a few volume percent must be removed per circulation. Younger geological formations tend to contain large quantities of sand in the upper portions of the hole and the circulation of sand, especially by high-pressure pumps, results in considerable wear on valves and pistons, together with wear on other parts subject to velocity changes in the stream. Cyclones operate by virtue of centrifugal force imparted to the fluid stream when injected tangentially into the cyclone at its largest diameter. The centrifugal force tends to move the sand to the cone wall and travel downward to the apex or discharge portion where it is discarded. The remainder of the fluid travels upwards where it is discharged back into the fluid stream. Cyclones do not impart large centrifugal forces but these are sufficient in low-viscosity, low-weight fluids to remove sand and larger silt particles. They will also discard some of the barite from weighted muds and the cost of this lost material must be added to the other costs for operating the system. The most popular cyclones are those of 4-inch or 6-inch size ratings and are skid-mounted in unitized groups of up to 12 cones per group. They are usually fed by centrifugal pumps taking suction from the mud circulating system.

Centrifuges were developed for handling high-weight muds required by some wells. Such muds may be weighted to 18 ppg, with weights of 14 to 16 ppg quite common. The incorporation of fine ground shale solids from the drilling action to such already high volume percent solids muds results in undesirable viscosities and gel strengths. These can be reduced to normal by watering the mud and raising the weight back by purchasing more barite, fluid loss agent, etc., or by centrifuging to split the stream into two parts, one essentially the barite of the mud, the other clays, silts and mud fluid. The first is returned to the mud while the second is discarded. Centrifuges used for this purpose are of the horizontal decanting type. They are from 14 to 16 inches in diameter, operate at 1,000-2,000 rpm and are capable of exerting up to 100 times the force of gravity on the mud particles. High-weight muds generally do not contain sand, which would also be removed along with the barite and added back to the mud stream. In utilizing a centrifuge care must be taken that operation does not result in an appreciable portion of the barite weight material being discarded. Centrifuges and cyclones do not compete with each other since cyclones are usuallly used on the upper portion of the hole to remove and discard sand, whereas centrifuges are used in the lower portion to remove and save the weight material. Jeffus and Jones [10] reported in 1958 on the use of a centrifuge to salvage high-weight mud and to maintain mud in South Louisiana. They estimated that a centrifuge reduced the overall mud cost on a single well by 36 percent, and in a field as a whole $150,000 was saved in purchases of new barite and chemicals through the use of a centrifuge.

It must be emphasized that cyclones and centrifuges reduce drilling costs by reducing the cost of rig pump and circulating equipment repairs and by reducing the purchase of new mud materials. This is of value not only in lowering well costs but as a conservation measure in reducing the drain on natural materials.

Gas cutting is frequently a common source of trouble where high-weight, high-viscosity muds drill into gas formations of slightly higher pressure than offset by the mud weight. Degassers in some form or other have always been used but they were improved in the 1945-1965 period to permit mud to return to the well in short handling time at its original weight without the necessity for adding new weight material.

3. MUD IMPROVEMENTS FOR HANDLING ABNORMAL PRESSURES, LOST CIRCULATION AND TROUBLE SHALES

It was shown by Cannon [11] in 1946 that, in general, the formation pressures of wells drilled along the Texas and Louisiana Gulf Coasts were normal, i.e., about 0.465 lbs./sq. in./ft., commonly abbreviated as ppf, down to about 7,000 feet. In many cases this increased below 7,000 feet to a gradient of about 0.90 ppf. Such a well would require a mud weight, without safety factor, from 8.9 to 17.3 ppg. Increases in formation pressure with depth are found the world over and result in many drilling troubles. These consist of stuck pipe from saltwater ingress into the hole where the mud weight is insufficient to restrain the abnormal fluid; stuck pipe or hole fill from the formation—usually shale—being blown into the wellbore from the differential pressures between formation and hole; lost circulation from raising the mud weight to overcome the abnormal pressure; danger of the well getting out of control from gas pressure, etc.

During the 1945-1965 period many studies were made to solve the problem of handling abnormal pressures but the problem largely remains. Studies of pressures required to fracture formations plus

10. Jeffus, D. M., and Jones, V. T., Jr., *Mud Reclamation in Timbalier Bay*, API, Southwest Dist., Div. of Production, Houston, Texas, Feb. 26-28, 1958.
11. Cannon, G. E., "Problems Encountered in Drilling Abnormal Pressure Formations," Meeting, API, Southwest Dist. May 1946.

studies of lost circulation pressure gradients have led to some valuable conclusions. Howard and Scott [12] in 1951 reported the fracturing breakdown pressures of 276 wells and found they could be plotted as a maximum pressure-depth curve and a minimum pressure-depth curve. The gradient of the maximum curve is 1.0 ppf or 19.1 ppg and the minimum curve is 0.83 ppf for the first 2,000 feet and 0.65 to 0.71 ppf for remaining depths to 14,000 feet (0.65 ppf is equivalent to 12.4 ppg). The pressure gradient of 1.0 ppg corresponds to pressures required to lift formations or give horizontal fractures. The gradient of 0.65 ppf corresponds to pressures required for vertical fractures in materials of about 1,000 psi compressive strength. Thus, depending upon the formation compressive strength, breakdown and lost circulation can occur with mud weights of 12.4 ppg or heavier unless earth stresses or shock loads are imposed. These can alter the breakdown pressures either upward or downward.

Goins et al.[13] and Clark [14] measured the added forces imparted to well formations by running pipe into hole fast, spudding the bit, running balled bits, etc. They found that pressure surges of 600 to 1,000 pounds could be set up but showed how these surges, which might be sufficient to rupture formations where high-weight muds were in use, could be reduced. Other methods of prevention of lost circulation include:

(1) Carry lowest mud weight possible.
(2) Carry lowest mud viscosity and gel strength possible.
(3) Keep pipe running-in speeds low; do not spud kelley rapidly with pumps on.
(4) Keep hole clean to prevent restricting the annulus.
(5) Prevent balling of bit and collars.

Where lost circulation does occur there are numerous lost circulation agents on the market. These have been graded [15] so that different materials are known to seal different sized slots. Good practice now calls for first lowering the mud weight and pump pressure, if possible, followed by circulating an agent capable of sealing a 0.10" slot followed, in case of failure to seal, by circulating an agent capable of sealing a 0.20" slot followed, in case of continued failure, with a squeezing agent such as a cement.

If drilling abnormal pressure formations is not complicated by lost circulation, the problem can be handled by gradually raising the mud weight as indicated by necessity through the well "kicking." In all probability, (from a small amount of well data) if the mud can be kept no less than 1.0 ppg less than the formation pressure, the formation will give some trouble but not enough to become serious before the weight can be raised to offset the pressure increase. Efforts to predetermine the increase in formation pressure with depth have largely been unsuccessful except on the basis of experience in field drilling.

Recently it has been found in South Louisiana that measurement of the shale formation density from cuttings or conductivity from logs can be used to determine the necessary mud weight. Unfortunately, this can still only be done about 50 feet behind the bit instead of 50 feet ahead of it as desired. Figure 29 shows density measurements of shale cuttings taken on the rig floor of a South Louisiana well while drilling. During the interval represented by the single sloped portion of the curve the mud weight was kept normal at about 10.2 ppg. When the densities deviated from the projection of this curve it was necessary to raise the mud weight in proportion to the deviation. It was not possible because of lost circulation to raise the mud weight to the required value and gas kicks were obtained until casing was set at 9,707 feet. Below this depth the weight was raised to the values indicated by the shale density and no further serious drilling difficulties were experienced.

Trouble shales take many forms but can roughly be classified as:

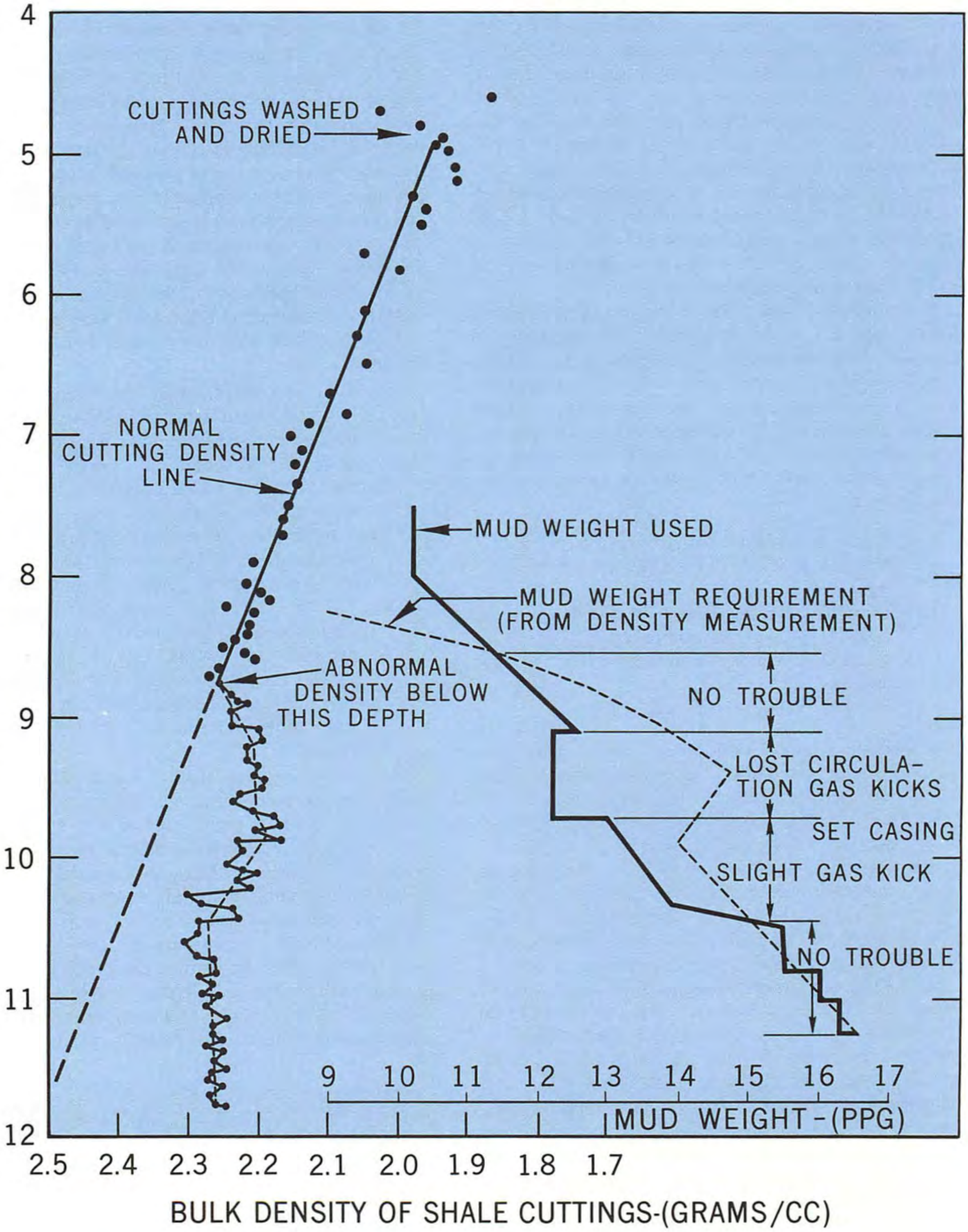
(1) Soft, unconsolidated, low - density, easily hydratable and dispersible shales found when drilling surface hole down to a maximum of about 3,000 feet.
(2) Shale trouble from insufficient annular velocity to bring shale from hole.
(3) Trouble shale from abnormal pressure breaking the shale surface into the hole or ingress of saltwater causing wall cake to slough.
(4) Trouble shale from normal pressure brecciated shales falling into hole where mud pressures are low as with air or gas drilling or water drilling where low-viscosity fluid filters around brecciated particles. This probably represents most badly washed out sections.

So-called "heaving shales" of the 1930's have largely disappeared because of improvements in inertness of drilling muds, higher horsepower mud pumps for higher annular velocities, prevention of bit and collar balling, etc. Shale problems do still occur and, while seemingly trivial, the mere division of shale troubles into basic problems such as the four mentioned above represents progress. Once the cause of the trouble is known the problem is largely solved, such as the case where trouble results from shale settling because of insufficient annular velocity. The solution is increased annular velocity and per-

12. Howard, G. C., and Scott, P. P., Jr., "An Analysis and Control of Lost Circulation," AIME, Petroleum Branch, St. Louis, Mo., Feb. 1951.
13. Goins, W. C., Jr., "Down the Hole Pressure Surges and Their Effect on Loss Circulation," *Drill. & Prod. Prac.*, API, 1951, p. 125.
14. Clark, E. H., Jr., "Bottom Hole Pressure Surges While Running Pipe," *Paper* No. 54—Pet. 22, ASME, 1954.
15. Howard and Scott, *op. cit.*

haps viscosity. Shale problems from abnormal pressures are still the most troublesome because of lost circulation difficulties. This problem is yet to be completely solved. Shale problems from washouts are better understood and their solution exists through the use of oil-type muds and/or inert-water base muds of higher than normal viscosity.

FIGURE **29**
Relation of Cutting Density to Mud Weight



C. Hydraulics

1. HYDRAULICS AND THE JET BIT DRILLING TECHNIQUES

The use of jet bits is one of the most significant developments in rotary drilling. In 1948 Nolley, et al.,[16] showed that with drag-type bits using tungsten carbide nozzles directed ahead of the cutting blades, rate of penetration was increased as either flow rates or jet velocity was increased. Drilling rate was also found to increase with bit weight to a point beyond which the rate decreased, but the maximum effective bit weight was found to be greater when circulating rate and jet velocity were increased.

Drag bits are now practically obsolete and the work described was in relatively soft formations, but the results were soon found to apply to rolling cutter rock bits.[17] In hard formations there is no maximum effective bit weight, but drilling rate is increased with jet velocity and flow rate.

In order to increase jet velocity and flow rate, pumps with greater horsepower capable of operating at increased pressure were needed, and 1,000-1,700 HP pumps have become common on big rigs. To minimize energy losses in the drilling string, internal flush tool joints, larger drill pipe and larger drill collar openings were needed. Methods of jet nozzle-size selection [18] were developed based on providing maximum flow rate and jet velocity within the limitations of available pump HP, maximum practical operating pressure, minimum acceptable annular velocity, maximum pump rate, and increased hydraulic energy loss in the circulating system as flow rate and depth are increased.

Under conditions of limited available power, flow rate can be emphasized at the expense of jet velocity or vice versa, and as a result there is inherent in all methods of maximizing bottom hole hydraulics a necessary choice of emphasis of one in relation to the other. Nolley, et al., concluded that drilling rate is proportional to the product of the two (QV). To maximize this product at the bit and within the hydraulic system limitations is equivalent to maximizing the impact force of the jets. Others have preferred to maximize the hydraulic horsepower [19] of the jet, which is proportional to QV^2. In other instances maximum jet velocity is sought.[20] The bit companies have provided booklets, worksheets and graphs, and technical assistance to aid in designing the various jet bit programs. Because of the limitations mentioned there are drilling intervals, particularly in the lower section of the hole, where each method results in identical flow rates and jet velocities.

Regardless of the different bases of jet program design, the overall effort to increase bottom hole hydraulics has generally resulted in substantial increases in drilling rate. This is most effective in softer formations where the effort allows higher bit weights to be run.

An associated advantage of bigger pumps and less flow-resistant drill strings has been the provision of adequate annular velocities in large hole sizes. This was most necessary for longer surface and protective strings set in deeper wells and eliminated considerable hole trouble.

D. Drilling Techniques

1. EFFECT OF MICROBIT STUDIES ON DRILLING

In the years 1955 to 1958 microbit drilling machines were constructed by several oil and service companies for the purpose of investigating under controlled conditions the variables encountered in normal drilling. The particular purpose was to determine why drilling rates were almost universally slow with depth. The machines permitted variations in the bit weight, rotary speed, type of mud, mud pressure, overburden pressure and pore fluid pressure. In most cases a 2-cone 1¼" diameter bit was used to drill cores of varying formations. These studies provided new information of great fundamental importance, placed the reasons for most slow drilling, and pointed the way to immediate and possible future improvements in drilling rates.

Murray and Cunningham [21] in 1955 presented one of the first microbit studies. In their work the stress on the rock, i.e., confining pressure, was maintained identical by fluid pressure on both the sample exterior and interior, or borehole portion. As the confining pressure increased the drilling rate was found to decrease. Confining pressures from zero to 5,000 psi were used, and at constant bit load and increasing confining pressure the drilling rate was reduced up to 78 percent. Such formations as Spraberry shales, Wyoming Red Beds, Pennsylvania Limestone and Rush Springs Sandstone were drilled. They also showed at any confining pressure that increasing bit weight increased drilling rate to the 1.36 power.

Eckel [22] in 1958 presented additional data from

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16. Nolley, J. P., Cannon, G. E., and Ragland, Douglas, "The Relation of Nozzle Fluid Velocity to Rate of Penetration with Drag-Type Bits," *Drill. & Prod. Prac.*, API, 1948, p. 22.
17. Bielstein, W. J., and Cannon, G. E., "Factors Affecting Rate of Penetration of Rock Bits," *Drill & Prod. Prac.*, API, 1950, p. 61.
18. Nolley, J. P., and Eckel, John R., "An Analysis of Hydraulic Factors Affecting Rate of Penetration of Drag-Type Rotary Bits," *Drill. & Prod. Prac.*, API, 1949, p. 9.
19. Colebrook, Ross W., "How to Get the Most Hydraulic Power at the Bottom of the Drilling String in Rotary Drilling," *Paper* No. 58—Pet. 6, ASME Petroleum Conf., Denver, Colo., Sept. 21-24, 1958.
    Kendall, H. A., and Goins, W. C., Jr., "Design and Operation of Jet-Bit Programs for Maximum Hydraulic Horsepower Impact Force on Jet Velocity," ***Petroleum Trans.***, AIME, 1960, vol. 219, p. 238.
20. Speer, John W., "A Method for Determining Optimum Drilling Conditions," *Drill. & Prod. Prac.*, API, 1958, p. 130.
21. Murray, A. S., and Cunningham, R. A., "Effect of Mud Column Pressure on Drilling Rates," *Trans.* 204, AIME, 1955, p. 197.
22. Eckel, J. R., "Effect of Pressure on Rock Drillability," *Trans.* 213, AIME, 1958, p. 1.

microbit studies. Eckel's machine was capable of applying pore pressure, confining pressure and mud pressure separately. Eckel found generally for a limestone, a shale, and a marble that increasing the differential pressure as a result of higher mud pressure than pore pressure on the sample resulted in a reduction of penetration rate. The shale was more affected than the lime or marble. This work also found both increasing bit weight and rotary speed result in increasing drilling rate, with the effect in each case about linear. It also found air as a drilling fluid to give increased drilling rates as compared to water.

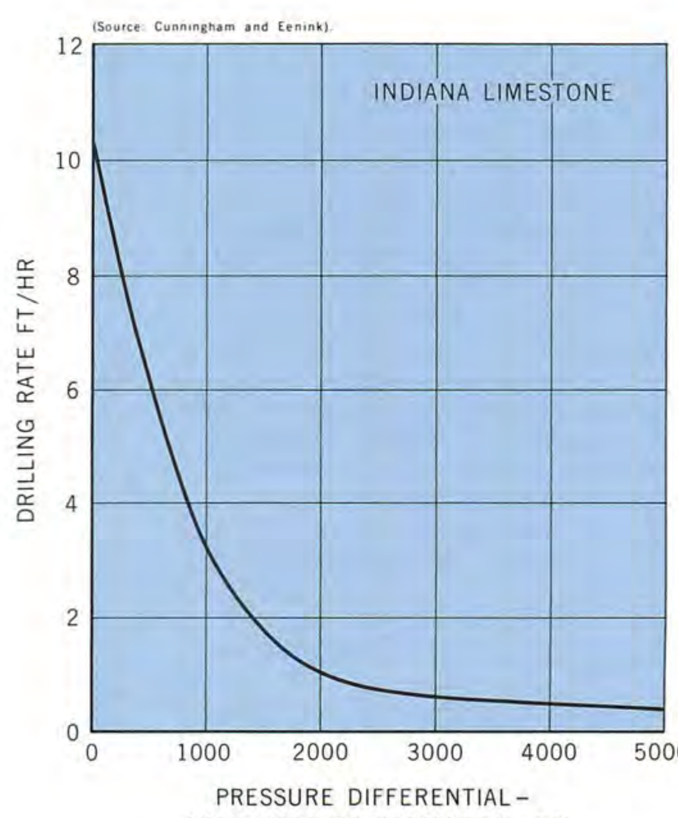
Cunningham and Eenink[23] in 1959 reported further studies on the microbit machine. In this work particular attention was paid to the effect of differential mud and formation pore pressure on drilling sandstone and limestone. The effect of overburden pressure, i.e., formation weight, was also investigated. They found, using mud, that the drilling rate in various formations declined sharply as the pressure differential between the mud column and the formation pore fluid increased. Figure 30 shows this for a limestone sample. Such differential pressure will develop as the result of mud weight increase during drilling. Differential pressure will also increase with depth even if the mud weight and formation pressure gradient remain constant. If the difference in mud pressure and formation pressure remains essentially zero, the formation drills as rapidly at depth as on the surface. They also found that the amount of overburden pressure, i.e., formation weight, did not adversely affect the drilling rate. Another important finding was that failure to remove the drilled chips from the formation hole bottom resulted in a filter cake on the bottom of the hole which seriously impeded drilling rates. The use of bit jet velocities helped to clean the hole bottom and likewise improved the drilling rate.

Garnier and Van Lingen[24] in 1959 also concluded from microbit studies that pressure differentials between mud and formation were largely responsible for drilling rate decline. They found that chip hold-down or failure to remove cuttings, filter cake and mixtures thereof were largely responsible for large pressure differentials between mud and formation fluid and, therefore, were principally responsible for reduced drilling rates with depth.

Maurer[25] in 1963 discussed the "Perfect-Cleaning" theory and developed a theoretical relation for

23. Cunningham, R. A., and Eenink, J. G., "Laboratory Study of the Effect of Overburden, Formation and Mud Column Pressures on Drilling Rate of Permeable Formations," *Trans.* 216, AIME, 1959, p. 9.
24. Garnier, A. J., and Van Lingen, N. H., "Phenomena Affecting Drilling Rates at Depth," *Trans.* 216, AIME, 1959, p. 232.
25. Maurer, W. C., "The 'Perfect-Cleaning' Theory," *Trans.* 225, AIME, 1962.

FIGURE **30.** Effect of Compaction Pressure on Drilling Rates



drilling rate by cone bits where all drilled portions of the rock are moved as rapidly as drilled. This relation differed seriously from drilling rate relations developed by others from microbit and field tests and differed in the direction of faster rates for the perfect cleaning relation. He concluded, therefore, that the difference lay in the inability of the bit and fluid circulation to remove all of the drilled cuttings, resulting in the maintenance of chips plastered against the hole bottom securely held in place by the pressure differential resulting from differences in mud hydrostatic and formation pressures. Figure 31 illustrates the difference in drilling rates resulting from lack of perfect cleaning.

The results of these microbit studies point the cause of the major problem in drilling, i.e., why wells drill slower with depth. The industry has taken steps to obviate the causes. Increased bit weights are used, rotary speeds have been increased, mud weights have been lightened, increased hydraulics and better application of hydraulics are utilized, and further studies are constantly underway to improve bottom hole cleaning to eliminate this portion of slowed rates.

2. AIR-GAS DRILLING

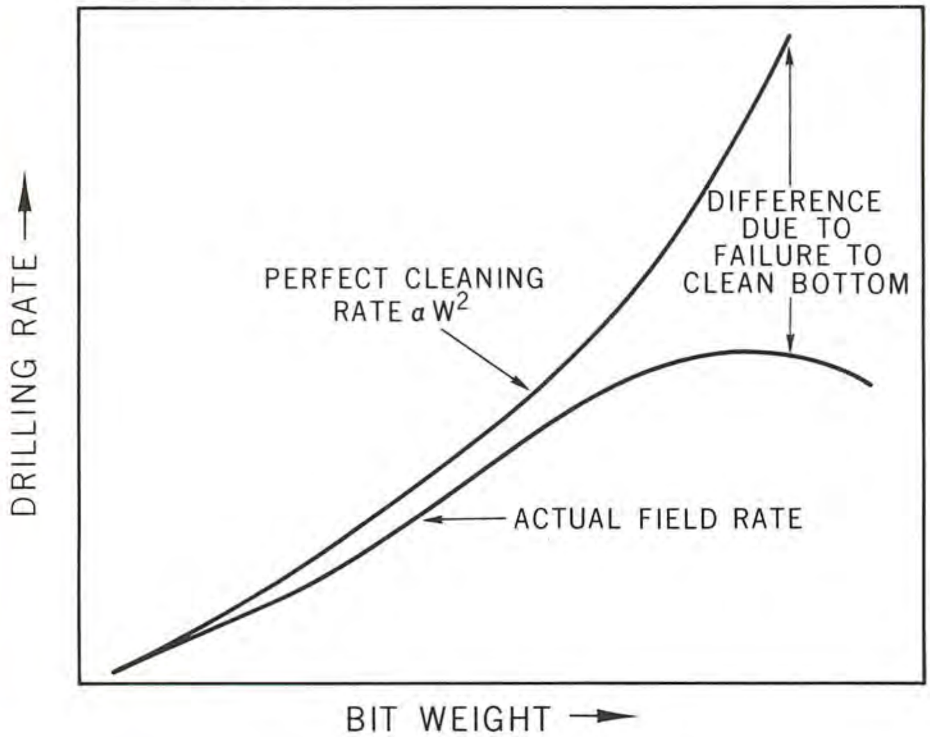
Although air or gas for drilling operations undoubtedly found limited acceptance for special purposes for years, the first large-scale use for rotary drilling probably occurred in Val Verde County, Texas in 1952. Cannon [26] reported results from two Val Verde County wells in 1955. The results indicated the method to be a breakthrough in drilling speed as rates of 360 feet per day were obtained compared to 89 feet per day with mud. Total drilling time on the second well was reduced from 90 to 22 days, a reduction of 68 days. Since 1952 air or gas has been tried in many wells in different parts of the U. S. and the rest of the world. In addition to straight air or gas, blends of one or the other with mud or water have been used to lighten the fluid column to aid drilling, particularly where lost circulation occurred or water entered the hole in too large a quantity for shutoff. The overall result is that air or gas drilling has been a marked success in many cases, but the well bore conditions for this to be so are quite limited and, on an overall basis, fewer wells can be drilled by this method than the oil business would like.

From the practical standpoint, air or gas drilling has been found to be successful where the formations drilled are essentially water free and are non sloughing. These seem to be simple requirements but are

26. Cannon, G. E., and Watson, R. A., "Review of Air and Gas Drilling," AIME, Petroleum Branch, Los Angeles, Calif., 1956.

FIGURE 31 Effect of Failure to Clean Bottom on Drilling Rate

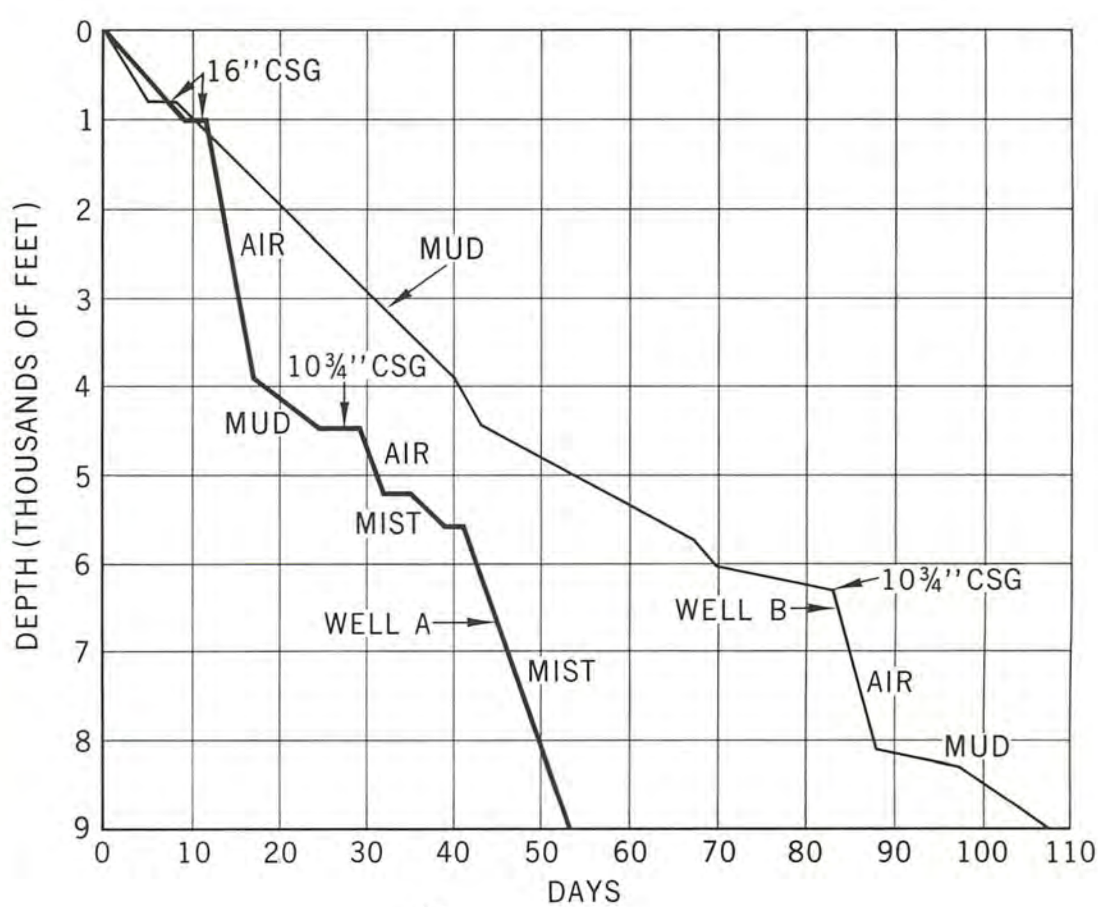
(Source: Maurer, Aime, 1962).



apparently best met when drilling older formations. In drilling with air or gas normal hole sizes and bits are used, but usually the bit weight can be reduced. Some special air operated percussion-rotary tools are available. As long as the formations are sufficiently dry that the cuttings do not ball on the bit, but can be carried out of the hole, drilling can proceed without difficulty. If water is produced to the extent that cuttings ball or become difficult to blow from the hole, then additional fluid may be added to disperse the balling to aid removal from the bottom. If the water increases sufficiently for the gas and water from bottom to "head" or require too much pressure to lift the water in slugs, foaming agents are added to reduce the column pressure. It is difficult to predict beforehand whether a well can be drilled with air or gas unless a well with adequate history has been drilled nearby. Wells where air cannot be used are those requiring high pressures to restrain oil, gas or water intrusion, hole walls cave because of insufficient support, numerous water formations produce water ranging from seepage to large amounts of influx, bits ball, and the formations cannot be dried or fluids plugged off. A difficulty which has been experienced many times is the occurrence of downhole fires or explosions from reaction of air with oil produced by the well. This has resulted in bits and drill collars burned to destruction.

Where the method can be used, drilling costs are usually reduced appreciably. Figure 32 shows the typical difference between mud-drilled and air-drilled holes in the same field. Well A was drilled with air and mist to 9,500 feet TD in 57 days while offset Well B was mud drilled, with the exception of 1,800 feet, to 9,500 feet TD in 112 days. The air-mist drilled well cost $71,000 less to drill. These same differentials in cost are found in the deepest wells which have been air drilled. Wells below 15,000 feet have been air drilled at rates of 300-400 feet per day in place of 25-50 feet per day with mud.

FIGURE **32.** Results of Air and Mud Drilling
Well A—Essentially Air Drilled,
Well B—Essentially Mud Drilled



While not exactly air drilling, the use of air or gas to lighten the fluid column has been successfully used many times when severe lost circulation problems have occurred. In these cases the drilling fluid has been water or very light mud and fractures or vugs are encountered in limestone or other rock. The use of air or gas to lighten the mud has resulted in water being produced from the fractured zones while drilling progressed without lost circulation but with excess water produced from the well.

Drilling with air requires compressors to deliver the necessary quantities of air at the necessary pressures, rotating head equipment to control gas at the wellhead, etc. Angel [27] in 1957 developed a method for calculating necessary quantities of air or gas for difficult hole sizes and depths. The requirements became standardized at an equivalent annular velocity of 3,000 feet/minute. Volumes required range from 1,500 to 4,000 cfm depending upon hole size. Pressures depend principally upon the amount of water to be lifted and vary from 50 to 1,500 psi. Costs for compressed air can run from approximately 15 to 35 cents per 1,000 cu. ft., with compressor and other service costs in the neighborhood of approximately $1,000/day. With rig costs of $1,000-$1,500/day depending upon size, and compressor costs of $1,000 per day, it is obvious that drilling rates need be at least doubled for air to be economical. In many cases a much better ratio than this is obtained.

Where gas is utilized it is procured either from a nearby well or gas line having, in either case, sufficient volume and pressure to fulfill requirements. In such case only the gas sales price and increased drilling rate become important.

3. CONTROL OF THREATENED BLOWOUTS

The principal means of preventing threatened blowouts has always been sufficient hydrostatic pressure, but when used to excess the results are slow drilling rates, lost circulation and wall sticking of pipe. An increasing understanding of the occurrence of abnormal pressures [28] has allowed use of low mud densities to the high-pressure section where casing can be set. Mud density can then be increased as required but without the difficulties described.

Some operators in the abnormal pressure areas deliberately drill until a kick is obtained with low-density muds. Usually this is small and easily controlled. Casing is then set. Most, however, avoid the deliberate kick and attempt to determine the high-pressure top by other means, i.e., correlation with nearby wells or area experience. Of recent date the resistivity,[29] sonic and density logs have been used to determine the depth of high-pressure intervals. This is possible because the high-pressure zones contain shales with abnormally high water content due to retarded loss of water during compaction.

Drilling into the high-pressure zones unexpectedly and with insufficient mud weight has resulted in a great many cases of blowouts, lost time killing kicks and stuck pipe. Considerable effort is now being expended to train crews in systematic killing of threatened blowouts. The practice of closing in a kicking well, reading the drill pipe pressure and adding the hydrostatic pressure of the uncut drill pipe mud column to determine required bottom pressure and mud density has become common. Establishing a constant circulating rate and initial choke pressure equal to the closed-in annular pressure [30] starts the killing operation with the required bottom hole pressure, which remains correct while circulating out if the circulating pressure and rate are not allowed to change. The drill pipe pressure is maintained by changing the choke size as necessary. Corrections in drill pipe pressure must be made as mud density increases, but this does not change the principle of operation. Using this method, or various slight modifications, results in quicker, less dangerous control whenever adequate surface or protective pipe to hold the pressures is set.

The majority of blowouts occur when tripping the pipe, and increased attention to hole filling and use of recording pit level indicators has been helpful in determining that the hole is taking an amount of mud equal to the pipe volume withdrawn. This by industry experience is the most important item in blowout prevention.

4. OPTIMUM WEIGHT—RPM

An increasing awareness of the effect of bit weight on drilling rate led first to the use of high bit weights in hard rock drilling and later to increased weight in the softer, shaly formations. Where 3,000 to 4,000 lbs/inch of bit diameter were formerly common in hard rock drilling, current practice runs as high as 6,000 to 8,000 lbs/inch.

Rotary speed was also recognized as having a pronounced effect on drilling rate, and although limited in hard rock drilling because of detrimental effect on drill collars and pipe, higher speeds were used in softer formations.

Although increased bit weight results in increased drilling rate, the increased weight also results in more rapid tooth wear and bearing wear so that the bit has a tendency to have a shorter life. Increased rotary speed also tends to increase drilling speed, but again bearings and teeth wear out faster. Typical curves showing the general effects of weight and rpm on

27. Angel, R. R., "Volume Requirements for Air or Gas Drilling," *Trans.* 210, AIME, 1957, p. 325.
28. Dickenson, G., "Geological Aspects of Abnormal Reservoir Pressures in the Gulf Coast Region of Louisiana, USA," 3rd World Pet. Congress, Sectional, The Hague, Holland, 1951.
29. Wallace, W. E., "Abnormal Pressures Measured from Conductivity or Resistivity Logs," *The Log Analyst*, Feb.-March 1965, vol. 4, No. 4.
30. O'Brien, T. B., and Goins, W. C., Jr., "The Analysis and Control of Threatened Blowouts," *Drill. & Prod. Prac.*, API, 1960, pp. 41-47.

drilling rate, tooth life and bearing life are shown in Figure 33.

An expression covering the cost per foot of hole is:

$$C = \frac{B + TR + HR}{L}$$

where:
C = Cost of hole per ft, \$
B = Bit cost, \$
T = Trip time, hours
R = Rig cost, \$/hour
H = Time on bottom, hours
L = Feet made by bit

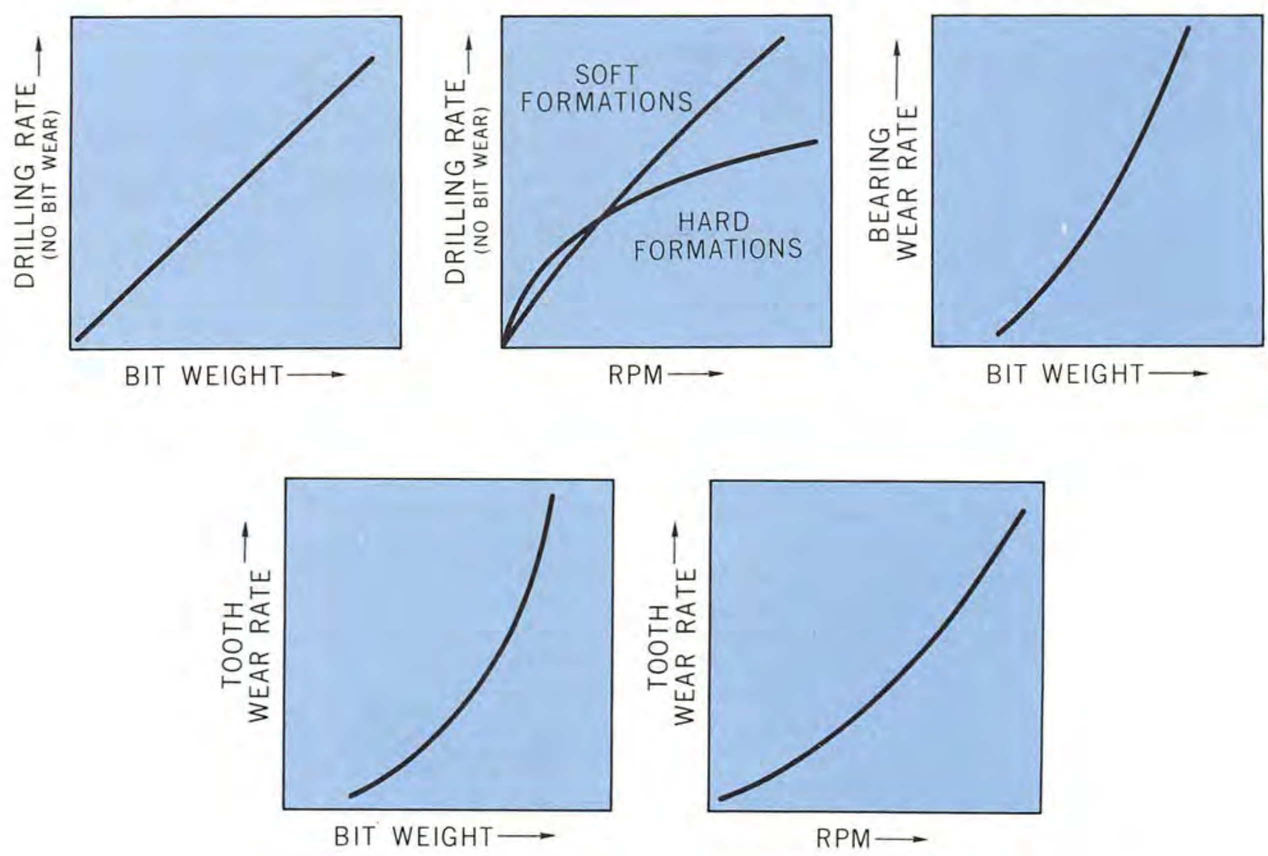
The object in drilling is to obtain the lowest cost per foot of hole drilled and the expression shows that at least five factors enter. Trip time and rig cost are fixed by the hole depth and rig size. The controllable factors then become time on bottom, feet made by the bit and bit cost. These are controlled by bit type, formation strength and abrasiveness, mud properties, weight and rpm.

Efforts have been made[31] to develop relations permitting calculation of minimum cost per foot from a knowledge of all these items and some progress has been made. A necessary adjunct to this technique has been the establishment of a grading system for bit and bearing wear standardized by the API and AAODC. This has made crews and supervisors more conscious of the need to use the bit effectively and has resulted in improved footage. Where wt-rpm studies are made to optimize drilling costs, curve sets are available from which the optimum weight and rpm can be selected after determining from experience or past history the necessary parameters. Computer programs have also been written to permit calculation of weight and rpm based

31. Spear, J. W., "A Method for Determining Optimum Drilling Techniques," *Drill. & Prod. Prac.*, API, 1958, pp. 130-145.
Galle, E. M., and Woods, H. B., "Variable Weight and Rotary Speed for Lowest Drilling Cost," Ann. Meeting, AAODC, New Orleans, Louisiana, 1960.
Galle, E. M., and Woods, "Best Constant Weight and Rotary Speed for Rotary Rock Bits," *Drill. & Prod. Prac.*, API., 1963.

FIGURE **33.** Generalized Relations of Bit Weight and RPM to Drilling Rate and Associated Tooth and Bearing Wear

(Source: Galle and Woods)



on data obtained on the rig while drilling. Such calculation for optimum cost, either by use of curves or computer, are not yet often used but are part of drilling engineering of the future.

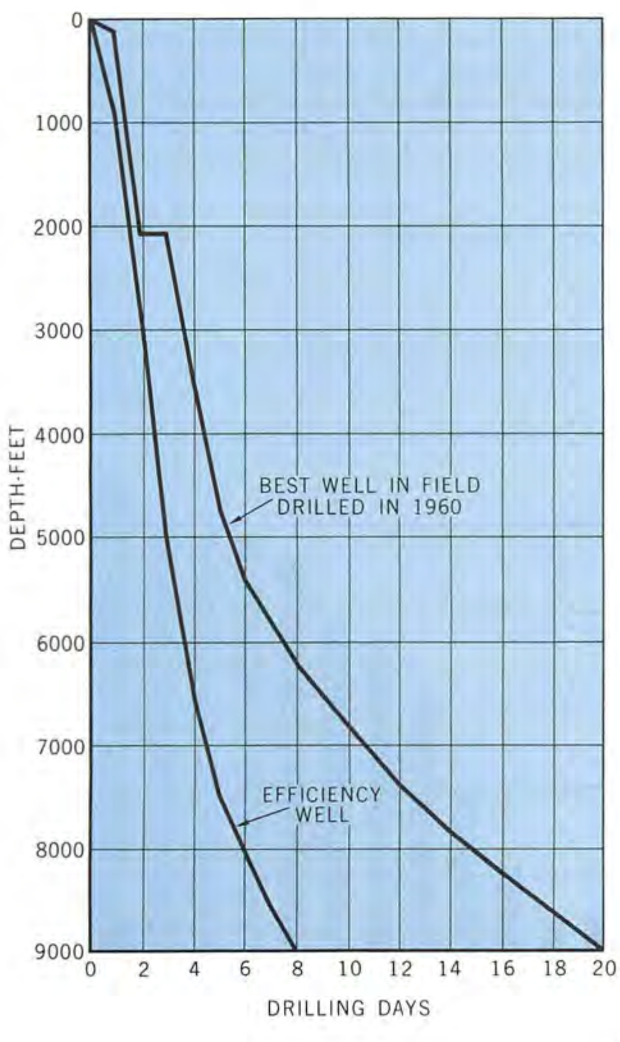
Another use of the cost per foot equation is to determine the effect of rig size on cost per foot using cost and power capabilities of various rig sizes. This has led to better fitting of rigs to well requirements.

5. EFFICIENCY DRILLING

The term "Efficiency Drilling" has been coined to represent an all-out analysis, planning, and supervision of a drilling well covering hole making, equipment requirements, time-consuming nonhole-making operations, and safety items. Efficiency drilling calls for a real desire to reduce well costs, a look at previous drilling time curves and techniques to determine the causes of slow drilling, the application of engineering design, plus some chance taking in terms of eliminating supersafe procedures. Reasons for slow drilling are found in the use of too high mud weights or too much mud solids; changes in casing depth may alter mud properties in the direction of faster drilling; a change in casing design may alter hole sizes for the better; selection of the proper bit plays a most important part; use of proper bit weight and rpm is essential; use of the proper sized pumps to exert the proper horsepower on bottom may be critical. The use of packed holes to prevent doglegs may be required, and fast connections, rapid handling of drill collars, elimination of unnecessary motions, the use of air or gas instead of mud, performing BOP connections properly, reduction of the number of BOP's all contribute toward increased or decreased time on the well.

FIGURE **34**

Efficiency Drilling



Such detailed approach is exemplified by Stone [32] in discussing Gulf Coast drilling. He shows a similar listing of small improvements which resulted in large total changes. Several wells in the area discussed have been drilled to 10,000 feet in less than four days time.[33] One well [34] was drilled to 16,000 feet in 41 days. Figure 34 shows the beneficial results of efficiency drilling in the Laguna Madre area of South Texas. In this case the detailed planning and rig follow-through resulted in the 9,000-foot well in question being drilled in eight days instead of 20 days. The saving resulted in a contract footage cost reduction from the field price of $4.75 per foot to $2.26 per foot. The $24,000 cost reduction on the well, from $72,000 to $48,000, was a 33 percent reduction. This reduction was made in spite of the fact the rig cost increased 9 percent during the period the well was drilled.

SECTION 2—Drilling—Mechanical Developments and Drilling Equipment

H. A. Rankin

A. 1945 to 1965 . . . A Period of Drilling Progress

A casual glance at the drilling rig of today would indicate little outward change from equipment employed by the industry 20 years ago. However, on exposure to the capabilities and accomplishments provided by the modern drilling machine, a second look is prompted to obtain full appreciation of the advances made in design and technology during the period under consideration. In addition to providing means for the present-day operator to drill deeper

32. Stone, V. D., "High Speed Drilling Techniques in South Louisiana," *Drill. & Prod. Prac.*, API, 1961, pp. 49-57.
33. "Gulf Shows Fast Drilling's No Fluke," *Oil & Gas Jour.*, April 24, 1961, vol. 59, No. 17, p. 67.
34. "16,000 Feet in 41 Days," *Oil & Gas Jour.*, Aug. 26, 1963, vol. 61, No. 34, p. 94.

and at increased rates of penetration, the rig of today serves as a laboratory and proving ground for even greater goals in the future.

Early activity during this period witnessed the replacement of steam by internal combustion engines as a source of power to drive the various rig components. This transition was brought about by industry demand for reduction in drilling costs and a rig design adaptable for movement into the expanding geographical areas of exploration and development—on both land and water. As a result, the present-day rig is capable of ready modification for marine service on fixed platforms or floating vessels, can be broken down into packages for air-lift into remote drilling sites, and may be furnished in an integral trailer design for maximum portability on land.

With an ever increasing trend toward deeper drilling during the 20-year period prior to 1965, progress in equipment design and performance was not restricted to the derrick floor. The basic concept of drilling by rotary bit action was retained during the period with increased performance obtained by transmission of increased mechanical and hydraulic horsepower to the bit.

1. A 20-YEAR TREND TO DEEPER DRILLING

Postwar demand for petroleum products sparked a drive for new reserves that has steadily increased over the past two decades. In addition to moving into previously unexplored geological provinces for new accumulations of oil and gas, the exploration effort was also directed at deeper horizons in areas of established production.

A depth record of 16,655 feet established by a Texas Gulf Coast wildcat in 1945 provided momentum needed for even deeper ventures and by 1958 a Delaware Basin exploratory well in West Texas reached a new record depth of 25,340 feet.

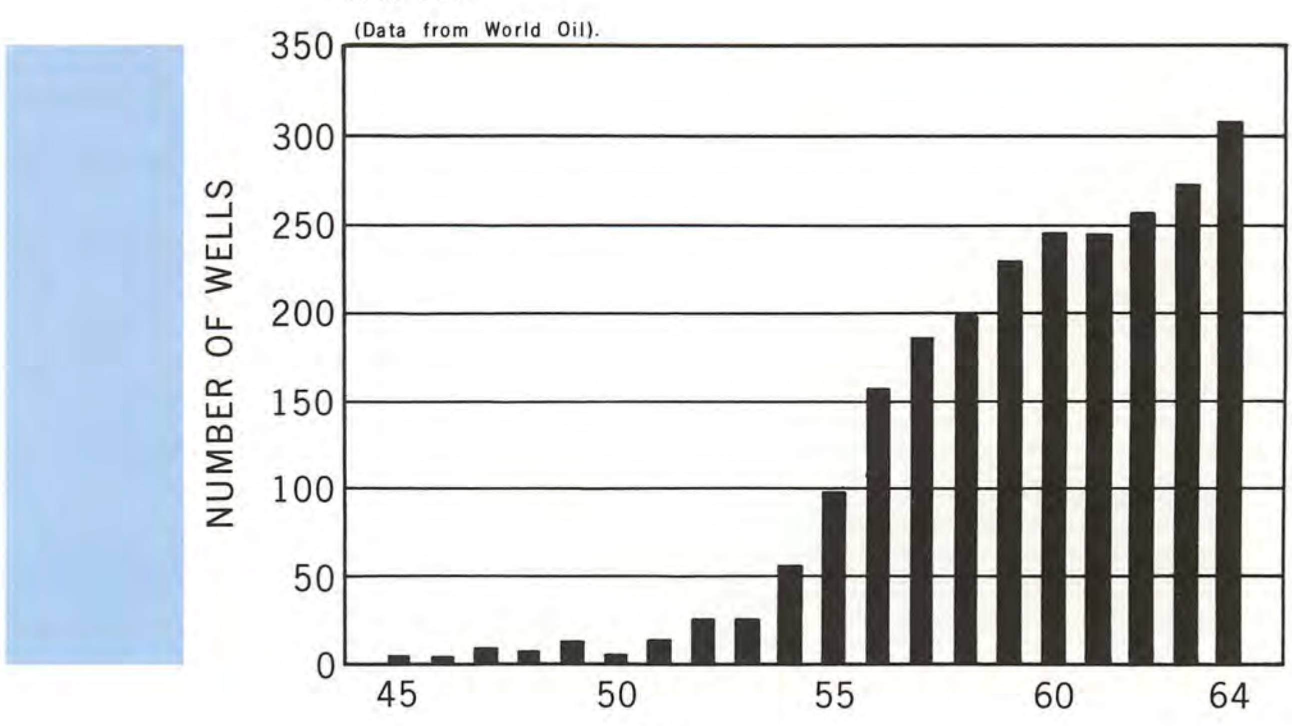
With the record-setting rigs serving as field laboratories, proving the capability of new equipment and technique, industry was quick to make practical application and an upward trend was established in deep completions. Figure 35 reflects the number of wells completed below 15,000 feet during the period 1945 to 1964 inclusive.

B. Advancements in Drilling Rig Design

As of 1945 steam had served the industry faithfully for over a half-century as a source of power for drilling operations. However, demands of the new era following World War II were such that the steam boiler for rig operation gradually gave way to the more efficient and versatile internal combustion engine.

A typical steam rig of 1945, capable of drilling to 12,000 feet, required in excess of 65,000 gallons of water and over a million cubic feet of fuel gas each day. With the spread of exploratory drilling to regions having wide variation in terrain, quality and quantity of water, and natural gas availability, the cumbersome steam rig was unable to compete with more portable equipment powered by diesel or butane fuel.

FIGURE **35.** Number of Wells Completed Below 15,000 Feet, 1945-1964



Only a few steam rigs were manufactured after 1950.

Rigs driven by internal combustion engines had been introduced prior to 1945. However, these were merely an adaptation of automotive type power plants and did not satisfy the requirement for heavy-duty drilling.

War needs were responsible for development of increased horsepower engines of compact design for use in military machines and, as they became available, rapid conversion was made to drilling rig service. Thus the gap was filled until such time as manufacturers could design and build engines specifically intended for oil field service.

Many in the industry consider development of hydraulic couplings and torque converters [35] for drilling rig service as being the key to success of present-day power rigs. Drillers were accustomed to handling heavy rig loads with steam engines having high-torque and low-speed performance characteristics and only through a combination of manual dexterity and inefficient clutch slipping were they able to bring the internal combustion up to proper speed under loaded conditions.

Installation of fluid drives on the output shafts of prime movers resulted in gratifying reduction in shock wave propagation back to the engine with material extension to service life. The torque converter, having torque multiplication capability at low output shaft speed, was a logical solution to the problem of extreme variation in torque and horsepower requirements encountered in accelerating heavy strings of drill pipe or casing from a dead load condition.

By 1950, torque converters were established as an integral part of power transmission and the smooth rig response experienced by steam drillers was again realized. It is significant that in 1952 one manufacturer increased his rig rated power capacity from 900 HP to 1,350 HP providing torque converters were used in place of a direct drive.

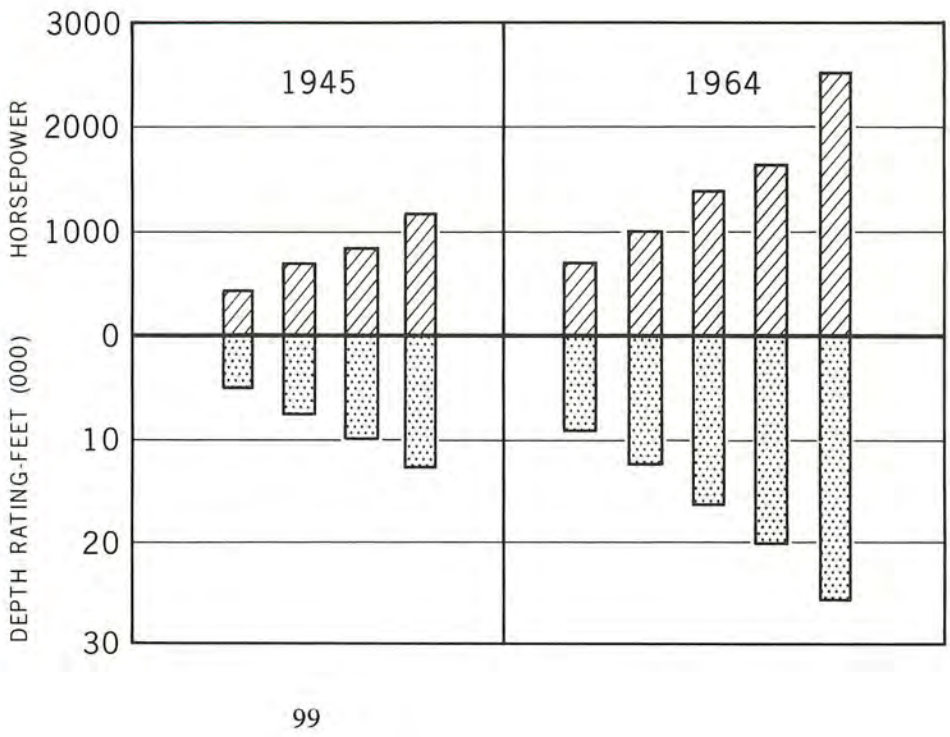
In 1961 a new and improved version of the electro-mechanical rig [36] appeared on the drilling scene. This rig incorporated the diesel engine-generator-electric motor type of configuration into an arrangement engineered for competitive deep drilling. Precision power control was accomplished by use of eddy current couplings as a counterpart to the torque converter adapted to all mechanical rigs. Need for an engine substructure was eliminated by locating the 4-500 horsepower turbo-charged engines and matching generators at ground level. Using plug-in power, this arrangement provided portability and added rig-up efficiency.

Having an efficient means of controlling power from internal combustion engines, manufacturers were encouraged to construct rigs rated at even greater horsepower and depth potential.

A popular heavy-duty rig of 1945 was approved for drilling to 12,500 feet with 1,125 horsepower behind the draw-works. By 1964 the same manufacturer offered three additional rigs capable of drilling below 12,500 feet with the heaviest machine recommended for operations to 25,000 feet using 2,500 horsepower input. Figure 36 illustrates rig selectivity and capability available in 1964 as compared to 1945.

35. Fredhold, Allan B., Jr., "Power Transmission," *Petroleum Engineer Drilling Fundamentals*, 1957.
36. Nelson, James K. B., "New Electrical-Mechanical Rig," *World Oil*, November 1962.

FIGURE **36** Rig Selectivity, Depth Rating and Horsepower, 1945-1964



Although 20,000 feet drilling became a reality during the period 1945-1964, the majority of exploration and development activity remained at much lesser depths. Bureau of Mines statistics [37] show the average completion depth for all wells in the United States to fall in the 4,000-foot to 5,000-foot range with the average level of production being 12 to 13 barrels per day per well.

Economy conscious operators began to investigate avenues to reduce drilling and completion costs in the exploitation of low-profit margin properties. This trend resulted in modification of existing rigs for "slim-hole" service by maximum use of horsepower and unitizing on trailers to reduce transportation and rig-up cost.[38]

Where applicable, drilling programs planned around slim-hole equipment resulted in savings from 25 percent to 35 percent over conventional methods (Table VIII) with oil and gas reserves activated that otherwise could not have been developed economically.

Table VIII

COMPARATIVE WELL COSTS—
SLIM-HOLE VS. CONVENTIONAL

TANGIBLE COSTS	SLIM-HOLE	CONVENTIONAL HOLE
Casing	$ 1,600	$10,400
Tubing	5,000	4,000
Wellhead	1,700	2,200
Other	900	1,200
Total Tangible	$ 9,200	$17,800
INTANGIBLE COSTS		
Contract Drilling	17,000	24,000
Location Expense	2,500	2,500
Cementing	3,000	1,800
Fracturing	3,500	5,800
Logging	1,200	1,200
Trucking	1,300	1,500
Perforating	600	600
Mud	1,000	1,000
Other	1,500	3,300
Total Intangibles	$31,600	$41,700
TOTAL WELL COST	$40,800	$59,500

C. Derricks and Substructures

Momentum gained prior to World War II in the direction of portability and increased load capacity of derricks and substructures was continued during the years following.

Several factors dictated further development of rig support equipment that would facilitate moving from location to location. Truck-mounted units became established as efficient means of handling lighter well service operations, and the drilling derrick was free to move with the rig.

Industry-wide movement toward economy in operations following 1945 resulted in universal acceptance of the drilling mast. This equipment could be transported in minimum packages meeting highway clearance regulations and was easily assembled on location and erected without special crews.

Increased drill pipe and casing loads, inherent in deep drilling operations, generated the need for derricks and substructures having greater capacity. A typical modern drilling mast has a clear working height of 142 feet, can support 1,300,000 pounds and has handling capacity for 23,500 feet of 5" drill pipe. Substructures extending 25 feet above ground level are available to accommodate the increased height of blowout preventers and wellhead equipment required in deep drilling. Table IX compares dimensions and capacities of drilling masts in common use, 1945 and 1964.

Table IX

DIMENSIONS AND CAPACITIES,
DRILLING MASTS, 1945 vs. 1964

	1945	1964
Height—feet	127	142
Nominal capacity—pounds	440,000	1,300,000
Bottom width—feet	17'-0"	25'-0"
Traveling block sheaves	4'-36"	6'-60"
Racking capacity—5" OD, DP	8,650'	23,500'

D. Advancements in the Circulating System

Starting as a secondary rig function in 1945, the circulating system grew in stature to a position of important contribution to drilling efficiency.

In an effort to improve drilling penetration rates, technology suggested the use of higher bit loading along with increased rotary speed.[39] Theories of drilling personnel were well founded, and the early 1950's witnessed a decided trend toward concentrating maximum hydraulic horsepower at the bit to clear the hole of additional cuttings being drilled.

Common drilling practice in 1945-1950 called for mud pumps rated at 500 horsepower input with a circulating pressure of 1,200 psi considered adequate. Operators filled the demand for more horsepower by compounding these pumps into a common discharge; however, in solving one problem, others of transportation and maintenance were created.

37. Data from "Forecast-Review," *World Oil*, February 15, 1965.
38. Walker, R. L., "Trends and Thoughts in Drilling-Rig Design," *Drill. & Prod. Prac.*, API, 1955.
39. Wardroup, W. R., and Cannon, George E., "Some Factors Contributing to Increased Drilling Rates," *Drill. & Prod. Prac.*, API, 1956.

Again equipment manufacturers met industry challenge for more horsepower in one package by producing the modern mud pump capable of 1,600 horsepower input and operating pressures in excess of 4,000 psi.

Drilling operations conducted in areas of high formation pressure require the use of a weighted mud system with fluid density often exceeding 18 pounds per gallon (water = 8.34 ppg). Abnormally high pressures are most often associated with deep drilling, and the mud expense incurred on such projects commonly ran into hundreds of thousands of dollars. High-density muds will tolerate solids content up to approximately 35 percent, and above this level prohibitive viscosity increase occurs. Application of the decanting type centrifuge and cyclone classifiers to mud conditioning provided drillers with a means of controlling solids content of drilling fluid at appreciable savings.

Progress in the use of air and gas as circulating media is reviewed in the technology section of this study. However, it is of interest that success experienced in certain areas of dense formation drilling led operators to replace mud pumps with compressors capable of furnishing up to 4,000 cubic feet of air per minute at pressures ranging from 300 psi to 1,500 psi.

E. Improved Metallurgy for Stronger Drill Pipe

A comparison of drill pipe performance capability over the 20-year period considered reveals marked progress through metallurgical control and heat treatment.

In 1942 the American Petroleum Institute established specifications for Grade E drill pipe having a minimum yield strength of 75,000 psi. Physical properties of the carbon manganese molybdenum steel used in the manufacture of Grade E pipe allowed tensile loading of 331,000 pounds or an equivalent length of 19,910 feet for a 4½" OD, 16.60-pound per foot string.

Use of special alloy composition and rigid process control has allowed steel manufacturers to provide the industry with drill pipe of even greater yield strength than that specified by American Petroleum Institute standards. Refinement of grain structure by quenching, and tempering to desired hardness and ductility produced steel having a minimum yield strength in excess of 135,000 psi for ultradeep drilling.

Table X sets out the trend of advancement in drill pipe performance during the past 20 years.

Use of aluminum drill pipe [40] was initiated on an experimental basis in 1961 and results to date have encouraged operators to obtain full benefit of advantages offered by the lightweight material. As an example, a 10,000-foot string of aluminum drill pipe weighs 83,500 pounds less than comparable steel pipe with considerable savings offered from the standpoint of transportation, rig depth limitation, and fuel cost.

F. Progress in Rock Bit Design and Efficiency

Full-scale experimental and development activity in rock bit design and performance continued throughout the period 1945-1965. Major advancements established in the category of drilling equipment and technique would have been of little consequence without the vast improvement brought about in drill bit efficiency.

In 1946 a group of investigators reported significant gain in rate of penetration by increasing fluid velocity through the nozzles of blade-type bits.[41] It was also found that positioning the water courses so as to direct fluid flow ahead of the bit blades resulted in material benefit by improved cutting removal. The result of this work was the forerunner to development of the jet-type bit in universal use today.

40. Boice, E. G., "Report on Use of Aluminum Drill Pipe," *World Oil*, July 1963.

41. Nolley, Cannon, and Ragland, *op. cit.*

Table X

PROGRESS IN DRILL PIPE PERFORMANCE

(4½" OUTSIDE DIAMETER, 16.60 POUNDS PER FOOT)

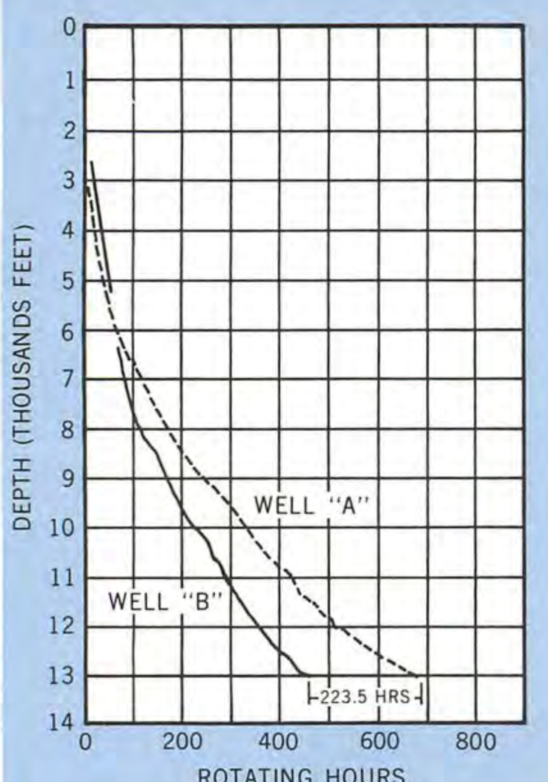
YEAR	MINIMUM YIELD STRENGTH-PSI	INTERNAL YIELD PRESSURE-PSI	LOAD AT MINIMUM YIELD-POUNDS	EQUIVALENT LENGTH-FEET
1945	55,000	7,210	242,000	14,600
1945	75,000	9,830	331,000	19,910
1954	80,000*	10,480	353,000	21,240
1956	105,000*	13,760	463,000	27,880
1962	135,000*	17,690	594,000	35,800

* Non-API

Figure 37 is an example of reduction in drilling time attained by increasing hydraulic horsepower across jet bits.

Deeper drilling operations conducted in certain areas of the Mid-Continent and West Texas were seriously hampered by poor performance of cone-type bits in dense and abrasive formations such as chert and quartzite. Teeth on these conventional hard formation bits were rapidly expended and bit runs of only a few feet were common. In 1952, manufacturers approached this problem using intensive laboratory and field investigation to obtain better knowledge of bit action on extremely hard formations. The product of this research was the "chert bit." Substitution of round tungsten carbide buttons in place of teeth on the conventional bit provided an effective formation crushing action with extended bit endurance.

FIGURE **37.** Reduction of Drilling Time with Jet-Type Bit



	WELL "A" (CONVENTIONAL BIT)	WELL "B" (JET BIT)
PUMP HYDRAULIC HP	370	508
BIT HYDRAULIC HP	62	182
PENETRATION RATE-FT/HR	16.3	24.2
AVG. FOOTAGE PER BIT	294	372

Progress in matrix metallurgy and stone-setting technique has resulted in the diamond drilling bit gaining prominence as a formation cutting tool. Early use of diamond bits was limited due to rapid erosion of the matrix material at required mud circulation rates. As a consequence, the bit was used only on occasions when other types failed to perform.

By 1957 improved matrix composition and heat treating allowed return to normal circulation rates and bit loading. Use of 3 carat and larger stones resulted in better cutting action and extended utility to medium-hard and even soft formation drilling.

In 1963, one operator [42] in South Louisiana concluded that a saving of $112,000 was realized by the use of diamond bits on six wells drilling in the 13,000′ to 15,000′ range. Bit runs averaging 93.2 hours materially reduced costly rig time required for bit changes.

G. Directional Drilling and Deviation Control

Directional drilling is the planned deviation of a wellbore from true vertical to a target located a specific distance, depth, and direction from the surface location.

The need for improved directional drilling equipment was emphasized by accelerated offshore activity subsequent to 1945. Economics of marine exploration and development set the pattern for multi-well drilling from a single platform with boreholes directionally drilled to desired subsurface positions.

While the open hole whipstock provided one means of deflecting the bit, it was difficult to handle in soft Gulf Coast type of sediments and led to development of the oriented jet bit.[43] This tool is essentially the jet-type rock bit with one of the three orifices enlarged. Increased fluid velocity through the larger jet washes downward and in the direction desired for wellbore departure. Use of the jet bit greatly facilitated directional drilling programs and resulted in material reduction in expensive rig rental.

Following the development stage in 1961, the turbodrill [44] has gained in confidence as a directional drilling device. The tool lends positive control in sidetracking operations and is expected to offer promise in the area of drainhole drilling.

Deviation control is accomplished by the use of tools and technique to limit wellbore departure from the vertical.

The industry trend toward drilling with more weight on the bit resulted in substantial increase in

42. Ross, L. C., "Diamond Bits Reduce Costs and Save Trips in South Louisiana," *World Oil,* February 1963.
43. Dwyer, Roy P., "Recent Advances in Directional Drilling," *Drill. & Prod. Prac.,* API, 1959.
44. Leonhardt, Ernst, "Mobil Finds Turbodrill Effective in Directional Drilling," *World Oil,* December 1962.

rate of penetration. However, it also became apparent to drillers that the bit had greater tendency to drift under the high-load condition, and crooked-hole trouble became a serious problem. Stabilization of the drill collar string by use of oversize joints was accomplished only after exhaustive theoretical investigation.[45] The development and use of packed-hole assemblies permitted operators to continue use of high-bit weight with minimum bit deviation.

The various approaches to the packed-hole concept included use of oversized drill collars and square drill collars having diameters only slightly less than hole size.

H. Coring Equipment

Information gained from inspection and analysis of cores provides the geologist and engineer with important data relative to exploration programs and formation evaluation.

Expansion in technology during the past 20 years created the need for larger and better quality cores to be used in the analysis and planning of well completion and secondary recovery projects. Development of the diamond core barrel provided recovery of cores up to 4" diameter and 50 feet long, enabling whole-core testing.

In many cases core recovery from soft, unconsolidated formations was disappointing due to the core washing out of the barrel. Core contamination by drilling fluids also limited or precluded interpretative analysis. Refinement and production of the rubber sleeve core barrel in 1958 made it possible to obtain cores from the most friable sediments with minimum of invasion by drilling fluid.

Appearance of continuous core equipment in 1960 provided geologists the advantage of full vertical scale inspection of formations penetrated by the drill. With 100 percent core recovery from the dual concentric drill pipe, any change in lithology or formation characteristics was immediately apparent.

I. Departure from Conventional Drilling Methods

While maintaining a continuous campaign to improve and refine the capability of today's drilling equipment and methods, the petroleum industry lends substantial support to research and development groups whose objective is to investigate and evaluate entirely new concepts in drilling.

One such tool is the pneumatic percussion drill developed for field application in 1958. This device combined the better features of rotary and cable tool drilling along with the advantage offered by use of air or gas as a circulating media. Installed below the drill collars and immediately above the bit, the percussion drill is operated at 1,800 strokes per minute using 350 psi air pressure. Normal rotary speeds are used and excessive bit loading is not required.

Most successful application of the percussion drill has been made in areas where dense formations occur at shallow depths. A comparison between percussion drilling and conventional air drilling is provided by data gathered on a 1962 development project in San Juan County, Utah. The air-drilled hole required 288 rotating and trip hours to reach a depth of 2,170 feet; whereas, the percussion drill arrived at the same depth in 138 hours, a 52 percent reduction in drilling time.

Another innovation in drilling equipment is the turbocorer which is a downhole hydraulic-actuated motor driving a bit or core barrel. This tool was tested during the year 1964 in connection with Project Mohole. On a 200-hour experimental run the drill successfully penetrated basalt having a compressive strength of 58,000 psi, comparable to that of mild steel.

SECTION 3—Well Completion

K. C. Vaughan

A. Summary

1. SIGNIFICANT DEVELOPMENTS FROM 1945 TO 1965 IN SUGGESTED ORDER OF IMPORTANCE ARE:
   a. Full consideration of reservoir mechanics in well completion design.

During the late 1940's and through the 1960's, many well completion programs were planned utilizing the improved knowledge of reservoir performance and producing requirements. The objective was to provide adequate reservoir drainage and producing capacity with a minimum number of wells and recompletions. This required a high degree of coordination among the various professional groups concerned with these problems. To optimize recovery from a reservoir, experience had proved it was necessary to control the individual well rates and the movement of reservoir fluids. This required an understanding of the trap geometry, reservoir fluid characteristics, interfaces, rock properties, reservoir pressures and temperatures. Studies of the many variables affecting well performance reflect work to improve the completion practices.[46]

   b. Hydraulic fracturing.

In 1949, Pan American Petroleum Corporation introduced hydraulic fracturing of reservoir rock

45. Woods, H. B., and Lubinski, Arthur, "Use of Stabilizers in Controlling Hole Deviation," *Drill. & Prod. Prac.*, API, 1955.
46. Wade, F. R., Union Oil Company of California, Los Angeles, Calif., *Proc.*, Spring Meeting, API, Pacific Coast Dist., Div. of Production, Los Angeles, Calif., May 16, 1947.
Huber, T. A., Allen, T. O., and Abendroth, G. F., Humble Oil and Refining Company, Houston, Texas, *Proc.*, 30th Ann. Meeting, API, November 13, 1950.
Mathews, C. S., Shell Development Company, Houston, Texas, *Jour. Pet. Tech.*, 1961, vol. 13, No. 9, p. 862.

as a means of stimulating production. This technique developed rapidly in the 1950's, with many improvements and is now a fully accepted practice. In excess of 400,000 jobs have been performed since 1949.

c. Shaped charge or jet perforating.

The tools for perforating casing in use at the close of World War II would be entirely inadequate for today's requirements in perforating deep, heavy wall, high-strength casings and cements. Jet perforating introduced after World War II has the capability of perforating any well being drilled today.

d. Bulk cementing.

Bulk cementing was introduced in 1940 but could not be developed until after World War II. It now has 90 percent of the market and with the automatic blending and control devices, a wide range of additives can be accurately proportioned to control physical properties for any well condition. Cements for pressures to 20,000 psi and 700°F temperature are available.

e. Cost reduction through slim-hole, permanent, tubingless and multiple completion techniques.

The necessity of reducing the investment per well brought forth in the early 1950's a completely new concept of well completions. These were termed permanent and/or tubingless completions. Also, slim-hole drilling and multiple completions increased. This development required a completely new line of tubular and completion tools—all designed to perform the same operations as in a conventional completion.

f. Improved ability to complete safely and control wells in high-pressure, high-temperature reservoirs.

In the 1940's, wells encountering abnormal pressures in the Gulf Coast were abandoned by cementing the drill string in place, or the well was lost by blowouts. The industry's ability to complete and control such wells was limited to 5,000 to 6,000 psi surface pressures. It is now feasible to control and complete wells with 14,000 to 16,000 psi surface pressures, and 400°F bottom hole temperatures.[47]

g. Squeeze cementing.

Squeeze cementing tools were first used in 1939, but this technique has been improved and special tools developed since 1945. It is the most important remedial technique available to the industry. The productive life of many wells and reservoirs has been extended by successful remedial squeeze cementing.

B. Well Casing and Tubing, General

1. CASING HANDLING METHODS

One of the significant changes in shipping and handling of tubular goods has been the shift from oil company field stocking points to mill-operated, in-transit and field terminals. This has reduced the number of stocking points, improved the availability of various sizes and grades, and reduced mechanical damage by less movement and extra handling.

With the increased usage of high-strength steels and special joints, improved mill and field procedures for quality control and inspection became necessary. This included improved equipment for full-length normalizing and tempering, the use of hydrotesting, combination mechanical-optical, and full-length magnetic particle inspection.

More care is devoted to proper handling procedures to avoid damage, to inspection prior to running, to cleaning and lubricating connections, and to running-in rates. The use of power equipment (tongs, slips, torque gauges) assures a more uniform and proper make-up of each joint.

2. TYPES OF CASING, SIZES, WEIGHTS, STRENGTH, PHYSICAL, AND CHEMICAL COMPOSITION

The changes in usage of the various sizes, weights and grades are reflected in Tables XI, XII and XIII. From Table XI, 4 and 4½ inch increased from 690,000 feet in 1950 to 37,414,000 feet in 1964. Intermediate sizes 5 and 5½ inch, and 6 and 7⅝ inch decreased 18,706,000 feet and 10,965,000 feet respectively. From Table XII, N-80 increased from 16.8 percent in 1950 to 27.8 percent in 1964. All lower grades (F-25, H-40 and J-55) decreased during this period. From 1950 to 1957, the tons used per 1,000 feet of hole drilled increased from 9.2 to 11.0. With the pressure on cost reduction and shift to smaller size because of slim-hole, multiple and permanent-type completions, the tons per 1,000 feet drilled dropped to 7.4 by 1962. This trend is reflected in Table XI with the changes from 5½ inch to 4½ inch in 1957 and 1958 respectively. Since 1962, a reverse is seen, mainly because of an increase in the number of completions below 10,000 feet (as shown in Table XIII). This shift to deeper drilling also accounts for the increased demand for high-strength steels N-80, P-110 and V-150. Some significant dates are:

1945 N-80 tubing was slightly over 5 percent of U. S. manufacturers' shipments of tubing. This percentage had increased to 31 percent by 1965.[48]

1946 Introduction of warm-worked casing.

1951 Introduction of high-strength (P-110) casing.

1953 High-strength casing and tubing (105,000 psi) shipments by U. S. manufacturers were first reported by American Petroleum Institute. By 1965, P-110 and V-150 cas-

47. "Mighty Cajun Well Sets Record," *Oil & Gas Jour.*, August 8, 1966, p. 41.

48. Report of "American Shipments of Casing, Tubing and Drill Pipe," *API Annual Surveys*, Div. of Production, Dallas, Texas.

INDUSTRY USAGE OIL COUNTRY TUBULAR GOODS

Table XI

BY M FEET: 1950-1964

OIL WELL CASING	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964
8⅝" & Up	17,920	17,840	15,840	19,160	22,880	25,520	26,320	31,760	12,440	21,680	13,480	17,880	17,000	17,280	20,440
6 – 7⅝"	32,965	38,344	34,344	42,551	40,758	38,068	41,241	40,965	15,517	28,689	17,931	19,586	20,345	19,862	22,000
5 – 5½"	43,882	51,882	40,353	53,059	68,706	85,412	79,765	87,059	30,941	54,353	21,647	23,765	27,059	26,118	25,176
4 – 4½"	690	690	517	1,379	2,931	7,069	6,379	7,931	13,966	26,035	22,241	38,448	33,103	33,276	37,414
OIL WELL TUBING															
3½"	1,600	3,400	2,800	4,000	3,200	3,400	3,600	8,000	5,200	4,800	3,200	3,600	3,800	3,800	5,800
2⅞"	34,687	42,188	31,563	46,250	50,625	52,500	48,125	46,875	20,938	34,063	27,812	34,689	36,250	35,625	36,563
2⅜"	80,870	80,870	76,087	84,782	101,738	118,695	125,651	138,260	65,217	130,869	63,478	83,043	78,260	78,695	80,000

PERCENTAGE BREAKDOWN BY WEIGHT OF OIL COUNTRY TUBULAR GOODS

Table XII

INDUSTRY—BY GRADE: 1950-1964

	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964
CASING															
P-110	—	—	—	1.1	1.8	2.3	3.0	3.2	4.5	4.5	4.9	4.3	5.5	5.8	4.7
N-80	16.8	20.0	19.9	24.6	29.1	26.4	29.4	27.8	24.8	28.0	30.7	26.6	27.8	28.7	27.8
J-55	61.2	63.5	65.2	60.6	54.4	57.8	56.6	58.9	58.7	57.9	54.3	59.1	55.8	55.1	57.8
H-40	21.4	16.0	14.6	13.1	13.9	13.1	10.6	9.9	11.9	9.6	10.0	10.0	10.9	10.4	9.7
F-25	.6	.5	.3	.6	.8	.4	—	.2	.1	—	.1	—	—	—	—
Totals—100%															
OIL WELL TUBING															
P-105	—	—	—	—	.5	.7	2.0	1.8	1.0	.9	.9	.8	.9	1.0	2.3
N-80	6.5	7.6	7.3	9.8	11.8	14.8	15.7	16.3	20.7	21.0	26.3	23.2	24.8	25.6	23.8
J-55	76.7	80.4	84.0	83.7	81.8	79.7	79.6	79.6	75.3	76.2	69.6	70.3	70.7	70.0	70.2
H-40	15.8	10.7	7.6	5.4	5.0	4.3	2.1	2.0	2.8	1.7	3.2	2.8	3.4	3.2	3.7
F-25	1.0	1.3	1.1	1.1	.9	.5	.6	.3	.2	.2	—	2.9	.2	.2	—
Totals—100%															
DRILL PIPE															
Hi-Strength	—	—	—	—	2.5	2.6	2.0	2.9	5.6	4.3	4.8	4.8	6.8	7.3	11.3
Grade E	48.4	48.1	51.9	64.2	70.4	73.5	73.7	82.8	80.4	76.0	82.7	86.4	86.8	87.0	82.9
Grade D	51.6	51.9	48.1	35.8	27.1	23.9	24.3	14.3	14.0	19.7	12.5	8.8	6.4	5.7	5.8
Totals—100%															

Pittsburgh Steel Company, Product Development and Market Research Dept., Oct. 1965.

WELL DEPTHS AND NUMBER COMPLETIONS

Table XIII

INDUSTRY: 1950-1964

Depth Range-Feet	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964
0- 2,500	15,757	15,022	14,275	16,358	17,183	18,473	19,281	18,582	17,944	17,593	17,360	17,359	16,123	15,665	14,289
2,501- 5,000	17,300	17,782	18,366	19,408	21,158	22,897	23,382	21,283	18,406	18,811	15,809	15,885	15,577	14,642	16,759
5,001- 7,500	6,800	7,416	8,033	8,410	9,719	8,813	8,696	8,675	7,792	8,394	7,119	7,074	7,013	6,695	7,183
7,501-10,000	2,300	2,913	3,526	3,383	3,843	4,013	4,210	3,773	3,316	3,841	3,407	3,604	4,128	3,710	4,000
10,001-12,500	970	1,162	1,354	1,340	1,516	1,673	1,705	1,814	1,733	2,029	2,137	2,087	2,282	1,985	1,969
12,501-15,000	155	243	331	395	583	695	831	738	663	850	697	678	775	709	737
Over 15,000	5	7	10	31	49	102	150	159	185	228	222	239	281	247	299
Total Completions	43,287	44,545	45,895	49,325	54,051	56,666	58,259	55,024	50,039	51,746	46,751	46,962	46,179	43,653	45,236

INDEX OF WELL DEPTHS DRILLED AND COMPLETIONS

1950=100

0- 2,500	100	95	91	104	109	117	122	118	114	112	110	110	102	99	91
2,501- 5,000	100	103	106	112	122	132	135	123	106	109	91	92	90	85	97
5,001- 7,500	100	109	118	124	143	130	128	128	116	123	5	104	103	99	106
7,501-10,000	100	127	153	147	167	174	183	164	144	167	148	157	179	161	174
10,001-12,500	100	120	140	138	156	172	176	187	179	209	220	215	235	205	203
12,501-15,000	100	157	214	255	376	448	539	476	428	548	450	437	500	457	475
Over 15,000	100	140	200	620	980	2,040	3,000	3,180	3,700	4,560	4,440	4,780	5,620	4,940	5,980
Total Completions	100	103	106	114	125	131	135	127	116	120	108	108	107	101	105

Pittsburgh Steel Company, Product Development and Market Research Dept., Oct. 1965.

ing totaled 6 percent of U. S. manufacturers' tonnage and P-105 and higher tubing was 0.615 percent of the total tubing tonnage.[49]

1956 Introduction of V-150 casing.

1958 4½ inch casing shipments exceeded 5 percent of U. S. manufacturers' tonnage. By 1965, this product totaled 15 percent of casing shipments.[50]

1961 API began reporting "macaroni" tubing shipments by American manufacturers.

1962 C-75 casing and tubing for hydrogen sulfide service.

3. TYPES OF JOINTS, ETC.

The abnormal pressures and temperatures encountered in deep wells in the Gulf Coast created a demand for an improved tubing joint. In 1942, Hydril Company introduced the PH-6 joint for 15,000 psi service.[51] In the past 12 years over a million feet of this tubing has been delivered to the industry. Changing from the API EUE 8 RD thread joint to an integral joint accomplished several improvements: (1) eliminated the coupling; (2) reduced the number of threads; and (3) provided a high-torque, leak-proof, internally smooth connection and small outside diameter joints for clearance for multiple completions. Some significant dates are:

1942 Introduction of Hydril PH-6 integral joint.

1952 Introduction of buttress-thread casing.

1956 Introduction of Hardy-Griffen tubing joint.

1960 Introduction of buttress-thread tubing.
Introduction of API 10 Rd integral thread.

1963 Introduction of Pittsburgh 8-Acme thread and ARMCO seal-lock thread.

4. DESIGN OF CASING STRINGS AND INSTALLATIONS

The trend toward deeper completions and the constant pressure on cost control has made the design of complex multiple weight and grade strings a more difficult and important part of the well design. Since casing used for this type well is a high-strength, special-joint, premium-priced grade, the savings by proper design are important. Computer routines are available for these complex design problems.

5. CASING EQUIPMENT

Continuous improvements have been made in guide shoes and differential pressure float collars, multiple staging collars, casing heads and hanging equipment, liner hangers, tie back tools, joint lubricants and sealing compounds. Flexible metal casing patches are now available for casing repair.

6. WELL TUBING, GENERAL

Table XII also reflects the increased usage of N-80 and P-105 tubing strings. To be able to safely complete and produce high-pressure wells required the development of the N-80 heavy wall and P-110 tubing, and the several special high-strength, tight-seal tubing joints. All other needed equipment (valves, fittings, end connections and xmas trees) was improved to meet these requirements. The Grayloc connection was introduced in 1954.

Table XIV is an estimate from several Gulf Coast operators showing reserves added since 1945 for wells with surface pressures 6,000 psi or greater. These wells could not have been produced with 1945's equipment.

The introduction of permanent-type completion techniques, tubingless completions and multiple completions created a demand for small tubing and casing strings. This required the design and development of a completely new line of tubing, tools and service equipment: (1) small tubing strings with special couplings required to provide clearance when run in casing for multiple completions; (2) through-tubing wireline tools for perforating, cementing and treating; and (3) special wireline trucks and pumping units to work on these wells. Table XV shows the number of wells completed in this manner for a six-year period, and the estimated reserves added had the savings been applied to exploratory drilling.

7. PACKERS AND ASSOCIATED EQUIPMENT

Design and development of packers, tubing anchors, squeeze tools, testing tools, and others for these many special and varied applications, kept pace with the rest of the industry. Packers for isolating zones for multiple completions are available with crossover features for inexpensive remedial plugbacks. Hookwall packers, designed for through tubing work, permit multiple operations (perforating, testing, treating and squeezing with set and reset features) with only one trip of the tubing. Special packing elements are available for high-temperature service, including thermal applications to 1,200°F.

C. Cementing and Cementing Methods and Equipment

The first recorded use of cement to shut off water was in the Lompoc Field in California in 1903. Frank F. Hill, with Union Oil Company of California, mixed 50 sacks of neat portland cement and dumped it into the well with a bailer. Casing was then set into the cement to bottom. After 28 days the cement was drilled out, and the well drilled on into the oil sand without further trouble from water. The purpose of cementing casing is to isolate zones and prevent fluid migration. It also supports the hole and casing, protects the casing from corrosive fluids, and reduces the dangers of blowouts from behind casing.

49. *Ibid.*
50. *Ibid.*
51. Daniels, E. M., Hydril Co., Los Angeles, Calif. Letter to A. Dawson, Union Oil Co. of Calif., Los Angeles, Calif., August 8, 1966.

Table XIV

RESERVES FROM HIGH-PRESSURE COMPLETIONS*

(RESERVOIRS W/INITIAL SITP IN EXCESS OF 6000#)

TIME PERIOD	GAS (MMCF)	CONDENSATE (M BBLS)	OIL (M BBLS)
1/1/1946 thru 12/31/1950	268,000	4,600	9,400
1/1/1951 thru 12/31/1955	4,430,000	142,000	3,110
1/1/1956 thru 12/31/1960	7,050,000	156,000	2,880
1/1/1961 thru 12/31/1965	14,100,000	132,000	26,200
1/1/1946 thru 12/31/1965	25,848,000	434,600	41,590

* Estimates shown are for total industry, based on data received from 11 major companies.

Table XV

NUMBER MULTIPLE COMPLETIONS[a]

INDUSTRY: 1960-1965

	OFFSHORE				ONSHORE						
	DUAL	TRIPLE	QUAD-RUPLE	QUIN-TUPLE	DUAL	TRIPLE	QUAD-RUPLE	QUIN-TUPLE	SEX-TUPLE	SEP-TUPLE	OC-TUPLE
1960	84	35	5	—	1,375	110	5	—	1	—	—
1961	194	121	7	—	2,826	500	30	3	4	1	—
1962	197	48	2	2	2,241	292	39	3	2	—	1
1963	263	13	—	—	1,926	301	57	3	—	—	—
1964	254	6	—	—	1,583	190	—	—	—	—	—
1965	261	3	—	—	1,517	155	24	1	—	—	—
Last 5 Years	1,169	191	9	2	10,093	1,438	150	10	6	1	1

Years 1950 to 1960 not available

MULTIPLE COMPLETIONS WITH TWO OR MORE STRINGS OF TUBING AND

TUBINGLESS COMPLETIONS WITH TWO OR MORE CASING STRINGS IN ONE WELLBORE

Estimates of savings on above wells by use of multiple completions:

Years 1961 Through 1965:	
Offshore	$ 745,500,000
Onshore	1,297,200,000
Total for United States	$2,042,700,000
For above dollar savings, equivalent barrels of oil reserves which may have been discovered if these savings were spent on exploration operations is estimated to be ($ × 0.695)[b]	1,420,000,000 Bbls.
Years 1956 through 1960:	
Offshore (assume duals ⅓ of above period and triples ½)	$ 274,000,000
Onshore (assume duals ⅔ of above period and triples ¼)	658,000,000
Total for United States	$ 932,000,000
This savings converted to equivalent barrels of oil reserves ($ × 0.88)[b]	819,000,000 Bbls.
Total dollars for 10-year period 1956 through 1965	$2,974,700,000
Total equivalent reserves for 10-year period 1956 through 1965	2,239,000,000 Bbls.

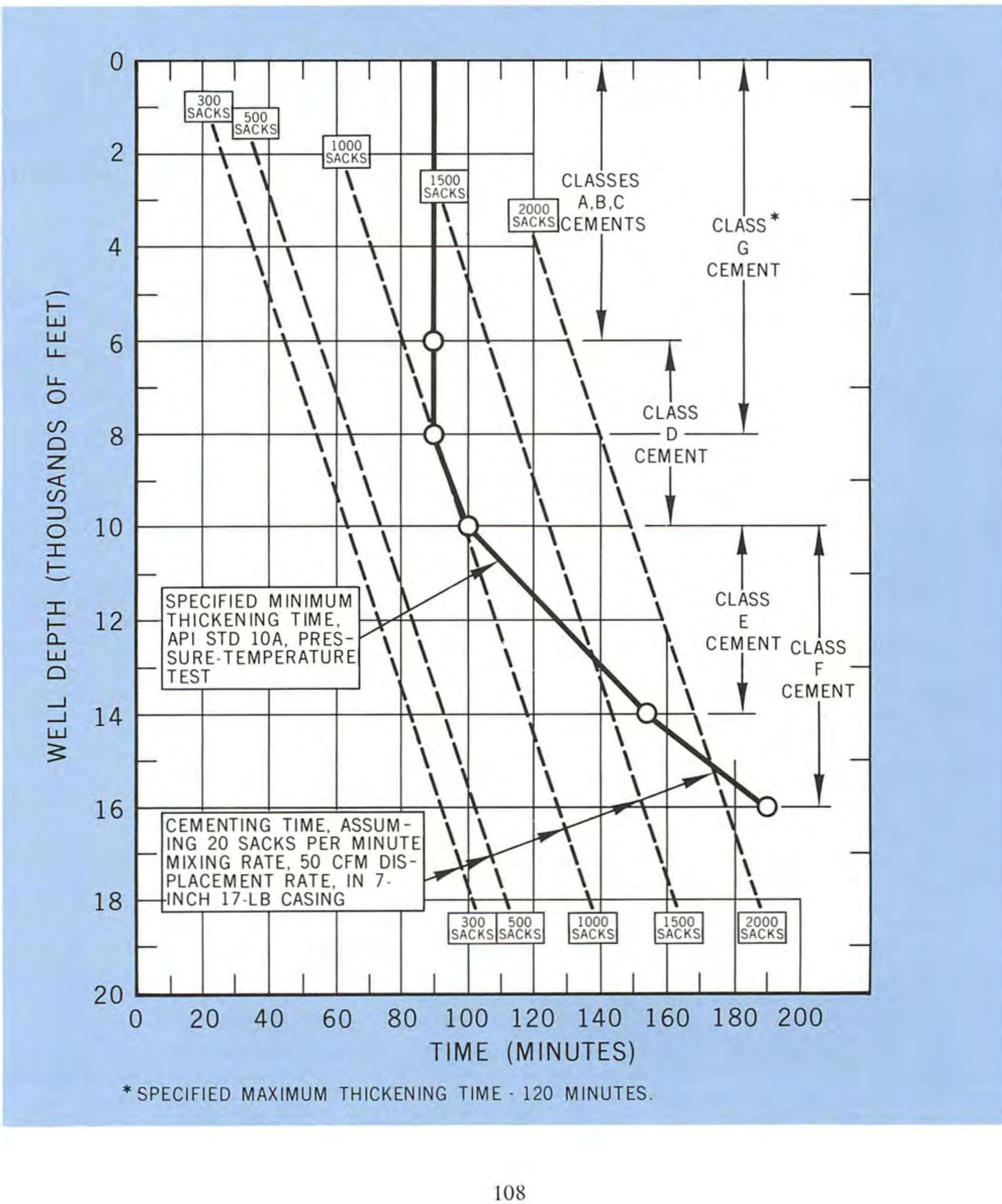
a—"Yearly Forecast-Reviews," *Oil & Gas Jour.*
b—*World Oil*, June 1964, p. 164.

1. OIL WELL CEMENTS, PHYSICAL AND CHEMICAL PROPERTIES, SPECIFICATIONS, TESTS, ETC.

The API set up a committee in 1937 to establish testing codes, but the first API code (API Code 32) for testing cements used in oil wells was not approved until 1947. The first edition of API specifications for oil well cements was dated April 1953, and 11 subsequent editions have been published. The API STD 10-A Twelfth Edition, March 1966, provides for seven classifications, and Figure 38 shows the relations of these classifications to well depth versus cementing time. Table XVI is the chemical requirements, and Table XVII the physical requirements of

FIGURE **38**

Well Depth and Cementing Time Relationships



* SPECIFIED MAXIMUM THICKENING TIME - 120 MINUTES.

oil well cements from the above API standard. Establishing these standards, with the ability to measure accurately and control the chemical and physical properties of a wide variety of cements and additives and to predict their performance under well conditions, is a major contribution of this period.

2. METHODS OF HANDLING AND PREPARATION

Until 1940, cement was packaged in 94-pound waterproof bags and transported and handled manually. Bulk handling equipment was introduced in 1940, but did not grow until the close of World War II. By 1957, bulk cement accounted for 75 percent of the

Table XVI

API STD 10A: OIL WELL CEMENTS AND CEMENT ADDITIVES

CHEMICAL REQUIREMENTS

1	2	3	4	5	6
	CEMENT CLASS				
	A	B	C	D,E,F	G
ORDINARY TYPE (O)					
Magnesium oxide (MgO), max, percent	5.00	....	5.00	....	....
Sulfur trioxide (SO_3), max, percent [a]	3.00	....	4.00	....	....
Loss on ignition, max, percent	3.00	....	3.00	....	....
Insoluble residue, max, percent	0.75	....	0.75	....	....
Tricalcium aluminate ($3CaO{\cdot}Al_2O_3$), max, percent [b]	....	....	15.00	....	....
MODERATE SULFATE-RESISTANT TYPE (MSR)					
Magnesium oxide (MgO), max, percent	....	5.00	5.00	5.00	5.00
Sulfur trioxide (SO_3), max, percent	....	2.50	3.00	2.50	2.50
Loss on ignition, max, percent	....	3.00	3.00	3.00	3.00
Insoluble residue, max, percent	....	0.75	0.75	0.75	0.75
Tricalcium silicate ($3CaO{\cdot}SiO_2$), max, percent [c]	....	....	....	....	58.00
Tricalcium silicate ($3CaO{\cdot}SiO_2$), min, percent [c]	....	....	....	....	48.00
Tricalcium aluminate ($3CaO{\cdot}Al_2O_3$), max percent [b]	....	8.00	8.00	8.00	8.00
Total alkali content expressed as sodium oxide (Na_2O) equivalent, max, percent [d]	....	....	....	....	0.60
HIGH SULFATE-RESISTANT TYPE (HSR)					
Magnesium oxide (MgO), max, percent	....	5.00	5.00	5.00	5.00
Sulfur trioxide (SO_3), max, percent	....	2.50	3.00	2.50	2.50
Loss on ignition, max, percent	....	3.00	3.00	3.00	3.00
Insoluble residue, max, percent	....	0.75	0.75	0.75	0.75
Tricalcium silicate ($3CaO{\cdot}SiO_2$), max, percent [c]	....	....	....	....	58.00
Tricalcium silicate ($3CaO{\cdot}SiO_2$), min, percent [c]	....	....	....	....	48.00
Tricalcium aluminate ($3CaO{\cdot}Al_2O_3$), max, percent [b]	....	3.00	3.00	3.00	3.00
Tetracalcium aluminoferrite ($4CaO{\cdot}Al_2O_3{\cdot}Fe_2O_3$3) plus twice the tricalcium aluminate ($3CaO{\cdot}Al_2O_3$), max, percent [b]	....	24.00	24.00	24.00	24.00
Total alkali content expressed as sodium oxide (Na_2O) equivalent, max, percent [d]	....	....	....	....	0.60

a - When the tricalcium aluminate content (expressed as C_3A) of the Class A cement is 8 percent or less, the maximum SO_3 content shall be 2.50 percent.

b - When the ratio of the percentages of Al_2O_3 to Fe_2O_3 is 0.64 or less, the C_3A content is zero. When this ratio is greater than 0.64, the C_3A content shall be calculated by the formula:

$$C_3A = (2.65 \times \text{percent } Al_2O_3) - (1.69 \times \text{percent } Fe_2O_3)$$

When this ratio is 0.64 or greater, the tetracalcium aluminoferrite content (expressed as C_4AF) shall be calculated by the formula:

$$C_4AF = 3.04 \times \text{percent } Fe_2O_3$$

When this ratio is less than 0.64, an iron-alumina-calcium solid solution [expressed as $ss(C_4AF + C_2F)$] is formed, the content of which shall be calculated by the following formula:

$$ss(C_4AF + C_2F) = (2.1 \times \text{percent } Al_2O_3) + (1.7 \times \text{percent } Fe_2O_3)$$

The content so determined shall conform to the maximum limit specified in Table 2.1 for $C_4AF + 2C_3A$.

c - The tricalcium silicate content (expressed as C_3S) shall be calculated by the formula:

$$C_3S = (4.07 \times \text{percent CaO}) - (7.60 \times \text{percent } SiO_2) - (6.72 \times \text{percent } Al_2O_3) - (1.43 \times \text{percent } Fe_2O_3) - (2.85 \times \text{percent } SO_3)$$

d - The sodium oxide equivalent (expressed as Na_2O equivalent) shall be calculated by the formula:

$$Na_2O \text{ equivalent} = (0.658 \times \text{percent } K_2O) + \text{percent } Na_2O$$

API STD 10A: OIL WELL CEMENTS AND CEMENT ADDITIVES

PHYSICAL REQUIREMENTS

1	2	3	4	5	6	7	8	9	10	11
				CEMENT CLASS						
				A	B	C	D	E	F	G
Soundness (autoclave expansion), maximum, percent				0.80	0.80	0.80	0.80	0.80	0.80	0.80
Fineness [a] (specific surface), minimum, sq cm per g				1500	1600	2200	....	....	....	....
Free Water Content, maximum, ml				....	....	....	....	....	....	3.5

	Schedule Number, (Table 7.1 RP 10B)	Curing Temp, deg F	Curing Pressure, psi	Compressive Strength, minimum, psi						
	..	100	Atmos.	250	200	300	....	....	....	....
Compressive Strength Test (8-hour curing time)	1S	95	800	....	....	....	....	....	....	300
	8S	140	3000	....	....	....	....	....	....	1500
	6S	230	3000	....	....	....	500	....	....	....
	8S	290	3000	....	....	....	....	500	....	....
	9S	320	3000	....	....	....	....	....	500	....

	Schedule Number, (Table 7.1 RP 10B)	Curing Temp, deg F	Curing Pressure, psi	Compressive Strength, minimum, psi						
	..	100	Atmos.	1800	1500	2000	....	....	....	....
Compressive Strength Test (24-hour curing time)	4S	170	3000	....	....	....	1000	1000	....	....
	6S	230	3000	....	....	....	2000	....	1000	....
	8S	290	3000	....	....	....	....	2000	....	....
	9S	320	3000	....	....	....	....	....	1000	....

	Well-Simulation Test Schedule Number (Table 9.1 RP 10B)	Simulated Well Depth, ft.	Maximum Consistency 15-30 minute Stirring Period, poises	Thickening Time, minimum, minutes [b]						
Pressure-Temperature Thickening Time Test	1	1,000	30	90	90	90	....	....	....	....
	4	6,000	30	90	90	90	90	....	....	....
	5	8,000	30	....	....	....	....	....	....	90 [c]
	6	10,000	30	....	....	....	100	100	100	....
	8	14,000	30	....	....	....	....	154	....	....
	9	16,000	30	....	....	....	....	....	190	....

a - Determined by Wagner turbidimeter apparatus described in ASTM C 115: *Fineness of Portland Cement by the Turbidimeter.*
b - Thickening-time requirements are based on 75 percentile values of the total cementing times observed in the casing survey plus a 25 percent safety factor.
c - Maximum thickening-time requirement for Schedule 5 is 120 minutes.

cement used and is now about 90 percent. Table XVIII shows the estimated industry usage of bulk cements and pozzolans, an additive, introduced in 1952. The use of bulk handling equipment has reduced cement loss 15 to 20 percent. It also provides the means of tailor making, under plant controlled conditions for later use in the field, any combination of cement and additives for specific applications.

3. CEMENT ADDITIVES

Over 30 additives are now available to blend with portland cement for control of specific physical properties. Figure 39 illustrates some in common usage and the properties they control. One important property to control is the thickening time. By controlling thickening time, cement can be properly placed without hazard of premature setting or the necessity of long "waiting on cement" periods. It is interesting that "waiting on cement" time has been reduced from the initial 28 days to four to eight hours. With the expensive rigs in use today, this is an important cost control item. Control of density is another major breakthrough. With a low-density slurry, it is possible to increase height of the cement column without the use of stage collars or danger of lost circulation. In many cases, use of low-density slurries makes it possible to obtain full string, casing shoe to surface, turbulent flow cement jobs.

4. METHODS OF CEMENTING FORMATIONS UNDER PRESSURE

Squeeze cementing, or the method of placing cement under pressure in a specific interval in the well, was first tried through casing in Conroe, Texas, in 1939. The first squeeze tool was introduced in 1939. This technique and the tools used have become highly sophisticated during the past 20 years, and is now a very valuable remedial technique and one of the most widely used by the industry. It is used to repair primary jobs, reduce water or gas entry, isolate potential zones of production, and repair casing and lost circulation zones. Squeeze cementing has added to the productive life of many reservoirs and wells.

5. METHODS OF CEMENTING, GENERAL

The method of primary or squeeze cementing has changed very little during the past 20 years; however, the materials and equipment have shown substantial improvement.

Two requirements are necessary for a successful primary job: (1) a uniform distribution of cement around the casing, i.e., the casing centered in the hole with proper displacement of cement using adequate plugs and cement flow conditions so that there is no undisplaced mud in the annulus; and (2) a competent seal and bond between casing and formation. There is no question that the effectiveness of the cement job has been greatly improved by the use of scratchers on the casing and the resulting movement of the casing while displacing the cement. After the casing is in position and the cement has been displaced, the cement is then held in place by back pressure valves in the float collar or float shoe, or pressure in the casing, until it is set. To cement squeeze a specific interval of casing, a packer is lowered on drill pipe or tubing and set above the perforations to be treated. After establishing a pumping rate with water or drilling mud, the cement is pumped into the formation until a refusal point is reached at a predetermined pressure.

Table XVIII

CEMENT USAGE

INDUSTRY—1945-1965

	BULK CEMENT M SACKS	POZZOLANS M CU. FT.
1945	5,933	—
1946	6,889	—
1947	10,623	—
1948	13,570	—
1949	14,418	—
5-yr Total	51,433	
1950	18,252	—
1951	20,669	—
1952	19,831	302
1953	21,139	1,156
1954	22,138	2,177
5-yr Total	102,029	3,635
1955	23,797	3,695
1956	24,237	4,079
1957	22,730	4,191
1958	18,601	3,991
1959	20,131	4,354
1960	17,828	4,076
6-yr Total	127,324	24,386
1961	18,352	4,015
1962	17,157	3,566
1963	16,217	3,272
1964	16,273	3,074
1965	16,163	2,824
5-yr Total	84,162	16,751

6. WELL CEMENTING EQUIPMENT

Mechanical advancements include: (1) automatic fill-up float shoes and collars; (2) automatic weighing and viscosity controls on pumping equipment; (3) increased horsepower of pumps and prime movers; (4) bulk equipment; (5) more efficient cementing plugs; (6) improved centralizers and scratchers; and (7) improved squeeze tools and packing elements such as the full-opening retrievable packer which permits repeated operations (perforating, testing, squeezing) with just one trip in the hole.

Before 1959, temperature surveys were the only means of determining the placement (the approxi-

FIGURE **39**

Oil-Well Cementing Practices in the United States

EFFECTS OF SOME ADDITIVES ON THE PHYSICAL PROPERTIES OF CEMENT		BENTONITE	PERLITE	DIATOMACEOUS EARTH	POZZOLAN	SAND	BARITE	ARSENOFERRITE	CALCIUM CHLORIDE	SODIUM CHLORIDE*	LIGNOSULFONATES	CMHEC†	DIESEL OIL	LOW-WATER-LOSS MATERIALS	LOST-CIRCULATION MATERIALS	ACTIVATED CHARCOAL
DENSITY	DECREASE	⊗	⊗	⊗	×											
	INCREASE					⊗	⊗	⊗	×	×	×					
WATER REQUIRED	LESS										⊗					
	MORE	⊗	×	⊗	×	×	×	×							×	×
VISCOSITY	DECREASE								×		⊗					
	INCREASE	×	×	×	×	×	×	×							×	×
THICKENING TIME	ACCELERATED	×					×	×	⊗	⊗						
	RETARDED			×						×	⊗	⊗	×	⊗		
SETTING TIME	ACCELERATED						×	×	⊗	⊗						
	RETARDED	×	×	×	×						⊗	⊗		×		
EARLY STRENGTH	DECREASED	×	×	×	×		×	×			⊗	⊗		×	×	×
	INCREASED								⊗	⊗						
FINAL STRENGTH	DECREASED	×	×	⊗	×		×					⊗		×	×	×
	INCREASED										×					
DURABILITY	DECREASED	×	×	×									×		×	
	INCREASED				⊗											×
WATER LOSS	DECREASED	⊗									×	⊗	×	⊗	×	
	INCREASED		×	×												

× DENOTES MINOR EFFECT.

⊗ DENOTES MAJOR EFFECT AND/OR PRINCIPAL PURPOSE FOR WHICH USED.

* SMALL PERCENTAGES OF SODIUM CHLORIDE ACCELERATE THICKENING. LARGE PERCENTAGES MAY RETARD API CLASS A CEMENT.

† CARBOXYMETHYL HYDROXYETHYL CELLULOSE.

mate top and any large uncemented gaps) of the primary cement job. In 1959 and 1961, more definitive sonic logging tools were developed, not just to locate the cement, but also to measure the quality of the bond between the casing, cement and formation. These logs help in determining whether or not remedial squeezing is necessary and where it should be placed.

The number of jobs performed is a measure of its importance to the industry. The following are estimates for the 1945-1965 period:

Primary casing jobs	1,875,000
Squeeze jobs	375,000
Other remedial jobs	250,000
Domestic total	2,500,000

D. Opening Formations for Production

1. SHOOTING WELLS TO START FLOW OF GAS OR OIL—NITROGLYCERINE OR DYNAMITE METHODS

This type shooting is seldom used now, being replaced with better and safer procedures.

2. CASING AND TUBING PERFORATION
   a. Introduction (1948) and development of shaped charges (jet) perforating.
   b. High-quality gamma ray-neutron logs and high-response collar locators for depth control.
   c. Development of a variety of shaped charge perforation size, a noncarrot forming shaped charge, and the ability to design guns for desired hole size with burr-free perforations and limited debris.
   d. Increased temperature capability from 250-275°F to 500°F.
   Improved reliability of small diameter cable. These cables are part of the system that permits dynamic well control in the 10,000-psi range.
   e. Reliable (mechanical and electrical) through tubing guns—introduced early 1950's.
   f. Pressure control equipment to permit 10,000-psi jobs without loss of well fluids. This enables perforating under pressure control with clean fluids in the hole, and with the pressure differential toward the bore from the formation.
   g. Development of through tubing shoot and treat tools and techniques.
   Oriented (radiation and mechanical) perforating equipment. With this equipment it is possible to perforate up to seven strings of pipe in one hole.
   h. Selective shot-by-shot and selective bank firing shaped charge guns permitting limited entry stimulation.
   i. API standard procedure for evaluation of well perforators (1962).

The low-temperature rating of bullet guns, with the limited penetration of bullets into strong targets (thick high-strength casing, multiple strings and hard formations), and the trend toward through tubing perforating cause the emphasis to be placed on improving the flexibility and performance of shaped charge guns. The propellant powders used for bullets were rated at 250°F and RDX explosives of shaped charges at 350°F. In 1959, "Hexil" increased temperature limit to 400°F, and in the 1960's "TACOT" and "Sulfone" to 500°F. Present capabilities are rarely exceeded by deep high-temperature wells.

The estimated perforating completions for the past 20 years are shown below:

Period	Number of Completions
1945-49	158,000
1950-54	219,000
1955-59	300,000
1960-64	260,000

The number of perforating jobs per completion ranged from 1.8 to 2.0. Workovers accounted for about one-third, and from 1960 to 1965 through tubing guns about 35 percent of all shaped charge jobs.

The techniques of perforating through tubing with depressed fluid levels reduces formation damage. When shaped charges were introduced, the static rating of pressure control equipment was 3,000 psi. Specially trained and equipped crews now perform jobs from 5,000 to 10,000 psi.

Large diameter holes (¾ inch to 1 inch) did not reduce flow rates or pressure drops enough to control sand movement. Small diameter-shaped charges (⅛ inch to $^1/_{10}$ inch) were developed which for Gulf Coast sands are below the "10 percent Coberly point" and control sand better than conventional sizes (⅜ inch to ½ inch).

3. FORMATION FRACTURING

As a result of investigations by Pan American Petroleum Corporation to understand the "pressure break" observed in acid jobs, squeeze cementing and other injection jobs, hydraulic fracturing was announced in October 1948. The initial method was to use napalm soap to thicken crude oil or kerosene, making it both the fracturing fluid and carrier of sand in the process.[52] This technique created a fracture in the formation and deposited the sand as a permeable propping material to keep the fracture from closing.[53]

52. Clark, J. B., "A Hydraulic Process for Increasing the Productivity of Wells," *Trans.*, AIME, 1949, vol. 186, p. 1.
53. Vance, Harold, "Evaluation," *History of Petroleum Engineering*, Dallas, Texas, 1961.

An exclusive license to perform the process was issued to Halliburton Company [54] and the first commercial jobs were performed on March 17, 1949.[55] This agreement was terminated in 1953 and all reputable service companies capable of performing the service were licensed. From March 1949 to March 1952, 10,460 treatments were performed on 9,360 wells. The success ratio was 75 percent with production increases averaging 175 percent.[56] As a result of early successful treatments and the improvements of equipment and treating techniques, the number of treatments increased rapidly from 1952 until a peak of 4,500 per month was reached in 1955 (Figure 40).

Major advancements in hydraulic fracturing:

1945-50 a) Hydrafrac introduced, March 1949.

1950-55 a) Use of refined and crude oils.
b) Fresh water fracture perfected.
c) Fluid loss control agents.
d) First equipment designed especially for fracturing, i.e., continuous blenders, frac wagon, etc.

1955-60 a) Special shaped propping agents.
b) Partial monolayer concept.
c) Multiple fractures made possible by:
1) Bridging agents
2) Ball sealers
d) Howard and Fast introduced treatment design relationship.

1960-65 a) Fluid friction loss reducing agents.
b) Limited entry technique.

Figure 41 shows the trend of average fracture treatment in the U. S. Figure 42 shows the shift from oil-base to water-base fluid. The increased volume per treatment resulted in the development of numerous additives, including fluid loss control agents to make aqueous-base fluids compatible with producing formations. This helped control the cost per treatment as the volume per treatment increased (Figure 43).

The development of a friction-reducing agent in about 1960 permitted the injection through small diameter pipe, or at reduced pressures. This made it possible to fracture thousands of additional wells otherwise beyond consideration, i.e., those with small casings or old wells with casing too weak to fracture through.

Incremental reserves have been added by hydraulic fracturing in two different ways: (1) by increasing the ultimate recovery of old semidepleted wells which are fractured primarily to increase productivity and prolong the economic life; and (2) by making entire new fields and reservoirs economically feasible.

54. Fast, C. R., Pan American Pet. Corp. Personal interview with R. C. Phillips, Union Oil Co. of Calif., July 5, 1966.
55. Owsley, Wm. D., Halliburton Co. Personal interviews with R. C. Phillips, Union Oil Co. of Calif., July 7, 1966.
56. Howard, George, et al., "9360 Wells Undergo Hydraulic Fracturing," *Oil & Gas Jour.*, September 1, 1952.

FIGURE **40**

Estimated Fracturing Activity by Months

FIGURE **41.** Trend of Average Fracture Treatment in the U.S.

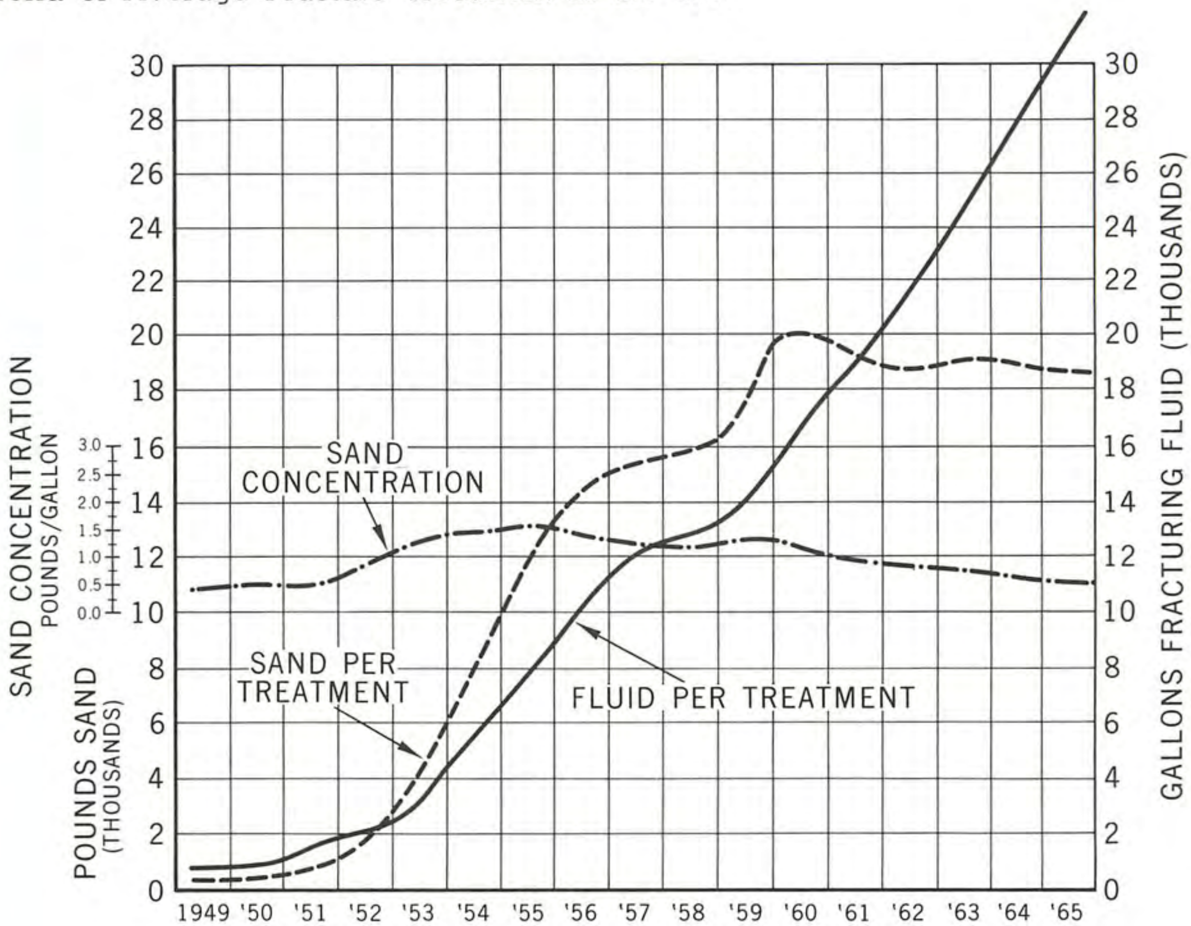
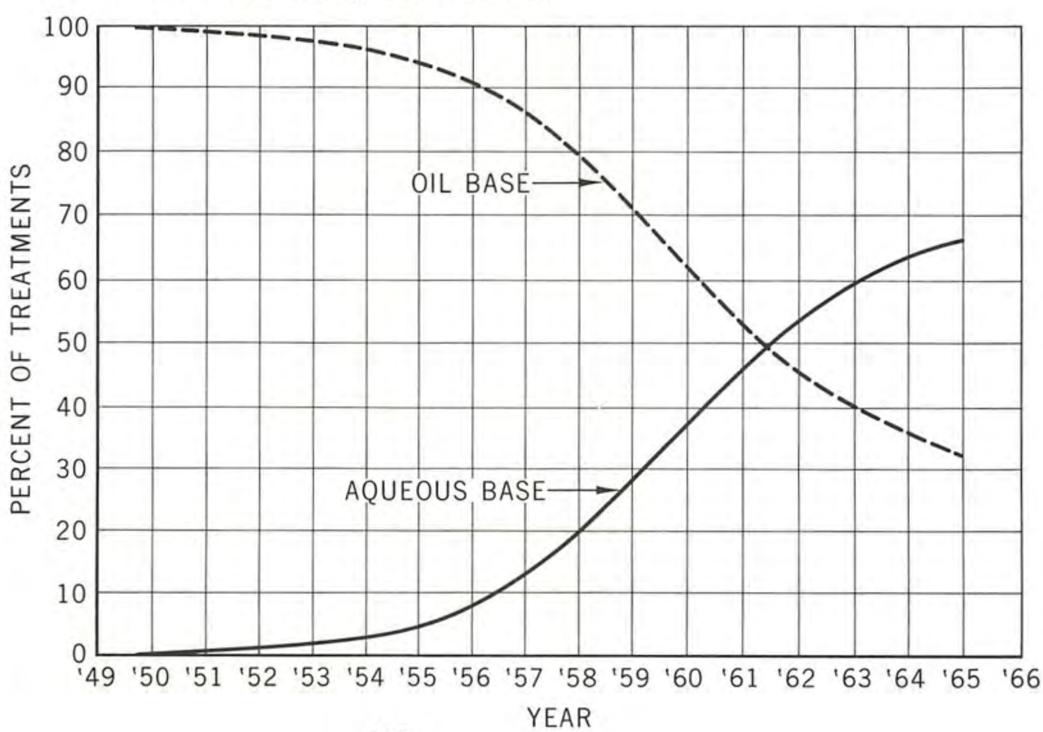


FIGURE **42**

Trend-Fracturing Base Fluids



DETERMINATION OF RESERVES DEVELOPED BY HYDRAULIC FRACTURING

	1950-55	1956-60	1961-65	TOTAL
Number of U. S. Frac Treatments:	114,741	168,327	136,393	419,461
Number of Treatments on Old Wells:	65,339	62,961	47,737	176,037
Number of Treatments on New Wells:	49,402	105,366	88,656	243,424
Additional Reserves from Old Wells: M Bbls.	609,940	587,740	445,625	1,643,305
Additional Reserves from New Wells: M Bbls.	1,067,080	2,275,910	2,340,520	5,683,510
Total Reserves Added by Fracturing: M Bbls.	1,677,020	2,863,650	2,786,145	7,326,815

The Pembina Field in Canada, without fracture treatments, was nonproductive, but now has 2,500 producing wells.

Using Figures 40 and 44, the number of treatments on old wells and new wells was calculated to be 176,037 and 243,424, respectively, of the total 419,461 performed.

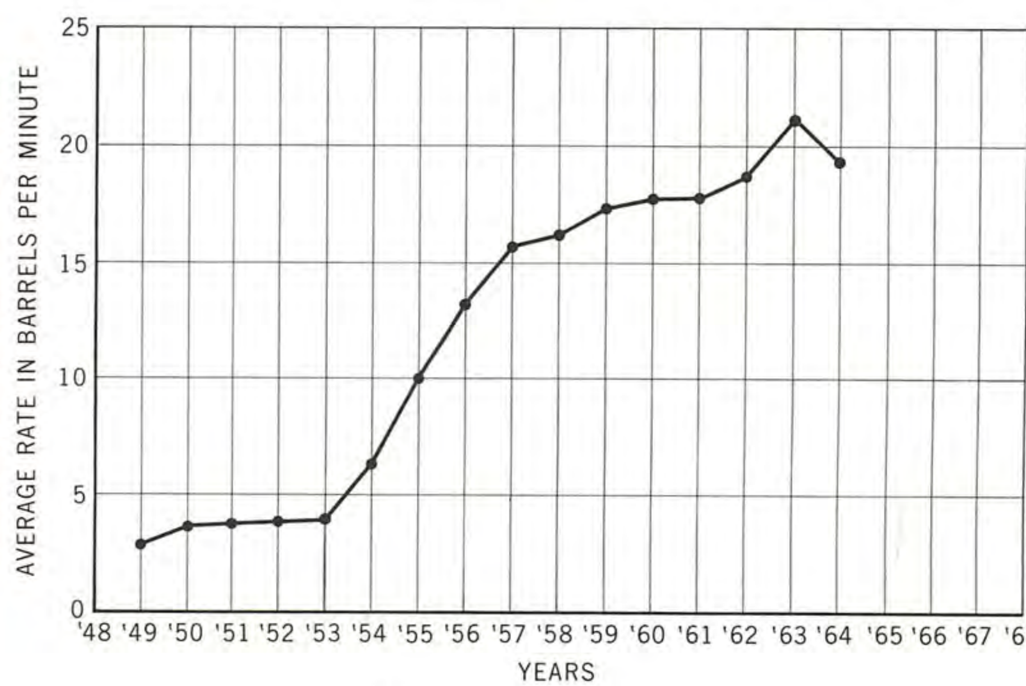
Based on the findings of Campbell [57] on 142 treatments in 28 areas, and Garland [58] on 4,663 treatments, the average increase in ultimate recovery per treatment on old wells is estimated to be 9,335 barrels. In 1958, Garland [59] obtained information on 191 new wells in four different reservoirs in Texas that would not have been productive without fracture treatment. All wells had at least three years production history. The estimated reserves for these wells were 48,000 barrels each. The success ratio for new well treatment prior to 1958 was estimated to be 45 percent; since 1958, 55 percent. Using the above figures for old and new well treatments, the estimated reserves added by hydraulic fracturing are as shown in Table XIX.

4. ACIDIZING

The first acid treatment was performed February 11, 1932 by the Pure Oil Company in cooperation with Dow Chemical Company on Pure's Fox No. 6 well in Midland County, Michigan. The hydrochloric acid

57. Campbell, J. B., "The Effect of Fracturing on Ultimate Recovery," *Proc.*, API, Production Bull. 243, p. 57.
58. Garland, T. M., U.S. Bureau of Mines, Wichita Falls, Texas. Information furnished to R. C. Phillips, Union Oil Co. of Calif., July, 1966.
59. *Ibid.*

FIGURE **43.** Trend of Average Injection Rate of Fracture Treatments in the United States



concentration was 15 percent by weight and arsenic acid was added as an inhibitor. By 1934, acidizing was a common practice throughout the areas where limestone was a producing horizon.

During most of the period 1946-1965, developments in acidizing were overshadowed by fracturing. However, late in the period, developments increased by the applicability of acidizing for well completion and stimulation.[60]

The principal acid utilized has continued to be 15 percent hydrochloric. Although acid pumping equipment has been improved tremendously, especially from a dependability standpoint, acid was being pumped at fracture inducing rates prior to 1945.[61] A number of improvements have been initiated which serve to reduce the cost of raw materials, transportation and pumping horsepower.

A multitude of additives, wetting agents, emulsifiers, demulsifiers and corrosion inhibitors have been developed since 1945. These led to the introduction of numerous specialized acids, each of which has probably expanded the utility of acidizing only slightly. The petroleum industry accepted and practiced acidizing in a rather unscientific manner until about 1960. As a result of research commenced in the late 1950's, the parameters which control acid reaction time, and hence depth of penetration, were isolated and analyzed under dynamic conditions.[62] This understanding of the acidizing mechanism led to the development of a surface active agent acid which was introduced in about 1963. The surface active agent acids are able to penetrate much farther into the formation before the reaction begins. This development has allowed the acidizing of deeper wells which, due to their excessive bottom hole temperatures, could not be treated using conventional acids. Thus, it can be said that the development of surface active agent acids in the 1960-1965 period was a significant technological breakthrough which has and will develop additional crude oil reserves.

Listed below are the important advancements keyed to the approximate date of introduction:

1950-55 a) Acid fracturing with propping material carried in acid.
1) thickened acids
2) emulsions
Both developed to make acid a more desirable fracturing fluid.
b) Selective acidizing with various blocking materials.

60. Hendrickson, A. R., and Wieland, D. R., Dowell Div. of Dow Chemical Co., Tulsa, Okla. Personal interviews with R. C. Phillips, Union Oil Co. of Calif., July 5 and 14, 1966. Harris, F. N., Halliburton Co., Duncan, Okla. Personal interview with R. C. Phillips, Union Oil Co. of Calif., July 13, 1966.
Owsley, Wm. D., Halliburton Co. Personal interviews with R. C. Phillips, Union Oil Co. of Calif., July 7 and 13, 1966.
61. Grebe, John J., and Stosser, S. M., "Increasing Crude Production 20,000,000 Barrels from Established Fields," *World Petroleum*, August 1935.
Hendrickson and Wieland. Interviews with Phillips, July 5 and 14, 1966.
62. Hendrickson, A. R., Hurst, R. E., and Wieland, D. R., "Engineering Guide for Planning Acidizing Treatments Based on Specific Reservoir Characteristics," *Trans.*, AIME 1960, vol. 219, p. 16.

FIGURE **44**

Fracture Treatments Performed on Old Wells

1955-60 a) Organic acids.
b) Wetting agents — demulsifiers, organic inhibitors, retarders.
c) Ball sealers—to attain selectivity.

1960-65 a) Acetic acid used as perforating fluid.
b) N_2 and CO_2 to provide increased agitation and backflow of solids.
c) Sulfamic acid—scale cleanup.
d) Surface active agent acids—necessary to obtain reasonable penetration with "live" acid.
e) Acidizing mechanism defined in terms of reaction time and "volume-area" relationships.

Despite its age, acidizing is actually a rather immature science. Very little research was performed in the field of acidizing between 1940 and 1958. Since the acidizing mechanism was only recently defined, the future of acidizing is much more likely to contain technological breakthroughs than any of the other well-stimulation techniques. Major improvements should be made in surface active agent acids. Also, research is being performed on the possible use of anhydrous hydrochloric (gaseous) acid in order to take advantage of its favorable viscosity and formation permeability characteristics.

E. Preparing the Well for Production

1. REMOVAL OF MUD CAKE, METHODS AND EQUIPMENT

The productive formation incurs some permeability damage near the wellbore due to loss of filtrate and mud solids to the formation, and the creation of a mud-filter cake on the formation face. The extent of the damage depends upon the pressure and time of exposure, the mechanics of drilling and completion, the formation, and the mud characteristics.

Casing scratchers were designed to mechanically clean the mud cake from the wellbore while cementing the production casing string. When the formation will withstand the required pressure, the cement is displaced at high velocities to create turbulent flow conditions in the annulus (cement is preceded by either fresh water, brine, or chemical flushing solution). Pumping equipment (which also has been developed with the capability of creating turbulence) and the use of additives for low-density cements have been factors increasing the use of this technique. Special shoes and float collars are also available to assist in creating this turbulent flow.

2. WELLHEAD EQUIPMENT

A very complex and sophisticated assortment of wellhead equipment has been developed since 1945 to keep pace with other developments in the industry. Improvements in design, metallurgy, chemical and physical quality control, and machine tools have all played a part. The present line of wellhead equipment is designed for extremely high pressure, complex multiple tubing string completions, with features to permit a high degree of safety and reliability.

In 1954, the "C" clamp-type end connection was introduced for high-pressure conditions. It utilizes a pressure-energized metal seal, reduced area exposed to pressure, and a positive stop for makeup. The use of the "C" clamp equipment on both wellheads and blowout equipment saves weight and space and reduces the time required for installation. Standard design xmas trees are now available for single, dual, triple, and up to quadruple completions, with four strings of tubing and dual solid block master valves and cross valves.

Comparable improvements have also been made on flow control equipment: positive, adjustable and velocity-type chokes, pressure regulators and safety valves.

3. PLACING WELL EQUIPMENT, TUBING, SUCKER RODS, PUMPS, CASING HEADS, LEADLINES

Power equipment has been developed for running two or three strings of tubing, with the required packers, simultaneously. This consists of multiple power slips, dual split-block elevators and power tongs with preset torque controls. This method required 15 to 20 percent more running-in time than with a single string, but saves rig time over running each string independently. It also assures proper spacing and interconnection of the packers.

Hoisting and racking equipment for running rods and pumps has been improved. The objective here is to reduce the time for installation and remedial work. Rods are automatically suspended in the mast instead of being racked manually on location. Improved design of down-the-hole pumping equipment, hydraulic,electrical-centrifugal, and plunger types has extended the depth and volume capabilities. One operator reports successful operation of hydraulic pumps at 15,000 feet with volumes up to 4,100 barrels a day.

A variety of plastic and fiberglass pipe has been introduced for use as flowlines. This pipe is light weight and easily placed, which reduces transportation and labor cost. It is also noncorrosive and frequently minimizes paraffin and scale deposition, thus reducing maintenance and lost production from plugging. Steel flowlines are also available with internal plastic coating. A new type lay-barge is in use in offshore areas. It is capable of spooling several miles of steel line pipe in onshore yards, transporting it to offshore and unreeling rapidly.

4. COMPLETION FLUIDS

The industry has long recognized the permeability damage to formations by water-base drilling fluids. New techniques have been developed to evaluate the effect of fresh water on formation shales and clays, and to formulate completion fluids to minimize the damage. These include brines, crudes, oil-base and oil-emulsion systems. Where possible, these are designed for low-density, low-solids and low-water loss.

In many instances it is not possible to convert to a special completion mud system; however, with the new through tubing perforating equipment, it is possible to convert to the desired completion fluid after the casing has been set. These tools permit perforating under reduced fluid levels with low-solid systems.

5. WELL SCREENS AND LINERS

Both were in use prior to 1945, and the methods of evaluating selections were well defined at that time. They are still in use with improved placing equipment.

6. FORMATION DAMAGE

Improved jet perforating techniques have reduced formation damage by elimination of carrots that plug the holes. Other techniques mentioned previously also reduce damage, and no doubt the most important of these is the ability to perforate through tubing under pressure control and with clean fluids in the hole.

By careful analysis of pressure measurement after completion, the extent of formation damage can be accurately determined, and remedial treatments can be designed. These treatments consist of crude, acid, N_2, CO_2 and other flushing fluids—or hydraulic sand and acid fracturing treatments may be used.

7. GRAVEL PACKS

Prior to 1945, control of sand was carried on through the use of slotted liners, sand screens, prepacked liners and gravel packs. Probably the most effective of these has been gravel packing, which has since undergone improvement and modification. As an illustration, in the Long Beach Unit, THUMS is now flow gravel packing separate intervals in many of its wells with two wet intermediate zones being isolated by means of Lynes packers. This enables more than one zone to be produced from the same wellbore at a considerable saving, as against having separate wells for each zone.

8. SAND CONSOLIDATION

Thermosetting plastics were developed for sand control prior to 1945, but were not very successful. During the period 1945-1965, several epoxy resins with curing agents were developed, as well as other plastic systems. The technique of placing these has been refined, closely simulating laboratory experiments, until 90 percent success ratio has been reported for some specific programs. Extreme care must be exercised in transportation, mixing and dis--placing to avoid contamination. Treatment should be concentrated in the sand section free of clays, or a preflush used to neutralize the clay content. In 1965, approximately 1,500 jobs were performed and the use of this method of sand control should continue to grow.

SECTION 4—Production Operations—Flowing, Lifting, Gathering and Lease Automation

R. B. Wilkins

A. Introduction

Improvement in technology and equipment relating to the production of oil and gas from an underground reservoir to the surface of the ground, and the handling of the captured fluids at the surface of the ground have undergone a steady advance during the last twenty years. Primarily, progress has been one of evolution rather than being marked by revolutionary technological breakthroughs. Much of the equipment being installed today is not radically different in appearance than that being used twenty years ago. Nevertheless, advances have been made so that it is now possible to produce fluids from greater depths than would have been possible twenty years ago. Methods of completing and producing the wells, as well as the handling of the produced fluids at the surface, have improved, not only from the point of view of reducing waste but also from the standpoint of reduced manpower requirements in capturing the hydrocarbons and thus making them available for refining and ultimate utilization at a relatively lower cost to the public.

B. Flowing Wells

As the name implies, flowing wells are those wells which are capable of producing hydrocarbons from the underground reservoir rock to the surface by means of the natural energy available in the reservoir. This energy may be in the form of reservoir pressure alone, or a combination of reservoir pressure and energy from the expansion of gas produced with, or coming out of solution from the oil. It is not unusual for a well to be capable of flowing when it is initially completed and then later, as the reservoir energy declines, artificial lift methods are necessitated to bring the hydrocarbons from the wellbore to the surface. In some cases, where there is an unusually strong water drive or where there is a large gas cap in an oil reservoir and if gas production from the gas cap is deferred until after the oil rim has been depleted, an oil reservoir can essentialy be depleted without ever having to install artificial lift equipment.

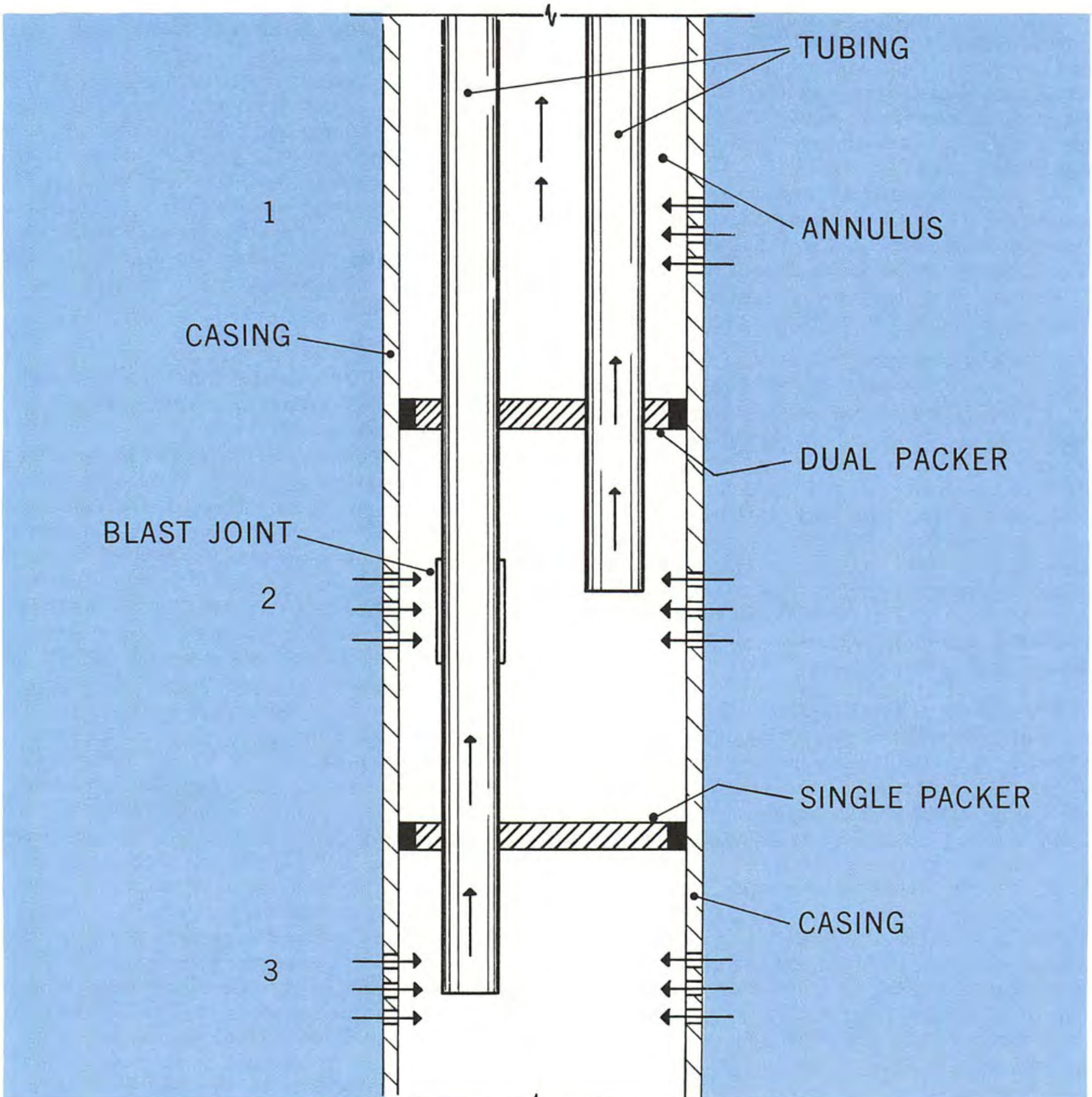
Advances in technique and equipment employed since the middle 1940's have in many cases extended the flowing life of oil wells; however, major contributions toward this end have been in advances in the basic concepts of reservoir engineering as well as the acceptance of these concepts by the majority of oil operators in order to obtain a maximum economic recovery from the reservoir and to utilize to best advantage the reservoir energy available.

Another major contribution to extending flowing life of wells has been in the enabling legislation of various state governments. These statutes have allowed the various state oil and gas regulatory agencies to provide for unitization of oil pools, whereby exploitation of a reservoir can be scientifically engineered to realize a greater economic recovery from the reservoir as a whole, rather than reducing exploitation to the "rule of capture" as between many individual operators. Prior to 1946, there were three states—Arkansas, Louisiana, and Oklahoma—which had some form of compulsory unitization statutes; however, all of these states have since amended the

FIGURE **45**

Schematic of Multiple Completion in Three Zones

(2 Completions Through Tubing, 1 Completion Through Annulus)



original statutes to extend the application thereof. At the present time, there are fourteen states which have adopted pool-wide compulsory unitization statutes. Regarding the term "compulsory unitization," as R. M. Williams noted in the 15th Annual Institute on Oil and Gas Law and Taxation: "The term 'compulsory' is unfortunate but is used because of common usage. It does not mean arbitrary government action compelling persons generally to act against their will any more than does any other law passed to accommodate and adjust for the common and public good, the co-related or correlative rights and interests of all persons in a community, or particularly those having interests in a common property or common fund, in instances where they cannot agree. This is the purpose and function of all laws. All are 'compulsory' in this sense. 'Statutory pooling and unitization' would be a better phrase."

In 1964, the latest year in which statistical data are available in this regard, 11.2 percent of all of the oil wells in the United States were listed as flowing wells. This percentage figure has remained essentially unchanged since 1946 when 11.4 percent of all oil wells in the United States were listed as flowing wells.

With the ever-increasing depth of drilling and the consequence of encountering higher formation pressures, production equipment to handle flowing wells is now available designed to handle up to 20,000 pounds per square inch wellhead pressures. In 1946, maximum pressure for which wellhead equipment was designed was of the order of 8,000 pounds per square inch.

A major improvement for handling flowing production has been in advances in technique and equipment for multiple completions (i.e., a single well producing from more than a single reservoir) coupled with improvements in tools which can be run on a wireline in working over wells or in changing producing zones with the minimum of downtime and expense. Although the multiple completion concept was first employed in the late 1930's, it was not until the 1950's that multiple completions effected a significant impact in oil producing operations. The early multiple completions were limited to only two producing zones because of the then limitations of packer development. With improvements in packer design and methods of running tubing, it is not uncommon to have multiple completions in as many as four zones at the same time. The greatest number of zones which have been completed and produced simultaneously by multiple completion techniques as of 1966 is six zones. Figure 45 is a schematic diagram of a multiple completion well. Multiple completions can be categorized by number of packers used, number of strings of tubing used, number of zones produced, or by a combination of these categories. The two basic classifications in which multiple completions can be categorized are (1) tubing and annulus production (the earlier multiple completions were limited to this type), and (2) parallel string production. Although multiple completions are not necessarily limited to the concept of flowing production, the majority of multiple completion wells are flowing rather than produced by artificial lift. The parallel tubing string-type of completion involves a higher initial capital outlay than the tubing and annulus-type of completion; however, the former has become increasingly popular in recent years. In tubing-annulus completions there is a disadvantage in that it is very difficult to conduct remedial work on the zone exposed to the annulus. Also, it is difficult to run a bottom hole pressure bomb or similar instruments down the annulus to record desired reservoir information. This is coupled with the fact that artificial lift of the zone produced in the annulus is difficult and awkward. Additionally, the zone which produces through the annulus will very often quit flowing sooner than would be the case if it were producing from a tubing string. This is due to the lower fluid velocities in the annulus and a resultant "liquid loading" of the annulus due to the decreased effectiveness of the expanding gas in bringing the liquids to the surface.

With the improved design of packers to accommodate multiple strings of tubing in multiple completion wells and by employing wireline tools for workovers and zone selection, it is now feasible to deplete several different zones in a well without having to move in a rig for recompletion at any time. This obviously results in an increase in the economic recovery from the well.

With the advent of improved plastic coating materials during the last twenty years, it is now commonplace to install internally plastic coated tubing in wells, particularly flowing wells, to overcome internal corrosion in the tubing. Additionally, as a result of the very "slick," smooth surface of the plastic coating material, the troublesome problem of paraffin accumulation in the tubing is effectively reduced, thus adding to the flowing life of the well.

C. Artificial Lift

1. GAS LIFT OPERATIONS

When the energy in a reservoir declines to the point where a well is incapable of flowing the reservoir fluids to the surface, or when the rate of production desired is greater than can be supplied by the reservoir energy available, it becomes necessary to supplement the reservoir energy to lift the fluids from the well. This is done by installing artificial lift equipment. Gas lift is one of the processes used in lifting fluids from the wellbore to the surface. This can be done by the injection of relatively high-pressure gas into the tubing string (continuous flow), or by the injection of a slug of gas underneath an accumulated liquid slug during a relatively short time interval to move the liquid slug to the surface (intermittent lift).

FIGURE **46**
Schematic Diagram of Intermittent Gas Lift Operations

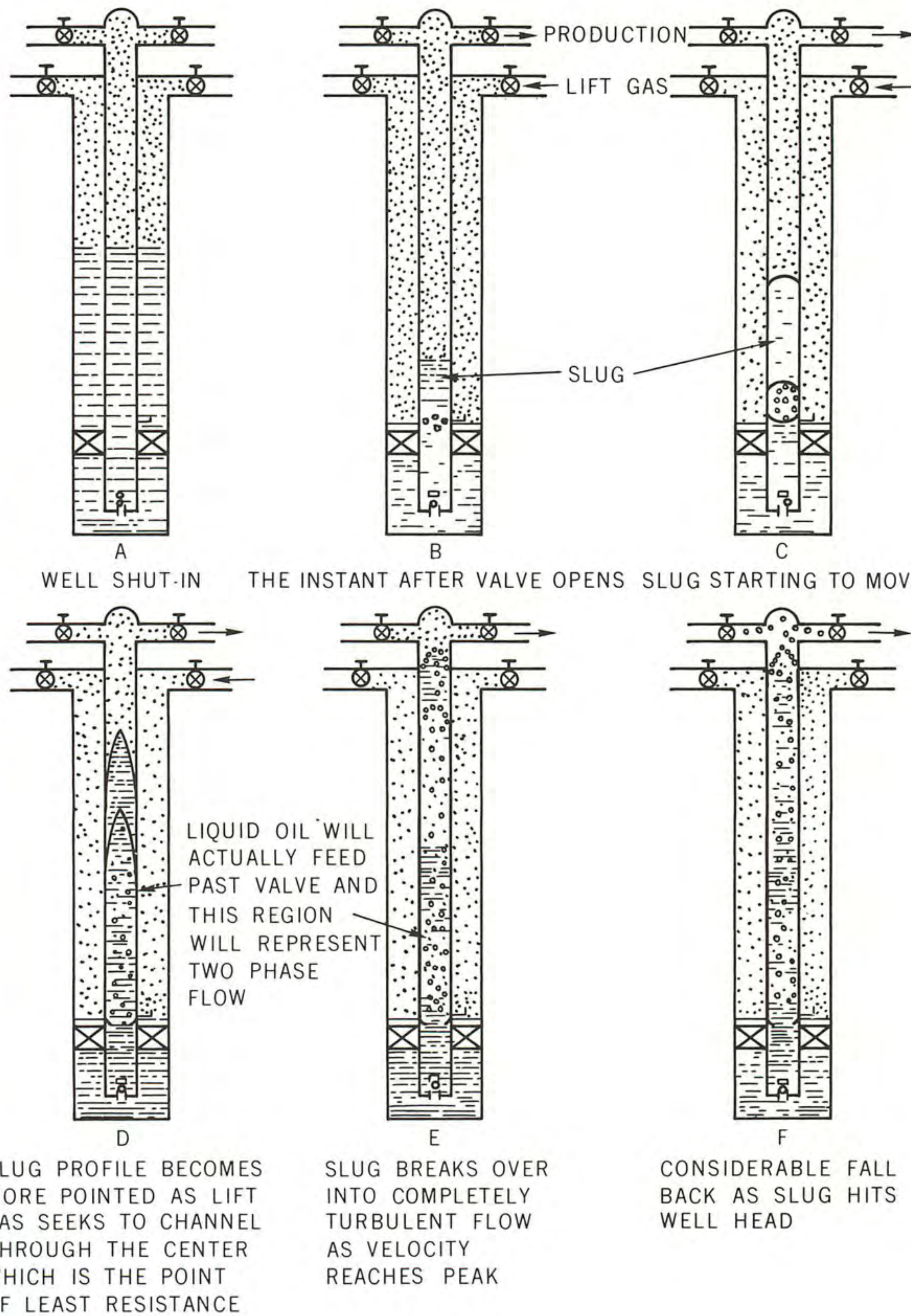


Figure 46 is a schematic diagram of intermittent gas lift operation. The gas injected into the tubing string lifts liquids to the surface by (1) reduction of fluid gradients, (2) expansion of injected gas, and (3) displacement of fluid by compressed gas.

In gas lift operations, since gas is the medium used in supplying the necessary energy to lift the reservoir fluids to the surface, it necessarily follows that there must be a dependable and adequate supply of high-pressure gas for satisfactory operation of this technique. Prior to the 1940's, it was common practice to obtain high-pressure gas to be used for gas lift operations from a gas well located near the gas lift operation if there were no market for the gas. After being used for gas lift, the gas was vented to the atmosphere. By the latter part of the 1940's, the rapidly expanding gas pipeline systems resulted in an economic market for the gas, and essentially brought an end to the practice of venting the gas after it had been used to lift the oil to the surface. At the present time, essentially all of the gas which is used for gas lift purposes is recovered and either sold to gas transmission lines or is recovered, recompressed and used again for gas lift purposes. The latter is known as a closed, rotative gas lift system.

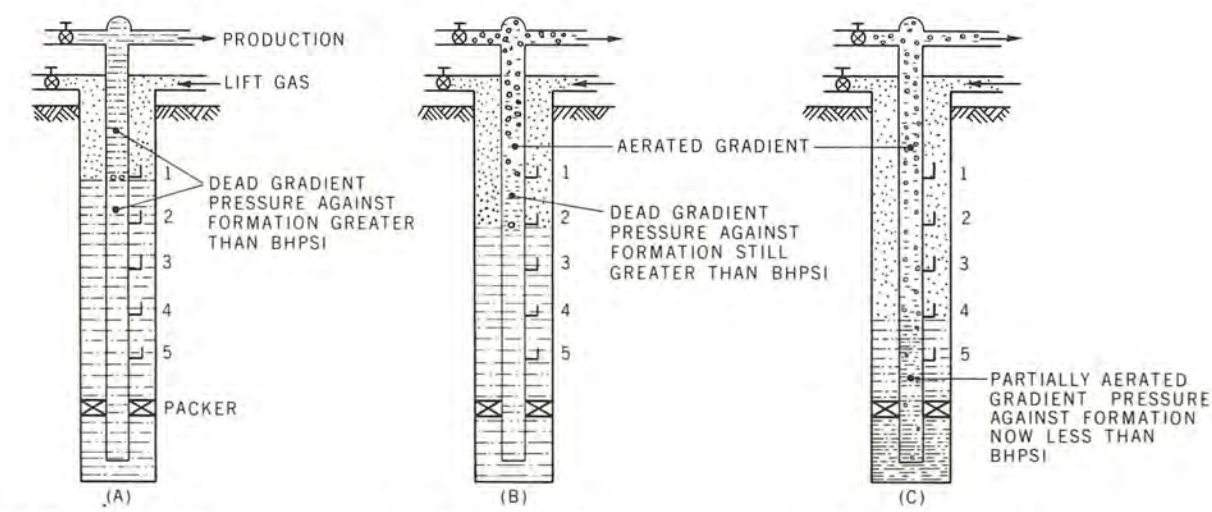
The initial cost of gas lift equipment, generally speaking, is less than other types of artificial lift equipment if high-pressure gas is available.

This is quite often the case even if a compressor station is necessary to recompress the gas and install a rotative gas lift system. Gas lift operations are particularly applicable to wells which have a relatively high static and producing fluid head and which produce large volumes of water. High producing rates can be sustained through higher water percentages economically, thereby contributing to a higher overall ultimate recovery of oil from this particular type of application.

Gas was first used to artificially lift fluids from mines as early as 1794. The older gas lift systems used "foot pieces," or single point entry techniques, until the spring-loaded differential valve was introduced in 1934. This valve made it possible to run multiple valves in the tubing string, which allowed the well to be kicked off by gas lift without excessive pressures and greatly extended the applicability of the gas lift technique. Figure 47 illustrates a multiple valve gas lift installation.

The most significant single contribution to the gas lift technique was the development of the King valve, which was patented in 1944 and put into extensive use in the late 1940's. This valve was the forerunner of most of the popular types of gas lift valves in use today. It utilizes a flexible bellows assembly charged with gas pressure and attached to a stem whereby the bellows' force keeps the stem on a valve seat. When the external pressure acting against the outside of the bellows creates a force greater than the internal bellows pressure, the bellows collapses, thus raising the stem from the seat. When gas pressure is utilized as

FIGURE **47.** Multiple Valve Gas Lift Installation



VALVE 1 UNCOVERED, JUST BEGINNING TO INJECT GAS. DEAD LIFT

VALVE 2 UNCOVERED, JUST BEGINNING TO INJECT GAS. DEAD FLUID BETWEEN VALVES 1 & 2.

VALVE 4 UNCOVERED, JUST BEGINNING TO INJECT GAS. NOTE THAT WELL HAS "KICKED OFF" AND THAT THERE IS NOW A PARTIALLY AERATED GRADIENT BETWEEN VALVES 4 & 5.

the external pressure force, as it is used in all gas lift operations, gas is injected through a valve port when the stem is raised from the seat. Figure 48 is a schematic diagram of the pressure-charged gas lift valve.

Most of the advances in gas lift since the introduction of the King-type valve have been in the technology of application. In the early 1950's, flowing gradient curves were developed which allowed the design of continuous flow gas lift strings for the most efficient use of gas at high producing rates. A very significant development in gas lift application has been the introduction of wireline retrievable gas lift valves used in conjunction with offset side pocket mandrels. This wireline system, which was introduced in 1949, made it possible to exchange valves economically by wireline technique without having to employ workover rigs to pull the tubing from the hole to replace and/or repair the gas lift valves.

A new system of gas lift valve placement has been introduced very recently which allows valves to be pumped into place hydraulically and retrieved by reversing the hydraulic system. This technique appears to be especially applicable in offshore operations. Recently, tubing-sensitive valves (fluid operated) have made it practicable to lift multiple completion wells simultaneously utilizing a common gas supply annulus. As a result, it is possible to gas lift multiple completions where multiple tubing strings are employed.

2. ROD-TYPE PUMPING

a. Pumping Units

A pumping unit is a mechanism which imparts a reciprocating motion to a string of rods which extends to a positive displacement pump, which pump is usually located at a depth near the producing formation. During the past twenty years, the competitive efforts of several of the major pumping unit suppliers have resulted in more versatile, more dependable, and more efficient oil well pumping units at prices below the inflationary trend of the period.

Versatility of the pumping unit has been improved by such innovations as dual track horseheads, dual and triple hangers that permit two or three zones to be pumped simultaneously from the same wellbore, and the introduction of improved and structurally stronger portable bases to improve the salvability of the pumping unit.

The dependability of pumping units has been increased by incorporating factory-lubricated and sealed structural bearings which are filled with new lubricants supplied by the petroleum refining industry. Hydraulically removable wrist pins and rack and pinion counterweight adjustments have been incorporated in some of the new developed units which results in a reduction in manpower to alter a unit for varying loads and pumping conditions.

As the depth of finding new reserves has increased since 1946, it has been necessary to design larger pumping units to lift the oil from the greater depths. In 1949, the largest pumping unit available was rated at 750,000 inch-pounds peak torque and 33,000 pounds polish rod load. In 1966, the largest unit available is rated at 1,824,000 inch-pounds peak torque and 44,000 pounds polish rod load.

b. Downhole Pumps (Rod Type)

Significant improvements in downhole rod-type pumps have been in the standardization to achieve interchangeability of pump parts furnished by the various manufacturers. Standardization has been carried on under the auspices of the American Petroleum Institute, which first instituted a degree of standardization in 1927 by the development of Standard 11-A, designed primarily to specify threads and dimensions of the various parts.

In the early 1950's, work was begun by an API committee for the development of a more complete standard to set forth specifications of the complete pump rather than being limited to individual pump parts. In 1961, the API came out with a revised standard which is known as Standard 11-AX. This new standard not only defines the elements of the pump, but in addition specifies pitch length of parts so that the pull tube, pull rod and maximum stroke length of any designated API pump are now interchangeable. This makes it possible now to designate a complete API pump assembly.

The metallurgy of the downhole pump has changed considerably from the initial cold drawn tubing barrel to a variety of materials now available to handle today's difficult pumping assignments. Greater volumes, greater lift depths and more corrosive well fluids have dictated the need for improved materials. Some of these materials are as follows:

(1) Carbon Steel—Shallow to medium depths, noncorrosive wells.
(2) Nickel Alloy Steel—Deep, heavily loaded wells producing well fluids containing H_2S, CO_2, and salt water.
(3) Stainless Steel—Deep, heavily loaded wells producing well fluids which contain severe CO_2 and salt water.
(4) Bronze—Shallow to medium depth wells producing well fluids which contain H_2S and salt water.
(5) Monel—Applicable to heavily loaded wells which are in an extremely corrosive atmosphere.
(6) Tungsten Carbide—Applicable to wells producing extremely high volumes of fluid.

In the early 1920's, considerable effort was made to case harden pump barrels in order to obtain longer wear life in wells producing abrasive well fluids. From this rather crude beginning, heat-treating techniques have progressed through the years, and in 1958 one of the pump manufacturers perfected a selective gas carbonization method for heat-treating pump barrels and pull liners. This method is capable of producing a hard core inside the barrel having a hardness of not less that 58 Rockwell C, which at the same time maintains a tough ductile core having a hardness of 20 Rockwell C.

In addition to the development of improved heat-treating techniques to obtain better wearing materials, similar results have been achieved by chrome plating or colmony spraying some of the wearing surfaces.

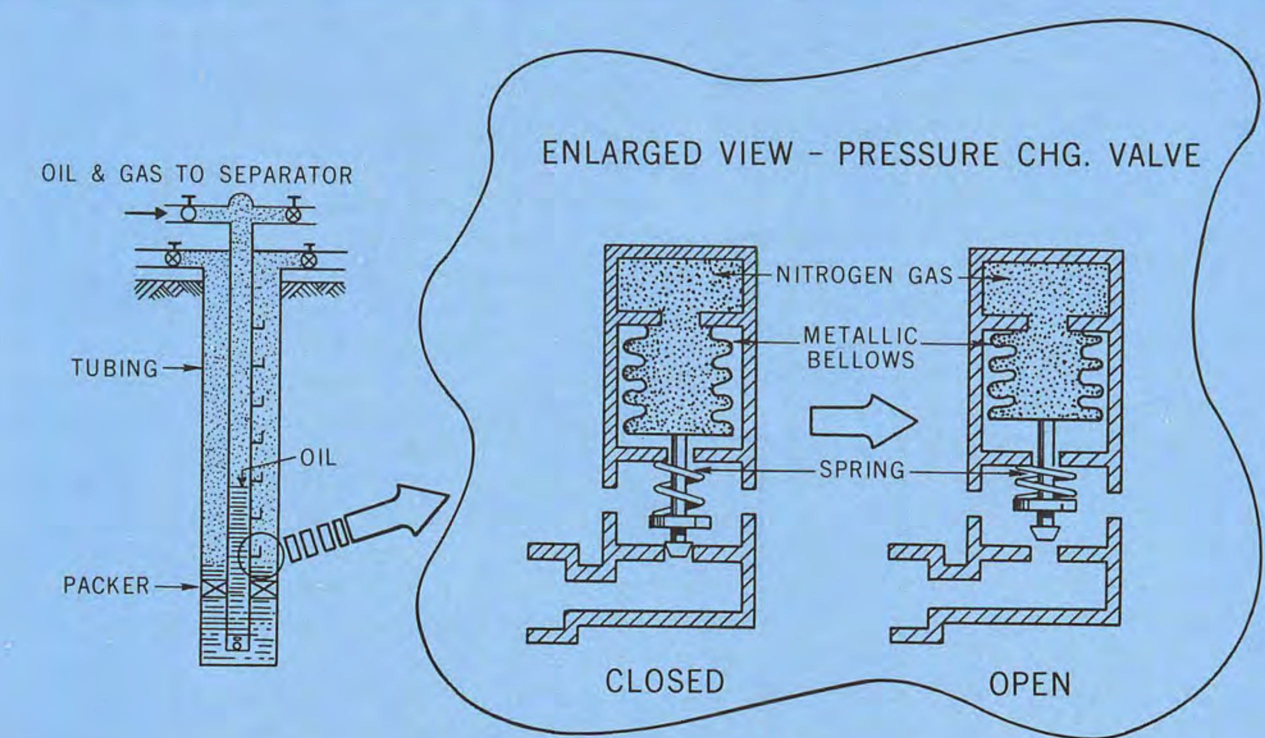
During the last fifteen years, there has been a greater variety of types of wells to be artificially lifted than prior to this time. Multiple completion of artificial lift wells started in the late 1940's followed by tubingless and slim hole completions in the early 1950's. In each instance the manufacturers of subsurface rod-actuated pumps developed the necessary downhole pumps to satisfactorily produce these types of wells. For the dually completed wells, a two-zone (tandem-type) pump was developed to simultaneously produce two zones with a single rod string. In order to produce tubingless and slim hole completions, it was necessary to develop pump adaptors to permit the use of hollow sucker rods to actuate the pump and develop a line of 1¼ inch and 1½ inch pumps for use in slim hole completions.

c. Sucker Rods

The impact of technology on sucker rod manufacturing improvements during the past twenty years very closely parallels the American Petroleum Institute's entrance into and continuing work with the publication of standards for sucker rod production. These standards are incorporated in the API's Sandard 11-B, "Specification for Sucker Rods."

Early API specifications were most specific with regard to sucker rod pin and box thread—form dimensions. All API sucker rods were thus being manufactured with the pins tapered nine degrees from the last fully engaged thread to the pin shoulder and with threads cut into the pin. Matching pin and box threads were held to a close tolerance in the belief that this was the only sure way to insure a secure makeup. However, it became apparent in time that these close tolerances, coupled with small imperfections in the threads occasioned by thread-cutting tools, and the introduction of bits of dirt and grit on location were causing difficulty. Galling, often resulting in stripped threads, was a frequent occurrence. Further, small deformation of the relatively sharp first thread by even a mild accidental blow would

FIGURE **48.** Pressure Charged Valve

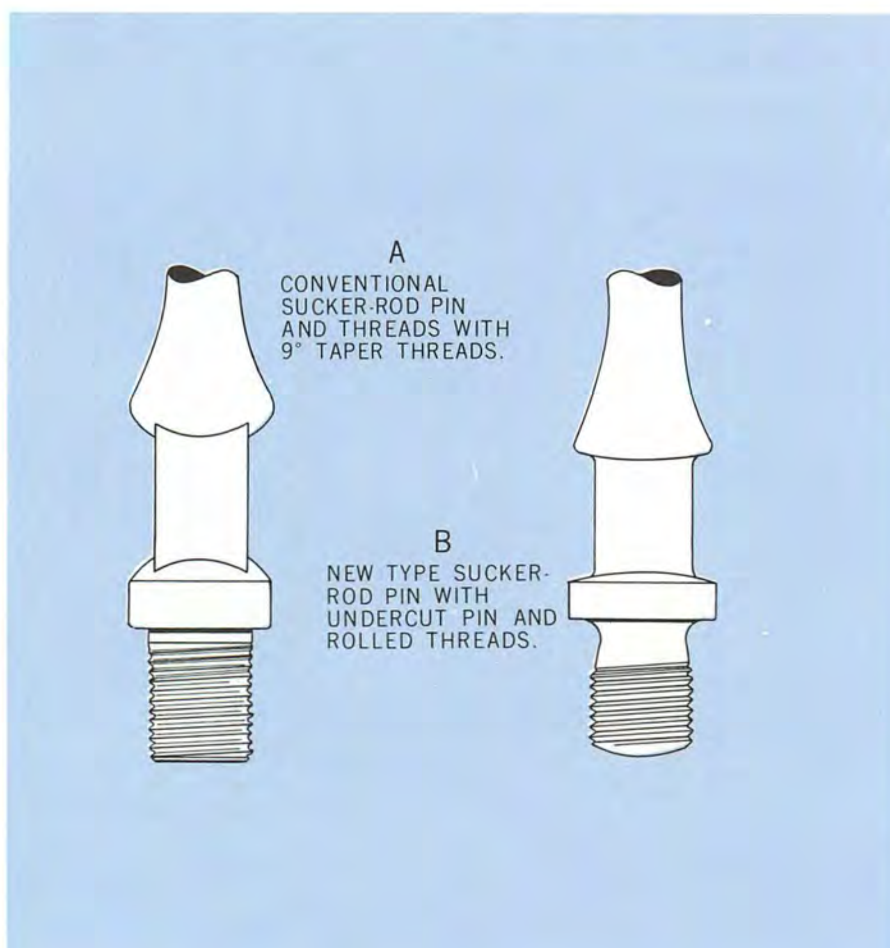


often result in making it virtually impossible for the proper makeup of a coupling. In conjunction with the advent of the undercut pin, discussed later, manufacturers took advantage of the opportunity to introduce rolled threads to the sucker rod industry. This formerly had been impossible due to the obstruction of the nine degree taper to the full travel of the rolling dies. This new smoother rolled thread not only added strength to the rod pin but eliminated in large part previous field makeup difficulties.

With regard to the nine degree taper from the last fully engaged thread to the pin shoulder, field experience with the run-out thread impressed on this taper began to indicate a decided weakness in this pin configuration. As it became necessary to pump wells from deeper depths, it became apparent that the weakest point in the rod string, generally speaking, was in the pins themselves. Probably more pin breaks were occurring than all other rod failures combined.

As early as 1949 the API committee on standard designation of production equipment placed on their agenda the discussion of stress-relieved pins. This subject was discussed by the committee until 1956, at which time no further work was reported and, due to an apparent lack of interest, it was again dropped from consideration. However, in 1959 and 1960, this item was again placed on the agenda; and by this time one manufacturer had already introduced the undercut pin and rolled thread on a ½ inch sucker rod, and one of the industry's major users reported that he had obtained better than one year's service from this type of pin with no failure. At the 1961 midyear meeting, the production equipment committee approved the stress-relieved (undercut) sucker rod pin. It was subsequently approved by the API Executive Committee and incorporated into the next edition of the API Standard 11-B. Figure 49 is a schematic sketch of the conventional nine degree

FIGURE **49.** Sucker-Rod Pin Ends



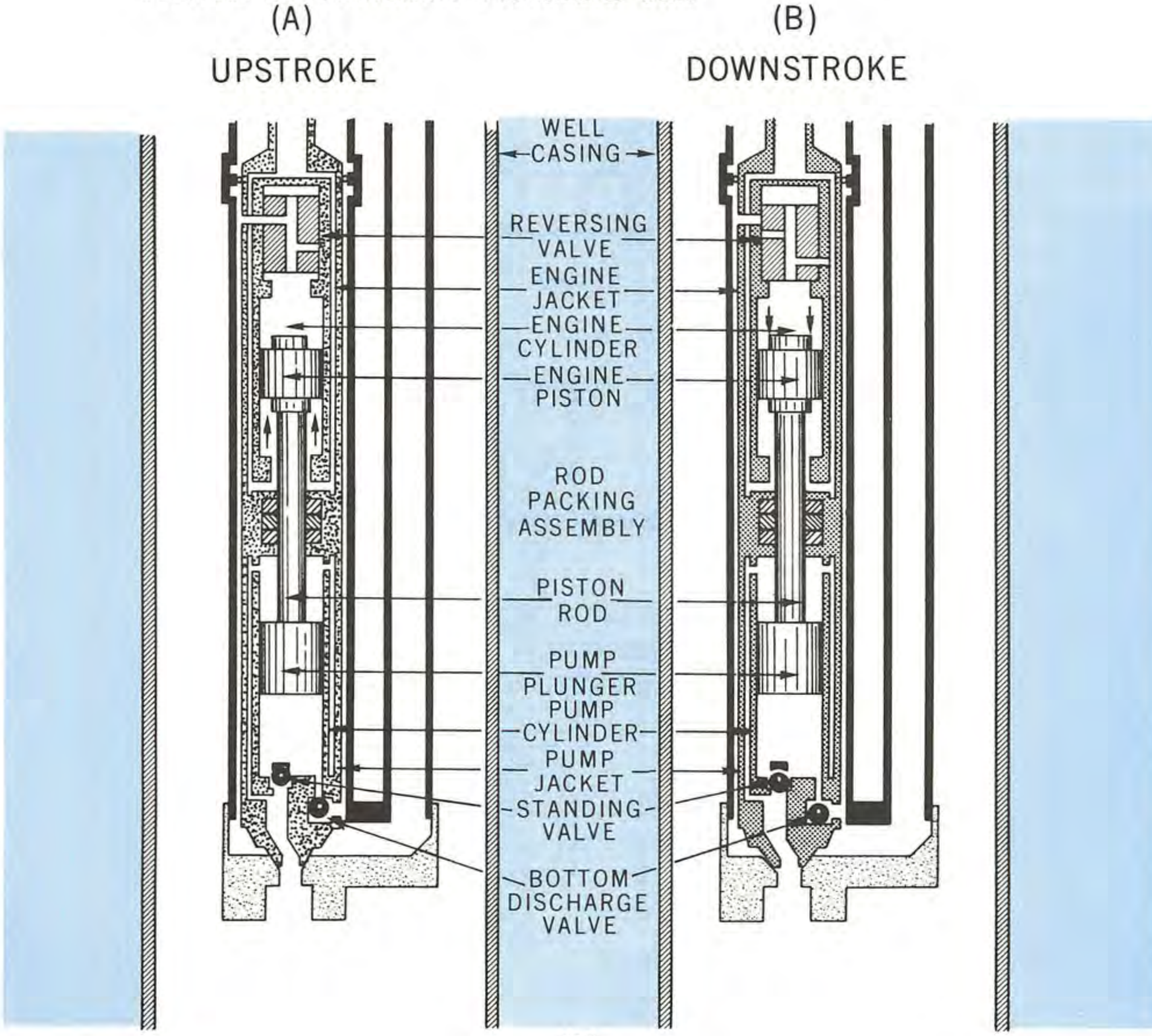
taper pin and the newly approved undercut pin with rolled threads.

The metallurgy of the basic steels employed in sucker rod manufacturing has not changed to any extent for several years. The carbon manganese and nickel molybdenum steels were being utilized as early as the 1920's; however, through experimentation, both within the API and private research, there has been considerable refinement of these steels. Recent developments in the sucker rod industry have enabled manufacturers to come closer to obtaining all of the desirable properties from the basic steels. These concepts are primarily in the field of normalizing techniques and superior quenching methods. The new normalizing facilities now in operation permit rapid heating, with a uniformity of temperature throughout the rod. This, coupled with proper control quench application, has resulted in sucker rods having a more refined grain structure, a marked improvement in hardness uniformity, and a tensile strength limited only by reluctance to harden to embrittlement.

3. SUBSURFACE HYDRAULIC PUMPING

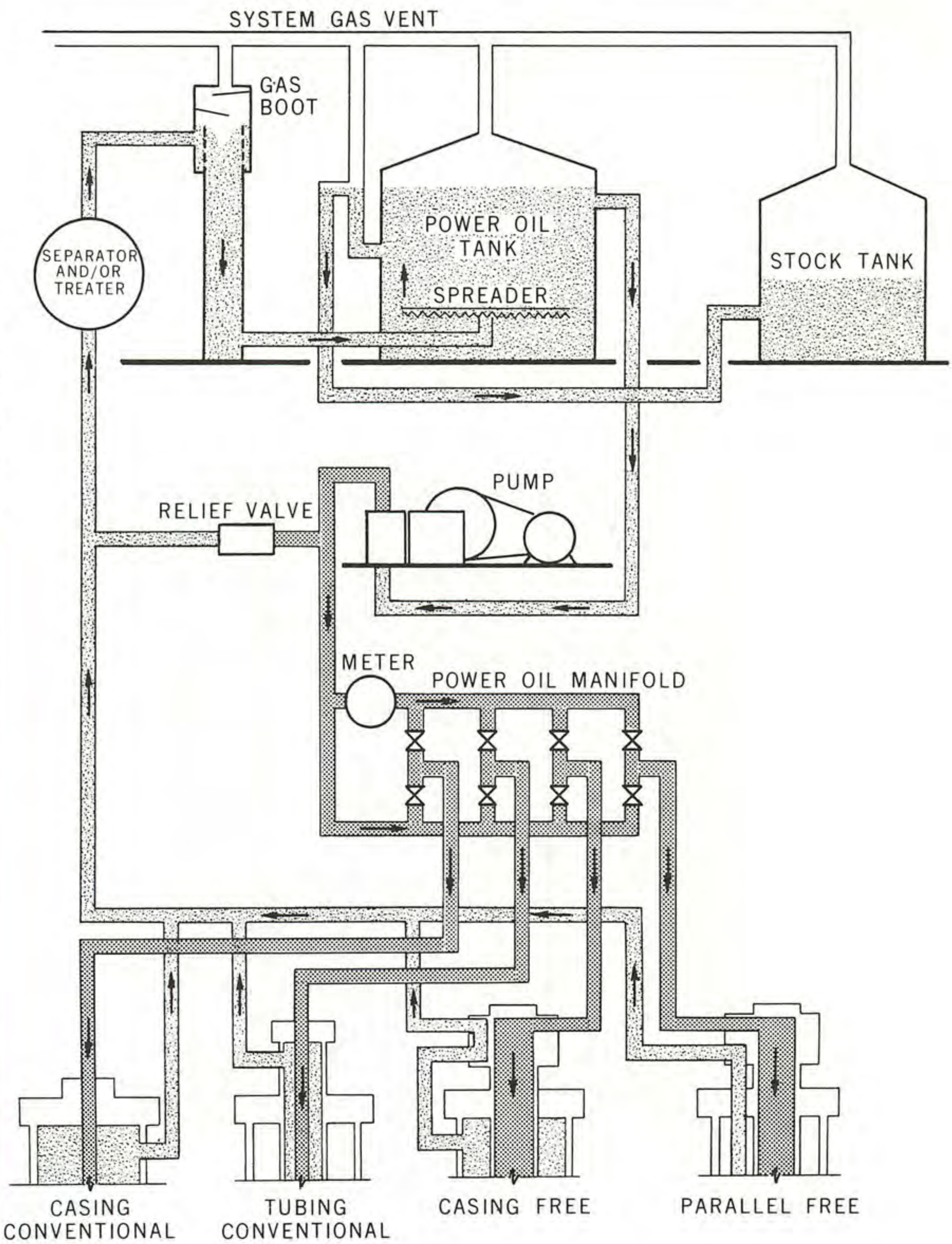
The basic difference between subsurface hydraulic pumping and sucker rod-type pumping is in the power-transmitting medium. In subsurface hydraulic pumping operations, oil under moderately high pressure is pumped from the surface of the ground to the bottom of the well, usually in a continuous unidirectional flow, to actuate a hydraulic engine. The engine is an integral part of the subsurface production unit which in turn operates the pump portion of the unit. Figure 50 is a sketch of the subsurface production unit. The oil which is used as a power-transmitting fluid (power oil) is generally the oil which has been produced from the oil well after the gas, water, and sand have been removed to a point substantially better than required for sale to the crude oil purchaser.

FIGURE **50.** Subsurface Production Unit



The layout of the lease surface equipment required for a hydraulic pumping system is illustrated in Figure 51. The sequence of operation begins with the power oil (clean crude oil) which is drawn from the power oil tank into the power oil pump. This pump delivers the power oil at the required pressure to the power control manifold, from which the power oil is directed to the individual wells through individual power oil lines and power oil tubing to the subsurface production unit. In an open power oil system, fluid returns to the surface as a mixture of produced well fluid and exhausted power oil which is conducted through the flowline to the tank battery. The oil in excess of that required for the power oil pump represents lease production and is directed into the lease stock tanks.

FIGURE **51** Surface Installation Hydraulic Pumping System



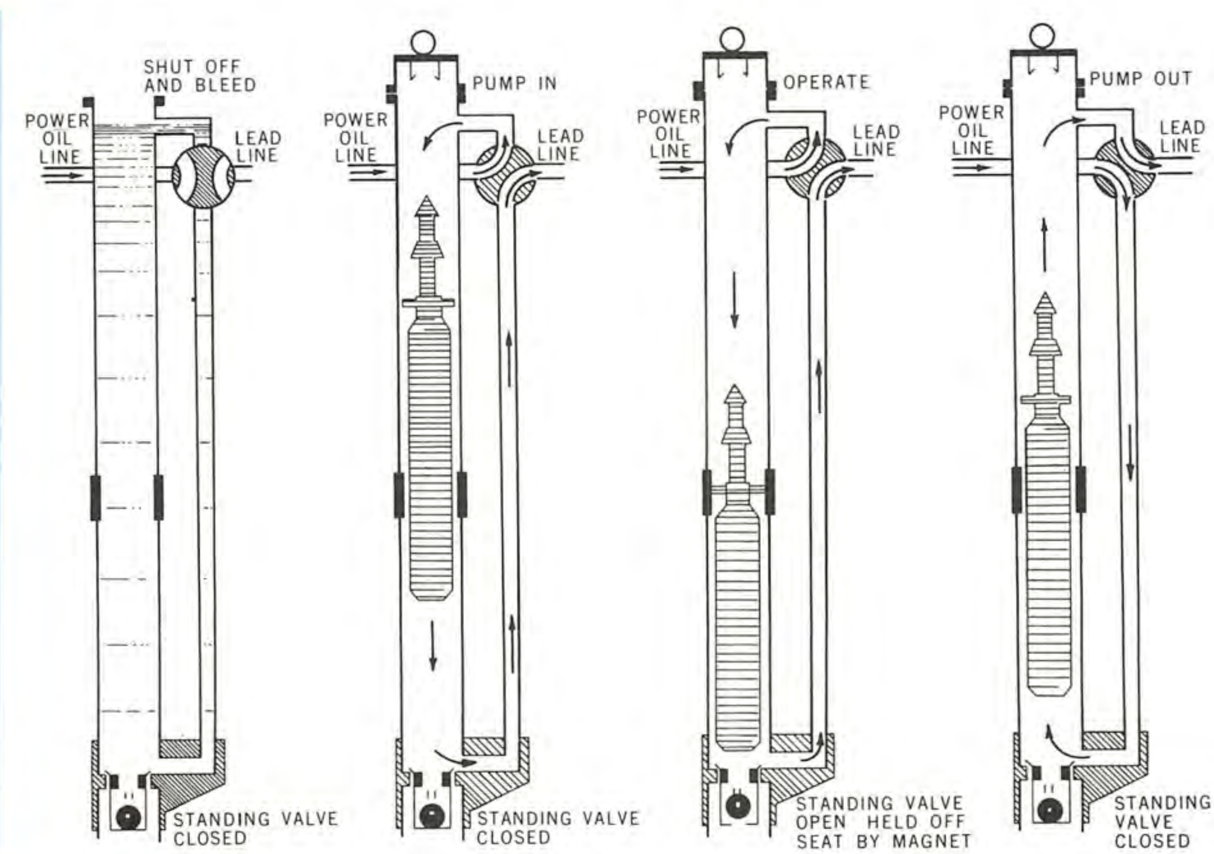
In the closed power oil system, exhausted power oil is returned to the surface and back to the power oil tank through a separate flow passage rather than being commingled with the produced well fluids.

The first commercially successful hydraulic pumping system was introduced in the 1930's and was a conventional insert-type installation. Although a number of improvements on the downhole hydraulic engine and pump were made in the 1930's and early 1940's, a major breakthrough in subsurface hydraulic pumping was the advent of the free pump system introduced in 1948. The free pump differs from the previous systems inasmuch as the production unit (hydraulic engine and pump) is not attached to the tubing and can be run into the well or removed from the well without having to pull the tubing. The production unit proper is the same as is used in a conventional installation, but which has had a packer nose-assembly added to provide a pressure seal in the tubing. Figure 52 is a schematic diagram showing the principal technique of a hydraulic free pump. With the free parallel system, a small tubing string is run parallel to the regular tubing string and is stabbed into a crossover shoe to provide a fluid passage to return the produced well fluid and exhausted power oil to the surface. Power oil can be directed down the regular tubing string to pump the unit onto its seat, at which point the unit is ready for operation to produce fluid from the well. By reversing the flow of the power oil, it is possible to raise the pump to the surface for observation and repair.

The free casing system utilizes the casing annulus as the second flow passage rather than utilizing a parallel tubing string. The casing system necessitates that formation gas must be produced through the pump, whereas in the parallel system formation gas can be vented to the casing annulus.

With the advent of the free pump concept and the obvious economics resulting therefrom, subsurface hydraulic pumping equipment has become increasingly popular, particularly for pumping the deeper wells. With the greater market which has

FIGURE **52.** Free Pump Principle



resulted, several manufacturers have entered the field and the resulting competition has led to improved design throughout. However, generally speaking, the development and research efforts of the manufacturers have concentrated on the subsurface components of the system.

Although it is not practical to attempt to detail all of the improvements which have been developed in subsurface hydraulic pumping since the advent of the free pump concept, a few of the more important advances will be enumerated.

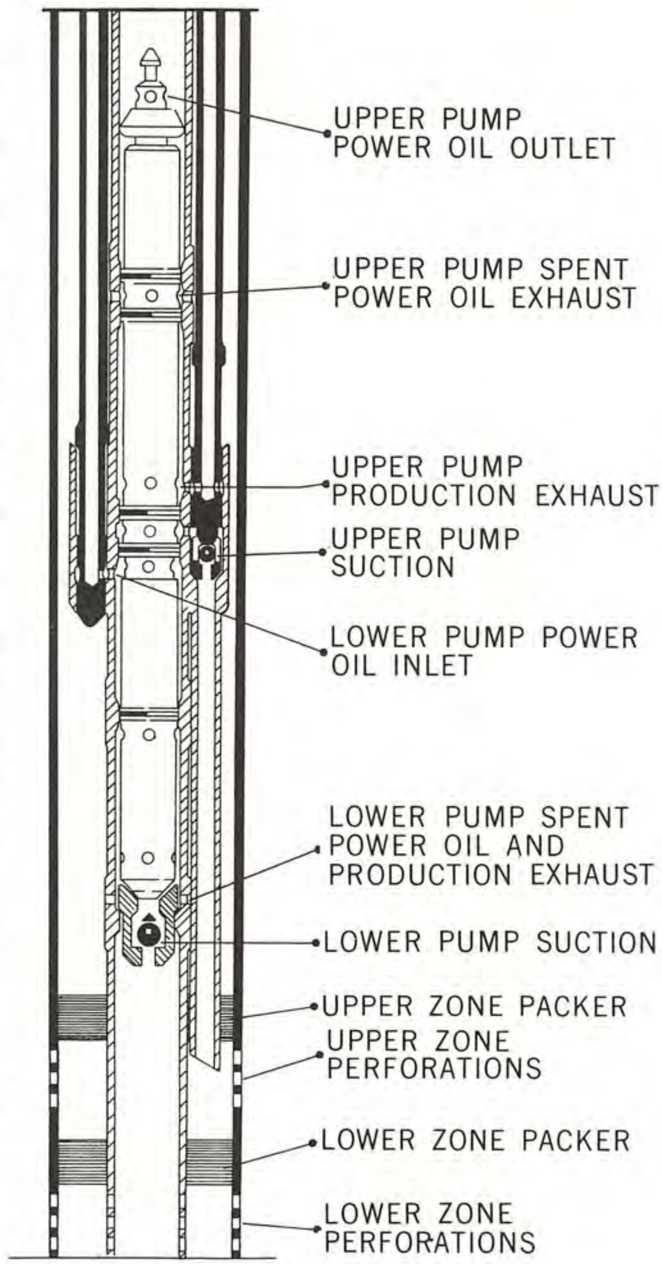
One of the major contributing factors to pump failure, whether it be with a rod-type pump or a hydraulic-type pump, is fluid pound caused by incomplete filling of the pumping chamber. In a hydraulic unit, this condition becomes even more serious than in the case of rod pumps because of the relatively high speeds which can be attained by the pump plunger before it hits solid fluid in the pump chamber. The suppliers of hydraulic units have taken various approaches to this problem, based on the characteristics of their unit design. For example, in the double-acting unit maximum piston velocity is limited by the governing effect built into the engine's hydraulic circuit. On the other hand, one of the companies producing a single-acting pump uses a selectively sized restriction in the hydraulic circuit which limits downstroke velocity which does not affect power consumption on the pumping stroke. One of the manufacturers employing the single-acting balanced design has in a large part overcome the problem of the unfilled chamber by "flooding" the pump chamber at the end of the suction stroke with spent power oil. This "flood valve" arrangement also prevents gas lock and improves low efficiency caused by free gas in the pumping chamber.

Of real significance in the matter of improvements of the subsurface hydraulic production units is the fact that during the last few years competitive manufacturers have developed units capable of providing approximately three times the displacement rate in a given tubing size as compared to pumps available before 1960. Additionally, subsurface units are now available with a double engine end or a double production end to reduce operating pressures or increase displacement rates.

In addition to improvements in the basic design concepts of the production unit, metallurgical improvements have been made which extend the service life of the component parts. The selection of special materials, surface finishings, and heat treatment have combined to provide increased resistance to wear and corrosion under adverse operating conditions.

Aside from the advances made in the production unit design, progress has also been made in developing the accessory subsurface equipment for special application of hydraulic pumping. One of the significant advancements in this regard was the development of equipment to permit independent landing of two or more parallel tubing strings in the hydraulic pumping installation. The parallel free pump installation frequently offers the more efficient hydraulic operation because of its capacity to produce free gas through the casing annulus; however, prior to the development of independently landed parallel strings, this arrangement had the drawback of time-consuming simultaneous running of clamped tubing strings. The independent landing technique has opened the way for a variety of parallel string installations which

FIGURE **53.** Tandem Dual Zone Installation



have broadened the range and application of hydraulic pumping.

With the increasing number of multiple completion oil wells in recent years, subsurface hydraulic pumping manufacturers have adapted the design of their units to accommodate this situation. One of the designs is called a tandem dual zone installation in which two hydraulic production units are physically connected into a tandem assembly to facilitate running and retrieving, but they are entirely separated in their hydraulic circuits. This arrangement provides completely independent operation and control of the two units and is a highly desirable feature for dual zone pumping equipment. The tandem assembly can be surfaced for inspection and repair simply by reversing the power oil flow. Each unit in the tandem assembly can provide rated displacement capacities up to 400 barrels of oil per day for depths in the 10,000-foot range. Another method of handling a dual zone completion is in the parallel installation. In this type of installation, two strings of $2\frac{1}{16}$-inch OD and one string of 1.315-inch OD tubing would be run in $5\frac{1}{2}$-inch casing. Free pump production units to operate in $2\frac{1}{16}$-inch OD tubing would be run to produce from the two completion intervals. A diagrammatic sketch of the tandem dual zone installation and the parallel dual zone installation is shown in Figures 53 and 54, respectively.

In addition to improvements in the downhole equipment, advancements have also been made in the

FIGURE **54** Parallel Dual Zone Installation

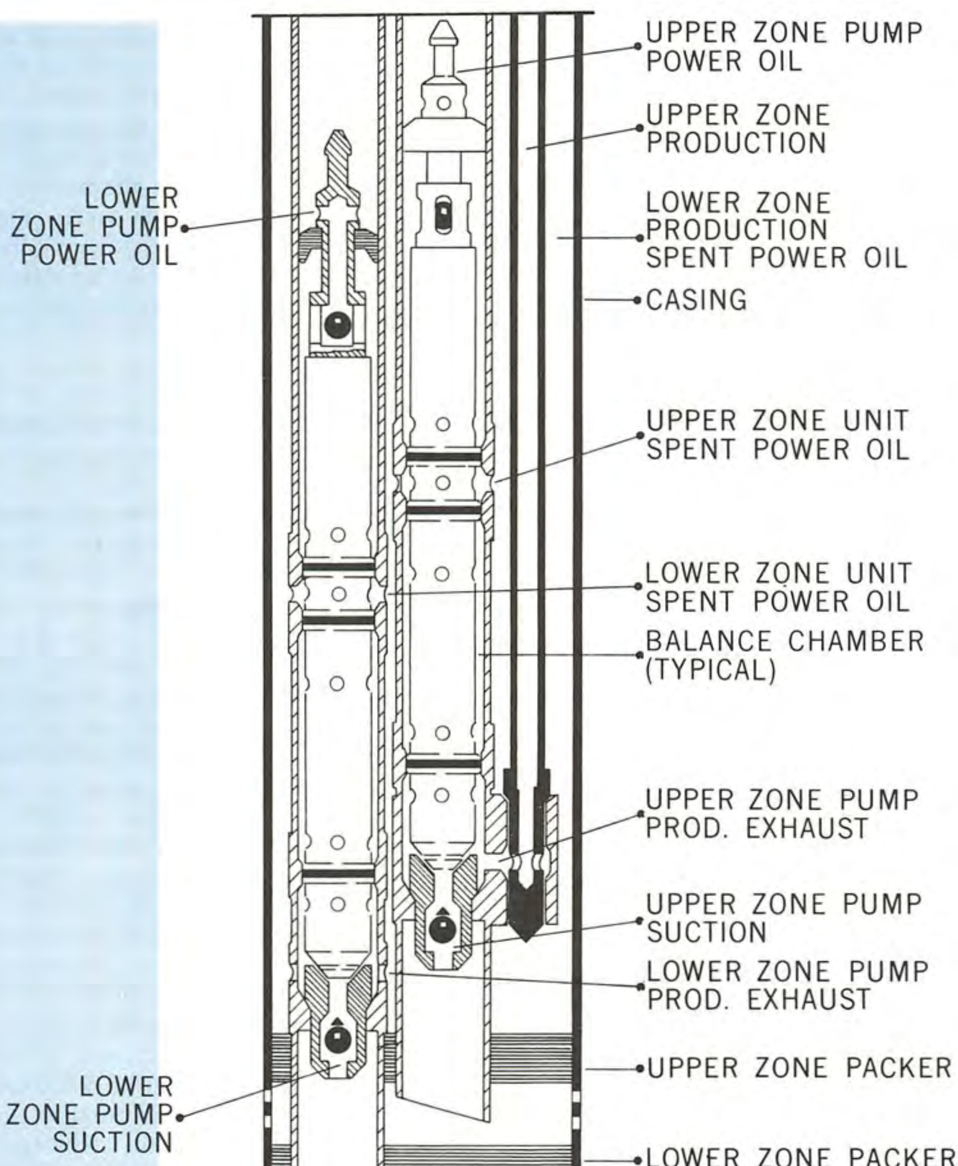
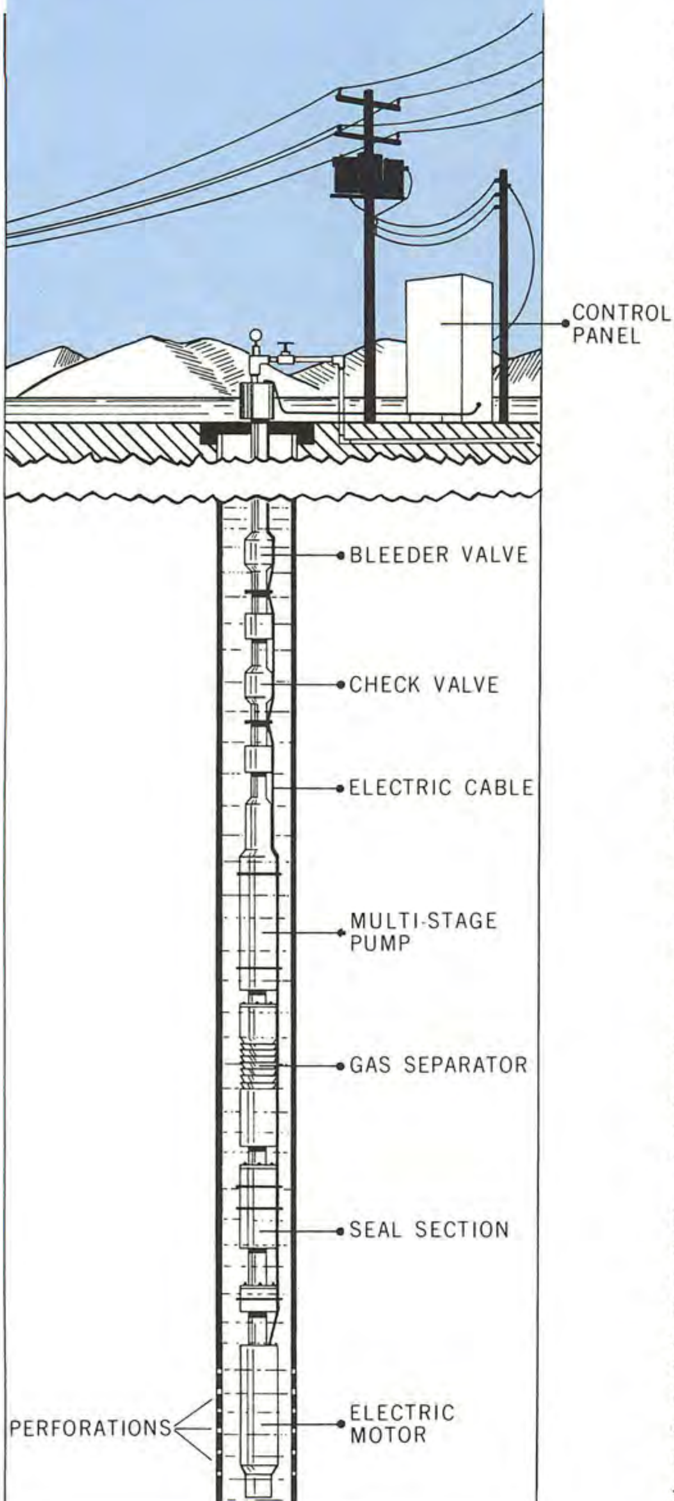


FIGURE **55**
Typical Submergible Pump



power oil pumps, manifold systems for controlling the flow rate and distribution of power oil to various producing wells, as well as in the metering equipment. One of the recent improvements relates to the surface installation which permits unattended pump-out operations of the free pump. In this regard, any free pump installation where high-pressure power oil is used to circulate the production unit from the bottom of the hole to the surface, controls at the well are required to direct the power oil and the production through the proper downhole circuits during the operating and pump-out cycles. A latching device is also needed to catch the production unit when it is circulated to the surface. Likewise, a safety relief is desirable to protect the production string or casing from excessive pressure during pump-out. Recently, a specially designed wellhead control has been devised wherein the control valves are set to circulate the production unit to the surface and the control provides automatically reset pressure relief protection, securely latches the surface unit and then safely bypasses the circulating fluid. With these operating features, the pumper is free to return at his convenience to the well to remove the surface unit. The time which would otherwise be spent by the pumper in attending the pump-out operations can be used to advantage in his other duties in the operation of the lease. The resulting economics are readily apparent.

4. ELECTRIC SUBMERGIBLE PUMP

An electrical submergible pump is essentially a multistage centrifugal pump connected directly to a submergible electric motor. The pump-motor assembly is run in the well suspended as a unit on the tubing with a cable from the surface supplying electricity to the motor. Figure 55 shows a sketch of an electric submergible pump installation. Improvements in the hydraulic design of submergible pumps have effected a higher operating efficiency of this type of installation ranging from five to fifteen percent higher than pumps of comparable capacity ten to fifteen years ago. In conjunction with more efficient hydraulic design, the manufacturers have been able to increase the product reliability of the downhole equipment such that the frequency of pulling jobs is, on the average, approximately sixty-five percent of what it was twenty years ago.

One of the factors contributing to product reliability has been in devising methods to prevent the entry of well fluids into the motor section of the unit. Failure of the motor due to fluid entry has been corrected in a large part by improvements in the mechanical seals, plus a pressure-balancing arrangement such that the internal motor pressure is essentially equalized to the submergent pressure, thus practically eliminating the pressure differential across the seals which would cause leakage into the motor section. Another improvement in electric motors has been brought about by newly developed insulating materials which will withstand higher temperatures than previously, and which will not hydrolize in the presence of moisture.

One of the weaker points in the early electric submergible pumps was in the thrust bearings of the unit. Because of the very limited diameter and the relatively small area over which to distribute the very great thrust-loading imposed on the bearing, this has been a very difficult problem to overcome. However, manufacturers have improved the design of the thrust bearing such that the expected life of these bearings is approximately two times as great as in the original unit.

One of the problems in operating a submergible pump has been the development of a reliable, effective gas-liquid separation system. With the relatively high speed of operation of the centrifugal pump, if the pump becomes starved for fluid (liquid) because of gas lock, the pump will fail within a very short period of time. Submergible pump manufacturers have greatly improved the downhole gas-liquid separation system whereby only a very minimum amount of free gas enters the pump section, assuming of course that the pump is otherwise submerged in liquid.

The cable used to conduct the electrical current from the surface to the downhole electric motor has been improved materially by employing improved insulating materials that will withstand higher temperatures for a longer period of time and will withstand deterioration in the presence of hydrocarbons or corrosive fluids at higher temperatures than were possible twenty years ago. Cable is now available to withstand temperatures for a relatively long period of time of up to approximately 300 degrees, whereas in 1946 the maximum allowable temperatures were of the order of 170 degrees. This means of course that pumps can now be run to a substantially greater depth than would have been possible in 1946.

Submergible pump manufacturers have developed systems whereby a pressure bomb can be run below the production unit and the actual operating pressure and/or static pressure can be determined at the surface of the ground. This equipment allows for continuous accurate monitoring of operating pressures and provides accurate readings of the actual submergence pressure in pounds per square inch without having to rely on sonic wave measuring devices or having to run a bottom hole pressure bomb into the hole on a wireline.

Continuous readings are available regardless of whether the well is at static level, pumping down, at a settled pumping rate, or filling up. As stated previously, a submergible pump will not operate long when it becomes starved for fluid. The new monitoring devices eliminate the question of fluid gradient inherent in the use of sonic wave devices. Whereas previously, an operator might think that he had as much as several hundred feet or even several thousand feet of submergence at a certain pumping rate as indicated by sonic measurements, actually the submergence of the pump might have been in a frothy, lightweight column of gas and oil or gas-cut oil and water, and the pump would fail due to its becoming starved for fluid.

By the use of the new pressure monitoring devices, valuable reservoir and pump performance data are readily available. For example, a steady decline in bottom hole pressure may indicate any one of the following conditions:

(1) Well plugging.
(2) Decline in reservoir pressure.
(3) Well interference.

A gradual or sudden increase in bottom hole pressure might indicate that the pumping equipment has become worn or is plugging up for some reason or that there is a tubing leak or casing failure. By correlating past and present pressure readings from the same well with offset well data, the operator can determine the probable cause of the pressure variation and take corrective action.

With the increased product reliability and the higher efficiency being built into the present-day submergible pumps, the cost of operation of this type of pumping equipment has been reduced very markedly, thus making it a very desirable type of installation in many situations. Conditions favoring the installation of an electrical submergible pump are those wells capable of producing at high rates which have sufficient producing formation pressure to maintain submergence of the pump. The Arbuckle formation production in Kansas, as well as a great many water flood operations in many different areas, are only two of a great many applications for which electrical submergible pumps are ideally suited.

D. Gathering Systems

The term gathering systems, as used in this discussion, relates specifically to crude oil and/or gas lines extending from individual wellheads to the lease storage or metering point where the produced hydrocarbon fluids are sold to the purchaser.

1. OFFSHORE

Basically, the methods of producing and handling fluids produced from offshore wells is the same as for onshore operations: the wells are produced, the liquids and gas are directed to a location where the water and gas are separated from the oil, and the marketable hydrocarbons are tendered for sale to the purchaser. However, offshore operations multiply severalfold the problems and expense of onshore operations. The solution of the inherent problems of offshore operations and making offshore production economically feasible is almost entirely a new development in the last twenty years. To attempt to cover the entire scope of these rapidly changing developments is beyond the scope of this discussion.

Even the enumeration of the problems of offshore operations would be a treatise in itself; however, basically the problems are those of transportation, communications, living arrangements for personnel, wave action, weather, limited working space with resultant increased fire hazards, safety, and protection from pollution—to name just a few. Combating corrosion is an extremely important factor to be taken into account in offshore operations. High humidity, salt water spray, alternate immersion in salt water and exposure to air at tide levels all contribute to corrosion of structures and equipment.

Initially in offshore operations, if an operation were fortunate enough to find production, the operator would simply install a separator and one or more small tanks on the drilling platform, and empty oil from the tanks into barges to be towed to shore and there sell the production. In some cases, the operator would produce directly from a well to a separator set on the barge deck, with the liquid being discharged from the separator into the barge; however, this type of operation can be conducted only in calm seas and thus involves a great deal of shut-in time for the well.

Another arrangement used, involving the use of a barge, employs a "carousel buoy" in conjunction with a barge. In this case, production lines from the well or wells are laid on the ocean floor to the anchored buoy with the production barge being moored to the buoy and allowed to swing with the winds and tides. By means of flexible couplings the production is flowed into the moored barge. When the barge is full of oil, another barge is towed to the location to pick up the production from the moored barge.

Another method of handling the production from offshore oil wells, particularly where an operator has a number of wells in a field, is to construct a production platform well above the water line and erect storage tanks, separators, testing facilities and related production equipment on the platform. In some cases, such platforms may be quite elaborate, with living quarters for the crews and storage facilities for several thousand barrels of oil.

In some cases, the full well-stream produced at the wellhead is delivered to onshore stations for treatment, storage and/or metering before delivery to the crude oil or gas purchaser. The gathering lines leading from the wellhead to the treating station often extend over very great distances as compared to onshore operations. Usually, the offshore lines are welded steel construction and are laid on the ocean or bay floor. In recent years, highly sophisticated barges have been designed to implement the welding and laying of these lines.

Due to the corrosive environment on the ocean floor, steps must be taken to prevent premature failure of gathering lines in offshore operations. Various types of wrapping and/or coating material have been developed to provide a physical barrier between the corrosive water and the steel pipelines. However, even with the best coating system, put on under the most rigidly controlled specifications, "holidays" or unprotected spots in the coating and wrapping inevitably develop. The most common method of protecting against such conditions is through cathodic protection. This is the technique of impressing an electrical current in the pipeline to overcome the outward flowing current present in natural corrosion processes. In this regard, two types of protective current sources are available. Where the current demand is large, direct current generators or rectifiers are employed. Under less severe conditions, the necessary current can be provided by anodes constructed of less noble metals than steel, i.e., magnesium, zinc, aluminum, etc. In any event, the anodes will be sacrificed or destroyed by the protective current which they discharge to the water, mud and soil environment to which the lines are exposed. Under favorable conditions, well-designed systems can be made to last several years before replacement of the line is necessary.

The above cited steps are designed to protect the outside of the gathering lines. The inside surfaces are also often subjected to corrosive environments as a result of the salt water produced in conjunction with the oil and gas. Dissolved acid gasses such as carbon dioxide and hydrogen sulfide are often present in the produced fluids and the resultant corrosive condition of the inside of the pipeline is greatly increased thereby. To combat this condition, either of two types of internal corrosion control is employed as necessary. The first involves linings which physically prevent corrosive fluids from contacting the steel. Early developments in internally coated pipe employed cement lining material. This material proved quite effective and is still used to a very considerable extent today. The development of new plastic materials has made rapid progress within the last fifteen years and this type of internal coating material is being used in increasing quantities as materials and techniques of application are constantly being improved. The major problem in any type of internal coating is to insure as nearly a uniform coating throughout the entire length of pipeline as possible without exposing any bare metal to the corrosive fluids being conducted through the pipelines. A major point of weakness in this process is in the pipe joints.

The other method of preventing corrosion to the interior surfaces of the gathering system involves the use of chemical inhibitors. In the last twenty years a wide variety of chemical compounds has been developed that effectively inhibit natural corrosion processes. Surprisingly small concentration of these chemicals can reduce corrosion rates to acceptable levels.

On occasion corrosion-resistant metals are selected for construction of gathering lines; however, ordinarily the high initial cost of such metals usually prevents the routine employment of such metals. Perhaps one exception to this rule is the application, in limited instances, of lines made of special, relatively inexpensive aluminum alloys.

The techniques of corrosion control, both diagnosis and prevention, are highly technical and demand extensive investigation on the part of a specialty engineer. Work of the National Association of Corrosion Engineers has contributed greatly during the past twenty years to the reduction of corrosion costs.

2. ONSHORE

Generally speaking, gathering lines installed in land operations are much shorter and involve far less investment per foot of installed line than in the case of offshore installations. Because of the fact that any leaks which may develop in gathering systems on dry-land operations are much more easily detected than in offshore installations and the fact that repairs can be made at far less expense than in the case of offshore installations, it is not necessary to employ the degree of protection against corrosion that is necessary in offshore installations. The soils traversed by onshore installations are very often corrosive, however, not to the same degree as offshore installations. Even so, it is usually desirable to provide protective coating and/or cathodic protection of the gathering system where known corrosive conditions exist.

In the previous discussion it has been pointed out that internal plastic-coating of gathering systems is often employed to overcome corrosion from the fluids transported through the gathering system. A side benefit has been realized from internally plastic-coated lines in cases where paraffin has a tendency to accumulate in the gathering system. The smooth surface of the plastic coating material has been found to overcome in a very large degree the accumulation of paraffin in such lines. In cases other than where internally plastic-coated lines are employed, chemical solvents and oil soluble plugs or "pigs" are often employed to physically remove paraffin deposits by pumping such material through the gathering lines. The selection of a specific preventative procedure regarding paraffin accumulation is determined by local conditions.

3. SALT WATER DISPOSAL

The handling and disposal of produced salt water during the course of the last twenty years has become an increasingly important phase of oil field operations. In order to protect underground, fresh water sands from contamination by seepage of salt water from surface evaporation pits, the oil industry has made tremendous strides in providing for underground disposal of the produced salt water. The horizons selected for the disposal of such salt waters are salt water-bearing formations which cannot be used for human consumption or for agricultural irrigation sources. The expense of collecting, treating and disposing of the produced salt waters is in many cases a very major portion of the operating expense involved in oil-producing operations. Care must be taken in providing corrosion-resistant salt water gathering and disposal lines and related facilities to avoid, insofar as possible, major operating and maintenance expenses which would otherwise be incurred. In addition to using internally coated steel lines, it is often feasible to use plastic pipe to handle the produced salt water. Very rapid strides have been made in the design of new types of plastics which will not deteriorate as rapidly as did the early plastic lines which came out in the late 1940's and early 1950's and will withstand higher temperatures and pressures. Some of the newer types of plastics which have proved to be quite effective are: Polyvinyl chloride (PVC), polyethylene, polypropylene and acetal resins. In addition to the extruded plastic pipe, important advances have been made in glass reinforced epoxy resin (fiberglass) tubular material.

E. Lease Automation

A degree of automation in the operation of oil field equipment has been in use for many years; for example, in the case of the gas-oil separator where oil is separated from the gas and is automatically dumped from the separator into the storage tanks. This operation involves a single, simple automatic operation. Automation, as commonly referred to today and as discussed herein, involves more than the automatic control of a single function or a series of single functions. Rather, it is the linking together of a series of controls to perform functions in the operation of an oil or gas lease which would otherwise require manual labor and close supervision of each individual function performed. The development and implementation of lease automation as discussed herein has all been developed within the last twenty years, with much of the development being in the last eight years.

Automatic lease operating functions can be broken down into the following categories:

(1) Automatic well control.
(2) Automatic well testing.
(3) Automatic tank battery control.
(4) Automatic custody transfer.
(5) Automatic lease process equipment control.
(6) Automatic supervisory control.

1. AUTOMATIC WELL CONTROL

Automatic well controls are usually located at the wellhead to regulate or control the flow or the operation of a particular well. Some of the functions that can be performed are:

a. Control the zones from which a multiple-completion well produces at any particular time.
b. Shut in the well.
c. Divert the production from the well through test facilities.
d. Regulate the length of time that a well is produced (artificial lift or flowing

wells), using time-cycle controls.

e. Indicate when a well may be off production by means of flow—no flow valves.

f. Regulate the rate of production with automatic variable flow control valves.

All of the automatic controls enumerated above can be designed to be operated by manual adjustment or by remote control through a control panel.

2. AUTOMATIC WELL TESTING

Automatic testing of wells requires the proper instruments and control devices to provide accurate measurement of a well's production over a given period of time. The functions performed by automatic well test equipment involve instruments and devices to automatically switch wells from the normal production facilities to the test facilities. This must be accomplished in a desired or predetermined sequence and for a desired length of time. It must be able to measure and record the volumes of oil, gas and water produced. Usually, the programming of the well test unit is done by means of a time-cycle controller. This controller may actuate the related valves and test facilities either pneumatically or electrically. The signal from the controller is used to energize the control valve on the well manifold, thus directing the production from the normal production facilities to test. Here again the control panel can be manually adjusted on location or controlled remotely. The metering facilities used in conjunction with automatic well testing are generally one of three types:

(1) Volume-type meters.
(2) Positive displacement meters.
(3) Capacitance product analyzers;

The volume-type meter consists of (1) metering separators, (2) liquid volume tank meters, and (3) metering treaters. All three of the above consist primarily of a volume chamber in which a predetermined volume of liquid is measured where the operation of this type meter is by liquid-level controls to open and close a fill and discharge valve at predetermined levels. From this a signal is sent to a meter counter to account for the volume of fluid measured.

The positive displacement meter consists of a stationary case and a mobile element that encases a fixed volume of fluid in its cycle of operation. Provision must be made to assure that the oil and gas are completely separated and that no free gas goes through the liquid meter because of the obvious erroneous readings which would evolve if gas were allowed to go through the meter. Increased accuracy can be obtained in a positive displacement meter by regulating the rate of flow, if possible, to a relatively uniform rate. Although gas measurements during testing can be accomplished by differential pressure flow meters, such measurements are more generally accomplished by means of a positive displacement gas meter.

The capacitance product analyzer is one of the latest additions to the field of measurement of oil and water. This type of equipment can be used to measure the complete liquid stream from the well (it is not necessary to separate the oil from the water). This is accomplished by the measurement of the dielectric constants of the fluids flowing through the analyzer. The detection of the dielectric is made by the use of a sensitive capacitance probe. Oil has a low dielectric constant whereas water is usually characterized by a high dielectric constant. The measurement of the dielectric constant of the mixture of oil and water will indicate the percent of oil in the total flowstream. Very often the equipment involved in this operation is skid-mounted as a packaged unit. In operation, the turbine or positive displacement meter will send out impulses as fluid is passed through the meter. These impulses are signaled to the capacitance analyzer which in turn diverts these impulses to a net oil counter or net water counter depending upon the percent of oil in the total stream indicated by the capacitance analyzer.

3. AUTOMATIC TANK BATTERY CONTROL

Automatic tank battery controls include devices to permit the filling of each tank in a battery in sequence to a predetermined level and then automatically switching the flow to the next tank available for filling. Controls can also be provided which will prevent the filling of a tank when such tank is "on the line" (oil being run to the pipeline). Also, these controls can be made to shut in all of the wells on a lease when all the tanks in a battery are full. Alarm signals can be provided for high liquid level in the tanks or when a lease is shut in. Additionally, controls can be provided to automatically recirculate tank bottoms.

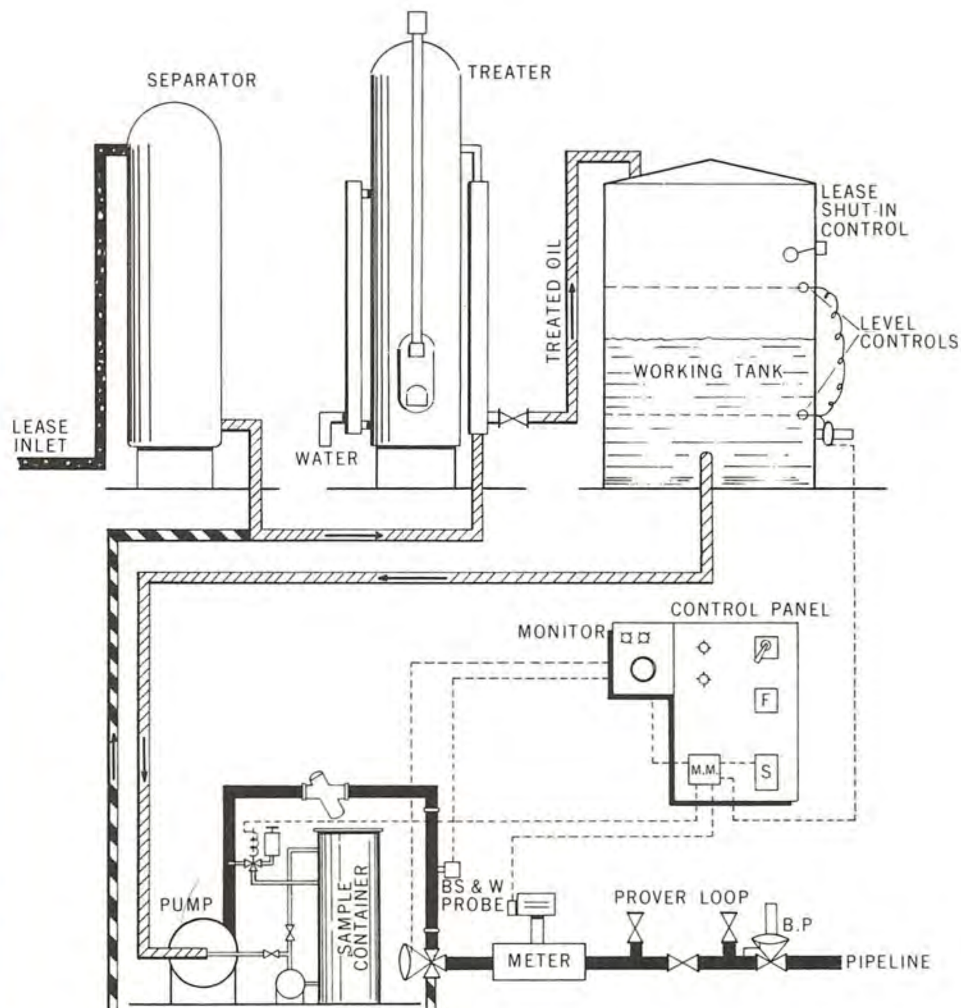
4. LEASE AUTOMATIC CUSTODY TRANSFER

The term "lease automatic custody transfer" (LACT) refers to the selling of oil from a lease to the crude oil purchaser on an unattended automatic basis as opposed to the conventional means whereby oil produced from a lease is stored in lease stock tanks which are individually, manually gauged prior and subsequent to pumping the oil out of the tank to the crude oil purchaser. The amount of the sale in the conventional case is based on the amount of oil in the tank immediately prior to pump-out and the amount of oil remaining in the tank after the sale to the pipeline has been completed. The volumes in this case are corrected for temperature and bottom sediment and water (BS&W) content. In lease automatic custody transfer operations, the automated equipment must operate in accordance with the pipeline requirements and will involve the automatic determination of the quantity and quality of the oil being delivered to the pipeline. It must include control devices to assure acceptable quality of the oil and accurate measurement of the volume of oil being transferred.

Most lease automatic custody transfer units are skid-mounted, prepiped and wired units. Such units will generally be comprised of the following major components:

a. Tank level controls to start and stop the transfer pump and motor at predetermined liquid levels in the accumulator tank.
b. Transfer pump and motor sized in accordance with the pipeline and production requirements.
c. Strainer-air eliminator to remove free gas and solids from the oil.
d. BS&W probe and monitor to control the quality of the oil being delivered to the pipeline. If excess BS&W is detected, the monitor is to cause a diversion of the bad oil from delivery to the pipeline.
e. Bad oil diversion valve to divert bad oil from delivery to the pipeline.
f. Sampler and sample container. The sampler must be placed adjacent to the meter and must give an accurate sample of the oil being delivered throughout the period of delivery. The sample container must be vapor-tight to assure gravity retention and must include either a hand pump or an electric mixing pump to mix the samples at the time they are being checked for BS&W content and gravity.
g. Positive displacement meter complete with automatic temperature compensation, meter counter and impulse transmitter.
h. Prover loop designed to accommodate the meter-proving equipment.
i. Back-pressure valve to hold a constant pressure on the LACT unit.
j. Control panel and equipment to include:

FIGURE **56**
LACT
Unit
Installation



(1) Safety switch and fuse disconnect.
(2) Motor starter.
(3) Meter failure circuit.

Optional items of equipment may be included such as lease allowable counter, time clock, lightning arrester, 110-volt outlet, indicating light to indicate that the allowable production has been run, run level, and meter failure indicator in conjunction with alarms or beacons to indicate trouble or an inoperative piece of equipment.

The use of lease automatic custody transfer equipment has generally been perfected to the point that both the producing company as well as the pipeline company benefit from more accurate measurements of oil and, at the same time, realize a reduction in operating costs. In many cases the oil operator is able to reduce the capital investment which would otherwise be required for lease oil storage facilities which are required for the conventional handling and running of oil from the lease. Figure 56 shows a schematic diagram of an LACT unit.

5. AUTOMATIC LEASE PROCESS EQUIPMENT CONTROL

Automatic lease process control equipment is available for the operation and control of production facilities such as water conditioning plants, water injection pump stations, gas compressor stations, gas process equipment such as dehydration equipment, refrigeration and absorption hydrocarbon recovery plant, etc. Some of the operations which are automated involve such things as the backwashing of filters in the water conditioning plant, control and recording of pressures and rates of water injection in water flood and water disposal operations, programming and control of the cycle of dehydration and process equipment, start up and shutdown of pumps, compressors and other process equipment, and safety devices to protect component parts of process equipment.

6. AUTOMATIC SUPERVISORY CONTROL

Automatic supervisory control refers to the remote supervision and control of automatic facilities from a central control point of an automated system. This is accomplished through the use of either a direct control electrical wire system, telemetering system, or radio system. It entails the sending and receiving of coded signals representing the existing conditions in the field or the desired conditions to be effected and the conversion of such signals into actual performance of the desired or existing conditions.

F. Economics Of Lease Automation

The amount of automation which can be justified under any set of circumstances is purely a matter of economics. Automatic operation of equipment will normally be used to replace manual operation where the savings in investment and operating expenses can effect a reasonable payout. The degree of automation in each particular situation is of course dependent upon the individual characteristics of the inherent problems as well as the availability and cost of qualified operating personnel. Some of the economic benefits available through automation are:

(1) Reduction in capital investment for lease production equipment.
(2) Reduction in operating expenses through savings in labor, maintenance, transportation and power cost.
(3) Reduction in evaporation losses with a corresponding increase in gravity of the oil sold to the pipeline.
(4) Make possible a more accurate measurement of production.
(5) Provide more accurate and more frequent test data for reservoir analyses.
(6) Improvement in safety of lease operations.

Obviously, there is a limit as to how far lease automation can be carried, even under the most ideal situations; however, tremendous strides have been made toward this end. The fact that governmental regulatory agencies, as well as a great number of crude oil producers and purchasers, now accept crude run measurements made by LACT units attests to the degree of reliability which can be placed in this type of equipment.

SECTION 5—Production Operations—Oil and Gas Separation and Field Processing

M. F. Westfall

A. Introduction

From the beginning of the petroleum industry, the producer has been confronted with a variety of problems in the handling of oil and gas after they have been reduced to possession. Oil, upon leaving the wellhead, generally passes through an oil and gas separator and a dehydrating unit before reaching the stock tanks where it is measured and sampled for quality preparatory to sale. Gas normally passes through a heater, a separator, a dehydrator, and an orifice meter, thence to the purchaser's pipeline.

In the past twenty years, important advances have been made in the handling of oil and gas above ground. Improvements in the old methods and developments of new techniques in the prevention of waste of natural gas and light products, and the separation of oil and water have definitely resulted in an increase in hydrocarbon recovery. The technology of handling these hydrocarbon fluids under high pressure and the development of controls and equipment making small packaged processing units feasible for small fields and/or single wells have been primarily responsible for improvements in all areas of field processing. The developments of materials, techniques, controls and know-how to process in the 1,000-pound per square inch plus pressure range has come in the last twenty years. Separation of oil, gas and water and field processing of natural gas at elevated pressures have greatly increased potential recoveries from known reserves, and have been directly responsible for many developments in the individual areas discussed below.

B. Separation of Suspended Solids

In recent years (since 1960) there has been a tremendous interest and development in dust scrubbers for the removal of suspended solid particles from natural gas streams. These scrubbers are of two types —mechanical and oil bath—each of which works very well. Particles in the micron-size range are satisfactorily removed. Another method, which uses energy present in a crude oil at the wellhead to impart a centrifugal force to oil while settling in a tank, has also been used successfully to remove suspended clay and sand particles from crude oil in many oil fields in recent years. The development of these methods for the removal of suspended solid particles from hydrocarbon streams have considerably decreased handling problems and have enabled trouble-free continuous production on many leases.

C. Separation of Oil and Gas

Separation of oil and gas has always been the most critical of the field processing operations. As producing pressures have risen and lighter condensates are produced, efficient separation has become more critical than ever. Moreover, some of the new concepts have been applied to advantage on old leases producing oil at moderate pressures. Improvements in the various separator types, separation techniques and stock tank vapor recovery systems have greatly increased hydrocarbon recovery.

1. OIL AND GAS SEPARATOR TYPES

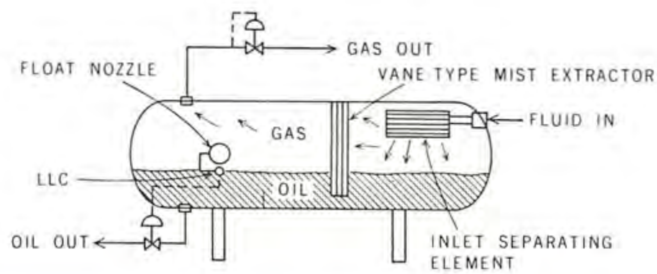
Two-phase separators were in common use before World War II. However, they operated at low pressure and did not provide for really efficient separation of oil and gas. Mist extractors and better knowledge for proper design have increased their recovery. Operation at elevated pressures has served to increase liquid recovery, though the problem of stock tank contamination with bottom sediment and water remains.

Three-phase separators remove bottom sediment and water from the oil and gas mixture while providing for separation of oil and gas. Improvement in control mechanisms and techniques have made possible the separation of water and oil through control of the liquid interface between the two liquids.

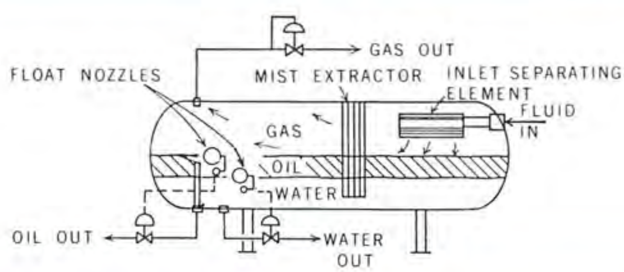
Among the different separator designs, the vertical separator is used to best advantage where gas-to-oil ratios are low, the horizontal where gas-to-oil and water-to-oil ratios are high, and the spherical where extremely heavy liquid loads are encountered. Knowledge of mist extractor design and performance has done much to improve the performance of all three types of separators with resulting increases in stock tank liquid recovery. Figure 57 shows oil and gas separators of various types.

FIGURE **57**

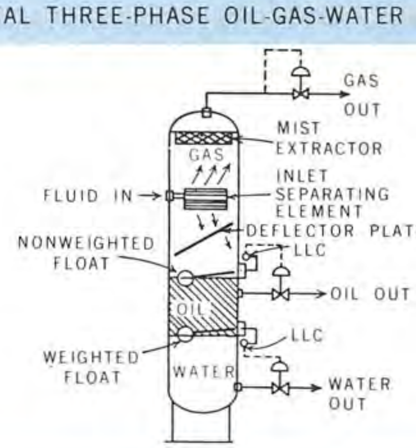
Types of Oil and Gas Separators



HORIZONTAL TWO-PHASE OIL AND GAS SEPARATOR



HORIZONTAL THREE-PHASE OIL-GAS-WATER SEPARATOR



VERTICAL THREE-PHASE OIL-GAS-WATER SEPARATOR

2. STAGE SEPARATION TECHNIQUES

The use of multiple-stage separation for increased hydrocarbon liquid recovery is a direct result of making the primary separation at higher pressures. The use of three-stage separation, one intermediate separator between the first and the stock tank was common on gas-condensate wells before World War II. It is on these wells producing light liquid that the additional stage of separation has shown the most gain in recoverable hydrocarbons. Three-stage separation may increase stock tank liquid recoveries by as much as 5 percent. A typical three-stage separation system is shown in Figure 58.

The recent development of practical methods for approaching differential flash conditions on liquids has resulted in increased recoveries above conventional stage separation. Differential liberation, a batch process equivalent to an infinite number of flash separation stages, represents the theoretical maximum recovery by pressure reduction as much as 10 percent more than is possible by three-stage separation. Figure 59 shows a flow diagram of the flash-differential system.

3. STOCK TANK VAPOR RECOVERY

Normally in oil and gas separation, liquid entering the stock tank has a higher than atmospheric vapor pressure. The vapors released on expansion to atmospheric pressure are sometimes rich in liquefiable components. In the past twenty years there has been an increasing number of plants built to recover these vapors, compress them, and recover the liquid components that formerly were vented to the air and wasted. A typical vapor recovery system is shown in Figure 60.

Recovery of stock tank vapors from lease tanks has materially increased hydrocarbon recovery by turning waste gas into an additional source of liquid reserves. It is a popular subject at present time, and a good deal of attention has been given to the design and equipment aspect. Some of the systems installed by producers have paid out in less than one year. The present trend towards consolidation of lease storage facilities for lease automatic custody transfer, automation and unitization insures a bright future for tank vapor recovery. It is estimated that gas being vented each year from lease storage tanks in the United States has a value of 35 million dollars.

D. Separation of Oil and Water—Dehydration

1. WATER KNOCKOUTS

The separation of entrained (free) water from oil has been made much more efficient. Increased knowledge of entrained droplets and their behavior has made the design of water knockouts more reliable. Inclusion of wire pads and/or ceramic spray condensers has made removal of free water almost complete.

2. DEHYDRATION OF OIL-WATER EMULSIONS

In many cases, oil and water produce at the wellhead as an emulsion. When this occurs, separation by density difference alone is impractical. Frequently, the oil-water emulsion can be broken by heating the well-stream which reduces the viscosity of the oil phase. The heating must be accomplished without loss of valuable liquids, and this is done through heater-treaters. These can be either vertical or horizontal, but are designed to heat the oil-water mixture, separate and remove the water and provide for minimum loss of liquefiable constituents.

Development of chemical additives to assist in breaking oil-water emulsions has greatly increased the efficiency of heater-treater operation. These chemicals speed the emulsion breaking process by promoting coalescence of the water droplets and lower the temperature necessary to obtain oil-water separation.

In some cases, static electrical charges tend to keep the water in suspension in the oil. When this occurs, the charges can be neutralized by an applied emf, and the oil-water separation accomplished. These led to the development of another type of treating process which has become quite popular in the last few years referred to as electrical dehydration. The process basically consists of an electric-type treater in which water droplets are removed from crude oil by electrical dehydration and precipitation. These treaters usually require less fuel and operate at lower temperatures, resulting in reduced shrinkage and considerable gain in liquid hydrocarbons.

E. Field Processing—Natural Gas and Condensate

A number of important advancements have occurred in field processing of natural gas for the recovery of products contained therein. Improvements have been made in the quality and application of the absorption and adsorption processes for recovery of liquefiable hydrocarbons. A major factor has been the utilization of higher pressures than were formerly thought feasible in the design and operation of these processes. In addition the new techniques of low-temperature extraction have been developed since World War II. While the removal of sulphur compounds and water vapor from natural gas are not new developments during the past twenty years, these processes have been improved and widely applied during this period.

1. HYDROCARBON RECOVERY SYSTEMS

The processes in commercial use today for recovering gasoline and liquefied petroleum gas products from natural gas streams are the oil absorption process, low-temperature refrigeration process, adsorption process, hydrocarbon stabilization and combinations of the preceding.

FIGURE **58.** Three-Stage Separation System

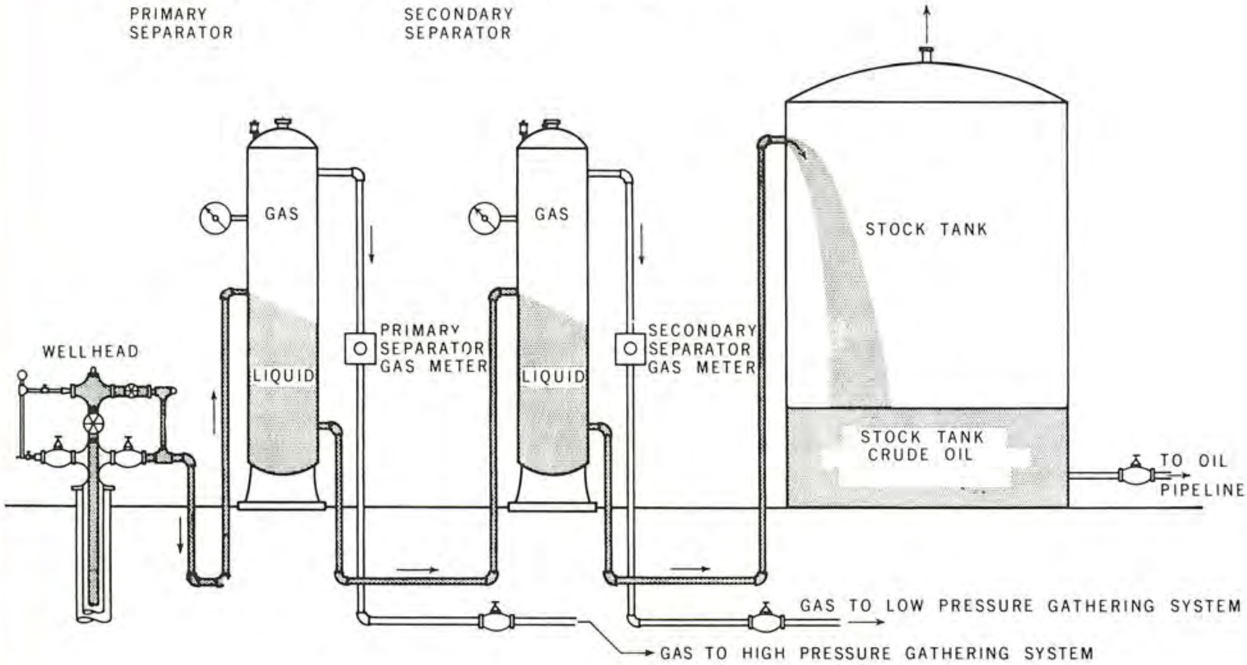


FIGURE **59**
Flash-Differential
Separation
System

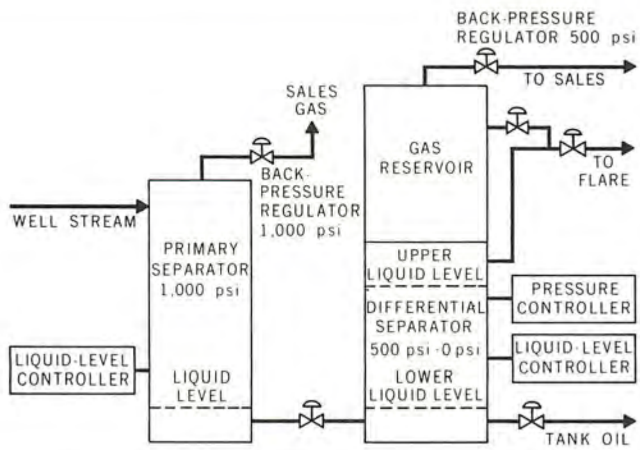
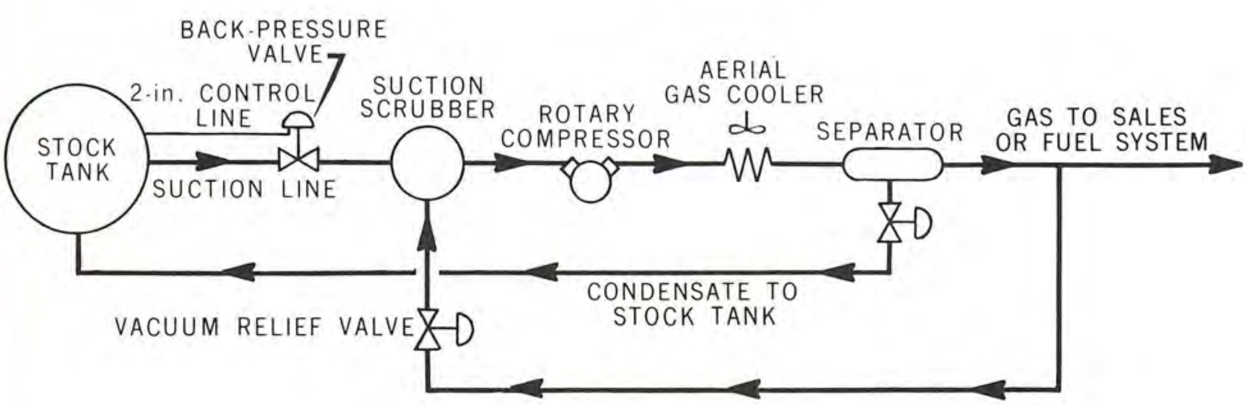


FIGURE **60.** Stock Tank Vapor Recovery System



The well-established oil absorption process is well suited for large central gasoline plant installations with recovery capacities of several thousands of barrels per day of numerous liquid products. However, the economics of an oil absorption process do not justify its use on small, relatively lean gas streams. The search for better production methods to increase revenue from gas condensate wells has led to the employment of low-temperature separation and adsorption units and processes for stabilizing the liquid recoveries from these techniques. Although these processes entered the market in competition with conventional separation methods, there was a ready acceptance of these types of equipment and they have been in common use for several years.

Low-temperature refrigeration plants have achieved success in treating small isolated gas streams rich in heavier hydrocarbon fractions. The adsorption process was developed to extract raw gasoline fractions from relatively small and lean natural gas streams. The liquid produced by these separation methods is rich in both normal and lighter liquid hydrocarbons. Hydrocarbon stabilization is frequently used to stabilize these liquids and insure that they will be produced to and remain in storage.

a. Low-Temperature Separation

Under conditions where hydrocarbons are under pressure, where liquid water is present, where the temperature is low enough and where agitation occurs—hydrates can form.

Hydrates are complex molecular structures, composed of hydrocarbons and water. They are solids and, depending on the pressure, can form fifty degrees or more above the freezing point of water. Field processing of natural gas streams was not really practical until techniques for controlling and handling hydrates were developed. There are essentially two approaches for handling hydrates—to prevent their formation, or to allow them to form under controlled conditions.

In cases where the gas is produced at the wellhead under high pressure, the gas can be expanded into a separator operating under hydrating conditions. Liquid hydrocarbons and hydrates fall to the bottom of the separator. Heat is applied to the bottom to melt the hydrates so the water and condensate can be separated. This process was developed in the late 1940's and resulted in increases of up to 15 percent in stock tank liquid recoveries from condensate wells.

In the early 1950's, the glycol-injection low-temperature separation process was introduced. By injecting a glycol (polyhydroxy alcohol) into the gas stream before expansion, the glycol takes up the water and no hydrates form. This permits expansion to lower temperatures, with correspondingly greater hydrocarbon liquid recovery. In addition, glycol injection makes low-temperature separation possible for lower flowing pressure wells. A typical low-temperature separator system is shown in Figure 61.

At the same time expansion-type low-temperature separation units were being developed, mechanical refrigeration units were being used to increase the recovery of liquids from hydrocarbon gas streams. Refrigeration is required in those cases where gas is only available at low pressure and no expansion-refrigeration can be obtained.

In recent years (middle 1960's) the expansion-compression plants have been introduced. Design of these plants awaited the development of expansion turbines that could handle mixtures of vapor and liquid in the last expansion stages. Extremely low temperatures are reached in these units, resulting in very efficient liquid recovery. Expansion-compression units have not yet been scaled down to lease size, but are used in central locations for relatively large volumes of gas.

The use of low-temperature separation to treat rich natural gas streams has become very common since the war and has proved an important addition to other existing methods. The increase in recovery by the refrigeration process is obtained due to the fact that approximately 0.05 barrels of additional condensate is recovered per million cubic feet of gas for each degree Fahrenheit that the separation temperature is lowered below normal separation temperature.

b. Adsorption Units

Gasoline and hydrocarbon recovery from natural gas streams by the adsorption process has been known to the petroleum industry for several years. However, the application of the desiccant adsorption process before World War II was limited due to high costs, large size and inflexible operations. Extensive laboratory research and field testing since the war have resulted in the development of new, small short-cycle, dry desiccant adsorption units for gas well applications. During the past few years the commercial feasibility of raw gasoline recovery from lean natural gas streams by means of this dry extraction process has been well established and has resulted in considerable increase in hydrocarbon recovery.

Small, "quick-cycle" adsorption units utilizing silica gel or aluminum adsorbents were developed in the late 1950's. This has filled an industry-wide need for a field processing method to treat relatively small or lean natural gas streams which cannot be processed economically by means of conventional oil adsorption or refrigeration plants. These hydrocarbon recovery adsorption units have provided a method of recovering hydrocarbons from a large number of gas streams that previously were considered too small or too lean to process economically.

c. Hydrocarbon Stabilization

The first low-temperature and adsorption units used stage separation to prepare condensate liquids for stock tank. Because of the high API gravity of condensate liquids, much potential liquid recovery was lost through vaporization. By hydrocarbon stabilization of this rich liquid, which is fractionation of the separator liquid under controlled pressure and temperature, practically all of the stable components are produced to and remain in storage.

Top-feed stabilizers, reboiled by salt bath heaters, were introduced to do a more efficient job of stabilizing the hydrocarbon liquids. These were soon followed by low-pressure stabilizers using steam as a source of reboiler heat. Both these systems have worked well and have increased stock tank recovery by 5-10 percent over stage separation.

2. NATURAL GAS TREATING

a. Removal of Water

Field dehydration of natural gas by adsorption on solid desiccants and by absorption in glycol has become common since the war. Improvements in these processes in the last twenty years have enabled producers to remove large volumes of water from the natural gas streams. Adsorption and absorption units used before World War II for dehydration of natural gas were very crude in comparison with the units being used today. Currently units are manufactured in smaller and more economical packages and have provided a market for gas from individual wells.

In the late 1940's aluminum oxide and silica gel desiccants were developed to remove water from natural gas streams. Newer units use molecular sieves as desiccants. The units work well, but are fairly expensive. Solid desiccant units are particularly useful where very low dew point gas is desired.

Glycol is adapted to water removal as well as hydrate control. These units were introduced shortly after the solid desiccant units and are particularly useful where small volumes of gas are to be handled with moderate dew point depressions.

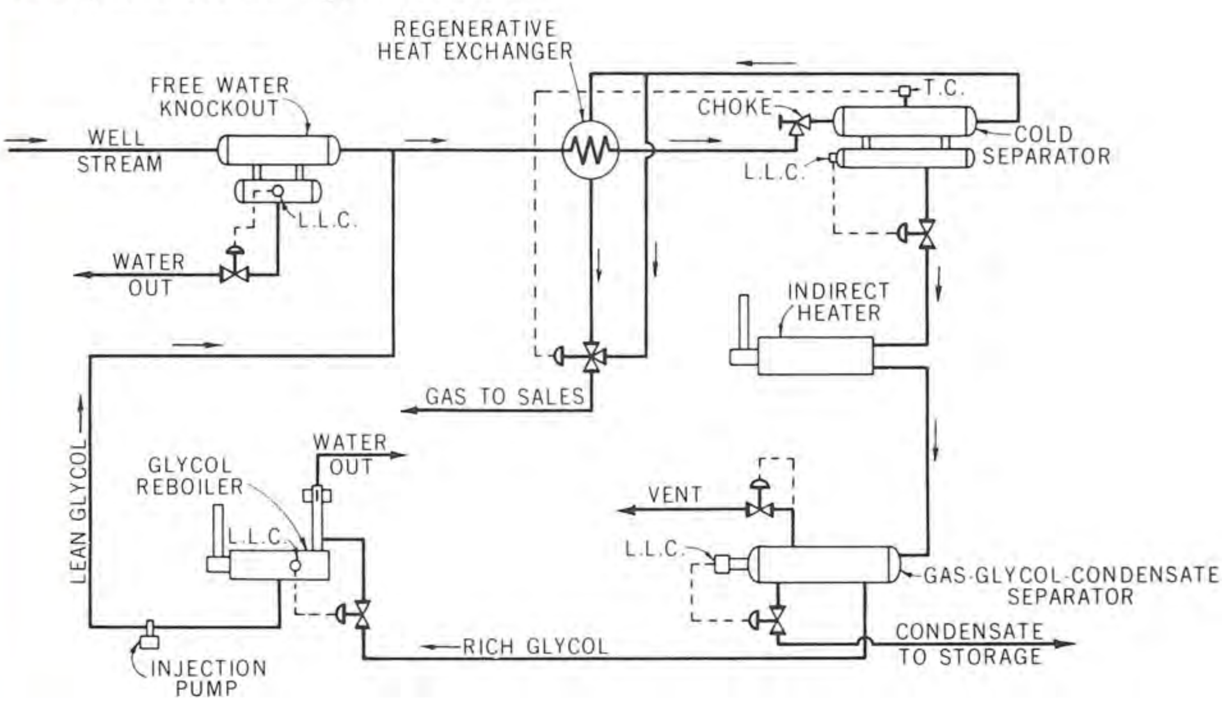
In the early 1960's glycol units were greatly improved through the use of gas stripping and vacuum distillation in the regeneration cycle. Maximum dew point depressions have been almost doubled.

b. Removal of Acid Gases

The methods for removing hydrogen sulfide, carbon dioxide and other contaminants from natural gas has commanded increasing attention with the passing of each year. Improvements in the old methods and development of new methods in the last twenty years have enabled producers to remove economically large quantities of acid gases from natural gas streams. Lower costs of treating and greater demand for sulfur products have resulted in economic production from many large gas fields containing higher percentages of acid gases and have added a large volume of natural gas to those reserves that are economical to produce.

From the early thirties to the late forties, basically two processes were available for the removal of hydrogen sulfide and carbon dioxide. Iron oxide was used for sweetening streams having low contents of

FIGURE **61.** Schematic Flow Diagram of Glycol-Injection Type LTS Unit



hydrogen sulfide. If higher percentages of hydrogen sulfide or carbon dioxide were present the conventional amine system was installed. The interest in lowering the cost of treating has spurred the development of new methods and consequently approximately six new systems have become available for consideration in the span of perhaps ten years. The absorption of acid gas in monoethanolamine is commonly used at present; however, molecular sieves have found increasing use for sweetening in recent years. They have the advantages of high selectivity for either H_2S or CO_2 and will sweeten gas to pipeline specifications if heavy hydrocarbons have first been removed.

3. GAS CYCLING OPERATIONS

The life of many condensate reservoirs can be extended by recompressing the gas produced and injecting it into the reservoir. These cycling operations are widely used and may double or even triple the amount of recoverable liquids. In most cases, the gas produced from the reservoir is processed through a natural gasoline plant for increased liquid recovery before recompression and injection. Processing in these plants has essentially kept pace with the chronology of developments outlined above for lease processing of natural gas and gas liquids.

4. PACKAGED GAS COMPRESSOR UNITS

An important trend in gas handling since World War II has been the development of specially packaged gas compressor units. Literally hundreds of improvements and innovations have produced small portable gas compressor units at very nearly the same economics as the large integral compressors normally used in gas plants and main line compressor stations. This has made possible the conservation of low pressure and isolated gas reserves formerly unrecovered.

CHAPTER FOUR—RESERVOIR EXPLOITATION

SECTION 1—Introduction

Lincoln F. Elkins

While there have been some totally new developments in the technology of development geology, reservoir engineering and operation since World War II, many of the changes have been evolutionary rather than revolutionary. In addition, the scope of technologies involved within this Chapter is so broad and many of them are so interrelated and overlapping that it was deemed helpful to provide a capsulized discussion of these subjects and the state of the art circa World War II before considering the individual items in more detail. This brief review is presented in this introductory section. Expanded discussion of the state of the art circa World War II, postwar developments in technology of development geology and reservoir engineering, and postwar developments in its application and the state of the art in 1966 are discussed in more detail in the succeeding sections of this Chapter which are devoted to individual facets of the technology.

A. Definitions

Development geology and reservoir engineering are concerned with the occurrence, distribution, movement and displacement in and recovery of naturally occurring gaseous and liquid petroleum hydrocarbons from individual underground reservoirs. They are primarily related to conditions that exist and things that happen within the reservoir rock in the interwell area forever removed from direct measurement. All that can be known about these conditions and performance must be inferred from data obtained through wells including:

(1) Depth, thickness and dip of individual geologic strata.

(2) Some physical and chemical properties of the reservoir rock measured on small samples of the rock recovered as cores or drill cuttings.

(3) Some physical properties of the rock and some semiquantitative measures of quantities of fluids present in the reservoir rock determined by electrical, radioactive, sonic and other logging methods.

(4) Physical and chemical properties of reservoir fluids determined from laboratory or field measurements on subsurface wellbore or surface samples of these fluids.

(5) Some gross in situ properties of reservoir rock and fluid systems determined from productivity tests and wellbore pressures.

(6) Fluid contacts in the reservoir determined through selective production tests, log and core measurements.

(7) Long-term changes in fluid saturations in the reservoir indicated by changes in productivity, gas-oil ratios, water-oil ratios and pressure as measured in wells.

B. Objective

The objective of development geology and reservoir engineering is to provide management with timely technical guidance toward the selection of proper development and operating programs to achieve the maximum economic recovery of petroleum from a lease or reservoir. The practice of development geology and reservoir engineering involves first the evaluation of the reservoir rock and fluid conditions as they exist using data available as listed above; second, the prediction of physical performance of the reservoir achievable through various possible development and operating methods; and finally economic evaluation considering investments and operating costs required and effects of applicable taxes, present value of moneys, and risks involved. The product of the analysis may range from a recommendation regarding drilling, completion and operation of a single well to one involving unitization of and injection of fluids into an entire reservoir. Then the only control of performance of reservoirs possible is that which can be effected through individual wellbores.

C. State of the Art—Circa World War II

By the middle 1940's, general geologic theory of accumulation of hydrocarbons had been developed and broad geologic factors, stratigraphic and structural environments were classified. Many of the mapping and interpretive tools in use then are still used today, but in many cases both the scope and accuracy of measurements have been improved by technologic advances in logging and coring and geologic processes and conditions involved have become better understood.

By the middle 1940's many of the fundamental features of reservoir performance had been established, at least theoretically for idealized conditions, from laboratory research, theoretical analyses, and studies of actual reservoirs. Among these were:

(1) Characterization of many reservoir rock properties including porosity, permeability and interstitial water saturation.

(2) Characterization of many hydrocarbon reservoir fluid properties including solubility, shrinkage and viscosity of reservoir oils containing dissolved gases and dew points and content of gas-condensate systems.

(3) Experimental development of and evaluation of Darcy's law indicating an approximately linear relation between pressure gradient and rate of flow of fluids in porous media and mathematical extension of this law to many practical two-dimensional and three-dimensional reservoir problems.

(4) Development of material or volumetric balance equations which utilize unit expansibility of oil-gas samples to interpret pressure-production performance of entire reservoirs.

(5) Determination of relative permeability-saturation relations for unconsolidated sands to two-fluid and to three-fluid phases and for one consolidated sand to two-fluid phases. Percentage effective permeability of a sand to the various fluids was found to be dominantly related in a direct but nonlinear manner to the relative saturations of the fluids within the pore spaces of the reservoir rock.

(6) Development of mathematical theory and electrical analog methods for analysis of transient flow and pressure behavior of aquifers in contact with petroleum reservoirs.

(7) Development of some field experience in performance of reservoirs with injection of gas or water to supplement natural forces and displacement mechanisms.

(8) Development of models for determining areal sweep efficiencies of cycling projects and water floods assuming completely filled reservoirs and unit mobility ratio.

While many of these methods remain as the tools of the trade of reservoir engineering today, there were relatively few engineers in 1945 who were thoroughly trained in the application of these methods. Equally important was the fact that, even for those engineers well trained in the theory, there had been too few case histories of actual reservoirs operated to depletion for which adequate data were available for judging the limitations of the methods.

By 1945, the importance of unitized operation of reservoirs for fluid injection to increase recovery of petroleum was recognized, and was being applied in many cases, but its impact on the industry was not nearly as great as it is now 20 years later. While laboratory experiments had demonstrated the superiority of water over gas as an oil-displacing agent in many reservoir rocks, this had not been adequately confirmed by large-scale field projects, particularly through comparison of results of so-called primary pressure maintenance gas injection projects with results of so-called secondary water flood projects. Although there were notable exceptions, such as return of produced water to the Woodbine Sand in the huge East Texas Field,[1] much of the emphasis of the era was on gas injection pressure maintenance projects. Some important field examples of the latter are the Schuler Field, Union County, Arkansas,[2] the South Burbank Field, Osage County, Oklahoma,[3] and the North Coles Levee Field, Kern County, California.[4]

SECTION 2—Production Geology

G. E. Archie

A. Introduction

Once a hydrocarbon deposit has been located by an exploratory well, exploitation must be in the most efficient manner. This can be done by locating successive wells in such a way as to (1) obtain the greatest amount of geological information for predicting extensions and limits of the reservoir and (2) achieve the most efficient production. The geology of the rocks surrounding and containing the hydrocarbons determines not only the limits of the accumulation but to a considerable extent the processes of extraction and other producing operations. The interpretation of the geologic history and the prediction of the limits and the distribution of the internal rock fabric of an accumulation is called production geology.

Subsurface interpretation of an accumulation is evolved step by step as operations progress. The interpreter can rarely give an opinion free from speculation, particularly for complex structures; yet, on an engineering basis, an interpretation or working geological hypothesis must be formulated at each stage of development from facts available at the time. Where subsurface conditions are complex, factual data at hand can always be explained in several ways, calling for multiple working hypotheses based on geological models of hydrocarbon accumulations.

By 1945, general geological theories of accumulations were developed, and broad geological factors, including stratigraphic and structural environments, controlling the limits of reservoirs were classified. This classification provided a basis for the designation and demarcation of the accumulations and also for the gross definition of the nature of the reservoir layer itself. A number of graphic reference tools were in use for preparing geological subsurface interpretations. These included structural maps extrapolated from known data based on the best geological model that could be visualized at the time. Differential thicknesses of formation intervals were shown by isopach maps, which were useful for predicting the shape of the reservoir and for detecting fault and stratigraphic convergence. Paleostructure maps for tracing the history of a structure through geological time were just coming into use. Electric logs were being used extensively in making these maps. Methods of detecting and locating faults, fault intersections, and fault patterns were being developed. However, little was known at this time about the internal fabric or heterogeneities of the reservoir; or relationships between pore structure and mineral composition with hydrocarbon saturation and flow characteristics. The latter relationships are discussed in the section on Properties of Reservoir Systems (Section 4) The geology of the reservoir as a whole and its internal fabrics are discussed in this Section.

During the past two decades, geological knowledge of the intricacies of the hydrocarbon deposit, including reservoir and fluid conditions, has increased and has had more widespread application; consequently analyses have become more significant.[5] These technological advances have increased the efficiency with which the industry can plan the operational development of a hydrocarbon accumulation. With further understanding of the internal fabric or heterogeneities of the reservoir, the reservoir engineer can design more productive secondary and tertiary recovery projects for specific conditions. Three areas of development stand out:

(1) Greater understanding of geological processes.
(2) Improved working techniques.
(3) Application of new well logging tools.

1. Morris, W. S., "Salt Water Disposal and Pressure Maintenance in East Texas Oil Field," *Mining and Metallurgy*, Dec. 1944.
Morris, W. S., "Results of Water Injection in Woodbine Reservoir of the East Texas Field," *Secondary Recovery of Oil in the United States*, API, 1950, 588.
2. Kaveler, H. H., "Engineering Features of the Schuler Field and Unit Operations," *Trans.*, AIME, 1944, 155, 58.
3. McWilliams, L. L., "Unitization and Gas Injection in South Burbank," *Drill. & Prod. Prac.*, API, 1946, p. 175.
4. Travers, W. J., "North Coles Levee Pressure-Maintenance Project Control of Gas Expansion," *Oil & Gas Jour.*, July 20, 1946.
5. Levorsen, A. I., *Geology of Petroleum*, W. H. Freeman and Company, San Francisco, California, 1954.

B. Greater Understanding of Geological Processes

Geological processes operate continuously, but their influences can be segregated conveniently into those that affect the sediment at the time of deposition and those that occur afterward. Both types of processes have been vigorously studied in recent years.

Although the process of sedimentation has been investigated by geologists for many years, it has been only recently that it has been understood on the fine scale needed for use in production geology. The need to know the external shape and internal fabric of hydrocarbon reservoirs has led geologists to study the form of recent examples of sediment accumulating today which are deemed to be similar to sediments composing various types of reservoir rock.[6] Research on recent sand deposition in the Gulf Coast, and associated research on the Rhine and Rhone deltas in Europe have provided a basic understanding of the processes responsible for the overall geometry and internal arrangement of reservoir scale sand bodies such as barrier bars, point bars, and distributary channels.

Studies of the processes determining the setting, shape, internal structure, and composition of recent sediment bodies have made it possible to recognize ancient rock types in terms of recent sediment examples. Because rock properties control reservoir properties, the quality, distribution, and variation of reservoir properties are characteristic of genetic types of sandstone reservoir bodies. The recent examples thus constitute analogs for various types of reservoirs encountered in the ancient hydrocarbon-bearing rocks. These analogs facilitate prediction of the shape and orientation of ancient rock reservoirs.

Additional knowledge of sandstone reservoir heterogeneity is also obtained from detailed studies of surface outcrops of older sandstone bodies.[7] Sediments exposed in vertical sections—including the geometry and distribution of shale barriers, which are so important in determining the performance of a reservoir—can be analyzed in detail over considerable distances.

Although many models are primarily based on studies of recent environments of deposition and surface outcrops of older rocks, a most important part in the development of models is played by well-documented examples of the ancient rocks in hydrocarbon-bearing deposits themselves. The production geologist is in a particularly favorable position to study the large amount of subsurface geological data available in producing areas,[8] and he has successfully applied these models to his subsurface studies.

Studies of both recent and ancient sand bodies have provided criteria for separating the various genetic sand bodies in a reservoir. The application of these criteria to a reservoir provides the production geologist with a useful tool to predict the pore space distribution more accurately, for if the environment of deposition of a reservoir can be determined early, it will facilitate the efficient development of the field.[9]

A knowledge of the internal structure of porosity and permeability patterns of a reservoir is also important in completion practices and in devising the most efficient secondary or tertiary recovery process.

Research on recent carbonate sediments in Florida, the Bahama Islands, Cuba, British Honduras, the Persian Gulf, and Sharks Bay, Australia, has provided basic understanding of the processes of carbonate sedimentation. Much of this work has been done on a scale useful to the production geologist. The detailed work on the oolite bodies, the tidal flats, the carbonate mounds, and the reef tracts, etc., has provided criteria for their recognition and enough information on their external and internal geometries to be used by the production geologist as a tool for predicting reservoir pore space distribution.

Diagenesis, the physical and chemical changes in sediments after deposition, can greatly alter the reservoir characteristics of a rock. Effective porosity can often be predicted and its pattern in the rocks successfully determined by examining the geological history and in particular the events of history related to compaction and movements of leaching or cementing fluids through the rock body. Thin sections and the petrographic microscope have been used extensively for these studies.

Diagenetic processes have been investigated for many years but only recently has our understanding reached a level that it could begin to be applied on a reservoir scale. The greatest advances have been made in carbonates. While before 1950, the main types of porosity were thought to be solution porosity and dolomite porosity, research into the origin of carbonate porosity has shown that relic primary porosity in lime sands is also important.

It has been found that dolomitization may select certain depositional types. Of note during the past few years have been discoveries of a mechanism for the formation of dolomite from lime sediments in a supratital zone by evaporative reflux.[10] These findings indicate the importance of sedimentary patterns on reservoir development even in dolomite which is

6. Peterson, J. A., and Osmond, J. C., eds., *Geometry of Sandstone Bodies*, A Symposium, Am. Assoc. Pet. Geol., 1961.
7. Hutchinson, C. A., Jr., Dodge, C. F., and Polasek, T. L., "Identification, Classification and Prediction of Reservoir Nonuniformities Affecting Production Operations," *Jour. Pet. Tech.*, 1961, vol. 13, No. 3, pp. 223-230.
   Zeito, George A., "Interbedding of Shale Breaks and Reservoir Heterogeneities," *Jour. Pet. Tech.*, 1965, vol. 17, No. 10, pp. 1223-1228.
8. Hewitt, C. H., and Morgan, J. T., "The Fry In Situ Combustion Test—Reservoir Characteristics," *Jour. Pet. Tech.*, 1965, vol. 17, No. 3, pp. 337-342.
9. Bernard, H. A., Major, C. F., and Parrot, B. S., "The Galveston Island Barrier Island and Environs: A Model for Predicting Reservoir Occurrence and Trend," *Trans.*, Assoc. Geol. Soc., Gulf Coast, 1959, vol. 9, pp. 221-224.
10. Pray, L. C., and Murray, R. C., eds., "Dolomitization and Limestone Diagenesis," *Spec. Pub. 13*, Soc. Econ. Paleontologists and Mineralogists, 1965.

the most common and prolific type of carbonate reservoir.

Thus criteria for reorganizing the origin of the porosity have improved due to the advances made in understanding the origin of carbonate textures. At present, enough criteria and information are available to the production geologist so that he can use diagenetic conceptual models as a tool in predicting carbonate pore space.

Porosity decrease of sandstone due to compaction and cementation, and porosity increase resulting from removal of soluble cements, are being studied with petrographic and geochemical techniques. The effect of depth of burial on porosity reduction, particularly with regard to compaction and temperature increase, is important in predicting reservoir rock distribution at greater depth.

Our improved knowledge of compaction of clays to shale as they are buried, and of the differential compaction of sand and shale, has helped solve major problems. For example, in areas of the Gulf of Mexico, the rapid burial of clay has not allowed the interstitial water to flow out and equalize with the hydrostatic pressure. This has led to abnormally high fluid pressures. These pressures may cause disastrous blowouts in already very expensive offshore wells. The recognition that these overpressured shales have lower densities than the normally preserved shales leads to the use of density logs for detecting the approach of these zones in drilling wells. This development has greatly reduced drilling and completion costs.[11]

The advances in understanding subsurface hydrodynamics have helped production geologists predict the oil-water contact in reservoirs with tilted contacts.

Our understanding of the mechanism of faulting of geologic structures containing hydrocarbons has improved, and typical models of fault patterns are now visualized. Prediction of fault patterns early in the operational development has therefore improved.

In conclusion, knowledge of the precise movement of fluids through the reservoir pore network is of prime importance in the proper development of a field as well as supplemental recovery methods. Research on the internal architecture of reservoir bodies will increase our ability to predict in this important area.

C. Improved Working Techniques

Vastly improved seismology techniques have been developed which better enable the production geologist to delineate the reservoir. Techniques which attenuate multiple seismic reflections enable resolution of interesting reflectors to greater precision; more accurate information is available on both shallow and deep geological markers. This increased accuracy results in better definition of structure and makes possible more reliable positioning of faults, both of which aid the production geologist in his task of locating wells for primary development of hydrocarbon deposits. Improved seismic data also permit analysis of thickness variations from flanks to crest of structures and from fault block to fault block. This extension of paleostructural analysis can be very useful in determining the history of structural growth. In order to locate extensions of a field efficiently, production geologists must understand the growth history of structures complicated by faulting that was contemporaneous with deposition and the shifting of structural crests with depth. This is best accomplished in some places by a combination of subsurface information from wells and seismic surveys.

Computers are important time-saving devices to the production geologist in data retrieval, map construction, and volume calculations. In the latter application, the future holds promise that many man-months of tedious planimeter measurements will be spared in work related to estimating reserves. A computer technique, called trend analysis, has been developed to produce structural maps which have the regional dip removed. This is a valuable tool for the production geologist who wishes to predict the position of deep untested closure from observations of shallow horizons where control is available.

Correlation of a formation from well to well is essential to all geological studies. The more abundant paleontological and paleobotanical information and improved techniques of the paleobotanist and paleontologist now give the production geologist a sounder, broad framework for his local, more detailed well log correlations. In subsurface studies, the application of detailed information concerning geometry and internal structure of individual sand bodies, such as models acquired from investigation of the recent sediments, rock outcrops, and known reservoirs themselves (all discussed above) depends on a sound correlative framework.

The production geologist also uses reservoir data, i.e., production and pressure history, oil gravities, water salinities, and hydrocarbon saturation gradients, in order to arrive at the best interpretation of the hydrocarbon deposit.

It should be mentioned that the geologists and engineers have shown an ever closer working relationship and an understanding of each other's problems in the last few years. This will continue to accelerate technological advances.

D. Application of New Logging Tools

New logging tools have improved the capabilities of the production geologist. Much subsurface interpretation must be done from logs because of the expense of coring and the sampling problems of ditch cuttings. Therefore, the improved logs as well as the better understanding of rock-log relationship have benefited. The focused resistivity logs have simplified

11. Hottman, C. E., and Johnson, R. K., "Estimation of Formation Pressures from Log-Derived Shale Properties," *Jour. Pet. Tech.*, 1965, vol. 17, No. 6, pp. 717-722.

interpretations and improved resolution so that small-scale geologic features can often be accurately delineated.

Radioactivity logs now provide a means for reentering cased holes and getting information valuable for determination of formation densities or for purposes of correlation. These radioactivity logs in many cases give more detailed records in carbonate sections than could be acquired with resistivity logging surveys.

The new continuous dipmeter first introduced in 1951, and the improved digital continuous dipmeter in 1962, permit detailed determination of the dip of layers intersecting the borehole. This provides a very useful check against structural interpretations based on seismic data or earlier analog correlations.

It is now common practice to record the log on magnetic tape and to calculate the dip at thousands of levels for each log by high-speed machines.[12] It is hoped that by this method the dipmeter will improve our knowledge of the relation of the dip of small laminations such as cross bedding to that of the beds containing them and help us to identify various types of sand deposits, such as barrier bars and channels. With this information, the external shape and internal matrix or fabric of sandstone reservoirs can be delineated, and the trends of sand bodies predicted. These are important factors in the initial development of the deposit as well as in the design of secondary recovery methods.

Density and porosity recording devices, such as those based on the acoustic and radioactive properties of the rock, are being used to detect geological anomalies such as abnormal pore pressures, faults, and unconformities. Combinations of logs measuring various physical properties are being used to map changes in lithology.

The development of the rubber sleeve core barrel has provided core material from unconsolidated sediments that was not previously available. Because the applications of the environmental concepts to reservoir geology are dependent upon rock lamination, this tool has allowed the effective use of this technique where it could not previously have been done.

E. Future Trends

A major impact on recovery will no doubt result from continued research on internal rock structure or reservoir heterogeneities. For example, additional types of sedimentary environments are already under investigation, i.e., those due to alluvial fans, sand dunes, estuary sand deposits, and subaqueous bars. Such research will contribute greatly to developing compatible production processes for increased recovery. A better understanding of internal variations in the reservoirs, such as vertical and lateral variations in porosity and permeability, will enable the reservoir engineer to design more effective secondary and tertiary recovery processes.

Studies underway by geochemists and geologists on the source, generation, migration, and accumulation of oil will improve the economics of locating extensions of a reservoir and discovering additional reservoirs, particularly on the more complex and deep hydrocarbon-bearing structures.

The use of the computer will be extended to increase technological efficiency.

SECTION 3—Formation Evaluation

G. E. Archie

A. Introduction

The geophysical and geological methods previously discussed locate favorable geological conditions for an accumulation of hydrocarbons, but a well must be drilled to evaluate the prospect. The filtrate of the drilling fluid used to remove rock cuttings and prevent blowouts invades the permeable rocks and pushes away from the hole any hydrocarbons which may be present. This leaves only a residual amount of hydrocarbons in the rock cuttings, as shown in Figure 62, and hence, merely drilling the well and analyzing the drill cuttings does not quantitatively evaluate the hydrocarbons present. It has been necessary to develop methods and tools to evaluate the formation around the borehole and beyond the invaded zone in order to assess its hydrocarbon content.

Although there is still no direct way to measure the amount of oil in place in a reservoir, many ingenious instruments and materials have been developed since 1945 by the oil service companies and the oil companies. In addition, the recognition of physiochemical rock-fluid relationships has helped to effect a dependable evaluation of the hydrocarbon-producing potential of a well.

Rocks are heterogeneous, and the pore size and fluid distribution are therefore very complicated from a microscopic point of view. It first appeared that a quantitative evaluation through indirect measurements might never be obtained. When rocks were studied macroscopically, however, definite relations or trends were found to exist between rock properties and fluid distribution.

The process of using information obtained from a borehole to determine the physical and chemical properties of the rocks and their fluid content, especially hydrocarbons, is known as formation evaluation. The complexity and importance of formation evaluation have led to the establishment of a new technical position in many companies—the forma-

12. Moran, J. H., Coufleau, M. A., Miller, G. K., and Timmons, J. P., "Automatic Computation of Dipmeter Logs Digitally Recorded on Magnetic Tapes," *Jour. Pet. Tech.*, 1962, vol. 13, No. 7, pp. 771-782.

tion analyst or petrophysical engineer, who brings into play a knowledge of physics, chemistry, geology, and engineering in developing and using physiochemical and petrological relationships.

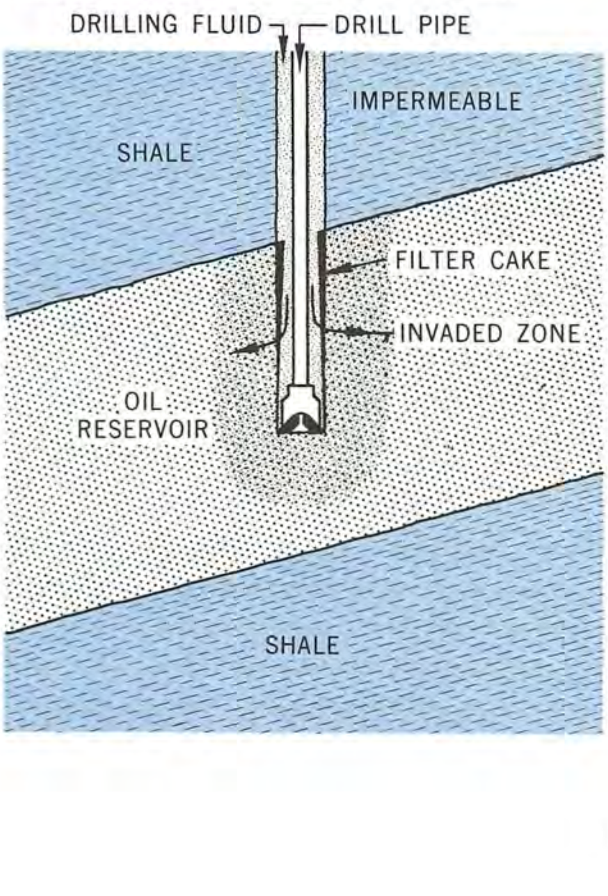
Evaluation of a reservoir involves defining its areal extent and determining its thickness, porosity, permeability, and oil saturation. Accurate determination of the last four of these parameters at a reasonable cost is the goal of the formation analyst or petrophysical engineer. Defining the areal extent is the responsibility of the production geologist. The quantitative values of permeability, porosity, and hydrocarbon saturation obtained by modern methods of formation evaluation are the basic data used by engineers and geologists for completing the well, for effective development of the field, and for the later applications of secondary and tertiary recovery methods.

Formation evaluation methods can be divided into two categories: those used while drilling is in progress and those used after the hole has been drilled. Analyses of cores, cuttings, and drilling fluids are the methods that constitute the first category. The second category includes drill-stem testing and all the tools run in the hole on wireline to measure natural electrical potential, electrical resistivity, radioactivity, acoustic velocity, and other physical parameters which provide an indirect measure of rock and fluid properties. The plots of the responses of the various tools versus depth are referred to as logs or borehole surveys.

FIGURE **62**

Filtrate of Drilling Fluid

(Drilling fluid pressure causes flushing ahead of the bit creating an invaded zone, which contains only residual hydrocarbon saturation and drilling fluid filtrate).



B. Formation Sampling

1. CORING

Core analyses of reservoir formations have long been used to determine porosity and permeability and to detect the presence of hydrocarbons. Coring is expensive, however, and with the increased difficulty of finding new reserves and the emphasis on maximum oil and gas recovery, new and improved methods of recovering cores and obtaining the maximum engineering information from them have been developed since 1945.

Conventional rotary coring of competent formations was quite advanced in the 1920's and 1930's. However, coring of unconsolidated sands did not become practicable until the 1950's, with the development of a rubber sleeve core barrel in which a stretched rubber sleeve is rolled onto the core and preserves it as it is cut.[13] A pressure core barrel offers promise of recovering cores without depleting core fluids while the core is being withdrawn from the higher pressures at the bottom of the hole.

Sidewall cores taken after the hole has been drilled and logged have been used for some time to obtain lithologic information and qualitative reservoir data. The quality of the samples has been improved sufficiently by gun and projectile improvements since World War II that sidewall samples now can be used for semiquantitative reservoir analyses. A recently developed diamond saw core slicer, which slices a long triangular vertical wedge out of the sidewall of a drilled hole, has some distinct advantages: the interval to be cored can be selected after logging and thus provides a relatively undisturbed formation sample, and a sample can be recovered with continuous vertical sequence not possible with gun sidewall samples.[14]

Many techniques have been developed since 1945 to measure various reservoir rock characteristics of cores in the laboratory. Since each reservoir differs, measurements on cores from specific fields provide the engineer with necessary data to determine applicability of new recovery methods.[15] Much information has already become available on fundamental relationships of relative permeability to oil, gas, and

13. Hildebrandt, A. B., Bridwell, H. C., and Kellner, J. M., "Development and Field Testing of a Core Barrel for Recovering Unconsolidated Oil Sands," *Trans.*, AIME, 1958, vol. 213, pp. 347-349.
14. "Mohole Turbocorer Passes Rigid Performance Tests," *Oil & Gas Jour.*, Nov. 23, 1964, vol. 62, p. 34.
15. "Recommended Practice for Core-Analysis Procedure," RP 40, API, New York, August 1960.

water, and on capillarity, wettability, electrical resistivity, acoustic velocity, and radioactivity of rocks. Many core properties can now be measured under high pressure and temperature to simulate conditions deep in the earth.[16]

A major goal, to which attention is still being directed, is a method to obtain formation samples containing reservoir fluids uncontaminated by drilling or circulating fluids.

2. ANALYZING DRILL CUTTINGS AND DRILLING FLUID

Analysis of drilling fluid returns and entrained bit cuttings for evidence of hydrocarbons and for lithology has always been employed to some extent. Continuous analysis of this type is called a drill cutting and mud log. It requires the services of trained technicians to examine the cuttings visually, to describe the lithology, and to operate the equipment used to detect quite small quantities of hydrocarbons. Prior to 1945, most of the data consisted of visually observed oil staining, or fluorescence of oil under ultraviolet light, and a record of gas in the mud returns. Since 1945, more sophisticated instruments and mechanical equipment have been developed. The most significant technical advances have been in the analysis of gas. The hot-wire analyzer has been replaced by the infrared analyzer and the partition gas chromatograph. The latter is used to obtain accurate quantitative analysis of individual components of gas in the samples. The common well log consists of plots of various parameters (rate of penetration of the drill, lithology, relative shows of oil in mud and cuttings, and relative shows of gas in mud and cuttings) versus depth. These logs are kept current and are often used as control for coring and open-hole testing with the drill pipe (drill-stem testing).

3. TESTING FORMATION FLUID

The most diagnostic method available for formation evaluation during drilling of the well—the drill-stem test [17]—allows fluid production from a zone of interest through the drill pipe used for drilling. Recent developments permit the determination of some basic reservoir data.

In 1945, drill-stem testing was still essentially a fluid sampling technique. Present-day testing equipment consists of a highly complex arrangement of subsurface valves manipulated from the surface and pressure recorders which record the pressure of the reservoir as the fluid is withdrawn.[18]

Application of the theory of pressure buildup analysis has been as significant as the equipment improvements.[19] Application of this theory permits determination, among other things, of reservoir pressure, average formation permeability, and permeability reduction near the wellbore.

Several new developments in tool design are underway, and further equipment improvements seem assured.

In 1955 a new system was developed for formation fluid testing run on a logging cable. Formation fluid samples (up to 24 gallons) at any desired depth can be obtained. Reservoir pressure data are continuously recorded at the surface as the fluid sample is extracted. This tool has become a valuable adjunct to other well logs in resolving difficult formation evaluation problems.

Improvements since 1955 include the formation interval tester designed to test low-permeability formations and zones behind casing (1959). Additionally, auxiliary equipment has been developed to cement off casing perforations after testing (1960).

Concurrent with the improvements in equipment, sophisticated data interpretation techniques have been developed. They allow interpretation of production rates on the basis of recovered fluids, and estimates of formation permeability from recorded pressure data.[20]

Development of a tool capable of making six tests during one wireline entry into the wellbore is now underway. Further improvements are expected.

C. Wireline Methods and Tools

1. HYDROCARBON-SATURATION DETERMINATIONS FROM ELECTRICAL RESISTIVITY

Cores are expensive and cannot be cut through all the rocks penetrated. Furthermore, cores cannot always be recovered, and when recovered may contain only a residual amount of hydrocarbons, since hydrocarbons are flushed from the cores by drilling fluid filtrate. Therefore, instruments which can be lowered in the wells have been developed to determine the amount of hydrocarbons in the rocks in place. There is no direct way to do this, but the amount of water in the pores is related to the electrical resistivity. The remaining pore space is filled with hydrocarbons. Knowing the porosity from another measurement, one can arrive at the amount of hydrocarbons by difference.

An added advantage of this method is that an electrical field can penetrate beyond the zone that has been flushed by drilling fluid filtrate. In this way a measure of the true hydrocarbon saturation in place is made.

Resistivity relations are therefore the basis for determining oil saturation, and great efforts have been made to improve the electric log. About 1946 a

16. Fatt, I., "Pore Volume Compressibilities of Sandstone Reservoir Rocks," *Trans.*, AIME, 1948, vol. 213, pp. 362-364.
17. Lynch, E. J., *Formation Evaluation*, Harper and Row, New York, 1962, chap. 8, pp. 284-320.
18. Johnston Testers *General Catalog*, 1966-1967. Halliburton *Sales and Service Catalog*, 1966.
19. Horner, D. R., "Pressure Build-up in Wells," *Proc.*, 3rd World Pet. Congress, Sec. II, Leiden, Holland, 1951.
20. Moran, J. H., and Finklea, E. E., "Theoretical Analysis of Pressure Phenomena Associated with the Wireline Formation Tester," *Trans.*, AIME, 1962, vol. 225, p. 899.

system was developed to record four curves simultaneously—the self-potential, the short normal, the long normal or short lateral, and the long lateral. In order to determine the true resistivity of the formation from these logs, departure curves to correct for the effect of the borehole and invaded zone were calculated and presented in 1947. They were applicable to very thick layers only. Departure curves for twin beds were issued in 1949. Use of these curves improved the accuracy with which true formation resistivity could be determined and emphasized the need for more quantitative data concerning the invaded zone.

The microlog introduced in 1948 partially met this need.[21] The tool consisted of three electrodes one inch apart embedded in a rubber pad which was held against the wall of the hole by springs. It proved to be an excellent tool to distinguish between permeable and nonpermeable zones, especially in carbonate rocks where the self-potential is often not diagnostic. Furthermore, the microlog was used for determining porosity. The microlaterolog, introduced in 1951, was considerably less sensitive to mud cake and proved quite accurate for measuring invaded zone resistivity in the carbonate provinces where salt muds are commonly used. In combination with the known resistivity values of the mud filtrate in the invaded zone and the estimated residual oil saturation, this tool was often used to determine porosity, or when the porosity was known from some other source, to determine the formation resistivity factor.

Two types of focused current resistivity tools were introduced for deep investigation in the early 1950's. These tools, the laterolog[22] and guard electrode log,[23] were relatively free from the short-circuiting effect of the mud column and were much less influenced by adjacent layers. They can, therefore, measure resistivity of thin layers with greater accuracy than could the standard resistivity log. This is true, however, only when the mud filtrate has not more than four times the resistivity of the connate water, so that the invaded zone resistivity is not abnormally high. Under these conditions it is possible to record accurate and detailed logs in formations whose resistivities may be several hundred times that of the mud filling the hole, where conventional electric logs are practically useless.

An induction log was introduced in 1948 to log in nonconductive oil-base mud.[24] It has proved so superior that it has practically replaced the standard electric log.[25] The induction tool consists of a transmitting coil or coils charged with an oscillating current which sets up an electromagnetic field in the surrounding formation. Thus, no electrical contact with the formation is required, and the tool can be used in wells drilled with air. The recorded signal is proportional to the conductivity of the formation. It is much less influenced than other logs by invaded zones that are more resistive than the uncontaminated formation. As this is the case in the majority of wells drilled, the induction log has had considerable impact on formation evaluation. The newer focused devices have a depth of investigation much greater than the electric log, are practically free from the effect of the borehole, and are automatically corrected for layer thickness.

2. ROCK-POROSITY MEASUREMENTS FROM RADIOACTIVITY AND ACOUSTIC VELOCITY

Rock porosities form the basis of all measurements and, of course, determine the maximum hydrocarbon saturation for a reservoir. In 1945, cores were the main source of data; today quantitative measurements of porosity in a borehole are also obtained from radioactivity and acoustic velocity measurements.

Increased knowledge of radioactivity, coupled with ingenious ways of practical application to the borehole by industry and service companies, has enabled measurement of porosity as well as of other rock properties. Logging the natural radioactivity (gamma rays) of rocks was commonly used in 1945 to detect changes in rock lithology.[26] Progress in exploiting other potential applications of downhole measurements with radioactivity was at first slow. There was a lack of understanding of rock response to radioactive bombardment. Also the formation response was masked by contributions from the borehole. This has changed significantly.

At the close of World War II, a combination radioactivity log was in service which recorded the natural gamma rays from the rock (related to lithology) and, independently, the gamma rays resulting from bombardment of the formation with neutrons. The latter, called the neutron log, could be related to porosity. Thus both lithology and porosity could now be qualitatively determined. This contributed significantly to well evaluation because (1) it was the first device which could give porosity independently of resistivity measurements, and (2) it was the only device that could be used in cased holes. However, the high level of gamma rays given off by the neutron source (radium-beryllium) hampered quantitative determination of porosity.

At this time, another log was used infrequently to obtain an estimate of formation density which in

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21. Doll, H. G., "The Microlog—A New Electrical Logging Method for Detailed Determination of Permeable Beds," *Trans.*, AIME, 1950, vol. 189, pp. 155-164.
22. Doll, H. G., "The Laterolog: A New Resistivity Logging Method with Electrodes Using an Automatic Focusing System," *Jour. Pet. Tech.*, 1951, vol. 3, No. 11, pp. 305-316.
23. Keller, George V., "An Improved Electrode System for Use in Electric Logging," *Producers Monthly*, 1949, vol. 13, No. 8, pp. 12-15.
24. Doll, H. G., "Introduction to Induction Logging and Application to Logging of Wells Drilled with Oil Base Mud," *Jour. Pet. Tech.*, 1949, vol. 1, No. 6, pp. 148-162.
25. Dumanoir, J. L., Tixier, M. P., and Martin, M., "Interpretation of Induction—Electrical Log in Fresh Mud," *Jour. Pet. Tech.*, 1957, vol. 9, No. 7, pp. 202-217.
26. Howell, Lynn G., and Frosch, Alex, "Gamma-Ray Well-Logging," *Geophysics*, 1939, IV, No. 2, pp. 106-114.

turn could be related to porosity. The principle of operation was to bombard the formation with gamma rays and record the returning scattered gamma rays. This is called the gamma-gamma density log.

The response of both these nuclear porosity logs was only qualitative, mainly because of the effect of variations in tool-borehole geometry, as well as the subtle effects of the differing chemical constituents in various rock types, which were not yet adequately evaluated.

By the early 60's, the well surveying companies had introduced a number of improved radioactivity tools which allowed quantitative determinants of porosity.[27] Improvements in the gamma-gamma log include the development of a dual spacing tool which automatically corrects for borehole effects.[28] In many cases, this correction is sufficiently accurate to allow quantitative interpretation. Previously, corrections for, say, mud cake often had to be estimated.

Improvements in neutron logging tools included (1) replacement of radium-beryllium neutron sources by more gamma-ray free plutonium-beryllium; (2) development of instruments employing more sophisticated radiation detectors capable of selective measurements of thermal neutrons and epithermal neutrons in addition to the neutron-induced gamma rays; and (3) improved techniques for calibrating and standardizing instrument performance.

3. IDENTIFICATION OF HYDROCARBONS BY RADIOACTIVITY LOGS

Although electrical measurements usually suffice in open hole to identify hydrocarbon-bearing formations, in cased hole only radioactivity measurements provide a means to distinguish between oil, water, and gas. As outlined above, the gamma ray log serves to identify lithology. The neutron log indicates relative porosity and usually identifies gas-bearing zones in cased hole. Also, certain specialized neutron logging instruments were developed during the 1950's which showed a somewhat different response to salt-water-bearing zones than to oil-bearing zones.

More recently a significantly better method has been developed for fluid saturation measurements in cased holes. This method employs a downhole neutron generator which can be pulsed while controlled from the surface.[29] Earlier neutron sources emitted continually which limited their applications. A pulsed neutron source provides a means of measuring neutron population as a function of time; for instance, the lifetime of thermal neutrons. The rate of decay of thermal neutron density is related to fractional water saturation.[30]

The advancements described above have proved of great importance to the oil producing companies. For example, before abandonment of existing wells upon depletion, it can now be ascertained with logs rather than expensive testing whether or not reservoirs other than the depleted horizon are hydrocarbon bearing. This is particularly important, but not limited to, old wells where available open hole logging data are inadequate for a meaningful interpretation. Through the use of the radioactivity "through casing" devices, questionable and unknown accumulations have been discovered. Additionally, the evaluation of newly discovered accumulations, particularly carbonate reservoirs, has been significantly improved through the use of radioactivity logging tools (porosity).

Present advancements in radioactivity logging are keeping up with higher temperatures associated with deeper wells and thermal recovery projects. The higher accuracies required for today's reservoir evaluations are being obtained from existing logs. In view of past experience, new tools and techniques are to be expected in the future.

4. POROSITY OF ROCKS FROM ACOUSTIC LOGS

The acoustic log was first recognized as a porosity tool in 1954. It was originally developed as an aid in interpreting seismic data but proved so effective in determining porosity that it has become the standard porosity tool in many areas.[31] It measures the transit time of a sonic impulse through a given length of rock. The rate of travel of the compressional wave through a rock depends on the composition of the matrix and the fluids it contains. Since the composition of the matrix can be obtained from other sources, and since the transit time varies with relative amounts of matrix and fluid, the porosity can be determined with fair accuracy.

The amplitude and variations of the acoustic wave train have also proved useful for determining bonding of the cement to casing. It was found that a sound pulse will travel through free casing with very little attenuation. When a cement sheath is firmly bonded to the outside of the casing the sonic pulse loses energy to the low-velocity cement, and a large attenuation results. The cement bond log has led to improved cementing techniques.

From an observation of the complete wave train data, formation fractures intersecting the borehole can be located. When the fracture is between the transmitter and receiver, the discontinuity causes a diagnostic change in amplitude. Although this technique is qualitative only and does not indicate the

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27. Lynch, *op. cit.*, chap. 6, pp. 226-267.
28. Wahl, J. S., Tittman, J., Johnstone, C. W., and Alger, R. P., "The Dual Spacing Formation Density Log," *Jour. Pet. Tech.*, 1964, vol. 16, No. 12, pp. 1411-1416.
29. "Neutron Generator Locates Oil," *Petroleum Week*, August 26, 1955, p. 15.
30. Youmans, A. H., Hopkinson, E. C., Bergan, R. A., and Oshry, H. I., "Neutron Lifetime, A New Nuclear Log," *Trans.*, AIME, 1964, vol. 231, pp. 319-328.
31. Vogel, C. B., "A Seismic Velocity Logging Method," *Geophysics*, 1952, XVII, No. 3, pp. 586-597.
Summers, G. C., and Broding, R. A., "Continuous Velocity Logging," *Geophysics*, 1952, XVII, No. 3, pp. 598-614.
Wyllie, M. R. J., Gregory, A. R., and Gardner, L. W., "Elastic Wave Velocities in Heterogeneous and Porous Media," *Geophysics*, 1956, XXI, No. 1, pp. 41-70.

open width of the fracture, it has found application in a number of hard and carbonate formations.

5. POROSITY OF ROCKS FROM NUCLEAR MAGNETISM LOGS

Another porosity tool—still in the process of development—which responds only to hydrogen in the formation fluids, measures nuclear magnetism.[32] Hydrogen confined in extremely fine pores, bound to the rock or contained in viscous fluids (say, over 600 cp) is not included in the measurement. Thus a minimum porosity value, called "free fluid index," is obtained.

Briefly, the method consists of subjecting the formation around the borehole to a magnetic field which aligns the hydrogen nuclei in liquids. Upon release of the field, the nuclei relax in the much weaker magnetic field of the earth and thereby produce a signal which is recorded. Hydrogen nuclei in highly viscous fluids, heavy oils, or those bound to a surface, as in clay, have such short relaxation times that they are not significant in the measured signal.

The tool thus far has had some use in determining (1) minimum porosity in low-viscosity oil horizons, and (2) water content of known high-viscosity oil horizons. However, the tool has considerable promise. It may be capable of in situ studies of microconditions in the fluid-filled pore. It also shows promise for a quantitative determination of permeability,[33] for which there is no borehole tool available.

D. Formation Evaluation by Combined Methods

Rocks vary greatly, but each geologic province has a characteristic suite of rock types. The Gulf Coast province, for instance, contains predominantly sandstones and shales, whereas parts of Kansas, Montana and West Texas contain predominantly carbonate rocks, i.e., limestones and dolomites. Particular formation evaluation methods have developed for each province.

Sandstone hydrocarbon reservoirs are more homogeneous, and evaluation is more quantitative.

In sections of relatively clean sands containing salty groundwaters, rock relationships determined from acoustic velocity to obtain porosity, from electrical induction to obtain hydrocarbon saturation, and from natural electrical potential to obtain changes in lithology are sufficient. Such measurements entail running only an electrical survey (natural potential, shallow resistivity log to determine effects of invasion, and a deep-penetration induction survey) and an acoustic survey. The density log (bombarding with gamma rays) is also frequently used for porosity instead of, or in combination with, the acoustic survey.

After a hydrocarbon reservoir is located from this suite of surveys, the type of hydrocarbon is then determined by sidewall sampling of wireline formation testing. Open hole drill-stem testing is seldom attempted in soft formations because of the danger of sticking the tool.

Shaly sands and relatively freshwater-bearing sands, being more difficult to evaluate, require the use of more tools. Drill cuttings and mud logging are used, and sidewall sampling of questionable zones are more extensive. Sidewall samples are analyzed for shale content, and possibly the cation exchange capacity is measured to weigh the effects of shale on electrical properties. Water recovered from drill-stem testing is used more frequently to determine salinity of groundwaters.

Although great advances have been made since the war, carbonate reservoirs require more coring for control, and a larger number of rock characteristics must be measured and interrelated to arrive at a suitable understanding of the reservoir. The petrologic fabric, as well as the pore structure, is heterogeneous; this is due not only to original sedimentary fabric but to later alteration by erosion, solution, or fracturing. The pore structure is therefore frequently on a coarse spatial scale which may intersect the borehole erratically.

To cope with these conditions, evaluation practices depend heavily on techniques used during drilling (coring, drill cuttings, drill-stem tests), as well as on wireline surveys run after the hole is drilled. This provides a cross reference of data to confirm interpretations.

On exploratory wells, drill cuttings are carefully examined for evidence of hydrocarbons and for porosity. As soon as a formation is encountered, either it is cored or drilling proceeds carefully, and a drill-stem test is made. Since permeabilities are often low, the test may last several hours; this is possible because the carbonate rocks are competent and will not cave in.

A suite of borehole surveys is then adapted to the problem. The layers of salt frequently encountered in a carbonate province necessitate drilling with a salt-saturated drilling fluid. A common set of surveys in this case includes a natural gamma ray log for noting changes in lithology and layer thickness, a focused current resistivity log, and a neutron survey (a type that is less affected by rock matrix and pore type) for porosity.

A density log may be used with either the neutron or the acoustic survey or with both in order to obtain estimates of mineral content for geologic information, since each is related differently to the mineral content.

The computer is being used more and more to aid in digesting and calculating the large amount of data necessary in carbonate evaluation.

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32. Brown, R. J. S., and Gamson, B. W., "Nuclear Magnetism Logging," *Trans.*, AIME, 1960, vol. 219, pp. 199-207. Also published in *Jour. Pet. Tech.*, 1960, vol. 12, No. 8, pp. 201-209.
33. Seevers, D. O., "A Nuclear Magnetic Method for Determining the Permeability of Sandstones," *7th Ann. Logging Symposium Trans.*, SPWLA, Tulsa, Oklahoma, May 8-11, 1966.

One of the greatest future contributions expected from wireline tools is much-needed additional geological information from exploratory wells and from development wells. This was discussed more fully under Production Geology.

E. Production Logging

After the well is cased and completed, the operator wishes to produce under the most efficient manner. Recently developed production logging tools provide information of certain conditions in and and around the borehole; this knowledge is necessary for efficient and economical well production.[34] A production log may be run immediately after a well is cased or at any time during its producing life. These surveys provide factual downhole data which allow (1) monitoring production performance, (2) determining flow characteristics, and (3) evaluating the condition of well equipment. Examples of these main categories include the measurement of downhole pressures, injectivity profiles, and casing corrosion.

Prior to 1945, temperature and bottom hole pressure surveys were the most notable production logs available. The major developments in production logging have occurred since Word War II. Applications of new technology developed in this field are numerous and include, for example, the packer flow meter (1958) designed to measure fluid velocity and thus indicate total fluid rates. Other examples are the gradiomanometer (1962) designed to measure the pressure differential between two sensors and thus indicate fluid specific gravity, and the casing-inspection tool (1962) designed to measure the effect of eddy currents in a magnetic field and thus indicate the existence of corrosion on tubular goods. Summaries of all production logging applications and equipment are available in the industry literature.[35]

Interpretation of production logs provides a significant portion of the data needed to diagnose causes for deficient production. Consequently, they are an important aid in the effort of restoring such wells to full productive capacity. Also, drainage patterns around individual wells can be established, thus allowing optimum exploitation of reservoirs.

Since 1960, further acceleration of improvements in production logging equipment and interpretation techinques has resulted in a twofold increase in industry utilization of these logging methods in the three-year period 1963-1965. Compared with its ultimate usage, production logging is now considered to be in its infancy, and new tools and techniques are to be expected in the future.

F. Field-Office Communications Link

Within the last two years, methods have been devised to transmit the logs from the well to the office. The logging cable signals are converted to a digital form suitable for transmission over telephone, microwave, or FM radio facilities.[36] The specialist, by directing the operations from the office, saves much travel time, particularly to offshore and other remote locations. He can thus increase his technical productivity severalfold.

The use of log transmission equipment is now very limited but will probably increase rather rapidly, because the specialist can monitor logging operations, evaluate logs, and issue instructions with a minimum of lost time. The transmission equipment also encourages utilization of large computers and technical consultation unavailable at the well site.

G. Summary

Research and technology were slowed by the war but were resumed at an accelerated pace by greatly increased staff within a fews years after the war.

During the last two decades, formation evaluation has grown from an art pursued by a few geologists and engineers to a recognized science practiced on a full-time basis by hundreds of engineers and geologists. Most of the basic petrophysical relations were recognized before 1945, but theoretical studies and laboratory experimental research on physicochemical rock and fluid properties since then have amplified and developed these relationships into quantitative form. This has given impetus to the improvement of existing tools and the development of new tools. As new tools were developed, some of the older ones were phased out, as shown in Figure 63. Note how the old electric resistivity log has almost been replaced by the focused induction log, and the microlog by the acoustic and radioactivity logs.

The more precise knowledge of petrophysical relations and the use of new tools have permitted the development of techniques which enable the engineer to evaluate wells more effectively and cheaply. Additional zones of lower porosity, greater heterogeneity, and thinner layers can be detected in exploratory wells. The development of modern methods of formation analysis has added greatly to our ability to explore and develop increasingly deeper accumulations, as well as to extend marginal zones to economic production by using proper stimulation and completion techniques. The more thorough evaluation of zones behind casing in old wells provides data for developing new recovery processes in old fields and for finding new fields. Recovery is also increased in new fields because the more quantitative evaluation of formations leads to the use of recovery processes best suited to the formation characteristics.

34. Bryant, Harvey L., "Production Well Logging Techniques," *Geophysics*, 1960, XXV, pp. 905-927.
35. Connolly, Edward T., "Resume and Current Status on the Use of Logs in Production," *6th Ann. Logging Symposium Trans.*, SPWLA, Dallas, Texas, May 4-7, 1965, vol. 1. Wade, R. T., Cantrell, R. C., Poupon, A., and Moulin, J., "Production Logging—The Key to Optimum Well Performance," *Jour. Pet. Tech.*, 1965, vol. 17, No. 2, pp. 137-144.
36. Eaton, F. M., and Decker, G. J., "Digital Transmission of Well Logs by Radio and Telephone," *Jour. Pet. Tech.*, 1966, vol. 18, No. 2, pp. 151-154.

One of the greatest advances in quantitative evaluation resulted from research into the electrical properties of rocks coupled with the development of focused logs. In the latter, the depth of investigation is increased beyond the invaded zone, and the logs are less affected by the layers adjoining the productive horizon. The focused induction log has within a few years of its introduction become a standard log used in combination with other logs selected according to the geologic province. The rock relationships discovered led to the use of acoustic and radioactivity logs for measuring the porosity and other formation properties in a quantitative way. The invaded zone, formerly so troublesome, is now used to advantage in obtaining additional information.

H. Future Technological Advances

One of the most important advances expected in formation analysis and reservoir geology is a better understanding of heterogeneities in the reservoir (natural changes in geologic fabric). This will improve field development and will aid in determining the type of recovery process and its operational control to increase production and reserves.

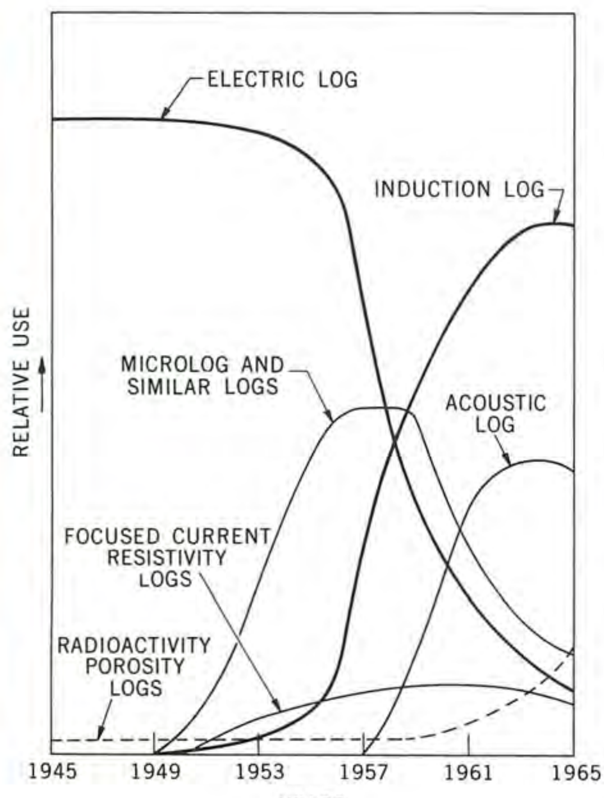
More ultradeep reservoirs will be discovered and economically produced, owing to rapidly increasing knowledge of deep basin geology, hydrocarbon origin and mitigation, and stress-strain relations in the earth. Reduced drilling and completion costs and improved formation evaluation, particularly as the present temperature limitation on logging tools is overcome, will also contribute to deep-reservoir production.

Production logging tools, now just in their infancy, will over the next ten years help to provide more oil from known reserves. Larger demands for crude will prompt more well workovers for maximum production from each well.

Use of computers to digest and analyze numerous well logging data, and transmittal of field data to the office, will greatly increase the efficiency of technical experts.

Improvements in formation evaluation tools run in casing, for example radioactivity logs, for fluid content and geological information, will make way for increased production from old fields, one of our greatest future potentials of oil.

FIGURE **63.** Technological Advances Evidenced by Evaluation of More Diagnostic Logs



SECTION 4—Properties of Reservoir Systems

G. E. Archie

A. Introduction

A reliable estimate of recoverable reserves depends upon how much hydrocarbon is originally present and upon specific properties of both the hydrocarbon and the reservoir rock. Three levels of phenomena must be considered in arriving at the desired reserve estimate: (1) the reservoir as a whole, (2) a unit cube of the reservoir, and (3) a single pore. At each of these levels, the properties and performance of both the rock and its fluids must be understood and integrated into the overall performance and reserve prediction.

During the past several years, significant advances in our knowledge have been achieved on all three important levels of investigation. Examples are: (1) prediction of porosity trends in the reservoir as a whole, (2) prediction of unit cube properties of the reservoir rock and its fluids from indirect measurements (logging) in a borehole, and (3) prediction of fluid flow performance and hydrocarbon saturations from a knowledge of pore structure and fluid properties. The latter two levels are discussed in this Section.

B. Fluid Systems

The petroleum industry appreciated very early the importance of volumetric and phase behavior of fluids in reservoirs. Knowledge of these properties was used to obtain maximum recovery.[37] By 1945, about 2,000 papers on related topics had been written.[38]

The past two decades have seen a great expansion in this library of quantitative data on petroleum and petroleum constituents. These data have been accumulated through investigations being carried on by universities, government agencies, and the petroleum industry; the largest single source of basic information on the phase behavior of hydrocarbons has been the continuing program by Sage and Lacey under a project sponsored and supported by the American Petroleum Institute, a cooperative effort of many American petroleum companies. Similarly, the outstanding evaluation and compilation of data on the physical and thermodynamic properties of hydrocarbons are the result of another API project. These basic data on the behavior of multiple component systems have been of value in interpreting and predicting the performance of newer recovery processes, which are discussed in other chapters.

Equipment used in studying the properties of reservoir fluids has improved during the past 20 years. More reliance has been put on windowed cells as experimental conditions approached the critical state for the fluids. A major aid in the quantitative study of compositions of fluids in phase equilibria was the development of gas-liquid chromatography [39] as a research tool. Development was due primarily to the inquisitiveness of workers in the oil industry's research laboratories. Gas-liquid chromatography permits routine analysis of petroleum fluids and many other fluids that often cannot otherwise be handled.

An increasing number of studies now are concerned with the properties of hydrocarbons with other substances found naturally in various petroleum reservoirs: nitrogen, helium, carbon dioxide, hydrogen sulfide, and water. Interest in hydrogen sulfide arose from the discovery of reservoirs containing commercial amounts of sulfur, which now have become an important source of sulfur. The current concern with thermal recovery processes is causing the industry to undertake phase studies at higher temperatures.

As attention of the industry turns to sources of fossil fuel other than petroleum, the research groups of the industry have already begun to study the physical properties of fluids from oil shale and from tar sands. Research on all phases of this subject will expand as the time approaches when these sources of fuel must be exploited.

C. Pore Structure of Reservoir Rocks

Underground natural reservoirs are made up of many types of porous rocks. Even though some are very heterogeneous, it is now possible to classify rock pore structure in a broad way and relate it to physicochemical and mechanical properties. Techniques have been developed to obtain pore structure characteristics of individual reservoir rock types of petrographic, capillary pressure, electrical resistivity, and surface area measurements.

Sandstone pore structure is reasonably homogeneous compared with other rock types because of the geologic history of the sandstone, i.e., its environment of deposition and the diagenetic processes that have occurred since original deposition.

Beach sands are composed of well-sorted grains and have high porosity; large river channel sands are not so well sorted but still contain little shale; delta fringe sands contain finer grains and shale. Postdepositional processes due to compaction, welding of the grains due to pressure-solution at the higher temperatures deeper in the earth, and cementation reduce the porosity and change the sand to sandstone. Therefore, sandstone pore structure is of many types, but any one type is usually relatively homogeneous.

Evaluation of carbonate reservoirs is made difficult by the diversity of sedimentologic and postsedimentologic processes which are responsible for their origin. In the late 1940's, the recognized types of carbonate pore space were primary porosity, solution porosity, dolomite porosity formed by a mineralogic change, and interconnected joints and fractures.[40] Of these, solution porosity and dolomite porosity were considered to be most important. Little was known about details of pore structure or the relationship between pore structure and the fluid distribution and productive characteristics of reservoirs.

The advent of electric logging techniques, capillary pressure measurements,[41] and fluid flow through rock samples,[42] pointed out the need for a better understanding of carbonate pore structures. Carbonate rocks with similar pore structures were grouped according to porosity-permeability relationships, capillary pressure data, electrical resistivity factors, and textural data.[43] This work brought out the importance of the matrix porosity and pore size distribution. Detailed petrographic studies of carbonate pore structures showed that pore geometries with similar petrophysical parameters could originate in different ways.[44] Therefore, in order to evaluate the

37. Sage, B. H., and Lacey, W. N., *Volumetric and Phase Behavior of Hydrocarbons,* Stanford University Press, Stanford University, California, 1939.
38. Katz, D. L., and Rzasa, M. J., *Bibliography for Physical Behavior of Hydrocarbons Under Pressure and Related Phenomena,* J. H. Edwards, Inc., Ann Arbor, Michigan, 1946.
39. Martin, R. L., "Applications of Gas Chromatography in the Petroleum Industry," *4th International Gas Chromatography Symposium,* L. Fowler, ed., Academic Press, New York, 1963, pp. 127-138.
40. Hohlt, R. B., "The Nature and Origin of Limestone Porosity," *Quarterly,* Colorado School of Mines, 1948, vol. 43, No. 4, pp. 1-51.
41. Purcell, W. R., "Capillary Pressures—Their Measurement Using Mercury and the Calculation of Permeability Therefrom," *Trans.,* AIME, 1949, vol. 186, pp. 39-48.
42. Stewart, C. R., Craig, F. F., Jr., and Morse, R. A., "Determination of Limestone Performance Characteristics by Model Flow Tests," *Trans.,* AIME, 1953, vol. 198, pp. 93-102.
43. Archie, G. E., "Classification of Carbonate Reservoir Rocks and Petrophysical Considerations," *Bull.,* Am. Assoc. Pet. Geol., 1952, vol. 36, No. 2, pp. 278-298.
44. Murray, R. C., "Origin of Porosity in Carbonate Rocks," *J. Sed. Petrology,* 1960, vol. 30, No. 1, pp. 59-84.

lateral extent of carbonate reservoirs, it became necessary to understand the origin of the porosity. For example, research on dolomitization has shown that dolomite distribution is often controlled by the selective dolomitization of a particular sediment type and that dolomitizing water is often formed in a specific sedimentary environment. Patterns of sedimentation therefore became important in predicting reservoir distribution, and research in recent carbonate sedimentation became important in understanding carbonate pore structures.

The trend for the future is toward an even better understanding of the processes responsible for the origin of the pore structures of reservoir rocks. This understanding should provide a basis for developing the ideas and techniques necessary to evaluate the lateral and vertical continuity of pore space in reservoirs. Such knowledge will allow us to produce known hydrocarbon accumulations more economically and to point out accumulations which are not being adequately recovered. More research on the relationship between pore structure and residual oil will be needed as supplementary recovery methods become more important.

D. Rock-Fluid Systems

The quantitative measurement of most physicochemical properties of rock-fluid systems is difficult. The simpler properties such as porosity, permeability, and resistivity of water-bearing rock can now be measured with considerable accuracy. Properties of rock-fluid systems involving two or more fluids are more difficult, and more research is necessary in this area. An example is wettability and its relation to relative permeability and electrical resistivity of oil-bearing rock for different rock pore networks.

The pores in reservoir rock are generally thought to be predominantly water-wet, so the oil in each pore is bounded by a film of water which contacts the rock pore surface. Capillary forces are therefore generated by pressure differences across curved interfaces of these immiscible fluids. Water fills the smaller pores, whereas only a film of water exists on the surface of the large pores. The water content in a rock of fine pore network is high. The oil and water distribution initially in a reservoir can be predicted from capillary pressure measurements on rock samples representative of the reservoir.

The importance of capillarity in oil field reservoirs and production processes was known by 1945, and accepted techniques of measuring capillary properties on rock samples were established.[45] An understanding of dynamic as well as static effects of capillarity and of the importance of wettability came later as a result of the surge of research activities immediately after the war by numerous physical chemists. Although the wettability of a rock changes rapidly during coring and transporting to the laboratory, and is difficult to control in the laboratory, methods of measuring relative wettability have been developed, and much information is now available to indicate the effects of wettability on capillary processes.[46]

Capillarity under dynamic conditions has considerable effect on flow properties and therefore on recovery mechanisms. For example, capillary pressure differences exist when water is injected into a water-wet oil reservoir. The water enters the more permeable layers, disrupting the capillary equilibrium with adjoining low-permeable layers. This capillary pressure causes water to be pulled into some of the low-permeable zones, forcing oil out into the high-permeable layers where it can be produced.[47]

The permeability of a rock to a single fluid is of course straight forward; however, the relative permeability of a fluid when two or three phases are present depends on capillarity and therefore on wettability. By 1958, methods of measurement and some understanding of two-phase relative permeability were established.[48] Techniques are being broadened to meet the challenge of three-phase systems (oil-gas-water) encountered in new, more complex secondary and tertiary recovery processes.[49]

Just as interrelation of pore structure, wettability, and capillarity control initial reservoir conditions, so does this relationship have a bearing on the amount of residual hydrocarbons in the reservoir at the economic limit of production. Residual oil is trapped by capillary forces. Research is continually underway to devise recovery processes which alter these capillary forces, in order to recover the residual oil after the use of known production methods.

Increased fundamental knowledge about the role of capillary forces in rock-hydrocarbon-water systems has provided the basis for increasing recoverable reserves from water-wet reservoirs. Imbibition processes have been applied, and new processes which involve altering the wettability of oil-wet reservoirs have been proposed. Continued research in the broad area of capillarity can be expected to result in further improvement in the exploitation of reservoirs by known processes and in the development of important new processes.

The indirect measurement of reservoir properties by the use of well logging techniques (measurements in a drill hole) has advanced rapidly in the years

45. Leverett, M. C., "Capillary Behavior in Porous Solids," *Trans.*, AIME, 1941, vol. 142, pp. 152-169.
Hassler, G. L., Brunner, E., and Deahl, T. J., "Role of Capillarity in Oil Production," *Trans.*, AIME, 1944, vol. 155, pp. 155-174.
46. Bobek, J. E., Mattax, C. C., and Denekas, M. O., "Reservoir Rock Wettability—Its Significance and Evaluation," *Trans.*, AIME, 1958, vol. 213, pp. 155-160.
47. Graham, J. W., and Richardson, J. G., "Theory and Application of Imbibition Phenomena in Recovery of Oil," *Trans.*, AIME, 1959, vol. 216, pp. 377-381.
48. Loomis, A. G., and Crowell, D. C., "Relative Permeability Studies: II. Water-Oil Systems," *Producers Monthly*, 1959, vol. 23, No. 10, pp. 18-24.
49. Snell, R. W., "Three-Phase Relative Permeability in an Unconsolidated Sand," *J. Institute Petroleum*, 1962, vol. 48, pp. 80-88.

following 1945. This is more fully discussed under Formation Evaluation, Section 3 above. In a great many instances, these techniques can now be used to determine lithology, porosity, initial hydrocarbon saturation, and the amount of hydrocarbon which can be moved by a limited water flood. Other important properties of the reservoir system such as permeability, capillarity, and reservoir heterogeneity can often be inferred from logging measurements.

One of the most important logging techniques is that of measuring the electrical resistivity of borehole-reservoir systems. When the resistivities of the borehole and reservoir waters are known, resistivity measurements provide a reasonably quantitative measure of hydrocarbon saturation. Quantitative relations between resistivity and hydrocarbon saturation were established for some rocks prior to 1945, and research in this area has continued to the present. Laboratory measurements of electrical resistivity of hydrocarbon-bearing rocks under simulated underground conditions are difficult. Since the war, however, much research has been reported on clean sandstones and the more homogeneous carbonates. Extensive research results are also now available on water-bearing shaly sand formations.[50] The presence of shale restricts fluid flow, causes a higher connate water, acts as an electrical conductor, and complicates interpretation of resistivity measurements. Further work is expected to result in improved data, and consequently in a better understanding of the relationships between resistivity and hydrocarbon saturation of shaly sandstone.

It was found early that a natural electrical potential exists in a borehole when drilling fluid contacts the rock formations. Since the war, considerable research has been devoted to these phenomena, for they are related to the salinity of the groundwater in hydrocarbon-bearing reservoirs. A knowledge of salinity provides an estimate of water resistivity, which is needed for estimating hydrocarbon saturation from resistivity measurements of borehole-reservoir systems. This potential is due to a number of sources, and it is possible so far to segregate the useful ones only in particular instances. A log of these potentials in a borehole, however, provides an excellent way to correlate similar formations from well to well and to indicate lithologic changes.

Other important logging techniques which have been developed since World War II are discussed in more detail elsewhere. They include (1) radioactivity logs to identify lithology and porosity, (2) acoustic logs to determine porosity, (3) focused resistivity techniques to provide improved response under complex reservoir geometrical conditions, and (4) the new nuclear magnetic log which has the still-unexplored potential of providing information on porosity as well as other useful information about the rock and fluids making up a reservoir system. Laboratory measurements of these rock properties form the basis of determining relationships used in interpreting these logs. All of these logging techniques yield information about the reservoir system, which greatly improves our ability to evaluate and exploit hydrocarbon reserves.

E. Interrelation of Reservoir Rock Systems

The infinite variations in rock-fluid systems which exist in nature make it necessary to interrelate various properties in order to solve engineering and geological problems associated with the discovery and production of hydrocarbons. By 1945, a number of rock-fluid relationships were known, in a qualitative way, and were used by engineers and geologists to interpret conditions of the hydrocarbon reservoir:

Rock type—porosity—permeability—gross geometry of pore structure
Rock type—porosity—permeability—capillary properties
Rock type—natural radioactivity
Rock type—self-potential—ground water salinity
Rock type—neutron bombardment—porosity
Rock type—gamma ray bombardment—density
Rock type—residual oil in cores—in situ oil saturation

At that time volumetric and phase behavior of hydrocarbons were fairly well known. A relationship between rock type—resistivity—porosity—water saturation of a hydrocarbon-bearing rock was well established for relatively clean sandstones and was used in the evaluation of nearly all sandstone reservoirs penetrated with the drilling bit.

After the war, research increased greatly, and many relationships have now been put on a quantitative basis for a number of rock types:

Rock type—capillary properties—connate water content of an oil-bearing zone
Rock type—relative permeability of oil and water, gas and water
Rock type—resistivity of hydrocarbon-bearing rock—porosity—resistivity of contained water
Rock type—neutron bombardment—porosity
Rock type—neutron bombardment—chlorine content of contained water
Rock type—acoustic velocity—porosity

These and other relationships make it possible to obtain subsurface data for formation evaluation and for prediction of reservoir performance.

It is important to continue the basic research of microscopic phase distribution of hydrocarbon-water systems in porous media in relation to mineralogy, wettability, diffusion, and oil trapping, particularly

50. McKelvey, J. G., Jr., Southwick, P. F., Spiegler, K. S., and Wyllie, M. R. J., "The Application of a Three-Element Model to the S.P. and Resistivity Phenomena Evinced by Dirty Sands," *Geophysics*, 1955, XX, pp. 913-931.
Hill, H. J., and Milburn, J. D., "Effect of Clay and Water Salinity on Electrochemical Behavior of Reservoir Rocks," *Trans.*, AIME, 1956, vol. 207, pp. 65-72.

from a dynamic point of view. Future research will no doubt provide new or improved ways to measure the pertinent parameters in situ, thus providing the techniques necessary to follow and control the performance of new recovery techniques.

SECTION 5—Methods of Reservoir Engineering Diagnosis

Lincoln F. Elkins

The general procedure of the reservoir engineer is first to determine the quantities of oil and gas in place and then to predict the performance of the reservoir under various feasible methods of operation including, of course, production by both natural forces and supplementary fluid injection. However, since all aspects of the reservoir and its performance must be inferred from information obtained through wellbores and are subject to much uncertainty, in practice, the procedures overlap.

A. Determination of Oil and Gas in Place

Volumetric calculations using core, log and fluid sample data and geological information provide one measure of oil and gas in place. Interpretation of pressure-production performance using the material balance principle, in combination with transient water influx relations, provides another.[51] Quite often there are significant differences between the results calculated by the two methods. In some cases this results from inadequate or inaccurate data and in other cases it is a reflection of fundamental problems within the reservoir itself. During the development period, measurement of reservoir pressures is necessarily limited to the developed area but the interpretation of pressure-production data involves expansion of the entire hydrocarbon accumulation and rock and fluids in a contiguous aquifer if any exists. Thus uncertainty is introduced by the necessity of estimating pressures in the undeveloped area. In many older fields, production of gas and water was not accurately measured. Obviously this introduced error because the pressure-production relation of a reservoir involves all fluids, not just oil alone. Fortunately, with improved markets for gas and improved practices of subsurface disposal of salt water and with improved understanding of the value of good reservoir data by both engineers and management, the quality of gas and water production data is much better now than it was before World War II. In some tight reservoirs it is a practical impossibility to obtain accurate pressure measurements—well pressure buildup approaching true reservoir pressures might require the wells to be shut in for many months to a few years. In general, use of too low pressures measured with too short well shut-in times in material balance calculations tends to indicate too low quantities of oil and gas in place.

Selection of a "most probable" value of oil in place depends partly on the type and quality of reservoir and performance data available and partly on the ingenuity, experience and judgment of the reservoir engineer making the analysis. The best results usually are obtained when the estimate is checked by all methods possible. For example, if water influx is inferred by the pressure-production performance, the rate and total amount of influx is checked for reasonableness, if possible, by comparison with water-production rate and reservoir volume invaded. Quite often a disparity between the volumetric estimate of oil and gas in place and that calculated by material balance has been turned to advantage. In many cases, it has led to the finding of important extensions of oil and gas fields; in others it has served as the impetus to a more thorough analysis of the reservoir and its performance with other benefits in its development and operation. Generally, the accuracy of performance measures of reservoir content improve with time and depletion, but the utility of the information decreases with time since more and more of the pertinent development and operating decisions will already have been made.

B. Determination of Natural Displacement Mechanism

Closely related to the performance measures of oil and gas in place are the performance measures of types and efficiencies of natural displacement mechanisms active in the reservoir. If reservoir pressure is declining and water influx is minor, some insight into the oil displacement mechanism in that particular reservoir is possible on a gross basis through combination of analysis of pressure-production trends and gas-oil ratio trends using the pressure-volume behavior of oil and gas samples from the reservoir.

Comparison of changes in oil saturation inferred from this analysis with similar data of other reservoirs more fully depleted often provides an additional measure of oil and gas in place. Then extrapolation of these trends combined through theory permits an estimate of recovery achievable through this primary or natural mechanism. This method considers only the gross behavior of reservoir performance and not the detailed internal mechanism of displacement of oil occurring within the reservoir. It does not necessarily provide reliable trend data for prediction of recovery by other methods such as fluid injection. For example, the trends of increase in gas-oil ratio and decline in reservoir pressure with production of oil during injection of gas in a pressure maintenance project may not necessarily be the same as the trends during natural production with solution gas

51. Schilthuis, R. J., "Active Oil and Reservoir Energy," *Trans.*, AIME, 1936, 118, 33.

drive. Particularly this would be true in fairly heterogeneous reservoirs where injected gas channels rapidly through more permeable streaks without efficient displacement of oil in other parts of the reservoir. During primary production with displacement of oil by gas released from solution in the oil, the efficiency at early state of depletion may be better since the solution gas is distributed throughout all the pores of the reservoir rock system whether they be in the tighter or more permeable streaks. The primary advance in the technology of determination of natural displacement mechanisms since World War II has been the compilation of a number of case histories which provide the practicing reservoir engineer with background for judgment. Indirectly this has resulted in significant increases in oil production rates and reserves because it has helped to provide more accurate predictions of performance to be expected if "nothing is done." Then comparison with performance predicted for alternate operating methods, often unitization and fluid injection, may provide the basis for instituting such enhanced recovery processes.

If reservoir pressure remains constant or declines slowly relative to withdrawals, the inference generally is that natural water drive is effective. Material balance calculations permit determination of the influx rate. Combination of that with the pressure decline history and the mathematics of the transient behavior of aquifers permits prediction of future water influx rates and pressure for assumed rates of production. This analysis by itself provides no measure of the oil displacement efficiency of the encroaching water. The latter can be determined only by volumetric studies of the portions of the oil reservoir actually invaded by water and by analysis of trends of produced water-oil ratios of individual wells and of the reservoir as a whole.

One of the earliest methods of estimating reserves of an oil property and one that will always remain is the extrapolation of production-decline trends with rate plotted against time or against cumulative production or both.[52] In such extrapolations for reserve estimates, the assumption is involved implicitly that forces active in the past will continue to act in the same relative manner in the future. While decline curves have considerable utility in guiding operations, particularly when changes in the trends occur, they provide little insight into the mechanism of displacement effective in the particular reservoir. Only when results of these analyses are coupled with other considerations of reservoir size and performance are they an aid to selecting alternate methods of operation which will increase recovery of oil.

C. Dynamic Methods of Formation Evaluation

The methods of formation evaluation discussed in an earlier section provide quantitative information about a reservoir in close proximity to a wellbore in an essentially static condition. Production and pressure measurements on a transient basis provide additional measures of some of the permeability characteristics of the reservoir within the drainage area of the well. While the mathematical theory of the flow of compressible liquids in porous media was developed by Hurst,[53] Muskat,[54] and others in the 1930's, the practical usage of the methods in day-to-day consideration of individual well problems by reservoir and production engineers was deferred until the simplified analysis methods by Horner[55] and by Miller, Dyes, and Hutchinson[56] and van Everdingen[57] were proposed. These various authors illustrated by mathematical analyses and by electric analog methods that the effective permeability of the reservoir rock can be determined for the region away from the wellbore area that may have been modified either favorably or unfavorably by the drilling and completion of the well and changes that have taken place during production from the well. Essentially the application of the method is plotting pressure buildup of the well vs. logarithm of time the well was shut in following a period of stable production rate. The slope of the pressure buildup curve is combined with the production rate to yield effective reservoir permeability or mobility by a simple formula. In addition, the comparison of apparent effective permeability based on the drawdown in pressure during the stable producing period and that calculated from pressure buildup provide a measure of the modification to permeability in the reservoir near the wellbore. The comparison of these two measures of permeability is often expressed as damage or improvement ratio. The major utility of this analysis is the prejudgment of effectiveness of fracture treatment or acid treatment of the well for improved productivity. Modifications of the method are also used in interpretation of drill-stem tests of new wells. In the latter cases, the major objective is the judging of reservoir quality as it has bearing on the economic practicability of completion of the well in the zone tested.

A large number of extensions of the mathematical analyses of pressure buildup have been made for varying geometries of reservoir rock and fluid systems. One of the most important of these is the so-called reservoir limit test in which boundaries of the

52. Arps., J. J., "Analysis of Decline Curves," *Trans.*, AIME, 1960, 160, 228.
53. Hurst, W., and Schilthuis, R. J., "Variations in Reservoir Pressure in the East Texas Field," *Trans.*, AIME, 1935, 114, 164.
54. Muskat, M., *Flow of Homogenous Fluids*, McGraw-Hill, 1937, p. 621.
55. Horner, *op. cit.* p. 503.
56. Miller, C. C., Dyes, A. B., and Hutchinson, C. A., Jr., "The Estimation of Permeability and Reservoir Pressure from Bottom Hole Pressure Build-up Characteristics," *Trans.*, AIME, 1950, 189, 91.
57. van Everdingen, A. F., "The Skin Effect and Its Influence on the Productive Capacity of a Well," *Trans.*, AIME, 1953, 198, 171.

reservoir such as faults or pinchouts cause changes of the slope of the pressure buildup curve.[58] While the mathematical theory has been developed the application has met with varying degrees of success and failure. Two major problems exist. The first is that the discontinuity in permeability or fluid properties must be relatively near a well to cause a distinct change in the pressure buildup trend during a reasonable test period. The second is that more than one model or assumed set of conditions can yield essentially the same change in pressure buildup trend. Thus the data must be interpreted in light of all other known factors about the well and geology of the reservoir and the uncertainties involved therein.

Some reservoir rocks have extensive natural fracture systems resulting in a directional permeability orientation for the reservoir as a whole. Pressure interference among wells may be used under some conditions to determine the orientation of the fracture system. One practical example of the application has been reported for the Spraberry Trend Field of West Texas. Computer studies of pressure transients during the early stages of development in many parts of the field indicated a NE SW trend of the major fracture system.[59] This was in good agreement with trends indicated by performance of water-injection pilot tests and gas-injection pilot tests. It has served well as a guide to selection of pattern of input wells and producing wells for large-scale water flooding to force water movement through the reservoir rock across the grain of the fracture system.

SECTION 6—Mechanisms of Displacement

L. P. Whorton

When oil is produced from the interstices of reservoir rock, some other fluid must of necessity take its place. Typically this is either gas or water. These fluids may exist in the rock itself and displace the oil under potential gradients set up by pressure reductions at the wells as a consequence of flow, or they may be injected in some wells while oil is withdrawn from others.

A. Solution Gas

Of all natural depletion mechanisms, the one of most common occurrence is solution gas drive. In this case when production is initiated from a virgin reservoir, the pressure soon falls to the saturation pressure of the crude oil unless the reservoir is in contact with a highly permeable aquifer. In many cases the virgin pressure is the same as the saturation pressure. When this pressure is reached, gas begins to come out of solution and fill the pore spaces initially filled with oil. Unless this pressure reduction is arrested by water influx or by expansion of a contiguous free gas volume (gas cap), solution gas displacement is the sole natural depletion mechanism available for recovery of the oil. Typically this leads to very low ultimate recoveries (10-25 percent of the in-place oil).

B. Free Gas

Sometimes the gas effecting oil displacement is a free gas phase (never in solution) either occurring naturally upstructure in the same reservoir as the oil or being injected through a system of wells to improve recovery over what can be expected from natural depletion.

In both cases, ultimate recoveries higher than those with solution gas are expected, mainly due to the fact that larger amounts of gas are usually available for oil displacement, and oil saturations can be reduced to lower values before the reservoir "runs out of gas." Also, higher pressures are maintained, which helps on two scores: (1) shrinkage is less severe, and (2) rates of production are maintained higher.

In either case (injected or gas cap drive), if the reservoir rock is very permeable (in excess of a few hundred millidarcies) and if the reservoir has substantial thickness or dip, gravity can play a determining role in recovery. High permeability is necessary for gravity drainage; otherwise economic rates are not attainable without sacrificing the effects of gravity. When gravity drainage is the displacement mechanism, the resultant gas merely fills the pore space left by the oil drained to lower portions of the reservoir by gravity forces. Gas is often injected in order to maintain high productivity even though ultimate recovery might be high in any event.

In the absence of gravity drainage, recovery by free gas displacement is generally poor. This arises from the fact that the viscosity of gas and the relative permeability properties of nearly all rocks dictate a high flow of gas relative to that of oil while oil saturations are still quite high. Producing gas-oil ratios reach quite high values, while most of the original oil is still remaining unrecovered. If the source of gas is the gas cap, it is soon depleted; if injected gas, it soon becomes uneconomic to continue injection.

C. Water

Water is by far the most effective immiscible displacing agent available for oil recovery. Most effective is a natural water drive, particularly in those cases where the aquifer is large enough and permeable enough to permit high producing rates over the life of the reservoir.

Nearly all reservoir rocks are preferentially water-

58. Jones, P., "Reservior Limit Test on Gas Wells," *Jour. Pet. Tech.*, June 1962, p. 613.
59. Elkins, L. F., and Skov, A. M., "Anisotropic Spread of Pressure Transients Delineates Spraberry Fracture Orientation," *Trans.*, AIME, 1960, 219, 301.

wet, so that water is imbibed into oil-filled rock. This tends to improve displacement, letting water invade tighter portions of the rock than would be the case with gas displacement.

Water generally has sufficient viscosity compared to that of reservoir oils of intermediate to high gravities and a relative permeability such that an invaded section of rock is reduced to residual oil within a short flow distance.

This does not mean that a large water production is not to be expected before a reservoir is depleted. Unfortunately, all reservoirs exhibit inhomogeneity, at least in the form of stratification, so that some strata are oil depleted while others are still productive —the depleted ones producing water in copious quantities while the remaining strata are being depleted. Often the depleted strata can be plugged off and water production reduced, particularly if the water is being produced from deeper zones than the oil.

Sometimes natural water influx is from the bottom of the pay zone rather than the edge; i.e., the pay zone is thick and all of the oil is underlain by water. This generally leads to unfavorable recovery because the water tends to "cone" into the wells, leading to high water-oil ratios before nearly all of the reservoir has been invaded by water. This is doubly bad if the reservoir oil does not have very low viscosity. Recovery in this case is a function of well spacing, and more wells lead to higher recovery. However, improving low recoveries very much by this route is generally uneconomic.

Water flooding is likewise quite effective. In past periods, water was generally used as a secondary recovery means (after natural depletion, generally solution gas drive, had run its course). Substantial additional oil was recovered. On the other hand, recovery may be even further increased by injecting water earlier. Unless production rates are unusually restricted by proration, economics permit water injection at the optimum time for maximum recovery. If rates are very much restricted, early injection might only be justified by a bonus allowable; otherwise the additional recovery is attained too long after initial expenditures for water flooding to be economically attractive.

Water injection earlier in the field life usually leads to higher recovery because it prevents the oil from shrinking. This shrinkage, caused by a reduction in pressure and attendant evaporation of gas in solution, leads to a residual oil after water flooding which represents more stock tank oil than would be the case if the reservoir had been depleted by water flooding at higher pressure. Also, this shrinkage is accompanied by an increase in viscosity which may adversely affect recovery. On the other hand, the optimum time for water injection may be after some gas has come out of solution (provided it is not redissolved by increase in pressure during water flooding) because free gas saturation has been shown in the laboratory to improve oil recovery by water displacement.

D. Miscible Agents

The concept has long been known that one of the factors which leads to incomplete recovery of oil from a reservoir could be eliminated if the displacing fluid were miscible with the reservoir oil. Water or gas are both typically immiscible with the oil, and interfacial forces between the phases lead to incomplete displacement of one phase by another. This is true in both cases of the rock-wetting phase displacing the nonwetting (water displacing oil) or the converse (gas displacing oil). If the displacing phase is miscible with the oil, e.g., gasoline, then these forces are eliminated, and the oil that is contacted is completely removed.

Of course, other deleterious factors are not eliminated, such as stratification and inhomogeneities, so that one hundred percent recovery is not to be expected in any actual oil field. On the other hand, sometimes miscible displacement can be practiced to economic advantage.

1. MISCIBLE GAS

So far the most successful agents for miscible displacement are natural gas and in some cases, flue gas (primarily nitrogen).

Under some conditions, depending primarily on the composition of the oil and the pressures attainable, natural gas can be made to develop miscibility with the reservoir oil through a series of contacts in situ. Similarly, flue gas can be used. The latter has the advantage of being inherently cheaper, but requires substantially more compression since it is always generated at near-atmospheric pressure.

This process is advantageous in that it results in essentially complete displacement of the oil contacted, but has some inherent disadvantages. In the first place, gas is less viscous than the oil, and this leads to unstable displacing "fronts," in which case the gas tends to bypass the oil due to fingering. Also, the effect of inhomogeneities is increased when compared to water flooding. These disadvantages can be overcome in part by injecting water simultaneously or alternately with the gas. This has the effect of reducing the effective permeability to gas or increasing the viscosity of the displacing medium.

2. GASEOUS MATERIALS USED AS SLUGS

More expensive miscible agents which have the advantage of being miscible at much lower pressures have been used in the form of slugs. That is, the expensive miscible agent is injected to displace the oil, and another agent miscible with the slug material is subsequently injected to displace the slug. Examples of this process are: (1) hydrocarbon gas enriched with LPG, followed by hydrocarbon gas; (2)

LPG followed by hydrocarbon gas or flue gas.

In the first case, the enriched gas through a multiple contact mechanism enriches that portion of the reservoir oil which it contacts, leading to a condition of miscibility. The displacing gas which follows is miscible with the slug at reservoir conditions of temperature and pressure. In the second case, the LPG is miscible on first contact with the reservoir oil.

Both these processes suffer from the fact that large early investments need be made in injected materials to recover oil which is not available for a number of years.

3. WATER MISCIBLE SLUGS

A third species of miscible agents potentially useful are compounds which are miscible in all proportions, both with reservoir oil and with water. Some of the higher alcohols meet this criterion. Cost of these materials has been an overriding, deterring factor in the use of this type of compounds, although laboratory work has been reported on their possibilities.

In this process the miscible agent is injected to displace the oil, and water is subsequently injected to displace the slug. These materials have the advantage of relatively good viscosity relationships, but a poor solubility relationship; that is, since connate water is also displaced with the oil, three components—oil, agent, and water—tend to be rather intimately mixed, leading to early loss of miscibility.

E. Thermal Methods

None of the above mechanisms are very effective if the reservoir oil is of very high viscosity. Typically miscible displacement and low-pressure gas injection are ineffective if the oil viscosity is greater than a few centipoises. Water flooding may be effective with oils having viscosities reaching a few tens of centipoises, but there remain substantial quantities of oil whose viscosities range into the hundreds of centipoises and, in some cases, into the thousands.

Use of heat to reduce these viscosities has considerable appeal, and in recent years methods depending on heating the oil have met with success. Most of these oils show a rather steep reduction in viscosity as temperature is raised, so that reductions of more than an order of magnitude are not uncommon.

1. IN SITU COMBUSTION

One method of accomplishing this is by means of in situ combustion, wherein air is injected into the reservoir and the resulting air-oil mixture ignited. Flow of hot combustion gases, steam, and cracked hydrocarbons (as well as thermal conduction) serves to heat the oil in front of the burning zone, lowering its viscosity.

There is a rather steep temperature gradient in front of the burning front, so that increased rate of production is often substantially delayed unless fingering or channeling of the hot materials is present to reduce oil viscosity nearer to the producing wells. Many times this is the case, and in nearly all cases very close well spacing is needed in order to deplete the reservoir at acceptably high rates.

This process is also dependent on burning a rather small fraction of the oil, displacing the great bulk of the oil in front of the burning front to the production well. In part what is burned is a coke or high-viscosity tar left behind the initial portion of the hot zone by the high-temperature flue gas and steam. At this point the air reacts with the residual material to generate the necessary heat.

2. STEAM

An alternative way of getting heat into the reservoir is through the injection of steam. Sufficiently high temperatures are attainable by this procedure. Similar recoveries are to be expected. Steam injection has certain advantages of control over the combustion process. Problems of getting heat sufficiently dispersed ahead of the heat front are present here, too, and stratification and fingering may be important. Steam has the advantage of avoiding the high compression costs of putting atmospheric air into a reservoir. On the other hand, it has several potential disadvantages. Heat losses may be greater. In the case of thin sands or a long production history, heat losses to bounding formations can be relatively large since with steam the entire reservoir volume from injection well to the displacing front must be kept hot. Also, losses are sustained between generator and the formation. In addition, marketable fuel is generally burned to get steam, and high-quality water is required.

SECTION 7—Mathematical, Physical and Analog Models and Production Techniques

C. R. Hocott

A. Introduction

The fundamental problem that must be solved by a reservoir engineer is the prediction of reservoir and well behavior.* Reservoir and well analyses are commonly made to compare various methods of reservoir depletion, describe well performance under changing reservoir conditions, and evaluate practices that may improve well or reservoir performance. This information aids management in determining the optimum development and operation of oil fields so that under conditions of sound engineering

* As a source of material for this Section, acknowledgement is hereby given to the Reservoir Engineering Manual, Std. Oil Co.,(N. J.), 1966 (unpublished).

practice, the maximum economic profit may be obtained during the course of reservoir depletion.

Comparisons of various methods of reservoir depletion often involve the study of reservoir performance for different programs of pressure maintenance or secondary recovery, for different oil production rates, and for various numbers and locations of production and injection wells. Furthermore, studies that predict the location of high gas and water saturations in the reservoir at different stages of depletion will aid in determining the optimum type of well completion and the need for future workovers or abandonment.

The following section will discuss the use of various types of models as aids in the prediction of reservoir performance. Reservoir models may be broadly classified into three general categories: (1) mathematical, (2) physical, and (3) analog. The general objective of each type of model is to achieve a representation of the reservoir in which producing time and physical size are scaled down considerably. A model run of a few minutes may simulate several years of field performance. Thus, the effect of factors such as field producing rate and fluid injection can be analyzed quickly. Since a reservoir model is designed from information based on log, core, and well test data, the reliability of model predictions is related to the reservoir description from which the model is built.

B. Mathematical Models

1. BACKGROUND

The mathematical techniques widely used in the past are largely hand methods that require only a slide rule or desk calculator to apply. Still the backbone of reservoir engineering, these techniques are fast and economic, can be applied in a straightforward manner, and are generally adequate. Despite their convenience, however, the conventional methods cannot adequately solve many reservoir engineering problems for systems that have widely varying rock properties, contain several flowing phases, and are subjected to irregular production and injection schedules. For example, one very useful conventional technique is the differential material balance method used to predict the performance of solution gas-drive reservoirs. This method assumes that the reservoir behaves like a large tank, so that an estimate of the average reservoir pressure as a function of time can be obtained by a step-wise solution to a differential material balance. However, it is sometimes desirable to solve for the pressure and saturation distributions within a reservoir where the assumption of a well-mixed tank does not apply.

To overcome the simplifying assumptions and other limitations of the tank analysis, we can take advantage of the progress made in the past few years in engineering mathematics, reservoir description techniques, and developments in high-speed digital computers. The application of numerical mathematics to reservoir engineering problems allows an engineer to consider more difficult problems than heretofore possible.

These new methods depend upon the selection of a suitable mathematical model of the reservoir, which depends upon the complexity of the reservoir (how heterogeneous is the rock, how many phases are present, etc.). When necessary the models can account for up to three-phase flow in two or three space dimensions. Regardless of the number of phases or dimensions, the model may include the effects of capillary and gravity forces; compressibility of the reservoir and reservoir fluids; solubility of gas in oil; variation of fluid properties with pressure and saturation; reservoir geometry; and variations in elevation, thickness, permeability, and porosity throughout the reservoir.

2. DESCRIPTION OF THE RESERVOIR MODEL

In order to predict the movement of fluids in a reservoir, we must be able to write a set of equations that describes the physics of the problem and then solve these equations for pressures and saturations at all points in time during the course of reservoir depletion. The set of equations is derived by combining two familiar concepts, a material balance for each phase and Darcy's law. The method of solution requires that the reservoir be divided into an array of small calculation blocks, which is called the grid network or mesh system. The final number of blocks may run into the thousands, depending upon the reservoir size, degree of heterogeneity, and number of wells. The basic idea is to solve the flow equations for each small block, rather than to treat the entire reservoir as one large tank. Rock and fluid properties are specified at each block, so that the grid network simulates the reservoir.

For simplicity, this discussion will be limited to two-dimensional, two-phase mathematical models, because this system contains all the detail common to more complicated systems. A two-dimensional grid network may provide an areal representation or a cross-sectional representation of the reservoir, as shown in Figure 64, or a cross-sectional representation of the region surrounding a single well, as shown in Figure 65. An areal study considers the view along the bedding planes of the reservoir and calculates fluid movement over the field area. This type of study predicts the positions of invading gas or water fronts and is very useful in determining areal sweep efficiency. A cross-sectional study considers the view across the reservoir bedding planes. This type of study is used to investigate vertical fluid distribution and to determine the effect of reservoir stratification on reservoir performance. The single-well cross section is a wedge- or pie-shaped cross section frequently used to study individual wells within a reservoir. These studies are made to predict coning tendencies and to investigate optimum production rates.

Both the areal and cross-sectional models neglect the third dimension. However, there are methods of minimizing the errors introduced by this omission.

Some work has been done using three-dimensional models to determine under what circumstances we can neglect the third dimension and use the simpler two-dimensional analyses without introducing significant errors. An effort is always made to use the simplest model necessary to describe the reservoir adequately, because as model complexity increases the cost of the study increases rapidly.

The prediction equations that describe the movement of fluids within the reservoir comprise a set of simultaneous differential equations. This set of equations cannot be solved by any known exact or analytic method. However, when the differentials are

FIGURE **64**
Example Two-Dimensional Reservoir Models

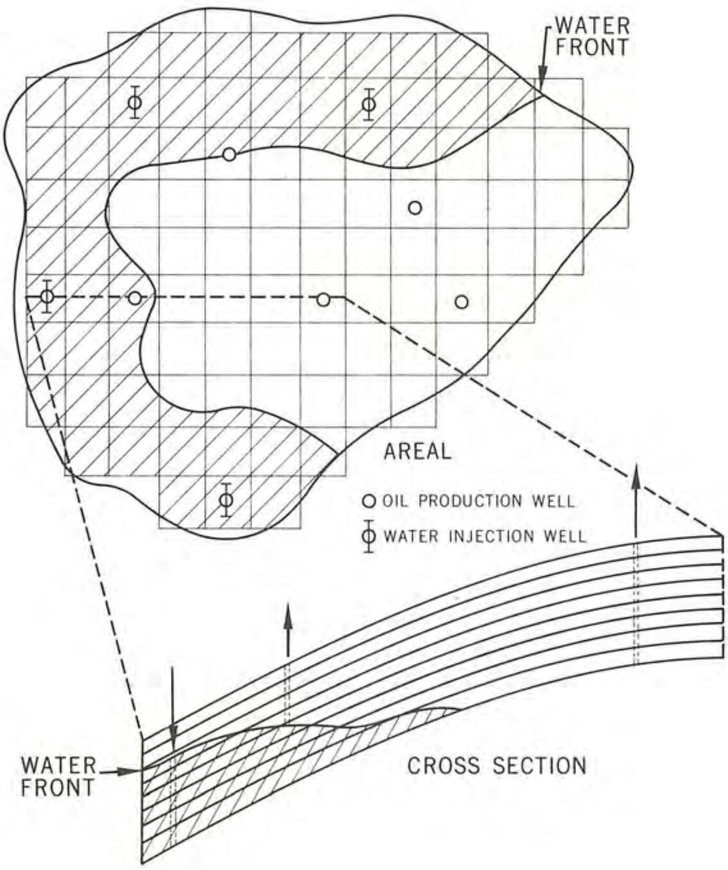
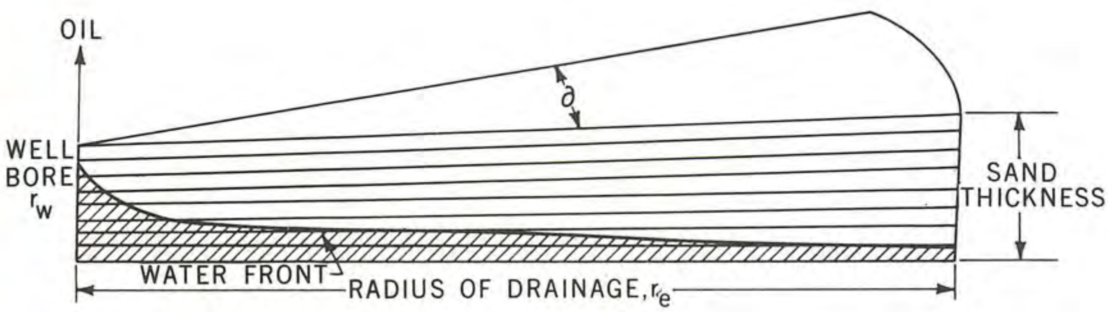


FIGURE **65.** Example Single-Well Cross Section



replaced by finite differences, the result is a system of finite difference equations that can be solved numerically. It is the numerical solution that requires the use of a grid network to represent the reservoir.

A typical reservoir study will involve several two-dimensional predictions, including several areal studies plus some cross-sectional studies. A common program would be to run several areal studies, then use the data obtained from these to study vertical fluid movement in a cross-sectional study. The cross-sectional runs are used to investigate possible areas of severe gas overriding or water underrunning indicated by the areal results. Fortunately, the problem of data gathering is simplified, because much of the data are common to both types of studies.

The need for both areal and cross-sectional studies may be eliminated in problems for which enough information is available to warrant use of a three-dimensional model. However, the more complex the reservoir model, the more a study will cost, so the model chosen should be the simplest one necessary to describe the reservoir adequately. Experience is required in order to select which model is really needed to supply the desired information.

3. APPLICATIONS

By calculating fluid movement throughout a reservoir and the resulting pressure and saturation distributions as functions of time, we can develop a wealth of information on which to base engineering and economic decisions. This type of reservoir study provides the best estimates available today on the relative effects of well placement, field rates, and fluid injection as compared to natural depletion. The most important data obtainable from these studies are probably the detailed production data for each well and for the entire field. These data are obtainable only in this type of reservoir analysis and are obviously important in estimating the economics of any proposed method of operation.

The following list indicates some of the information that can be obtained reliably with numerical prediction methods:

a. Reservoir Description
   (1) Location of faults.
   (2) Establishment of reservoir permeability.
   (3) Identification of anisotropic permeability. In this general area, two-dimensional methods are used along with actual field pressure and production data to determine exactly how a reservoir's permeability must be distributed to match the given production history.

b. Individual Well Behavior
   (1) Prediction and control of gas or water coning.
   (2) Detailed production histories, rate, gas-oil ratio, water-oil ratio, and expected life.
   (3) Completion practices.
   (4) Well damage effects. This general area is very important in making decisions about when new wells will be drilled, when old wells will have to be recompleted, etc.

c. Reservoir Management
   (1) Gas and/or water injection.
   (2) Development drilling.
   (3) Lease-line drainage problems.
   (4) Conservation board hearings.
   (5) Water flooding. The question of whether to inject gas or water or both in a pressure maintenance operation is difficult to answer with any other method of analysis. Will the gas overrun so severely that a low recovery efficiency will make gas injection unattractive, etc.? Is a proposed water flood really worthwhile or will stratification cause poor pattern efficiency? These are the types of data that are obtainable.

d. Research Studies
   (1) Physical model simulation.
   (2) Feasibility of patent memos.
   (3) Miscible displacement.
   (4) Thermal flooding and stimulation.
   (5) Simulation of new recovery techniques.

The use of mathematical models for simulation of multidimensional, multiphase flow in reservoirs has been increasing rapidly in recent years. A number of papers that cover both the development and application of numerical methods have been published in the literature. An excellent treatment of the development and solution of the flow equations is presented by Douglas et al.[60], McCarty and Barfield [61] presented a study of water flood patterns for various field geometries. Richtmyer [62] and Varga [63] have published methods for solving the sets of simultaneous linear algebraic equations that are derived from the finite difference flow equations. The above authors also include references to other important publications.

C. Physical Models

1. GENERAL DESCRIPTION

Fluid-flow models are scaled-down reproductions of flow systems. The model consists of a porous medium,

60. Douglas, J., Jr., Peaceman, D. W., and Rachford, H. H., Jr., "A Method for Calculating Multi-Dimensional Immiscible Displacement," *Trans.*, AIME, 1959, vol. 216, pp. 297-308.
61. McCarty, D. G., and Barfield, E. C., "The Use of High-Speed Computers for Predicting Floodout Patterns," *Trans.*, AIME, 1958, vol. 213, 139-145.
62. Richtmyer, R. D., *Difference Methods for Initial-Value Problems*, Interscience Publishers, Inc., New York, 1957.
63. Varga, R. S., *Matrix Iterative Analysis*, Prentice-Hall, Inc., Englewood Cliffs, New Jersey, 1962.

shaped either to simulate the field area which it represents or, more frequently, to represent a significant section of a repeated pattern in an injection production system such as a water flood. Glass beads or unconsolidated sands are generally used as the porous medium, because an irregularly shaped model can be packed easily with these materials and their flow characteristics can usually be accurately predicted. The model generally contains two or more fluids that represent flowing phases in the reservoir. Scaling factors that must be considered in building a model are covered later in this Section.

Flow models can be enclosed with either transparent or opaque material. In a transparent model, the progress of fluid movement can be directly observed or photographed. This capability is useful for demonstration purposes and for illustrating such factors as the effect of mobility ratio on pattern coverage.[64] These "visual" models are usually enclosed in clear plastic and normally must be operated under limited pressure. Although high-pressure models must be enclosed in steel, flow patterns can be determined indirectly from the volumes of fluid injected and recovered, or from probes that measure resistivities, which can then be converted to saturation information.

Flow models can be one-, two-, or three-dimensional. The simplest flow model is a reservoir core plug. This model is used for one-dimensional, gas-oil or water-oil, relative-permeability tests. It provides displacement data for many reservoir studies, but the effects of geometry and gravity must be accounted for independently. Reservoir core plugs are also used for capillary-pressure tests and imbibition tests to evaluate wettability.

A two-dimensional model can be used to study the effects of geometry or areal heterogeneities on flow patterns (horizontal model) or the effect of gravity (vertical model). The Hele-Shaw model is a special type of two-dimensional flow model in which no porous medium is used and fluid flows between two closely spaced, parallel, transparent plates.

A three-dimensional, packed model can be designed to account for all factors that might affect flow in the reservoir. However, scaling requirements cause a three-dimensional model to be quite large and thus expensive to build. Specific uses of the different types of flow models will be discussed later in this Chapter.

The design of fluid-flow models is largely a matter of compromise. Actual reservoir core material is generally used only in one-dimensional models, so the data cannot be applied directly to most field flow problems. On the other hand, data from two- or three-dimensional models must be adjusted because the flow characteristics of the unconsolidated porous media usually are not representative of reservoir rock. Generally, a combination of models is used to obtain flow data for reservoir studies. For example, linear cores may be used for water-oil displacement flow behavior and two-dimensional glass-bead models for pattern flow behavior.

2. SCALING FLUID-FLOW MODELS

The analogy between the fluids and rock of a model and those of an actual field demands that certain properties of the model and the field be the same. The two systems must have the same geometry, mobility ratio, and boundary conditions. In addition, all forces that affect fluid displacement in the reservoir should be scaled so that the relative importance of each force in the field is retained in the model. To implement this scaling, groups of variables relating the interaction between the rock and fluid systems must be the same for the model and the field. The kinds of scaling groups and their significance will depend on the system itself. Frequently, limitations such as model size and the fluids and porous media available make exact scaling impossible. The reader is referred to the literature for a complete discourse on scaling.[65]

3. SCALED MODEL LIMITATIONS

A reliable flow model must be scaled to the field it represents and must be geometrically similar to that field. Furthermore, the model must be small enough to be handled in the laboratory. In addition, there are other factors that limit the use of models and restrict their ability to match the field:

a. Accurate and adequate reservoir description information is often lacking. (This, of course, applies equally well to mathematical models.)
b. Relative permeability and capillary pressure characteristics of the porous medium used in the model usually will not match those of the field. However, in many cases the characteristics of the model may match those of the field as closely as do the "average" curves picked for engineering studies from core and other data.
c. It is difficult to find synthetic fluids to scale both gravity and viscous forces.
d. Short flow times in the model may cause problems such as fluid supersaturation and fluid buildup at the model outlet.

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64. Haberman, B., "The Efficiency of Miscible Displacement as a Function of Mobility Ratio," *Jour. Pet. Tech.*, Nov. 1960, vol. 12, No. 11, p. 264.
Saffman, P. G., and Taylor, Sir G., "The Penetration of a Fluid into a Porous Medium or Hele-Shaw Cell Containing a More Viscous Liquid," *Proc. Roy. Soc.* 6124158, June 24, 1958, vol. 245, No. 1242, pp. 312-329.
65. Craig, F. F., Geffen, T. M., and Morse, R. A., "Oil Recovery Performance of Pattern Gas or Water Injection Operations from Model Tests," *Trans.*, AIME, 1955, vol. 204, p. 7.
Geertsma, J., Croes, G. A., and Schwarz, N., "Theory of Dimensionally Scaled Models of Petroleum Reservoirs," *Trans.*, AIME, 1956, vol. 207, p. 118.
Rapoport, L. A., "Scaling Laws for Use in Design and Operation of Water-Oil Flow Models," *Trans.*, AIME, 1955, vol. 204, p. 143.

e. In a small model of a large field, the wells are too large to accurately simulate actual geometry. This limitation applies only to modeling individual well behavior and does not affect modeling overall reservoir behavior.

f. The combination of diffusion, solubility, and compressibility factors is difficult to scale.

g. Time and costs involved in building a model to solve a specific problem are often greater than the time and cost for computer program solutions. In some cases the opposite may also be true.

4. APPLICATIONS

Although mathematical flow models are continually being developed and improved, some flow problems can be solved faster and more economically with a physical model than by mathematical techniques. To show the ability of physical flow models, some of the types of applications that have been made of such models are:

a. Water Flooding Models

Physical flow models have been used to analyze both field-wide water flood performance and pilot performance. The effect on oil recovery of factors such as directional permeability and the presence of a gas phase can be determined for both of these cases. Also, capillary, viscous, and gravitational forces, as well as operating effects, can be included. Water flood models, however, normally are not scaled for capillary forces because the flooding process is generally assumed not to be controlled by imbibition.

b. Flank Water-Drive Models

Models of flank water-drive fields have been used to study the effect of producing rate on the shape of the advancing water front. Field problems such as underrunning of the oil by water have been demonstrated on flow models. The movement of transition zones has been studied in models that predicted the saturation distribution in the transition zone for a variety of operating conditions.

c. Fractured, Water-Drive Reservoirs

Fractured, water-drive reservoirs present special modeling problems. Although water-oil displacement is generally not controlled by imbibition, recovery from a reservoir with closely spaced fractures may be controlled by imbibition. Scaled flow models are one method of studying the imbibition process.

d. Water Coning Problems

The behavior of water cones in a homogeneous system has been studied with a flow model. This study provided a basis for estimating the time required for a water cone to build up from the static water-oil contact to the well.[66]

e. Clay-Water Influx

The behavior of reservoirs producing by clay compaction has been modeled. The model was scaled for viscous, gravity, and capillary forces and was used to study the effect of producing rate on the vertical water saturation profile.

f. Pattern Solvent-Bank Process

Reference below presents results of a flow model study of the gas-driven solvent process in a horizontal reservoir.[67] Recovery data from the model provide a basis for estimating field-wide recovery for various solvent bank sizes.

g. Gas-Oil Displacement

There is little experience with flow model studies of gas-oil displacement processes, although flow models have been used to study pattern gas injection projects and gas-cap-pressure maintenance projects. The most difficult scaling factors are gas solubility and compressibility. Generally, these factors can be eliminated by modeling constant-pressure operations. Since models are usually restricted to one or two dimensions, most studies of this type can be made inexpensively with high-speed computer programs.

D. Analog Models

1. GENERAL DESCRIPTION

An analog model is a device in which the behavior of electricity or heat is analogous to the flow of fluids in a reservoir. The model is constructed so that the differential equations involving model quantities are analogous to the differential equations governing fluid parameters in the reservoir. Thus, by measuring changes in voltage, current, temperature, or similar observable quantities in the model, we can "solve" for pressure, rate of fluid flow, and other reservoir parameters.

Electric analog models can be classified as either potentiometric models or electric analyzers. Potentiometric models represent the reservoir by a continuous liquid or solid phase that will conduct electricity. In electric analyzers, the reservoir is represented by a network of resistors and capacitors. As described later, the capacitors are omitted for modeling steady-state conditions. In all cases, electric current is permitted to flow through the model and the voltage drop at various points in the model is related to fluid movement in the reservoir.

Another type of model is based on the analogy of heat conduction to unsteady-state fluid flow in porous media. The model consists of a metal plate shaped to the reservoir area. A heat source is applied at the desired point, and the measured temperature

66. Sobocinski, D. P., and Cornelius, A. J., "A Correlation for Predicting Water Coning Time, *Jour. Pet. Tech.*, May 1965, pp. 594-600.

67. Lacey, J. W., et al., "Effect of Bank Size on Oil Recovery in the High-Pressure Gas Driven LPG-Bank Process," *Jour. Pet. Tech.*, Aug. 1961, vol. 13, No. 8, pp. 806, 812.

gradients are related to fluid movement. The use of these heat conduction models for studying fluid movement is described by Landrun.[68] The following paragraphs discuss the various physical analog models, some problems they have been used to study, and the model limitations.

2. POTENTIOMETRIC MODELS

Potentiometric models are the simplest type of analog to build. For example, a tank of electrolytic liquid [69] (generally called an electrolytic model) or an electrically conductive solid is used as a two- or three-dimensional model of the reservoir. These models are basically two-dimensional since gravity forces are not involved, but variations in thickness can be modeled. Gelatin models [70] have been used to study flow patterns where the mobility ratio is other than one.

Carbon-impregnated paper and blotters saturated with an electrolytic solution have been used as potentiometric models. These paper models are basically two-dimensional, but multiple layers of paper have been used to represent reservoirs having varying permeability-thickness values. Fluid flow is simulated by passing an electric current through the model. The fluid front is traced visually by an electrochemical process or the front position is calculated from measured potential gradients.

The basis for a potentiometric model is the analogy between the flow of electricity in a conductor and the flow of fluid in a porous medium. Darcy's law relates the rate of fluid flow to fluid mobility and pressure drop. Similarly, Ohm's law relates the flow of electricity to electrical conductivity and voltage drop. Table XX shows the analogy between Darcy's law and Ohm's law for a linear system.[71]

In constructing a potentiometric model, we must scale on the basis of the foregoing analogies and on a time basis. To be practical, the model must be scaled so that model time is very small compared with field time. When the model has complete geometric similarity with the reservoir, fluid mobility (k/μ) is analogous to the conductivity of the model ($1/\rho$). As already indicated, the above equations are for linear systems, but if the model is shaped like the reservoir, the flow geometry will be the same for both systems, so the factor A/L will cancel.

A potentiometric model can be used either for a specific field problem or for general problems such as predicting pattern coverage efficiency for various types of flood patterns. A specific field problem would use an irregularly shaped electrolytic tank or conductive paper to represent the field area. The depth of fluid in the tank or multiple layers of conductive paper represent the field kh value at any point. Any of these models can be used for general

68. Landrum, B. L., et al., "A New Experimental Model for Studying Transient Phenomena," *Trans.*, AIME, 1959, vol. 216, p. 33.
69. Amort, D. L., "The Electrolytic Tank Analog: Design, Applications and Limitations," *Electro-Technol.*, July 1962, vol. 70, No. 1, pp. 86-92.
70. Bureau, M., and Manasterski, G., "An Electrolytic Model for the Study of the Displacement of Oil in a Reservoir by an Injected Fluid," *Inst. Franc. Petr. Rev.*, (Hors-Serie) Dec. 1963, pp. 369-390. (In French)
Crawford, P. B., and Burton, M. B., Jr., "Application of the Gelatin Model for Studying Mobility Ratio Effects," Tech. Note, *Jour. Pet. Tech.*, Oct. 1956, pp. 63-67.
71. For a thorough development of this analogy, see Muskat, M., *Physical Principles of Oil Production,* McGraw-Hill, New York, 1949.

TABLE XX

ANALOGY BETWEEN DARCY'S AND OHM'S LAWS

	DARCY'S LAW	OHM'S LAW
Flow Rate	$q = \frac{kA}{\mu L} \Delta p$	$i = \frac{A}{\rho L} \Delta E$
Driving Force	Δp	ΔE
Transmissibility or Conductance	$\frac{kA}{\mu L}$	$\frac{A}{\rho L}$
Mobility or Conductivity	$\frac{k}{\mu}$	$\frac{1}{\rho}$

where

q = flow rate, cc/sec,
k = permeability, darcies,
A = area, sq cm,
Δp = pressure difference, psi,
μ = viscosity, cp,
L = length, cm,
i = electric current, amperes (coulombs/sec),
ΔE = potential difference, volts,
ρ = resistivity, megohms/cm.

flood pattern studies, but model studies of regular patterns are being rapidly replaced by high-speed computer programs that can more economically solve the same and even more complex problems.

Odeh, et al.,[72] have shown that when large variations exist in the permeability-thickness of the reservoir being modeled, scaling may be difficult. If, for example, the resulting variations in electrolyte depth in the model are appreciable compared with the horizontal dimension of the model, modeled results may be seriously in error. Error can be reduced by increasing the horizontal scale or decreasing the vertical scale of the model.

Potentiometric models are generally restricted to a mobility ratio of one. However, Bureau and Manasterski describe a gelatin model in which the gelatin's resistance changes as current flows through the model to automatically account for different mobilities between the displaced and displacing fluids.[73] Mobility ratios ranging from 0.1 to 25 have been successfully modeled.

Potentiometric models are restricted to steady-state flow problems. Thus, their use is limited to injection projects where the average reservoir pressure remains constant. Although methods have been devised for handling high mobility ratios, most electrolytic analog models are limited to a mobility ratio of one.

3. RESISTOR MODELS FOR STEADY-STATE FLOW

A resistor model for steady-state flow is similar to a potentiometric model except for the manner of representing the reservoir's flow resistance. Whereas the potentiometric model uses a continuous medium similar in shape to the reservoir, the resistor model uses a network of individual resistors connected by wires. In some respects, the resistor model offers more flexibility than the electrolytic model. For example, reservoir heterogeneities can be taken into account by using the proper resistor values. Reservoirs possessing directional permeability because of fractures have been successfully studied with resistor models. It is also possible to change resistor values to account for changes in mobility during a model run. On the other hand, the resistor model is inferior to the potentiometric model in accounting for flow geometry. Also, flow gradients around input or producing wells are particularly difficult to simulate on a resistor model. The potentiometric model automatically accounts for flow geometry because its shape is geometrically similar to the reservoir.

The analogy between fluid flow and electrical flow has been described for potentiometric models. The only complication in applying these relationships to resistor models is in the type of resistance used. For the potentiometric model, reservoir resistance is controlled by the value of ρ, the fluid or solid resistivity. In the resistor model, the resistance value of each resistor must be fixed to correspond with the portion of the reservoir that it represents.

Like potentiometric models, resistor models are applicable only to steady-state flow conditions. Resistor models can be used for predicting flow patterns for fluid injection on either a field-wide or an individual pattern basis. A resistor model of a reservoir can be adjusted to match the actual individual well history of an injection project. This can provide an excellent model for predicting future flow patterns. The resistor model is usually applied to systems with a mobility ratio of one. Although it is possible to adjust resistors in a stepwise fashion to account for frontal movement where the mobility ratio is not one, this is a difficult and time-consuming process. Two-dimensional mathematical models using high-speed computers are replacing the resistor models.

4. RESISTOR MODELS FOR UNSTEADY-STATE FLOW

The most complex and most useful of all analog models is the resistor-capacitor model, commonly called the electric analyzer. This model[74] was designed in the early 1940's to solve unsteady-state reservoir engineering flow problems. At that time many unsteady-state flow problems could not be solved economically by mathematical methods. For over a decade the electric analyzer provided the best means for predicting the pressure behavior of water-drive fields. However, recent progress in high-speed computers has made mathematical models preferable to analyzer studies in many cases.

The electric analyzer provides a model of a reservoir and its associated aquifer by means of a resistor-capacitor grid. Although the model is three-dimensional to the extent of modeling the volumes of fluid and rock in place, it is only two-dimensional for flow. The method for modeling the field and aquifer can be described with the aid of Figure 66, which is an areal map representing an oil reservoir and its associated, effective aquifer, together with a superimposed representation of the analyzer's resistors and capacitors. The aquifer extent must be estimated from logs, cores, and well-test data from the area. A numbered grid is superimposed on the area to be modeled. A constant-size square grid is shown on the figure but rectangles and squares of varying size can also be used. Each resistor represents the flow resistance between two adjacent blocks and each capacitor represents the fluid expansion of a block.

The electric analyzer is generally used to study and predict the pressure behavior of large aquifers containing one or more oil fields. For example, the

72. Odeh, A. S., et al., "Scale Limitations in Potentiometric Model Construction," *Trans.*, AIME, 1956, vol. 207, p. 200.
73. Bureau and Manasterski, *loc. cit.*
74. Bruce, W. A., "An Electrical Device for Analyzing Oil-Reservoir Behavior," *Trans.*, AIME, 1943, vol. 151, pp. 112-124.

Woodbine Basin in East Texas [75] and the extensive Arab "D" aquifer in Arabia [76] have been modeled. Both of these systems include a large aquifer in communication with several oil fields. Analyzer studies can predict the effect of aquifer influx on the pressure behavior of each field. In addition, field pressure changes that result from production or injection at other fields in the system can be evaluated.

75. Rumble, R. C., et al., "A Reservoir Analyzer Study of the Woodbine Basin," *Trans.*, AIME, 1951, vol. 192, p. 331.
76. Wahl, W. L., et al., "Matching the Performance of Saudi Arabian Oil Fields with an Electrical Model," *Jour. Pet. Tech.*, Nov. 1962, vol. 14, No. 11, p. 1275.

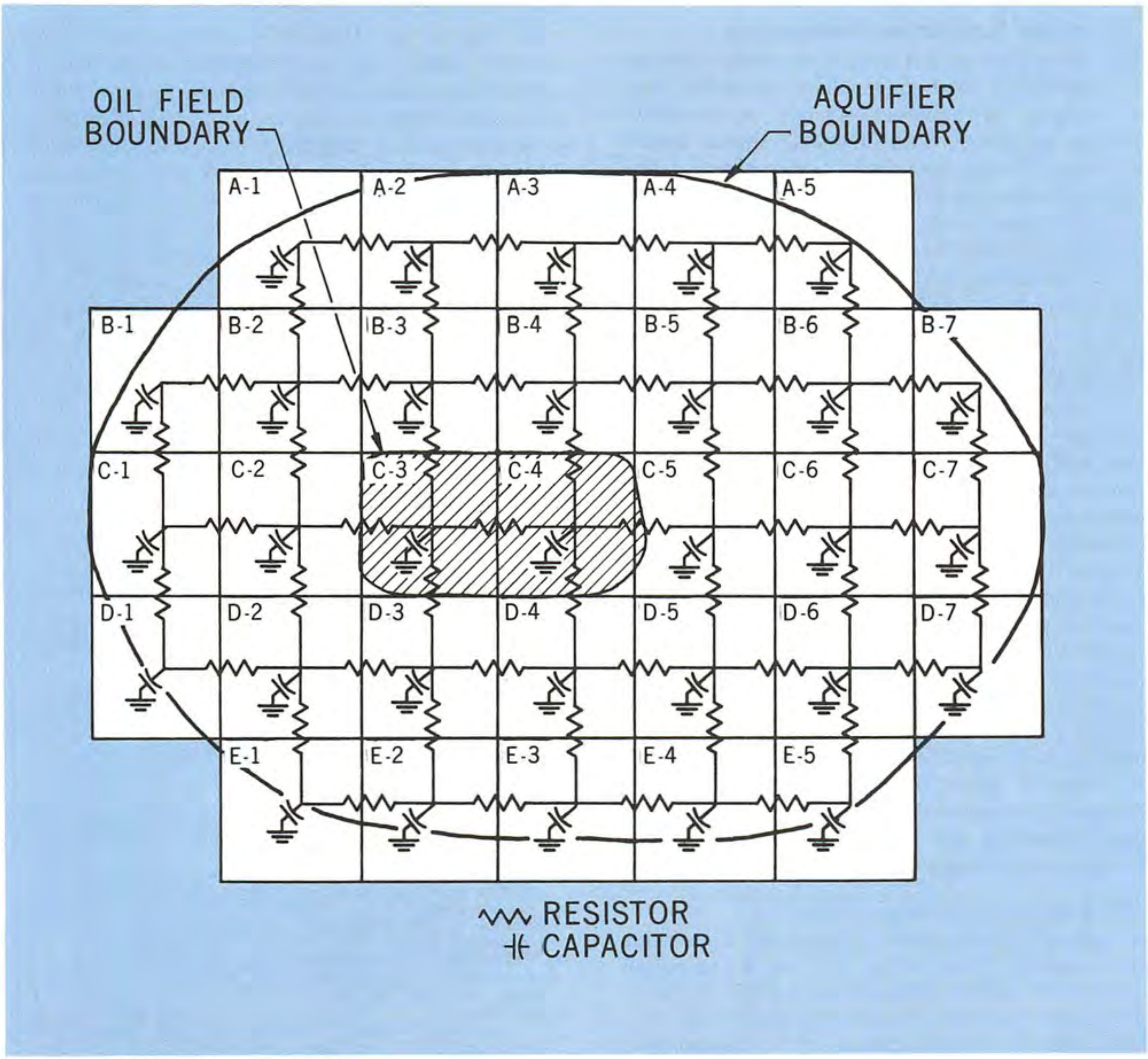
SECTION 8—Natural Performance of Reservoirs

Lincoln F. Elkins

A. Introduction

An important part of the development of technology during the last two decades has been an improvement in the understanding and evaluation of the performance of oil and gas reservoirs during recovery by natural forces. This is of value both in selecting the production practices that will optimize the utilization

FIGURE **66.** Analyzer Representation of an Oil Field and Aquifier



of these natural forces and in providing a base for evaluating the improvement in recovery of oil and gas that can be achieved through the use of supplementary recovery methods. By the end of World War II the rudimentary concepts of relative permeability and the displacement of one fluid by another from porous rocks had been developed from experiments performed on unconsolidated sands. Subsequently, experiments on actual reservoir rock systems greatly extended this understanding. In particular correlations of the relative permeability characteristics and the pore size distribution of the rocks were developed, insensitivity of relative permeability to flow rate was observed in the laboratory for a wide range of conditions, and the importance of wettability of the internal reservoir rock surfaces on the displacement process was observed.

Developments in application paralleled the improved knowledge coming from laboratory and theoretical research.

B. Solution Gas-Drive Reservoirs

Actual pressure—gas-oil ratio—recovery relations for a number of solution gas-drive reservoirs have been reduced to apparent relative permeability-saturation relations.[77] For otherwise similar conditions, they indicate moderately higher gas-oil ratios and thus moderately lower percentage recoveries of oil in place than would be calculated from tests on individual core samples. This was confirmed by one detailed comparison of field performance and calculation based on relative permeability measurements on many cores from that field.[78] This results partly from uncertainty in correct methods of averaging data of different cores from heterogeneous reservoirs. Combination of typical laboratory-determined relative permeability relations for a wide variety of sandstones and limestones with average properties of crude oils ranging from 15° API to 50° API indicate theoretical recoveries ranging from 2 percent to about 40 percent of oil in place initially through solution gas drive. These calculated recovery percentages are very compatible with indicated actual field recoveries in one comparison involving 29 fields. The majority of recoveries for these fields with 30° API to 45° API gravity oils fell within the range of 10 percent to 35 percent of oil in place.[79] Many reserves containing low-gravity viscous oils have recoveries of 5-15 percent of oil in place, or less, during a producing life of many decades. Many of these latter reservoirs are candidates for enhanced recovery through the application of heat as discussed more completely in a subsequent section of this Report.

C. Water-Drive Reservoirs

The analysis of performance of water-drive reservoirs consists mainly of two parts: (1) the determination of past water influx and the forecasting of future water influx rates for various oil production programs, and (2) the forecasting of oil displacement efficiencies. Basic methods for the first of these were developed from analytic theory of transient flow of compressible fluids in porous media in the 1930's in studying the East Texas Oil Field.[80] They were greatly extended in the 1940's by the development of electric analog reservoir analyzers[81] and in the late 1950's and 1960's by analysis using high-speed digital computers.[82] Some excellent examples of the effects of production of fluids from one field on the pressure in another reservoir in a common aquifer have been noted.[83]

A study of performance of many reservoirs having strong natural water drives indicates that substantially all of them have high permeability either within the rock matrix itself or within fractures and solution channels. For many reservoirs containing oils with low to intermediate viscosities actual performance indicates recoveries of 20 percent to 70 percent of oil in place initially by natural water drive.[84] Some exceptional cases exist where recoveries will probably be as high as 80-85 percent.

A recent development in formation logging through casing discussed previously offers considerable promise in permitting improved recovery from some water-drive reservoirs. The neutron lifetime log or its equivalent is reported to have discovered many instances where oil was trapped below encroaching water by some apparently minor shale bed or impermeable barrier.[85] Recompletion of wells to expose such oil-filled zones to production will add significantly to the oil reserves of many individual wells. Application of this very new technique has been too limited to permit an accurate evaluation of its ultimate impact on the overall recoverable oil reserves of water-drive reservoirs.

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77. Elkins, L. E., "The Importance of Injected Gas as a Driving Medium in Limestone Reservoirs as Indicated by Recent Gas-Injection Experiments and Reservoir-Performance History," *Drill. & Prod. Prac.*, API, 1946, p. 160.
78. Smith, M. R., and Henderson, J. H., "Performance of a Solution Gas Drive Reservoir, Rosenwald Pool, Oklahoma," *Jour. Pet. Tech.*, Jan. 1957, p. 25.
79. Arps, J. J., and Roberts, T. G., "The Effect of the Relative Permeability Ratio, the Oil Gravity, and the Solution Gas-Oil Ratio on the Primary Recovery from a Depletion Type Reservoir," *Trans.*, AIME, 1955, 204, 120.
80. Hurst, *loc cit.*
    Muskat, *op. cit.*
81. Bruce, *loc. cit.*
82. Henson, W. L., Wearden, P. L., and Rice, J. D., "A Numerical Solution to Unsteady-State Partial-Water-Drive Reservoir Performance Problem," *Trans.*, AIME, 1961, 222, 184.
83. Bruce, W. A., "A Study of the Smackover Limestone Formation and the Reservoir Behavior of its Oil and Condensate Pools," *Trans.*, AIME, 1944, 155, 88.
    Bell, J. S., and Shepherd, J. M., "Pressure Behavior in the Woodbine Sand," *Trans.*, AIME, 1951, 192, 19.
84. Craze, R. C., and Buckley, S. E., "A Factual Analysis of the Effect of Well Spacing on Oil Recovery," *Drill. & Prod. Prac.*, API, 1945, p. 144.
85. Marquis, G. L., Wichmann, P. A., and Millis, C. W., "Studies of Producing Reservoirs with the Neutron Lifetime Log," *Jour. Pet. Tech.*, April 1966, p. 412.

REPORTED OIL SPACING ORDERS ISSUED

	20 ACRES OR LESS	40 ACRES	80 ACRES	160 ACRES OR MORE
1940	25	6	0	0
1950	63	70	8	1
1955	159	136	46	4
1960	76	185	106	16
1961	113	259	207	15
1962	78	248	222	23

REPORTED GAS SPACING ORDERS ISSUED

	160 ACRES OR LESS	320 ACRES	640 ACRES OR MORE
1940	5	0	0
1950	23	16	18
1955	52	41	50
1960	105	142	190
1961	108	122	129
1962	87	134	172

Source: A Study of Conservation of Oil and Gas, Interstate Oil Compact Commission, 1964.

D. Trend Toward Wider Well Spacing

An important development in reservoir technology during the last twenty years has been an increasing acceptance by engineers, oil producers and regulatory bodies of the thesis that efficiency of recovery of oil and gas is relatively independent of well spacing within practical ranges. This acceptance of wider well spacing by state regulatory bodies in the U.S. is illustrated by the summary of spacing orders summarized in Table XXI.

The trend toward wider spacing has helped to increase economically recoverable oil and gas reserves, even in the face of increasing labor and material costs, since the drilling and equipping of wells for production is the largest single cost in production. This practice has permitted the economic development of many otherwise marginal reserves of oil and gas.

Field performance supporting this thesis with respect to effect of well spacing on oil recovery efficiency is of four main types: (1) pressure interference between wells over long distances, (2) decline in productivity and increase in gas-oil ratio of shut-in test wells due to continued production from offset wells, (3) change in established decline trend in production of wells resulting from in-fill drilling in the same pool, and (4) statistical correlation of ultimate oil recovery efficiency indicated by extrapolation of actual performance of many fields with significant production history. Examples of extensive testing of the first type in the Spraberry Field of West Texas, the Aneth Field of Utah, and the Tioga Field of North Dakota are reviewed in the literature.[86] Similarly an example of the second type in the Spraberry[87] and numerous examples of the third type have also been published.[88] A major statistical study of indicated recoveries of over 100 actual fields was published shortly after the end of World War II.[84]

SECTION 9—Recovery of Oil by Injection of Gas

L. P. Whorton

A. Pressure Maintenance

Gas used as a secondary recovery fluid is the oldest of all injection agents. When solution gas-drive depletion reservoirs began to lose their pressure, with attendant reduction in rate, operators turned to gas injection as a means of restoring this rate.

Torrey[89] has given a good account of the early use of gas, citing early patents (circa 1900) directed at this art, the first technical article postdating these patents by quite a few years. Gas was first used about 1890, but did not come into wide use for some 30 years.

86. Elkins, L. F., "Reservoir Performance and Well Spacing, Spraberry Trend Area Field of West Texas," *Trans.*, AIME, 1953, 198,177.
Cole, F. W., *Well Spacing in the Aneth Reservoir*, University of Oklahoma Press, 1962.
Keplinger, C. H., "How to Determine Most Efficient Pattern of Well Spacing for a Field," *Oil & Gas Jour.*, Oct. 4, 1954, vol. 53, No. 22, p. 126.
87. *Ibid.*, Elkins.
88. Kaveler, H. H., "More Wells—More Oil?" *Drill. & Prod. Prac.*, API, 1950, p. 215.
89. Torrey, Paul D., *Secondary Recovery of Oil in the United States*, API, 1950, chap. I.

In most of the gas injection projects in the pre-World War II years, increased productivity was the economic driving force, although increase in ultimate recovery was sometimes recognized as a resultant benefit. The practice of gas injection was encouraged by the feeling that water injection was not beneficial. With the marked success of water flooding, starting out in the old Eastern fields and more recently (1940 and later) extended to the Mid-Continent, the use of gas as a primary displacing agent decreased in relative importance. Dahlgren [90] has shown that production from gas injection projects reached a maximum in about 1935 (concentrated in Oklahoma and Wyoming), although the decline was not precipitous through 1945. He points out that part of the decline can be attributed to the conversion of some projects to water flooding. By the time of World War II, the advantages of water flooding over gas injection had become sufficiently demonstrated that the latter fell into disuse except in those cases where water injection was not acceptable (formation too low in permeability to accept water at sufficient rates, or the formation adversely affected by water).

L. L. McWilliams has given a case history of the South Burbank Field, where produced gas was returned to the field beginning quite early in the field life.[91] Gas was returned when the reservoir pressure had declined only to 900 psi from an initial pressure of 1200 psi. He estimated that ultimate recovery with this type of partial pressure maintenance would be 38 percent of oil in place, compared with natural depletion by solution gas drive of 21 percent. He also compares this with North Burbank, a field with essentially identical properties, where gas injection was started after the reservoir pressure had been drawn down through natural depletion to 100 psi. In the latter case, ultimate recovery after gas injection was estimated to be only 25 percent of oil in place, an increase of only 20 percent of natural depletion. He concludes that this illustrates the advantage of partial pressure maintenance begun early in the life of a field. It is probably fair to state that gas injection at South Burbank was unusually successful, perhaps due to the beneficial influence of gravity, the effects of which were not well understood at the time the study was made. Ordinarily recovery of this high a percentage of the oil in place through injected gas drive would not be expected unless a significant gravity drainage were present or inordinately high amounts of gas were cycled.

Under natural depletion by solution gas drive, relative permeability to gas and low gas viscosities dictate that a rather low ultimate recovery of oil must result. This varies from a few percent ultimate recovery when the oil is viscous and relative permeability to gas is high (relative permeability is an inherent rock property) to a value of around 25 percent under favorable conditions. Injection of gas influences recovery primarily in two ways:

(1) It provides additional gas to force the gas saturation to higher values in the rock, thereby lowering oil saturation.

(2) By pressure maintenance, it keeps the dissolved gas in solution, thereby eliminating or reducing the effects of shrinkage, which means that a volume of oil unrecovered contains less "stock tank" oil than otherwise.

Usually one might expect these to lead to increased ultimate recovery varying from a few percent to possibly as high as 15 percent of the oil in place. Generally these advantages, and more, can be attained by water injection at lower costs.

B. Gravity Drainage

Under favorable conditions sometimes existing, very high ultimate recoveries can be attained due to the effect of gravity. For gravity to be an effective force in oil recovery, rock permeability must be high (in excess of a few hundred millidarcies) and the dip or thickness of the reservoir must be great. Other reservoir rock and fluid properties are important, but the two mentioned are generally determining.

The theory of gravity drainage and means of calculating recovery under conditions of gravity drainage have been adequately treated in the literature.[92] Although gas injection is not necessarily practiced concurrently with gravity drainage—and, in fact, in some cases little may be gained in ultimate recovery by such practice—in general, substantial practical advantages do result from its use.

The recovery under gravity drainage conditions tends to be rate sensitive, as has been pointed out.[93] Higher recoveries before gas breakthrough are attained if the rate is low. Inordinately high rates lead to early free gas production with the attendant disadvantages, even though ultimate recovery, given sufficient time, is not reduced significantly.[94] This effect is in part determined by the viscosity of the oil, which in turn is more favorable (lower) if gas is maintained in solution by pressure maintenance. Also, maintenance of pressure often has the advantage of holding up production rates in the individual wells. Even if gravity segregation in the reservoir is sufficiently rapid to permit evolved gas to migrate to the gas cap countercurrent to oil flow for high rates of oil withdrawal, insufficient reservoir pressure could lead to low well rates if the pressure is allowed to decline. Then if the reservoir is to be produced at reasonable rates of depletion, either more wells would have to be

90. Dahlgren, E. G., *Secondary Recovery of Oil in the United States*, API, 1950, chap. II, p. 33.
91. McWilliams, L. L., *Drill & Prod. Prac.*, API, 1946, p. 175.
92. Lewis, J. O., *Trans.*, AIME, 1944, 155, 133.
Cardwell, W. T., and Parsons, R. L., *Trans.*, AIME, 1949, 179, 199.
Terwilliger, Wilsey, Hall, Bridges, and Morse, *Trans.*, AIME, 1951, 192, 285.
Hall, H. N., *Trans.*, AIME, 1960, 222, 997.
93. *Ibid.*, Terwilliger, et al.
94. Sims, W. P., and Frailing, W. G., *Trans.*, AIME, 1950, 189, 7.

drilled or gas injected updip to at least partially maintain pressure. The degree of pressure maintenance justified is a function of rock and fluid properties (permeability, relative permeability, capillary pressure, viscosity, solution gas-oil ratio) and can be determined by methods reported in the literature.[95]

If gravity drainage is exploited in those reservoirs where favorable conditions permit, ultimate recoveries may exceed those attainable by other methods and generally are similar to what would be expected in fields with good water drive (50-80 percent of the oil in place). In most cases gas injection can be credited with a substantial portion of this obtained early in the life.

C. Miscible Displacement by Gas

When miscible displacement was originated, it was received with considerable interest because of its ability to obtain essentially 100 percent recovery from that part of the reservoir contacted. Water flooding, to date our most effective aid to natural recovery, involves an immiscible displacement of the oil and therefore, due to capillary effects, leaves 10 to 30 percent of the initial oil as residual oil even in that part of the reservoir which is swept.

Two processes have been developed to displace oil miscibly from a reservoir using gas alone.

In the high-pressure gas process, a high pressure is maintained in the reservoir by gas injection. The injected gas is enriched by intermediates evaporated from the crude oil. (Intermediates are defined as hydrocarbons approximately in the ethane-to-hexane boiling range.) If the oil contains a substantial fraction of intermediate constituents (ethane through hexane), and the pressure is sufficiently high (generally above 3,000 psi), the process continues until the enriched gas at the front of the displacement becomes miscible with the reservoir oil. The injected lean gas (or even flue gas) then displaces the reservoir oil miscibly. This process was first applied to Block 31 in West Texas.

The second process for miscible displacement by means of gas alone is the enriched gas drive. In this process the injected gas has a high intermediate content. The crude oil is enriched by intermediates from the gas being injected until at the pressure being maintained (1,500+ psi), the oil becomes miscible with the injected gas, and miscible displacement ensues. The first engineered applications of this process were at Bronte and at Seeligson.

The high-pressure gas process has been applied [96] at University Block 31, Neale, Headlee, and Dora Roberts. The enriched gas drive has been applied or planned for [97] at Haynesville, Bronte, Seeligson, South Coles Levee, Stratton, Elk Basin, Midland Farms, Neches, and Ghiawar.

In general, miscible displacement is favored over water flooding when: (1) the crude has a high API gravity (high concentration of intermediates), (2) the reservoir permeability is low, and (3) the formation is rather uniform. For example, at Block 31 the oil gravity was about 40 and was undersaturated to the extent of over a thousand pounds. The reservoir had a permeability of about a millidarcy. This meant that under natural drive not only would the recovery be very low, but also the initial productivity would drop extremely rapidly because of the high degree of undersaturation and the low permeability. The high-pressure gas process not only prevented the rapid decline of well productivity of the wells, but also made it possible to achieve a very high ultimate recovery—substantially higher than that for the usual water drive. Incidentally, it would not have been feasible to have water flooded this reservoir because its low permeability would have led to very low rates. Fortunately, although the reservoir has a low horizontal permeability, it is rather uniform, and, more importantly, it has an extremely low vertical permeability, so that gravity segregation problems which have been a cause of severe difficulty in some instances have given little trouble at Block 31.

D. Miscible Displacement by LPG

When the concepts of miscible displacement were considered along with hydrocarbon phase behavior data, it was recognized that the introduction of a sufficient slug of propane (or other intermediate—even CO_2) ahead of a gas injection program, and keeping the pressure high enough to maintain miscibility between the gas and propane, the oil would be swept miscibly by the propane and the propane miscibly by the gas, so that the miscible displacement would continue through the reservoir until the slug was dispersed. The pressure required is usually in the neighborhood of 1200 psi.

In the three years 1957-1959, some 19 miscible slug operations were started or planned.[98] It soon became apparent that a number of these would be failures. (1) In many cases the reservoirs showed unanticipated problems involving inhomogeneities or fractures. (2) Adverse mobility ratios led to fingering of the scavenging gas through the miscible zone into the reservoir oil. (3) Gravity segregation sometimes caused the scavenging gas to override the injected slug of propane and bypass the slug displacement. (4) Failure to appreciate some of the technical problems led to applications which were improperly designed. (5) A fundamental economic problem became apparent because, even though miscible displacement would lead to a higher ultimate recovery, in many cases it did not cause any increase in production in the near term, and therefore led to an immediate investment which could not be justified in terms of the postponed increased return. For these

95. Terwilliger, et al., *op. cit.*
Hall, *op. cit.*
96. Brownscombe, McNeese, and Miller, *Proc.*, 6th World Pet. Congress, Sec. II, 1963, 563.
97. *Ibid.*
98. *Ibid.*

reasons, in the last five years only ten additional projects were undertaken. However, recently interest has been revived.[99] Several carefully engineered projects have been started. They take advantage of gas plus water for improving sweep,[100] or of special reservoir circumstances such as gravity drainage.[101] Steeply tilted, highly permeable reservoirs may offer particularly favorable circumstances for gravity to help miscible slug operation.

E. Potential Use of Miscible Displacement

As indicated above, the use of water and gas as combination sweeping agents for the miscible slug process improves the operation over that of gas alone as the scavenging agent. This, of course, to a certain extent gives the benefits to be obtained both by water flooding and by miscible displacement. If a reservoir has already been water flooded, it may still be possible to gain additional oil by miscible displacement. For this to be possible, the residual oil saturation left by the water must be high; otherwise the expected recovery would not justify the additional field operation. One serious drawback is that since the reservoir starts out with a high water saturation throughout the region available for miscible displacement, a large fraction of a reservoir volume of water must be produced ahead of the oil bank before the increased oil production starts. Further, there is some indication that the slug leaves more oil behind when the reservoir ahead is filled with water. From a recovery viewpoint, the optimum time to initiate a miscible displacement is early in the development of the field. However, in many cases the higher production rates made possible by the increased recovery due to miscible displacement will not be effective for many years after the investment in the slug operation has been made. This seriously limits the feasibility of applying the process. If proration continues, then an incentive allowable proportional to the increased recovery to be expected would make it well worthwhile to gain the additional recovery. Or, if oil demand rises so that allowables are eliminated, the shorter reservoir life may make the discounted production value high enough to justify the initial expense of miscible operations.

Some physical factors which detract from the feasibility of miscible displacement are: (1) a viscous reservoir oil, (2) a thick sand of high vertical permeability, (3) the presence of fractures or inhomogeneities in the reservoir.

It would be interesting to know how much additional oil may be recovered by miscible displacement from reservoirs where its use is feasible. No data are available on a field-by-field basis, but perhaps we can get some idea from recovery numbers typical for different types of processes. Solution gas drive, or natural depletion in the absence of water influx, may be as low as 5 percent for tight reservoirs with viscous oils; under very favorable conditions, solution gas drive may give as high as 35 percent. Natural depletion with higher permeability reservoirs with a natural water drive or a favorable gravity drainage situation may give from 50 to 80 percent recovery. Low-pressure gas injection might increase the recovery from a solution gas drive range of 5 to 35 up to 15 to 40. Water flooding in a reservoir with moderate stratification might yield from 30 to 65 percent recovery. A similar reservoir with miscible displacement followed by gas and water might give from 45 to 70 percent recovery.

Another important question is, what fraction of our reserves is amenable to miscible displacement? A limited survey within one company suggests that about 25 percent of our reserves may be in reservoirs large enough, and with sufficiently favorable physical characteristics, to permit an increase in recovery by miscible displacement if the economic environment is favorable.

SECTION 10—Recovery of Oil by Injection of Water

C. R. Hocott

A. Introduction

Water is generally recognized as a more efficient displacement agent than natural gas in most reservoirs. It has accordingly become common practice to inject water to augment oil recovery in fields that do not have an adequate natural water influx.

Water injection was first applied to obtain a second crop of oil from dissolved-gas-drive reservoirs approaching depletion. It was then extended as a supplemental source of energy to improve pressure performance and oil recovery of partial water-drive fields, and finally to provide an artificial water drive for fields that would otherwise produce by gas expansion. In modern practice, early pressure maintenance operations are preferred over primary depletion followed by secondary flooding, because pressure maintenance yields more total oil in less time and at a lower cost.

99. *Oil & Gas Jour.*, May 3, 1965, vol. 63, No. 18, p. 74.
100. Dyes, A. B., and Caudle, B. H., *Trans.*, AIME, 1958, 213, 281.
Laue, Teubner, and Campbell, *Jour. Pet. Tech.*, 1965, 18, 661.
Gernert and Brigham, *Jour. Pet. Tech.*, 1964, 16, 993.
Holloway and Fitch, *Jour. Pet. Tech.*, 1964, 16, 372.
Kloepfer and Griffith, *Jour. Canadian Pet. Tech.*, 1964, 4, 30.
Oil & Gas Jour., July 27, 1964, vol .62, No. 30, p. 114.
op. cit., footnote Nos. 96 and 99.
101. *World Petroleum*, Sept. 1964, vol. 35, No. 10, p. 65.

B. Historical Development

1. SECONDARY RECOVERY WATER FLOODING

The first recognition of the benefits that might flow from water injection came as a result of accidental flooding when water was inadvertently admitted to producing sands through abandoned wells. Carll,[102] writing in 1880, reported increased oil production following accidental flooding in the Pithole City area, Pennsylvania, and suggested the use of intentional flooding.

Large-scale water flooding was first applied in the Bradford Field of Pennsylvania and New York. Although water flooding was illegal in Pennsylvania prior to 1921 and in New York prior to 1919, J. O. Lewis [103] reports illicit flooding as early as the 1890's. These "circle floods" were rather inefficient operations in which water was injected through widely scattered wells under gravity head and progressed very slowly through the tight Bradford sand. Furthermore, the oil was displaced in an ever-widening circle so that much of the potentially recoverable oil swept past the surrounding wells. Introduction of the line drive in 1922 and the five-spot pattern in 1924 when combined with pressure injection of water provided more effective methods of flooding in which the oil is surrounded by the injected water and driven towards the producing wells. These new methods increased production from less than 3 million barrels in 1925 to over 16 million barrels in 1937, and they gave a total water flood recovery considerably exceeding the primary recovery.[104]

The water flooding procedures developed at Bradford spread slowly, and real growth in water flood production to volumes that are significant relative to total United States oil production did not occur until after 1950. Depression conditions and low oil prices were deterrents during the 1930's. Wartime shortages of equipment and technical manpower deferred secondary recovery activity in many fields in the 1940's. The timing and extent of water flooding is also a reflection of need and opportunity. For example, a high percentage of production in Gulf Coastal Texas and Louisiana is obtained from fields in which secondary recovery water flooding can have no applicability because of strong natural water drives. Many of the West Texas Permian fields that are being successfully water flooded today had not yet been discovered or were in flush production stages when water flooding techniques were being developed at Bradford. Neither the need nor the opportunity for large-scale water flooding had yet developed in this area.

2. WATER INJECTION AS A SUPPLEMENT TO NATURAL WATER DRIVE

The initial, and still an outstanding, application of water injection to supplement a natural water drive is that in the East Texas Field. Discovered in 1930 prior to the adoption of effective conservation regulations, this field's peak producing rate was over 1,200,000 barrels per day. Newly developed mathematical descriptions of unsteady-state fluid flow were used about 1938 to show that control over oil and water production was essential to efficient oil recovery.[105] At the same time, rapidly increasing volumes of saltwater production were creating serious pollution problems. These conditions led to state control of oil producing rates and to a field-wide program by which substantially all of the produced water is returned to the producing formation. After 35 years of production, this field still has many flowing wells and a large reserve producing capacity. An additional 600 million barrels oil recovery has been attributed to the pressure maintenance effected by water injection.

The first use of extraneous injection water to supplement a weak water drive occurred in 1943 in the Midway Field, Arkansas.[106] Commentators of the day viewed this as an extremely important development in which industry was shifting to the aggressive use of water injection to improve reservoir performance rather than merely reacting defensively with injection programs when pressed by saltwater disposal problems. This project also attracted attention as one of the earlier water injection projects in limestone reservoirs. There was at the time some question whether the erratic pore space in limestone could be effectively flooded.

Numerous similar supplemental-type water injection operations have been initiated over the years in both sandstone and limestone reservoirs. As a result of a plan adopted in 1959 to control land subsidence, the Wilmington Field in California is being subjected to the largest repressuring operation in the world.[107] The effects of injection are evident in reduced land subsidence and by increases in reservoir pressure and oil producing rates.

3. PRESSURE MAINTENANCE BY ARTIFICIAL WATER DRIVE

The next logical advance in the application of water injection was taken during 1945 and 1946 with the injection of extraneous water into the Pittsburg sand

102. Carll, John F., "The Geology of the Oil Regions of Warren, Venango, Clarion and Butler Counties," *Second Geological Survey of Pennsylvania 1875-79*, 1880, p. 268.
103. Lewis, J. O., "Methods for Increasing the Recovery from Oil Sands," *Bull.* 148, U.S. Bureau of Mines, 1917, pp. 108-114.
104. For additional history of water injection operations see James A. Lewis in *History of Petroleum Engineering*, API, 1961, pp. 863-879.
105. Buckley, Stuart E., "The Pressure-Production Relationship in the East Texas Field," *Drill & Prod. Prac.*, API, 1938, p. 140.
106. Horner, William L., and Snow, D. R., "A New Application of Water Injection for Maintaining Reservoir Pressure and Increasing Natural Water Drive," *Drill & Prod. Prac.*, API, 1943, p. 28.
107. Huey, Wallace F., "Subsidence and Repressuring in Wilmington Oil Field," *Summary of Operations—California Oil Fields*, Dept. of Conservation, State of California, 1964, vol. 50, No. 2.

and Bacon lime reservoirs of the New Hope Field, Texas.[108] This marked the initiation of water injection pressure maintenance in reservoirs producing without benefit of significant natural water influx. It has since become common practice to initiate water injection pressure maintenance in such reservoirs early in their producing life rather than conducting deferred secondary recovery operations, since more oil can usually be recovered in less time and at a lower cost. An outstanding operation is being conducted in the Kelly-Snyder and Diamond M Fields in Scurry County, Texas.[109] Three unitized flood areas totalling 68,000 acres were formed when it became evident that water influx was negligible and that primary oil recovery would be poor. Water injection on peripheral and center-line patterns is expected to increase oil recovery by 930 million barrels, or 27 percent of the oil in place.

4. EXTENDED CONDITIONS OF APPLICATION

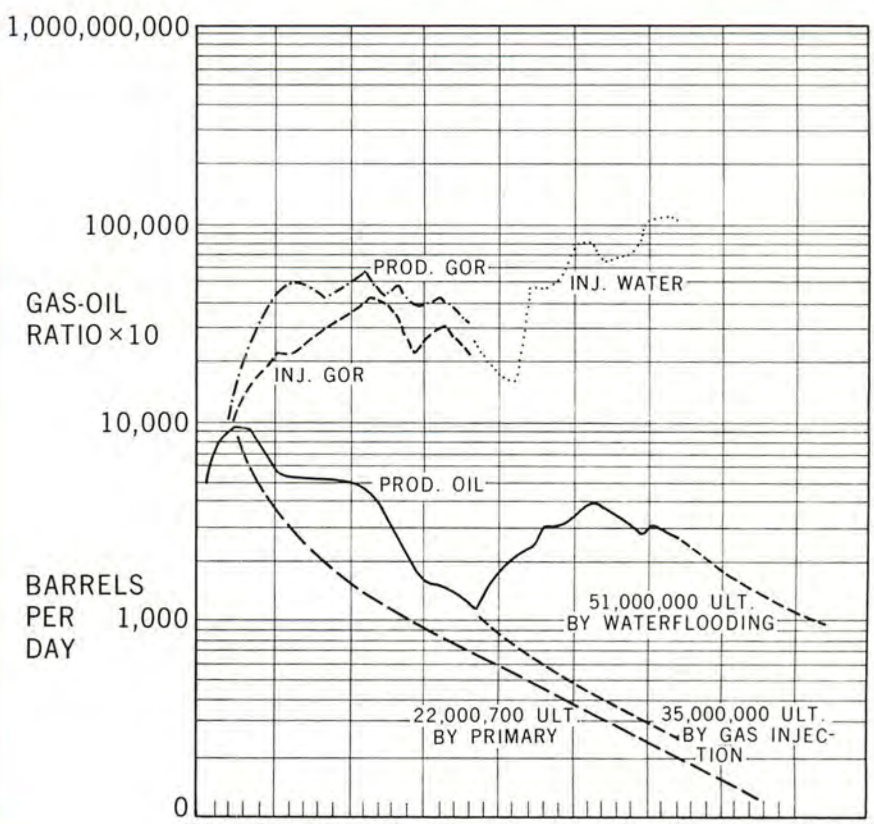
There have been marked extensions in the conditions of application of water injection as related to formation conditions, oil characteristics, producing depths, and well spacings. The early Bradford floods produced oil of about 4 centipoise viscosity from a relatively uniform, low-permeability sandstone at depths of less than 2,000 feet. Wells were drilled about one to the acre, and injection was under gravity head. Successful injection operations have since been conducted in highly heterogeneous formations, including limestones and reservoirs with extensive natural fracture systems. The oils being flooded have ranged from very light materials possessing viscosities of less than one centipoise to heavy California oils with a viscosity at least as high as 65 centipoises. Water has been injected to depths of 12,000 feet at 4,000 psi surface pressure. Pattern floods with 10 to 40 acres per well are common, and in a few instances 160-acre spacing has been used. The import of this recitation is first that water injection has economic application under a wide range of conditions and second, that the capability and equipment exist to conduct water injection in almost any situation where it might be expected to provide an effective and economical means of oil recovery.

Many of the water injection programs have been undertaken following depletion or near depletion of fields under gas injection operations. Experience in the South Burbank Unit, Osage County, Oklahoma, as presented in Figure 67, is illustrative of the more effective oil displacement that can usually be obtained with water injection as compared with displacement by gas injection. A gas return project was carried on from 1935 to 1951 at which time the unit was ap-

108. Trube, Albert S., Jr., and DeWitt, Sam N., "High Pressure Water Injection for Maintaining Reservoir Pressures, New Hope Field, Franklin County, Texas," *Trans.*, AIME, 1950, 189, 325.

109. "A Survey of Secondary Recovery and Pressure Maintenance Operations in Texas to 1962," *Bull.* 62, Texas Petroleum Research Committee, Project Nos. 433, 434 and 488.

FIGURE **67**
South
Burbank Unit
Production
History



proaching economic depletion. Conversion to a water injection project was accompanied by large increases in daily producing capacity and ultimate recovery. It has been estimated that production by solution drive would have recovered 22 percent of the initial oil in place; that continuation of the gas injection program would have recovered 34 percent, and that the conversion to a water injection program will result in a recovery of nearly 50 [110] percent.[111] Early water injection, without the intervening period of gas injection, would have recovered as much total oil and the operating life would have been materially shorter.

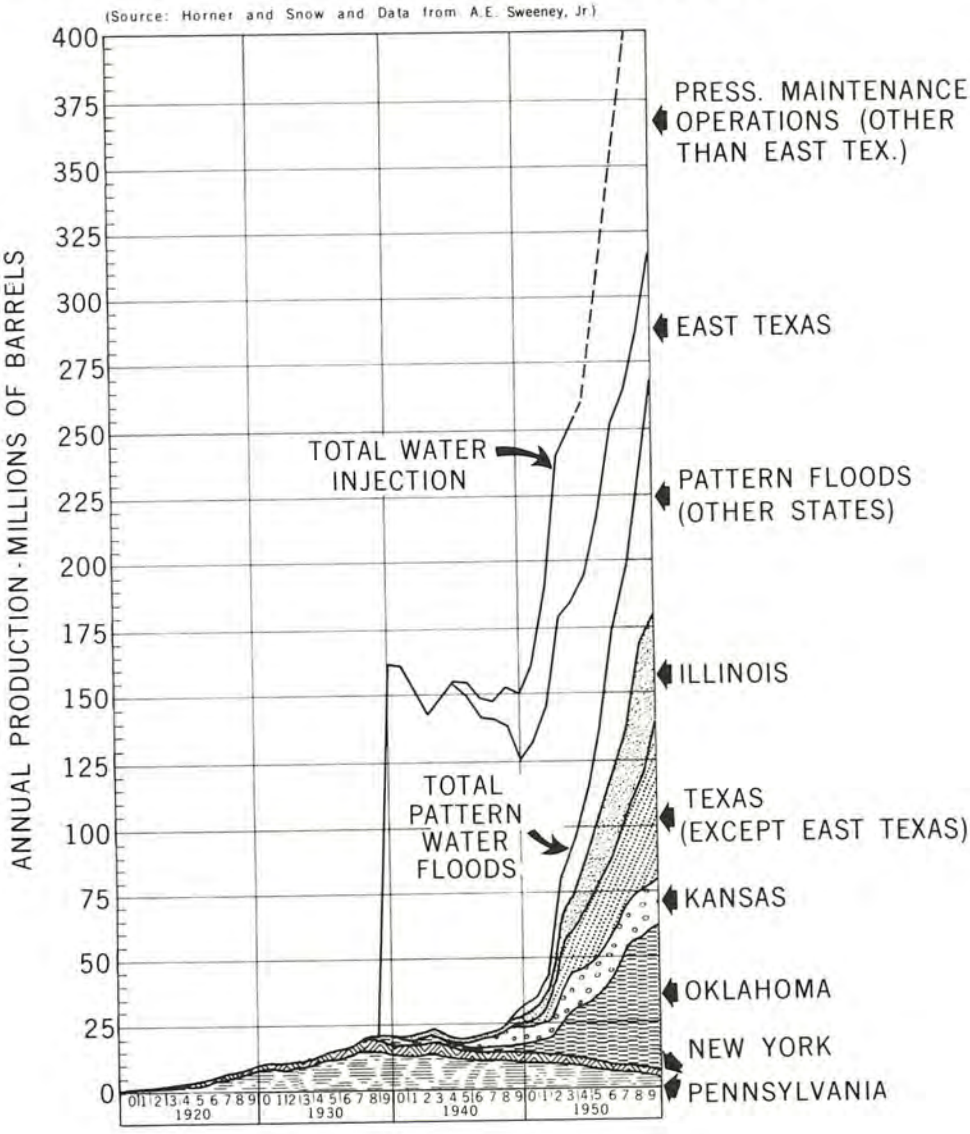
5. GROWTH OF WATER INJECTION ACTIVITY

Although complete and current statistical data on water injection operations are not available, there is a sufficient record to illustrate the rapid growth in both absolute terms and relative to gas injection operations.[112] The number of water injection operations increased sevenfold from 724 in 1947 to 5,057 in 1960, while the number of gas injection operations increased only from 529 to 568. Oil production from secondary recovery water floods increased from about 104,000 barrels per day or 2 percent of U.S. production in 1947, to about 820,000 barrels per day, or over 11 percent of U.S. production in 1961.

Figure 68 prepared from data by Sweeney [113] illustrates the rapid growth in secondary recovery water flooding since 1950 and also shows estimates of total

110. Estimated ultimate recovery by water flooding has been modified from that given in the citation below to reflect additional production experience.
111. Matthews, T. A., "The South Burbank Unit—A Comparison of Oil Recoveries by Various Type Drives," *Jour. Pet. Tech.*, Nov. 1963, 11, p. 1181.
112. Dahlgren, E. G., "Magnitude of Secondary-Recovery Operations in the United States," *Secondary Recovery of Oil in the United States*, API, 1950, Fig. 2, p. 32.
"A Study of Conservation of Oil and Gas in the United States," I.O.C.C., 1964, Table 2, p. 76 and Fig. 3, p. 79.
113. Lewis, James A., "Fluid Injection," *History of Petroleum Engineering*, API, 1961, Fig. 5, p. 874.

FIGURE **68.** Production from Fields under Injection



oil production from water injection projects, including pressure maintenance operations.

In appraising the impact of water injection on crude oil producing capacity and reserves, we should recognize that the production data cited are the total production from the injection areas and are not limited to the incremental production that results from injection. The incremental production and reserve are some indeterminate but lesser quantities. In the case of pressure maintenance operations, the incremental production over the life of the project may be as much as perhaps 60 percent or as little as 5 percent of the total, depending on the time of initiation, the characteristics of the field, and the effectiveness of any natural water influx. In secondary recovery water flooding, the proportion of the total recovery attributable to injection will generally be relatively high, ranging from perhaps 70 percent up to 100 percent when a previously abandoned field is flooded. The distinction between total production and the incremental recovery that results from injection is becoming increasingly important in view of the trend toward earlier installation of projects in fields that still have substantial producing capacity.

C. Postwar Advances in Prediction and Control

Extensive field experience and the enlarged research effort since World War II have provided firmer bases for assessing the benefits that should flow from initiating water injection programs and have provided the know-how to design and operate programs tailored to the requirements of specific reservoir situations. In general, it has been found advantageous to use pattern floods for secondary recovery operations. The most common pattern is the 5-spot in which every other well is converted to injection. The large number of injection wells thus provided reduces the time between the initiation of injection and the first increase in oil producing rates by permitting more rapid fill-up of the gas saturation created by prior oil production. The large number of injection wells also tends to compensate for any limitations on injection pressures and individual well injection capacities that may be imposed by the relatively shallow depths of many of the older fields in which water flooding is being applied. Uniform injection patterns are additionally beneficial in that they provide a practical and convenient means of avoiding uncompensated drainage of oil across lease lines, and they permit secondary recovery operations to be undertaken without the delays and difficulties often encountered in unitizing old fields in which the various leases may be at different stages of depletion. In pressure maintenance operations, the most efficient and economic procedure is frequently to unitize for peripheral flooding in which injection wells are spaced around the edge of the field to create a broad water front that simulates a natural water drive.

The research developments and engineering techniques involved in the prediction and control of reservoir behavior are adequately described elsewhere; they will be discussed in the following sections only to the extent necessary to indicate their application to the effective use of water injection as an oil recovery method.

1. FORMATION EVALUATION

Modern formation evaluation methods (including the various electric, nuclear, and sonic logging devices, coring and core analysis techniques, and more sophisticated measurement of transient pressure-production behavior) provide much better information on the characteristics of formations and their fluid content than were formerly available. Thus we now know more about the quantities of oil available for displacement and about the rock and fluid properties that will control the efficiency of recovery.

2. PREDICTION OF SWEEPOUT PATTERN AND DISPLACEMENT EFFICIENCY

Early postwar predictions of the sweepout pattern of a water displacement front were limited to two-dimensional areal sweep performance for idealized conditions involving homogeneous sands and incompressible fluids. Capillary and gravity forces were ignored, the oil-water mobility ratio was taken as unity, and the oil saturation was assumed to be reduced instantaneously to residual saturation as the front passed. Continuing research on fluid flow regimes has provided a better appreciation of the consequences of permeability stratification and adverse water-oil mobility ratio; it has also provided quantitative means for including these parameters in predictions of the volumetric sweep and production performance to be expected from water injection operations.

Early postwar treatment of the microscopic displacement efficiency of an advancing water front was similarly limited to simplified solutions that ignored capillary forces and assumed uniform sand properties and incompressible fluids. The advent of the high-speed computer has greatly expanded computational capability to permit the treatment of realistic reservoir situations and the inclusion of such refinements as the calculation of capillary cross flow between beds of different permeability. When circumstances warrant the expense, it is now possible to develop full three-dimensional predictions of the volume of the reservoir that will be swept by water and of the amount of oil that will be displaced therefrom.

3. PREDICTION OF PRESSURE BEHAVIOR

Another area of improved predictive ability relates to the pressure behavior of water-drive fields. It is no longer necessary to accept solutions based on the behavior of homogeneous aquifers with idealized geometry. Realistic geometry and spatial distribution of porosity, permeability and formation thickness can be properly accounted for, as can the pressure effects of several mutually interfering fields producing in a common aquifer. The adequacy of natural water influx and the benefits, if any, that might accrue from water injection can be judged with greater confidence.

4. SCALED MODELS AND PILOT FLOODS

Notwithstanding the improvements in formation evaluation and reservoir analysis, difficult and serious questions frequently arise concerning the amount of oil available for displacement by water and the portion thereof that can be recovered. In secondary recovery water flooding, small-scale pilot floods are often conducted to help find out how much additional oil might be recovered and whether a full-scale project might be economically feasible. However, pilot tests have sometimes been misleading. The production from an isolated pilot can be substantially more or substantially less than that of a confined pattern surrounded by an array of similar patterns, depending largely on the relative pressures in the pilot area and the surrounding reservoir. This problem has been alleviated through investigations of pilot flood behavior with scaled fluid flow models and the development of reliable methods for extrapolating pilot flood results to the behavior that would be expected from full-scale operations.

Scaled-model studies have also played a part in resolving controversy over the effects of flooding rates on the efficiency of secondary recovery water floods. These and other studies of the problem had the very practical importance of showing that secondary recovery water floods could be integrated into market-demand proration systems without loss of oil recovery.

5. IMPROVED EQUIPMENT, PROCEDURES, AND SERVICES

A number of improvements in well completion methods, equipment, auxiliary services, and operating procedures have contributed to more effective use of water injection as a means of oil recovery.

Drilling and completion practices in some of the earlier fields provide neither the information nor the mechanical means for controlled water flooding. For example, many of the prewar wells drilled in West Texas had no electric or radioactive logs run; the only indication of a formation was the driller's notation that it drilled like shale or it drilled like sand, perhaps supplemented by drilling-time logs and sample sacks that were like as not filled en masse at the end of a tour. Few cores were taken, and even fewer were subjected to any type of core analysis. Casing was set on top of the pay, and production was from open hole that had been shot with nitroglycerin—thus precluding effective control over the zones of injection or production. The sparsity of reservoir pressure data and subsurface oil samples and the lack of reliable water and gas production records were impediments to reservoir analysis. These conditions are in marked contrast to the organized efforts now made to secure adequate information about the characteristics of formations and their contained fluids and to keep adequate records of pressure-production performance. Also, modern practice of setting casing through the producing zone and perforating provides better control over zones of injection and production.

A variety of devices has been developed to measure the vertical distribution of water injection into a producing formation. Devices are also available to measure the vertical distribution and approximate oil-water composition of the produced fluids. With this information available, plugging agents or mechanical well completion procedures can be used to exclude injected water from thief zones or high-permeability streaks. Production from watered-out zones can be similarly excluded from the producing wells. Radioactive or chemical tracers added to injected water can be detected in producing wells to assist in defining underground fluid movements. By these means, more efficient use of injected water and a more uniform floodout of the pay zones can be accomplished.

The ability to carry on water injection operations in low permeability and deep, high-pressure reservoirs has been enhanced by the availability of durable, high-pressure injection pumps, by the hydraulic formation fracturing process, and by treating injection waters to control corrosion of metal goods and minimize plugging of the sand face.

Digital computers are being employed to assist in the programming of injection and production rates and the interpretation of observed behavior. Automated equipment is being introduced to provide more effective and lower cost control over producing operations and in the transfer of custody of the produced crude oil to pipeline companies.

D. New Concepts of Water Displacement

The increasingly widespread and more effective application of conventional water injection has made available large quantities of otherwise unrecoverable oil. There remains, nevertheless, a need to develop improved and economically practical processes to minimize or overcome the physical limitations on conventional water displacement that frequently leave one-quarter to one-half of the oil in the ground. Simply stated, the two physical limitations that preclude complete oil recovery by conventional water displacement are:

(1) Water tends to move toward a producing well along the course of least resistance, and thus water may not invade substantial portions of an oil-bearing formation. This problem is most

acute when producing high-viscosity oils under conditions of adverse mobility ratio, and in formations with marked permeability variation or extensive natural fracture systems.

(2) Surface tension effects at oil-water interfaces and capillary forces in the microscopic flow channels of the porous rock cause the oil phase to become discontinous before it has all been displaced. When this happens, oil-retentive forces are set up that far exceed the viscous displacing forces that can be applied in an oil reservoir.

The extensive research efforts directed toward improved methods of oil recovery by water displacement fall into one or more of three general categories. First is to increase the portion of a reservoir effectively water flooded by improving the mobility ratio, or, in the case of extensively fractured formations, by operating them in a manner to employ capillary imbibition as the dominant recovery mechanism. Second is the substitution of some injected fluid, such as natural gas or carbon dioxide, for a portion of the residual oil saturation. Third is the elimination or modification of surface and capillary forces by the use of miscible solvents or surface-active agents.

E. Improved Volumetric Sweep in Heterogeneous Formations

1. MOBILITY RATIO IMPROVEMENT WITH THICKENED WATER

Increasing water viscosity would improve the mobility ratio and cause a larger portion of the reservoir to be effectively swept by water. Microscopic displacement efficiency would also be improved as the residual oil saturation could be further reduced before the onset of uneconomic water-oil ratios.

Until recently, efforts along this line have been rather discouraging because of the large quantities of thickening agent required and the high costs incurred in obtaining significant increases in water viscosity. However, a new avenue of experimentation indicates that dilute solutions of certain synthetic water-soluble polymers exhibit a much higher apparent viscosity when flowing through porous media than is measured by conventional viscosimeters.[114] Laboratory data and limited information on field pilot tests confirm that the use of these polymers can sometimes improve flooding behavior, especially in reservoirs with high-viscosity oils. Whether they will have important commercial applicability has yet to be determined.

2. MOBILITY RATIO IMPROVEMENT WITH CARBON DIOXIDE

Carbon dioxide is substantially soluble in crude oil at pressures above 800 psi, with attendant oil viscosity reduction of as much as 90 percent and concurrent oil volume swelling of about 20 to 40 percent. Laboratory investigations indicate that the lower oil viscosity obtained with water-driven carbon dioxide banks can yield oil saturations significantly below those obtainable with water alone.[115] Since the residual oil is in part dissolved carbon dioxide, oil recovery is further enhanced. In closed reservoirs, an additional increment of production is possibly obtainable as fluids are expelled by carbon dioxide coming out of solution.

The success of field applications will depend on a number of variables including crude oil characteristics, the portion of the reservoir that is effectively contacted, the practically attainable pressure, and the volume and unit cost of the carbon dioxide required. Although some field testing has been done, economic applicability has yet to be demonstrated.

3. IMBIBITION FLOODING

The 500,000-acre Spraberry Field in West Texas has its oil contained in an extremely tight and virtually impermeable sandstone matrix with flow channels provided by intersecting systems of vertical fractures. Primary recovery by gas expansion will be less than 10 percent.

Conventional thinking on the application of water flooding under these conditions has been that the water would flow through the fractures and reappear at the producing wells without displacing significant amounts of oil from the matrix. Atlantic Refining Company conceived the idea that capillary imbibition of water could be used as a dominant oil recovery mechanism.[116] Water injected into the fractures would be spontaneously imbibed into the matrix with concurrent expulsion of oil into the fractures by which it could flow to the producing wells. Various modifications of this basic concept have been field tested and some 350,000 acres are being brought under unitized water flood.[117]

Although water flooding may no more than double the low primary recovery, an addition to reserves on the order of 200 to 300 million barrels is a reasonable expectation. Continued study and experimentation may yet develop further improvements in the process.

F. Substitution of Free Gas for Residual Oil Saturation

A number of investigations have indicated that the presence of free gas during water displacement can

114. Pye, David J., "Improved Secondary Recovery by Control of Water Mobility," *Trans.*, AIME, 1964, 231, 1-911.
Sandiford, B. B., "Laboratory and Field Studies of Water Floods Using Polymer Solutions to Increase Oil Recoveries," *Trans.*, AIME, 1964, 231, 1-917.

115. Beeson, D. M., and Ortloff, G. D., "Laboratory Investigations of the Water-Driven Carbon Dioxide Process for Oil Recovery," *Trans.*, AIME, 1959, 216, 388.
Holm, L. W., "CO_2 Requirements in CO_2 Slug and Carbonated Water Oil Recovery Processes," *Producers Monthly*, Sept. 1963, 6.

116. Brownscombe, E. R., and Dyes, A. B., "Water-Imbibition Displacement—A Possibility for the Spraberry," *Drill. & Prod. Prac.*, API, 1952, p. 383..

117. Elkins, Lincoln F., and Skov, Arlie M., "Cyclic Water Flooding the Spraberry, Utilizes 'End Effects' to Increase Oil Production Rate," *Trans.*, AIME, 1963, 1-877.

reduce residual oil saturations.[118]

When a water front advances through a reservoir with a mobile high-pressure gas phase, the oil bank ahead of the front displaces only a part of the gas and leaves behind a residual, trapped gas saturation existing as bubbles within the oil phase. This gas remains in place and occupies space that would otherwise be occupied by residual oil. In typical situations, the net reduction in residual oil is equivalent to about half the volume of the trapped gas.

Although pressure-depleted fields that are candidates for secondary recovery water flooding will already have a large gas saturation, the pressure increase caused by water injection will cause the gas to go back into solution in the oil. Accordingly, any benefits of a free gas saturation could not be realized unless sufficient gas were injected to repressure the field to water flooding pressure. If this were done, the oil expansion and reduced oil viscosity resulting from gas repressuring should provide another increment of oil recovery. In water-injection pressure maintenance operations, a free gas saturation could be established by gas injection or by letting the pressure decline so that gas would come out of solution with the oil.

The presence of a free gas phase can also have detrimental effects on the oil recovery process in that the permeability to oil will be reduced, the mobility ratio will be adversely affected, and producing well capacity may be lowered. In any specific situation, the potential advantages and disadvantages of establishing a free gas saturation should be carefully assessed to determine whether there will be a net benefit from the operation.

There exists very little field information from which to judge the practical consequences of establishing a free gas saturation. A few small-scale instances of gas injected into secondary recovery water floods have been reported, but the evidence is sparse and inconclusive.

G. Elimination or Modification of Surface and Capillary Forces

1. MISCIBLE DISPLACEMENT WITH MUTUAL SOLVENTS

When oil is contacted with a fluid with which it is miscible, they dissolve each into the other and form a single phase. There is no interface between the fluids and hence there are no capillary forces. Miscible displacing fluids, used in sufficient quantity, can effect complete oil recovery under laboratory conditions.

Early interest in miscible processes centered on the use of slugs of LPG or gases rich in intermediates followed by dry gas as a driving fluid. However, the high-pressure requirements of the gas-driven miscible displacements and difficulties with their field application have led to a number of recent studies of water-driven miscible displacements, using materials such as alcohols that are mutually soluble in both oil and water.[119]

These solvent processes are not yet well understood. The solubility of the solvent in the interstitial water causes the behavior to be different from that of gaseous phase miscible displacement, and there are unresolved differences of opinion concerning the exact mechanism of displacement. It is known that the phase behavior characteristics of the solvent-crude oil system have important effects on the effectiveness of oil displacement. Systems with high API gravity, low molecular weight oils reach miscibility at lower solvent concentrations than do the heavier low-gravity oils, and accordingly the light oils are more apt to be economically recoverable. Solvents with a preferentially higher solubility for oil than for water appear to be more effective in recovering oil than solvents with a preferentially higher solubility for water. Unfortunately, isopropyl alcohol, one of the most readily available and lowest cost alcohols, has a high solubility for water. This situation has led to experimentation with composite solvent slugs. For example, a preferentially oil-soluble solvent such as tertiary butyl alcohol might be used at the leading edge of a slug to improve oil displacement, followed by a preferentially water-soluble solvent.

While the use of mutual solvents is a promising area for research, limited pilot testing has yet to demonstrate economically significant improvement in oil recovery. A great deal more must be learned concerning the mechanism, and such important operating parameters as the size of solvent slug required under field conditions and the selection of slug compositions appropriate for recovery of specific oils.

Another approach to the use of solvents with solubility for both oil and water is the injection of carbon dioxide as a miscible displacing agent. Holm [120] in laboratory experimentation found that essentially complete oil recovery was obtained when the temperature and pressure were such that complete miscibility existed between the oil and carbon dioxide.

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118. Holmgren, C. R., and Morse, R. A., "Effect of Free Gas Saturation on Oil Recovery by Water Flooding," *Trans.*, AIME, 1951, 192, 135.
Kyte, J. R., Stanclift, R. J., Jr., Stephan, S. C., and Rapoport, L. A., "Mechanism of Water Flooding in the Presence of Free Gas," *Trans.*, AIME, 1956, 207, 215.
Dyes, A. B., "Production of Water-Driven Reservoirs Below Their Bubble Point," *Trans.*, AIME, 1954, 201, 240.
119. Taber, J. J., Kamath, I. S. K., and Reed, Ronald L., "Mechanism of Alcohol Displacement of Oil from Porous Media," *Trans.*, AIME, 1961, 222, 11-195.
Holm, L. W., and Csaszar, A. K., "Oil Recovery by Solvents Mutually Soluble in Oil and Water," *Trans.*, AIME, 1962, 225, 11-129.
Taber, J. J., and Meyer, W. K., "Investigations of Miscible Displacements of Aqueous and Oleic Phases from Porous Media," *Trans.*, AIME, 1964, 231, 11-37.
120. Holm, L. W., "Carbon Dioxide Solvent Flooding for Increased Oil Recovery," *Trans.*, AIME, 1959, 216, 225.

Shell-Oil Company has announced plans for the first field test of a miscible carbon dioxide drive to be conducted in the Devonian reservoir of the Crossett Field, Crane and Upton Counties, Texas. If the process works as anticipated, there could be other operations in the West Texas area since several possible sources of high carbon dioxide content gas exist. The prospects for application in areas without natural sources of carbon dioxide are less promising because of the higher costs involved.

2. SURFACE-ACTIVE AGENTS

It has long been agreed that unrecovered oil is retained by capillary forces that are large relative to the viscous forces imposed by water. It was accordingly logical that early workers should turn to surface-active agents to reduce the capillary forces and facilitate the recovery of oil. The known mechanisms by which surface-active agents might improve oil recovery include: (1) reduction of interfacial tension so that bubbles of residual oil will be more easily distorted to pass through constrictions in the flow passages, (2) the formation of oil-external emulsions that will act as a high-viscosity miscible displacing fluid, and (3) causing permanent or transient changes in formation wettability that will mobilize discontinuous residual oil by aggregating it into large continuous bodies, thus maintaining effective permeability to oil at lower oil saturations.

Since it appears unlikely that interfacial tension can be reduced sufficiently in reservoirs to permit free flow of residual oil bubbles, discussion will be limited to emulsions and wettability changes. However, it is recognized that surface-active agents that affect emulsification characteristics of the oil-water system or the wettability of the rock are also likely to cause some change in interfacial tension.

An important aspect to the addition of surface-active agents to the flood water concerns the mobility of connate water.[121] During a water flood, the connate water is miscibly displaced by the injected water and forms a zone that separates the injected water from the continuous oil phase. For this reason, additives in the injected water cannot contact the oil during the initial displacement and can act only on the residual oil left behind.

In the application of surface-active agents to oil recovery processes, there is the economic problem that these expensive chemicals tend to be adsorbed within the formation. Thus, large quantities of surfactant would be required to maintain a given concentration, even if this concentration were quite low. It has been suggested that this problem can be alleviated by applying the principles of chromatography.[122] A small volume of concentrated surface-active material would be injected as a bank followed by water. Although the leading edge of the surface-active slug would continuously lose surface-active material by adsorption onto the formation, a substantial part of the lost material would be resorbed in the water that follows at the trailing edge. Thus, there is hope that a relatively small volume of surface-active material could be made to travel through a large volume of oil-bearing formation.

3. MICROEMULSIONS

Oil-external emulsions have been formed in situ in laboratory experiments in which a surface-active agent and sodium hydroxide were used as additives to the flood water.[123] The experiments were encouraging in that oil recovery was good, but discouraging in that adsorption was excessive and large throughput volumes were required. Continued experimentation may find the key to successful application. However, no successful field trials have been reported to date. An alternative approach is presented in a recent Dutch patent application[124] in which an oil-external microemulsion[125] is prepared at the surface and injected to miscibly displace the oil. Water is used as the driving agent. In another embodiment of the invention, the oil-external microemulsion is followed by a water-external emulsion to provide miscibility with the driving water. The viscosities of the emulsions can be controlled to assist in obtaining good sweep efficiency.

4. WETTABILITY CONTROL

The term wettability as applied to petroleum reservoirs refers to the relative affinity of the co-existing oil and water phases to adhere to the surface of the rock. If the rock is predominantly in contact with water it is said to be preferentially water-wet. Similarly, if the rock is predominantly covered with oil, it is referred to as oil-wet. Increasing attention has been given in recent years to methods of measuring wettability, to the effects of inadvertent changes in wettability on the accuracy of laboratory measurements of oil displacement, and on the possibility of increasing oil recovery by introducing chemicals to cause suitable alteration of wettability.

Leach[126] and co-workers have proposed that reversing the wettability of oil-wet reservoirs to water-wet may improve water flood recovery. Experimental work indicated that the interaction of relatively inexpensive acids, bases, and salts with

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121. Brown, W. O., "The Mobility of Connate Water During A Water Flood," *Trans.*, AIME, 1957, 210, 190.
122. Preston, F. W., and Calhoun, J. C., Jr., "Application of Chromatography to Petroleum Production Research," *Producers Monthly*, 1952, 16, 22.
123. Reisberg, Joseph, and Doscher, Todd M., "Interfacial Phenomena in Crude-Oil Water Systems," *Producers Monthly*, Nov. 1956, p. 43.
Taber, J. J., "The Injection of Detergent Slugs in Water Floods," *Trans.*, AIME, 1958, 213, 186.
124. Dutch Patent Application No. 6,409,405 filed August 14, 1964.
125. The literature also speaks of "microemulsions" as "soluble oils," "transparent emulsions," etc.
126. Wagner, O. R., and Leach, R. O., "Improving Oil Displacement Efficiency by Wettability Adjustment," *Trans.*, AIME, 1959, 216, 65.

the naturally occurring surfactants in several crude oil-brine systems caused large changes in rock wettability and that reversing the wettability of oil-wet Berea sand cores increased oil recovery at practical levels of water throughput. Although limited amounts of additional oil are reported to have been recovered in a field pilot test using a 2 percent slug of sodium hydroxide in water as the chemical agent,[127] the economic practicality of the process remains uncertain.

While the foregoing may possibly point the way to increased recovery from the relatively few oil-wet reservoirs, the broader question of how to recover the oil left by conventional floods and natural water drives in the large group of predominantly water-wet reservoirs will remain.

Researchers at MIT[128] have suggested a novel double wettability reversal process that has recovered additional oil from initially water-wet sand packs under laboratory conditions. Studies were being made of the chromatographic transport of small volumes of reverse-wetting agents. During these studies it was found that the residual oil left after water flooding was rearranged within the pore spaces into larger continuous bodies when the system was converted from water-wet to oil-wet, so that additional oil was mobilized and displaced when the system reverted to water-wet conditions after passage of the band of surfactant. It has not been established that this can be accomplished under field conditions.

An interesting sidelight to the investigations of wettability phenomena is the discovery that rock wettability can be altered during the process of core recovery and laboratory manipulation so as to give erroneous measurements of oil recovery by water displacement. There are indications that some water-drive fields may be producing a good deal more efficiently than heretofore believed. Also, the quantity of oil remaining after water drive or secondary recovery water floods for possible recovery by tertiary methods may, in some instances, be substantially less than has been indicated by conventional laboratory experiments.

H. Summary

Real progress has been made in developing technology for the efficient conduct of water injection operations and in field application of this technology. Practical means for recovering significant amounts of the oil that cannot be produced by conventional water displacement have not yet been found. Nevertheless, there are a number of promising avenues of investigation, and it is reasonable to expect that the continuing evolution in technology will in time provide methods for making important additions to crude oil reserves and producibility. There is no basis other than speculation for assessing the timing or ultimate volume of these reserve additions.

SECTION 11—Thermal Applications—In Situ Heat Generation

Guy R. Brainard, Jr. and Leonard W. Emery

A. Introduction

An intriguing idea for supplying heat to oil reservoirs has been that of actually generating heat by burning in the reservoir rock. The motivation for using this process lies in anticipated efficient use of heat. For almost 20 years field tests of underground burning as a secondary recovery method have been active. Many modifications of underground burning have been conceived. Major efforts, however, have been limited to the following three basic processes:

1. FORWARD COMBUSTION

This basic process has received the most industry attention. Air is injected and ignition is obtained at the wellbore in an injection well. Continued injection of air drives the combustion front toward producing wells. As the fire front progresses, reservoir fluids (water and oil) are vaporized, carried forward in the flue gas stream and condensed by cooler reservoir rock. These condensed fluids, in turn, displace oil and water ahead of them. Fuel for the process consists of the nondistillable portion of that oil held by capillary forces after the fluid displacement. The zone of combustion can only move as rapidly as the residual fuel is burned off the formation making its rate of movement dependent upon the quantity of fuel deposited and the rate at which air is injected. Considerable laboratory work has been done in developing methods for determining the amount of fuel which will be deposited in a given reservoir. Unfortunately, very little verification of these methods as a result of field tests has been published. In addition to the effect of the oil characteristics it appears that lithology and rock properties also affect fuel deposition. Basically, this process differs from other thermal methods in that oil is primarily produced by a distillation-frontal gas drive rather than the major benefit being oil viscosity reduction. Most of the oil is displaced piston-like by the bank of condensed reservoir fluids and is not directly affected by heat.

2. REVERSE COMBUSTION

When applying forward combustion to very viscous oil or tars there is a tendency for the hydrocarbon

127. Leach, R. O., Wagner, O. R., Wood, H. W., and Harpke, C. F., "A Laboratory and Field Study of Wettability Adjustment in Water Flooding," *Trans.*, AIME, 1962, 225, I-206.
128. Michaels, Alan S., and Timmins, Robert S., "Chromatographic Transport of Reverse-Wetting Agents and Its Effect on Oil Displacement in Porous Media," *Trans.*, AIME, 1960, 219, 150.
Michaels, Alan S., and Stancell, Arnold, "Effect of Chromatographic Transport in Hexylamine on Displacement of Oil by Water in Porous Media," *Trans.*, AIME, 1964, 231, II-231.

to flow forward while warm and solidify in the cool part of the formation reducing gas permeability to the extent that the process becomes inoperable. A unique process conceived to overcome this problem consists of reverse burning. In this process the formation is ignited at the producing well and the fire moves countercurrent to the injected air and reservoir fluid stream. As the fire moves through the reservoir it heats up the oil making it mobile. The intensive drive caused by the flow of air and subsequent combustion products pushes the oil toward the producing wells. Because the oil flows into a zone already heated, there is no tendency for it to congeal and decrease permeability. Fuel for the process consists of crude oil since all of the oil must go through the fire front. Considerable laboratory and field work have been done on this process; however, few field tests have been conducted.[129]

3. CONDUCTION HEATING

The application of forward combustion may result in the fire burning through a relatively thin vertical portion of the reservoir if certain combinations of permeability stratification, oil viscosity and gravity segregation exist. Heat is conducted into the unburned reservoir matrix by conduction, reducing the viscosity of the oil and allowing it to be produced by the flue gas drive or by gravity drainage. One of the characteristics of this modification is that very little oil is produced before the fire burns through into the producing well. This means that the producing well must be operated at high temperature and under corrosive conditions. Because heat generated while sweeping a thin zone is used to heat a large matrix, the process is efficient and has accounted for some of the most successful field applications [130] of underground burning.

B. Development of Special Equipment

1. IGNITERS

The initial key to successful fire flood application, after selection of an appropriate location, has been recognized as the ignition step.[131] It is interesting to note that the methods used on the first reported tests [132] are still the most popular. These two methods were downhole electric heaters and air-gas burners. To achieve ignition it is necessary to heat only the formation immediately adjacent to the well to ignition temperature. After this temperature has been reached, no other external heat source is necessary for sustained combustion.

The favored ignition methods both use convective heat transfer as the primary means of getting heat into the formation. This is accomplished by injecting air while the heaters are in operation. The air not only serves as the transfer media but also is used as a cooling agent to keep wellbore temperatures at a level below that which would destroy the heating equipment and damage the well tubular goods.

Electrical ignition has received the most use perhaps because of its simplicity of operation and its ability to maintain close temperature control. It has a relatively low allowable maximum temperature (less than 1,000° F) because of the limitation of the electrical construction materials. It also is somewhat limited to shallow installations (probably less than 2,000 feet) because of the voltage drop through downhole cables. It has been used quite successfully to ignite reactive (easily oxidized) crudes.

The air-gas burner is perhaps better suited to ignition of formations containing light or less reactive crudes where generation of high temperatures (up to 2,000° F) may be needed. It also has the advantage of being operable at any depth.

Successful ignitions have been obtained using other methods such as surface heating of air or the injection of easily oxidized chemicals to promote spontaneous combustion. In at least one case [133] the crude was found to be so reactive that injection of air caused ignition to occur spontaneously.

Development of reliable ignition methods has required a substantial effort on the part of most companies involved in fire flooding and this effort has resulted in techniques applicable to most any situation.

2. WELL COMPLETIONS

The early underground combustion tests experienced considerable difficulty with high temperatures and corrosion problems in injection and producing wells. The use of stainless steel pipe in the interval being burned has lessened some of the difficulties. Another significant development has been a refractory cement [134] designed specifically for thermal recovery completions. This cement has been found to have much less tendency to crack when subjected to high temperature than standard portland oil well cements.

Another innovation which has proved very beneficial in cases where the conduction heating process

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129. Trantham, J. C., and Marx, J. W., "Bellamy Field Test: Oil from Tar by Counterflow Underground Burning," *Preprint* No. SPE 1269, 40th Ann. Fall Meeting, SPE of AIME, Denver, Oct. 3-6, 1965, 12 pp.
130. Koch, R. L., "Practical Use of Combustion Drive at West Newport Field," *Petr. Engr.*, Jan. 1965, vol. 37, No. 1, pp. 72-81.
Gates, C. F., and Ramey, H. J., Jr., "Field Results of South Belridge Thermal Recovery Experiment," *Trans.*, AIME, 1958, 213.
131. Strange, L. K., "Ignition: Key Phase in Combustion Recovery, Pt. 1," *Petr. Engr.*, Nov. 1964, vol. 36, No. 12, pp. 105-109.
132. Grant, B. F., and Szasz, Stefan E., "Development of an Underground Heat Wave for Oil Recovery," *Preprint* No. SPE 348 G, Ann. Meeting, SPE of AIME, New York, Feb. 14-18, 1954, 16 pp.
Kuhn, C. S., and Koch, R. L., "In Situ Combustion," *Oil & Gas Jour.*, August 10, 1953, vol. 52, No. 14, pp. 92-96.
133. Gates and Ramey, *op. cit.*
134. Walker, Wayne A., "Cementing Composition for Thermal Recovery Wells," *Jour. Pet. Tech.*, Feb. 1962, pp. 139-142.

required that most of the production be obtained from hot wells is the circulation of cooling water in the wellbore. This has been found to be effective in controlling severe corrosion tendencies.

3. OTHER EQUIPMENT

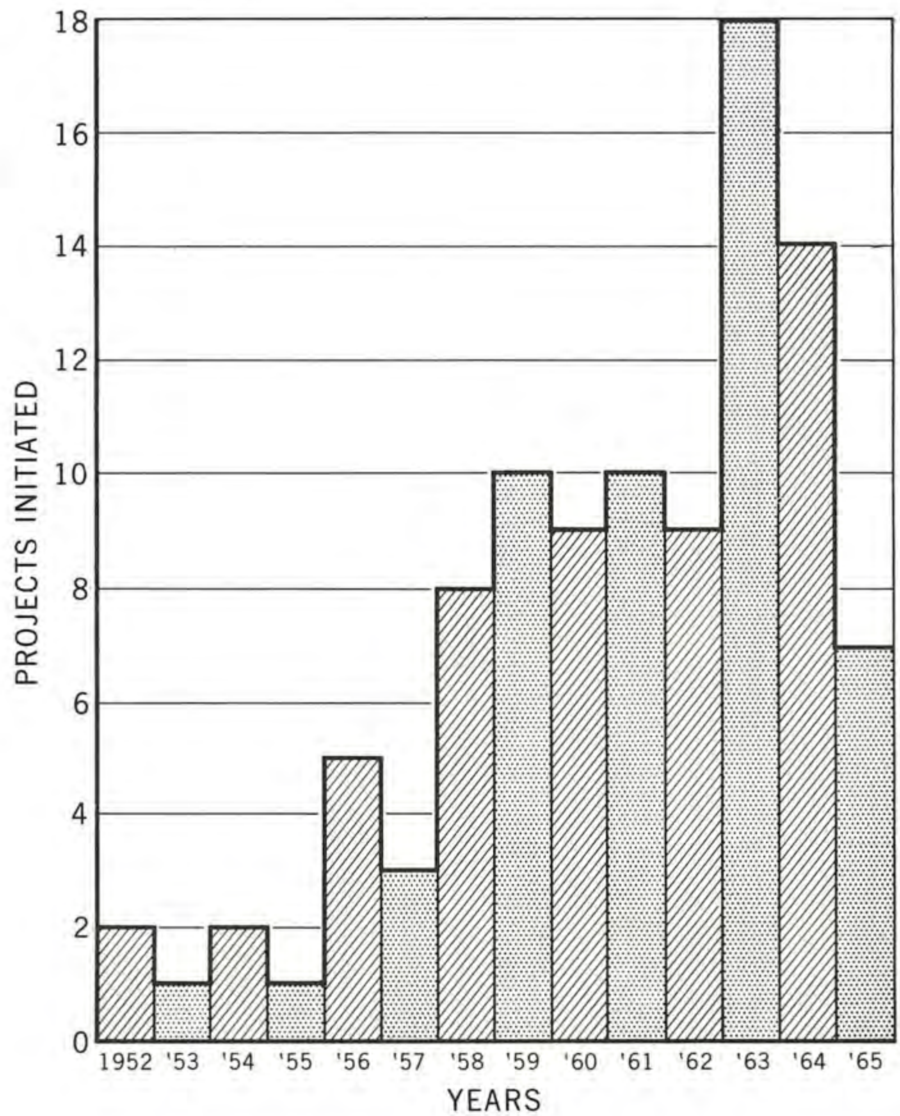
Other than the special downhole equipment described, conventional producing techniques and equipment are used. The aboveground installation resembles that required for a simple air-injection project. Emulsion problems have been encountered sooner or later on most combustion projects; however, the use of conventional heavy duty heater-treater equipment and treating compounds has been adequate. The produced gases from underground combustion are malodorous and special gas-treating facilities [135] have been found necessary in populated areas.

C. History of Applications to 1966

The first significant tests of fire flooding in the United States were begun about 1948.[136] Results from these research tests were first reported in 1953 and 1954. A list of reported tests and their current status appears in Table XXII. Of 99 projects initiated 44 are active at present. Figure 69 shows the number of new projects reported for each year since 1952. The number of new pilot test starts increased to a maximum of 18 in 1963. The significant drop to a value of 7 tests in 1965 is thought to be due to competition for research money from steam injection projects.

135. Koch, *loc. cit.*
136. Grant and Szasz, *op. cit.*
Kuhn and Koch, *loc cit.*

FIGURE **69.** In Situ Combustion Projects Initiated



IN SITU COMBUSTION PROJECTS INITIATED

YEAR	OPERATOR	FIELD	COUNTY	STATE	STATUS
1952	Mobil	W. Loco	Jefferson	Oklahoma	Terminated
	Sinclair	Delaware-Childers	Nowata	Oklahoma	Terminated
1953	Worthington; Forest Oil	Parker	Clark	Illinois	Terminated
1954	Cal. Research	Irvine-Furnace	Estill	Kentucky	Terminated
1955	Sinclair	Spraberry	Upton	Texas	Terminated
1956	Atlantic	Sisar-Silver Thread	Ventura	California	Terminated
	Chevron Res.	Midway-Sunset	Kern	California	Terminated
	Genl. Petr.	S. Belridge	Kern	California	Terminated
	Phillips	Bellamy	Vernon	Missouri	Terminated
	Sinclair	Humboldt-Chanute	Allen	Kansas	Terminated
1957	Atlantic	Ojai	Ventura	California	Terminated
	Bradley-Kendall	Bolivar	Allegany	New York	Terminated
	Southworth and Wood	Camp Hill	Anderson	Texas	Terminated
1958	Continental	N. Tisdale	Johnson	Wyoming	Active
	Gulf	Kyrock	Grayson	Kentucky	Terminated
	G. E. Kadane	W. Newport	Orange	California	Active
	Pan American	Shannon	Natrona	Wyoming	Terminated
	Standard of Calif.	Huntington Beach	Orange	California	Terminated
	Texaco	Bowes	Blaine	Montana	Terminated
	Texaco	Jennings	Zapata	Texas	Terminated
	Texaco	Pine Island	Caddo	Louisiana	Terminated
1959	C. W. Colgrove	Tepusquet Canyon	Santa Barb.	California	Terminated
	John DeFord	County Regular	Coleman	Texas	Terminated
	Humble	N. Midway-Sunset	Kern	California	Terminated
	Humble	Pleito Creek	Kern	California	Terminated
	Lamret	County Regular	Brown	Texas	Terminated
	Mobil	Ed Cox	Carter	Oklahoma	Active
	Mobil	San Ardo	Monterey	California	Terminated
	Texaco	Charco Redondo	Zapata	Texas	Active
	R. E. Wood	Camp Hill	Anderson	Texas	Terminated
	M. R. Young	Cook Ranch	Shackelford	Texas	Terminated
1960	Barron Kidd	Columbia Southern	St. Mary	W. Virginia	Active
	Gulf	Midway-Sunset	Kern	California	No Report
	Mobil	Lost Hills	Kern	California	Active
	Mobil	Midway-Sunset	Kern	California	Active
	Shell	Pleito Creek	Kern	California	Terminated
	Shell	White Wolf	Kern	California	Terminated
	Sohio	Asphalt Ridge	Uintah	Utah	No Report
	Sun	Delhi Area	Richland	Louisiana	No Report
	Tejas	Loco	Stephens	Oklahoma	Active
1961	Cox & Johnson	Chicon Lake	Medina	Texas	No Report
	Gulf	Fruitvale	Kern	California	Terminated
	LaBrea Corp.	McKittrick	Kern	California	Active
	Marathon	Robinson Main	Crawford	Illinois	Active
	Mobil	N. Govt. Wells	Duval	Texas	Active
	Nicholas Sage	Coffeyville-Cherryvale	Montgomery	Kansas	Terminated
	Quaker State	Goodwill Hill-Grand Valley	Warren	Penn.	Terminated
	Sinclair	Delaware-Childers	Nowata	Oklahoma	Terminated
	Texaco	Miranda City	Webb	Texas	Terminated
	Texaco	San Ardo	Monterey	California	Active
1962	Gulf	Yorba Linda	Orange	California	Active
	Mobil	Chittim Ranch	Maverick	Texas	Active
	Pan American	Toberg	Pecos	Texas	Terminated
	Pan American	Walters	Cotton	Oklahoma	Terminated
	Quaker State	Reno	Venango	Penn.	Terminated
	Standard of Calif.	Cymric	Kern	California	Active
	Texaco	Bird Creek	Tulsa	Oklahoma	Terminated
	Texaco	Kevin-Sunburst	Toole	Montana	Terminated
	Texaco	N. Midway	Kern	California	No Report
1963	Continental	W. Loco	Stephens	Oklahoma	Active
	Falcon	Charco Redondo	Zapata	Texas	Active
	Humble	S. Mountain	Ventura	California	No Report
	Mobil	San Ardo	Monterey	California	Active
	Mobil	Saner Ranch	Maverick	Texas	Active
	Occidental	Placerita	Los Angeles	California	Active
	Mobil	Pyramid Hills	Kings	California	Active
	Pan American	Panhandle	Gray	Texas	Terminated
	Pan American	Slaughter	Hockley	Texas	Terminated
	Pan American	Sloss	Kimball	Nebraska	Active
	R. Rutledge	Taylor-Ina	Medina	Texas	No Report
	Shell-Layton	Iola	Allen	Kansas	Active
	Sinclair	Avant	Osage	Oklahoma	Terminated
	Southton	Southton	Navarro	Texas	Active
	Standard of Calif.	Granite Canyon	Kern	California	Terminated
	Texaco	County Regular	Clay	Texas	Active

YEAR	OPERATOR	FIELD	COUNTY	STATE	STATUS
	Texaco	Rodrigues	La Salle	Texas	Active
	Tidewater	Bellevue	Bossier	Louisiana	Active
1964	Belridge	S. Belridge	Kern	California	Active
	Continental	E. Arnim	Fayette	Texas	Active
	General O & G	McCune	Crawford	Kansas	Terminated
	Humble	Jacalitos	Fresno	California	No Report
	Marathon	Louisburg	Miami	Kansas	Active
	Mobil	Irma	Vernon	Arkansas	Active
	Mobil	S. Belridge	Kern	California	Active
	Mobil	Vine Dome	Murray	Oklahoma	Active
	Pan American	Little Buffalo Basin	Park	Wyoming	Active
	Pan American	Fourbear	Park	Wyoming	Terminated
	Shell	Deerfield	Vernon	Missouri	Active
	Standard of Calif.	Coalinga	Fresno	California	Active
	Sun	W. Moran	Allen	Kansas	Active
	Tidewater	Midway-Sunset	Kern	California	Active
1965	CRA	Baldwin	Franklin	Kansas	Active
	Marathon	Belton	Cass	Missouri	Active
	Pan American	Refugio-Heard	Refugio	Texas	Terminated
	Pan American	W. Hastings	Galveston	Texas	Active
	Sunray DX	Escobas	Zapata	Texas	Active
	Sunray DX	Red Bank	Creek	Oklahoma	Active
	Tenneco	Taylor-Ina	Medina	Texas	Active

Most of the projects have been conducted on a pilot basis too small for economic success. A total of 8 projects have yielded sufficiently encouraging results that they have been expanded to commercial size. These projects are listed in Table XXIII.

The operation and interpretation of this radically new process have been so different from other secondary processes that movement from the pilot testing stage into commercial-size operations has been slow. Another inhibiting factor has been the high capital investment in air compression equipment required for commercial-size activity. Many of the pilot tests have been conducted in fields where underground combustion was a last resort before abandonment. These projects can be expected to have a low success ratio; however, they have been of considerable value in determining the operating limits of the process. It can be expected that as more sophistication is developed in underground combustion applications, producing properties selected for testing will be better suited for the process; hence, a bigger percentage of tests will be expanded to commercial status.

TABLE XXIII

COMMERCIAL IN SITU COMBUSTION PROJECTS IN THE UNITED STATES

				ESTIMATED INCREASE		
				RATE, BBLS./DAY		RESERVES
OPERATOR	FIELD	STATE	COUNTY	FROM	TO	MILLIONS OF BBLS.
Mobil	Midway-Sunset	Calif.	Kern	1,000	10,000	158 [a]
G. E. Kadane	W. Newport	Calif.	Orange	170	670	119 [a]
Texaco	Charco Redondo	Texas	Zapata	10	190	5 [a]
Marathon	Robinson Main	Ill.	Crawford	17	73	27 [b]
Mobil	San Ardo	Calif.	Monterey	—	23,500	573 [b]
Mobil	N. Govt. Wells	Texas	Duval	2,000	2,600	53 [b]
Continental	N. Tisdale	Wyo.	Johnson	150	330	11 [b]
Layton	Iola	Kansas	Allen	10	80	20 [a]
					Total	966

a—Estimate of reserve increase based on in situ combustion project area only.

b—Estimate of reserve increase assumes that the in situ combustion process will be applied to the entire field.

D. Range of Reservoir Conditions for Successful Application

Successful fire flood applications have been demonstrated under greatly different conditions making it difficult to generalize as to favorable reservoir parameters. Undoubtedly, the complexity of interrelations among oil, rock and geological characteristics make it necessary to consider each reservoir individually. Projects have been expanded in reservoirs having the following ranges in characteristics:

	From	To
Depth, feet	160	2,500
Well Spacing, acres	1.2	9.0
Porosity, percent	20.0	37.0
Permeability, millidarcies	300	2,000
Oil Gravity, degrees API	10	29
Oil Content, barrels per acre foot	1,000	1,900
Sand Thickness, feet	15	500

The process has been used at relatively shallow depths not because depth is detrimental but rather because other favorable reservoir characteristics are usually found at shallow depths. The required equipment and operating procedures seem to be applicable to any depth.

The wells in existing projects have been closely spaced because most shallow fields are developed on close spacing and existing wells have been used for combustion operations. This close spacing has also allowed earlier evaluation of test results. Provided sufficient permeability exists to allow adequate injection rates well spacing is not a highly significant parameter.

The porosities in which successful applications have been demonstrated have been high and while no generalization about minimum porosity can be made it seems likely that reservoirs with porosities below 20 percent will not be attractive.

Permeability is an important parameter since it determines to a large extent at what pressure air must be injected and the rate at which oil can be produced. Permeabilities in successful applications have been high with the lowest being 300 md. Applications can undoubtedly be made below this minimum; however, economics will favor reservoirs having high permeabilities and hence low injection pressures.

Oil gravities have generally been on the low side with the maximum gravity produced from an expanded project being 29° API. Combustion has been maintained in reservoirs having oils as high as 35° API and this must be considered the maximum at this time. Since light oils bring a higher price, we might expect application to favor light oil reservoirs; however, these reservoirs usually have better primary recoveries and are attractive for other secondary recovery methods such as water flooding and gas injection. We can expect that most underground combustion projects will be conducted in reservoirs below 25° API where water flooding cannot be or has not been efficiently applied.

The minimum oil content for successful expansion has been 1,000 barrels per acre foot. This value of course is quite high and in itself limits application to reservoirs having poor primary recoveries. The necessity for having high oil content is largely a function of crude price and we can expect the process to be applicable to reservoirs having lower oil content as price increases.

The successful projects have been conducted in reservoirs having thickness from 15 to 500 feet. Since this range is so broad it implies that sand thickness is not a critical parameter.

E. Influence on Production and Reserves

Table XXIII indicates that the effect of underground combustion upon current production and reserves has been minor. Production from the eight listed projects is estimated to be approximately 30,000 barrels per day. While the other 36 projects listed in Table XXII are producing oil, it seems unlikely that current production attributable to underground combustion is more than 50,000 barrels per day. Total potential reserves for the projects in Table XXIII are estimated to be 966 million barrels. The reserves to current production ratio is very high on these projects and indicates that further expansion and consequent increased producing rates will occur.

Documented production from the field tests in Table XXII is incomplete. Based upon what information has been published it is estimated that 15,000,000 barrels have been produced to date.

Published figures indicate that 50 percent of the oil in place can be recovered in an underground combustion project. This is a high percentage for heavy oil reservoirs; however costs, particularly capital investments in compression equipment, are now making oil production by underground combustion an economic problem rather than a technical one. Because the economics appear somewhat marginal at the present time it is difficult to predict when and if underground combustion will have a major influence on domestic producing capacity. We can predict that the high capital investment required will continue to inhibit application so that growth of underground combustion production will be slow.

SECTION 12—Thermal Applications—External Heat Sources

E. B. Miller, Jr.

A. Introduction

The purpose of this section is to provide a detailed study of thermal technology as developed to the present, a discussion of the range of physical conditions under which steam stimulation and displacement can be used effectively, a study of the mechanical equipment that has thus far been developed for use in thermal recovery projects and, finally, to offer several conclusions on the estimated present and future impact of steam on crude oil production in the United States.

B. A Brief History of Thermal Recovery

The idea of injecting heat into an oil reservoir to increase proportionate recovery of the oil in place is not new. Over 100 years ago, in 1865, a U. S. patent was granted for a primitive bottom hole heater. There are also records that in the 1920's and 30's operators in California, West Texas and Louisiana experimented with steam injection. Although these early attempts deserve recognition for their pioneer contributions, the practical use of thermal recovery techniques to increase recovery in low-gravity reservoirs commenced in the late 1950's.

Among the earliest reports of a modern thermal recovery project is a steam drive test begun in 1957 by Shell Oil Company of Venezuela in the Mene Grande Field in Western Venezuela. Another operator, Tidewater Oil Company began its research on thermal recovery in 1956, when it utilized bottom hole heaters in California's Kern River Field. This was followed by hot water injection experiments and then by steam injection tests. Steam was determined to be the more efficient medium for carrying heat to the resorvoir.

As recently as 1962, however, there were only three or four steam projects in California. California has been the major area of thermal activity due to the existence of extensive reservoirs, with massive sand bodies at shallow depth, containing enormous deposits of viscous oil in place.

By 1964 the level of steam stimulation activity in California began to rise rapidly, and by year-end 1965, according to the Conservation Committee of California Oil Producers, net increase over primary rates due to steam stimulation in California was 75,000 barrels per day from some 280 projects and 5,000 wells in 38 fields.

One example of the impact of thermal recovery on California production is illustrated in the Kern River Field near Bakersfield. Since first injecting steam in Kern River in 1964, one operator has recovered more than 9 million barrels of oil above that established by primary production rates from its acreage in this one field. That company alone injected more than 100,000 barrels of water per day as steam in Kern River and produced in excess of 37,000 barrels of crude oil per day in August, 1966, a gain from 16,277 barrels daily in August, 1964.

As a result of thermal recovery success in California, operators in several Mid-Continent and Rocky Mountain states are now conducting thermal projects.

C. How Steam is Used in Thermal Recovery

Steam is utilized in two thermal recovery processes: (1) as a stimulation medium to heat the area of the reservoir around the wellbore (called variously steam stimulation, huff-and-puff, cyclic steam injection and steam soak); (2) as a displacement medium to drive crude oil to producing wells.

1. STEAM STIMULATION

In the first method, steam under pressure is injected down the casing or tubing of a producing well. The length of the injection period is governed by a number of factors, including size of the steam generator, rate of steam injection, and amount of water injected as steam. The amount of steam injected per cycle is generally related to the thickness of the producing zone. A typical steam injection lasts for approximately five to eight days, with about 6,000 to 10,000 barrels of water converted to steam being injected.

Following the injection period, the well is returned to production, and during the first two days it usually produces primarily water. Within five to ten days, however, net oil production in a successfully stimulated well can rise to ten or more times its prestimulation production rate. Since decline rates are high, within four to six months production will usually decline to the prestimulation level, at which time the cycle is repeated. The total production increase for each steam cycle is generally in the range of two to three times what the prestimulated production would have been. Experience indicates that stimulation performance varies according to existing reservoir pressure. Heat is important to make the crude more mobile but energy is required to get it into the wellbore. Where some reservoir pressure is present, injected steam can reinforce the natural energy in the reservoir and help return the heated oil at rates and volumes that are economically attractive. Zones where no remaining reservoir pressure exists generally do not respond as well to straight stimulation methods as areas where some pressure remains. In pressure-depleted reservoirs it appears that steam displacement will be more successful than steam stimulation.

There is some difference of opinion among steam stimulation experts as to whether injected wells should be returned to production immediately after steam injection or whether they should be allowed to "soak" for a period of time before being returned to production.

Those favoring immediate production with no "soak" period point out that as steam is injected into low-pressure reservoirs it pushes against a cold, viscous reservoir crude that moves at a slower rate than the fluid injected. Therefore, it is believed, a "pressure bubble" develops around the wellbore. If the well is allowed to "soak" this pressure dissipates and production is lost. If the well is immediately produced after steam injection is discontinued, this "pressure bubble" and the existing reservoir pressure help push oil into the wellbore. Keeping the well "pumped off" at all times is important in obtaining maximum ultimate recovery from each steam cycle, according to "no soak" advocates.

If a well is allowed to "soak" more heat will remain in the reservoir but pressure advantages mentioned above will be lost. When wells are allowed to "soak" it is generally in the range of one to ten days. If adequate reservoir pressure exists, "soaking" may prove advantageous in some fields since it will enlarge the radius around the wellbore contacted by heat, and total production during a cycle may be higher. The operator should consider the value of production not produced during the "soak" period compared with any total production increase obtained during a cycle as a result of "soaking."

Variation in volume of steam injected and rate at which it is injected will have some effect on production. Field experience and statistical comparisons of total recovery during a cycle by various operating methods is the best guide to follow. It should be emphasized that the various parameters are interrelated and not independent of each other.

When reservoirs that have virgin or near virgin reservoir pressures are steam-stimulated, much higher injection pressures are generally required. Pressure will approximate that necessary to lift the overburden. In these cases higher temperatures are necessary if steam is to be flashed in the reservoir.

2. STEAM DISPLACEMENT

Steam displacement (or steam drive) follows the same basic principle as the water flood. Steam under pressure is fed into special injection wells, both to heat the oil in place and to drive it to producing wells.

At the present time, steam stimulation projects far outnumber displacement projects. However, thermal experts generally look on stimulation as only an interim step in the technological advancement of thermal recovery. They believe stimulation will economically recover only a limited amount of oil because of declining reservoir pressure. This opinion is partially substantiated in some areas by production declines noted on successive stimulation cycles. Maximum recovery, it is believed, will require some form of a steam drive or combination steam drive and steam stimulation to provide energy to move heated oil to the wellbore as normal reservoir pressure declines.

If the description of these thermal recovery techniques appears simple, development of the technology that made them economically practical was anything but simple. In fact, the complex problems that had to be solved in the development of sound thermal techniques is a principal reason why thermal recovery has only come into general use within the last two or three years.

D. Effect on Rate of Production and Ultimate Recovery

Normally, rate of production will increase when oil within the formation is heated since oil production rate is generally inversely proportional to viscosity. If viscosity is reduced to one-fifth of its original value, the oil rate will increase proportionately, provided there is energy in the reservoir to move oil to the wellbore. If energy is not present, heating alone will not measurably improve production except by gravity drainage.

In some cases, the function of steam in cleaning out asphaltene deposits around the wellbore can result in much higher producing rates long after the heat has been dissipated in the reservoir.

Based on laboratory core studies, it has been shown that it is possible to obtain as high as 84 percent recovery in a swept-out zone. This would be at 100 percent sweep efficiency. Based on practical sweep efficiencies, the ultimate recovery would probably be more like 40 to 50 percent from a steam-drive process. One particular field test has recovered 40 percent of original oil in place by steam drive and it is expected that ultimate recovery will exceed 45 percent. More pilot testing is required to substantiate these recoveries on a field-wide basis.

The high recovery of crude using steam can be attributed primarily to:

(1) Viscosity reduction which improves the mobility ratio between the crude and the displacing fluid.
(2) Thermal expansion of the crude.
(3) Partial distillation of the crude.
(4) Reduction of wellbore plugging.

Some problems to recognize are steam channeling from the injector to the producer similar to channeling in water floods. Some wells may be rate sensitive; others may require remedial work to prevent channeling. Some channels will "heal" if injection is slowed or interrupted to permit cold crude to fill the channel. As the entire zone becomes heated, channeling problems appear to lessen.

When only a steam stimulation process is used without an actual steam drive, it is expected that recoveries will be much less except under ideal conditions—perhaps five or ten percent additional oil can be recovered over and above primary levels.

From a general standpoint, total recovery (primary recovery and steam stimulation) should approximate a solution gas-drive reservoir of lesser viscosity providing the reservoir is adequately heated and gravity drainage is not a factor. In areas where gravity drainage would apply, recovery will be higher.

If additional energy (steam drive) must be supplied to the reservoir for maximum recovery, recoveries probably will exceed a normal water flood recovery because thermal benefits are lacking in a normal water flood.

In some situations, where wells are drilled on close spacing and all wells are being stimulated, the recovery mechanism may reflect both steam drive and steam stimulation. When the entire reservoir becomes heated and well interference is obtained, stimulation of one well will affect nearby wells. Recoveries similar to steam drive appear possible under these conditions.

E. Range of Conditions Under Which External Heat Sources (Steam) Can be Used

There are a number of physical conditions that are necessary for successful secondary recovery using steam stimulation or steam displacement. The following portion of this section describes these necessary characteristics and also outlines certain economic factors to be considered in potential thermal recovery projects.

1. WELL DEPTH

Thermal experts generally agree that the maximum practical well depth for successful steam stimulation and displacement projects is approximately 3,000 feet. Wells have been successfully steamed at greater depths, but steam operations below 3,000 feet represent a very small percentage of wells steamed. In fact, the most successful steam injection projects have occurred at depths of from 100 feet to approximately 2,500 feet, as illustrated by Table XXIV.

A shallow depth is more desirable for several reasons. The main factor is that more heat is lost in the longer wellbore of a deep reservoir. Second, higher formation pressure at greater depths requires higher injection pressures and temperatures and added expense of high-pressure equipment. Third, high injection pressures and temperatures bring more chance for well failure. Finally, deep formations already benefit from higher temperatures, and there would be less viscosity reduction from heat injection.

2. FLUID CHARACTERISTICS

A major requirement for a successful steam injection application is large reduction of crude oil viscosity with increasing temperatures. Experience indicates that best results are generally offered by a crude of 10° to 15° API gravity. Most crude oils in this gravity range exhibit the desired viscosity reduction when the temperature is increased to levels achieved by steam injection.

Unless the normal reservoir viscosity is several hundred centipoises or more (corresponding to 15° API gravity or less), the viscosity reduction will not be large enough to be economically successful. Steam has been successfully used in producing some crudes of less than 10° API gravity, but the economics are generally poor because of the low posted price for such crudes.

3. ZONE THICKNESS

In thin reservoirs, a large percentage of the injected heat is lost to the overburden and underburden. In

TABLE XXIV

PRINCIPAL STEAM STIMULATION FIELDS IN CALIFORNIA[a]

FIELD	DEPTH OF ZONES BEING STIMULATED	NO. PROJECTS	TOTAL INCREASE IN PRODUCTION OVER PRIMARY (BOPD)
South Belridge	400–1500	14	2,000
Coalinga (east & west)	700–2500	25	3,600
Kern River	750–1250	50	17,000
Midway-Sunset	800–2500	85	20,000
Cat Canyon (east)	2100–2600	4	2,100
San Ardo	2100–2300	3	13,400
Yorba Linda	350–1800	6	5,600
	Total	187	63,700

a-Compiled from *Annual Review of California Oil and Gas Production*, Conservation Committee of California Oil Producers, 1965.

thick zones, the heat loss is a much smaller percentage. Evidence to date indicates that steam injection projects will be more profitable in thick, massive formations.

Minimum net sand thickness, to be economic, should be about 50 feet or more. However, actual projects have been conducted in zones no thicker than 15 feet. Depth of the producing zone and cost of drilling is important if wells are drilled specifically for steam injection. A thermal project obviously requires very careful analysis when the zone is thin and depth to the producing zone increases.

4. ROCK PROPERTIES

High porosity is desirable since it permits a large quantity of oil to be present in relation to the rock solids. Oil temperaure cannot be increased without heating the rock, and low porosity is therefore a cause of inefficiency.

Porosity should exceed 25 percent and generally does in shallow, unconsolidated sand reservoirs where porosities of 35-40 percent are not uncommon in California. Oil saturation in this porosity should average at least 50 percent. To permit steam injection at adequate rates, the permeability of the formation should be at least 1,000 millidarcies.

5. WELL SPACING

Well spacing is not particularly important for steam stimulation of normal primary development wells, and interference between stimulated wells does not generally occur. In a steam drive, the spacing should be close enough to minimize heat losses to the overburden and underburden. Nothing definite has been established on the exact range of well spacing, but some operators consider a 10-acre, 5-spot pattern as a possible maximum. Most projects have been on a two- to five-acre well spacing pattern.

6. ECONOMIC CONSIDERATIONS

There are many economic factors to be considered when examining a potential steam injection project. The most important elements, in terms of continuing costs, are royalties, fuel and water. Additional considerations include normal lifting and collecting expense, cost of equipment, and market value of low-gravity crudes.

7. ROYALTIES

It is certainly an important economic advantage to the producer to hold the bulk of land in fee. The payment of royalties in addition to thermal costs can reduce profit margins to an uneconomic level; thus, the economics of some potential projects are such that they simply cannot be attempted with existing royalty agreements. In some areas it may be necessary to renegotiate royalties or share costs with the landowner to make thermal recovery economically worthwhile to both the lessee and lessor.

This problem can be illustrated as follows:

CRUDE OIL GRAVITY	AVERAGE REALIZATION FOR CRUDE	FEE PROPERTY VALUE TO PRODUCER	ROYALTY VALUE TO PRODUCER 12½%	16⅔%	20%	25%
9° API	$1.09/bbl.	$1.09	.95	.91	.87	.82
10° API	$1.22/bbl.	$1.22	1.07	1.02	.98	.92
13° API	$1.70/bbl.	$1.70	1.49	1.41	1.36	1.27
15° API	$1.94/bbl.	$1.94	1.69	1.61	1.55	1.45

8. FUEL COSTS

Steam generator fuel may be either gas, LPG, diesel oil, fuel oil or crude oil. When low-cost gas is available, it is the preferred fuel. Where gas costs are high, general practice is to burn crude oil. The following table illustrates relative fuel cost when using crude:

VALUE OF CRUDE OIL USED AS FUEL	COST OF FUEL PER BBL. OF OIL PRODUCED BASED ON STEAM/OIL RATIOS OF 2:1	3:1	4:1
$1.09/bbl.	$.14	$.22	$.25
1.22	.16	.24	.32
1.70	.22	.34	.45
1.94	.26	.39	.52

9. WATER COSTS

Costs of water and water treatment can vary from a few mills per barrel to several cents per barrel. The types of impurities present in the water, and their concentration, can cause wide variations in water treatment costs.

The effect of water costs on the economics of producing a barrel of thermal oil is illustrated in the following simple example:

COST OF WATER	ADDITIONAL OPERATING COSTS PER BBL. OIL BASED ON STEAM/OIL RATIOS OF 2:1	3:1	4:1
5 Mills/Bbl.	$.01	$.015	$.02
5 Cents/Bbl.	.10	.15	.20

Water relatively low in total solids, containing mainly calcium and magnesium salts, can be reduced in hardness with a simple ion exchange softener. Water high in chlorides is usually high in other dissolved solids and will require a more complex treatment such as hot lime. Some success has been obtained using generators designed for blowdown of solids where cost of water treatment to remove the solids would be excessive. Organic chemicals are added to the water to keep both undissolved and dissolved solids in a fluid sludge form so it can be blown down with minimum scale formation on the boiler tubes.

Steam or hot water injected into a well should be free of undissolved solids to prevent plugging in the wellbore or in the formation. When permeability is low, filtering may be necessary to remove turbidity, thus adding another cost factor. Normally, filtering is not required. The softener quite effectively removes material normally removed by a filter.

To minimize corrosion, the water system should be designed to eliminate oxygen. Otherwise oxygen scavenger chemicals must be used, adding another element to water treatment costs.

Where possible it is advantageous to flow or pump water directly from a water source to the softeners and then to the generators without using storage tanks. Where tanks are used gas blankets are helpful to prevent oxygen entry into the water at this point.

When oxygen scavengers are necessary, it is best to introduce them as far upstream as possible. Use of steam to strip out oxygen and mechanical deaerators are not normally used.

(The section on water treatment later in this Section contains a detailed chart on water treatment problems and solutions.)

10. OTHER FACTORS

Another important economic factor in thermal operations is sand control. Often a smaller mesh liner and/or gravel packing is necessary because thermal wells have a greater tendency to sand up than non-thermal wells. Unless remedial work is performed, operating costs can be excessive.

Condition of wells is also an important factor. Specifically, the cement pipe bond must be in good condition and the well equipment must be able to handle increased production rates.

11. COMPLEX COST MIX

With so many economic variables, it is not difficult to see why operating costs can vary from approximately $.40 per barrel to more than $1.00 per barrel, and why some projects can be economically successful while others in the very same field are unsuccessful.

F. Mechanical Equipment

Development of steam stimulation and displacement technology has caused parallel development of mechanical equipment designed especially for thermal recovery. Much of this equipment has been adapted from existing oil field equipment, but certain items have been developed explicitly for thermal work.

1. STEAM GENERATORS

There are three basic types of generators in use to manufacture steam for thermal recovery projects: (1) the conventional natural circulation generator with either fire tubes or water tubes; (2) the forced circulation generator with separating drum; and (3) the forced circulation "once through" (or single pass) generator which produces steam in the 80 percent quality range. A separator may be added to this type to produce high-quality steam. The generator may be equipped with or without an economizer section.

The majority of oil field steam generators currently in use are of the "once through" type. They are preferred because (1) since only about 80 percent of the water is vaporized, feedwater can contain a relatively high solids content—provided the solids have been converted to soluble form; (2) the "once through" generator does not use a separating drum, thus eliminating the need for level controls and blowdown operations.

Steam generators are designed with operating pressure limits ranging from about 500 psi up to 2,600 psi. The pressure required to inject the necessary volume of steam determines the generator pressure rating required. The considerations for selection of the steam generators include steam volume and operating efficiency, availability of parts and service, ease of repair (accessibility to components), and price.

Single pass generators range in size from 5 million BTU's per hour to 40 million BTU's per hour heat output. The most common sizes presently being used range from 18 million to 22 million BTU's per hour output. Forced circulation generators with steam drums with heat outputs of up to 100 million BTU's per hour are in limited use. Various sizes of miscellaneous generators are also being used, some as small as 1 million BTU's per hour.

Burner equipment to burn one or more types of fuel can be installed on the larger generators. Because of combustion space limitations on the smaller generators, it is not common practice to fire them with fuel oil or crude oil. In order to fire with fuel oil or crude oil most burners require that the oil be heated so that its viscosity is from 100 to 150 SSU.

2. GENERATOR PROBLEMS

Steam generators have been reasonably trouble-free but early models gave some trouble with overheated controls.

Tube turn failures have been minor in most generators. Some operators have experienced abnormal tube turn failures which were determined to be caused by corrosion rather than erosion, the result of overtreating the feedwater.

When crude oil is used as fuel, there is a gradual plugging of the stacks with soot and sediment. This causes a gradual decline in boiler efficiency. Stacks are now cleaned out approximately every 3 months. When gas is used as a fuel there is no problem with soot or sediment.

3. WATER TREATMENT FACILITIES

Water treatment facilities vary with the type of source water, type of steam generator, volume of water demand, and concentration of demand. Each installation has to be considered separately. Tabulated in

Table XXV are listed the common feedwater constituents along with problems caused and treatment practices.

4. SURFACE EQUIPMENT CONSIDERATIONS

Surface equipment must distribute and measure the injection fluids, and produce, collect, measure, and clean the produced fluids. These functions must be accomplished safely and at optimum economics. Safety requirements are specified in regulatory body codes and the ASME codes.

The cyclic nature of steam stimulation and production variations in steam drives require equipment which can accurately measure injected and produced fluids for each well.

There are several types of steam-transmission systems, including individual steam lines, trunk lines, and combination steam and production lines. In any transmission system, however, a method for switching the steam from well to well is normally required.

Several factors to be considered in designing the transmission system are:

a. Heat loss. Insulating the surface injection lines is generally an economical means of limiting heat loss.
b. Pressure loss. When sizing steam lines, frictional pressure loss with the high specific volume of steam must be considered, to prevent abnormally high generator operating pressures.
c. Thermal expansion. Provision should be made for thermal expansion of steam transmission lines to prevent failure due to stress. Provision for line movement at the wellhead is also required because of probable casing head movement from casing expansion.

Turning to production-handling equipment—as a result of increased gross production, larger

TABLE XXV

FEEDWATER TREATMENT FOR STEAM GENERATORS

FEEDWATER CONSTITUENT	PROBLEM CAUSED	NORMAL TREATMENT PRACTICES	COMMENTS
Oxygen	Corrosion	Eliminate air leaks into water systems. Add oxygen scavenger normally catalyzed sodium sulfite or in a few cases hydrazine.	Deaerators used in some cases to reduce oxygen scavenger requirement. Oxygen should be reduced to zero as far upstream as possible.
pH	Usually not a problem.	Normally none required.	Some operators add caustic or ammonia for protection against possibility of corrosion of boiler tubes.
Carbon Dioxide	Usually not a problem.	Normally none required.	Some operators add volatile or filming amines or ammonia for protection against possibility of condensate corrosion.
Sulfides	Corrosion	Aeration or aeration w/pH reduction or flue or inert gas stripping. Chlorination for small amounts or polishing.	Sulfides normally not present in most source waters. Can be a problem where produced waste water is used.
Dissolved Solids	Usually not a problem.	Normally none required.	High-salinity waste waters are more difficult to soften due to "back regeneration" of zeolite resin.
Hardness	Scale	Sodium zeolite softening.	Hot lime-soda ash softeners used in cases where salinity is too high for zeolite. Chelants (EDTA) may be used in cases where hardness leakage cannot be reduced to tolerable levels.
Silica	Usually not a problem.	Control hardness as shown above.	
Oil and Suspended Solids	Plugging and Fouling.	Filtration w/pretreatment if necessary. a) Retention or gas flotation for oil reduction. b) Chemical coagulation.	Potable source waters generally clean enough so that no treatment is needed. Oil is a problem where produced waste water is used.

surface pumping equipment may be required on old wells. New wells have to be provided with adequate size equipment. Normally on old wells it is necessary to install new wellheads for the pressures and temperatures to be encountered.

Cleaning plants of sufficient size are required to handle the increased production. Added emulsion and sand production should not be overlooked.

5. SUBSURFACE EQUIPMENT CONSIDERATIONS

Old wells normally will require installation of larger pumps to handle the increase in gross fluid. Pumps will also have to operate at higher temperatures, and production of sand should be considered. In some cases, gas-locking due to steam will be encountered. The fluid level in the producing wells should be measured and the pump speed and stroke adjusted in accordance with the fluid available.

Steam injection can be down the tubing, down the casing-tubing annulus, or both. Injection down the casing is the simplest method, but this subjects the casing to steam pressure and temperature, with resultant heat loss and possible casing failure.

Injection down the tubing allows the operator to take measures to protect the casing, such as using a packer. Injection down the tubing normally requires pulling the rods and pump in a "huff-and-puff" project. However, techniques such as unseating the pump have been developed to eliminate the need for pulling the rods and pump. A larger I.D. joint of tubing has been used at times to permit steam to pass around the pump.

High-temperature packers have been developed for use with steam. These vary from simple cup packers to packers with two-way slips and expansion joints. When using packers, the creation of hydraulic force is a possible problem. It is possible to "hydraulic" the pipe assembly up the hole or even out of the well if it is not properly designed.

Injection profile can sometimes be improved by changing tubing depth. If the steam is being injected at the top of a very thick pay zone, there is a tendency for steam to enter the formation in the upper intervals. By lowering the tubing to the bottom of the zone, injection can be made to take place down the tubing. The lower part of the zone is then heated and the injectivity profile is usually improved.

6. TUBULAR GOODS REQUIREMENTS

If steam injection takes place down the casing or down the tubing and no packer is used, tubing expansion is not a problem. In this case, the tubing merely grows down the hole. When the tubing is set on a packer, however, provision must be made for thermal expansion. This can be done with expansion joints in the packer, on the tubing string, or at the surface.

Casing failures due to thermal expansion are the most severe tubular goods problems resulting from steam injection. For restrained pipe, a stress of 204 psi for each °F temperature change is imposed on the steel. This is based on a modulus of elasticity of 29×10^6 and a coefficient of thermal expansion of 7.02×10^{-6} in./in./°F. Therefore with a 400°F temperature change, restrained pipe would have an imposed stress of 81,600 psi. Any buckling in the casing string has the effect of increasing the stress.

The five following means can be employed to reduce casing failures from thermal stresses:

a. By using high-strength casing materials and high-strength joints.

b. By cementing casing with an induced tensile stress. This can be done by cementing around the shoe, pulling pipe in tension and completing the cement job through a D.V. collar. Cementing should be performed with high-temperature compositions.

c. By cementing casing only at the shoe, leaving the remainder of casing string free to move. In order to prevent casing from sticking, the casing-hole annulus should be filled with a special material such as a heat-resistant viscous grease. Also an inner string of casing can be used.

d. By reducing casing temperature to alleviate stress. This method requires injection down tubing and some means of insulating tubing to reduce heat transfer from tubing to casing.

e. By using expansion joints on the casing.

Steaming operations in old oil fields can result in many casing failures. Often it is possible to proceed with steam injection down the tubing after a packer is set below the bad spot in the casing. Where low pressure (less than about 700 psi) injection is possible, cup packers can be used.

7. WELL COMPLETION PRACTICES

The completion of a well drilled specifically for thermal recovery is basically the same as a standard primary well completion. There are, however, certain points that deserve attention.

For proper sand exclusion, fine mesh liners and/or gravel packs are commonly used in thermal completions since steam operations often cause increased sand production.

Cements with compositions that have a minimum strength loss at steam injection temperatures must be selected.

Consideration must be given to providing selective injectivity with the production zone. Without control of injection interval, it may not be possible to obtain satisfactory coverage, a factor that is especially important in displacement project injection wells.

Finally, thermal well completions must permit running of temperature and/or pressure surveys.

G. Impact of Thermal Methods on Total Crude Production

The impact of thermal recovery upon total United States crude oil production is dependent upon the relative economics of all methods of production—primary and secondary. Those recovery methods with the lowest costs per barrel will be favored irrespective of the amount of technological advance in any particular area. Since this Chapter does not delve into the economics of alternative means of producing oil, it is not possible to predict how much production will result in the future from each of the various recovery processes.

This Section provides an estimate of the possible impact of thermal production from a barrel standpoint (as distinguished from a dollar approach) based upon an analysis of domestic demand for crude oil and the nation's crude oil reserves.

In the 10-20° gravity range no attempt has been made to distinguish potential reserves recoverable by steam from those that might be recovered by in situ combustion. Also, no estimate has been made of potential reserves above 20° API that might be recovered by a combustion process as it is beyond the scope of this Section.

At the present time steam has its greatest impact on reserves in the 10-15° API range. A 20° API cutoff is somewhat arbitrary. It was selected to include some steam projects operating on crudes above 15° API and to reflect a reasonable cutoff where other types of secondary recovery methods may be equally successful.

1. IMPACT OF THERMAL TECHNOLOGY ON RESERVES

Data resummarized from a 1965 U.S. Bureau of Mines report indicate that there are approximately 50 billion barrels of oil in place in fields in the United States [137] possessing the following reservoir characteristics:

(1) 3,000 feet or less in depth.

(2) 20° or less gravity crude oil.

(3) Minimum net pay zone of 25 feet.

Ultimate recovery of these low-gravity crudes by thermal means is related more closely to economics than technology. Pilot testing of steam drive and in situ combustion projects have indicated that recoveries of 40 percent or more of oil in place may be possible. However, current data are insufficient to suggest that the nation's proved reserves can be increased by 20 billion barrels at this time.

If it is assumed that ultimate recovery by thermal means will approximate 25 percent of oil in place, then the impact of thermal technology upon the nation's crude oil reserves can be summarized as follows:

137. Approximately 35 billion barrels of this total are located in California.

	BILLION BARRELS	PERCENT OF TOTAL
Proved Crude Reserves (ex thermal)	31.0	71.3%
Thermal Reserves	12.5	28.7%
Total Crude Reserves	43.5	100.0%

2. IMPACT OF THERMAL TECHNOLOGY ON PRODUCTION

The impact of thermal technology on crude oil production will depend largely upon profitability to both the producer and the refiner. The current low posted price for most heavy crude oil has resulted partially from a lack of refining facilities to process the crude into the higher value products, partially from high transportation costs from some fields to the refinery, and from oversupply in local areas. California, a crude oil deficit area with the bulk of the heavy oil reserves, has been a leader in the installation of hydrocracking and coking facilities necessary to full treat low-gravity crudes. Some crude oil transportation systems capable of handling increasing volumes of more viscous production have been built; however, more such projects will be required before the full potential of California's heavy crude oil reserves can be realized.

Since considerable work has been done in the last few years in these two important technological areas, the impact of thermal technology on production has been more pronounced in California than elsewhere in the United States. Net increase due to steam stimulation at year-end 1965 was 75,000 B/D from some 280 projects and 5,000 wells in 38 California fields. This production increase indicates both the technology and the economics are successful in recovery of heavy crudes.

California, however, has other favorable conditions that are generally lacking in other sections of the United States that have encouraged development of refining technology necessary to maximize profitability of low-gravity crudes. Generally speaking, California low-gravity crudes are found at shallow depth, and the producing zones are measured in hundreds of feet with high porosity, permeability and oil saturation. Large reserves are found near existing piplines and refineries. A high density of wells already exists on close spacing in many fields. Elsewhere in the U.S. the low-gravity crudes generally are found in much thinner zones and lack several of the other advantageous factors of the California fields. As a result, major refinery improvements either are not warranted or will be slower in development outside of California.

The rate of thermal production in California should increase until all of the adequately designed pipeline space and recently completed heavy oil refining capacity has been utilized. The development of steam-stimulated production elsewhere in the United States will probably remain at fairly low levels as long as the present refining and transportation configurations are unchanged and the supply of high-gravity crudes is adequate.

SECTION 13—Impact of Reservoir Technology

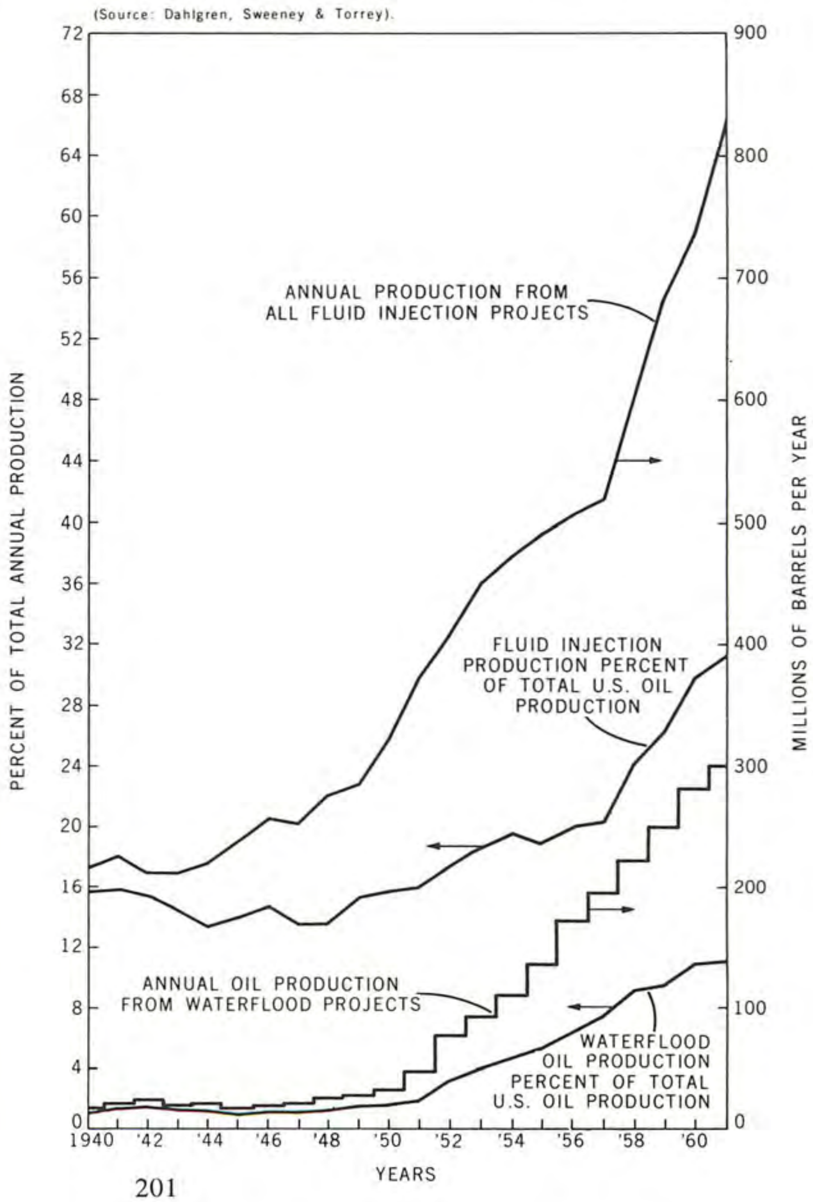
Lincoln F. Elkins

The present state of the art and progress in the various facets of reservoir technology and operation during the last two decades have been reviewed. Each part of the technology has contributed to sustained or increased crude oil producing capacity and reserves and each shows promise of continuing improvement in sustaining producing capacity and in increasing oil recovery efficiency. Various investigators have made estimates of this impact of technology on crude oil availability, particularly that portion resulting from fluid injection. The most extensive of these have been the biennial studies of the Secondary Recovery Subcommittee of the Interstate Oil Compact Commission. As of January 1, 1962, this Committee estimated remaining primary crude oil reserves of the United States at 31.399 billion barrels and additional economic recovery of 16.332 billion barrels of crude oil by fluid injection. In the same study it was reported that 5,834 fluid injection projects were responsible for the production of 732.9 million barrels of oil in 1960 which is equal to 29.6 percent of the 2,471.5 million barrels total oil produced in the United States that year.[138] The history of oil production from fluid injection projects and its relation to total oil production in the U.S. from 1940 through 1961 is presented in Figure 70.

An important area study of the Permian Basin reports the impact of fluid injection on both oil

138. *A Study of Conservation of Oil and Gas,* I.O.C.C., 1964.

FIGURE **70**
Oil Production from Fluid Injection Projects in Relation to Total U.S. Production



production rate and oil reserves added during the period 1950 through 1964.[139] In this area it was estimated that about 75 percent of ultimate primary oil reserves that have been found occur in solution gas-drive reservoirs. Thus a large potential exists for successful application of fluid injection. Significant fluid injection started in 1948 and has grown rapidly as illustrated by the following data:

YEAR	NEW PROJECTS
1950	20
1955	30
1960	58
1961	78
1962	99
1963	96
1964	155

By 1964 year-end, 806 fluid injection projects were in operation. During this period, oil production from fluid injection projects increased from 71,000 bbl/day in 1950 (8 percent of total area production) to 536,000 bbl/day in 1964 (36 percent of total area production). Additions to proved oil reserves by secondary recovery increased from 66 million barrels per year in 1950 to 622 million barrels per year in 1964. During the 5-year period of 1960-64, additions to reserves by secondary recovery totalled 2,097 million barrels equal to 54.4 percent of all reserves added during the period. As of January 1, 1965, it was estimated that 4.8 million barrels had been added to proved developed reserves in the Permian Basin by secondary recovery and that, in addition, there remained a potential undeveloped secondary recovery reserve of 8.3 billion barrels, using known methods, in fields already discovered. These data correspond to 22 percent average recovery efficiency by primary methods and an increase to 40 percent average recovery efficiency by the fluid injection methods being applied or applicable. This leaves 60 percent or 43.8 billion barrels of oil unrecovered in known fields in this one area as a research objective for improved recovery techniques.

The crude oil reserves of the U.S. estimated by the American Petroleum Institute Reserves Committee are limited to the proved category. Additions to reserves resulting from secondary recovery are included only when the various processes are applied to part or all of particular reservoirs. These additions are then incorporated in the revision category along with changes for other reasons such as improved estimates resulting from additional performance data, etc. During the twenty-year period 1946 through 1965, additions to the API estimates of reserves of crude oil only by discovery, extension and revision totalled 57.6 billion barrels.[140] Of this, 20.3 billion barrels or 34.4 percent was added by revision. Although no breakdown of the additions to reserves by revision is compiled by the API Committee according to reason for the change, it is our considered opinion that at least half of this addition or about 10 billion barrels has resulted from fluid injection. In part this estimate results from a parallelism between the percentage of total production from fluid injection projects in the Permian Basin and in the U.S. and the addition of 4.8 billion barrels to proved developed reserves by secondary recovery in that one area alone.

The accelerating growth in application of fluid injection in the past two decades and a knowledge of many specific projects under study portend continuing growth in conventional fluid injection for many years. Timing of many of these projects depends in part on economic factors as total demand for crude oil in the U.S. grows with respect to new primary production resulting from discovery and extension drilling. In addition, it is anticipated that there will be a significant growth in selective application of the newer recovery techniques, particularly thermal, as additional experience is developed through projects now in operation. As of January 1, 1962, the Secondary Recovery Subcommittee of the Interstate Oil Compact Commission had estimated the additional reserves physically recoverable by all known methods at 40.2 billion barrels.[141] This was in addition to primary reserves of 31.4 billion barrels and economic recovery of 16.3 billion barrels by fluid injection.

139. Hudson, C. H., "Status of Secondary Recovery in the Permian Basin," *Paper* No. SPE 1141, presented at Permian Basin Oil Recovery Conference, Midland, Texas, May 10, 1965.

140. *Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas*, American Gas Association and API, 1946-1965, vols. 1-20.

141. *A Study of Conservation of Oil and Gas*, I.O.C.C., 1964.

CHAPTER FIVE—OFFSHORE OPERATIONS

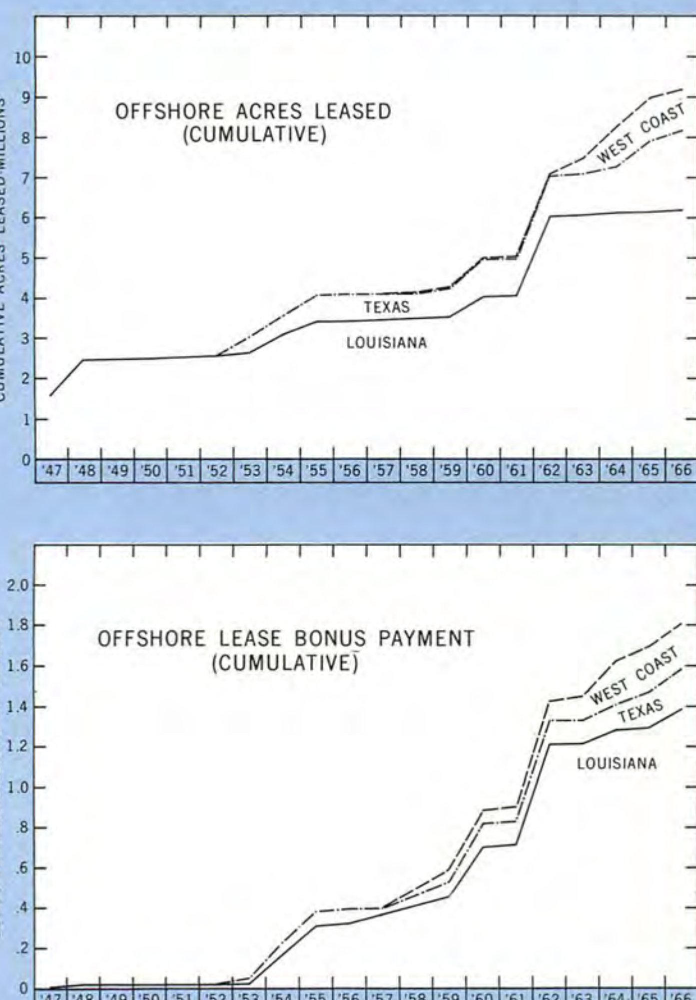
SECTION 1—Introduction

A. L. Vitter and C. P. Besse

Initial production of oil and gas from beneath the ocean waters along the California coastline was accomplished by directional drilling from shore and from piers. This was followed in 1937 by the development of the Creole Field off the Louisiana coast using a timber piling structure. Another timber piling platform which was lost in a hurricane was used in an attempt to drill a well in what is now the Bay Marchand Field.

Offshore operations were at a standstill until 1946, when Mobil Oil Company drilled south of Morgan City, Louisiana, in Eugene Island Block 58 in 14 feet of water. This time, the drill rig and its appurtenances were supported on a combination of timber and steel tubular piling. This operation set off a program of drilling in the Gulf of Mexico off the Texas and Louisiana coastlines. The first producing oil well was completed by Kerr-McGee Oil Industries in Block 32 of Ship Shoal Area, Louisiana

FIGURE **71**
Leasing Activity
in Offshore
Louisiana, Texas,
and West Coast



on November 14, 1947. Initial operations ventured to approximately 50 feet of water depth; however, rapid technological developments have extended drilling to a depth of approximately 500 feet with fixed platforms having been installed in water depths to 285 feet.

The self-contained platforms proved to be expensive, particularly for wildcatting operations. Operators in the Gulf of Mexico soon turned to the experience of those in Lake Maracaibo, Venezuela, and adapted the concept of a floating drilling tender anchored adjacent to a small fixed platform for their drilling programs.

It was logical that the concepts of the extremely successful marsh-type drilling barge would be modified and extended into the open waters. The early mobile drill units consisted of barges with elevated machinery decks and used many methods of stabilization to lower the barge to the bottom of the Gulf of Mexico. This fixed-height mobile drilling unit has been limited to a maximum of approximately 50 feet of water.

The second effort to develop mobile drilling equipment produced a jack-up unit using either individual legs or legs attached to a mat which rested on the bottom. Jack-up types have been designed to operate in water depths as great as 300 feet.

The third class of mobile drill unit to be used in offshore operations is the column-stabilized type, consisting of large diameter vertical columns extending from the hull to the operating deck. These have been built for water depths as great as 145 feet; however, the majority are limited to a maximum of 75 feet.

As operations tended toward deeper water, primarily off the California coast, the industry turned to floating drill units and initially worked with ship-type hulls. These units generally are rated to operate in water depths as great as 600 feet. Because these vessels encountered difficulty in maintaining a reasonably steady platform for drilling operations in heavy seas, the next design was the semisubmersible consisting of vertical columns for flotation stability and submerged the major hull. These units have been built and are rated to operate in up to 600 feet of water.

Figure 71 presents a history of the leasing activities in three major offshore areas of the United States: Louisiana, Texas and the Pacific Coast. The ever increasing rate of land acquisition and the mounting bonus payments are excellent indications of the impact of the above technological developments on offshore activities. Original leasing was limited to shallow water, but leasing extended to deeper locations as technology developed.

Wells drilled by years are presented on Figure 72 which offers a vivid graphical presentation of offshore production. This confidence must be attributed primarily to new technological developments, because labor, materials and leasing costs increased while oil and gas prices remained static.

The history of oil and gas production for offshore Louisiana is presented in Figure 73. Although Texas, California and Alaska are expected to have large growths in production, they compared as follows in 1965:

STATE	CRUDE & CONDENSATE (MILLION BARRELS)	NATURAL & CASINGHEAD GAS (BILLION CUBIC FEET)
Louisiana	199.3	977
Texas	0.5	20
California	19.0	29
Alaska	nil	nil

Even though open ocean operations of the oil industry have been in existence for approximately 18 years, there is still much unexplored potentially productive acreage in the oil provinces lying along the shorelines of the United States. These prospects are awaiting technological development which will make them economically attractive to produce.

SECTION 2—Oceanography

When the oil industry ventured into the open waters of the ocean to build platforms and drill oil wells, it found itself faced with the need for developing a new structural engineering technology. As they searched for design criteria, they turned to the oceanographer and found that he too was faced with developing a new technology. A few oceanographers who had made diligent studies of the subject had far too little information available to give accurate answers to what wave heights, tide levels and wave forces should be used for structural design purposes. Perhaps it was fortunate that in 1949, shortly after the oil industry entered the Gulf of Mexico, a minor hurricane moved across Grand Isle, Louisiana, and caused considerable damage to the then embryonic offshore oil operations, but added materially to the appreciation of the problems, difficulties and necessities of designing for hurricane conditions.

This started a long series of oceanographic studies and research to determine what these design conditions should be. Prior to this time, data had been accumulated on hurricane conditions which existed in Lake Okeechobee in Florida. These data are from an inland body of water of rather limited size and, therefore, while the best available, were of relatively minor value.

In the early stages of operations in the open ocean, Texas Tower #4, a radar station, was installed on George's Bank in the North Atlantic. During the final stages of construction a severe storm gave opportunities to observe the wrath of a storm-tossed ocean.

FIGURE **72**
Wells Drilled
in Offshore Louisiana,
Texas, and West Coast
Including Alaska

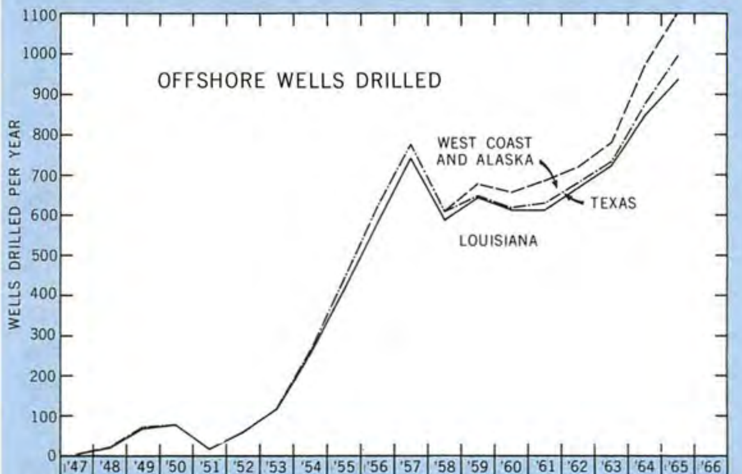
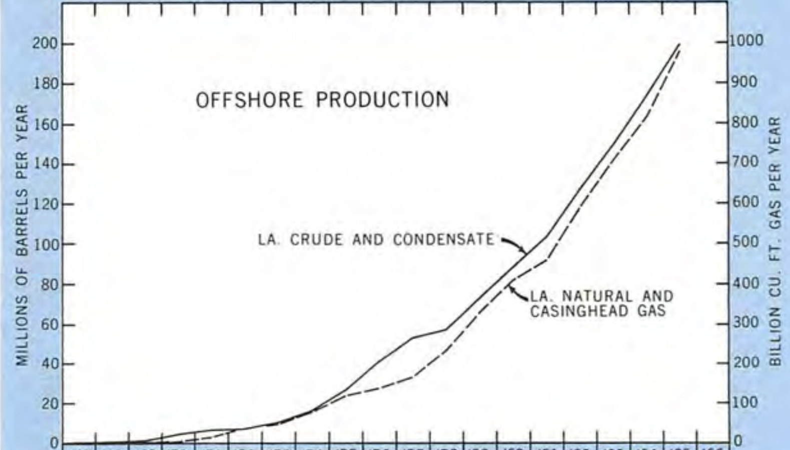


FIGURE **73**
Louisiana Offshore
Oil and Gas Production
(Other States Very Small)



The oil industry has allocated considerable funds and made its facilities available for experimentation to determine the oceanographic principles and data needed for structural design. Some of these projects are as follows:

(1) Humble Oil & Refining Company installation on a pier in 20 feet of water at Galveston Island, Texas.

(2) Texas A & M University installation on Pure Oil Company platform off Pointe Au Fer, Louisiana, sponsored by Bureau of Yards and Docks, measured wave forces and heights in 18 feet of water depth from 1951 to 1952.

(3) Texas A & M University project sponsored by Gulf Oil Corporation located on Mobil Oil Platform off Pointe Au Fer, Louisiana, measured wave heights and wave forces in approximately 30 feet of water depth from 1952 to 1956.

(4) Humble Oil & Refining Company installation on a platform in approximately 55 feet of water depth off Grand Isle, Louisiana. This project measured wave heights and wave forces.

(5) Standard Oil Company of California experimental installation on a platform in Bay Marchand Field, Louisiana. This project was conducted from 1954 to 1958. It measured wave heights and wave forces on four diameters of piling located in approximately 30 feet of water.

(6) Texas A & M University project located on Sun Oil Company pier off Caplan, Texas. This project was sponsored by the Bureau of Yards and Docks in 1954.

(7) Standard Oil Company of California experimental installation in South Timbalier Block 63 Area, Louisiana, in approximately 95 feet of water, measured wave heights and wave forces from 1960 through 1963.

(8) Signal Oil and Gas Company project conducted by the University of California on a pier on the California Coast, 1952 to 1954, measured wave forces and heights.

(9) Humble Oil & Refining Company installation in South Timbalier Area, Louisiana, approximately 65 feet of water depth measured wave heights.

(10) Standard Oil Company of California on El Segundo Pier on the California Coast, 1962 through 1963, measured wave heights.

(11) Standard Oil Company of California wave height measuring installations in Bay Marchand Field, Louisiana, in 20 feet and 30 feet of water depth, and in South Timbalier Block 63 Area, 95 feet of water depth conducted from 1963 through 1965.

(12) Humble Oil & Refining Company, West Delta Area, Louisiana, installation in approximately 190 feet of water measured wave heights and dynamic behavior of platform under storm conditions, conducted in 1965 and 1966.

These installations have measured wave heights, wave periods and wave forces under natural environmental conditions on a number of different diameters of piling during storms and have provided the most valuable data currently available in this field of physical oceanography. These very expensive research efforts have cost in excess of $2,000,000.

Data from these projects have been used to improve the forecasting accuracy of wave heights and to develop wave force calculation procedures. These data plus a need for better weather predictions for offshore operations have contributed to many theoretical studies in the field of meteorology, wave height prediction and wave physics. These studies, sponsored by the oil industry, have brought about major technological advances.

One project sponsored by the American Petroleum Institute and conducted by Dr. Herbert Riehl developed the first method of predicting the development of a hurricane. The science of predicting their paths has also been improved; however, present methods still leave considerable uncertainty.

A major oceanographic study is currently in progress. This Naval research project is installed on Argus Island in the Atlantic Ocean and is located in the path of hurricane storms, as well as North Atlantic winter storms. It should provide very valuable information at an early date.

There is still considerable technology to be developed in the area of oceanography and meteorology. This can best be pointed out by the fact that two very competent oceanographers have estimated maximum waves heights which can be developed by hurricanes in very deep water in the Gulf of Mexico; one estimates 60 feet and the other estimates 100 feet. While the spread in height in these waves will be reduced as they approach the shoreline, they still present drastically different design factors for structures in water depths greater than 100 feet. One of the major problems encountered in obtaining information is the maintenance of instrumentation in the open ocean during hurricanes. Normally, these installations are unmanned, and in Hurricane Betsy in 1965, four installations of wave height measuring equipment were in operation; however, not one of these installations obtained complete records of the waves.

As in all new areas of activity, the technologists had difficulty in establishing a common ground of communication which would permit the oceanographer to supply the structural engineer with the information which he needed. Many of the early reports were limited to isolated locations and did not consider the potential severity of storms which had been encountered by adjacent areas.

SECTION 3—Platforms

A. Platform Design

With the advent of offshore oil drilling and producing operations, the structural designer was confronted with the problem of installing platforms in the ocean; previous marine structures had been in protected areas of harbors, bays and lakes. The original platforms were timber and steel piling pier. These quickly gave way to what is known as the template platform, a unit which consists of a number of vertical tubes interlaced or trussed by horizontal and diagonal members. The truss extends from the mud line to a location above the water plane (Figure 74). Pilings are driven through the vertical tubes and the deck is placed above the pilings. Many variations of this configuration, originally proposed by Mr. M. B. Willie of J. Ray McDermott & Company, have been used in the Gulf of Mexico.

The original platforms consisted of a great number of steel tubular piling as small as 10¾" diameter and were located in water depths less than 50 feet. As technology has improved and operational water depths have increased to 285 feet, the numbers of piling per platform have decreased and their diameters enlarged up to 48 inches, and soil penetration to 300 feet.

In early designs insufficient consideration was given to some of the major design problems, such as joint design and lateral pile loading. In these designs, the structures were often considered to be pin-connected truss units with the piling pin connected at some arbitrarily selected distance below the mud line. As the structures were primarily installed in water depths of 50 feet and less, these rather arbitrary and inaccurate assumptions have produced suprisingly successful platforms. Experience with major storm waves and the damaging effects of landing boats and barges adjacent to the platforms proved that some of the designs were inadequate. As technology and research progressed, even these design methods proved to be as accurate as the available design criteria.

A problem which attracted major attention was that of lateral load distribution into the soil from the piling supporting the platform. A number of experimental installations of instrumented piling, both in the Gulf of Mexico and in soft soil locations on shore, provided data for analysis of the problem. This was supplemented by many theoretical studies by university faculty members and consultants which have materially improved the technology of design in this area.

A second area of interest which was slower in developing is that of joint design as related to the joining of tubular members into a truss frame. While some research was conducted by oil companies as early as 1958 to 1960, detailed programs of joint design research have been instigated only in the past few years. Research projects currently in progress are carefully planned and technological progress in this field should be rapid.

With offshore operations moving into deeper water, thereby presenting more complex structural design problems, the more competent design engineering offices today are using digital computers for the structural analysis of oil well drilling and producing platforms. Many variations of computer programs for loading, analysis, and design are being used; however, there is considerable similarity in the programs and objectives.

Shortly after the advent of development drilling operations on the California Coast, a new type of platform was introduced and, for purposes of identification, will be termed the tilt-up platform (Figure 75). It is moved to location by flotation of very large legs in a horizontal position, then tilted to a vertical position by flooding the legs in the

FIGURE **74.** Launch Barge in Operation, West Delta Block 104, Louisiana

FIGURE **75.** Tilt-up Platform in Process of Being Erected

process of installation. This platform has found favor in California coastal operations and in Cook Inlet in Alaska. Use of the tilt-up configuration is particularly attractive in Cook Inlet where platform legs must be made large to resist ice and provide protection for wells located inside the legs.

At three locations off the California coastline, operators have chosen to use rock-filled islands (Figure 76). These are built up of crushed rock with extremely heavy capping stones or special cast concrete blocks termed tetrapods. These three islands are located within three miles of the coastline and this fact may account for the operator's choice of method and materials of construction.

Other types of islands or piers have been used, but have not gained great favor with the oil industry and, therefore, are not discussed.

The original platforms were installed with available derrick barges and marine equipment. These soon proved to be inadequate for the task at hand, particularly in locations remote to shoreline and harbor protection. Today, a number of derricks with lift capacities of 250 tons placed aboard barges 90 feet in width by 300 feet in length are available for open ocean oil operations. The most recent innovation in this respect is the enlargement of the barges to 100 feet in width and 400 feet in length and the escalation to cranes with lift capacities of 500 tons (Figure 77).

This construction equipment also has its attendant utility craft, consisting of tug boats up to 3,000 horsepower and cargo barges. Launching barges up to 300 feet in length have been developed for template type of construction (Figure 74). These barges have dimensions up to 90 feet in width and 300 feet in length and are equipped with launching rails upon which the templates are mounted for transportation to the installation location where they are launched off the end of the barge in much the same manner as the end launching of a ship. After they are in the water, the templates are upended by the derrick barges and placed on bottom in the required location.

The technology of offshore construction has kept pace with the requirements of the petroleum industry. As one example, some of the very largest pile-driving hammers in the world are currently being used because they are particularly adaptable to the problems associated with platform installation.

The technological developments of the past years of offshore operation have placed the industry in a position to install offshore drilling and producing platforms in any water depths where it is economically feasible to produce oil or gas. The economical operating water depth was increased and will continue to increase with developing technology.

B. Self-Contained Platform

The self-contained platform (Figure 78), that is, one containing all of the necessary materials and equipment for drilling as well as personnel housing, was selected for the initial drilling operations and has continued to be a well-accepted method of drilling prolific proven areas.

This platform places all materials, supplies and

FIGURE **76.** Rock-Filled Island with Two Drilling Rigs

FIGURE **77**
500-Ton Derrick Barge.
Barge is 100' X 400'.
Pipe Line-Laying Ramp and Equipment in Foreground

personnel on a fixed island in a compact, well-organized manner which provides the most idealized arrangement for drilling purposes. No doubt, all operations in the offshore industry would be conducted from self-contained platforms if costs could be disregarded. If a great number of wells are to be drilled from a single location, the lower daily drilling costs of a self-contained platform will pay for the added structural costs invested before drilling operations commence. The uncertainties of geological prognostication of the complicated subsurface structures of most oil fields make it very difficult to forecast with any degree of certainty that 10 or more wells can be drilled from a single location. This fact is the greatest deterrent to the use of self-contained platforms.

A current version, often termed minimum self-contained platform, reduces the storage area and housing spaces to lower platform costs. These platforms have been accepted for development drilling after exploratory programs have determined that no major drilling problems exist, such as high pressure. Some operators have expressed the opinon that they will enlarge future platforms because they have found their current versions to be too small for efficient operation.

The self-contained platform has maintained a position of prominence in offshore operations, and there are approximately 35 drilling operations currently in the offshore waters of the United States.

SECTION 4—Tenders

A. Platform Tender Operations

In the early stages of oil industry operations in open Gulf waters an effort was made to reduce platform cost by the use of a floating drill tender to support supplies, machinery, and personnel, thereby reducing the size of the fixed platform (Figure 79). This combination was a logical adaptation from operations which had been conducted in Lake Maracaibo, Venezuela, for a number of years. While the weather conditions and anchorage problems of the drill tenders in Lake Maracaibo were minor compared to the open Gulf, the necessary changes were made and drill tenders found their way into Texas and Louisiana Gulf Coast waters.

The first drill tenders were converted from available war surplus vessels. These were primarily the YF barge, measuring 48 feet in width by 260 feet in length, and the LST, which is 50 feet in width and 328 feet in length. The vessel is anchored adjacent

FIGURE **78.** Self-Contained Drilling Platform "B," West Delta Block 133, Louisiana, 285' Water

FIGURE **79.** Tender-Platform, Equipped with 2 Drill Rigs and 2 Completion Rigs

to the drilling platform by six to eight anchor lines, depending upon the pattern selected by the operator. The utilization of the drill tender varies considerably with the operator involved; however, the general plan is as follows: (1) storage of pipe; (2) storage of mud materials; (3) storage of liquid mud; (4) storage of drill water; (5) storage of diesel oil; and (6) a hotel accommodation for personnel.

The use of these vessels reduced the loads to be supported by the fixed platform and the degree of reduction again varied with the drilling operator. In some cases, the platforms were reduced to a size which would support only the derrick, drawworks, a small mud pump and a single well. In other cases, they have been expanded to accommodate a pipe rack, mud-pumping facilities, production equipment and as many as 24 wells.

There are approximately 30 drilling tenders in operation in the coastal waters of the United States. While most of these tenders were converted or constructed prior to 1960, there is a continued interest in the use of these vessels, particularly in the Gulf of Mexico. The complicated fault patterns and small oil reservoirs of piercement salt dome geological structures seem to be particularly adaptable to this operation.

SECTION 5—Drilling

A. Innovations in Drilling Operations

The challenges of cost of drilling platforms and daily drilling operations have caused offshore engineers to develop many new items of equipment. For instance, the first multiple-well derrick was designed for an offshore location. Derricks have been constructed to accommodate 2, 4, 6 or 25 wells within the confines of the derrick floor. These multiple-well derricks maximize utilization of the platform space by placing the wells close together and minimize rig-up time between locations. The 25-well derrick was equipped with two drilling rigs which operate simultaneously.

Another innovation using the six-well derrick is the installation of a completion rig consisting of a small mud pump and a small drawworks to take over the completion operations after the drilling and the setting of oil string casing. This method has saved from 25-50 percent of the time required to drill and complete a well and added relatively little to daily operating cost.

Dual rigs were first installed on a platform in September, 1949, in the Bay Marchand Field off the Louisiana Coast. Seven 10-well platforms in this field were equipped with dual rigs between 1949 and 1957. In the West Delta 30 Field off the Louisiana Coast, two 12-well platforms were equipped with dual rigs during the years of 1956-1958. Again, in Bay Marchand in the years of 1959 to 1962, two 24-well platforms were equipped for dual rigs, each rig used a six-well derrick and each derrick was equipped with a completion rig (Figure 79). Four rig operations were conducted at one time on these platforms. All of the above dual rig operations were conducted on tender platforms using a single LST drill tender. In 1965 and 1966, dual rig operations on self-contained platforms were conducted in West Delta Block 73 Field off the Louisiana Coast on three 24-well platforms.

All of these dual rig operations have reduced

FIGURE **80**
Mat-Supported Jack-Up
Drilling Unit

FIGURE **81.** 250′ Water
Depth, Leg-Supported Jack-Up
Mobile Drilling Unit

drilling and platform costs. Continuing innovations will make it possible to economically drill and produce oil from deeper water locations and less prolific fields.

B. Mobile Drill Units

As oil and gas producing operations moved from the bays and marshes of South Louisiana and Texas into the offshore operations of the Gulf of Mexico, it was logical that the highly successful marsh drill barge would be a pattern for a new species of mobile drilling equipment.[1] The initial adaptation of mobile drilling equipment for the open sea consisted of a barge with an elevated deck to support drilling machinery, supplies, and personnel. These barges used various methods to maintain vertical stability while being lowered to the sea bed. In general, these units have been limited to use in less than 50 feet of water.

As operators extended mobile units to water depths beyond the 50 feet contour, the jack-up drill barge came into being. This barge consists of legs which extend from the flotation element into the ocean bottom with a jacking system to raise the flotation element above the water surface, or of legs attached to a mat which extends to the ocean bottom and a flotation element which is jacked clear of the water surface (Figure 80). This barge has many variations; some have as many as ten individual supporting legs, others as few as three. Some use individual mat supports on each leg and in other instances a mat is attached rigidly to all of the legs. On some of the more recent designs the legs have been tilted outward to give an increase in the base dimension at the mud line and create structural stability for the greater water depth (Figure 81). Jack-up drilling units have been constructed with rated operating water depths as great as 300 feet. Many units for water depths of 100 feet and greater have been fabricated in the past few years and some are currently under construction.

Concurrently with the jack-up drill barge, the bottom setting column-stabilized unit was developed, which consists of a lower mat attached to an upper deck by large diameter tubular members (Figure 82). The column diameters vary up to 30 feet and the units have rated operating water depths up to 175 feet. However, the majority of these rigs are limited to approximately 70 feet of operating water depth. Their greatest attribute lies in the simplicity of their raising and lowering system.

After the mobile units drilled wells which could be completed for the production of oil or gas, the wells needed individual support to protect them from the ravages of the sea. The initial wells drilled in relatively shallow water were protected by large diameter tubular members (caissons) which were driven directly into the ocean bottom in water depths as great as 100 feet (Figure 83). These caissons will adequately support the well, but provide little space for the normal daily production procedures. Another support mechanism consisting of three and four pile towers has been developed to provide the necessary

1. Howe, Richard J., "Evolution of Offshore Mobile Drilling Units," *Offshore*, March, April, May, 1966.
Macey, Robert H., "Mobile Drilling Platforms," *Jour. Pet. Tech.*, SPE, Sept. 1966.

FIGURE **82.** Column-Stabilized Drilling Unit. Designed to be Semisubmersible Unit Beyond 175' Water Depth

FIGURE **83** Caisson-Supported Oil Well

structural support and operating platform for these wells (Figure 84). In some cases, to obtain the economy of initial construction and production operations, these wells have been clustered in groups of two to four and the support mechanism altered accordingly. The pile structures for these wells have followed the template pattern in the Gulf of Mexico.

Mobile drilling units were initially considered to be a wildcatting tool. They reduced the initial investment required to determine the existence of oil or gas deposits by providing mobility for wildcat wells. This was often followed by the installation of a fixed platform for either self-contained operation or to be used with a drilling tender. They were also found to be extremely valuable tools to drill step-out wells to extend known producing areas. As experience with these units was accumulated, they were used successfully and economically to develop complete oil fields. This is particularly true of small fields and shallow water locations. Another valuable application of these tools is to the drilling of fill-in or final development wells. After multiple well platform drilling has been accomplished, a few additional wells can be added by these units at minimum cost.

C. Floating Drilling Vessels

Coring vessels were developed in about 1953 as a part of the exploratory operations off the California Coast. The objective of these vessels was to take core samples from the upper strata so that geological formations could be identified. All of these early vessels were of the barge or ship hull shape and at this early stage, were used primarily in the Santa Barbara Channel, California. However, floating drilling vessels were used in the Gulf of Mexico to drill sulfur tests in approximately the same period.

The success with these coring vessels caused operators to extend their coring depth, and in 1956, the first full-scale center well drilling vessel, Cuss #1, was constructed. Following this initial success with shallow coring and the first center well drilling vessel, a series of floating drilling ships and barges were constructed for use in the offshore waters of California and the Gulf of Mexico and were later extended to Cook Inlet in Alaska. Most of these drilling vessels were equipped for center well drilling operations, with the derrick located amid ship and the drill pipe lowered through a hole in the center of of the vessel. A few vessels were constructed with an arrangement for drilling over the side; however, these did not prove to be as successful as the center well arrangement and very few are in use today. These vessels have varied in size from 260 feet by 48 feet for the initial full-scale drilling vessel to 380 feet by 64 feet and 365 feet by 75 feet (Figure 85). Their anchorage patterns and abilities to orient into prevailing seas vary considerably.

On the Cuss #1 and a few of the subsequent vessels, specialized drill pipe, casing, and tubing handling equipment were installed. This specialized equipment was arranged to control the motion of these tubular materials with respect to the vessel as it rolled and pitched in the rough waters of the open ocean. The devices are very ingenious and have made possible the handling of these tubular materials when other floating vessels have been forced to suspend operations.

One operator decided to use a catamaran vessel to increase beam width and thereby reduce roll and increase storage and work area. Two catamaran vessels have been constructed with the drilling operation being conducted through the center area between the twin hulls. These vessels are somewhat more stable than the single hull vessel, but still experience difficulty with vessel motion under adverse sea conditions.

The primary use of these floating vessels has been to drill wildcat wells. However, they have completed a few submarine wells off the California Coast.

D. Semisubmersible Floating Drilling Vessels

Faced with the problem of exploratory drilling on leases in the Gulf of Mexico in water depths in excess of 300 feet, Shell Oil Company designed a floating vessel which would provide a steadier drilling platform than the ship or barge hull. They selected a column-stabilized mobile drilling unit, Blue Water #1, for conversion to a floating drilling unit. By maintaining a draft of 30 to 40 feet with only the

FIGURE **84**
Four Well-Satellite Platform Drilled by a Mobile Drilling Unit

vertical columns in the water surface plane the unit provided an extremely steady platform from which to conduct drilling operations.

This unit was equipped with eight cable anchor lines 3 inches in diameter by 3,000 feet long attached to 20,000-pound anchors. These cables terminated on spring buoys from which special multipart smaller anchor lines were extended to anchor winches located on the deck of the vessel.

This special floating vessel proved to be a very successful drilling platform for water depths of 100 feet to in excess of 300 feet and opened the door to the development of an entirely new class of drilling vessels. The design was enhanced materially by research and development work conducted by Shell Oil Company.

Ocean Drilling and Exploration Company followed the path of a semisubmersible unit with the "Ocean Driller" which varied considerably in the hull configuration and flotational columns. It was placed in operation in 1963 and has been followed by a number of vessels, each varying from the last, with the variations being generated by operating experience.

A third vintage of semisubmersible drilling platforms was initiated by Southeastern Drilling Company with "Sedco 135" (Figure 86) which was placed in operation in 1965; however, it was initially used as a bottom-supported drilling platform. This class is triangular in shape with three main stability columns located on the corners of the triangle. One of its primary features is the placement of barges under the individual legs as the bottom portion or footing of the columns. These barges have sufficient displacement to float the entire rig and are formed in a manner to enhance the towing characteristics of the vessel. This vessel had led to the fabrication of a number of drilling units of the same general design.

The primary use of these rigs is to drill in water depths in excess of 150 feet, and they are generally classed as being capable of drilling in water depths of 600 feet. At the present time, there are more than 15 of these semisubmersible rigs in operation or in process of fabrication. Approximately seven are either operating in or scheduled for the offshore waters of the United States. These vessels have been used for exploratory drilling and have generally used submarine wellhead and casing hanger equipment. When they were drilling from a floating position these rigs had not been used to complete oil or gas wells, which indicates that an economically competitive technique has not been developed. These units are attracting worldwide attention for exploratory drilling even though they have never completed an oil or gas well; however, some wells have suspended operations on bottom in a manner which will permit their being completed from platforms at a later date.

These vessels have been equipped with some of the heaviest anchoring systems in use in offshore operations today. The specially designed anchors weigh up to 30,000 pounds, have anchor lines that consist of both cable and/or chain and extend to lengths as great as 5,000 feet. The distance across

FIGURE **85.** Floating Drilling Vessel on Location. Vessel is Equipped with Mechanical Pipe-Handling Devices

FIGURE **86** "Sedco 135" on Drilling Location in Gulf of Mexico

an anchor pattern is as great as two and a quarter miles. These anchorage systems emphasize the difficulty of drilling and production operations in extremely deep water.

E. Subsea Wellheads and Completions

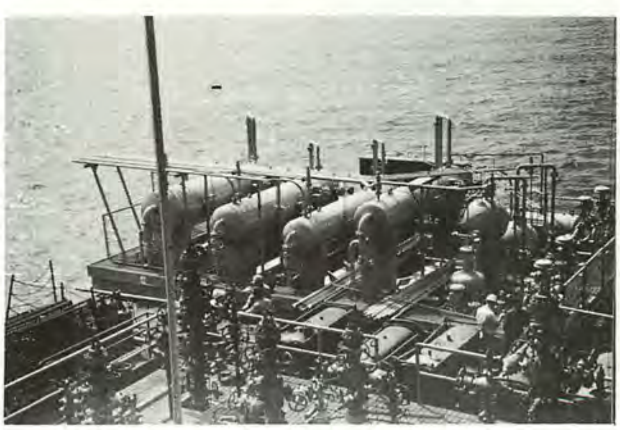
The high cost of platforms caused operators to develop interest in the possibility of submarine completion of oil and gas wells. These early interests were related to water depths in excess of 100 feet. The first efforts were directed to the development of wellhead equipment with which to drill core holes off the California Coast, with little thought given to the possibility of completing oil and gas wells. However, beginning about 1956, operators and equipment manufacturers started engineering designs and developmental work directed toward the production of oil and gas wells from ocean bottom completions. Oil and gas producing wells have been primarily limited to the California coastline where the wells are less than three nautical miles from the beach, some in water depths approaching 240 feet, and are permitted to flow to shore. In the Louisiana and Texas Gulf Coast areas all work has been limited to experimental ventures conducted either in rather shallow water (60 feet or less) or on land under simulated conditions.

All of the currently producing wells off the coast of California were completed prior to or in the year of 1963. The lack of completion of producing wells by submarine methods in the last two or more years indicates that the technology has not developed competitive methods of drilling and producing oil and gas wells. Much effort is being expended on this problem and improvement may make this method of production economically competitive as water depths increase and technology improves.

Even though the submarine well has not been used as a development technique for general application, submarine wellheads and preventer assemblies have been used extensively in the drilling of wildcat and exploratory wells. They have proven to be an extremely valuable and very economical method of locating oil and gas fields in deep water.

The last five years have seen extensive development in the technology of deep diving and the accommodation of men in submarine housing for periods of up to four weeks. While these methods have found relatively few applications in oil drilling and producing operations, they may be the key to underwater completion of oil and gas fields. We have also witnessed the development of small submarines which could be used for transport of personnel and small equipment. Application of this technology to oil and gas operations is being studied and adaptations will probably be made. Many conceptual ideas have been advanced and some show promise of being practical.

FIGURE **87.** Producing Facilities on Offshore Platform



SECTION 6—Production Methods

As oil discoveries were made in offshore waters, the first production systems consisted of minimum producing facilities placed on the platforms, sometimes including small oil storage tanks but often using floating barges for the initial oil storage. These temporary facilities gave an opportunity to test the original discovery well and to drill a few additional wells to determine that adequate oil reserve existed. Early operations in the Gulf of Mexico proved the value of multiple well platforms which permitted the concentration of a number of wells at one location for producing and testing.

Some of these multiple well platforms have become very sophisticated producing units (Figure 87). They are called upon to provide space for oil and gas separation, water and oil separation, testing facilities for wells, pipeline pumping facilities, gas compressors, water flood systems, rig equipment for remedial work on the wells and possibly housing facilities for personnel to operate the equipment. A platform which contains many of these items more nearly resembles a process plant than a producing oil field.

In some fields which have been developed by a combination of multiple well platforms and mobile drill units, the multiple well platforms also provide producing facilities for the wells drilled. These wells are often termed satellites (Figure 85), as they are dependent upon the multiwell platform for their operations. Flowlines are laid from the satellite wells to the multiwell platform. Where all drilling is performed by mobile units, a central producing platform is provided where the above-described attendant services are accomplished.

Oil producing operations offshore have required artificial lift. The limited space of the platforms and the very close spacing of wells combined with the necessity of installing rigs for remedial work on the wells have precluded consideration of beam pumping units, and limited artificial lift to either gas lift or hydraulic pumping. In the Texas-Louisiana Gulf Coast area gas lift has been used; however, on the California Coast some hydraulic pumps have been installed. Either system can be used quite satisfactorily within the limited space available.

A number of water injection pressure maintenance systems have been installed at offshore locations using either water produced from subsurface formations or sea water. Treatment processes for injected water have varied from very simple desanding equipment to extremely elaborate water purification plants which will produce water with a much lower turbidity than the average city water supply. This water is injected into the wells at pressures up to 3,000 pounds per square inch and if pressure maintenance is adequate, artificial lift can be minimized.

The transportation of offshore oil to market again presents a very unique and sometimes quite perplexing problem. Only two transportation systems have been used, barges and pipelines. A third system using extremely large volume salt cavity oil storage and tanker loading facilities has been discussed many times but has not been considered practical or economical.

Offshore storage of the oil is required for any transportation system; however, the amount of storage required can change materially depending upon the methods of transportation. Storage facilities have been placed on drilling platforms to accumulate minimum volumes of oil for barge transportation. Even when these storage facilities are placed on platforms that were originally constructed to support drilling machinery and supplies, they are very expensive on a per barrel basis and volume is limited. As a result, operators have looked for other methods of storing crude oil. In the early stages of operations in the Gulf of Mexico, a number of attempts were made to anchor barges in the vicinity of the platform to provide oil storage tanks. These anchorage systems have proven to be quite hazardous and difficult to maintain; however, one installation consisting of an anchored carrousel buoy and a 15,000-barrel oil storage barge has been in operation in the Gulf of Mexico for approximately three years and has presented no major problems. It has stayed in place during severe winter weather; however, the operator has chosen to move the barge to sheltered waters during hurricanes.

Many proposals for the installation of storage tanks resting on the bottom of the sea have been made with the objective of reducing installation and operating costs (Figure 88). Five of these storage facilities have been installed in the Gulf of Mexico off the coast of Louisiana consisting of 10- to 30-thousand barrel capacity units with four located in relatively shallow water. A few other smaller storage facilities are located in water depths less than 10 feet and in bays where they receive some protection from hurricane wind and waves.

The use of rubber pillow-shaped small-volume containers for the storage of crude oil has been proposed. One installation made in the Gulf of Mexico experienced partial failure of its supporting system, even though it did not encounter a tropical storm approaching hurricane proportions.

One of the above submarine storage units has a tubular toroidal-shaped tank placed on bottom in the Gulf of Mexico in 130 feet of water with structural members extending above the water surface to support a small tank (Figure 89). This unit has been in operation for a relatively short

FIGURE **88.** 20,000 Bbl. Submarine Oil Storage and Producing Facilities Under Tow to Location

FIGURE **89.** 30,000 Bbl. Crude Oil Storage Structure. The Structure Incorporates Two Storage Sections: A Ring-like Submerged Tank, Resting on the Bottom at a Depth of 131', and a 45'-Diameter, 53'-High Tank Above the Water.

period; however, it demonstrates the technological advances which are assisting the oil industry to move into deeper water.

Many of the major offshore oil fields have pipelines connecting them to shore terminals. These pipelines may transport oil and water to shore where the final separation is performed. The use of pipelines can reduce the volume of offshore storage to a small surge tank for the automatic operation of pumps. Some very ingenious systems have been developed which automatically handle the oil at the rate it is produced. The oil is either flowed from the individual platforms to a central producing and pumping facility in the field or pipeline pumps are installed on individual multiple well platforms. In both cases, the operation is carried on as a continuous flow process. Offshore pipelines have proven to be the most successful and economical means of transportation where daily producing volumes and reserves can justify their installation cost.

A very ingenious method of placing pipelines in offshore locations has been developed.[2] The pipe is spooled onto a 40-foot diameter drum at an inland terminal (Figure 90). This drum is located on the deck of a seagoing barge which is towed to the location where the pipe is unreeled onto the sea bottom with a minimum offshore exposure to weather. Pipelines up to six inches in diameter have been handled in this manner and equipment for larger diameters is under development.

In a few locations, it has been possible to lay flowlines from the individual oil wells to the shore and to install all producing facilities onshore. These are rather unusual cases and limited to the very few wells which are located immediately adjacent to the beach.

Offshore gas field operations have followed the same pattern as offshore oil fields; in deeper water they have often been drilled on multiwell platforms. In some shallow water fields individual wells or groups of two to four wells have been drilled with model drill units and produced to a central separation and dehydration facility.

The primary producing problem related to offshore gas wells is the prevention of hydrates before dehydration can be accomplished. In some cases it is possible to flow wells at wellhead pressure to central facilities by burying flowlines into the sea bottom and insulating all underwater piping. Even in these cases it is often necessary to provide some type of hydrate inhibitor during start-up operations until reservoir heat can be brought to the surface by the flow stream. In other cases a hydrate inhibitor must be injected on a continuous basis or individual wellhead dehydration must be provided. Continuous inhibitor injection has been accomplished either by storing the inhibitor at the individual well and pumping it in from this location, or by placing a small diameter (less than one inch) pipeline from a central producing facility to the well. This latter method has proved to be more successful.

The few submarine completed gas wells located less than three nautical miles off the California Coast have been flowed to shore facilities through individual or multiple well flowlines. This method is not generally applicable to gas field development in locations a great distance from the shoreline.

In some instances the producer transports the gas to a shore base and delivers to the purchaser at this point, and in other instances, the purchaser builds a pipeline to the field. Regardless of the method used, the gas must be dehydrated in the field before it is transported through a long pipeline as the temperature at the ocean bottom is low enough to induce the formation of hydrate ice. Occasionally, the liquid hydrocarbons produced with the gas are dehydrated in the field and recombined with the gas to flow to a processing plant on the shore.

2. *Oil & Gas Jour.*, May 7, 1962.

FIGURE **90.** Pipeline Reel Barge Laying 4" Pipeline

FIGURE **91.** 48 Passenger, 100', Twin Screw Crew Boat

Both oil and gas wells require servicing by wireline tools, and a system of small jack-up barges and special floating units has been developed for the shallower water locations. These units are particularly applicable to mobile unit drilled locations as wireline tools are permanently located on the multiple well platforms. Considerable engineering effort is being expended on the development of units for deeper water locations.

As in all other industries, automation is being utilized in offshore producing operations. These automatic systems vary from very simple engine control systems to complex computer programmed production testing and individual well product allocation. Some of these systems are quite sophisticated and operators are discussing the possibility of controlling an entire field from a shore base.

SECTION 7—Transportation and Logistics

Offshore oil and gas operations presented a new problem of logistics to the industry and, as surprising as it may seem, to the marine transportation industry. One of the unique problems related to offshore oil and gas operations is the fact that vessels had not been docked in the open ocean for the transfer of personnel or cargo. There were no suitable vessels available for this unique transportation assignment. As the operations started shortly after World War II, a number of war surplus vessels found their way into offshore transportation. Among these were the wood hull air-sea rescue boats which were used for personnel transportation and the LCT which was used for cargo transportation.

The wood hull boats of the air-sea rescue type proved to be completely unsatisfactory, as they were too fragile to land alongside the steel platforms and drill tenders. Personnel transport made a rapid change to steel hull fishing boats and eventually to a series of steel hull water buses (Figure 91). These steel hull personnel transport boats vary in length from 35 feet to approximately 100 feet, depending upon the remoteness of the drilling location from the last sheltered water. This can exceed 100 miles in some locations which requires an extremely seaworthy and rugged boat. These crew transport boats must remain on location at all times when crews are in the field, as they provide a means of rescue and transport of injured personnel, as well as the transportation for personnel from platform to platform within the field.

The helicopter was an early competitor for the personnel transport assignment (Figure 92). The comparatively high speed of the helicopter, its ability to land on a very small area, and its ability to operate when the seas are 12 to 15 feet, or even 20 feet, in height has made it an extremely valuable personnel transport vehicle for offshore oil operations. Of course, it has its own limitations, based primarily upon weather conditions, such as low ceiling clouds, fog and extremely high winds. Today it is quite common to use a combination of crewboats and helicopters to transport personnel.

As the first rigs ventured into the offshore operation, it was quite natural to expect the cargo barges which had been used extensively in onshore marine operations to be extended to the offshore. These tugboat and barge operations proved to be quite cumbersome, unwieldy and dangerous. As a result, the war surplus LCT was pressed into service and served well on the shallow water locations close to the shoreline, but could hardly be considered a seaworthy vessel for remote and deeper water locations. This self-propelled barge did prove to be the pattern for the most satisfactory cargo vessels in operation in the offshore oil and gas industry today. These vessels are 125 to 165 feet in length, with a beam of 30 to 35 feet (Figure 93.)

The vessels are equipped with cabin and pilot

FIGURE **92.** Sikorsky S-62 Jet-Powered Helicopter on Offshore Heliport

FIGURE **93.** Cargo Boat for Offshore Drilling Rig

house in the bow with a flat deck aft to provide space for the loading of long length drill pipe, oil well casing and tubing, as well as other cargo. Most cargo, except drilling water and potable water, is carried on the deck. These boats have proved to be extremely valuable for the transport of drilling materials and supplies.

This cargo boat has also been adapted to accommodate pressure tanks for the transport of dry cement and powdered mud materials. These items are placed in pressure tanks which are built into the hull and equipped to air convey the materials through hoses and pipelines to an elevation of 50 to 75 feet above the boat deck.

After drilling operations are completed, a workboat is needed which can transport personnel and smaller items of materials and equipment from platform to platform and from shore base to the field. The primary transportation of personnel from the base to the field is still accomplished by the crewboats and helicopters. The workboat has generally developed as a smaller version of the cargo boat which is used for drilling operations. It has a rather large afterdeck area which is available for the transport of materials and supplies required for the production operations, with the cabin and pilot house located forward. Their arrangement and size vary from owner to owner and operator to operator, but they all follow the general pattern described above.

Recently offshore operations have moved into rough, open ocean areas, such as the Pacific Northwest. For such areas, the problem of material and personnel transfer between boats and platforms or drilling vessels has become much more critical, and still awaits satisfactory solution.

SECTION 8—Workover and Servicing Rigs

Inevitably, it becomes necessary to do remedial work on the producing wells. This requires reasonably

FIGURE **94**
Hydraulic
Snubbing Unit
in Operation

heavy equipment, which presents a problem, as it must be located on a platform deck 35 to 50 feet above the water. This problem becomes more perplexing when it is realized that a well must either be left shut in, thereby losing production, or that this equipment must be moved onto the platform, at a considerable cost, for the purpose of performing a short duration task on a single well. This problem has been handled by accumulating two or more wells before remedial procedures are started. New remedial work rigs are being developed along the same principles as the helicopter-lift drilling rigs. The units are packaged for installation by light lift capacity cranes, which are placed permanently on the platforms.

In addition to the packaged units, ingenious methods are being developed to permit working inside the flow tubing with 1 inch or 1¼ inch tubing which can easily be moved onto the platform with small cranes (Figure 94). By the development of special completion techniques, many of the remedial work jobs that were originally allocated to heavier rigs can be accomplished with these small tubing units.

Remedial work on wells drilled by mobile drilling units presents another problem which was originally solved by using the unit which drilled the well. High daily cost encouraged operators and contractors to look for less expensive yet adequate equipment. In 1965, the mobile unit, Hustler (Figure 95), was constructed and equipped to handle deep well remedial work. This particular mobile unit also has the advantage of being able to cantilever its derrick equipment over the wells on a multiple well platform and perform remedial work. It has also skidded the derrick and drawworks onto the multiple well drilling platform to perform operations which could not be reached by cantilevering. This very versatile unit should point the way for many additional mobile workover rigs.

FIGURE **95**
Jack-Up, Workover Rig at Caisson Supported Well

CHAPTER SIX—TRANSPORTATION (Crude Oil and Liquid Products)

SECTION 1—Oil Pipelines—Design and Construction

F. B. Neptune

A. The Trend to Larger Diameter Pipe

On October 7, 1865, crude oil began to move a distance of five miles from Pithole to Miller's Farm, Pennsylvania, through a 2″ wrought iron, lap-welded, threaded and coupled line, reducing the transportation cost from $3 to $1 a barrel. This initial success started a boom in construction of short local lines ranging from 2″ to 6″ in diameter.[1]

In the early 1930's the first long liquid petroleum products pipeline, an 8″ line, 1,000 miles in length, was engineered and constructed.

The first "big inch" oil line, 24″ in diameter, was constructed in 1941 to offset wartime tanker losses in the movement of vital crude oil supplies from the Gulf Coast to the Eastern Seaboard.

Liquid petroleum pipelining was advanced to its present maximum of pipe size, length of system, and capital outlay with the completion in 1963 of the 2,600 mile Colonial Products System. This system

1. From "Statement of Views of the API Central Committee on Pipe Line Transportation of the American Petroleum Institute," March 31, 1966.

included 1,046 miles of 36" thin-wall, high-strength line pipe. The outstanding technical success of the Colonial System is deemed adequate proof that the limits on liquid pipeline size will be established by the economics of market demand and horsepower requirements rather than the nature of the product to be transported.

1. USE OF HIGHER STRENGTH STEEL

The tremendous growth of the pipeline industry in the past 20 years has forced rapid development in the technology of making and laying line pipe of steadily increasing diameter and strength. Pipe, while it represents staggering outlays of capital, will be available as the demand requires. The technology of welding, laying and producing these advanced pipelines is already at hand.

There is no doubt that future problems attendant to the use of higher strength steels will arise and will be resolved so as to produce safe, serviceable and economic installations.

Perhaps the overriding limitation to progress toward higher pressure pipelines, liquid or gas, lies in the art and science of metallurgy itself. The steel to meet the strength requirements can be produced now. The available steels are unfortunately not immune to environmental deterioration, either from the product within or the soil outside. More sophisticated alloys may bring some answers, although the cost squeeze fairly effectively blocks progress in this direction. A basic change from dependence upon steel chemistry, in the present-day, hot-finished product, to control of mechanical properties by heat treatment using relatively lean chemistry steels appears to be the more promising route.

API Standard 5 LX, "High Test Line Pipe," was first issued in 1947. Chemistry, mechanical properties and methods of manufacturing and testing of high-strength line pipe became standardized. The yield strength of pipe covered by API 5 LX first ranged from 42,000 psi to 52,000 psi. Progressive advancement upward in yield strength was rapid at first, leveled off for a brief period at 60,000 psi minimum yield strength, and is now being advanced to 65,000 psi minimum yield strength.

With the safety of both gas and liquid pipelines now under the jurisdiction of federal authority, the trend is anticipated to be avoidance of the use of line pipe steels not covered by an API specification. Accordingly, the natural development of higher strength line pipe steels by experimental action may be slowed down somewhat. However, the impetus to develop specification requirements for high-strength steel becomes stronger under these circumstances; hence, the current effort by line pipe users and manufacturers to standardize Grade X65, a hot-finished, micro-alloyed, carbon-manganese line pipe steel of 65,000 minimum yield strength.

Within the limits of weldability and toughness required by the method of joining and the service intended, the approach to higher strength levels with hot-finished or cold-expanded, carbon-manganese line pipe steels may well find its limit at the 65,000 psi or possibly the 70,000 psi level. Above that level, a heat-treated product appears both promising and necessary.

A lot of hope is placed in pipe manufactured by the quenching and tempering process. It is felt that quenched and tempered pipe of chemistry known to be compatible with ready weldability can be produced with any mechanical properties wanted. The fine-grain, tempered-martensite structure to be realized from this method of manufacture holds promise of providing the desired weldability and toughness at 80,000, 90,000, or 100,000 psi yield strength. Favorable response to unfavorable environments is also a hope with this material because of the relatively low hardness-to-strength ratio obtainable by controlled heat treatment. However, product conditioning, for example, H_2S removal and dehydration, will necessarily require increasing consideration as yield strengths move upward.

2. IMPROVED WELDING AND LAYING TECHNIQUES

In the past twenty years, a number of industry-inspired and developed specifications and recommended practices governing pipeline construction have come into being in the liquid petroleum pipeline field. These documents have as their goal the sharing of information designed to insure that pipelines are installed in accordance with safe and sound engineering practices. Such documents as API Bulletin 1105 titled, *Construction Practices for Oil and Products Pipelines,* have been given official industry-wide recognition by virtue of their inclusion in the revised ASA B31.4 code, Liquid Petroleum Transportation Piping Systems. Code inclusion is the selected route for adoption by the industry of valid new engineering advances.

Welding techniques for the joining of line pipe have kept pace with the metallurgical problems introduced by the development of higher strength steels and thinner walled tubes. Again, industry-developed recommended practices such as API Standard 1104, Standard for Welding Pipe Lines and Related Facilities, have been formulated in pace with newly developed techniques and are now absorbed into the ASA B31.4 code. Welding, whether by gas metal-arc, gas tungsten-arc or shielded metal-arc; whether by manual, semiautomatic or automatic welding techniques, is adequately controlled by the complex welder and welding procedure qualification tests of the API and ASA Standards and Codes.

The coming higher yield strength steels, those above 65,000 psi minimum yield strength, when used in pipeline construction may require new welding procedures. The present growing employment of "gas metal-arc" welding appears to provide the means of successfuly joining these higher strength steels. The problem is less one of coping with a difficult-to-weld material than of preserving parent metal strength adjacent to the weld deposit. New welding methods, such as the CO_2 microwire process, permit welding with less heat input and a resulting smaller heat-affected zone. In return the more rapid cooling at the weld produces the required high-strength joint.

As recently as two years ago, the ASA B31.4 code was restricted in scope to the design of a pipeline. To meet the needs of the pipeline industry, the code has been expanded to provide guidance in the safe design, construction, maintenance and operation of liquid petroleum pipelines.

Practically all features of the construction of a modern, liquid-petroleum pipeline system, from ditching, stringing, bending and welding to non-destructive testing of the welds, coating inspection, lowering-in and backfilling are covered in detail in Chapter V of the Revised ASA B31.4 code.

3. COATING AND CATHODIC PROTECTION

When service deterioration of liquid petroleum pipelines became economically painful to the owners, attention was directed to alleviation of the problem. It became the practice to add wall thickness to pipelines to provide longer service life in the face of environmental deterioration. As pipe sizes and operating pressures gradually increased, the economic advantages of this form of "compensating" for corrosion loss had to yield to the cost for pipe.

The petroleum transportation industry, without governmental intervention, developed and is making extensive use of coatings and supplemental cathodic protection. These modern forms of corrosion mitigation have reached the point where the use of a corrosion allowance is now outmoded in the petroleum-pipeline industry. This fact has been recognized in the latest revision of the American Standard Code for Pressure Piping, ASA B31.4. Section 402.4.1 of the code states: "A wall thickness allowance for corrosion is not required if corrosion mitigation procedures are maintained to protect the piping against external corrosion, in accordance with recognized practice." Thus, the code clearly defines for the pipeline designer his responsibility in providing protection against deterioration of the pipeline by corrosion. The economics of modern, large-diameter, high-pressure pipeline design and the staggering cost of pipe effectively rule out the use of a corrosion allowance. Hence, by code, corrosion mitigation becomes mandatory.

Protection against external corrosion has become commonplace, even in mildly corrosive soils, wherever the owners of a pipeline plan for other than a limited operational life for the installation.

External coatings, more and more frequently combined with supplemental cathodic protection, have improved to the extent that a properly applied coating along with properly engineered supplemental cathodic protection system will result in unlimited life for a pipeline, from the standpoint of external corrosion.

When, or if, internal corrosion in a liquid petroleum pipeline is anticipated, the modern pipeline design engineer considers internal corrosion mitigation as mandatory. He cannot afford to buy added wall thickness to be sacrificed to internal corrosion. He makes a choice between product conditioning through dehydrating or sweetening, or the creation of a corrosion barrier by means of inhibition or internal coating of the line.

SECTION 2—Oil Pipelines—Operation

A. The Trend to Automatic Control and the Rapid Improvement of Control Hardware

The remote or automatic control of liquid pipeline pump stations was first accomplished to a moderate extent in the early 1950's. At that time, attempts to control pump stations remotely were limited primarily to those with electric-driven prime movers. Telemetered data were brought into the control center for the most part in analog form and either recorded or displayed on recording or indicating receivers. In order to conserve channel space and limit the amount of hardware required, some systems were designed to bring in data on an "on demand" or "as called for" basis. The supervisory control systems were primarily relay or a combination of relay and audio tone-type systems. They were of the quiescent type; i.e., the field equipment was designed to report automatically into the master only when upsets at the respective remote locations occurred.

During the mid-to-late 1950's, digital relay systems were developed and installed along with the first successful solid state supervisory control system. Improvements in the instrumentation field along with the development of engine and turbine sequencing equipment resulted in the extension of remote control techniques to engine and gas turbine-driven pump stations.

Rapid improvements in the solid state design of supervisory control systems as well as in the local instrumentation area have been made in recent years. Special problems such as product interface detection and accurate metering have also been substantially solved through the development of new hardware. Most systems being installed today are relatively high-speed, continuous-scan, solid-state systems with digital telemetering. In some instances computers have been incorporated in the central office equipment. This has resulted in a high degree of flexibility when modification of the master scan program is required. The mass storage capacity of a computer-controlled master has also proved desirable when the handling and processing of large volumes of data are required. The use of computers has been further extended into the area of scheduling and dispatching and in a few instances to the "on line" control of the pipeline system itself.

It is anticipated further development in hardware and design techniques will continue and that the trend toward the complete automation of liquid pipeline systems will follow.

B. Principal Differences Between Crude and Products Pipelines

In the petroleum industry, the term "oil pipelines" has come to mean both crude and products lines whether the products are finished or only partially processed. The hardware (pipe, valving, pumping equipment, etc.) is essentially the same for both services. However, there are some differences in both equipment and methods of operation. Generally, crude lines are of larger diameter than products lines.[2] The capacity or pumping rate of products lines is only slightly affected by changes in the temperature, and resulting change in viscosity, of the pumpage. In crude oil lines temperature of the pumpage has a considerable effect, depending upon the nature of the oil being pumped.

Crude pipelines, except in the case of some sour and corrosive oils, are not subject to internal corrosion. Products lines, however, need internal protection. To protect the interior of pipe in products service, the pumpage is either dehydrated or corrosion inhibitors are added. In the case of interior corrosion of steel tanks the opposite is true. Tanks in product service rarely show serious internal corrosion. On the other hand, internal corrosion in crude oil tankage remains a somewhat serious, expensive problem. The attack is usually most severe in bottoms, because of saline bottom water, and the upper rings and roof, because of constant exposure to vapors containing various amounts of sulfur. Cone roofs are, of course, more subject to attack than floating roofs.

A products line adequately protected against internal corrosion rarely needs internal scraping or "pigging." On the other hand most crude lines need regular scraping to remove paraffin buildup on the inside wall. This paraffin coating probably accounts for the lesser interior corrosion in crude oil lines.

Batch separation and quality control are much more critical in products lines than in crude lines. Most crude oil lines haul different grades of oil on a segregated basis. However, intermixing of a few barrels of one grade with another will not affect market value or cause problems at the refinery. On the other hand, finished products can tolerate very slight intermixing. As little as ¼ of 1 percent by volume of gasoline in kerosene being moved at near-minimum flash will throw the kerosene off specification as to flash point. Critical products, such as aviation gasoline, will tolerate no contamination whatsoever. For this reason products systems normally have far more elaborate procedures and instrumentation for batch detection and interface cutting at the terminals than do crude oil systems. In products pipeline operation the rule is always to protect the most valuable and/or critical product. For example, if a slug of aviation gasoline is "pushing" a slug of housebrand motor fuel, the stream will be kept going into the housebrand tank at the terminal until after the interface plus a few barrels of pure avgas has been received, and then the stream is switched to avgas storage. At the tail end of the avgas slug the stream is switched to other storage (depending on what is following the avgas) just before the interface arrives. This results in a slight upgrading of housebrand motor fuel and a slight loss in volume of avgas, as such, received in the terminal but does protect the avgas.

One other major difference between crude and products pipeline systems is the distribution of personnel. On a crude oil system, employee concentration is at origin. Here the oil is gathered, gauged and put into the pipeline. Here most of the producer-pipeline contacts exist. Here depending on the size of the producing area and the extent of the gathering system is where connection crews are required and where most of the records on oil movements originate. Automation in the past ten years, particularly in lease automatic custody transfer (LACT), has greatly reduced the number of lease tanks and the number of gaugers required in most producing areas. Even so, on most crude oil pipeline systems, employee concentration is at origin point. By contrast in the case of an automated products system few, if any, employees are required at origin. While most pipeline operators prefer to control their systems from one end to the other, the pipeline operator may contract with the refiner to push-button control the origin station, "stamp out" hourly or daily meter readings and maintain the pipeline-owned equipment. If the pipeline company performs terminaling service for its shippers (as many do), employee concentration occurs at such terminaling points, generally far downstream from origin.

C. The Economics of Joint Ownership of Pipelines

Often a need for overland oil pipeline transportation exists or is foreseen, but the investment for a pipeline by a single shipper-owner cannot be justified. In these circumstances, it is not uncommon for a group

2. Notable exception is the huge Colonial Pipeline System.

of shipper-owners to pool their capital and volumes and enter into a joint project.[3]

Joint ownership tends to divide the financial risk, provides a larger, more economical system and virtually guarantees sufficient traffic to pay out the investment. The higher volumes result in lower tariffs and ultimately lower cost to the consumer of the end product.

These joint pipeline projects are set up and operate with some variations. Ownership may be determined by negotiations, or by the revenue estimated to be generated by each shipper-owner. There may be a single tariff for the entire system (Colonial Pipeline) or each interest-owner may publish his own tariff applying on his "space" in the system (Rancho Pipe Line). In such cases the tariffs are usually comparable but not necessarily identical. Management for the system may be "hired" and functions much as a separate company with its own accounting, legal, engineering and operating staff. However, the more common practice is for one of the interest-owners to manage the system for the benefit of the group. This is usually referred to as an "agency" operation. The "agent" in this case performs all management and administrative functions above the field operating level. For this the agent gets a negotiated agent's or overhead fee. The agency operation has certain advantages over a "hired" operation. For example, in an agency operation, the services of such people as accountants, lawyers, draftsmen and other specialists are used (and charged for) only to the extent needed. Thus, assuming a reasonable agent's fee, the agency operation offers substantial economy in the administration of a pipeline system. Also if the agent is a large oil or pipeline company, there exists usually a sizeable reservoir of expertise which would not be available to the "hired" organization except at high cost.

D. The Changing Concept of Pipe vs. Horsepower

When it becomes necessary or desirable to increase the capacity of an oil pipeline, it can be done in several ways. Pressures can be increased if the system is operating at less than the maximum safe allowable; larger diameter pipe can be installed; existing lines can be looped; more horsepower can be added; or in some cases a combination of these methods may be indicated. There is, of course, no set formula to apply, and action will depend on the circumstances in each case.

Until about 1957 when the oil pipeline industry began extensive automation of pumping stations, the economics of a capacity increase usually favored larger pipe or looping. The payout was based on lowered labor and power costs. However, because of the rapid advance in the past eight or nine years of the technology and improved hardware for remotely controlling pumping stations, there has been a sharp swing to the horsepower route. To reach a predetermined increment of capacity increase, pumping stations can be added normally at much less investment than equivalent pipe. Therefore, in this concept, lower investment, appreciable labor savings (especially when remotely controlled, unattended stations are considered) make the horsepower route more attractive, more than offsetting the added energy input required.

SECTION 3—Oil Terminals—Pipeline and Marine

A. Terminal Automation

As is the case in petroleum refining and nearly all processing operations, recent developments and continued improvement in the tools for central control by push-button have been applied to petroleum distribution terminals. For reasons discussed earlier in this chapter, automation and central control have been applied more generally in products distribution terminals than in terminals handling crude oil only. The following discussion applies primarily to products terminals, although where justified the same techniques could be used in crude oil terminals.

Remote tank gauging and temperature read-out from a central point are not particularly new, but it has been only in recent years that equipment of desirable accuracy and reliability has been available. In large terminals this equipment usually can be justified by labor savings. A recent development in terminal automation is central control of switching. Here the main valves are power-actuated and operated from a central panel or console. This system is a "must" in terminals fed by large-diameter, high-flow lines. Hand operation of large valves is too slow to avoid undesirable product mixing within the terminal.[4]

Another recent development in tank truck outloading from products terminals is driver loading or "keystopping."[5] In this concept the truck loading

3. "Pooling" in the sense here used does not relate to pooling or division of traffic or of service as prohibited in Part 1, Section 5, of the Interstate Commerce Act. Also while the interest-owners in such joint projects are usually oil companies or pipeline companies, there are many instances of investment also by nonoil related firms and even individuals.
4. O'Donnell, John P., "Colonial's Atlanta Junction Tank Farm Features Central Hydraulic System," *Oil & Gas Jour.*, January 13, 1964, vol. 62, No. 2, pp. 74-76.
5. "An Old Terminal Goes Modern," *National Petroleum News*, July 1964, vol. 56, No. 7, p. 122.
"Automated Terminal Loads, Fills Truck in 15 Minutes," *Petroleum Management*, September 1963, vol. 35, No. 10, pp. 258-264.
"Automation Makes Big Key-Lock Terminals Fast and Efficient," *Oil & Gas Jour.*, May 13, 1963, vol. 61, No. 19, pp. 68-69.
"First Key-Lock Loading System for LP-Gas Opens," *Oil & Gas Jour.*, September 16, 1963, vol. 61, No. 37, pp. 68-69.
"Here's a Punched-Tape Terminal," *National Petroleum News*, January 1965, vol. 57, No. 1, pp. 94-97.
Richardson, Jules O., "Keystop Rack Can Cut Cost, Bring Better Data Handling," *Oil & Gas Jour.*, April 22, 1963, vol. 61, No. 16, pp. 94-96.
Ruhl, K., "Unattended Loading Terminal," *ISA Journal*, May 1963, vol. 10, pp. 71-72.

dock is attended by terminal loaders only during certain daylight hours. This limited attendance by terminal personnel normally is to load trucks for drivers who have not yet qualified for self-loading or to handle customers required to pay cash upon delivery. Because of built-in automatic features such as positive static drain and remote gallonage recording, keystop installations are generally considered safer and more theft proof than conventional loading. Economic advantages are less manpower required at the terminal and more efficient utilization of tank trucks. For example, a low-volume terminal often cannot justify loaders around the clock. Therefore, the trucker can be loaded only when the terminal dock is manned. However, in the case of a keystopped facility, he can load if necessary around the clock, thus serving his "drops" with less equipment and less investment.

B. Refrigerated Storage of Volatile Products

The containment of volatiles by cryogenic means is not a new art, but utilization of the principle by the gas, oil and chemical industries for transporting and storing volatiles in large volume is a post-World War II development.[6] The catalyst for this development is unquestionably the trend to jumbo in all forms of commodity transportation. Pressure storage of volatiles, such as propane, butane and anhydrous ammonia was simply economically out of reach for the volumes the industries began to contemplate at the end of World War II. Underground storage offered a partial solution. The early 1950's saw the beginning of active development of underground storage.

By the end of 1965 there were nearly 100 million barrels of underground cavern storage capacity in LPG service available. In addition there were 185 thousand barrels of frozen pit storage in Canada and the United States and an additional 500 thousand barrels planned or under construction.[7]

While underground storage of volatile liquids is much more economical than aboveground pressure storage, subsurface conditions are not always suitable at the location where such storage is needed. This has led to development of aboveground refrigerated storage, using low-pressure vessels. While generally more expensive than underground storage, it is considerably less expensive than aboveground pressure storage.

While low-pressure, aboveground refrigerated storage for volatile liquids has certain advantages (such as generally unrestricted location) there are limitations as to transfer rates. Propane, for example, is cooled to about −50° F in low-pressure refrigerated storage. Receipts into such storage must be cooled to this temperature. It would not be economically feasible to provide enough refrigeration to receive at most pipeline rates. Therefore, the transfer rate must be reduced to the capacity of the refrigeration equipment. In practice, to avoid a low-transfer rate, the stream is split, sending the bulk to warm storage. The rate at which a pipeline can deliver propane to refrigerated storage facility depends upon (1) cooling capacity, (2) line temperature of the propane, (3) ethane content of the propane and (4) barometric pressure at the receiving point. A typical installation having the most economical cooling capacity could receive about as follows:

PROPANE TEMPERATURE	FILL RATE (BPD)
85° F	4,200
80° F	5,100
70° F	6,800
60° F	8,600
50° F	10,300
40° F	12,000

(Assumes propane contains not over 5% ethane)

When refrigerated liquid is outloaded to conventional tank trucks, tank cars or barges, it must be warmed (to about 20° F). This normally does not present a transfer rate problem because the outloading rate is low, compared to receiving rate. Also there is no thermo transfer rate problem in receiving or outloading between refrigerated storage and refrigerated tankers.

SECTION 4—Oil Tankers

A. The Trend from Jumbo to Monster in Water Transportation

Elsewhere in this chapter we have mentioned the trend in recent years to larger diameter pipelines and related facilities such as valving, pumping equipment and tankage. Actually this trend from what has been considered conventional to jumbo to monster is apparent in all forms of transportation, pipeline, barge, tanker, road, rail, air, and even into outer space. The primary motivation, of course, is to reduce the unit cost of hauling. The effect of bigness on unit cost is shown graphically in Figure 96.

Assuming full utilization, a 10 percent average annual rate of return to the shipowners, and a 20-year project life, a new U.S. built T-2 size tanker would deliver a barrel of 34.2 API product from the Gulf Coast to the New York harbor area for 56¢.

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6. Lillquist, Vann and Maher, "World's Largest Refrigerated LPG Storage Facility," *American Gas Journal*, October 1961, vol. 188, No. 11, pp. 24-30.
Reynolds, Orin F., "Deep South Deep Freeze," *Gas*, April 1963, vol. 39, No. 4, pp. 65-67.
Sharp, Howard R., "Refrigerated Storage Requires New Techniques in Design," *Oil & Gas Jour.*, November 30, 1964, vol. 62, No. 48, pp. 52-54.
7. "Frozen Pit in Utah Will Store 135,000 Bbl. of Propane," *Oil & Gas Jour.*, July 29, 1963, vol. 61, No. 30, pp. 100-101.
Massey, P. S., "Frozen Earth Propane Storage," *Oil & Gas Jour.*, March 16, 1964, vol. 62, No. 11, pp. 102-103.
"Report on Frozen Earth Storage," *Petroleum Management*, January 1965, vol. 37, No. 1, p. 157.

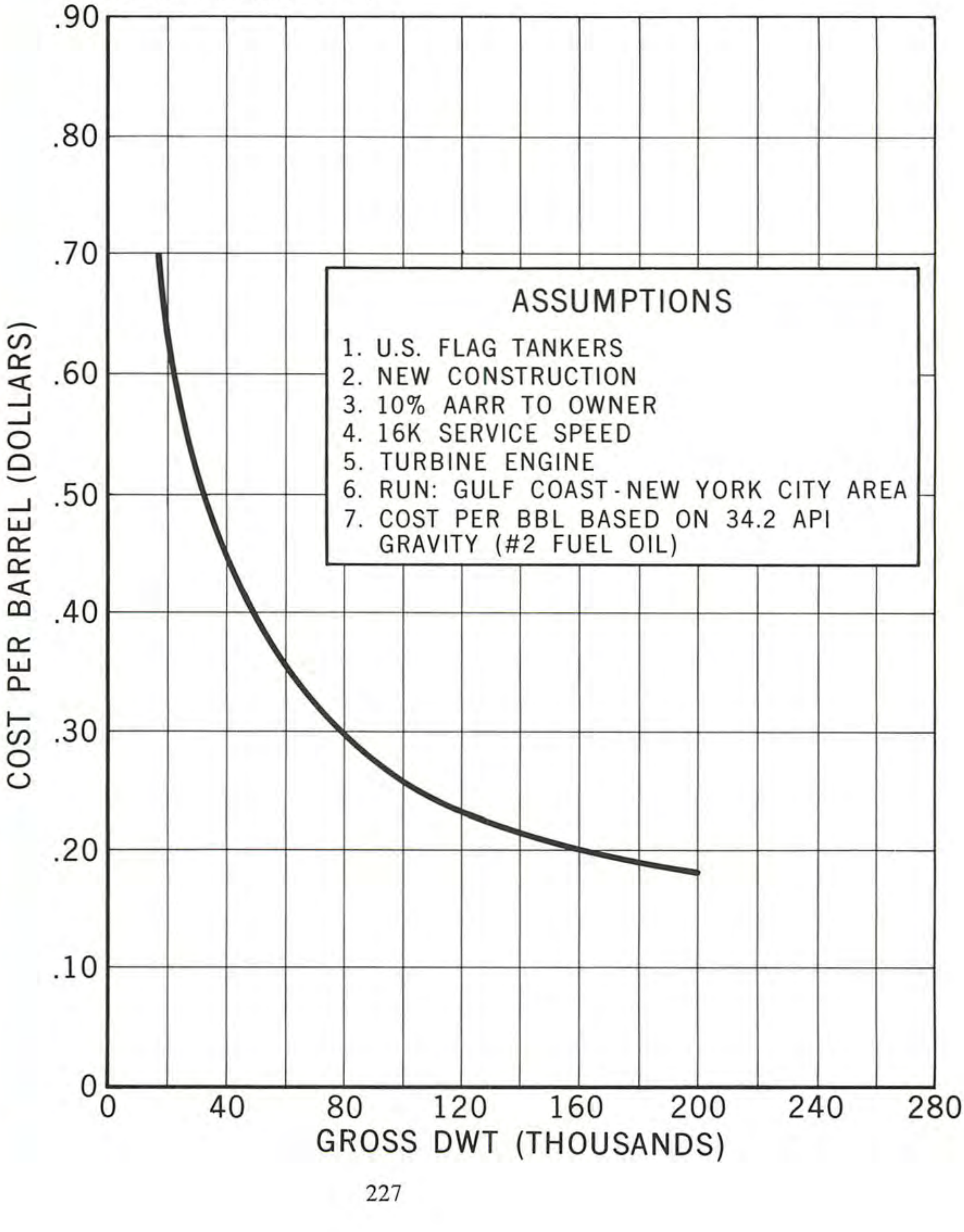
Using the same assumptions, a 100,000 DWT tanker would deliver for 26¢, and a 200,000 DWT tanker would deliver for 18¢. Presumably the 300,000 DWT tankers now on order will show an even lower unit cost, although it is not planned to use these monsters in coastwise shipping.[8]

Although the increase in individual tanker size is spectacular, the effect on the average size of all

8. *Oil and Gas Jour.* May 2, 1966.

FIGURE **96**
Gross
DWT vs. Cost
per
Barrel

(Source: Manufacturer's Data).



vessels in service has been relatively small (Figures 97 and 98).

Conventional harbor facilities do not now exist to handle these giant tankers. The Tokyo Maru, for example, a 150,000 DWT and currently the world's largest tanker in service can dock under full load at only a few ports in the world.

In the case of the 300,000 DWT tankers, the Japanese builders will have to enlarge their yards before construction can even start. Harbor depths are not the only problem. Horizontal clearances at bridge locations on channels leading to many major ports will not tolerate the broad-beamed giants.

At a recent meeting of the API tanker conference in Absecon, N.J., Lt. Gen. William F. Cassidy, Chief of U.S. Army Engineers, pointed out the tremendous cost of deepening U.S. coast channels to accommodate the big tankers. Currently joint offshore terminal and pipeline facilities on the U.S. East Coast capable of handling the giant tankers coming into world oil trade are being planned by three major U.S. oil companies.[9]

One solution for loading and unloading the new giant tankers is the offshore buoy connected by submarine pipeline to shore facilities. A type in general use at many Far Eastern terminals is sketched in Figure 99.

Remote control in ocean tanker transport is confined almost entirely to the newer vessels. The technical know-how for bridge control is available, and the ocean tanker shipping industry is moving ahead in this field.

9. *Oil & Gas Jour.* May 23, 1966.

FIGURE **97.** International Tanker Building Trend

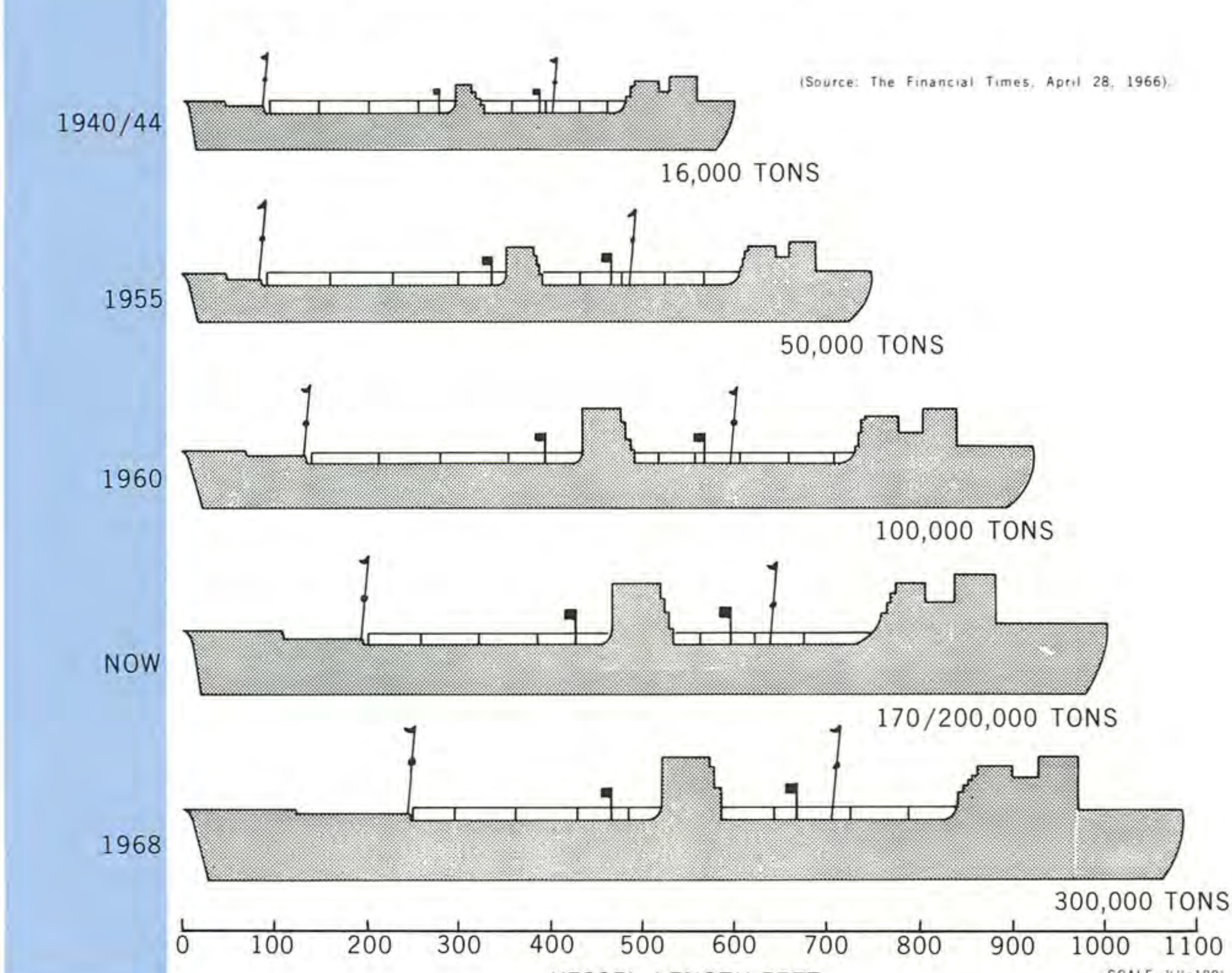


FIGURE **98**
Increase in Tanker Size (International)

(Source: Petroleum Press Service)

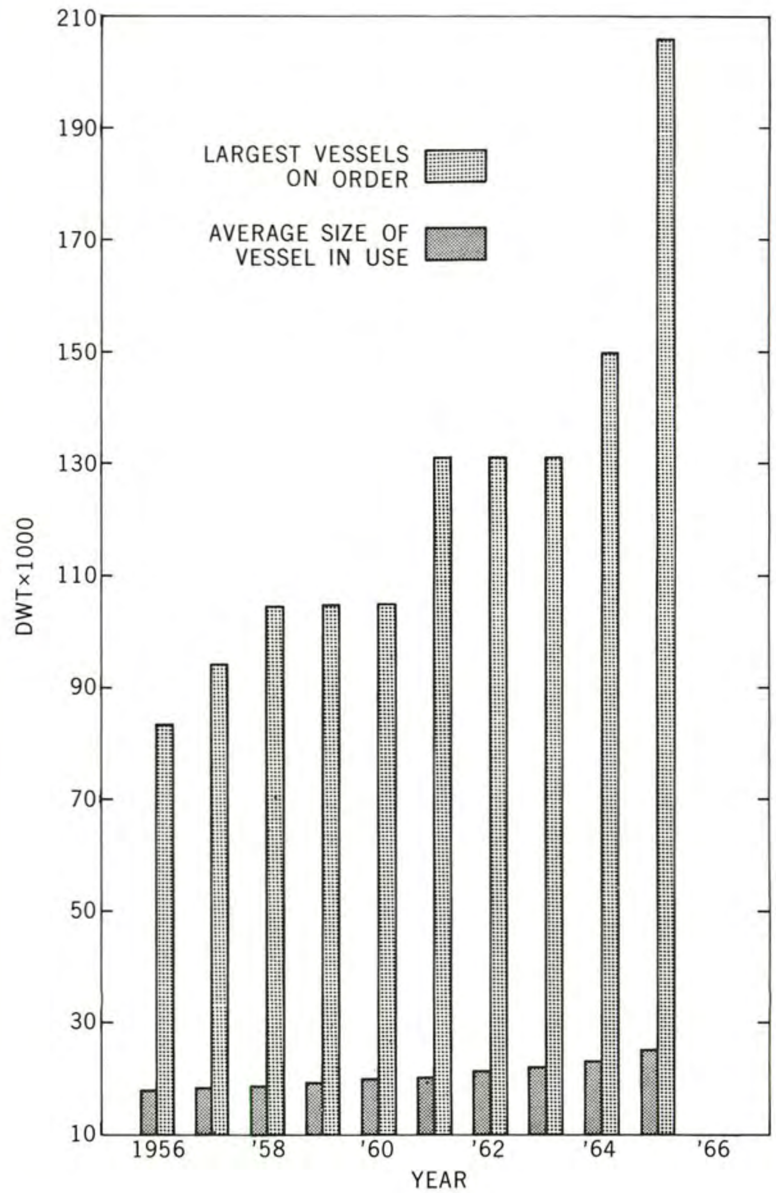
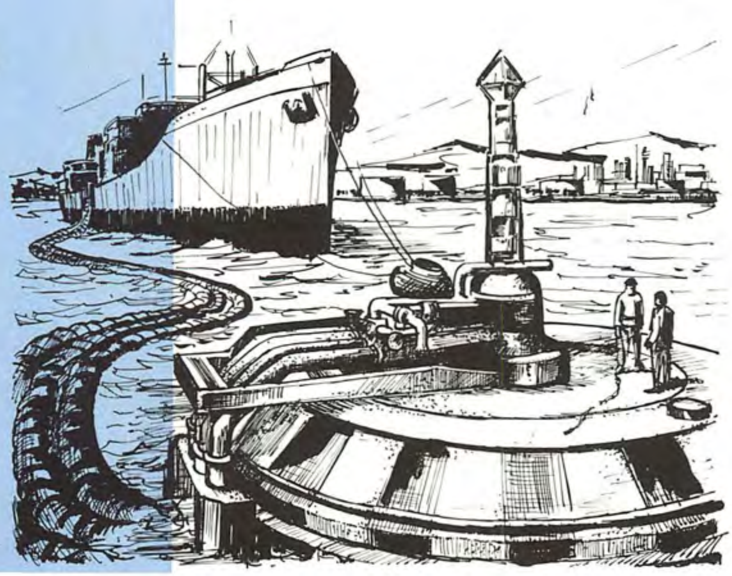


FIGURE **99**
Terminal Facilities for Giant Tankers



CHAPTER SEVEN—CORROSION

SECTION 1—Introduction

Lloyd E. Elkins, J. H. Jones, L. W. Jones

Uhlig [1] defines corrosion as "destruction of metal by chemical or electrochemical reaction with its environment." A somewhat broader definition is desirable for this discussion, since these materials also deteriorate through reaction with their environment. Additionally, problems of equipment malfunction resulting from both metal loss and the effects of accumulated products from the corrosion process are logically a part of the corrosion problem.

The corrosion problems encountered in oil drilling, production, and transportation are many and varied from the standpoint of the large number of different types of installations employed, as well as the vast number of different materials of construction employed. For example, for oil to reach a refinery, the well must be drilled, cased, tested, stimulated, and produced with the oil then being treated, separated, metered, pumped, and stored. The delivery

1. Uhlig, H. H., *Corrosion Handbook,* John Wiley and Sons, New York, 1948.

may be by a combination of truck, railroad car, pipeline, ship or barge. All equipment associated with these operations is subject to corrosion and the total annual cost of corrosion could well exceed $500,000,000 for the industry.

For the purposes of this discussion, an attempt is made to simplify much of the detailed technical knowledge and specific achievements so that a general picture of the technological developments and their impact on the oil production industry can be drawn. The importance of the detection and mitigation of corrosion and the developments in the major areas of corrosion mitigation and control will be discussed. The impacts, economically and in terms of production and production capabilities, are considered. Finally, an effort is made to define those areas in which new technology will be instrumental in protecting equipment and thus be helpful in further increasing the supply and availability of crude oil.

SECTION 2—Importance of Corrosion Detection and Mitigation

Some idea of the importance of corrosion prevention can be obtained from the following statistics. In 1964, there were:

588,657 producing oil wells [2]
2,786,822,000 barrels of crude oil produced [2]
112,899 producing gas wells [2]
72,950 miles of crude oil trunk lines [2]
78,861 miles of crude oil gathering lines [2]
899,598 tons of sulfur recovered (1962) [3]

In addition to equipment replacement costs, corrosion affects the productivity from a field through downtime for repairs and replacement of equipment, plugging of flowlines and pumps, increased injection pressures and early abandonment of problem wells. The advances in technology and increased need for petroleum products have continually pushed all operations toward higher temperatures and pressures and more corrosive conditions.

An additional aspect of corrosion on which no true monetary value can be placed is safety. Populated areas completely surround many oil fields, particularly in California and Texas. Minor leaks in wells or flowlines could result in fires and explosions which would endanger life and property. Platforms used in offshore drilling and producing operations are subject to severe corrosion which could be a safety hazard to life as well as to the costly investment. In this regard, it should be mentioned that the petroleum industry has achieved an enviable safety record over the years. This has been achieved because both management and engineering have tended to design and build with the worst foreseeable conditions in mind and to instill safety consciousness in its employees.

The growing stringency of controls and the increased attention being given environmental pollution by both the oil industry and political organizations have increased the necessity for maintaining the integrity of equipment holding, producing or transporting hydrocarbons. It is essential, for example, that no perforation in a casing or pipeline permit hydrocarbons or brines to escape into water-bearing sands or surface water. Early detection of corrosion and effective mitigation programs are necessary to provide the maximum safety in all phases of the operations.

SECTION 3—Development of Oil Industry Corrosion Control Measures

A. Technological Foundations

The application of corrosion control techniques to the oil industry varied considerably in timing and extent of usage depending upon the urgency of a recognized problem. For example, the first experiments to increase oil production of wells by injection of hydrochloric acid were made in 1895 by Frasch. After a long dormant period, the discovery of oil in limestones spurred interest in acidizing to the extent that an inhibited acid was developed and put into an oil well in 1931,[4] and within months stimulation of wells by acidizing attained economic importance. As another example, severe corrosion in water-cooling systems of gasoline plants in the Salt Creek field of Wyoming led to the use of sodium chromate as early as 1925.[5]

Corrosion mitigation efforts were applied early to pipelines.[6] Modern development of pipeline coatings and cathodic protection were started after technical meetings of the U.S. Bureau of Standards, ASME and the API in the 1926-28 period. Full-scale powered coating and wrapping machines with powered cleaning and priming machines were in operation by the late 1930's. By 1930, coal-tar enamel attained a predominant position as a pipeline coating which it still held in the 1950's. Cathodic protection, suggested by Davey in 1825 [7] was first applied to pipeline protection in 1930. By 1939 some

2. *Petroleum Facts and Figures,* API, 1965.
3. Kerr, James R., Rand, Lenox H., and Vallely, James L., "The Sulfur and Sulfuric Acid Industry of Eastern United States," *Information Circ.* 8355, U. S. Dept. of the Interior, Bureau Mines, 1965.
4. Fitzgerald, Paul E., "A Review of the Chemical Treatment of Wells," *Jour. Pet. Tech.,* September 1953, vol. 5.
5. Finney, W. R., and Young, H. W., "Scale and Corrosion Problems in Gasoline Plants," AIME, Petroleum Div., New York.
6. Logan, H. H., "Corrosion and Protection of Pipelines in the United States of America," *The Science of Petroleum,* Oxford University Press, London and New York, 1938, vol. 1. *Oil & Gas Jour.,* vol. 57, No. 5, Petroleum Panorama No. 1959.
7. "The Beginners of Cathodic Protection." Collected papers of Sir Humphrey Davy as published in the Philosophical Transactions of the Royal Society, (London 1824-25), Nat'l. Assoc. of Corr. Engineers, Houston, Texas.

540 cathodic protection units were in operation to protect 2,000 miles of pipeline.[8] Magnesium anodes became important in the late 1940's for use at locations not suitable for rectifiers.

In oil production, the inroads of corrosion in various areas were early outlined by R. Van A. Mills [9] and later by such reports as those of the API Sub-Committee on Production Corrosion.[10] In 1933, the relationship of corrosion fatigue to sucker rod failures was well established.[11]

In general, it may be said that aside from the successful work to prevent some pressingly serious corrosion problems, little effort was made prior to World War II to study systematically the varied aspects of corrosion in the oil producing industry and to develop and apply better control measures and techniques. About this time technological advances in drilling, metallurgy and production practices together with the need for more oil permitted operations to shift to higher temperatures and pressures and to more corrosive environments. Possibly as a result of the more urgent need, a spontaneous and widespread effort was directed at educating people in all work categories, from operations to management to research, to the nature and role of corrosion in equipment failures. This program occurred both as individual company efforts and in the organization and growth of the National Association of Corrosion Engineers (NACE). The advent and growth of the NACE, founded in 1943, can be considered as the focal point of a major effort to combat corrosion in the oil industry. The early work of W. R. Whitney [12] helped channel theoretical and practical work in the corrosion mitigation field.

B. Recognition, Detection and Measurement of Corrosion

With the advent of major emphasis on combating oil production corrosion, numerous methods were applied to the detection and measurement of corrosion. In the area of pipelines, an improved method came into use in 1943 for determining the current required for cathodic protection.[13] A greatly expanded number of pipeline surveys were made involving such aspects as coating conductance, potential profiles, line currents in test sections and soil resistivity. In the case of oil and gas wells, measurement was made in 1941 of the electric current being conducted from flowlines into wells. This stemmed from work [14] showing the serious corrosion caused by such currents and the benefit achieved by using insulated flanges to insulate the wellheads. After the cathodic protection of oil well casing was initiated in 1947,[15] subsurface surveys were occasionally made to determine casing potential profiles and numerous surface surveys were made to determine required electrical current to protect the casing. Service companies came into being to provide this service.

Considerable attention was paid to the effect of bacteria on buried or submerged steel. Although the basic technology of the influence of bacteria on corrosion was well known, it was not until the 1950's that serious attention was given to the premise that bacteria might influence oil well casing corrosion. A study in a California field [16] showed the influence of pH of drilling mud on external casing corrosion attributed to bacterial action.

Practical use of some of the fundamentals of the causes of corrosion brought closer attention to undesirable galvanic couples, thermogalvanic effects and various concentration cell phenomena including differential aeration. Metallurgists attracted to petroleum industry problems began investigating the relationship between corrosion resistance and alloying constituents, metal phases,[17] inclusions, internal stresses and the like.

The insidious effect of hydrogen absorption in metals was recognized in 1947 [18] and in the following year hydrogen blistering of crude oil storage tanks was reported.[19] A report on an early study conducted under NACE auspices cited hydrogen as the culprit in the reaction of hydrogen sulfide with steel.[20]

The advent of chemical inhibitors in the 1940's to control corrosion caused by hydrogen sulfide and by organic acids led to analysis of produced fluids for these constituents and carbon dioxide. To monitor the corrosion control treatments of sweet condensate wells, iron determinations of the produced water became routine. As water flooding grew in importance, examination of waters for sulfate-reducing bacteria came into use.[21] More recently (1963) improved apparatus was devised to measure the oxygen con-

8. *Oil & Gas Jour.,* vol. 57, No. 5.
9. Van A. Mills, R., "Protection of Oil and Gas Field Equipment Against Corrosion," *Bull.* 233, U. S. Dept. of the Interior, Bureau of Mines, 1925.
10. "Corrosion of Production Equipment," *Production Bull.* 206, API, December 31, 1930.
11. Westcott, Blain B., and Bowers, C. Norman, "Corrosion Fatigue and Sucker Rod Failures," *Production Bull.* 212, API, 1933, vol. 29.
12. Whitney, W. R., "Corrosion of Iron," *Corrosion,* July 1947, vol. 3, No. 7, pp. 331-340.
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14. Huddleston, W. E., "Cathodic Protection to Prevent Corrosion of Gas Well Casings," *Oil & Gas Jour.,* May 8, 1941, vol. 39.
15. Ewing, S. P., and Bayhi, J. F., "Cathodic Protection of Casing in Loudon Pool," *Corrosion,* June 1948, vol. 4, No. 6.
16. Doig, Keith, and Wachter, Aaron, "Bacterial Casing Corrosion in the Ventura Field," *Corrosion,* July 1951, vol. 7, No. 7, pp. 212-224.
17. Manuel, E. W., "Effect of Carbide Structure on Corrosion Resistance of Steel," *Corrosion,* November 1947, vol. 3, No. 11.
18. Fontana, M. G., "Surface Studies of Metals from the Corrosive-Standpoint," *Corrosion,* November 1947, vol. 3, No. 11, pp. 567-579.
19. Bartz, M. H., and Rawlins, C. E., "Effect of Hydrogen Generated by Corrosion of Steel," *Corrosion,* May 1948, vol. 4, No. 5, pp. 187-206.
20. Report by Tech. Unit Comm. I-G on Sulfide Stress Corrosion Cracking, Pub. 54-5, *Corrosion,* November 1954, vol. 10, No. 11, pp. 413-419.
21. *Recommended Practice 38,* 1st Ed., API, May 1959.

tent of these waters conveniently.[22] At the same time, increased attention was given to the examination of failed equipment to determine the possible role of corrosion; this was carried out by research people making inspections of field equipment, conducting chemical tests of deposits either in the field or laboratory, and sometimes metallurgical examinations.

To an increasing extent metal loss measurements were employed by exposing metal coupons in the produced fluid or by installing test nipples to permit more direct measurement of the corrosion rate. Insertable probes for monitoring corrosion rate by conductometric methods were developed in the late 1950's.[23] A probe design based on polarization resistance was developed in the early 1960's for instantaneous measurement of corrosion rates.[24] These have been useful in the laboratory and are now coming into use in the oil fields.

C. Chemical Control Measures

An excellent review of chemical control of corrosion is given by Bregman.[25] Little effort was made to chemically control corrosion in producing oil wells until formaldehyde was introduced as an inhibitor of sulfide corrosion in 1944.[26] This inhibitor was used to a considerable extent for several years until replaced for the most part by the long-chain, film-forming nitrogenous inhibitors. One of the earlier compositions of this type, imidazolines and their derivatives, was described in 1945.[27] Later the organic acid salts of relatively high molecular weight amines were found useful.[28] Various other corrosion inhibitors of the nitrogenous type have been developed as listed by Bregman. Today the great bulk of inhibitors used in producing oil and gas wells are the film-forming nitrogenous type, largely the amine-acid salts.[29] Internal casing corrosion by hydrogen sulfide was recognized as a serious problem in the early 1950's and use of volatile chemicals such as ammonia [30] and diethylamine [31] was developed for prevention of the attack.

Comparatively small volumes of chemicals other than inhibitors are used for corrosion control in oil production. Alkaline agents, ammonium hydroxide, soda ash, and others were successfully applied to gas condensate wells about 1946. The use of these agents was limited to waters of low solids content preferably below 2,000 ppm as otherwise objectionable scales were formed. The use of neutralizing chemicals is minimal compared to the organic inhibitors.

In water flood operations for secondary recovery of oil, corrosion inhibitors and bactericides have had considerable application but the volumes of water are so large that continuous chemical treatments are often economically unattractive. Quaternary ammonium chlorides are probably the most widely used type of oil field biocide.

As mentioned previously, corrosion inhibiting chemicals found early application in oil well acidizing. Arsenic-compounds were used initially and are to some extent today. With the production of oil from progressively deeper wells improved organic corrosion inhibitors have been developed to perform satisfactorily in acid at temperatures of at least 200° F.[32]

D. Electrochemical Control Measures

Electrochemical control measures include both cathodic and anodic protection. The former is by far the more important and widespread as a protection technique. Either sacrificial galvanic anodes or direct electric current from rectifiers or generators may be used. In anodic protection, the object is passivated by adjusting its electrical potential in a positive direction to a level where corrosion is minimal.

Success of applications in 1928 gave cathodic protection a big start on pipeline protection. Despite the early use of cathodic protection on pipelines more than 10 years was taken to bring widespread use to the pipeline industry. Sacrificial magnesium anodes rapidly became important in the late 1940's with zinc and aluminum metal anodes being used also. A recent innovation is the adaptation of thermoelectric generators for impressed current cathodic protection at remote locations not served by electric power lines. These can use gas fuel taken from the gas pipeline being protected.

In 1947, cathodic protection was first applied to protecting oil well casing.[33] Also applied here was a subsurface survey of the distribution of current on the well casing and a surface method of determining current requirements to protect casing, namely, the E-Log I curve. During the early 1950's cathodic protection of casing commenced to have

22. Garst, A. W., and McSpadden, T. W., "Measurement of Dissolved Oxygen in Oil-Field Waters," 144th National Meeting, ACS, Div. of Petroleum, Los Angeles, 1963.
23. Dravnicks, A., "Corrosion of Steel in Molten Sulfur," *Ind. Eng. Chem.*, December 1951, vol. 43.
24. Marsh, G. A., "The Measurement of Instantaneous Corrosion Rates," *2nd International Congress on Corrosion*, NACE, March 1963.
25. Bregman, J. L., *Corrosion Inhibitors*, The Macmillan Company, New York, 1963.
26. Menaul, P. L., and Dunn, T. H., "Formaldehyde as Inhibitor of Corrosion Caused by Hydrogen Sulfide," *Technology Pub.* No. 1970, 1946.
27. Justice, W. H., and Jones, Edward N., "Tests Demonstrate Possibilities of New Corrosion Inhibitor," *Oil & Gas Jour.*, November 9, 1946, vol. 45.
Gross, Wm. F., and Andrews, Howard W., "Prevention of Corrosion in Sour Wells with Organic Inhibitors," *Oil & Gas Jour.*, 1948, vol. 47, No. 26.
28. Jones, L. W., and Barrett, Jack P., "Laboratory Development of Corrosion Inhibitors," *Corrosion*, May 1955, vol. 11, No. 5.
29. Minutes of Meeting, NACE Tech. Unit Comm. T-ID, October 22, 1964.
30. Greenwell, H. E., Loucaric, Rado, and Byars, H. G., "Use of Ammonia to Prevent Casing Corrosion," *Corrosion*, November 1955, vol. 11, No. 11.
31. Jones, L. W., and Barrett, Jack P., "Inhibitor Reduces Vapor Space Corrosion," *Oil & Gas Jour.*, September 24, 1956, vol. 73.
32. Report by NACE Tech. Unit Comm. T-8, *Materials Protection*, May 1962, vol. 1, No. 5.
33. Ewing and Bayhi, *op. cit.*

widespread use.[34]

Cathodic protection is now so widely used in all phases of the industry that it can be considered the "standard" procedure for protecting the exterior of structures submersed in earth or water. For buried structures such as pipelines, the cathodic protection is usually supplemental to protective coatings. However, in water-submersed structures, notably the piling of marine drilling platforms,[35] cathodic protection is generally the principal means of retarding corrosion.

Although known in theory for many years, the practical adaptation of anodic protection principles for control of corrosion was initiated largely through the efforts of Sudbury and associates.[36] The technique is principally of value in special applications such as protection of acid storage tanks and has found little use in oil producing industries to date.

E. Protective Coatings

To test the relative merits of pipeline coatings, the Bureau of Standards, API and the pipeline industry conducted a 10-year test of buried samples at widely scattered sites from 1930 to 1940.[37] Since 1940 the standards and materials for coatings have steadily improved. Major oil pipelines reported that coating of lines had increased from 78 percent in the 1940-50 period to 95 percent in the 1950-55 period. In 1951, applicators reported 95 percent of their customers specified coal-tar coating with different preferences as to type of wrapping, i.e., asbestos, glass type, and combination of glass and felt. Since 1954, asphalt coating use has been increased and new plastic coatings and tapes have been developed.

Major advances in the protective coatings field occurred in the 1950's with development of catalytic and heat-cured phenolic, epoxy, and vinyl plastic coatings, coal tar-epoxy combinations, and inorganic zinc base primers for example. Coatings based on these developments were quickly used in a multitude of oil-producing applications; including coatings to protect the interior of drill pipe, tubing in deep, hot condensate wells, oil storage tanks, offshore platforms and lines handling water for secondary oil recovery. Inorganic zincs with vinyl or epoxy mastic or chlorinated rubber topcoats have come into widespread use for protection of marine drilling structures above the splash zone.[38]

Extruded coatings also are about ten years old and increasingly used. These are relatively thick polyethylene, vinyl or other plastic materials extruded onto or into pipe exteriors or interiors at the mill. Pipe can be obtained in a wide range of sizes with one plastic outside and another inside if necessary.

F. Metallurgy and New Materials of Construction

Some of the oil industry's biggest forward steps have been outgrowths of advances in metallurgy and manufacture of steels of improved properties. Deeper drilling has demanded stronger casing and pipelines have sought higher pressure line pipe. The American Petroleum Institute has long played an important role in standardization of various grades of tubular goods, sucker rods for pumping wells, etc. Most line pipe for gas and oil lines must meet API Standard 5LX "Specification for High Strength Line Pipe."

In oil well drilling, corrosion fatigue of drill pipe has plagued the industry and was particularly severe in the Permian Basin in the 1940's. Results of research financed by the American Association of Drilling Contractors at Battelle Memorial Institute aided in greatly reducing this problem. This work revealed the influence of corrosion in accelerating failure of a metal when stressed and aided in the adoption of drilling practices which minimized stressing of the drill pipe. Results of Batelle work appeared in 1948.[39]

In 1948, stress corrosion cracking associated with hydrogen sulfide was recognized as well as the greater susceptibility of the high-strength steels as compared to the mild steels.[40] Initial hardness of the metal determines to a large extent the susceptibility of cracking and a Rockwell hardness of C-22 seems to be near the maximum for steels with yield strengths greater than 90,000 psi in sulfide systems. In recognition of the problems related to stress corrosion cracking experienced with steels used in sour service, NACE's Technical Group Committee T–1 on Corrosion of Oil and Gas Well Equipment made cooperative studies. A report titled "Sulfide Cracking Resistant Metallic Materials for Valves for Production and Pipeline Service" has been published.[41]

Aluminum drill pipe has shown promise for deep drilling but its use has not been extensive to date. Cement-lined pipe has been used in water handling for secondary recovery and for brine disposal since the middle 1930's and was reported by the NACE to be widely used in 1963 for the larger lines. Plastic pipe has been progressively improved in physical properties since the early 1950's and is being used to an increasing extent for handling corrosive waters.

34. Battle, Jack L., "Corrosion of Casing in Oil and Gas Wells," *Corrosion*, September 1953, vol. 9, No. 9.
35. Mackdanz, C. H., "Protection of Offshore Structures," *Materials Protection*, October 1965, vol. 4, No. 10.
36. Sudbury, J. D., Riggs, O. L., Jr., and Shock, D. A., "Anodic Passivation Studies," *Corrosion*, February 1960, vol. 16, No. 2.
37. *Oil & Gas Jour.*, vol. 57, No. 5.
38. Munger, C. G., "Coatings for Offshore Drilling Structures," *Corrosion*, May 1959, vol. 15, No. 5.
39. McMaster, Robert C., "Prevention of Drill String Failures," *World Oil*, May 1948, vol. 128, No. 5.
Texter, H. G., and Grant, R. S., "Causes and Prevention of Drill Pipe and Tool Joint Troubles," *World Oil*, October-December 1948, vol. 128, Nos. 10-12.
40. Prange, F. A., "Mechanical Properties and Corrosion Resistance of Oil Well Tubing," *Corrosion*, February 1959, vol. 15.
41. "Sulfide Cracking Resistant Metallic Materials for Valves for Production and Pipeline Service," *Materials Protection*, September 1966, vol. 5, No. 9, pp. 81-82.

SECTION 4—Influence of Corrosion Control on Drilling, Production and Transportation of Oil and Gas

A. Corrosion in Drilling Operations

1. ECONOMIC ASPECTS

It is difficult to estimate the economics of corrosion control in drilling operations because of the varied influence of other factors. Drilling fluids in many cases are noncorrosive or sometimes even protective, whereas in other instances, the fluids are corrosive from contaminants such as hydrogen sulfide originating from the drilled formation or from thermal degradation of certain mud additives. With the advent of air or mist drilling, an increasing amount of drill pipe corrosion occurred. Clear water, low solids and aerated drilling fluids are also quite corrosive.

One writer stated: "Contractor costs continue to rise while footage prices and number of wells drilled have declined sharply during the past 10 years."[42] Equipment failures due to corrosion are undoubtedly responsible for a large portion of the drilling contractors costs in certain corrosive areas. The petroleum industry spent approximately $36 million for new drill pipe in 1961 and much of this cost probably represents replacement of pipe losses due to corrosion rather than increased inventory.[43] The economic consequences of the corrosion of drill pipe is seen in the estimate made in 1952 that each of the 700 or more drilling rigs operating in West Texas had about $137 a day in corrosion damage. Each well at that time had an investment of from $30,000 to $70,000 in drill pipe.[44]

2. RECOGNITION OF CORROSION-RELATED DRILL PIPE FAILURES

Since 1948, stress corrosion cracking associated with hydrogen sulfide has been recognized and experience has shown the lower susceptibility of low-strength steels to this type of fatigue as contrasted to the higher alloy steels.[45]

The work at Battelle[46] resulted in a good understanding of the importance of keeping entire drill strings in tension by use of sufficient drill collars. The paper by Texter and Grant[47] enlarged on the Battelle information and discussed various conditions leading to fatigue of drill pipe, e.g., adequate drill collar, weight, importance of keeping hole straight, etc.

With deeper drilling much more attention has been given to understanding the capabilities of materials under bending, axial loads and combined stresses. In a 1960 paper,[48] Lubinski showed the pronounced effects of rate of change of hole angle on stressing drill pipe. Effects of corrosive environment on drill pipe failure under stress were studied for the Mohole Project by Curtiss Wright Corp. (Report No. C–2951).

It was pointed out in a recent article that without a constant check on corrosion rate, drill pipe can be severely corroded and pitted in a very short time and this condition may not be detected until damage is done.[49] A technique has been developed for detecting abnormally corrosive drilling fluids and measuring the rate of downhole corrosion during drilling of an oil well.[50] The procedure consists of placing a ring-shaped coupon with the same inside diameter as the drill pipe in the clearance between the pipe ends inside a tool joint. The weight loss and pitting of the coupon after a certain time exposure are good indications of corrosion severity.

3. CORROSION CONTROL MEASURES

In addition to keeping drilling strings in tension, other proven preventive measures include coating of the interior of drill pipe, cleaning drill pipe frequently, and inspection to segregate damaged pipe. Sodium chromate was used for several years to inhibit corrosion but was largely discontinued after 1948 because of cost, toxicity, and its unsuitability in sulfide systems. Organic inhibitors are now being used to an increasing extent and improved compounds are being developed.[51]

Use of protective coating systems specially designed for retarding internal corrosion of drill pipe is growing rapidly. The experience of one company[52] depicts the possible value of this protection method. It was reported that 75 percent of the company's failed drill pipe was being lost from internal corrosion while less than 8 percent was lost from external wear. Internal coatings have greatly reduced corrosion failures and the savings have more than paid for the coatings application costs.

B. Corrosion in Producing Operations

1. ECONOMIC ASPECTS AND INFLUENCE ON PRODUCING CAPABILITIES

The cost of production corrosion has been variously estimated to range from nine cents to as high

42. Hobbs, Mel, "The Growing Price Squeeze," *World Oil*, February 1, 1965, vol. 160, No. 2.
43. "Ring Coupon Technique Accurately Measures Down Hole Corrosion," *Materials Protection*, Staff Feature, August 1963, vol. 2, No. 8.
44. Moore, Stanley C., "Drill Stem Corrosion in West Texas," *Corrosion*, April 1953, vol. 19, No. 4, pp. 112-114.
45. Prange, *op. cit.*
46. McMaster, *op. cit.*
47. Texter and Grant, *op. cit.*
48. Lubinski, Arthur, "Maximum Permissible Doglegs in Rotary Boreholes," *Trans.*, AIME, 1961, vol. 222.
49. Rollins, H. M., "Fatigue Failure in Drill Pipe Design," *Drilling Magazine*, June 1966, vol. 27.
50. *Op. cit.*, footnote 43.
51. Bundrant, C. O., "Some Gyp-Mud Drilling Fluids Can Be Corrosive," *Materials Protection*, September 1962, vol. 1, No. 9, pp. 11-17.
52. Sheridan, Hunter, "Coated Drill Scores for Penrod," *Oil & Gas Jour.*, November 15, 1965, vol. 63.

as sixteen cents per barrel of oil produced; resulting in an industry-wide cost estimate as high as $450,000,000 per year.[53]

From the late 1930's to the present it has become increasingly necessary to produce from reservoirs yielding fluids with high concentrations of hydrogen sulfide, carbon dioxide, and organic acids. Higher pressures and temperatures in the deeper formations intensify the corrosiveness. Fortunately, there has been a simultaneous growth in corrosion control knowledge during this time period as discussed in the preceding sections. Of special importance has been the advent of good corrosion inhibitors. Adaptation of the improved corrosion control techniques as needed has undoubtedly affected the economics of oil production to a very great extent and permitted the continued production of wells that would otherwise have become uneconomic due to excessive maintenance expense.

Because of the ever changing situation as regards corrosiveness and corrosion control, it is not possible to assess quantitatively the impact of improved technology on production capacity. However, a specific example of one very important production corrosion problem can serve to illustrate the importance of corrosion control. The example is the external corrosion of casing in oil and gas wells. The paper by Battle summarized the status of the problem as of the early 1950's. Quoting from this paper:

> "At the close of 1951, the American Petroleum Institute reported 482,260 producing oil and gas wells within the United States. Although the maximum productive depth at that time was 15,530 feet, the average depth of the productive wells was 3,888 feet. A conservative estimate of the steel used in the production string (assuming 7-inch OD 29-pound per foot casing) of these wells is approximately 27 million tons which, at today's prices, is worth some 5 billion dollars. Casing failures are occurring in many wells of the older fields as well as in some of the newer fields at a time when only a part of the recoverable reserves have been produced. The wells which must produce these reserves represent tremendous investments. Because of the vigorous and prompt prosecution of remedial work by the industry when casing failures have occurred, major damage to a reservoir has seldom actually occurred. Nevertheless, the potential damage to a reservoir in such cases is great.
>
> "Repair of such failures often can be made only by setting inside liners, the cost of which frequently approaches the original cost of the well. In some few instances, repair takes the form of redrilling the well which, at today's drilling costs, may not be economically feasible in the case of some of the poorer fields. Thus, unless the oil is produced by adjoining wells, such failure can result in the loss of recoverable oil." [54]

According to a 1954 report by NACE Unit Committee T-1H on Oil String Casing Corrosion,[55] casing corrosion failures were occurring at a rate of 40–50 failures per 10,000 producing wells and the failure frequency was predicted to double by about 1964. In 1955, it was reported [56] that repair of 420 casing failures in the West Texas-New Mexico area cost $5,161,200 or more than $12,000 each. Applying these figures to the approximately 600,000 wells operating in the U.S. in 1955, the annual cost of casing repair was about $33,000,000 at that time. At the projected rate of 90 failures per year per 10,000 wells and an assumed average repair cost of $19,000 per job, the 1964 total estimated casing repair is about $120,000,000. The actual casing repair costs are believed to be well below this figure due to the widespread application of cathodic protection by oil producing companies throughout the country during the last 10 years.

The effectiveness of this corrosion control procedure and the savings resulting from its use were demonstrated by a 1963 study of 2,264 cathodically protected wells in Hugoton Field, Kansas.[57] The predicted casing failure rate was reduced by at least 50 percent and the estimated savings projected from the late 50's to 1966 amounted to $6,438,160. The figure for savings is necessarily arbitrary since, if projected to the 30-40 year expected field life, the savings figure increases toward the approximately $57,000,000 invested in drilling and equipping the wells. This does not account for loss of gas production if the corrosion had been allowed to go uncontrolled and early abandonment of the field had resulted.

Corrosion occurring inside the wells and surface equipment accounts for most of the corrosion costs in oil production. Use of chemical corrosion inhibitors is the most widely used method of controlling internal corrosion in oil and gas wells.[58] It is estimated that the producing industry spends about $25,000,000 a year on chemical inhibitors.[59] The savings resulting from use of chemical inhibitors in production operations has been found to be about five times the cost of the inhibitors,[60] giving a total accrued savings figure of $125,000,000 a year. This is equivalent to a savings of about 4½ cents per barrel of crude oil produced in the United States. Without such savings the industry would undoubtedly be unable to operate many marginal, low-profit wells.

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53. "Corrosion of Oil and Gas Well Equipment," *Paper*, API, Div. of Production, Dallas, 1958.
Phenicie, John W., "Increased Petroleum Production Demands Increased Corrosion Control," *Materials Protection*, March 1966, vol. 5, No. 3.
54. Battle, *op. cit.*
55. *Corrosion*, October 1954, vol. 10, No. 10, p. 14.
56. *Corrosion*, July 1955, vol. 11, No. 7, p. 58.
57. Koger, W. C., "Cathodic Protection of Casing a Good Investment," *World Oil*, January 1963, vol. 156, No. 1.
58. Report by NACE Tech. Unit Comm., *Materials Protection*, December 1963, vol. 2, No. 12.
59. Phenicie, *op. cit.*
60. NACE, *Materials Protection*, *op. cit.*

C. Corrosion in Transportation and Storage Facilities

1. ECONOMIC ASPECTS AND PROTECTION METHODS

Several factors influenced the early development of method for controlling corrosion of pipelines and storage tanks. First, being located on the surface, corrosion of the equipment is detected and measured fairly easily. Failures are soon obvious. Due to the simple configuration and mechanics of operation, effects of corrosion on maintenance expense can be clearly defined and accounted for. Further, the physical size of transportation and storage facilities are necessarily very large to accommodate the volumes of petroleum being handled. Consequently, only protective measures of low unit cost can be considered.

Early experience demonstrated the value of thick external coatings of asphalt or coal tar. These are still widely used and augmented with felt, paper, concrete, and plastic sheeting. Machines of special design have been developed to rapidly apply the coatings and wrappings to pipelines. Even so, the applied cost of a pipeline coating can amount to 10 percent of the cost of a new pipeline.[61]

Modern practice is to apply cathodic protection in addition to the external coatings. The calculated 30-year present worth cost of cathodic protection on a 10-inch pipeline with an almost perfect coating is 3 cents per foot.[62] However, due to coating imperfections and damage, this low value is probably not often achieved.

Protection of pipelines in especially corrosive environments, as in river crossings or salt water, has reached a high degree of sophistication. Pipe to be submerged is commonly wrapped or coated onshore with specially weighted materials and then floated, shoved or towed into position from barges or specially constructed pipe-laying boats. Cathodic protection is applied routinely to pipe laid in water.

There are a number of comparatively extensive systems of aluminum piping, particularly for gas gathering.[63] Aluminum pipelines also are cathodically protected.

External protection of tankage is normally obtained by periodic application of paint which also has esthetic value. Corrosion-resistant metals such as aluminum are often used for tank docks or roofs. Special tank designs utilizing floating roofs are used to minimize internal vapor space corrosion as well as prevention of vapor losses.

Internal tank linings consist of such varied materials as plastics, rubber sheeting, concrete (gunnite), and coal tar-epoxy combinations. Large pipelines are normally not coated internally but some use is made of water-removing devices and corrosion inhibitors. For example, it was recently reported that a savings of $27,000 per year on repair costs of an East Texas gas gathering system was achieved by periodically injecting an organic corrosion inhibitor into the line.[64] The same study reported a reduction in corrosion rate from 60 mils penetration per year to 0.3 mils penetration per year by fogging inhibitor into a gas transmission line. These striking results are rather typical of the achievements being obtained throughout the oil industry by intelligent application of corrosion control measures.

It was estimated in 1956[65] that the cost of uncontrolled corrosion inside a 17,000-ton ship tanker is at least $150,000 per year. A saving of up to $1,000,000 over the life of a 30,000 DWT tanker in clean service is estimated from the use of coatings.[66] New application methods and materials offer some promise that serious corrosion damage suffered by tankships with petroleum ladings will be reduced significantly in the future. High-sulfide crudes also severely damage tanks in ships, and no completely effective way to control it has been developed so far.

Cathodic protection effectively controls damage in tanks when they are carrying saltwater ballast. Regulations of the Coast Guard prevent the use on tankships of galvanic anodes which have a pyrolytic effect on iron sulfide scale.[67]

D. Safety Aspects of Industry Corrosion

Considering the enormous variety of machines, equipment, and operating conditions involved in drilling, producing, transporting, and storage operations, the opportunity for corrosion-related accidents is very great. It is, however, a tribute to the many companies involved that the accident rate in 1964 averaged 6.70 per 1,000,000 man-hours worked in the petroleum industry as compared to an average of 6.45 for all industries.[68]

Safety standards are in force in all phases of the operations. During drilling, constant checks are made of well pressures and heavy drilling muds are used where high-pressure formations are expected. The hazards of operating drill pipe in H_2S environments

61. Hunter, J. N., Jr., "Laboratory and Field Evaluation of Pipeline Coatings," *Materials Protection*, February 1964, vol. 3, No. 2.
62. *Ibid.*
63. Wanderer, E. T., and Sprowls, Donald O., "Aluminum Alloys for Offshore Pipelines," *Corrosion*, July 1952, vol. 8, No. 7, pp. 225-226.
64. Graves, John W., and Sullivan, E. H., "Internal Corrosion in Gas Gathering Systems and Transmission Lines," *Materials Protection*, June 1966, vol. 5, No. 6.
65. Watkins, F. M., "Corrosion Costs for Tank Ships in Clean Products Service," *Paper*, API, Absecon, New Jersey, June 13, 1956.
66. Purlee, Lee, Leyland, Walter, Jr., and McPherson, W. E., "Economic Analysis of Tank Coatings for Tankers in Clean Service," *Materials Protection*, June 1965, vol. 4, No. 6, pp. 50-63.
67. Title 46—Shipping. Chapter I—Coast Guard, Department of the Treasury. Subchapter D—Tank Vessels, Part 35—Operations. Subchapter 35.01—Special Operating Requirements. Aluminum or Magnesium Sacrificial Anode Installations Prohibited in Cargo Tanks, dated May 13, 1964. Amended by: Navigation and Vessel Inspection Circular No. 3-64, dated June 11, 1964. 46 CFR 35.01-25 in the Federal Register of 16 May 1964.
68. *Accident Facts*, National Safety Council, 1965.

(which cause embrittlement failures) have been recognized and protective operating procedures have been developed.[69] Blowout preventers are provided in case corrosion embrittlement or some other condition causes failure of the drill pipe. In known corrosive areas, the pressure equipment is frequently checked by pressure testing and by various metal wall-thickness measuring devices. Use of gas masks is required for workmen around production equipment handling sour (hydrogen sulfide containing) gas where a corrosion failure might release the gas.

Stress corrosion cracking was blamed for a break leading to the explosion of a 24-inch gas transmission line in Louisiana which killed 17 persons in 1965.[70] The special problems of protecting buried pipelines in congested areas are being studied.[71]

The importance of safety led to a recent study by the FPC of gas pipeline failures. In this first complete list of gas pipeline failures, corrosion was found responsible for 19 percent of the failures, and the need for uniform adherence to safety practices in coating, cathodic protection and pressure testing was stressed.[72] Early recognition and appropriate measures have and should continue to minimize the hazards of equipment failures from corrosion.

SECTION 5—Areas of New and Future Development

The basic tools for corrosion prevention are available and field proven. Continued improvements are expected in chemical inhibitors, paints and coatings, plastics, metal alloys and the like, but major advances are anticipated in applications technology. This is the area of learning when and how to best apply the varied means of corrosion control. Following are a few exemplary categories that show promise of great growth:

A. Nondestructive Methods for in Place Detection and Measurement of Corrosion

Instruments are already in use which can measure the instantaneous and cumulative corrosion of test probes. More widespread use and automation of such devices for routine monitoring and recording of corrosion rates are expected. Such measurements and records can rapidly show where corrosion losses are excessive and provide economic justification for applying protective procedures.

Metal wall-thickness measurements by sonic, X-ray and other directed energy beams should become routine maintenance procedures.

B. Corrosion Data Storage and Retrieval

The rapidly increasing investment in equipment subject to corrosion, the improved methods of measuring corrosion losses, and the increasing awareness that such losses can be controlled are factors which point to strong growth in corrosion cost accounting. Central data storage and retrieval by machine can be invaluable not only for cost analyses but for materials selection. There are extensive sources of data on corrosion control available now. These consist of the 20-year accumulation of papers and reports in its own publications and more than 50,000 abstracts of technical literature in bibliographies and abstract publications of the National Association of Corrosion Engineers. Extensive indexing makes this information immediately available. Increased use of data processing and computer services in corrosion control is predicted.

C. Special Protective Procedures for Unusual Environments

While the basic tools of cathodic protection, protective coatings, and chemical inhibitors will continue to be used, new methods of applying and controlling them must be worked out as unique problems are encountered. These unique problems come about as the search for and production of oil goes deeper into the earth and farther out into the oceans. For example, drilling in 3,000 ft. waters is seen within the next decade.[73] Studies are currently underway to determine how metals react and how effective cathodic protection is at these great depths.[74] Undoubtedly, special metals, coatings, and electrical gear will be designed to meet the requirements of hardware used in the deep sea environments.

Changing production, transportation, and storage techniques are also imposing new requirements. Thermal recovery operations by steam injection or subsurface combustion are introducing heat, oxygen and oil decomposition products into the producing wells. Efficient inhibitors and special alloys are needed to retard corrosion resulting from these operations.

Research on problems such as failure prediction, fracture propagation resistance, and hydrogen-stress cracking in line pipe is being sponsored through the American Gas Association.[75]

Installation of very long, extra high voltage direct current power transmission lines is expected to create corrosion problems on adjacent buried structures.[76] The stray currents induced in the earth from

69. Rollins, H. M., "Drill Stem Failures Due to H_2S," *Oil & Gas Jour.*, January 24, 1966, vol. 63.
70. *Oil & Gas Jour.*, July 1965, vol. 63.
71. West, Lewis H., "Cathodic Protection of Buried Pipelines in Congested Areas," *Materials Protection*, February 1963, vol. 2, No. 2.
72. Sheridan, Hunter, *op. cit.*
73. *Oil & Gas Jour.*, Domestic News, May 23, 1966, vol. 64, p. 110.
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such systems have an effect basically similar to the interference corrosion that can be induced where cathodically protected structures are located near nonprotected structures or ones at a lower cathodic potential. The basic remedies are to keep the installations spatially isolated or to bond everything together so that little or no potential gradient exists. With the crowding induced by a rapidly growing population, it is expected that much study and cooperation between neighboring equipment owners will be mandatory. Unitization for cooperative and coordinated protection of all buried structures within given areas may be required. For example, all buried lines and wells in a whole oil producing area may have to be brought to a substantially uniform electrical potential to avoid mutual interference. Such efforts should promulgate developments in instrumentation and specialty electrical hardware.

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PART II

IMPACT OF NEW TECHNOLOGY ON U. S. PETROLEUM REFINING

Contents of PART II

IMPACT OF NEW TECHNOLOGY ON U. S. PETROLEUM REFINING

CHAPTER EIGHT—SUMMARY

Technological advances have had a major impact on the petroleum refining industry since World War II. Rapid growth in the demand for motor gasoline and distillates has been met both through increased refinery capacity and by installation of new processes to convert heavy residual materials into needed light products. Even with a major shift in refinery yields to maximize the gasoline and distillates, the industry has more than doubled its refining capacity during the 1945-1965 period. New processes employing complex catalysts have been introduced which are far more flexible and efficient than the old thermal operations commonly used during World War II. In addition to quantity, the quality of all petroleum products has been steadily improved, not only by more intense refining methods, but also through wide use of chemical additives developed during the past two decades.

By the end of the war, no excess refining capacity existed. Starting in 1945, the industry expanded at such a rapid rate that in a few years the refining capacity exceeded the demand for products. This has resulted in an intensely competitive industry, with the individual refiners working diligently, as new equipment is installed, to find ways of increasing efficiency and reducing operating cost. Great emphasis is placed on heat economy, consolidation of operations, automatic control, improved maintenance practices and other steps to produce products at the lowest possible costs.

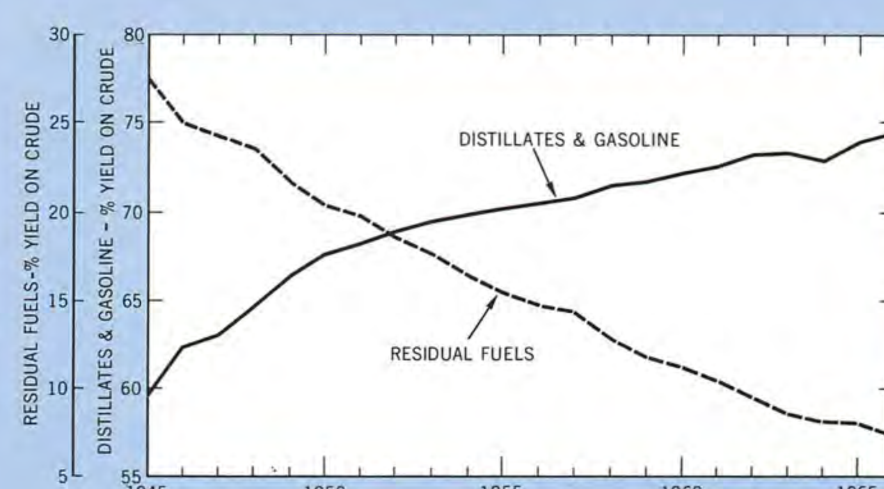
In the same postwar period the so-called petrochemical industry underwent a vigorous development and expansion. The industry was pioneered prewar by both chemical and oil companies, received a boost by wartime demand, and grew rapidly thereafter. While related in part to refinery technology, the development of this new industry represents a large technical achievement in itself and is not considered as refining technology to be examined in this report.

A. Refining Processes

Most impressive in this era of change has been the transformation of the refining industry's chief product, motor gasoline. Prewar gasoline was a simple mixture of largely unprocessed stocks with basic additives for octane improvement and storage stability. Today we find many different processes producing specific hydrocarbon types for blending into motor gasoline. Among these, catalytic cracking, alkylation, catalytic reforming, isomerization, polymerization, and hydrocracking are the most common. Additives now are used not only for octane improvement and stability, but also to reduce carbon deposits, clean carburetors, prevent carburetor icing, prevent corrosion, reduce spark plug fouling, and for many other quality improvements. Volatility is now optimized seasonally and by geographical areas to give the consumer peak performance in quick starting and warmup, while minimizing evaporation loss and carburetor icing.

The thermal processes which adequately met quality requirements during World War II were no longer able to provide efficiently the octane improvement needed for postwar high-compression engines. Catalytic cracking, introduced during the war for production of aviation gasoline, became the workhorse of the industry for producing motor gasoline stocks. This process was subsequently greatly improved through engineering changes that made the process much more efficient, and by introduction of new catalysts that gave higher yields of more valuable products. Catalytic reforming, which provides high octane blend stocks, came into wide use with the development in the 1950's of a new process utilizing a highly efficient catalyst made of platinum. By 1965, the platinum catalytic reforming capacity was over two million barrels per day, or nearly 20 percent of the industry's crude distillation capacity. Catalytic cracking by then was 5.5 million barrels, over 50 percent of the crude throughput capacity. Another wartime process, alkylation, was pressed into motor gasoline production to give maximum road performance in the high-compression engines introduced in the late 1950's. These three processes account for most of the octane quality found in postwar gasoline. However, still another very significant development was catalytic hydrogen treating, a process used to remove sulfur and nitrogen compounds from the intermediate process feed streams. Without this versatile opera-

FIGURE **100**
Refinery
Product
Yield Shift



tion, feedstocks would be limited to low contaminant levels and the catalytic octane improvement processes would not have found wide application. As more stocks were used to manufacture gasoline, more advanced methods were found to blend these materials together. In-line blending, a technique for blending continuously while delivering the product to a pipeline, barge or tanker, became possible as continuous quality analyzers were developed. The next step, computer control, was soon added to maintain precise control of all blending stocks and additives to optimize performance quality of the gasoline.

A major new aircraft fuel was introduced with the jet age. In the span of a few short years, jet fuel consumption surpassed aviation gasoline and shifted the demand pattern of the refiner's output. To obtain the yield pattern required to meet the growing motor gasoline market and the heavy demand for jet fuel distillates, the refiner turned to processes to convert residual fuels into stocks that can be further processed into motor gasoline and jet fuel. This had a profound effect on the yield pattern of major products produced by refineries with the residual output dropping markedly and the yields of distillate and gasoline increasing just as rapidly. This postwar yield change is shown in Figure 100 and in more detail in the tabulation.

Residual fuels are converted into more useful products by several process developments. Vacuum distillation enables more catalytic cracking feedstocks to be removed from the residua. Hydrogen pretreating and deasphalting of feed streams make catalytic cracking of heavy stocks economical. An old refining process, coking, was redesigned to be more efficient and now finds wide acceptance for complete destruction of residua into petroleum coke, catalytic cracking feed, naphtha and fuel gas. Greater demand for motor gasoline than distillates in the mid-1960's was satisfied by the development of a low-cost hydrocracking process. This versatile process produces gasoline, jet fuel and distillates from a wide variety of charge stocks ranging from kerosene to residua. Hydrotreating of finished stocks produces products having significantly lower sulfur impurities and less corrosiveness, as well as improvement in odor and color, and higher stability.

B. Refinery Efficiency

Along with new processing techniques, refiners were also introducing ways to improve efficiency and reduce product cost. Over the 1945-1965 period, total operating costs, after adjusting for inflation, were actually reduced by about 12 percent in spite of the refiner spending considerably more for chemicals, additives, and utilities to provide the higher quality products. Extensive use of automatic process control, consolidation of operations, high quality of skilled workers, improved construction materials, efficient planning of mechanical work, preventative maintenance, and ability to engineer and construct large efficient units are among the items that contributed to the more efficient operation. With the larger sized units and increased investment in labor-saving equipment, the productivity of the refinery worker, as measured by output per man-hour, was increased threefold. Although wages paid the refinery worker are about one-third higher than the

	Percent Yield on Crude		
	1945	1955	1965
Gasoline	40.5	44.0	44.9
Distillate Fuels	19.1	26.1	29.0
Lubricants and Other	13.1	14.5	18.0
Residual Fuel Oil	27.2	15.3	8.1

average wage of all manufacturing industries, and this differential has been maintained over the 20-year postwar period, the direct total labor cost of refining a barrel of crude oil has remained about the same since 1950.

C. Petroleum Products Demand

In 1945, the total demand for petroleum products was less than 5 million barrels per day, about the same as today's demand for motor gasoline alone. Total demand in 1965 was over 11 million barrels per day which represents a per capita consumption of 890 gallons, up from 530 gallons in 1946. By far the most spectacular increase was in air travel where aviation fuel consumption increased more than twenty times over the 1946 level. Increases in major fuel product outputs during the postwar period were:

	MILLION BBL./DAY 1946	1965	AVERAGE ANNUAL INCREASES, % PER INTERVENING YEAR
Total Gasoline	2.0	4.9	4.7
Jet Fuel		.6	
Distillates	.9	2.4	5.2
Residuals	1.3	1.6	1.0

Home heating demand for distillates increased sharply after the war, chiefly because of the postwar popularity of oil heating over coal furnaces. Railroad conversion from coal to diesel-powered locomotives also increased distillate demand.

D. Improvement in Product Quality and Handling

Along with the increase in volumes, the quality of virtually all products has been improved significantly. This is especially true in the lubricants field where increased knowledge of solvent extraction chemistry and hydrogen treating have led to base stocks possessing wide viscosity ranges, very low pour properties, high stability, and excellent qualities of odor and color. In addition, additives have been developed to provide specific performance qualities, and strong detergents have been found for elimination of engine deposits and crankcase sludge. These improvements have resulted in engine oils capable of maintaining quality over long drain intervals, as well as automatic transmission fluids, greases, gear oils, and hydraulic oils good essentially for the life of the equipment they serve. Specialty products, i.e., solvents, naphthas, waxes and liquefied petroleum gas, have greatly increased in volume and variety, and, in general, the trend has been toward purer, higher quality products with more exacting specifications. Asphalt products, both paving and roofing types, have seen rapid growth in their use; and asphalt products now represent nearly 3 percent of the total U. S. demand for petroleum products. A substantial effort by the Asphalt Institute, the industry's research arm, has been successful in standardizing the specifications of asphalt products and greatly reducing the number of major grades. New techniques in asphalt highway construction have been developed to the point where asphalt highways can be built for less money and require less maintenance than comparable concrete highways. Sulfur reduction of distillate products, diesel fuels, heating oil, kerosene, and naphthas have greatly improved odor, anticorrosiveness, and stability of these products.

An important development in storage of petroleum products is the use of caverns and frozen earth pits to store light products such as propane and butane. This has provided low cost storage for these vapor products and enables economical production during off season periods. Great strides have also been made in preventing evaporation of hydrocarbon vapors from storage tanks. Automatic control and modern electronic computers have made efficient terminal and distribution control systems possible. Direct pipeline supply to airports has been of major importance in holding down the cost of aviation fuel as the demand for this fuel has increased. Also, the transportation of oil products itself has undergone a trend to larger equipment with increased capacity and high efficiency.

E. Industry-Government Relations

The petroleum refining industry, like all manufacturing industries, has frequent contacts with the public and with state and local governments. The industry is also subject to many forms of federal regulation. Most of these are primarily economic and political in character, and involve refining technology only incidentally. There are three fields, however, where there is maintained a particularly close relationship between refining technology and the interest of the government and the community. These are national defense, safety, and the many problems that arise in the fields of air and water cleanliness. The mobilization of the industry during World War II was an outstanding example of companies pooling their technical resources and sharing production know-how to meet the needs of national defense. As a result, the industry was able to move forward in refining technology at great speed to meet the high wartime demand for critical products. The close cooperation which characterized industry-government relations in World War II has continued through the succession of crises and conflicts occurring during the past and present decades, notably the Korean Conflict (Petroleum Administration for Defense), the 1956 Suez Crisis, the Vietnam War and the 1967 Middle East War. Working primarily through the National Petroleum Council, and in close association with the Office of Oil and Gas in the Department of the Interior, the refinery segment of the industry has made important contributions to strengthen the country's defense posture, particularly as related to the standby Emergency Petroleum and Gas Administration.

Government regulation of industrial safety has historically been a function of state governments. The refining industry, however, has always provided strong safety emphasis in its operations, with the result that its accident frequency rate is less than half the average attained by other manufacturing industries.

Air and water cleanliness is receiving a great deal of attention by the petroleum refiner. In water pollution abatement, technology and procedures are well advanced and the industry is moving rapidly to meet or exceed required water cleanliness criteria. Air pollution, however, is complicated by the fact that the most serious problem exists not with the industry itself but with the emissions created by use of its products. Further complications result from the lack of complete understanding of conditions or compounds responsible for air pollution. Thus, much of the research effort today is directed toward identifying the problems and, at this point in time, it is difficult to predict the effect this research will have on the refining technology of the oil industry. However, the impact could be considerable since many of the problems deal directly with the composition of the industry's product.

F. Future Outlook

No change is anticipated in the continued growth of the petroleum industry, and in the next ten years, the refining capacity is expected to be one-third larger than it is today. Gasoline will continue to be the principal product with 100 million cars and 20 million trucks and buses expected on the U. S. highways by 1975. Quality of gasoline should continue to show improvement as more active additives are developed. The impact of air pollution research is uncertain, but radical changes in gasoline composition and refining techniques do not appear likely at this time. There is optimism within the industry that the performance of the gasoline engine and its fuels can be controlled to meet reasonable standards of air cleanliness.

Quality of lubricants will continue to improve even though prime raw material sources possibly will not keep up with lube demand. More intense processing plus extensive use of additives will provide the quality required for the demanding service of future equipment. Jet engines will continue to place exacting requirements on the industry, with the need for high volumes of supersonic fuels capable of removing combustion heat at extremely high heat densities without appreciable deterioration.

Refining techniques will expand the use of catalytic processes to meet more exact specifications on all products. As demand for motor gasoline continues to increase, more application of the hydrocracking process will result. Continued research and introduction of improved catalysts can be expected even though the processes themselves may not show significant change. Hydrogen treating for sulfur removal will become more widely utilized and it is likely that the output of residual fuels will continue to decline as a refined product.

Computers and continuous analyzers will be widely used for process control. Refinery operation will very likely be controlled and optimized by a centralized system utilizing a computer. The trend to large efficient refining units, designed to minimize maintenance and personnel, can be expected to continue.

CHAPTER NINE—PRODUCT QUALITY IMPROVEMENT

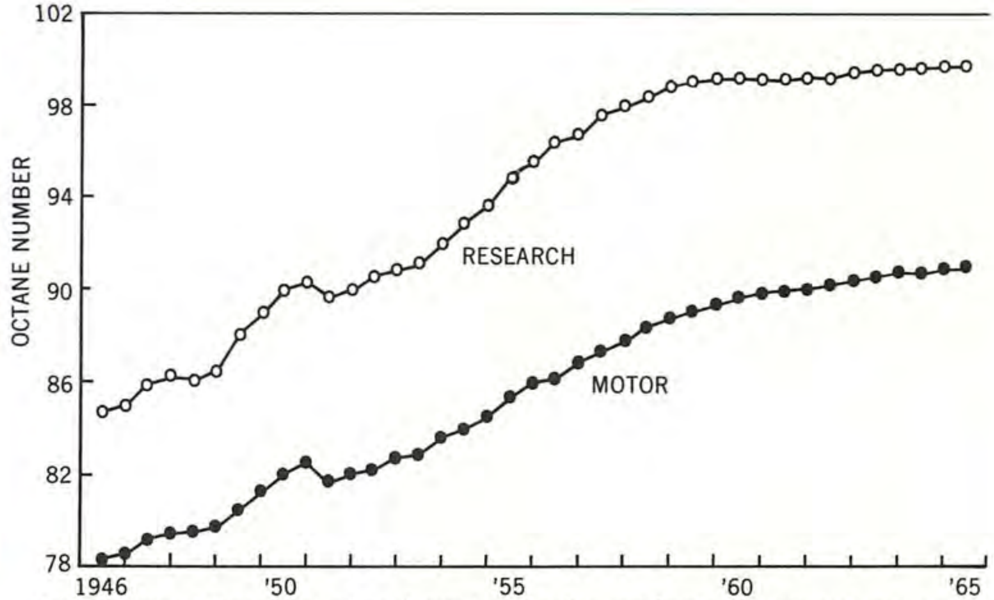
SECTION 1—Motor Fuels and Lubricants

Since World War II, there has been a steady upward trend in the quality of automotive fuels and lubricants. Intense competition in the petroleum industry has led to higher quality products as well as the introduction of numerous additives to improve both performance and engine life. Automotive designers were quick to modify their products to take advantage of these improvements with the result that a new era in reliable, high-performance transportation was begun.

A. Motor Gasolines

Following World War II, motor gasoline changed from a relatively simple mixture of petroleum fractions into a complex product made by careful blending of many intermediate refinery stocks. Where straight-run and thermally cracked stocks were the primary gasoline components before the war, today we find many different refining processes producing specific hydrocarbon types for blending into motor gasoline. Among these, catalytic cracking, alkylation, catalytic reforming, polymerization, isomerization and hydrocracking are the most common. Consequently, the refiner is able to exercise close control

FIGURE **101**
Trends in Octane Numbers of Motor Gasolines—Premium Grade



Sources: Bureau of Mines-Mineral Industry Surveys-Motor Gasolines- and Coordinating Research Council Reports.

over the final product to give it desired properties. In addition to processing, he also has a large selection of additives available that can be used to provide specific control over final product performance.

The most outstanding change in gasoline quality during the past two decades has been the vast improvement in antiknock quality as measured by research and motor octane number. This trend is shown for premium gasoline in Figure 101. Regular gasoline shows the same improvement trend but at a lower octane level. The immediate benefit of the antiknock improvement in gasoline has been to enable the automobile industry to produce a high-compression, high-performance engine either with increased fuel economy, increased power, or both, depending upon the consumer's desires.

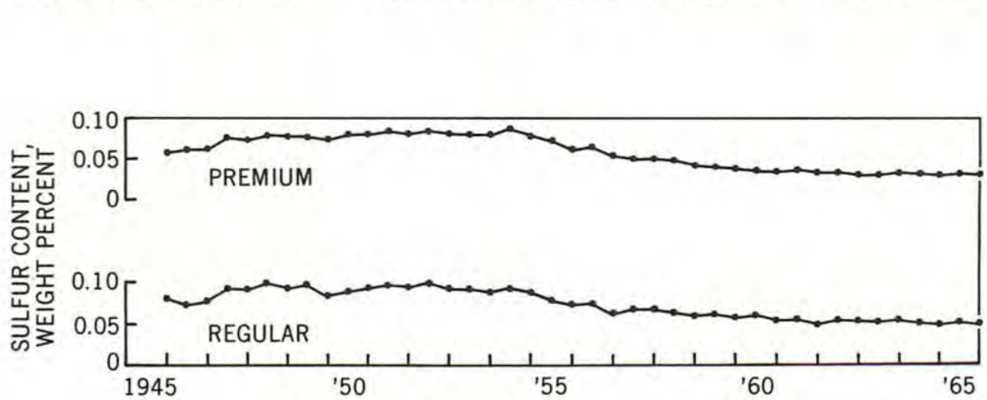
Most of the octane increase in gasoline has been achieved through new processes introduced into refining technology rather than by increasing the amount of tetraethyl lead added to the blend. A major contributor has been the octane improvement of base stocks provided by more extensive use of catalytic cracking. Development of an efficient catalytic reforming process has made relatively large quantities of high-octane aromatics available, and alkylation plants idled by a decline in the demand for aviation gasoline have been pressed into motor gasoline production.

Although the amount of tetraethyl lead added to gasoline has not increased significantly, two important developments have made the antiknock additive more effective. First, desulfurization of gasoline base stocks was developed to lower the sulfur content of the finished product. Since sulfur detracts from the ability of lead alkyls to increase octane, this process increased the octane gain from the same concentration of TEL. A second development was the introduction of other lead alkyls such as tetramethyl lead, TML, as antiknock additives which offer an economic advantage over TEL in certain gasolines.

Reduction of sulfur in motor gasoline gave advantages in addition to improvement in lead response. Inasmuch as sulfur in gasoline is an important contributor to engine wear and deposits, the reduction in sulfur itself represented a significant quality improvement. Figure 102 shows the reduction in average sulfur level in finished premium and regular gasolines since 1946.

More intense processing and increased natural gas liquids production has resulted in an increase in the availability of low-boiling base stocks with the result that volatility of motor gasoline has steadily in-

FIGURE **102**
Trends in Sulfur Content of Motor Gasolines



Source: Bureau of Mines-Mineral Industry Surveys-Motor Gasolines 1965.

creased. This trend toward more front-end volatility is shown in Figure 103 below. The changes in volatility have improved performance characteristics markedly. With the more volatile gasolines, starting is easier, warmup is quicker, there is less crankcase dilution and, to a lesser extent, an improvement has been made in cylinder deposits and engine wear. On the other hand, more volatile gasolines increase evaporation losses and also the occurrence of vapor lock and carburetor icing. As a consequence volatility has been optimized to give peak engine performance even to the extent of controlling volatility by geographical areas and seasons.

Prior to 1950, the number of different additives used in gasolines was relatively small. Tetraethyl lead was the only antiknock compound in general use and various antioxidants and metal deactivators were used to improve storage life. Dyes were also available to distinguish grades. Since then, however, development of new additives has resulted in many improvements in motor gasoline quality.

In 1953 the first detergent additive was added to gasoline and the use of detergents has now been expanded so that the majority of today's gasolines contain detergents. These materials have the ability of minimizing deposits in the venturi and throttle body sections of carburetors and thus help maintain a uniform carburetor adjustment. Carburetor detergents are a significant quality improvement because, by maintaining proper idle, they improve gasoline mileage in town driving, reduce the cost of carburetor maintenance, and reduce exhaust pollutants.

Many of the carburetor detergents have the ability to function as anti-icing additives. Carburetor icing occurs primarily under climatic conditions of cool, wet weather. Under these conditions, the evaporating gasoline causes atmospheric moisture to form ice which deposits around the throttle valve and starves the engine for air. Many other anti-icing additives such as isopropyl alcohol are also employed. With the exception of high proportions of alcohols, stalling due to carburetor icing is not completely eliminated but has been substantially reduced.

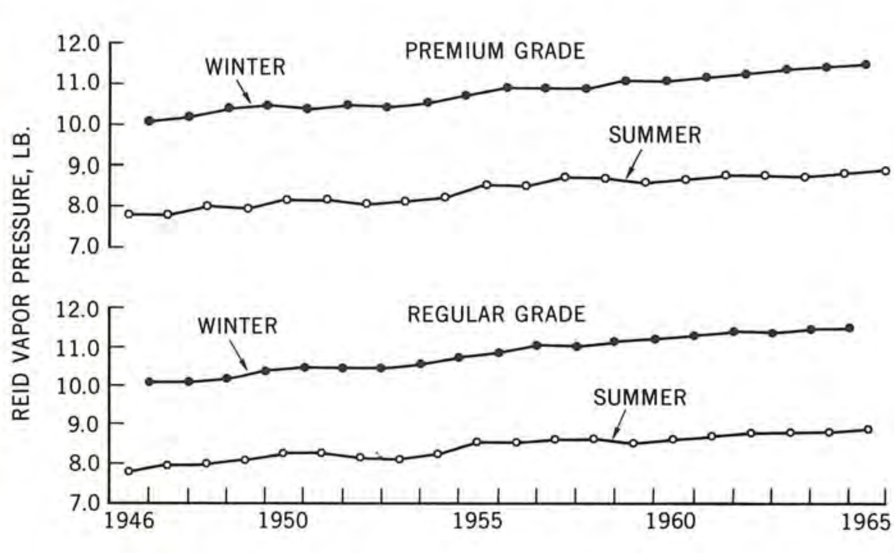
Most modern gasolines have the ability to reduce rusting in fuel systems usually as a plus feature of the surface-active detergent deicers. Some gasolines also contain special rust preventives. Rust prevention is generally required in petroleum product pipelines.

Another additive achievement was made in 1953 with the addition of tricresyl phosphate and other combustion control additives to gasolines. This material has the ability to modify combustion chamber deposits and reduce their tendency to initiate combustion. Thus, phosphorus compounds control deposit-induced ignition, reducing the so-called "wild ping" or intermittent knock, and reduce rumble, a very loud noise caused by a rapid rate of pressure rise in combustion chambers. Phosphorus compounds also reduce spark plug fouling. The need for and the effectiveness of phosphorus compounds increases with higher compression ratios. The effects become noticeable in some vehicles at 10 to 11:1 compression ratios and were spectacular in experimental 12:1 compression ratio engines. Many premium gasolines have phosphorus additives to control engine noise. This, too, is an important consumer benefit as those phenomena which lead to engine noise also can lead to engine deterioration.

This progress in additive use is most impressive when it is recognized that the introduction of a new additive in gasoline is a major research undertaking. In each instance it is preceded by months, sometimes years, of research and development work with exhaustive field testing before the additive becomes a commercial reality.

Another improvement in gasolines is in elimination of trace contaminants. These contaminants have become more important with the use of fine filters in automotive fuel systems. Special filters have been installed in service station pumps and, by at least one marketer, at the end of the filling hoses.

FIGURE **103**
Trend in Motor Gasoline Volatility



It has been established that gasoline evaporation and automobile exhaust emissions are major contributors to photochemical smog. A number of companies and government agencies are conducting research to lower these emissions as may be required by future car populations. Those involved in this research have expressed confidence in eventual success; but at this time, it is not clear which of several possible solutions has the best chance of being successfully developed. Some changes in fuel composition possibly may be involved, but such changes are not at all definite at this time.

B. Diesel Fuels

Like motor gasolines, diesel fuels, too, have been changed during the past 15 years to meet the requirements imposed by changes in engine design and operation. Major performance factors of diesel fuels are characterized by sulfur content, cetane number as a measure of ignition quality, viscosity which indicates fluidity or flow at low temperatures, and volatility.

The most significant improvement in diesel fuels has been realized through the use of hydrogen treating in the refineries primarily to reduce sulfur level. Sulfur contributes to engine deposits and wear, and its reduction is a significant improvement. In addition, fuels have been gradually improved in viscosity and volatility which has lessened engine deposits, smoke and odor. This steady quality improvement in key properties is shown for a typical high-volume diesel fuel in Figure 104. Other types have experienced similar improvement over this period.

Railroad fuels have not changed significantly with time. Some railroads operate on special economy grade fuels that have much broader volatility, lower cetane, and almost always contain large percentages of cracked stock. The large diesel engines in railroad service are less sensitive to fuel properties than their smaller counterparts and can operate satisfactorily on fuels with less exacting specifications.

Most diesel engines in truck service can operate satisfactorily on truck and tractor fuels available today. However, there is a wide range of fuels possible under this classification, and variations within the classification can have significant effect on a given engine's performance. With engine design emphasizing higher power output, reduced smoke, and maximum economy, more uniform fuel quality is desirable. In order to optimize performance, fuel specifications with narrower gravity and volatility requirements are likely in the future.

About 80 percent of the total U. S. diesel fuel oil sales is for use in transportation. Trucks and buses consume about 45 percent and railroad engines about 35 percent. Industrial, marine and military power plants use the remaining 20 percent.

As in the case of gasolines, the use of additives has become much more common in diesel fuels. Cetane improvers, largely alkyl nitrates, provide ignition quality improvement. Ignition quality influences ease of starting, roughness of operation and exhaust smoke.

A variety of additives are used to improve storage stability and permit the use of otherwise unstable stocks. Polymeric and other types of additives have been used as detergents and dispersants. The detergents have the ability of maintaining fuel injection nozzle cleanliness and will markedly increase operating time between nozzle overhauls. The so-called dispersants affect fuel filter life and a similar improvement has been achieved here. Many diesel fuels also contain rust preventives.

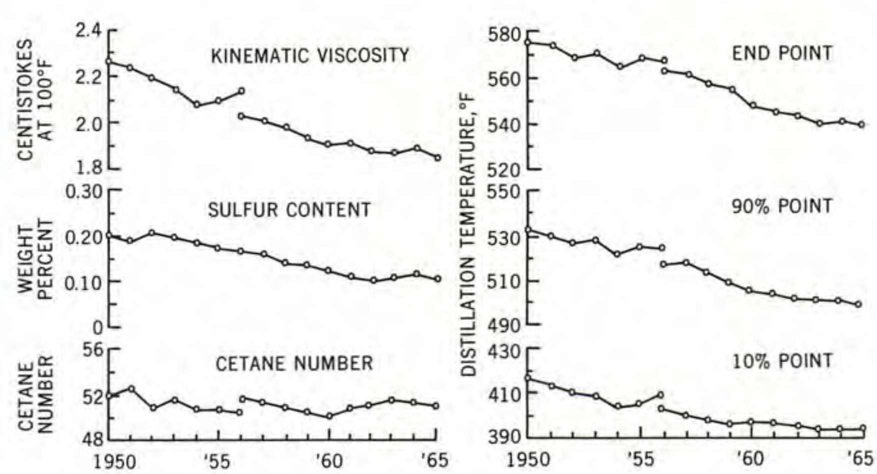
The high demand for diesel and jet fuels has made it difficult to obtain appropriate low-temperature flow characteristics by stock selection. This has led to increased use of pour depressant additives. Several of these materials, both polymeric and nonpolymeric, have the ability to greatly reduce pour points, resulting in substantial improvement in flow through distribution and truck piping systems. However, their effect on cloud point or the first appearance of wax crystals which can cause filter plugging under cold conditions, is small. This has limited their acceptance; but as experience is obtained, improvements will be made and their use should increase.

Recent air pollution laws have led to an increased

FIGURE **104.** Trends of Some Properties of Type C-B* Diesel Fuel Oils

*Formerly Listed as Grade 1-D Diesel Fuel, Now Designated "City Bus" Fuel

Source: Bureau of Mines-Mineral Industry Surveys Diesel Fuel Oils 1965.



interest in antismoking additives. The most functional of these are overbased barium compounds which are effective at concentrations about 1,000 ppm. Effective concentrations of the barium additives are quite costly, and the ash contributed by the barium salts could be a problem in some engines.

Two other types of additives are emerging from the development stages. They are biocides to prevent bacterial attack on the fuel and masking agents to improve the odor of exhaust fumes in city bus service.

The number and variety of available diesel fuel additives have enabled the petroleum industry to increase significantly the quality of diesel fuels. Further improvements are anticipated over the next several years.

C. Engine Oils

These are products on which the research challenge is great and where rewards for success are high. Also, because they are complex, ingenuity has a high payoff. Engine oils are comprised of refined oil-base stocks plus additives. Parenthetically, a few synthetic oils for engine lubrication have appeared on the market; but, presumably because of high manufacturing costs, none has lasted.

Lubricants are manufactured to meet a multitude of service requirements. Through development of improved lubricants, longer engine life has been achieved and the severe operation ranges required in modern-day engines have been made possible. Among the many performance requirements are wear protection, ability to lubricate heavily loaded parts, provide and maintain correct frictional properties, insure adhesion and oil film strength, maintain physical stability with regard to temperature and pressure, maintain chemical stability against oxidation and thermal decomposition, avoid producing corrosive acids, offer resistance to foaming, act as a detergent in removing deposits, disperse impurities, be nonvolatile and possess proper fluidity at low temperatures.

All of the high-quality motor oils on the market contain additives to enhance their service characteristics. This is not new. Compounded oils were started in the 1920's when their objective was to eliminate chatter in Model T Ford transmissions. They became an operating necessity to the early Caterpillar diesel engines in the 1930's and contributed importantly to military operations during World War II. But, there have been many important developments and many new levels of quality established since then.

The only lube refining process that has shown a significant change in importance to product quality since World War II is hydrogen treating. It was of small commercial importance in 1946, but now about half of all lubricating oil stocks receive a finishing treatment that employs hydrogen.

Superior oxidation stability and color are produced by hydrogen treating and at a lower operating cost than previous finishing methods. Experimentally wide degrees of severity have been used, but essentially all commercial processes are mild and are used as a finishing step to replace the older, final clay treatment. However, a plant has been announced to produce high viscosity index (V.I.) neutral oil from heavy cylinder and bright stock by hydrocracking.

Base stocks well above 100 V. I. have been produced by solvent extraction (double extraction), by thermal diffusion, and by severe hydrotreating. These very high V. I. stocks in the 120 to 140 range have improved thermal stability and response to additives, but their solvent power is poorer than present commercial stocks. Nevertheless, they are expected to become more important.

The types of additives used in lubricating oils are many; the combinations of additives used are even more. The following table is a list of the important lubricating oil additives and their dates of introduction.

Additive	Application	Companies Originating	Year Commercialized
Wax Naphthalenes	Pour Depressants	Jersey	1931
Polybutenes	V. I. Improvers	Jersey	1935
Phenates	Detergents	Socal, Jersey, Mobil	1939
Thiophosphates	Antiwear	Union, Socal	1940
Sulfonates	Detergent, Antirust	Lubrizol, Jersey	1941
Sulfurized Paraffins	Detergents	Socal, Jersey	1941
Phosphonates	Detergents	Indiana	1943
Salicylates	Detergents	Shell	1945
Methacrylates	V. I. Improvers	Rohm and Haas	1945
Polymers	Detergents	DuPont, Rohm and Haas, Socal	1955
Bis-Hindered Phenol	Antioxidation	Ethyl	1957
Highly Overbased Phosphonates	Detergents, Antirust	Lubrizol	1957
Succinimides	Dispersant	Lubrizol, Socal	1958
Highly Overbased Sulfonates	Detergent, Antirust	Lubrizol, Conoco Bray	1960
Highly Overbased Phenates	Detergent	Socal	1960

It should be pointed out that several varieties of many of these individual additives have been developed to maximize desired performance characteristics. For example, there are at least six different zinc dialkyl-dithiophosphates. As an example of the complexity of the mechanism by which these additives function, detergents alone are effective by at least three different routes:

(1) Neutralization—Supplying a sacrificial alkaline material to react with inorganic acids and protect engine parts from attack, or to react with acidic gum precursors and render them inactive.

(2) Peptization—Coating particles in the ½ to 2 micron range with a buffer film and/or supplying an electric charge to the particles thereby keeping them separated and suspended. These systems are thermodynamically unstable.

(3) Solubilization—Forming intimate bonding-type reactions with particles in the 200 A range and causing them to act as though they are oil soluble. These systems are thermodynamically stable.

In addition to the additives listed in the table, there are a number of proprietary materials used in lubricating oil formulas, such as pour point depressants, foam inhibitors, silver pacifiers, corrosion inhibitors, rust preventives and dyes.

The biggest activity in lubricating oil additives is in the development of combinations of additives called "packages" which are designed to provide previously decided upon performance characteristics. Many improvements have come through this route.

Depletion of additives in lubricating oils through overuse has presented a serious deterrent to performance where additives are relied upon for maintenance of quality. Although most motorists exercise care in maintaining a recommended lube change interval, there are many cases where engine life has been seriously reduced through failure to change motor oil and replenish the additives.

A development in the 1950's that offered the motorist a lubricant possessing superior properties under variable temperature conditions was perfection of the multiviscosity grade oils. Very severe processing plus large amounts of viscosity improver additives produced oils having desirable operating characteristics of both SAE 10W and SAE 30W grades. They provide the quick flow and easy engine starting of 10W oils and the lubricating oil mileage and engine protection of SAE 30W oils. Furthermore, because they are comprised of relatively low viscosity neutrals plus oil-soluble polymers having molecular weights of 100,000 or more along with other additives to improve service characteristics, their high-temperature viscosities are somewhat shear dependent; and, under conditions of shear existing in engines, operating viscosities are reduced below those of the new oil. These oils provide improvements in gasoline mileage plus higher horsepower output at low operating temperatures. Because they seldom contain bright stock, they minimize combustion chamber deposits. These are important advantages to the consumer.

Many agencies have contributed to progress in engine lubricants. These include technical societies, such as the Society of Automotive Engineers, American Petroleum Institute, American Society of Testing Materials and the American Society of Lubrication Engineers, who have provided testing methods, standards, and technical meetings for exchange of information on new developments. Many of the automobile, tractor, and engine manufacturers have had important programs on lubricants and lubricant testing methods. In fact, most of the test procedures used in lubricating oil performance specifications have been engine tests developed by the equipment manufacturers. This type of work started in the 1930's and is still going on.

Another impact of the influence of the automobile industry on lubricating oil developments is in the extension of the lubricating oil drain periods which have increased from about 3,000 miles in 1960 to over 4,200 miles in 1966. Also, the positive crankcase ventilation (PCV) valves have increased the load on the lubricating oils and have added a new dimension, namely, the ability of an oil to maintain these valves in good condition.

The longer drain periods with the complication of the PCV valves were made possible without seriously detracting from the performance of the engines by the use of the new ashless dispersant additives, and for the most part the service has been satisfactory.

Besides those lubricants mentioned, there are several important types of specialized engine lubricating oils. Oils for two-cycle outboard engines and other two-cycle engines have a special requirement because these engines are sensitive to lubricating oil ash which tends to foul spark plugs. Under conditions of high output, such as water skiing, this ash can cause preignition and burn holes in pistons. Consequently, many lubricating oils for this service have used ashless detergents of the amido-amide or the succinimide type and have been an outstanding success.

Another specialized service is the railroad diesel engine. Most of these engines employ silver wrist-pin bearings which are easily corroded by active sulfur. Consequently, they cannot use oils containing zinc thiophosphates even in the presence of silver pacifiers. It is necessary, therefore, to formulate these oils with high detergency and high resistance to deterioration with other inhibitors. This has been done successfully and outstanding service is being obtained with the best oils.

The specification tests have been a big help in defining lubricating oil quality and in assisting in development of improved products, but they do not always provide the final answers. In fact, it is sometimes possible to "fool the laboratory tests." It is therefore essential that laboratory tests be confirmed by field tests. This is done for all important new branded lubricating oils and/or for the additive packages used. Favorite testing units are taxi fleets in large cities and it is estimated that perhaps a thousand taxicabs are currently in use testing lubricating oils. When a new lubricating oil has given satisfactory results in taxis and in other field tests, the oil company can have confidence that it will give satisfaction in customer vehicles.

An important phenomenon in engine oil additives which has developed since World War II is the growth of companies selling these materials to the oil industry. During World War II there were two, or at the most three, companies with significant business in this field. Now there are at least ten, and besides the individual additives many of these companies have vast backgrounds and great ability to formulate packages for their customers. Technical advances in lubricants are no longer exclusive to the oil industry and this know-how is available to any manufacturer interested in producing lubricants.

Another important development is in lubricating oil testing where such organizations as Southwest Research Institute, Auto-Research Laboratories, and Automotive Research Associates have built laboratories and are engaged in the business of conducting specification engine tests for their customers. Their proficiency is high, their reputations are excellent, and their results are accepted by all approving agencies. They will also conduct field tests or special engine tests if their customers request it. This is another method by which smaller oil companies and compounders can be assured of high-quality products.

It is not possible to predict exactly what kind of lubricating oils will be supplied in the future. It is certain that better base stocks and more functional additives will be developed and that progress will continue in preparing packages from these products to improve service characteristics. Here the industry is highly competitive, and improved products provide an important marketing advantage. Lubricating oil technology is already highly developed and satisfactory products for new engines, for new service conditions, and for increased benefits to the customers can be expected in the near future.

D. Gear Lubricants

The gear lubricants supplied the military during World War II were, by present standards, relatively low-performance materials. Specifications were simple and easy to meet with products available at that time. Although these lubricants proved to be entirely satisfactory when using the equipment available then, they could not match the advancements in gear design that greatly increased loading and introduced the hypoid gears. Therefore, many automobile manufacturers used "active sulfur" gear lubricants which were primarily mineral oil plus 1-2 percent flowers of sulfur. These gave satisfactory performance in passenger car axles in use at that time with the only undesirable quality being a high corrosion rate.

More powerful engines developed in the early 1950's and the wide use of complex hypoid gears to lower the height of the car again made improved gear lubrication necessary. This was met with improved base oils to provide better thermal stability and improved flow characteristics at low temperatures, plus introduction of numerous additives to give wear protection, corrosion resistance, and high abrasive protection. Lubrication under the most extreme pressure conditions is afforded by additives that chemically react with the gear teeth to form a protective wear-resistant film. These lubricants are vastly superior to the World War II product.

A new type of axle design, offered in recent years as an option on passenger cars and light trucks, has more demanding lubrication requirements than standard differentials. It is the so-called "limited slip" differential which provides maximum torque on the wheel having the best traction. These axles greatly increase an automobile's traction under slippery conditions and are very desirable where operation in snow or mud is common. The major difference in lubrication requirements involves the clutches in this complicated differential that require special lubrication to avoid chatter. This has been met by new additives which provide frictional characteristics that eliminate or at least minimize this problem.

Developments in axle and gear lubricants have reached the stage where on a practical basis they have ceased to be problems. Drain periods are essentially the life of the car; and in recent years, manufacturers have even eliminated the drain plugs.

Commercial fleets, including those employing heavy-duty trucks, use essentially the same kinds of lubricants as do the passenger cars. In low-speed, high-torque service, lubricant replacements are more frequent; but here, too, the gear lubricants have been highly satisfactory and service complaints are rare.

In the future, gear lubricants should continue to be improved in wear protection and stability in view of the 5-year/50,000-mile new car warranties and the long drain periods desirable to minimize maintenance costs in commercial operation.

E. Automatic Transmission Fluids

The fluids used in the automatic transmissions of passenger cars and light trucks are considered extremely sophisticated, exacting, and the most complicated of all petroleum products.

When the first automatic transmission, "the Hydramatic," was introduced by Oldsmobile in 1938, the only source of fluid was the Oldsmobile Division of General Motors Corporation. The product obtained from the petroleum industry was supplied by

Oldsmobile and, generally speaking, gave satisfactory performance. Neither uncompounded mineral oils nor the few compounded engine oils available in 1938 were satisfactory in this transmission.

The automatic transmission was so successful and grew in use so rapidly after the war that better, more functional lubricants were required. The functions of an automatic transmission fluid may be described as follows:

(1) A mild extreme-pressure lubricant to protect the transmission planetary gears and thrust surfaces.

(2) A hydraulic fluid with nonfoaming properties for trouble-free operation in torque converters and fluid couplings, and in the hydraulic valve controls.

(3) A fluid with such high oxidation resistance that it can sustain exposure to high temperature (up to 300°F) and atmospheric oxygen without forming varnish and sludge which would prevent operation of the sensitive transmission valve systems.

(4) A rust preventive and anticorrosion lubricant which will not affect any of the various metals, gaskets, rubber seals, clutch facings, and other materials present in the transmission.

(5) A fluid with proper low-temperature viscosity for rapid-response and trouble-free operation down to −20°F and preferably lower.

(6) A lubricant which will allow smooth engagement of the transmission clutches and bands without excessive slipping or grabbing. It must retain its frictional characteristics virtually for the life of the converter, even when mixed with other approved fluids.

(7) A heat transfer medium which can transfer up to 1,500 BTU/minute to the oil cooler and transmission case for dissipation to the atmosphere.

The types of additives used in automatic transmissions and their functions are described below:

a. Detergent	Metal phosphonates Nonmetallic nitrogen containing polymers Basic metal sulfonates
b. Rust Preventive	Metal sulfonates Amine salts
c. Wear Prevention	Metal dialkyl dithiophosphates Paraffin sulfides and disulfides
d. Oxidation Inhibitor	Metal dialykl dithiophosphates Aromatic amines Alkylated phenols
e. Friction Control	Organic acids or amine salts
f. Viscosity Index Improver	Polyalkyl methacrylates Polyisobulytene
g. Foam Suppressant	Silicones
h. Esastomer Swell	Aromatic phosphate esters Aromatic petroleum fractions

In spite of the very high quality of automatic transmission fluids and their exacting specifications, some service troubles have developed. These have been caused primarily by long, hard service, such as pulling trailers or operating in severe stop-and-go service. On an overall basis, automatic transmissions and automatic transmission fluids have been highly successful commercially. They are used in a vast majority of passenger cars (80 percent of all cars sold in 1966 were equipped with automatic transmissions), and the drivers have come to expect perfect functioning. By and large, they are getting it.

The automatic transmission fluids used in trucks, buses, and tractors, with only a few exceptions, are analogous to the passenger car products. They differ in two important respects, namely, they use far less V.I. improver, being more like single grade motor oils, and more emphasis is placed on extreme pressure and wear-resistant properties. Because the operators of this type of equipment engage in preventive maintenance and because the transmissions themselves can be drained, flushed, and refilled, excellent service is being obtained.

A new generation of automatic transmissions is about to become commercial and new test procedures, new specifications, and new approvals are getting underway. With the experience of the previous products behind them, it is anticipated that the performance of these transmissions and their fluids will be even better.

F. Lubricating Greases

A lubricating grease is a lubricating oil or other lubricating fluid that has been thickened to control flow. The greases containing oil are the most important commercially, and essentially represent the entire grease volume produced by the petroleum industry.

Since 1946, improvements have been made in the three types of components of a grease: thickener, fluid, and additives. New thickeners introduced include modified clays, polyureas, calcium and aluminum complex soaps, sodium terephthalamate, and dyes. All of these are multipurpose in that they are both water resistant and high melting. Although lithium soap greases were discovered during World War II, they have reached prominence since 1946 and now constitute over 40 percent of the volume of grease sold in the United States.

The improvements in fluids have been largely in the synthetic oils. Examples are silicones, fluorinated silicones, di- and polyesters, and fluorocarbons. These generally permit the grease to operate over a broader temperature range and are of principal interest in the aerospace field.

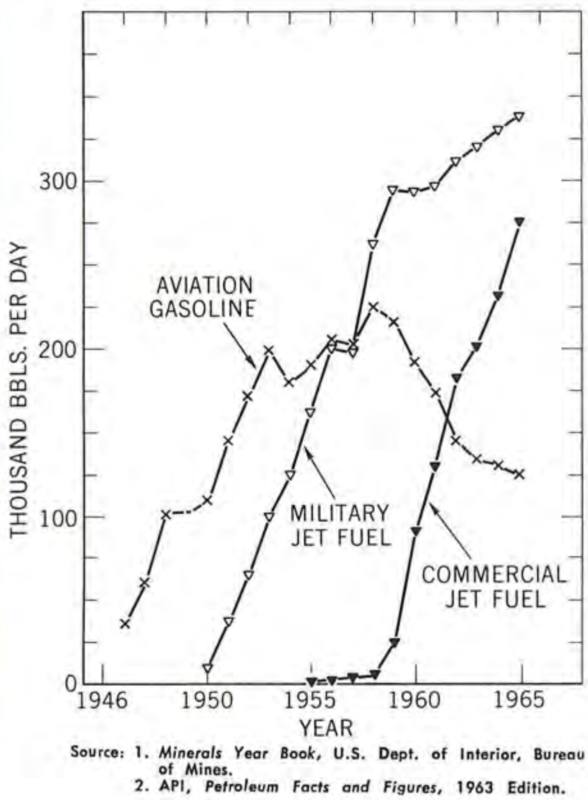
Improvement in high temperature performance has been substantial since World War II. A marked increase in bearing life has been achieved due to improvements in all three types of components. It is of interest that, at a temperature of 300°F, bearing life due to improved greases has increased from 250 hours to 4,000 hours. Such improvement could benefit a customer, for example, in the trouble-free performance of the alternator on his modern car. With the 4,000-hour grease, alternator bearings would be protected for the equivalent of 100,000 miles at speeds of 100 miles per hour. The greases prepared with silicones and fluorecarbon fluids are spectacularly more resistant to high temperatures but at $10 to $100 per pound are much too expensive for general use.

Opposing trends have caused total grease production to remain fairly constant in recent years. The general rise in industrial activity and output of machinery has been counterbalanced by the extended relubrication intervals made possible by improved grease quality. "Lifetime" greases are in particular demand for automobiles and electric motors, and the manufacturing and mobile equipment industries are asking for superior greases to allow them to reduce frequency of relubrication without endangering their operations or equipment. Greases with improved resistance to oxidation, heat, water, and mechanical breakdown as well as greases which protect against rusting and lubricating film failure are finding an expanding market.

To a large degree, grease improvements have followed the pattern of lubricating oil. Base oils and additives are selected to give maximum resistance to heat and oxidation and to provide antirust and extreme pressure lubricating properties. A thorough investigation of thickening agents has made it possible to select those which provide the proper balance of cost and resistance to heat, water, and mechanical degradation. In addition, the grease manufacturing process itself has undergone extensive development to ensure the maintenance of high and uniform quality products.

FIGURE **105**

U. S. Aviation Fuel Demand



Source: 1. *Minerals Year Book*, U.S. Dept. of Interior, Bureau of Mines.
2. API, *Petroleum Facts and Figures*, 1963 Edition.

SECTION 2—Aircraft Fuels (Including Jet Fuels)

Two types of aircraft fuels are used in the United States today. These are aviation gasolines (AVGAS) for spark ignition engines, and jet fuels for aircraft turbine engines. Figure 105 shows the U. S. demand for aviation fuels over the past 19 years. Note that in 1958, the U.S. demand for jet fuels exceeded the demand for AVGAS and has steadily increased since then.

A. Aviation Gasolines

The American Society for Testing and Materials in 1947 issued specifications for aviation gasolines, Grade 91–98 and Grade 100–130. The first number refers to antiknock performance under lean conditions and the second number under rich conditions. Since then specifications for three additional grades were added; i.e.,

1. Grade 115–145 (1948)
2. Grade 80–87 (1951)
3. Grade 108–135 (1953)

Other changes made in the specifications included: (a) dyes for the five grades; (b) improved test methods; and (c) an increase in the number of approved antioxidants from three to five.

Quality control in aviation gasoline is even more critical than in motor gasoline since engine failure is a much more serious matter. Antiknock control is especially critical because, unlike the motorist, the pilot is unable to hear an engine knock over the high noise level. Volatility, freezing point, heat of combustion, and oxidation stability are all very important to the AVGAS consumer. Quality control techniques and close control of processing have made aviation gasoline a reliable premium refinery product.

Aviation gasolines contain up to 4.6 ml TEL per gallon (115-145). Ethylene dibromide is added to scavenge the lead; it has been found more effective under high-load aircraft conditions than the chloride/bromine scavenger mixtures used in motor gasolines. Other alkyl leads, tetramethyl lead or methylethyl lead compounds, are not used in aviation gasolines.

Some hydrocarbon constituents of AVGAS tend to oxidize during storage at ambient temperature. The products of oxidation, fuel-soluble and fuel-insoluble gums, interfere with metering of the fuel to the engine and must be controlled. Certain amine and phenolic chemical compounds have been found to be particularly effective in this service.

B. Jet Fuels

Commercial kerosene was used as a fuel in early development work on jet aircraft in the United States. The choice of kerosene over gasoline was based on its low volatility to avoid occurrence of vapor lock under certain flight conditions and its availability as a commercial product of uniform characteristics. JP–1, the first military jet fuel, was highly refined kerosene having a very low freezing point (−76°F).

Kerosene from selected crudes high in naphthenes was the only fuel having the low freezing point (−76°F) specified for JP–1. The demand for this fuel increased very rapidly and the Military Petroleum Advisory Board took a long hard look at the appetite of jet engines, together with availability of JP–1 and AVGAS. The Board made a strong recommendation for the development of a military jet fuel having greater availability in wartime than either JP–1 or AVGAS. The second try at a jet fuel was JP–2, but it did not have the desired availability. Next was JP–3 fuel; it included the total boiling range of kerosene and gasoline. A cooperative program of testing by the Coordinating Research Council demonstrated that the high vapor pressure of JP–3 (Reid vapor pressure of 5-7 pounds) resulted in vaporization of the fuel during climb to altitude. In addition, some fuels foamed excessively during vaporization so that very large losses of liquid could occur along with the vented vapors.

To overcome the disadvantages of JP–3, the Reid vapor pressure was reduced to 2-3 pounds and JP–4 was developed in 1951. The new fuel is a blend of 25-35 percent kerosene and 65-75 percent gasoline components and has proven quite satisfactory for military requirements.

One important Navy turbine fuel developed for carrier operation during the Korean War was a mixture of a special kerosene and AVGAS. AVGAS is stored in tanks in the central zone of carriers to minimize the possibility of hazardous fuel leaks in the event of battle damage. Space in this area is in high demand for other purposes, thereby limiting available storage space for AVGAS. The problem was solved by the development of JP–5 fuel for aircraft carriers. This fuel is a special 140°F flash point kerosene and because of its low volatility can be stored safely in outer tanks of carriers. When mixed with AVGAS, JP–5 gave a fuel similar to JP–4. Later Navy use eliminated the AVGAS mixture and used the JP–5 alone.

Commercial airline jet fuels in the U. S. fall within the general framework of ASTM Jet A, A-1, and B fuels. Jet A and A-1 are of the kerosene type. Jet B corresponds to the Military JP–4 fuel. Volume demands for Jet A and A-1 are large, but small for Jet B.

Jet fuel fulfills a dual purpose in the aircraft. It provides energy and serves as a coolant for lubricating oil and other aircraft components. Exposure of the fuel to high temperatures may cause the formation of particulate matter (gums) which reduces the efficiency of heat exchangers, and clogs filters and valves in aircraft fuel handling systems. Thermal stability is the resistance to formation of gums at high temperature. The JP–4, JP–5, and equivalent commercial fuels have satisfactory thermal stability for aircraft operating at speeds up to about Mach 2.0 and will be used in the Boeing Supersonic Transport (SST) planes. Future jet aircraft operating at higher speeds, e.g., Mach 3, may expose the fuel to greater thermal stresses and may require a more stable fuel. The development of Mach 3-4 turbojets, Mach 6+ ramjets, and rockets using hydrocarbon fuels will pose additional problems on fuel capabilities.

An attractive method of improving jet fuel quality is through the use of additives. The more common applications of additives are discussed below.

1. ANTIOXIDANTS—Some jet fuels may oxidize during storage at ambient temperature to form fuel-soluble and fuel-insoluble gums. These oxidation products may cause (a) clogging of filters in the aircraft fuel distribution systems or (b) coking of engine burner nozzles. The same antioxidants approved for AVGAS are used in jet fuels to inhibit oxidation.

2. COPPER DEACTIVATOR—Dissolved copper in jet fuel accelerates oxidation of the fuel during storage at ambient temperatures. A copper chelating agent, N, N'disalicylidene-1, 2-propanediamine, has been approved for addition to jet fuel to deactivate the pro-oxidant effects of copper.

3. CORROSION INHIBITORS—Fuel soluble corrosion inhibitors have limited specific approval for jet fuels. The inhibitors are added to protect pipelines against corrosion by occluded water and indirectly to reduce contamination of the fuel with rust. Several commercial inhibitors are available.

4. ANTI-ICING ADDITIVE—The major hazards of free water in jet fuels are plugging of fuel lines and filters by ice during subsonic flight, causing erratic operation of electrical fuel gauges and providing a suitable environment for growth of bacteria and fungi. Fuel heaters are used in civilian aircraft

to prevent ice formation and its resulting consequences. The military adopted the approach of adding 0.1 to 0.15 percent of an anti-icing inhibitor comprising a mixture of 99.6 percent weight of ethylene glycol monomethyl ether and 0.4 percent weight of glycerol. The additive has the added feature of having biocidal properties.

5. ANTISTATIC ADDITIVE—High-speed flow (600-800 gallons/minute) through fill lines, filters and valves generates electrostatic charges in jet fuels. Electrostatic potential differences between the fuel and fuel tank walls may cause sparking in the vapor spaces of fuel tanks. If the vapor compositions are ignitable and the electrostatic discharges have enough energy to ignite the vapor, then fires or explosions may result. Intensive investigations have shown that additives which decrease resistivity of the fuel can reduce electrostatic hazards.

Refiners make every effort to deliver clean and water-free fuel to jet aircraft. However, in handling and delivery there are many places where contaminants may enter the fuel.

Particulate matter and free water can be removed by bulk settling or filtering. The filter units (filter/coalescers) contain resin-coated filters to remove particulate matter followed by a glass fiber filter or specially resin coated filter to coalesce and remove free water. Removal of solids down to 5 microns (0.00019 in.) is generally desired to avoid plugging of filters on fuel control valves and burner nozzles.

Surface active agents (surfactants) in jet fuels are highly undesirable because they promote the formation of water-fuel oil emulsions and reduce the efficiency of filter/coalescers. Certain surfactants in extremely small quantities (1 ppm) appear capable of reducing the efficiency of filter/coalescers.

Surfactants produced by refining operations are removed by neutralization, water washing, clay treating, filtration, or settling. Polar additives that are added to jet fuel are chosen on the basis of having minimum surfactant properties.

Bacteria, fungi, and other microorganisms can live in water underneath jet fuel in storage or wing tanks. Rapid growth of the microorganisms may cause plugging of filters in fuel delivery lines or aircraft fuel lines, and may accelerate corrosion of aluminum wing tanks on aircraft.

Good housekeeping does much to eliminate this problem. The anti-icing additive added to JP–4 fuel is a biocide and has helped to eliminate the problem from aircraft supplied with this fuel.

C. Future Fuels

By proper selection of structural materials and aircraft design, it may be feasible to use conventional hydrocarbon fuels up to flight speeds approaching Mach 4. Flight speeds higher than Mach 4 will require more heat sink capacity than normally provided by fuels in the liquid state. Vaporization of the fuel can increase the overall heat sink capacity about 25 percent over allowing the fuel to reach its maximum liquid temperature without degradation. A promising alternate is to allow endothermic fuels to undergo mild thermal cracking which can absorb several times the heat picked up in the liquid state alone. Cryogenic fuels, i.e., liquefied hydrogen, methane, and propane, also offer an attractive way of cooling aircraft.

Low-altitude, high-speed, ramjet-powered aircraft require a fuel with a high volumetric heat content. The Air Force has been pursuing the development of slurry fuels in which metal is burned to take advantage of the high heat of formation of metal oxides. Research efforts are continuing to develop fuels having the greatest possible metal content and to overcome problems such as poor pumpability, abrasiveness and low combustion efficiency.

The Air Force is not presently supporting research on the high-density fuels (aromatics, condensed polycyclic hydrocarbons), but is interested in evaluating new materials that may possess heating values of about 150,000 BTU/gallon, with a freezing point of −50°F or lower.

SECTION 3—Aircraft Lubricants

A. Aircraft Engine Oils

World War II marked a turning point in the history of aircraft lubricants. The world became air-minded —airplanes proved to be the commercial transports of the future—and jet aircraft became a reality—new concepts and materials were needed.

During the past two decades improvements in the quality of mineral oils and the development of improved additives, especially ashless dispersants, have provided lubricants to meet the increasingly severe requirements of piston aircraft engines. Even as engine output increased, the development of improved lubricants enabled extension of periods between engine overhauls. In large engines, the time between overhauls has been extended from about 600 hours, to more than 2,000 hours. Further, oil changes and other maintenance between overhauls have been almost eliminated.

Oils containing improved, ashless dispersants and antioxidants show marked improvement in performance over nonadditive straight mineral oils. Deposits throughout the engine, including oil filters and coolers, are greatly reduced. Also, harmful combustion chamber deposits which might arise through the use of some metallic additives are avoided.

Future improvement of these oils could be achieved through new refining processes or more effective additives, but the market may not warrant them. The increased versatility of turbine engines probably will force a decrease in the use of piston engines. However, the development and acceptance of family airplanes might arrest or reverse this trend.

In jet engines, oil consumption is reduced by a factor of 80 over the piston engine, i.e., one barrel of oil per 4,000 barrels of fuel. Further, jet engine lubricants are not oil stocks, but synthetic chemicals. While some of the raw materials may be petrochemicals, the market for petroleum products is limited.

Although some of the earliest jets could function on light petroleum oils, it soon became necessary to furnish synthetics to meet more severe operating conditions. Typical of these synthetics were diesters of dicarboxylic acids; e.g., di-2-ethylhexyl sebacate. The way, of course, was led by the needs of military aircraft. Not only were the high operating temperatures important, but with bases in all parts of the world, the need to start engines at low temperatures required suitable viscosity limits for oils usable at low temperatures. Certain of the diester-based lubricants are still in wide use today.

As jet engines became more powerful and more efficient, operating temperatures increased and led to more severe thermal stressing of the oil. This, in turn, led to a need for improved oils capable of operating satisfactorily as oil temperatures increased above 400°F. To meet this need, a new family of synthetics was developed. These oils are esters of alcohols possessing the neopentyl nucleus, e.g., esters of trimethylols and pentaerythritol. Higher viscosities at low temperatures have had to be accepted to achieve the desired high-temperature viscosity and stability.

Besides the more severe conditions which the fluids had to combat, there were requirements which could only be met by the use of additives. Addition of high-temperature antioxidants such as the phenothiazines reduces the loss of volatile oxidation products. Additives are also used to increase film strength, prevent or reduce foaming and to impart load-carrying qualities.

Oils of the foregoing types are meeting the present commercial and military requirements. In addition, other synthetics such as silanes, silicates, silicones, fluorocarbons and polyphenyl ethers have been used in certain special applications. The latter two especially have some stability in the 600-800°F range, if oxygen can be excluded. It is anticipated that continuing research will produce still further improved fluids useful over broader temperature ranges and with improved lubricating quality. The trend of this research will be away from organic materials since the limits of their thermal stability are being reached. New fluids must be sought among inorganic materials.

B. Aircraft Greases

For the past two decades most of the military and commercial aircraft have been lubricated with greases comprised mainly of a petroleum oil or synthetic ester base fluid thickened with a metallic soap (primarily lithium). Sodium, calcium, and lithium soaps have been adequate for thickening mineral oils and esters for application up to 250°F. Much above this temperature, however, the low viscosity and high volatility of these oils, and the instability of both the fluids and thickeners, drastically reduce the life of the greases.

In recent years, much effort has gone into the development of greases suitable for use at higher temperatures (600°F) and speeds (50,000 rpm). Hundreds of materials have been screened in the search for solids stable up to 600°F which could be used to thicken stable fluids (e.g., silicones, polyphenyl ethers). These synthetic fluids have relatively low volatility and high thermal stability. Certain aryl ureas, triazines, imides, dyes and toners were found to be suitable thickeners.

At the same time special lubricants were needed in space, where not only high temperatures and low temperatures (to −100°F), but also extremely low pressures and high speeds are encountered. Lubrication of those regions in rockets which are exposed to liquid oxygen posed special problems which were met by fluorocarbon oils thickened with tetrafluoroethylene polymers.

As temperature extremes have increased, a general trend is discernible away from greases made from petroleum products to greases made from synthetic oils and more recently to bonded solid films. A film of molybdenum-disulfide bonded by a resin to the metal surfaces of the bearing is practical in some high-temperature bearings.

SECTION 4—Home Heating Oil

Grade No. 2 fuel oil is the designation given to the heating oil most commonly used for domestic and small commercial space heating. This product is a distillate product, normally fractionated to a boiling range of 350-650°F. The twenty-year period since World War II has seen marked change in both the quality of home heating oils and the manufacturing techniques employed in producing these products. Originally, No. 2 heating oil was composed of selected refinery straight-run stocks blended to meet product quality standards. The resultant product had good stability and was very satisfactory in performance. As the refining industry was called upon to make greater and greater amounts of motor gasoline at higher octane levels, cracking processes were developed to convert virgin gas oils to lighter boiling products. This necessitated the use of increasing amounts of both catalytically and thermally cracked gas oils in finished heating oil blends. Heating oil blending became a more complex operation to maintain a satisfactory quality level without excessive treating expense.

Domestic heating oil must be a clean product. It should form no sediment in storage and leave no measurable quantity of ash or other deposit on burning. Since it is stored at low temperatures, it should be fluid at storage conditions encountered during the winter months. The chemical composition of the product must be controlled to assist in reducing smoke emission. Sulfur content at one time was not considered a problem; however, it is quite important today. In addition, domestic heating oils must satisfy several other requirements that were not necessary prior to World War II. The fuel must have a light color, an attractive appearance, and an acceptable odor. It is these properties, along with sulfur removal, which have undergone the greatest change in the past twenty years.

The first cracking process to be used was thermal. This process achieved the fundamental objective, more and higher octane gasoline, but yielded a high percentage of olefinic material. This type of compound was not particularly objectionable in gasoline; however, it produced instability in fuel oils. Distillate fuels containing high percentages of cracked stocks tended to form organic sediment. As octane requirements for motor gasoline went higher, catalytic cracking processes were installed. Fuel oils produced from catalytic cracked distillates were high in aromatic compounds. These oils were not as stable as straight-run materials and were more difficult to burn in older equipment, although they gave no problem in modern burners.

The oil industry worked in several directions to correct the quality problems associated with the extensive use of cracked distillates. New treating processes, improved burner design, and the development of additives all progressed simultaneously. Refiners worked closely with equipment manufacturers in the development of improved combustion devices to handle adequately the fuels which were more difficult to burn. At the same time, the industry began to develop and use additives to improve stability. Another development which proceeded concurrently was the use of caustic washing for fuel oil. Several processes were developed using either sodium hydroxide or potassium hydroxide in varying concentrations. These processes were preferred over acid treating and proved to be more effective from the standpoint of improving product stability. Many refiners still use a caustic wash in their processing sequence.

In the early 1950's, "reforming" of straight-run gasoline came into widespread use. This process made available to the refining industry large volumes of hydrogen which heretofore had been costly to produce. With this relatively cheap by-product hydrogen, it was possible to adopt hydrogen treating as a means of obtaining further improvement in fuel oil quality. The primary objective in the hydrogen treating of heating oils is to enhance their quality by a reduction in sulfur and removal of small, but objectionable, amounts of nitrogen compounds. This treatment also reduces carbon residue, improves burning characteristics and color stability, and reduces sludging tendencies. The problem of sulfur removal has come to the front as refiners have increased processing intensity. Incremental crude has also, in many cases, been high in sulfur, further contributing sulfur removal problems.

Quality inspections of the feed and hydrogen-treated product from both straight-run and catalytically cracked heating oil stocks show that critical properties are significantly improved in every case by hydrogen treating. Sulfur reduction is 70-80 percent complete. Carbon residue is reduced to less than 0.10 percent. The stability tests show that hydrogen-treated products are of excellent quality from the standpoint of both a change in color and in sludge formation during storage.

Additives developed by the industry have also made a significant contribution to product quality improvement. Of prime importance are the additives used to reduce sludge formation. Most additives of this type are oxidation inhibitors and dispersants which inhibit the formation of organic sediment. A secondary effect of these inhibitors is to keep suspended, in finely dispersed form, the small amount of sediment which still persists. Metallic-based materials were first used; however, today most inhibitors are nonmetallic amines. Additives to accomplish other purposes are also quite commonly used. Rust inhibitors, color stabilizers, pour point depressants, and combustion aids are typical examples.

Low temperature pumpability is an essential property of No. 2 heating oil. Pour point depressants are used to improve low temperature flow properties. The effect of additives on the pour point of three typical fuels is as follows:

POUR POINT DATA ON COMMERCIAL POUR DEPRESSANTS IN NO. 2 HEATING OILS

POUR DEPRESSANT	CONCENTRATION WT. %	FUEL I	FUEL II	FUEL III
	No Additive	− 2°F	− 5°F	+ 5°F
X	0.01	− 3°F	− 6°F	+ 2°F
	0.03	−10°F	−20°F	−10°F
	0.06	−25°F	−30°F	−23°F
Y	0.01	−10°F	−20°F	−20°F
	0.02	−15°F	−25°F	−30°F
	0.05	−35°F	−40°F	−50°F

Additives to improve combustion properties have also been developed. Field test results from one of these compounds indicate a pronounced reduction in smoking tendencies and carbon deposits. In this specific case, eight residential heating units were tested. The additive reduced carbon deposit thickness by 19-23 percent and improved overall operating efficiency by an average of 6 percent.

Minimum standards for domestic heating oils have not changed appreciably during the past few years, even though product quality has improved significantly. The quality improvement trend is perhaps best illustrated by the following table showing average carbon residue and sulfur content of No. 2 heating oil since 1956.[1]

YEAR	CARBON RESIDUE[a]	WT. % SULFUR
1956	.137	0.330
1957	.128	0.305
1958	.121	0.273
1959	.122	0.260
1960	.116	0.249
1961	.121	0.228
1962	.115	0.229
1963	.114	0.238
1964	.104	0.232
1965	.104	0.241
1966	.095	0.227

a—Ramsbottom carbon residue on 10 percent residue.

The above data indicate that both carbon residue and sulfur content have been reduced by about 30 percent during the past 10 years. There are undoubtedly other properties which have changed and the two discussed above are merely illustrative of the technological progress made in the petroleum industry toward the development of higher quality products.

Now what does this change in product quality do for the consumer, whether he be the general public or the government? In this particular case, improvements in the quality of heating oils have resulted in more efficient, less costly heating systems. The superior processing techniques used today, coupled with the improvements and developments in additives, result in a cleaner burning product. The reduction in sulfur has been a significant improvement in air pollution. The use of pour point depressants has improved the low-temperature fluidity of the product, thereby reducing line plugging and other problems associated with outdoor tank storage by the consumer. For those users who have indoor or basement storage, improvement in odor of heating oils is a positive advantage. Better storage stability is also a factor. The frequency of tank cleaning and oil filter changes has been extended. All of these things are of definite value to the end user.

SECTION 5—Specialty Products

The field of specialty products has experienced enormous growth since World War II. For example, in 1946 the demand for special naphthas was only 60,000 B/D. By 1965 this demand had increased to 147,000 B/D. Not only has the volume demand for these products expanded, but the number of specialty items has increased severalfold. To a large extent, new technology is responsible for both the greater demand and the wider variety of products. Included in the specialty category are naphthas, solvents, lighter fluids, waxes, and refinery-produced liquefied petroleum gas.

In today's market, specialty products are frequently custom made to fit a particular customer's specification. This is in contrast to most fuel products which are made to conform with generally acceptable standards. It is therefore difficult to outline changes in the quality of these products in terms of specific properties. In general, the trend has been toward purer, higher quality products with more exacting specifications. Technological advances in allied industries, such as petrochemicals and paper, are responsible for this trend. Numerous specialty products are utilized in some way in the manufacture of petrochemicals where product quality is of utmost importance. The paper industry uses a wide variety of waxes for coatings. Since many paper products come in contact with foods, the waxes used must be highly refined to meet stringent requirements.

A. Petroleum Solvents

Solvents may be divided into two groups, those that are mixtures of saturated hydrocarbons and those rich in aromatics. In either case, most solvents are comparatively narrow boiling range fractions. Absence of low-boiling compounds reduces fire hazard, while freedom from high-boiling materials reduces residue left after evaporation. Critical specifications are largely a function of the end product use. Some idea of the large variety of uses and boiling ranges is shown by the list below of representative solvents and naphthas.

USE OF SOLVENT	BOILING RANGE
Perfume extraction	160-260°F
Castor oil or fat extraction	125-300°F
Toluene substitute, lacquer formulas, fast-setting varnishes	179-275°F
Seed extraction	160-300°F
Rubber cements, tire manufacture	95-370°F
Lacquers, art leather, rotogravure ink, adhesive tape	95-370°F
Rosin extraction, shade cloth, rubber dip goods	205-300°F
Brake linings, leather degreasing, bone degreasing	125-400°F
Printer's ink, cellulose lacquer diluent	160-370°F
Paints and varnishes, thinners	105-455°F

1. *National Survey of Burner Fuel Oils,* Eastern Division (1956-1966), Bureau of Mines.

Textile printing and proofing	160-410°F
Paints and coatings (aircraft), paint removers and solvents	179-410°F
Paint shop rinsing and cleaning (aircraft)	210-340°F
Floor coverings, wax, polish, wash for printing plates or rolls	200-410°F
Dry cleaning, metal and machinery cleaning	200-400°F
Xylol substitute (in many instances)	275-370°F
Flat finishes, rustproof compounds	300-455°F
Synthetic resin thinner	357-410°F
Wood preservatives	312-650°F

In addition to boiling range, chemical composition can be most important. For example, the aromatic content of any solvent used in a dry cleaning fluid must be low. Rigid specifications also exist for petroleum solvents used in the paint industry. These products must contain no materials that would discolor pigments. If they are to be used in interior paints, they must be free of aromatic hydrocarbons and possess low odor characteristics. Naphthas and lighter fluids are subjected to some of these same quality requirements.

Improvements in quality of solvents and naphthas have resulted from both the development of new techniques and the adaptation of older ones to the manufacture of these products. Technological advances in distillation, both in design procedures and fractionating tray design, have made possible the production of narrower boiling range products. Development of new solvent extraction and adsorption processes makes possible the separation of compounds by type, i.e., aromatics, paraffins, etc. Modern-day treating systems, such as hydrogenation, have resulted in a reduction of sulfur and improved color and odor. Of equal importance is the development of improved process control instrumentation. Continuous onstream analyzers and internal reflux controls for fractionators are but two examples of the progress made in this field during the past twenty years. These control devices make it possible to maintain consistent product quality under even the most rigid specifications.

B. Aromatic Solvents

Another line of specialty products closely akin to solvents is high-purity aromatics. With the advent of catalytic reforming and solvent extraction processes, the refining industry found itself with a tremendous potential source of aromatic hydrocarbons. In the beginning, the major portion of these products, particularly toluene and xylene, were utilized as solvents. These products produced from petroleum were of extremely high purity in comparison to those produced from coal tar operations and found immediate customer acceptance. Petroleum-based aromatics have taken even a greater position in the rapid development and expansion of the petrochemical field. Benzene is a basic petrochemical feedstock and is used in the production of styrene, cyclohexane and phenol. Toluene at one time was used almost exclusively as either a solvent, a raw material for TNT, or in motor gasoline. Today it is the raw material for additional benzene. Dealkylation of toluene accounted for 21 percent of the benzene produced during 1965. The xylenes have also undergone a shift in market use. New technology provided the means for separating the xylene fraction into pure compounds. Paraxylene is the raw material for polyester fiber. Orthoxylene is used in the production of phthalates. Metaxylene, the remaining isomer, is produced in its pure state in only limited quantities. However, the metaxylene rich concentrate is finding increased use as a raw material for isomerization processes where it is converted to paraxylene.

In addition to aromatics, there are several other specialty products in the category of petrochemical raw materials that are worthy of mention. Propylene trimer and tetramer are both produced by the catalytic polymerization of refinery propylene. Originally the trimer was used as a gasoline blend stock and tetramer production was minimized. The rapid growth of the synthetic detergent market caused a shift in emphasis and production of tetramer became commonplace. The tetramer was combined with benzene to produce dodecylbenzene, the prime starting material for the manufacture of more than 85 percent of the total organic detergent content in these products. The development of biodegradable detergents will surely have its impact on the current market for detergents and propylene tetramer may be of lesser importance in years to come. The development of the oxo process and the growing demand for alcohols created markets for both propylene trimer (nonene) and heptenes. C_8 and C_{10} alcohols for use in phthalate and phosphate esters used in vinyl plasticizers are examples of products made from these olefin specialties.

C. Waxes

Waxes, like other specialties, have also undergone changes in manufacturing technique. At one time wax was regarded as a waste material and was cracked to yield gasoline and other fuel products. Large amounts are still processed in this manner. However, the growth of the paper industry has developed new markets for paraffin wax, while developments in waterproofing, impregnation of electrical equipment, and other allied uses have resulted in an increased demand for microcrystalline waxes. These two types of wax are produced from entirely different feed streams.

Paraffin wax is separated from paraffinic distillate and is subsequently purified to produce a fully refined wax. Prior to 1940, most paraffin wax was recovered by pressing and filtration. The slack wax so produced was purified by sweating (slow heat treatment) and further filtration. Fully refined wax is essentially free of oil and has been rendered tasteless, odorless, and stable to light and heat. Since World War II, solvent extraction techniques have been developed and now replace the pressing operation in the production of slack wax, which is further processed to either scale wax or fully refined wax. Although several grades of paraffin wax are produced, physical and chemical properties of this product are very similar. The exact properties of a particular grade are a function of its end use. A very high percentage of paraffin waxes is used in the field of paper coatings. Other uses are pharmaceuticals, cosmetics, candles, and rubber compounding.

Microcrystalline wax can be separated from three sources as motor oil wax, residual microcrystalline wax, and tank-bottom wax. In contrast to paraffin wax, no two grades of microcrystalline wax are alike. This difference results from both a variation in crude source and in processing techniques. Of the three types of microcrystalline wax, that produced from the residual of a crude refined for lubricating oil is of significant commercial importance. There are only a few producers of the other two grades. The residual microcrystalline wax is the least like paraffin. Its color varies from black to white and it is tough, ductile, and flexible over a wide range of temperatures. In these characteristics, these waxes closely resemble such natural waxes as beeswax and spermaceti. The lamination of paper products is the largest single use of the microcrystalline waxes. Other uses are waterproofing, electrical equipment coatings, rubber compounding, and applications where they replace either vegetable wax or beeswax.

The wax industry was affected in the early 1960's by the widespread use of synthetic polymer coatings on paper products, such as milk and juice containers. As coatings of polyethylene extrusion resins replaced wax in many markets, the demand for wax in paper and board coating decreased to about 590 million pounds in comparison to the record demand of 995 million pounds in 1960. Wax producers believe, however, that by 1968 coatings will consume about 715 million pounds of their products. This recovery is due primarily to the development of new wax-modifying synthetic resins. These blends are cheaper than straight plastic coatings and have more desirable properties than wax alone. These wax-resin blends are harder, more flexible, adhere better, have better gloss, more resistance to water vapor and grease, and do not flake. The resin additives currently in use include ethylene-ethyl acrylate copolymer and ethylenevinyl acetate copolymer.

Although synthetic resins have taken a large share of the wax market in the past few years, other promising uses for this product are developing. Wax producers are investing in a substantial research effort for product improvement. One recent new use for wax is in wax-impregnated corrugated containers. These cartons are replacing the metal-bound wooden boxes used to ship poultry and fresh vegetables. Other areas of expected growth are waxed paper and frozen food containers. Besides improving products, wax producers have launched an extensive promotional campaign intended to inform customers of the technical advances made recently in wax formulations and modifications.

D. Liquefied Petroleum Gas

Liquefied petroleum gas (LPG) is a specialty product that has taken on increased importance during the past few years. The most common constituents of this product, propane and butane, do not exist to any great extent in most crude oils. However, the extensive use of catalytic cracking and catalytic reforming processes and the growth in hydrocracking have resulted in the production of large quantities of refinery LPG. Prior to the start of the tremendous growth in the petrochemical industry, namely in ethylene production, the major use of refinery-produced LPG was for household and industrial fuel.

Catalytic cracking of gas oil produces a light ends material which is a mixture of olefins and paraffins. The olefinic portion, propylene and butylenes, is normally converted to gasoline blending components by either polymerization or alkylation. LPG products are produced conjointly in both of these operations. Catalytic reforming of straight-run naphtha is a high-yield process, but appreciable amounts of LPG are produced as a by-product.

Since LPG must be stored at either reduced temperature or elevated pressure, conventional storage is extremely costly. The refiner was faced with either the development of less expensive storage techniques or sale of the product on an as-produced basis. Underground storage proved to be the answer to this problem. Large volumes of storage capacity could be obtained for a reasonable price, allowing the refiner to store product during the summer months for sale during the heating season. The large petrochemical demand for LPG has created a need for even greater storage capacity.

On January 1, 1966, there was reported to be a total of 112,421,000 barrels of underground storage capacity. This figure represents a 5.2 percent increase over 1965 and another 5 percent or so is in the planning stages for completion during the next three years. Of this amount, approximately 18,000,000 barrels is directly associated with refineries. Various types of storage are employed. Some facilities are mined from granite, shale, limestone or chalk, while others consist of caverns in salt domes or strata. Water and gas sands are used in some areas and recently the use of frozen pits has been employed. Storage in salt formations is the most prevalent installation. This type of storage can be developed very economically by drilling a hole into the salt strata. Water is then forced into the hole to dissolve the salt. At such time as the cavern reaches the desired capacity, circulation is discontinued and the required injection equipment for the specific product to be stored is installed. Products are removed from storage by adding saturated brine or water. When products are added to storage, water is displaced into pits or ponds, as the case may be.

Underground storage was originally developed for conventional LPG products. It is now used for numerous petrochemicals such as ethylene, propylene and butylenes. This development has saved industry and the consuming public millions of dollars during the past few years.

SECTION 6—Asphalt

The heaviest fractions of a great many crude oils include natural bitumens or asphaltenes and are generally called asphalt. Actually this material is the oldest product of petroleum and has been used throughout recorded history.

In 1965 a total of over 25 million short tons of asphalt products were sold in the 50 states. This represents about 140 million barrels or approximately 380,000 barrels per day, some three percent of the total U. S. demand for petroleum products in 1965. Seventy-three percent of the asphalt went into paving products, 16 percent went into roofing products and the remainder went into a variety of other uses.

Since asphalt is essentially a natural product of petroleum, its characteristics vary considerably with the nature of the crude oil. Some crudes, like those found in Trinidad (natural pitch lake) or Boscan in Venezuela, produce excellent asphalts, but in general they are not available in large quantities in all the right places. Hence there have been many local asphalts with varying qualities, and at one time there were as many as 102 usable grades of asphaltic cement. Largely through the work of the Asphalt Institute, which is the research and engineering arm of the asphalt industry, this number of grades has been cut to five.

Asphalt products used for roofing and other waterproofing services can be modified in quality by airblowing. Blowing hot asphalt with air alters the relationship between the hardness at a given temperature and the softening point. Thus the temperature at which the material becomes too soft and tacky can be raised, making the material more suitable for many services.

Asphalts emulsified with water and modified with certain chemicals have been developed and make excellent cold coating and paving materials. Since they can be used with wet aggregates, they increase the percentage of time paving can be done in areas of normal or high rainfall.

Asphaltic cements, liquid asphalts and asphalt emulsions used for highway and road paving meet a wide variety of criteria necessary to do a good job. This has been proven by the fact that more than 90 percent of the existing paved highways, roads and streets (1,400,000 miles in the U.S.) are paved with asphalt. Recent technology has been developed to a point where "deep-strength" asphalt highways can be built for less money and stand up better with less maintenance than comparable concrete highways. Similarly, the various asphalts and fluxes used for waterproofing (roofing shingles and felts, linings, etc.) meet a wide variety of needs well.

In-line blending has been developed by the refiner to permit an asphalt and a solvent to be drawn from their respective storage tanks and be correctly and rapidly blended to the desired material on the way to the waiting tank car or tank truck for shipment to the place of use. This has enabled the refiner to reduce the number of storage tanks and lower his operating costs. It helps the purchaser because there is no delay for making up his desired blend; or in heating and pumping out his particular material.

In recent years, advancement in know-how of ways of placing asphalt paving mixtures has been achieved. The use of self-propelled pneumatic tire rollers has been one of the biggest contributions to better compaction of asphalt concrete highways. Electronic controls have been developed for full automation of the asphalt pavement mixing plants. Numerous electronic methods have been developed for control of depth, leveling, etc., on asphalt pavers. User agencies have pioneered the construction of asphalt pavements by the " thick lift " operation. This construction method consists of placing from five to eighteen inches of paving material in one operation rather than placement of multiple layers of 1½ to 3 inch thicknesses. This method results in much more rapid construction and considerable reduction in cost. Other benefits are better compaction and density. Another development in paving construction that has added to the safety of roads is the design of more skid resistant surfaces by the use of thin overlays of asphalt and selected aggregates.

All of these improvements in paving design and construction practices have resulted in increased use of asphalt. They have also made it possible to use lower quality aggregates in high-quality roads. This is an important point, because high-quality aggregates are becoming scarce and their acquisition has resulted in considerable increase in the cost of road construction.

New and expanding uses for asphalt, other than road construction, are the lining of reservoirs, canals, swimming pools and sewage lagoons for seepage control. Other new uses are the facing of dams and river banks for erosion control and the construction of asphalt-stabilized breakwaters, seawalls, groins, etc., for the control of sea currents. One new application for asphalt which is still in the development stage, but looks very promising, is the use of asphalt concrete for railroad roadbeds. According to experiments carried out by the Japan National Railways, this type of construction could be the answer to roadbeds for the high-speed special-car freight service and very high-speed commuter and intercity service which is envisioned for the near future.

All of these new and improved uses of asphalt have increased its consumption tremendously. In the last 21 years since World War II the average annual increase in asphalt sales has been 900,000 tons. Since 1945 the annual usage of asphalt for paving has increased from 5.0 to 20.4 million tons; that used for roofing materials has increased from 1.6 to 4.4 million tons per year while miscellaneous uses have increased from 0.7 to 2.7 million tons. Total consumption of asphalt in 1966 has been estimated at 27.5 million tons.

To meet the increased demand for asphalt, the industry has increased capacity by installing additional seasonal tankage, by adjusting crude runs and providing additional plant yield by installing in-line blending and solvent extraction facilities. Special barges and tankers have also been constructed for economical long distance transportation facilities to ease the local shortage situations.

Now research is finding further uses for this versatile material as an extender in polymer-asphalt systems. Thermosetting and thermoplastic composition result with enhanced properties for use as special coatings, cement and adhesives. Alone or in combination with polymers, asphalt will continue to be highly used by our building and highway industries. Very promising results have also been obtained in the use of asphalt in soil stabilization and as a moisture barrier in sandy soil.

SECTION 7—Residual Fuels

Grades 4, 5, and 6 are the designations given the fuels most commonly used for large commercial, industrial, marine and other uses involving larger installations than those used for domestic and small commercial uses as described in Chapter Nine, Section 4, Home Heating Oil. Typically these fuels are used to provide steam and heat for industry and large buildings, to generate electricity in competition with coal or gas, and to power ships. Most users of residual fuels have converted their equipment to handle Grade 6, which is less costly as it utilizes less of the distillate stocks which can be converted more readily into gasoline. In marine circles, heavy bunker fuels are known as Bunker "C" which generally correspond to Grade 6 fuel oil.

Residual fuels are by their nature high boiling and contain stocks which are difficult to burn quickly under "cold" conditions. Accordingly, such fuels are generally burned in equipment which permits relatively steady operation in an environment where firebox temperatures can be high.

Since residual fuels compete directly with gas and coal in many areas, the price of the fuel must be competitive. Accordingly, it has not been economically practical to improve the quality of residual fuels beyond the quality inherent in the stocks.

The steady increase in the use of catalytic cracking following World War II had the effect of decreasing the percentage yield of residual fuels as well as changing their makeup. As more high-boiling materials were charged to cat cracking, the remaining oil which was sold as residual fuel became heavier and heavier. Common industry practice was to flux these heavy stocks with a distillate to raise their viscosity for a salable fuel. Continued work in this field led to the use of mild thermal cracking of the vacuum still bottoms which yielded a small additional amount of distillate product and reduced the viscosity of the remaining bottoms. Such bottoms required less distillate cutter stock to produce a salable residual fuel oil. This modest advance, using a method developed before the war, known as visbreaking, could be classed as a beneficial step in residual fuel oil production.

After the war, refining processes in the United States continued to become more efficient in producing the more profitable products until residua amounted to only about 8 percent of the crude refined. Increasing imports of foreign residual fuels has kept the sulfur level fairly constant and the quality of domestic fuels has remained essentially unchanged during this period. On a worldwide basis, residual fuels do vary considerably in quality. Quality in a given location varies, depending on the crude used and the economy of the country where it is refined.

Most of the advances in residual fuel oil technology since World War II have led to improvements in its use rather than in oil quality. Metals such as sodium and vanadium, which are commonly found in small amounts in residual oils, can cause fireside tube deposits in boilers, corrosion, and fly ash air contaminants. Some of the sodium can be removed by water washing and centrifugation. There is no known commercially feasible way to remove such metals as vanadium from residual oils. Fly ash and other solid particulates can be removed from stack effluents by use of electrical precipitation, although some practical problems exist.

On combustion, part of the sulfur in the oil may contribute to boiler tube deposits, part may be converted to sulfuric acid, leading to corrosion at low temperature points, and the remainder escapes as oxides into the atmosphere. Methods for desulfurizing residual oils have been developed but have not been economically feasible to date. This economic situation with regard to sulfur content will change in the future as air pollution requirements become more widespread and the availability of low-sulfur fossil fuels cannot keep pace with demand.

The oil industry and boiler manufacturers have recently stepped up their efforts considerably in the areas of desulfurizing fuel oil and flue gas and reducing fuel oil metals content. A fuel oil desulfurizing unit is being designed for installation in the Middle East for a U. S. company and two more will be built in Japan. Several test installations designed to remove sulfur from flue gas are being evaluated. Much work is under way in the research laboratories of both oil and boiler manufacturing companies.

A large number of additives has been developed for reducing residual fuel oil sludge, tube deposit formation and corrosion and for increasing combustion efficiency. Some of these additives are polyfunctional. Metal-organic, dispersant-type compounds such as sulfonates have been found effective in reducing sludge. Additives for reducing fireside fouling of superheater tubes by metallic compounds have met with some success but the fouling problem has not been completely solved. Some of the metallic compounds are corrosive at temperatures in excess of about 1,100°F. Use of additives to reduce this high temperature corrosion has been reported to be effective in some power plants and gas turbine operations in the United States and Europe. A number of additives for control of deposits and high-temperature corrosion contain magnesium, calcium, barium, aluminum and silicon compounds, singly or in combination. These metals are intended to raise the melting point of the potential deposit material so that it will not fuse to the tubes but will be carried away in the flue gas as fly ash.

Some of the problems in making use of residual oil as a fuel have been alleviated by improvements in burning and handling equipment and engineering practices. Better alloys have been developed for boiler and turbine components which are more resistant to corrosion. Better oil atomization has resulted from new burner designs which has led to improved combustion and reduction of tube deposits. Advances in insulation practices and pump design have made it easier to handle high-viscosity oils. Minimizing excess combustion air has reduced heat loss and the formation of sulfur trioxide, which in turn has reduced corrosion and acid mists escaping to the atmosphere.

From the above discussion it is seen that although residual fuel oil is a by-product, there have been advances in its use which, at least partly, make it more competitive in quality with gas. Future advances in technology will probably reduce the amount of residual oil while increasing the production of more valuable products. Catalytic hydrogenation processes will upgrade the heaviest high-sulfur residua to more volatile stocks of lower sulfur content.

CHAPTER TEN—REFINING TECHNIQUES

Since World War II major changes have taken place in refinery processing. Entirely new processes, many employing catalysts, have been introduced and perfected while older thermal processes have almost disappeared.

This Chapter on "Refining Techniques" traces the flow of crude oil and its fractions through the modern refinery. It starts with desalting, which removes fouling and corrosive contaminants, and follows with atmospheric and vacuum distillation, which separates the crude into various fractions.

The trend toward replacement of the older thermal conversion processes of cracking, visbreaking and coking by catalyst systems is described. The newer processes include catalytic cracking and hydrocracking. This same trend toward catalytic processes is seen in the rapid growth of catalytic reforming, alkylation, and isomerization which are used to produce high-octane components for gasolines.

Hydrotreating processes, also employing catalysts, are shown to be growing rapidly in application to remove sulfur and nitrogen compounds, and to improve odor, color and stability of gasoline and other fuels.

The final finishing, treating and blending techniques used in the modern refinery to insure highest product quality are outlined.

A short section on the refining of lubricating oils, including growth pattern of the various techniques employed, is finally described.

SECTION 1—Major Refinery Processing Steps

A. Desalting

Broadly speaking, desalting involves elimination of water-soluble, corrosive contaminants from crude oil. Deposition of salt and corrosion resulting from these contaminants causes a decrease in heat transfer rates by fouling, and promotes the formation of coke deposits in refinery processing equipment. Modern desalting practice also reduces oil pollution in process condensate water. Such condensate is used in the desalting process to provide necessary dilution water for "salting" out contaminants from the crude oil. At the same time, the crude oil extracts the dispersed oil from the condensate, thus eliminating one source of waste water pollution.

Crude oil desalting capacity has increased significantly since 1945, chiefly because of a change in the pattern and character of worldwide crude development and exploration, which has resulted in the refining of increasing quantities of salt-contaminated crude. Essentially the same desalting processes (chemical treatment, electrical treatment and combinations of the two) are being used today as were used in 1945.

The extensive use of desalting by the refining industry has contributed in two ways to producing petroleum products at lower cost. First, lower fuel costs are realized by operating at higher heat transfer coefficients with clean equipment, and second, less corrosion and fouling of equipment has meant longer processing intervals between mechanical overhauls.

During the period 1967-1975, U.S. petroleum desalting capacity is expected to increase at the same rate as the amount of crude oil processed—about 3 percent per year. Essentially all the crude run in 1975 will be desalted prior to processing. Desalting plants will consist of large multiple-stage units using a combination of thermal, chemical and electrical techniques. Better chemical additives and improved electrical coalescing devices will be used, but there should be little or no change in capital costs of desalting equipment (dollars per daily barrel of oil processed) after correcting for inflation.

B. Distillation

Distillation is the first step in the refining of desalted crude oil, and, therefore, as the amount of oil refined has increased during the twenty-year period since World War II, so has the amount of crude oil distilled. Distillation capacity has doubled during this period with the overall trend in equipment toward larger, more highly automated crude distillation units of increased complexity. Whereas the capacity of the average atmospheric distillation unit built in 1945 was about 20,000 barrels per day, units with capacities in excess of 100,000 barrels per day were common in 1965. This increased size has resulted in a lower cost per unit capacity. During the same period, both process and mechanical design improvements (new tray designs) have resulted in better separation efficiency and increased operating flexibility.

With high-boiling stocks, decomposition by thermal cracking begins at about 800°F. And for this reason, heavy crude oils must be distilled in vacuum. The economic incentive for converting more of the residual crude fraction to gasoline, heating oil and jet fuel has promoted increasing use of vacuum distillation. Since 1945, vacuum distillation has been widely used to augment the yield of catalytic cracking feedstocks. In 1965, total vacuum distillation capacity corresponded to 35 percent of atmospheric distillation capacity. The trend has been toward larger capacity vacuum distillation towers (units of 50,000 B/D capacity in 1965 compared to units of less than 10,000 B/D in 1945). Design improvements include better fractionation (more, larger, better designed trays), improved control of recycle streams (better reflux operation) and more effective equipment for minimizing entrainment of heavy asphalt and metal contaminants. The control of entrainment in vacuum operations has become increasingly important because of the heavier feedstocks being processed, and because of the great importance of minimizing contaminants in heavy distillate catalytic cracking feedstocks. A very small fraction of these undesirable constituents can poison catalysts and reduce cracking product yields to a marked degree.

Capital costs for vacuum distillation equipment, in constant dollars per daily barrel of capacity, were about 30 percent lower in 1965 than in 1945. There have been wide swings in these costs from the fact that when tower internals were largely eliminated (about 1947) increased capacity was quickly gained. However, refiners (and contractors) were soon forced to reduce capacity again in order to eliminate entrainment of mists containing trace metals that contaminated products and caused cracking catalyst problems. During the 1954-1956 period, better fractionation and entrainment equipment became available, and capacity has since increased steadily. The trend toward larger vacuum distillation units has had a major effect on the reduction in capital costs that has occurred during the past twenty years.

Atmospheric distillation capacity is expected to grow to about 14 million barrels per day by 1975, and vacuum distillation capacity is expected to increase by 40 percent to about 5 million barrels per day. This will represent 35 percent of atmospheric distillation capacity. Much of the increased capacity will be needed to satisfy an increasing demand for heavier feedstocks for both catalytic cracking and hydrocracking. Capital costs of both atmospheric and vacuum distillation equipment are expected to continue to decrease.

Computer control will be used more extensively on 1975 crude distillation equipment in order to optimize operations.

C. Deasphalting

Deasphalting refers to a low-temperature process which uses solvents, such as propane, to remove the heavier boiling components from a vacuum residuum leaving a higher quality gas oil for lube processing or catalytic cracking feed. Three major developments in deasphalting since 1945 are in the number of units in service, the types of feedstock being processed and the mechanical design of the processing equipment. The number of plants in service has grown severalfold during this period. Although deasphalting continued to be popular as a process for lube oil manufacture, an increasing number of units were built for treating catalytic cracking feedstocks during 1945-1965. The process is useful for making cracker feedstocks because it can demetalize high-boiling stocks without subjecting them to cracking temperatures. Because the higher boiling fractions of crude oil generally contain high concentrations of metal contaminants, deasphalting makes it possible for the refiner to crack even deeper into a barrel of crude oil. Recent engineering and processing design improvements include replacing packed-bed equipment with mechanical contactors and employing improved solvents (butane-propane mixtures). These advances have significantly increased operating flexibility. Capital cost per unit of charge for deasphalting has remained about constant since 1945.

Deasphalting is expected to become increasingly important for deep feed preparation of both catalytic and hydrocracking feedstocks. Also, the continued growth in lube oil refining capacity will require additional expansion of deasphalting facilities.

D. Thermal Cracking

Prior to World War II, thermal cracking of gas oil was a major source of gasoline. However, this process started to decline in importance as soon as catalytic cracking was commercialized. With the tremendous growth in catalytic cracking, the construction of new thermal gas oil cracking units for gasoline production stopped. Existing ones were used primarily to crack catalytic cycle oils, and even this use has declined. The trend in thermal cracking capacity is shown below.

The capacities shown for 1945 and 1950 are somewhat uncertain because some reported figures did not clearly distinguish between gas oil cracking and visbreaking, but the rapid decline thereafter is unmistakable. The process is likely to disappear altogether during the next decade, except possibly as a means of producing raw materials for chemicals.

E. Visbreaking

Visbreaking is a mild thermal cracking process used to lower the viscosities and pour points of crude oil residua, and thus to decrease the ultimate yield of salable heavy fuel oil. The feed is heated quickly to a temperature of 850-900°F at a pressure of 200-500 psi in a pipe coil, and is then quenched with light gas oil to stop the cracking. After quenching, the pressure is reduced, gas oil and lighter fractions are flashed off and fractionated, and the residue is further flashed in a vacuum tower to recover additional heavy gas oil. Salable fuel oil is obtained by blending the vacuum bottoms with a light gas oil to meet desired specifications. Alternatively, the fuel oil can be produced directly by using less extensive flashing, thus leaving visbreaker gas oil with the cracked residuum and avoiding the need for extraneous cutter stock.

Visbreaking has been applied to full range and topped crudes, and atmospheric reduced crudes, but the usual visbreaker feed in U. S. refineries is now vacuum residuum ,because heavy virgin gas oil is better processed by catalytic cracking. Mild cracking conditions are used in visbreaking in order to avoid coking in the furnace coils and to ensure adequate fuel oil stability. The operation is carried out once-through because recycling the residuum would lead to excessive coking. If any further thermal cracking of the heavy gas oil is desired, it is done in a separate coil under different conditions. In many refineries, visbreaking is carried out in modified equipment formerly used for gas oil cracking.

The yields obtained in visbreaking are strongly affected by the type of residual feedstock. However, when compared to the coking process, the yields of gas oil and lighter products are lower, the octane number of visbreaker gasoline tends to be somewhat higher, but the quality of visbreaker gas oil as cat cracker feed is usually superior to that of coker gas oil.

TRENDS IN THERMAL GAS OIL CRACKING

		Capacity at Year End	
		BARRELS OF FEED PER STREAM DAY	% OF CRUDE
	1945	1,900,000	36.0
	1950	1,900,000	26.5
	1955	1,000,000	11.2
	1960	647,000	6.2
	1965	372,500	3.5

Trends in visbreaking capacity are shown below from which it can be seen that less barrels of residuum are visbroken currently than ten years ago, despite a 20 percent increase in crude running capacity.

TRENDS IN U. S. VISBREAKING CAPACITY		Capacity at Year End	
		BARRELS OF FEED PER STREAM DAY	% OF CRUDE
	1955	676,000	7.5
	1960	636,000	6.1
	1965	580,000	5.4

Visbreaking will no doubt continue to decline in importance in this country, and where its use persists it will probably be in combination with some sort of hydrogen treatment as the need for lower sulfur fuels becomes more urgent. Such combinations are already being used to a limited extent.

F. Coking

Coking of petroleum residua is a well-established technique for decreasing residual fuel yield. This process depends on thermal cracking to break down heavy fractions into lower boiling oils, and the thermal decomposition is continued until a solid residue (coke) remains. At first, coking was carried out as a batch process in which reduced crude or other heavy oil was heated and decomposed by direct fire in horizontal vessels called tower stills, because they were equipped with condenser towers. After volatile products had been driven overhead, the hot coke was allowed to cool and was then removed manually by laborers who entered the still. Labor, fuel and repair costs were high in this process. More economical processes were later developed that operate continuously.

Delayed coking, which is still the predominant process, was commercialized in 1930. In this process the feed is heated rapidly in a pipe still furnace to a temperature of 900°F, or higher, and is then discharged into insulated vertical drums where it remains while cracking occurs from the contained heat. Temperature and pressure in the drums are in the ranges of 775-850°F and up to 90 psi (usually about 30 psi). Vapors of gas oil and lighter fractions pass into the fractionating system, while heavy fractions remain behind and gradually decompose into lighter products and coke. The highest boiling distillate portion of the fractionator product is commonly recycled to the reaction section. Continuous operation is achieved by using two or more drums in rotation, the cycle for each being on the order of one to three days. When a drum is full of coke it is switched offstream and replaced by another. The original technique for removing the coke involved winding a cable in the drum before filling, and afterward withdrawing it with a winch to break the coke bed into lumps. Coke still adhering to the walls of the drum was then removed manually and the cable was rewound for the next cycle. After several years this technique was replaced by hydraulic decoking, wherein high-pressure water jets cut the mass into lumps and fragments that fall out of the bottom of the drum.

The continuous fluid-coking process was announced in 1953, and the first commercial unit was brought onstream by the end of the following year. In this process the heavy feed is cracked by contacting it with a fluidized bed of coke particles at a temperature in the range of 900-1,050°F and essentially atmospheric pressure. Coke formed by decomposition of the feed is deposited on coke particles already in the bed. Vapors are removed overhead through a cyclone separator that returns suspended coke particles to the bed. Heat required by the process is supplied by circulating a stream of fluidized coke to a burner vessel, where a portion is burned with air to maintain the vessel temperature at about 1,100°F. A stream of heated particles is then returned to the reactor to maintain the coking temperature. Net coke produced in the process is withdrawn from the system. If desired, it can be transported to storage as a fluid in pipes.

Another continuous process called contact coking was developed in which the preheated feed was cracked by contacting with a stream of hot coke granules circulated through a reactor. There have been no large commercial installations in this country, but the Russians have announced commercialization of a similar process.

Coking yields vary widely with the nature of the feed and are also influenced by the amount of recycling and by other conditions. The maximum yield of cat cracker feed is obtained by operating with little or no recycling and at low pressure, but the gas oil thus produced has a higher end point. Also, overall results are better when the crude is flashed to a lower percent bottoms before coking. These expedients are advantageous not only because they increase the yield of cat cracker feed, but also because they minimize the yield of coker naphtha, which is of poor quality.

Coker gas oil is somewhat inferior in quality to virgin gas oil of the same boiling range from the same crude, but is much superior to residuum because metals and large condensed-ring nuclei in the coker feed end up largely in the coke. Coker naphtha tends to be relatively high in unsaturates and sulfur content. The research octane number typically ranges from 60-70 for paraffinic feeds to as high as

80 for highly naphthenic feeds. The coke is largely used as fuel, but increasing quantities are used in the manufacture of carbon electrodes for the aluminum or other electrometallurgical industries. It is also the major raw material for making synthetic graphite, and is used in ore sintering operations and in the manufacture of silicon carbide and other chemical industry uses. The rapidly increasing export market is also playing a key role in coking capacity expansion.

Trends in U. S. coking capacity are shown below:

TRENDS IN U. S. COKING CAPACITY

CAPACITY AT YEAR END

	BARRELS OF FEED PER STREAM DAY					TONS OF COKE PER
	BATCH	DELAYED	FLUID	TOTAL	% OF CRUDE	STREAM DAY
1950	—	—	—	—	—	9,400
1955	28,200	298,800	13,800	340,800	3.8	10,900
1960	17,300	365,700	102,500	485,500	4.6	16,900
1965	7,000	530,000	108,200	645,700	6.0	23,000

opment of new zeolitic cracking catalysts. The greater activity and selectivity of the new zeolitic catalysts give higher yields of valuable products than the old natural clay or synthetic silica-alumina catalysts. Although the crystalline zeolite cracking catalysts have only been used commercially since 1962, it is estimated that in the U. S. at least 50 percent of total catalytic cracker feed is processed over zeolitic catalyst, and approximately half of all the cracking catalyst consumed is zeolitic.

With the relatively stagnant demand for residual fuel (actually decreasing as a percentage of crude or total products) and the increasing proportion of that demand supplied by imports, coking capacity nearly doubled between 1955 and 1965. Since coker feed has become heavier, on the average, with the expanded use of vacuum crude reduction, coke production has increased even faster than total coker feed. The pressure to install facilities for decreasing residual fuel yield has been especially pronounced on the West Coast, where locally produced crudes are heavy but natural gas has been capturing an increasing share of markets formerly supplied by residual fuel. Air pollution considerations will continue to apply pressure to lower the sulfur content of residual fuel or to restrict its use.

Further growth in coking capacity can be expected in the near future, but in the long run better methods of processing residua are likely to be developed—processes which would remove sulfur but would have greater flexibility for controlling the product distribution. A new process should also produce light products in higher yields and of better quality.

G. Catalytic Cracking

During the 1945-1965 period, U. S. catalytic cracking capacity has increased about fivefold. During the same period, catalytic cracking expressed as a percent of total oil refining capacity, has increased almost threefold to a present level of about 50 percent.

Of the many important technological and mechanical advances made in catalytic cracking since the end of World War II, a major one is the development of new zeolitic cracking catalysts.

Prior to development of zeolite catalyst a significant advance was the introduction of the high alumina-base (25 percent Al_2O_3) catalyst which gave superior attrition resistance. This material is still in wide use today in plants lacking flexibility to take advantage of the zeolitic catalyst.

Major improvements have been made in the catalyst flow and handling equipment especially in the fluid catalyst units. These for the most part have been in the direction of designing for maximum heat economy, minimum catalyst attrition, improved process control and less wear of mechanical equipment. A process modification has been the two-stage (transfer-line) cracking which utilizes dual reactors operating at different cracking conditions.

The paramount objective in the modern U. S. refinery has been, and continues to be, conversion of the heavy end of the barrel into gasoline and other distillate products to meet changing market requirements. Therefore, the trend in catalytic cracking has been to feed even heavier, less valuable gas oils, and to operate at higher temperatures to achieve increased conversion.

Another design trend has been to recover much of the energy from the regenerator flue gas through flue gas expanders and carbon monoxide boilers. Expanders depressure the regenerator gas through a turbine, recovering most of the power required to drive the blower for the regenerator air supply. The boilers have a carbon monoxide combustion furnace for converting the carbon monoxide in the stack gas to carbon dioxide, using the heat generated for producing steam or for preheating oil feed to the reactor. Improved design has resulted in very high efficiency cyclone separators for removing catalyst fines from the regenerator stack gas. These cyclones have been very effective in abating air pollution from catalyst dust.

The mechanical reliability of catalytic cracking units has been greatly improved since 1945; units now operate from two to three years between major maintenance shutdowns. The service factor for present units is about 96 percent (only one month out of twenty-four is the unit down for maintenance). Mechanical design improvements made during the past two decades have made possible the building of much larger cracking units. Although the average unit built at the end of World War II had a throughput capacity of about 15,000 B/D, cat crackers are presently being constructed with capacities of from 80,000 to 100,000 B/D. These large units, in addition to having lower operating costs and higher efficiency, have been a major factor in reducing capital cost per barrel of capacity.

By 1975 catalytic cracking capacity is expected to increase by about 30 percent to 7 million barrels per day, corresponding to 50 percent of total crude oil processing capacity.

By the end of this decade, improved zeolitic catalysts will be used in nearly all U. S. catalytic crackers. The improved selectivity of these catalysts will permit more of the cracker feedstocks to be converted to gasoline and fuel oils at the expense of coke and gas. As a result, smaller regenerators and gas compressors will be used in the 1975 catalytic crackers. The current practice of charging even heavier feedstocks to the catalytic cracker is expected to continue through the next decade. Cracking units in 1975 will probably be controlled on a closed loop basis by digital computers, at conditions determined by product demand and the optimum overall economic situation of each refinery.

H. Hydrocracking

Hydrocracking represents one of the oldest catalytic processes for hydrocarbon conversion. While it was originally employed in Germany in 1927 to convert lignite into gasoline and later to convert petroleum residues into distillate fractions, the first commercial hydrocracking installation in this country was operated in the late 1930's for the production of aviation gasoline.

Early applications of hydrocracking used extremely high pressures, and were very costly to operate. Years of independent research by the petroleum industry were required to bring hydrocracking technology to its present level.

In the early 1960's, several small hydrocracking units of 3,000 barrels per day to 8,000 barrels per day capacity were installed. Successful operation of these units aroused the interest of the refining industry such that by 1966 five U. S. licensors were offering hydrocracking processes, and 15 units with a combined capacity of over 200,000 barrels per day had been installed. The largest of these had a design capacity in excess of 60,000 barrels per day.

Projections for 1970 indicate a total of 700,000 barrels per day of hydrocracking capacity will be installed. This total will represent 11 percent of the total U. S. cracking capacity.

The prime reason for the accelerated interest in hydrocracking by refiners is to maintain their product balance. Nationwide gasoline market requirements are increasing at a greater rate than the middle distillate fuels. This requires the refiners to steadily increase their gasoline percentage of the product "barrel." Hydrocracking offers many refiners the most economic solution to this product balance problem by converting distillates into gasoline stocks. While most units to date are designed to maximize gasoline production, hydrocracking provides the additional flexibility of producing middle distillate fuels which have superior combustion characteristics, i.e., low sulfur, excellent smoke point, etc. Thus, because of its extreme versatility, hydrocracking has been used to upgrade a variety of stocks, such as cycle oil, coker oils, thermal distillates and vacuum distillates, into more desirable lighter products.

The hydrocracking process consists basically of mixing hydrogen with hydrocarbon feed at elevated pressures, heating the mixture and contacting with catalyst in a fixed bed or ebullient bed system consisting of one or more reactors in series or parallel. Provision is made for recycling hydrogen-rich gas and unconverted hydrocarbon. Most hydrocrackers operate within the range of 500-800°F and 500-3,000 psi. This process scheme has many similarities to the catalytic reforming of naphtha; however, considerably higher pressures are employed.

There are a variety of catalysts which can be employed in the hydrocracking process; such as sulfided nickel supported on a silica-alumina cracking catalyst, noble metals on silica-alumina, cobalt molybdena-alumina, tungsten on silica-alumina, etc. Considerable work is presently being done to improve general catalyst performance and develop catalyst combinations for specific process applications. Hydrocracking catalyst development has reached the point where some catalysts in specific applications can be kept in operation without regeneration for over two years affording as high as 98 percent onstream efficiency.

Hydrogen must be furnished to the hydrocracking unit from an external source, often the off-gas from catalytic reforming operations. Normally, the hydrogen requirements for hydrocracking vary from 100 cubic feet per barrel for light feeds to 3,000 cubic feet per barrel for heavy feeds. Should other hydrogen-consuming processes expend the reformer hydrogen in a given refinery, hydrogen must be purchased or manufactured by a separate facility to meet the hydrocracking requirements. This process is covered in a subsequent section of this report.

Hydrocracking is a most versatile of refinery processes, being able to process a wide variety of feeds into a large number of lower molecular weight products. The following table lists a number of applications for hydrocracking which are presently under consideration by refiners.

APPLICATIONS OF HYDROCRACKING

CHARGE STOCK	PRODUCTS
Naphtha	Propane and Butane (LPG)
Kerosene	Gasoline
Straight-Run Diesel	Gasoline and/or Jet Fuel
Atmospheric Gas Oil	Gasoline, Jet Fuel and/or Distillates
Natural Gas Condensates	Gasoline
Vacuum Gas Oil	Gasoline, Jet Fuel and/or Distillates
Propane Deasphalted Gas Oil	Gasoline, Jet Fuel and/or Distillates
Catalytically Cracked Heavy Cycle Oil	Gasoline and/or Distillates
Catalytically Cracked Light Cycle Oil	Gasoline
Coker Distillate	Gasoline
Coker Heavy Gas Oil	Gasoline and/or Distillates
Residuum	Gasoline, Jet Fuel and/or Distillates

It is noted that the majority of applications call for maximum gasoline production. The original units processed feeds with an end point of about 700°F. Hydrocracking technology has now been developed to the point where feeds with end points of 1,100°F, or higher, can be processed successfully. Within these boiling ranges, all kinds of straight-run and cracked distillates are being successfully hydrocracked.

The present (1966) capital costs of hydrocrackers vary between $450 and $700 per barrel of installed capacity, depending on the size of the unit and nature of the process scheme. A typical 6,500 barrel per day two-stage unit processing cat cracker cycle oil would cost approximately $4,000,000 at this time, exclusive of hydrogen-producing facilities. Technological advances will likely offset any increase in equipment and materials, thus stabilizing hydrocracking capital costs at approximately their present level.

Future developments which could hasten the installation of hydrocracking units are: (a) the development of more rugged catalysts which can handle feed with higher levels of contaminants and a broader range of boiling points; (b) metallurgical developments which allow the fabrication of larger reactors and, therefore, larger "single train" units; (c) development of technology to reduce operating pressures and increase onstream efficiency; (d) development of low-cost hydrogen—the vital raw material; and (e) air pollution requirements that eliminate present residuals as fuels making it necessary to find a suitable refining step for their disposal.

I. Thermal Reforming

At the end of World War II, octane improvement of virgin heavy naphtha depended primarily on thermal reforming, a severe pyrolytic process introduced in the early 1930's. The octane improvement resulted primarily from production of olefins and a downward shift in boiling range. With a Mid-Continent heavy naphtha having an octane number in the low 40's, it was possible to obtain about 75 volume percent of 80 research octane number product (without tetraethyl lead); however, when reforming conditions were made more severe, a sharp yield loss resulted for only a small further increase in octane number. The yield loss was primarily gas, but there was also a small amount of liquid product boiling above the end point of gasoline. Although a portion of the yield loss was salvaged by polymerization or alkylation of propylene and butylene in the gas, the commercial use of thermal reforming was severely limited because of the high operating cost. Essentially all of the thermal reforming plants were replaced by 1960 by catalytic reforming units.

J. Catalytic Reforming

In addition to the thermal reformers at the end of World War II, there were eight catalytic reformers with a combined charge capacity of about 80,000 B/D which had been used during the war to produce toluene and aviation gasoline components. Catalytic reforming was first commercialized in 1940. In this process, naphtha vapors were passed through a fixed bed of molybdenum-alumina catalyst at temperatures in the range of 900-1,050°F and pressures of about 100-400 psi. Hydrogen-rich gas was mixed with the entering naphtha vapors to suppress deposition of coke on the catalyst. More hydrogen was then produced in the process and recycled to mix with the feed. Octane improvement resulted primarily from dehydrogenation of cyclohexanes to the corresponding aromatics and, to a smaller extent, from conversion of paraffins and cyclopentane homologs to aromatics and low molecular weight paraffins. Yields and octane ceiling were much better than for thermal reforming. For example, roughly 75 volume percent of 95 research octane number product could be obtained from the Mid-Continent heavy naphtha. Another advantage over thermal reforming was that essentially all the sulfur was removed from the naphtha. However, regeneration of the catalyst was required after 1-12 hours onstream in order to maintain activity, and this necessitated extra reactors used alternately to permit continuous operation. Also, since the hydroforming reaction was highly endothermic, most units had two reactors onstream in series, with intermediate reheating.

One of the new processes used a fluidized molybdenum-alumina catalyst in powder form at about the same pressure and the same average frequency of regeneration as in the fixed-bed process. However, the fluid process was cheaper to build (particularly in the larger sizes) and simpler to operate, but gave slightly poorer yields than the fixed-bed process. The superior performance was due to continuous operation, uniform temperature in the reactor, and elimination of the thermal cracking that is unavoidable in the preheater and inlet end of the reactor in fixed-bed units.

Other developments involved moving-bed processes in which a chromium-alumina or cobalt molybdenum-alumina catalyst was continuously circulated through separate reaction and regeneration zones. Naphtha and hydrogen-rich recycle gas were processed at 100-400 psi pressure, and the circulating catalyst was regenerated continuously at an average frequency of about once every 6-20 hours.

By far the most important of the new processes are those using platinum catalysts on an alumina base. The first one was announced in 1949, and it was soon followed by several others. The several platinum reforming processes are all fixed-bed processes. They differ in various respects, but all have distinct advantages over the other processes described above. One advantage is that the platinum catalysts inherently produce less carbonaceous deposit (coke). By operating at relatively high pressures (up to 750 psi) and at moderate octane improvements, the process can be operated continuously for many months, without catalyst regeneration, before catalyst activity and product yields are seriously impaired. The catalyst can then be economically regenerated. Another advantage is that acidity and platinum in catalysts give better yields because they do a better job of converting cyclopentane homologs and paraffins to aromatics, and give less degradation of these feed components to low molecular weight paraffins. These factors lead not only to a higher gasoline yield for given octane number, but also to a greater yield of by-product hydrogen which is valuable for various refinery hydrotreating processes. The yield advantages are enhanced by operating at lower pressures and the yield enhancement is greater at higher octane levels. With the Mid-Continent virgin feed at 300 psi, a gasoline yield of about 92 percent can be obtained at 95 research octane number and nearly 85 percent at 100 octane number, both without tetraethyl lead. Because of the greater selectivity toward dehydrogenation reactions, reforming with platinum catalysts (especially at low pressures) is even more endothermic than with molybdenum or chromium catalysts. For this reason most units have several reactors in series with intermediate reheating.

Although low pressure operation is preferable from a yield standpoint, it has the drawback that rapid degradation of catalytic properties occurs—especially at higher octane levels and with heavier feeds. Regenerative processes were, therefore, developed for such operations. In all cases, regeneration can be less frequent with platinum catalysts than with molybdenum or chromium catalysts at the same pressure and product octane number. In so-called semiregenerative units, the catalyst is operated at an intermediate pressure for several months, and the unit is then shut down for several days while the catalyst is regenerated in place. Even in fully regenerative units operating at 200-300 psi and producing gasoline of over 100 research octane number, unleaded, only one extra reactor is required to permit continuous operation. The extra reactor can be switched in place of any other reactor when it needs regeneration. With special techniques that have been developed, the catalyst can be regenerated hundreds of times, but eventually it must be replaced because of loss of physical strength or catalytic properties. Even though the platinum content of the catalyst is only a fraction of a percent, the high cost of platinum makes it economical to recover it chemically from the catalyst for reuse.

Other methods of achieving very high octane numbers involve extraction of the reformate with a selective solvent or a solid adsorbent. If desired, the low-octane raffinate can be further reformed, either in another unit or by recycling to the same catalytic reformer. These alternatives have seen only limited commercial application thus far but may become more important as gasoline octane levels continue to rise.

Performance of platinum catalysts is adversely affected by sulfur and nitrogen compounds, olefins and trace poisons, such as arsenic and lead. The latter two are permanent poisons. For this reason, it is a common practice to remove these constituents by mild acid treating or by hydrogen pretreating with a rugged catalyst. This makes it possible to reform even the worst virgin and cracked naphthas to high octane number with less frequent regeneration than would otherwise be necessary.

The 20-year trends in reforming capacity are summarized in the following table.

TRENDS IN DOMESTIC NAPHTHA REFORMING CAPACITY
Capacity at Year End in 1,000 Barrels per Stream Day
(% on Crude)

		CATALYTIC REFORMING		
	THERMAL REFORMING	NONPLATINUM CATALYSTS	PLATINUM CATALYSTS	TOTAL
1945	370 (7.0)	80 (1.5)	—	80 (1.5)
1950	500 (7.0)	85 (1.2)	1(<0.1)	86 (1.2)
1955	370 (4.1)	143 (1.6)	778 (8.7)	921(10.3)
1960	175 (1.7)	38 (0.4)	1,917 (18.2)	1,955(18.6)
1965	40(<0.4)	23 (0.2)	2,060 (19.2)	2,083(19.4)

Thermal reforming capacity at the end of World War II was on the order of 7 percent on crude, while catalytic reforming amounted to between 1-2 percent. Catalytic cracking was the major contributor to increased gasoline octane number. With the advent of new and better processes, catalytic reforming came into its own in the early 1950's, and combined capacity by 1960 amounted to 18.6 percent on crude, while thermal reforming dropped to less than 2 percent. As the marked superiority of platinum processes became apparent, the other catalytic processes gradually fell by the wayside. Catalytic reforming with platinum has grown slowly during the last few years, but is expected to show further expansion during the next several years because of the need to upgrade heavy naphtha produced by hydrocracking, which is expanding rapidly.

K. Polymerization

Polymerization of by-product petroleum gases to liquids boiling in the gasoline range was already being practiced on a substantial scale before and during World War II. Thermal polymerization processes relying on pressure and high temperature were developed to the commercial stage in the early 1930's. The thermal processes were operated at temperatures of 900-1200°F and pressures from 60-3,000 psi. They converted paraffinic, as well as olefinic C_3 and C_4 hydrocarbons, to liquids of high octane number for those days; but they were soon superceded by catalytic processes.

The most important catalytic polymerization processes used phosphoric acid in some form as catalyst, and were introduced before World War II. During the war, these processes were operated on butane-butene feeds to produce mainly isobutene dimer or butene codimers for hydrogenation to aviation gasoline components. After the war, however, most of them continued to be operated to produce polymer from butenes and propylene for inclusion directly in motor gasoline. To some extent, they are also used to produce polymers for manufacture of various chemicals or specialty products. Ethylene is not reactive enough to be a good feed for these processes. Catalytic dehydrogenation of propane or butanes to olefins is technically feasible, and would thus increase the potential yield of polymer gasoline from light gases; but this route is uneconomical.

Catalytic polymer gasolines are characterized by high olefin content, high research octane numbers, fairly high motor octane numbers, good octane blending value in straight-run gasolines, but mediocre octane response to addition of tetraethyl lead. Typical octane ratings of polymer gasolines are shown below.

OCTANE RATINGS OF
POLYMER GASOLINES

OCTANE NUMBER	PROPENE POLYMER	BUTENE POLYMER	MIXED POLYMER
Research, clear	93	99	97
with 3 ml TEL/gal	99	100+	101
Motor, clear	80	81	83
with 3 ml TEL/gal	85	84	86

The polymers also have high gum-forming tendency, but this is easily controlled by inhibitors. Propene polymer contains a large proportion of trimer, while butene polymers are largely dimers. The antiknock quality of thermal polymer varied widely with operating conditions, but was generally inferior to that of catalytic polymer. Trends in polymerization capacity are shown below.

TRENDS IN POLYMERIZATION CAPACITY

	NUMBER OF REFINERIES INVOLVED	BARRELS POLYMER PER STREAM DAY	% ON CRUDE
1950	94	65,000	0.9
1955	154	141,000	1.6
1960	135	150,000	1.4
1965	99	120,000	1.1

The capacity reached a maximum in about 1960 and then began to decrease. Because alkylation gives a better product and roughly twice the yield per volume of olefin, little or no new construction of polymerization units is expected. Many of the existing units will continue to be used, at least for the near future, but as they are retired, polymerization capacity will continue to decline.

L. Alkylation

Although alkylation involves broadly the addition of an alkyl group to any compound, the present discussion is limited to the reaction of an olefin with a paraffin to form a branched-chain paraffin of higher molecular weight. The industrially important reaction is the acid-catalyzed union of C_3-C_5 olefins with a paraffin having a tertiary carbon atom, specifically isobutane, using either sulfuric acid or hydrogen fluoride (HF) as catalyst. Aluminum chloride promoted by anhydrous hydrogen chloride is also an excellent catalyst that will even catalyze the alkylation of isobutane with ethylene to produce good yields of a blending component superior to isooctane. One commercial unit was placed onstream in 1944, but this process has not been widely adopted.

The first commercial alkylation plant using sulfuric acid as catalyst was placed in operation during the late 1930's, and the first HF alkylation unit was completed late in 1942. Some of the units continued in use after the war to produce alkylate for aviation gasoline or premium motor gasoline, but many of them were shut down. Alkylate manufacture was increased again for aviation gasoline during the Korean War. Subsequently, with the shift toward jet aircraft engines, which do not require high-octane fuels, the aviation demand for alkylate fell off sharply. However, this decline has been more than offset by increased use of alkylate in motor gasoline since about 1954, stimulated by the continued rise in automotive octane requirements. Alkylate is a particularly valuable blending stock because of its high-octane number by both research and motor methods, and its good response to tetraethyl lead.

Alkylation units are much more expensive to build and operate than polymerization units, but are justified by the superior product quality and the much higher yield based on olefin feed. Sulfuric acid is the most widely used alkylation catalyst. The process is carried out at a temperature of 30-60°F (usually 40-50°F), using makeup acid of 98-99.5 percent concentration. Catalyst activity gradually decreases because of dilution and spent acid is withdrawn continuously. Acid consumption is in the range of 10-80 pounds per barrel of alkylate, depending primarily on the olefin used. Refrigeration is required to maintain the desired temperature.

HF alkylation is similar in many ways to sulfuric acid alkylation, but differs in several important respects. Because HF-water mixtures are extremely corrosive, the feed must be dried; bauxite or activated alumina are typical drying agents used for this purpose, but other agents such as molecular sieves can be used. HF alkylation is less sensitive to temperature than sulfuric acid alkylation, and most of the commercial units are operated at temperatures of 75-100°F. This higher operating temperature often allows the use of water cooling instead of refrigeration for temperature control, but also causes some sacrifice of alkylate yield and quality. As in the sulfuric acid process, the catalyst becomes diluted with hydrocarbon degradation products and water. However, since HF is volatile, it can be readily recovered and purified on site by distillation. Catalyst makeup requirement is, therefore, only a fraction of a pound per barrel of alkylate. Although the corrosive nature and volatility of HF imposed many problems in design and operation, they are satisfactorily solved, and service and safety records have been good.

Alkylate is a premium quality gasoline component. It is low in sulfur and gum contents, and has excellent stability, high energy content, high octane number and good lead response. Although trimethylpentanes predominate in butane alkylate and dimethylpentanes in propene alkylate, the product contains many different isoparaffins ranging from C_5's to C_{10}'s and higher, regardless of the olefin feed. Typical octane ratings for alkylate are shown below.

TYPICAL OCTANE RATINGS FOR ALKYLATE

OCTANE RATINGS	PROPENE	BUTENES	PENTENES
Research, clear with	89- 91	92- 96	88- 90
3 ml TEL/gal	100-104	103-109	100-102
Motor, clear with	87- 90	92- 95	87- 89
3 ml TEL/gal	99-101	100-104	98-100

Newer designed units, improved control of operations, and various additives have made it possible to reduce acid consumption significantly in the sulfuric acid units. Improvements have also been realized in both processes in alkylate yield and quality. Trends in U. S. alkylation capacity during the last twenty years are shown below.

TRENDS IN U. S. ALKYLATION CAPACITY

CAPACITY AT YEAR END, BARREL OF ALKYLATE PER STREAM DAY[a]

	SULFURIC ACID PROCESS	HF PROCESS	TOTAL	TOTAL CAPACITY % ON CRUDE
1945	105,000 (31)	64,000 (9)	169,000	3.2
1950	105,000 (29)	23,000 (9)	128,000	1.8
1955	195,000 (45)	59,000 (17)	254,000	2.8
1960	322,000 (65)	102,000 (38)	424,000	4.0
1965	410,000 (67)	140,000 (54)	550,000	5.1

a—Number of refineries involved are shown in parentheses.

The early figures are probably less reliable than those in the remainder of the tabulation because locations and capacities of alkylation units were not publicized prior to about 1954. Alkylation capacity is continuing to increase. Already announced new units and expansions of existing units will result in a net increase of about 100,000 barrels per day by the end of 1967, and a total alkylate capacity of as much as 750,000 barrels per day by 1970 has been forecast.

Quantitative information on the proportion of alkylation capacity that is represented by propene or pentene alkylation is lacking, but this is certainly increasing. Growth of butene alkylation is somewhat limited because much of the new cracking being added is hydrocracking, which does not produce olefins. However, the large yields of isobutane from hydrocracking should help to foster the use of available propene and pentenes for alkylation. Any influence that would lead to decreased usage of lead antiknock additives, eliminate olefins, or reduce volatility of gasoline would further stimulate the growth of alkylation, possibly even ethylene alkylation.

M. Isomerization

Isomerization is the rearrangement of molecular configuration without change in molecular weight. Although such rearrangements occur in many processes, such as catalytic cracking, catalytic reforming and hydrocracking, the present discussion is concerned with processes in which isomerization is the predominant reaction. Isomerization was investigated by numerous laboratories during the 1930's, and, stimulated by the demand for high-octane aviation gasoline, several processes were commercialized during World War II.

The most extensive commercial application of isomerization was the conversion of n-butane to isobutane for alkylation using aluminum chloride catalyst at 180-300°F and 200-365 psi. The first plant began operation in November, 1941. By the end of the war, there were 34 butane isomerization units in the U. S. There were also two units that converted n-pentane to isopentane, and two units that isomerized light naphthas (mostly pentane and hexanes). These isomerates were blended directly into aviation gasoline. In addition, there were two units that isomerized dimethylcyclopentanes to methylcyclohexane for dehydrogenation to toluene. Altogether, there were five commercial butane isomerization processes, two pentane isomerization processes, one light naphtha (pentane-hexane) isomerization process, and one naphthene isomerization process.

Many of the isomerization units were shut down when the military need for aviation gasoline dropped after World War II. Interest in isomerization was revived in the middle 1950's, both as a means of augmenting the supply of isobutane for alkylation and as a way of improving the octane number of light ends in straight-run naphtha. In the meantime, refinements had been made in aluminum chloride processes to improve operations, extend catalyst life and decrease cost. Also, several new processes were developed in which the paraffinic feed and recycle hydrogen were passed through fixed beds of solid catalyst at pressures of several hundred psi, in a manner similar to that in catalytic reforming. The active catalyst ingredient usually was a noble metal, but in at least one process it was a nonnoble metal.

The new processes avoid the corrosion and catalyst handling and disposal problems inherent in the aluminum chloride catalyst processes. Operating temperatures in some of the first announced processes of this type were in the range of 700-900°F, but subsequent developments permitted operating temperatures of 250-500°F.

Although the technology on isomerization of C_4-C_6 paraffins is fairly well developed and long-term growth may well occur, widespread application is not expected in the near future. There will be a growing need for isobutane for alkylation, but hydrocracking will supply a large share of this demand for the next several years, and in some refineries may even displace existing isomerization units. In certain special situations, isomerization of pentane and/or hexane will be attractive. The attractiveness of isomerization would, of course, be enhanced by any restrictions on lead content of gasoline or any change in engine design that required decreased octane "sensitivity" or more uniform distribution of octanes throughout the boiling range. Isomerization of C_7 and higher constituents of gasoline seem unlikely because they can be better processed by catalytic reforming. Isomerization of paraffin waxes to lube oils of high viscosity index and low pour point has been accomplished in the laboratory, but no commercial application has been reported.

There are several commercial plants that isomerize xylenes with a platinum-type catalyst, separate the desired isomers, and recycle the remainder. However, these operations are carried out for the production of petrochemicals.

N. Hydrotreating

Although hydrogenation processes had been associated with hydrocarbon processing since the early 1900's, it was not until World War II that any significant use of this process was attained.

During World War II, hydrogenation was used to convert selected petroleum stocks into blending components for aviation gasoline. For economic reasons, these processes were discontinued after the war. Interest in hydrogenation was revived in the mid-1950's when substantial quantities of hydrogen became available from the rapidly developing catalytic reforming process.

Under the general name of hydrotreating, a number of hydrogenation processes became popular with refiners at this time. The principal processes involved were hydrodesulfurization, saturation of diolefins and hydrodealkylation. By 1957, the installed capacity of these processes represented 8 percent of U. S. refining capacity. They were used to hydrotreat crude fractions produced from lower quality crudes or products from more severe refining operations. Hydrotreating enabled the removal of sulfur, improved odor and color, reduced gum-forming tendency and corrosion.

The hydrotreating process consists of mixing hydrogen with the material to be treated, heating it to the desired temperature, and passing it over a catalyst in a fixed-bed reactor system. The reactor effluent enters a separation system where hydrogen-rich gas is removed and recycled. Liquid material is then fractionated into the desired products.

In 1964 hydrotreating capacity reached 2,749,000 barrels per day of installed capacity with 11 licensors offering processes. This total went to 2,929,000 in 1965 and 3,095,000 in 1966. Volume-wise, hydrotreating is the fastest growing refining process. It is predicted that 270,000 barrels per day will be added this year.

Hydrotreating operations have many catalysts available. Cobaltmolybdena catalysts supported on alumina, nickel-molybdena on alumina, molybdena, nickel-tungsten sulfide and nickel catalysts are employed. Most units include provisions for periodic offstream regeneration where deposits of carbon are burned off the catalyst at temperatures controlled by mixing steam or recycle flue gas with combustion air. After regeneration some catalyst is in the oxide state, and then must be reduced by hydrogen. Hydrogen treating operating conditions range from 15-3,000 psig and 250-800°F. Hydrogen recycle rates vary from 270-6,000 cubic feet per barrel of feed.

The principal reasons for the rapid upsurge in installed hydrotreating capacity are first, the wider use of catalytic processes where even low quantities of nitrogen and sulfur compounds cannot be tolerated, and second the demand for higher quality refined products. Hydrotreating technology has reached an advanced stage, and catalyst development is continually improving to allow treatment of an increasing variety of refinery streams both internal and finished. Refiners are finding that extensive hydrotreating of internal streams can be economically justified to improve performance of their cracking or reforming units.

O. Hydrogen Generation

Late in the 1950's, hydrogen was a surplus by-product from catalytic reforming. There was some consumption industrially by hydrotreating, but in 1961, 50 percent of the hydrogen produced from reforming was burned as fuel. Today, as more and more processes consume hydrogen, this value is less than 25 percent. With increased installations of hydrocracking, hydrodealkylation (such as toluene to benzene), ammonia manufacture and other petrochemical uses, hydrogen generation will become a common refinery process.

The major processes for making hydrogen are: (1) by-product from catalytic reforming; (2) steam reforming; and (3) partial oxidation. The petroleum refiner normally utilizes all possible hydrogen from catalytic reforming before installing any process to manufacture hydrogen as a primary product.

Steam reforming is the mainstay of industry for producing hydrogen. It handles hydrocarbons from natural gas to naphtha. The hydrocarbon is mixed with steam in excess of the chemical quantity required. It is then reformed over a nickel catalyst packed inside tubes in a furnace. The reformer effluent is a mixture of hydrogen, carbon oxides, and excess steam. Plant sizes vary from 0.1 to 100+ MM SCF/D. Pressures vary from 50 to 400 psig and can be extended to 500 psig. Final product purity ranges from 90 to 98 percent hydrogen with methane being the major impurity.

Partial oxidation handles any hydrocarbon feed —even coke. It has considerable more flexibility than steam reforming. The feed is burned in a reactor to hydrogen and carbon monoxide. A small amount of steam can be used to control this highly exothermic reaction. Pure oxygen (99 percent) is used to sustain the combustion. Conventional plant designs range from 2 to 50 MM SCF/D. Hydrogen purity is 98 to 99 percent at pressures from 50 to 500 psig.

Many refiners have an alternate source of high-purity hydrogen available in limited quantities. Off-gases from ethylene, butylene, acetylene, and other units producing olefinic feedstocks provide hydrogen in the purity range of 30 to 50 percent. Other sources are tail gases from hydrotreating, hydrocracking, and other hydrogen-consuming plants. This hydrogen can be purified up to the 90+ percent purity required by most hydrogen-consuming processes. Cryogenics, adsorption on molecular sieves, or palladium diffusion can be used for purification. Cryogenics is favored in most refinery applications as it is basically a large-volume process giving high purity product at high recovery.

The future requirements for hydrogen appear substantial. Hydrocracking is projected to increase severalfold in the next few years. Feedstocks to hydrocracking will tend to get heavier, and larger amounts of hydrogen will be consumed per barrel of feed. Increased needs for jet fuel will force the refiner to synthesize jet fuel components rather than to distill them from conventional crude sources. Increased emphasis on removal of pollutants from conventional fuels will most probably require additional hydrogen processing. Declining supplies of premium crudes for lubricating oil production will force the refiner to synthesize lubricating oils from lower quality crudes. High-pressure hydrotreating for lubricating oil manufacture is already projected as an attractive process by several oil companies.

In summary, hydrogen processing has increased in the past few years to the extent that most refiners consume all of the by-product hydrogen from conventional operations. Direct manufacture of high-purity hydrogen is required for additional supply. Several commercial processes are available for hydrogen supply and indicated future needs show that the recent extensive growth in hydrogen processing will continue for some time to come.

SECTION 2—Product Treating, Finishing and Blending

In addition to the hydrotreating process previously discussed, there are many other treating, finishing and blending steps required in petroleum refining.

The product specifications of all refinery products have been steadily changing since World War II to improve the performance of these products in end use. As the equipment and machinery using petroleum products have become more sophisticated, so have the treatment and finishing techniques. Technology advances have improved the operating and economic aspects, resulting in a beneficial influence on blending, as well as improvements in the uniformity of product quality. Usually, blending formulations are dictated by product volume requirements and product costs, and the treating and finishing steps are taken to assure that the blend meets specifications.

Sulfur and sulfur compounds, by far, constitute the most significant contaminants in crude oil fractions. Other foreign materials which create treating problems are oxygen compounds, nitrogen compounds and metal compounds of iron, vanadium, calcium, magnesium, aluminum, nickel, copper, sodium, potassium, arsenic and zinc.

Mercaptans (sulfur compounds) are one of the especially undesirable contaminants of crude oil and petroleum fractions. One of the oldest processes for removing mercaptans was caustic treating or washing with aqueous sodium hydroxide solutions. The use of this process is decreasing throughout the U. S. because of the chemical requirement costs and waste disposal problem it creates. Another process which has virtually been discontinued is acid treatment, for economic, safety and water pollution reasons. One problem with the above processes is that they are able to remove only light mercaptans, but the higher boiling mercaptans are not affected. Consequently, these heavier mercaptans have to be converted into disulfides, which are odorless, by a number of sweetening processes such as doctor, copper chloride, hypochlorite, lead sulfide, air-inhibitor and air-solutizer processes.

The doctor process was the first to gain wide use in the industry, and was still being extensively used in 1960. However, it is gradually being replaced by other processes. Copper chloride sweetening processes offer an advantage over the doctor process by not requiring sulfur to be added to the process stream. One problem with the copper chloride process is that trace amounts of copper left in the gasoline have the effect of catalyzing the deterioration of gasoline and, therefore, must be removed or deactivated. Cracked petroleum stocks such as catalytically cracked gasolines can be sweetened by air-inhibitor processes, whereas the air-solutizer processes are able to treat all gasolines. In these processes, an inhibitor is added to the prewashed gasoline which is then mixed with air and caustic in a line mixer. Hypochlorite sweetening is used for sweetening natural gasolines and solvent naphthas, and for removal of trace mercaptans.

When the use of tetraethyl lead (TEL) as an antiknock agent became common in the late 1920's, processes to extract mercaptans from gasoline received strong attention, as all sulfur compounds reduce the effectiveness of the TEL. Caustic circulation with steam regeneration was first employed for this purpose. However, because of the limited solubility of higher boiling point mercaptans, caustic extraction was limited to about 80 percent removal. By using solutizing agents, the extraction efficiency was greatly improved.

The trend has been towards regenerative processes for removal of mercaptans, both for economic and water pollution reasons. Some processes utilize an ion-exchange catalyst.

In the early 1960's, increased attention to motor fuel performance and the quest of refiners to improve their operating efficiency were two of the factors which led to the use of linear programming techniques to guide refinery operations, and the use of elaborate processing monitoring devices such as continuous boiling point analyzers, monitoring chromatographs and continuous flash and pour point analyzers. The increased utilization of this type of hardware has reduced the cost of both monitoring and complete automation systems to the point where they can be economically justified.

In-line blending, where components and additives are blended together continuously in a product line, is one of the significant new developments in the refinery industry which has greatly improved the operating efficiency of finishing operations and product quality control. More than 30 in-line blending systems were in service in 1965, representing 25 percent of the total gasoline production. At present, approximately 50 percent of the gasoline produced in the U. S. employs in-line blending techniques. This percentage should approach 90 percent in another ten years. The advent of the continuous, automatic octane analyzer in 1963 has made possible complete digital computer control of gasoline blending. The ultimate in refinery operation will be one which operates at optimum conditions at all times using a complete computer control system. Such a system would control not only the operating conditions of individual process units, but also would optimize the blending of products to minimize production costs. This achievement is now possible, and will probably become economically feasible to many refiners within the not too distant future.

SECTION 3—Lubricating Oil Refining

Since 1945, the quantity of lubricating oils produced annually in the U. S. has increased 50 percent as shown below.

GROWTH IN U. S. PRODUCTION OF LUBRICATING OILS[a]

	ANNUAL PRODUCTION OF LUBRICATING OILS	
	MILLIONS OF BARRELS	PERCENT OF TOTAL CRUDE PROCESSES
1945	41.9	2.4
1950	51.7	2.5
1955	55.8	2.0
1960	59.4	2.0
1965	62.9	1.9

a—*Petroleum Facts and Figures*, 1959 and 1965 editions.
b—Bureau of Mines, *Monthly Petroleum Statements, 1965.*

Even though the crude oils processed have become less paraffinic, and hence less desirable as bases for lube stocks, the quality of finished lubricating oils has steadily been improved. The much better quality of today's lubricants is chiefly the result of three major improvements in lube oil refining since the end of World War II: wider use of solvent extraction, development of catalytic hydrogen-treating processes, and the development of improved chemical additives.

Since 1945, solvent extraction lube refining facilities have progressively replaced the more costly sulfuric acid treating processes. At present, 30 of the 52 U.S. lube oil refiners practice some kind of solvent extraction for lube base stock preparation. Total solvent extraction capacity is 257,000 barrels per day. The increasing use of solvent extraction techniques also has been helpful from the standpoint of air and water pollution control, because "sludge" from acid treating poses a disposal problem. Chemical solvents, such as methylethyl ketone, rather than propane have captured most of the growth in lube oil dewaxing because of superior yields, and, similarly, solvent deoiling of waxes has replaced the old sweating processes in all but a few U. S. plants.

Hydrogen processing for lubes was demonstrated experimentally as early as 1928. However, only as low-cost hydrogen became available in our refineries —as a by-product from catalytic reforming—have such operations become economical. Since 1954, when the first commercial hydrofinishing plant was put into operation, hydrogen-treating capacity has grown rapidly, and today the total capacity of U.S. hydrotreating facilities exceeds 96,000 barrels per day, corresponding to approximately 50 percent of total finished lube oil capacity. Hydrogen treating has given the lube oil refiner increased flexibility because it can be used to replace either clay or acid treating, depending upon severity of operation. The advantages of hydrogen treating is that an improved lube oil can be manufactured at less cost and with better yields than can be done with clay contacting or acid treating.

Although solvent extraction and hydrogen treating have improved the quality of finished lubes, most of the improvement in recent years has resulted from better chemical additives. Additives not only are used to supplement or reinforce well-refined lube base stocks, but also they make it possible to extend the range of crudes acceptable for lube base stocks. Because research has led to a better understanding of how chemical additives function, the number of lube oil additives and additive combinations has increased greatly.

A significant engineering improvement in lube oil processing during the past 20 years has been replacement of packed-bed equipment with contacting tray towers or mechanical contactors (rotary disc or centrifugal contactors). Such contactors, while equal in operating efficiency and flexibility to packed beds, operate at lower cost and often permit a substantial saving in the plant inventory of expensive solvents. Significant increases in operating intervals between shutdowns of solvent units have resulted from better control of solvent oxidation and degradation. Although plant costs have been reduced somewhat by integrating various lube oil processes, thus reducing tankage requirements, capital costs per unit of capacity (constant dollar basis) in 1965 were about the same as in 1945.

In 1975, it is estimated that the total quantity of lubricating oils produced annually in the U. S. will have increased to about 70 million barrels representing about 1.7 percent of the total crude oil processed. During the next decade improved lube oil additives will be developed to satisfy the continuing demand for better quality products. Lube oil manufacturing plants will become larger, more highly automated, and more complex. Hydroprocessing of lube oil base stocks will become increasingly important, and new solvent refining techniques will be developed. However, little change is expected in capital costs of lube refining facilities.

CHAPTER ELEVEN—REFINERY EFFICIENCY

SECTION 1—Introduction

During the period 1946-1965, average refinery operating costs increased from 74.6 to 119.5 cents per barrel, but when corrected for inflation, overall operating costs have actually shown a reduction. The following table is a breakdown of these costs by major categories.

AVERAGE OPERATING COSTS OF U. S. REFINERIES [a]
Cents/Bbl.

	PURCHASED FUEL & POWER	TEL, CHEMICALS & SUPPLIES	MAINTENANCE MATERIALS	TOTAL LABOR	NON-[b] EFFICIENCY COSTS	TOTAL
1946	6.5	7.2	5.5	36.7	18.7	74.6
1950	7.1	12.1	5.7	41.0	24.1	90.0
1955	7.2	17.9	6.7	45.5	31.0	108.3
1960	9.8	22.9	6.0	50.3	38.1	127.1
1965	16.1	24.4	7.0	43.1	28.9	119.5
Adjusted 1965 for inflation [c]	8.9	13.4	3.9	23.8	15.9	65.9

a— API, *Petroleum Facts and Figures*, 1965, p. 106.
b— Nonefficiency costs include insurance, taxes, royalties, research, obsolescence and improvements, and interest on capitalization.
c— Bureau of Labor Statistics, wholesale prices for all commodities.

These data show very clearly the effect that major efficiency improvements in the refineries have had in maintaining the cost of manufacturing petroleum products below the postwar inflationary increase. Efficiency improvements for the most part are reflected in lower labor costs and labor costs have been held at about the same absolute level since 1950 even though wages have increased nearly 80 percent (Chapter XII, Personnel). Adjusting for inflation, the 1965 labor costs are 35 percent below those experienced immediately following World War II. This, plus small reductions in maintenance materials and nonefficiency items, offset a fairly large increase in fuel, TEL, chemicals and supplies to give a net decrease in the total operating costs after adjusting for inflation of nearly 12 percent. Efficiencies were also made in the consumption of fuel and chemicals but these costs were markedly increased as a result of more intensive processing, extensive use of additives, greater utilization of catalytic processes and additional treating to provide the major improvement realized in the quality of refined products. This improvement was discussed in Chapter IX, Product Quality Improvement.

Product quality, although a significant improvement, is not the only major change in refinery products during the postwar period. Equally demanding on refinery technology was the major shift in product yield pattern necessary to meet the change in demand of major refinery products. The shift in yields is illustrated in the tabulation below.

PERCENT YIELD ON CRUDE [a]

	1945	1950	1955	1960	1965
Gasoline	40.5	43.0	44.0	45.2	44.9
Distillate Fuels	19.1	24.6	26.3	27.0	29.0
Lubes and Other	13.1	12.1	14.4	16.7	18.0
Residual Fuel Oil	27.2	20.2	15.3	11.2	8.1

a-*Annual Statistical Review, 1940-1966,* API, p. 18.

A sharp reduction has been made in the output of residual fuel oil with a corresponding increase in distillates and gasoline. Most of the increase in distillate demand was to satisfy jet fuel requirements, an entirely new product for the refineries. The lower yields of residual fuel were made possible primarily by upgrading heavy gas oils into suitable cat cracking feedstocks. This was accomplished by several processes as described in Chapter X, Refining Techniques.

The change in yield pattern together with the higher quality products, especially motor gasoline, had a major impact on refinery processing. The older thermal processes could no longer handle the new requirements and a major refinery technology change came into being with development of catalytic processes to shift the yield pattern as well as increase quality. Catalytic reforming, alkylation, coking, lately hydrocracking, more extensive use of catalytic cracking, and hydrogen treating were added to the refinery processing sequence to meet the demand. This substantially increased the complexity of the refineries which made the improvements realized in efficiency even more difficult to achieve.

There were many areas in which improvements were gained but developments in manpower efficiency, operations control, maintenance and construction, and size of facilities, are thought to be most important.

Continued progress in refinery efficiency improvement is expected in the future. Most of the improvements are expected to be extensions of techniques already in use. Particularly significant further progress is expected in heat efficiency, computer control, and in closer integration of process units. A relatively new maintenance technique, onstream repair, is expected to find increasing use in the future and contribute to further efficiency gains.

SECTION 2—Manpower Efficiency

Manpower is a major item in refinery costs as shown in the total labor column of the table on page 295. Although wage increases have been about 50 percent above inflationary trends, total labor cost has increased only by about 20 percent since 1946, and has remained relatively constant for the past 15 years. This reflects a substantial improvement in manpower efficiency and has resulted in part from technology improvements in the last three areas listed above which will be described in later subsections. In addition to advances in refining technology, manpower efficiency was obtained also by improvements in the skill levels and utilization of individual workers. These include improvement of existing skills, retraining or the development of new skills, and more effective organization of work forces. This will be covered further in Chapter XII, Personnel.

SECTION 3—Operations Control

Another factor which has improved the overall efficiency of refineries is improved methods of monitoring and controlling refining operations. These methods include process control, computer control, and on-stream analysis. Subsequent paragraphs will describe each of these methods in more detail.

A. Process Control

Developments that have had an influence on refinery efficiency are methods of data presentation to the operators in control centers, advanced control, and turbine and positive displacement metering—especially in product blending applications.

The density of recorders and controllers on control panel boards has been increased from a 1946 figure of 1+ per linear foot of the large instruments used then, to 12 per foot of the miniature instruments on a control panel board in 1965. Two developments have made this possible. The more important of the two is the concept of shared recording, in which a recorder is no longer connected to just one measured variable, but can be plugged into any one of the variables in a "bank" of indicating controllers. With this concept, the number of recorders used is commonly 20-25 percent of the number of controllers. A second point is that the recorders and controllers were miniaturized without sacrifice of ruggedness and reliability. An example of such a design is shown in Figure 106.

The effect of all such data display developments had been to allow an operator to oversee an increasing number of measurements and loops, thus overseeing more and more process equipment. In addition, improved coordination between the operations of adjacent process units results in improved overall stability of operations.

In implementing automatic process control, the feedback control loop, consisting of a single measurement controlling a single valve, essentially covers what was done for many years. Along with the knowledge of process and control dynamics came an appreciation that incentives for better control existed. Using conventional analog-type computing and relaying equipment, extensions have been made into feedforward control. In feedforward control, the disturbance (for example a change in feed rate to a fractionator) is measured as it happens and another process variable adjusted (for example overhead product flow rate) based on a predetermined model of its performance so that the effect of the disturbance on important process variables is minimized (in the example, overhead purity). Other advanced controls include control of more than one loop simultaneously when interaction exists between the variables, sampled-data control and nonlinear control. The increasing availability of digital control computers has generated increasing use of advanced control.

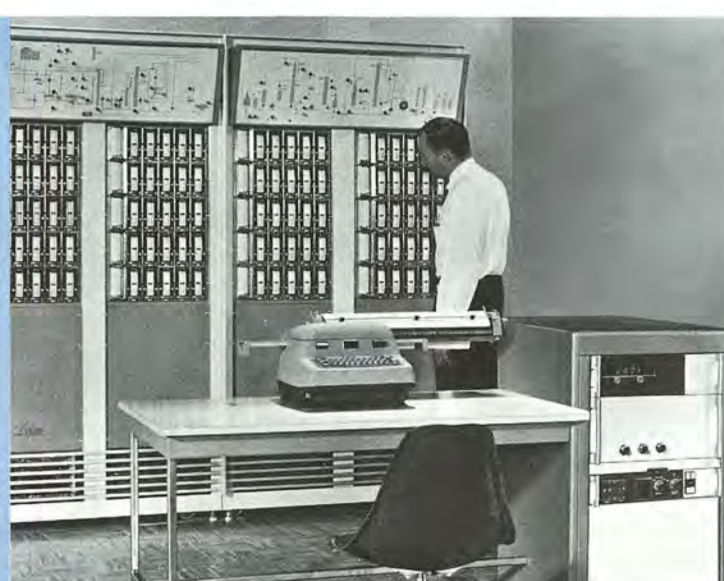
The trend toward increased integration between units in refinery design and operation increases the need for good control and for advanced control to maintain stability of operation of the integrated units. With heat integration, an upset or disturbance on one unit can be reflected and re-reflected rapidly to other units, thus demanding quick compensation by the control system.

Turbine and positive displacement meters have also benefited refinery efficiency. The accuracy and ability of such meters to operate over a wide flow range has led to their widespread use in gasoline and other product blending, thus adding impetus to the trend to blending automation and reduction of blend tankage requirements.

B. Computer Control

This Section covers only digital computers located in a process unit area, and in full-time use performing a control job for one or more process

FIGURE **106**
A 1965
High-Density
Control Board
Design



or offsite units. The small special-purpose computers built by adapting the hardware of conventional controller assemblies (analog computers) are excluded. Similarly, the large general-purpose data processing computer located in an office and not directly connected to equipment at a process unit is also excluded.

Within these limits, computer control includes three main types of application. In the most complex service (optimizing) the correlations between the important operating variables and economic criteria (the model) are programmed into the computer memory. When one of the "uncontrolled" variables changes, the computer calculates the values of the "controlled" variables needed to meet the economic optimum. The computer then calls for the new values of the variables, either by printed message to the operator (open loop) or by direct adjustment of the set points of the plant controllers (closed loop).

In the direct digital control (DDC) type of computer application, the functions of conventional controllers are also carried out by the digital computer.

The third type of computer control application, called supervisory, can cover a broad range of duties, between DDC on one end of the scale and optimization on the other end. A typical task would be keeping track of the integrated flow rates of the feed and products and printing out a daily material balance and yields.

A computer should be able to perform any one or all of the three types of applications—optimization, DDC, or supervisory. Installations now exist that combine optimization with DDC as well as DDC with supervisory.

Figure 107 shows the growth of computer control installations in refineries and petrochemical plants to over 100 in 1965. The absolute numbers may be somewhat approximate due to the difficulty of obtaining complete and accurate data from all sources. However, the shape of the curve is undoubtedly correct.

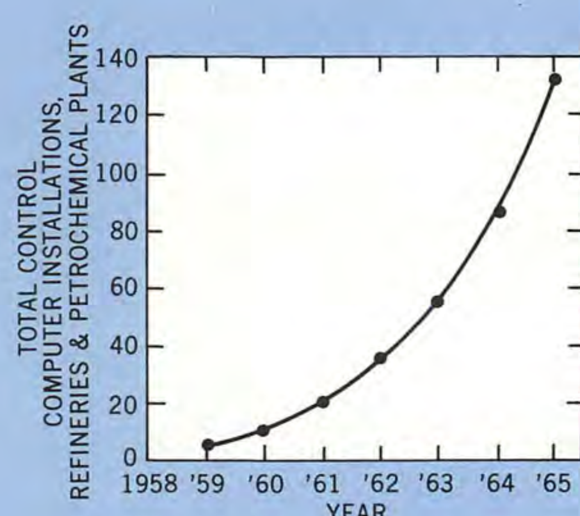
Prior to 1965, applications were of the optimizing and supervisory types, working on the process through set point adjustments of conventional refinery-type controllers or through printed instructions. Starting in 1965, DDC entered the picture. It came about as computer speed, flexibility and reliability all increased to a point where one rather small computer became capable of handling the work of 200+ conventional controllers.

Computer control contributes to refinery efficiency in several ways. In attractive optimization applications there are frequent changes to one or more uncontrolled variables—feed quality, for example. This requires complex calculations, based on the model, to find the new optimum values of the controlled variables—a task far beyond an operator's hand calculations. Thus, the computer allows rapid compensation for plant disturbances and upsets in a consistent manner. Without a computer a nonoptimum situation can prevail for long periods.

C. Onstream Analyzers

Onstream analyzers are instruments located at the process unit that continuously measure one or more components or properties of a refinery stream. About 1945, developments in physical methods of analysis for laboratory use, such as infrared and ultraviolet absorption, made their adaptation to onstream use look feasible. In addition, war-developed technology, including the mass spectrometer, became available. As a result, a steady parade of onstream analyzers

FIGURE **107**
Growth of
Control Computer
Installations



Source: *The Oil and Gas Journal*, Oct. 25, 1965 pg. 91 on.

was developed starting in the late 1940's and continuing today. In the early years, instruments for such measurements as viscosity, flash point and boiling points became available. The infrared and ultraviolet devices allowed some applications in which one component or a family of components were measured in a stream. In the late 1950's, rapid advances in chromatography which made possible the determination of one or more components by a single instrument, accelerated the development of other analyzers.

A significant point in onstream analyzers is that they are largely developed by petroleum and petrochemical processors, whereas conventional measuring and controlling instruments are largely the product of instrument manufacturers. The reasons for this are the small number of analyzers of any one type that the market will absorb, and the high cost of development which can exceed $250,000. This makes the gamble less attractive for an instrument company. The incentive for the processor is process operation improvement, which shows up as greater throughput, more product from a given feed, higher quality, or less cost. In all cases this reduces costs per unit of production. Usually, the analyzers are licensed to instrument companies in order to recoup some of the development costs.

The usefulness of onstream analyzers stems from the fact that the usual measurements of temperature, pressure, flow and level do not directly give the information an operator needs, such as a product quality. The analyzer makes as close a direct measurement of what the operator needs as is practicable with current technology.

Essentially all U.S. refineries use analyzers. The larger, more complex ones may have in the order of 200. At the present time, the installation rate of process analyzers exceeds over one thousand per year.[1] The total number of installations has more than doubled every five years since 1946.

SECTION 4—Maintenance and Construction

One of the large contributors to refinery cost is maintenance. There have been many improvements in maintenance practices, and this has contributed materially to refinery efficiency. In addition to improved personnel training, the principal improvements have centered on three technological areas:

Corrosion control.

Onstream equipment inspection.

Improved planning and critical path scheduling.

The first two improvements have permitted large increases in run lengths, and the third has reduced the downtime and cost of periodic plant overhauls.

1. Cropper, W V., "Effects of Process Monitors on Refinery Laboratory Operations." Presented at API Division of Refining Subcommittee on Quality Control, May 10, 1966.

Each of these improvements will be described in more detail in the following sections.

A. Corrosion Control

Control of corrosion has been one of the primary means of achieving long runs in many of the operating units of a refinery. This is probably best illustrated in crude still operations. In the late 1930's, as refiners began to process high-sulfur crudes containing high concentrations of salt, principally sodium, magnesium and calcium chloride, a typical crude still run was often less than 1,000 hours. Today, even though the crude quality is lower, a crude unit may run for one to two years between turnarounds.

Corrosion rates were first reduced by injection of caustic for neutralization of the acids present in overhead streams. Then ammonia supplanted caustic and came into widespread use in the 1940's, although caustic continued in use in the crude charge. The salt content of crudes continued to increase, from levels of 20-50 pounds per thousand barrels to levels of 75-125. Therefore, in the early 1950's, desalting of crude oils by electrostatic precipitation was adopted, which not only reduced the amount of corrosive acid formed, but also significantly reduced fouling in the crude preheat exchangers.

But it was not until the use of corrosion inhibitors in the mid-1950's that corrosion was brought under control. These organic amine chemicals, added in amounts as low as 2-3 ppm, were credited with an incremental 50-95 percent reduction in corrosion over results with ammonia and desalting alone.[2] By 1960, the industry was spending about $1.00 per thousand barrels of crude oil for inhibitors.[3]

Together with these measures, selective use of alloys has resulted in further improvement. Monel replaced steel in the upper trays, shell and overhead lines of the gasoline column. Cast iron run-down coolers which had been plagued with selective "graphitization" corrosion gave way to shell and tube condensers using admiralty brass or Monel tubes. Type 410 (12 percent chromium) stainless steel has virtually eliminated sulfur corrosion in the pumps, vessels and towers handling reduced crude in the 500-800°F temperature range. Type 316 stainless steel combats corrosion in this temperature range of naphthenic acids present in some crudes.

In the 1960's, further improvements in crude still efficiency have been made by such efforts as two-stage desalting and caustic additions to the desalted crude oil. Shorter turnarounds have been achieved by better maintenance planning and parallel heat exchange to permit onstream cleaning and maintenance.

In other units of a typical refinery, corrosion also

2. R. J. Hafsten, K. R. Walston, "Use of Neutralizers and Inhibitors to Combat Corrosion in Hydrocarbon Streams," *Procedures*, API, 1955, 35 III 80-91.
3. D. L. Burns, R. L. Hildebrand, Paul D. Thomas, "Corrosion Inhibitors in Refinery Process Streams," *Procedures*, API, 1960, 40 III, 155-62.

has created obstacles to long runs although to a lesser degree than in crude stills. In catalytic cracking equipment, alloys and wear resistant refractory materials are the principal tools to prevent equipment failure; however, corrosion inhibitors and water washing serve to prevent failures in the gas handling equipment.

Catalytic reformers which were built extensively in the 1950's were unexpectedly plagued with iron sulfide scale formation which caused plugging of the reactor beds. In the presence of high-temperature hydrogen at hydrogen sulfide levels hitherto considered low (under 0.5 percent), a voluminous flaky sulfide scale formed. Hydrodesulfurizers were built shortly thereafter to remove 95 percent of the sulfur from the reformer feed. The hydrogen sulfide problem was then shifted to the desulfurizer units where it was effectively combated by the use of stainless steels in the feed-hot effluent exchange, and corrosion inhibitors in the stripper overhead streams.

B. Onstream Equipment Inspection

Thorough inspection of equipment has been a major factor in achieving the high safety standard of refineries. Until the early 1950's, inspection of refinery equipment was done only when the unit was shut down. Then the inspector would determine equipment condition by visual examination wherever he could, calipering for wall thickness of piping and heater tubes where these were opened, and internal measuring of corrosion of vessel walls by reference to "bench mark" bars of stainless steel previously attached to the wall. Not only were these methods time consuming for the inspector, but many craftsmen would be involved in breaking connections, dropping valves, unplugging furnace tube headers, etc. As a result, turnarounds were long and frequent.

Today, nondestructive testing techniques enable the inspector to do much of his inspection while the units are onstream. This can then make longer runs possible by allowing operation to the safe limiting thickness. For example, the run length of one refiner's fluid catalytic cracking units has increased from an average of one year to present runs of over three years. Turnarounds are shortened also by making it possible to better plan the maintenance and inspection required during unit downtime.

Inspection of piping is the critical problem, not only because there are literally miles of it even on a single refinery unit, but also because the corrosion and wear rates are usually higher than in pressure vessels and heat exchangers. No element of piping, however small, can be ignored, since failures have occurred at orifice taps, flanges, threaded connections, nipples, and couplings. For measurement of onstream pipe thickness radioactive methods or ultrasonic testing are most frequently used. Other onstream inspection methods are electrical resistance probes to measure the corrosiveness of a stream, magnetic particle methods to inspect for cracks in welds, and temperature measurement of pipe and vessel walls using fusible crayons, or contact and radiation pyrometers.

Cobalt 60 and iridium 192 radioactive sources are commonly used for onstream inspection of piping and vessels. The radioactive source is exposed to one side of the pipe with film in lead casettes on the opposite side; thickness is estimated by film exposure. This latter method is useful in outlining worn areas in catalyst lines, or detecting areas of internal refractory failure. Radiography has also been used to reveal the cause of equipment malfunctioning such as ice formation, valve gate jamming, tray upsets, etc.

Hand-held direct-reading radioactive instruments for measuring pipe wall thickness have been available since the early 1950's in which the gamma ray source is on one side of the pipe and the detector on the other. These must be calibrated to allow for the type of metal, corrosion products, and density of fluids in the pipe. This instrument has been gradually replaced by the newer ultrasonic testers.

The Atomic Energy Commission controls and licenses the use of these radioactive sources and operators must take certain precautions to safeguard those in the area from the radiation hazard. These requirements have led most refiners to rely on specialist contractors for this work.

Ultrasonic instruments determine pipe wall thickness by the principle of introducing high-frequency sound waves into the metal and measuring either the mechanical resonant frequency which varies with the thickness (resonance principle), or the pulse-echo technique which measures the time for return of a pulsed signal from the opposite wall (reflection principle). Current instruments display the thickness values on an oscilloscope or direct-reading dial which makes them quick and easy to use.

Thickness measurement with ultrasonic instruments can be very rapid. Readings are not affected by internal fluids and deposits and there is no radiation hazard. Measurements have been made on hot pipes up to 1,150°F using water-cooled transducers. However, cold pipes present a problem in that frost or ice interferes with good contact.

Ultrasonic instruments can also be used for crack and flaw detection in welds, shafts and plates. Because of the attenuating effect that subsurface discontinuities have on the back reflection of sound waves, some refiners have used ultrasonics to determine hydrogen fissuring of steel, grain boundary melting in aluminum and abnormal grain size in furnace headers. This usage requires suitable flaw standards and usually involves more training in the use of the instrument.

The inspector can determine the corrosion rate on the pipe or vessel indirectly, through the use of inverted probes which change in electrical resistance with corrosion. These are monitored on an intermittent basis and are used extensively to gauge the effect of neutralization and inhibitors in corrosion control.

Cracks in magnetic steels can be revealed by magnetizing the material, which causes an iron powder to preferentially adhere to the crack. Use of this nondestructive technique is widespread during turnarounds, but is occasionally used during a run, for example, to inspect for fatigue cracks in reciprocating compressor discharge piping while onstream.

The ideal inspection instrument would combine the see-through ability of the radiation methods with the direct-reading features of the ultrasonic instruments, ideally reading out on a TV screen the radiographic image of the part, together with numerical thickness measurement, without the necessity for time-consuming film exposure and development. Elements of these techniques are already in limited use by industry, such as TV imaging of ultrasonic test signals, and pulsed X-ray motion pictures. Combining these developments into a practical tool would be a boon to the refinery inspector.

C. Critical Path Scheduling

Increasing use now is being made of relatively new critical path scheduling approaches in refinery maintenance and construction planning. The two basic versions of these techniques are PERT (Program Evaluation and Review Technique) and CPM (Critical Path Method). PERT was developed some ten years ago to improve planning, scheduling and control of complex military projects and CPM was independently developed at about the same time for major civilian construction activities. Several variations have evolved from CPM and PERT. Some of these are specifically tailored to the problems of refinery construction and turnaround, and incorporate added features such as computer scheduling of manpower to reduce peak requirements. Properly selected and applied, these newer methods serve to enforce a systematic, logical and disciplined approach to planning and carrying out major projects. In refinery operations these can lead to reduced elapsed time and more efficient use of manpower and materials. In consequence, they can help to cut the cost for building a refinery or major addition, or accomplishing a refinery turnaround, and can lead to improved refinery returns by getting the facility onstream faster.

Quantifying the cost reductions over conventional methods is not easy, because of the many factors that influence any one specific turnaround. Figures of 20 to 25 percent time and cost reduction for a turnaround have been reported. Such figures do not include the value of the added productive capacity that results from the added onstream time.

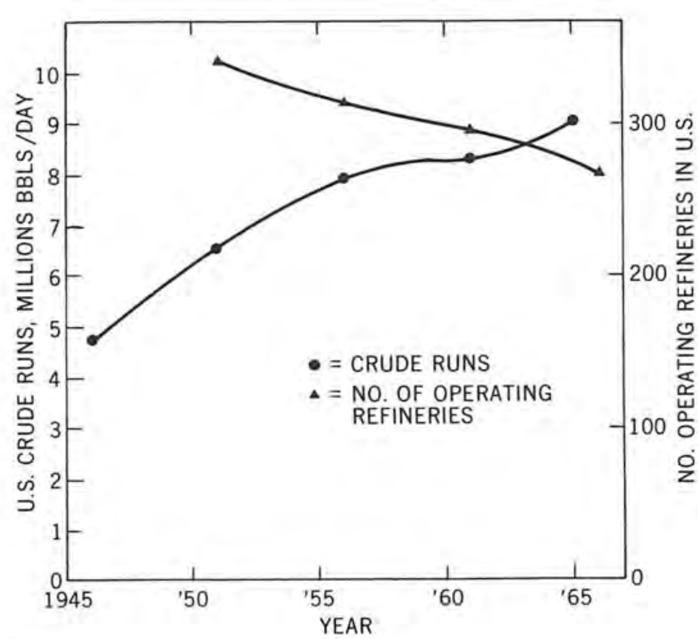
A good start has been made in the use of these tools in turnaround and in construction planning and scheduling. Present trends indicate that their use will be extended in these fields. The use of CPM for other tasks, such as product planning, is also advocated and will undoubtedly receive attention.

SECTION 5—Size of Facilities

It is a well-established principle that within limits of practicability it costs less to build and to operate a single unit of double size than two units of single size. The refining industry has been intensively using this principle—in entire refineries, in individual process units and in individual items of equipment.

The increase in U.S. crude throughput, shown in Figure 108, is one factor that has contributed to the increase in the size of refineries. In addition, the number of operating refineries has decreased with time, thus accentuating the increase in average refinery size. This decrease in the number of operating refineries is also shown in Figure 108. These

FIGURE **108**
Crude Runs and Operating Refineries in U. S.



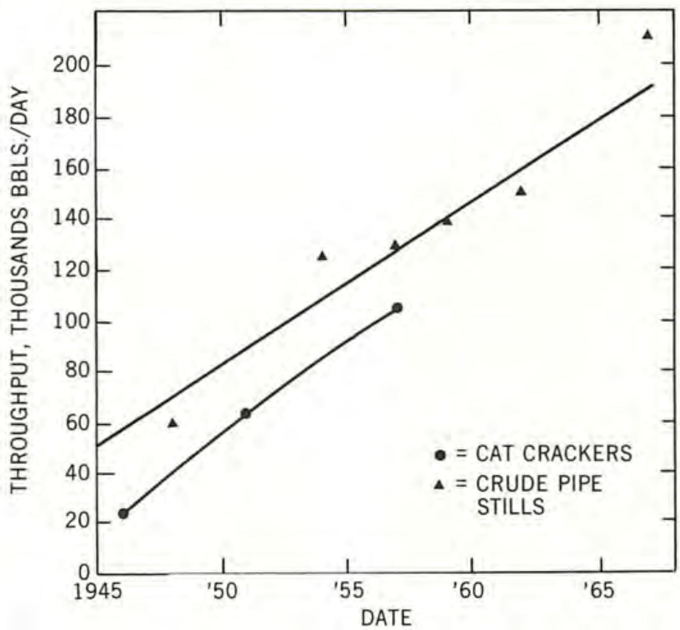
Sources: Operating Refineries; *Oil & Gas Journal* Survey Articles, 3/29/51, 3/19/56, 4/3/61, 3/28/66, Crude Runs; *Oil & Gas Journal*, 7/18/66, Pg. 95.

data show that the average size of refineries has about doubled during the past 20 years.

Developments in heat transfer, fractionation, pumps and compressors, fabrication and metallurgy all contributed to the ability to build individual process units larger. This trend is illustrated in Figure 109 showing for various years the maximum announced sizes of crude pipe stills and catalytic cracking units. It is quite possible that units exist above the lines of Figure 109 due to some large units being unannounced and due to some confusion over throughput figures, especially for cat crackers. However, the shape of the curves rather than the absolute numbers is the primary point being illustrated; thus, some change in the absolute numbers would not be too significant.

The trend to larger process units was accompanied by a change in philosophy on equipment design. The smaller units of the early part of the period commonly utilized, as an example, two half-sized air blowers for the regeneration air supply to the catalytic crackers. In part, this was based on the thought that failure of one blower would not cause the unit to shut down completely. In contrast, it is common practice today to use one blower for such a service. Such changes, which cut capital and operating costs, resulted from experience and attention to those factors important to reliability.

FIGURE **109.** Maximum Announced Size of Unit, U. S.



Data References—Pipestills:	
1945, Humble, Baton Rouge.	*Petroleum Refiner* 12/45, Vol. 24, Pg. 117.
1948, Humble, Baton Rouge.	*World Petroleum* 7/48, Vol. 19, #8, Pg. 100.
1954, Gulf, Philadelphia.	*Oil & Gas Journal* 6/7/54, Pg. 59.
1957, Tidewater, Delaware City.	*Petroleum Refiner* 6/57, Vol. 36, Pgs. 148-9.
1959, American, Whiting.	*World Petroleum* 7/59, Vol. 30, Pg. 122.
1962, American, Texas City.	*Oil & Gas Journal* 5/28/62, Pgs. 133-5.
1967, Humble, Baytown.	*Oil & Gas Journal* 10/18/56, Pg. 58.
Data References—Cat Crackers:	
1946, American, Whiting.	*World Petroleum* 7/46, Vol. 17, #8, Pgs. 82-3.
1951, Gulf, Port Arthur.	*Journal of Commerce* 10/23/51, Pg. 13.
1957, Tidewater, Delaware City.	*Petroleum Refiner* 6/57, Pgs. 148-9.

Whether total or fresh fed not always clear.

CHAPTER TWELVE—REFINERY PERSONNEL

Nowhere have the effects of changing technology in the refining industry been more impressive than in the area of personnel. The dramatic advances in equipment, instrumentation, and materials together with the steadily increasing pace of technological and process development have resulted in a new generation of major changes in the refining industry.

SECTION 1—Personnel Skills Required

In the succeeding sections, the question of how advancing technology affects the numbers of refinery personnel will be examined. The first consideration is how these personnel may be expected to change by occupational groups and by required skill and educational background.

The 1962 NPC study, *"Petroleum and Gas Industries Manpower Requirements,"* gave comprehensive breakdowns of major work categories for the petroleum industry, including petroleum refining.

Grouping the eleven skill divisions reported at that time gives the following picture of the industry:

Major Skills	1962 Percent
Management, Engineering and Professional	21
Operators and First-Line Supervisors	22
Maintenance Workers	36
Office Workers	21
Total	100

It appears reasonable in the years ahead to forecast continuing changes in the direction of increasing percentages of business-oriented, technically trained personnel in the operations support area. The job of providing information to refinery managements on such key decisions as what crudes to run, what changes in unit operating variables to make, what products to produce and where to best invest new capital has become steadily more important and more complex. Professionals are increasingly required in these areas.

Operators themselves will be better trained and have a better basic understanding of the processes they are controlling. To solve these problems, today's refineries have raised their hiring standards and developed extensive training programs designed to equip the operator with skills he must have. However, the percentage of these operators will surely continue to decrease.

It would not be at all surprising to find that the 1962 skill pattern had changed by 1976 to something approaching the following:

Major Skills	1962 Percent	1976 Percent
Management, Engineering, and Professional	21	40
Operators and First-Line Supervisors	22	15
Maintenance Workers	36	25
Office Workers	21	20
Total	100	100

An example of the changing requirements for today's highly automated refining units can be seen from the staffing of a large "grass roots" refinery in 1956. All employees hired were at least high school graduates. About 90 of the 550 total hold college degrees.

New instrumentation has also been reflected in refinery personnel changes. While much has been written on refinery automation and its effect on manpower requirements, it has also brought about the need for highly skilled technicians. Computers require programmers, key punch operators, and specially qualified maintenance personnel. Chromatographs, infrared analyzers, end point analyzers, vapor pressure analyzers, octane comparators, and other types of onstream analytical equipment have been responsible for a new breed of instrument men with a sound knowledge of electronics.

The trend in refineries to larger units with fewer people has required that the operators themselves be better trained and have a better basic understanding of the processes which they are controlling. Delay or uncertainty in solving complex problems can mean costly rerunning or even expensive shutdowns and repairs. To combat this, today's refineries have raised their hiring standards and developed training programs designed to equip the operator with skills he needs.

No longer are refinery equipment inspectors "hammer and tong" men. On-the-line inspection techniques include everything from X-ray equipment to ultrasonic leak detectors.

Refinery maintenance and maintenance planning groups are likewise becoming more skilled. By the use of better planning and such aids as critical path scheduling techniques, their efforts are being more efficiently utilized than ever. Major unit turnarounds have been shortened and manpower requirements lessened. Even craft groups have begun to be trained and used in skills that frequently cross traditional craft lines. They are becoming more flexible in handling groups of related assignments, instead of a narrow field of craft specialization.

Typical of these skill-related craft groups could be the following:

Metal Workers	Machinery
Boilermakers	Machinists
Ironworkers	Millwrights
Pipe Fitters	Tool Rooms

Electrical & Instrument	General Services
Electricians	Operating Engineers
Instrument Men	Insulators
	Painters
	Carpenters
	Laborers

SECTION 2—Employment Trends

The constant drive for larger more economic units in recent years has had a major impact on both the number of personnel required per barrel of refining capacity and on the qualifications and duties of these employees. As modern units have replaced old, smaller units, a strong trend toward reducing the total number of refinery employees required has been observed. The installation of these new units specifically designed to make use of the latest advances in equipment and control techniques has obviously been a major factor in significantly reducing labor requirements per barrel of capacity.

An informal survey of a typical group of 10 major refineries reveals an interesting pattern of reductions in the number of employees in the 10 years between 1956 and 1966. Where these refineries had 22,855 employees in 1956, by 1966 this had been reduced to 12,309 or a reduction of 46 percent of the level existing 10 years before. Information on these refineries is outlined below.

REFINERY	1956-1966 PERCENT REDUCTION
A	26
B	48
C	46
D	32
E	67
F	70
G	41
H	42
I	30
J	20
Total	46

During this same period, the rated capacity of these refineries had increased from 1.02 to 1.08 million barrels per day. Thus, rated capacity per employee for this refinery group had increased from 45 to 87 barrels per day for a 92 percent gain in overall productivity.

Bureau of Labor Statistics figures recently published covering the entire country also confirm this trend. As of 1965 total salaried and hourly employment for all manufacturing had dropped by 13 percent in the preceding eight years, while total employment in petroleum refining had dropped 25 percent in the same period.

However, helpful as they may be, these studies do not reveal the whole story. There are several major counterbalancing factors which are tending to bring total refining related employment into closer balance with earlier figures.

First has been the major growth in the use of outside special services. Many refineries now make extensive use of such outside services to provide assistance in areas in which they previously considered it necessary to maintain their own competence. The long-range result of these moves has been to level out individual company employment by reducing major peaks and valleys. This has also significantly reduced costs by eliminating the burden of maintaining full peak manpower to handle all problems, and in some cases has improved performance by making specialists available to handle certain types of nonrepetitive jobs. Examples include the following:

(1) Analytical Laboratories
(2) Computer Programming Groups
(3) Computer Service Bureaus
(4) Contract Engineering and Construction Firms
(5) Contract Maintenance Firms
(6) Leased Equipment Maintenance Firms
(7) Metallurgy Consultants
(8) Pollution Control Consultants

The second factor has been the major increase in petrochemical manufacturing units. Much of the disappearance in refinery employment has been picked up by staffing requirements for new units in petrochemical areas including plastics, synthetic fibers, detergents, and the vast field of organic chemical raw materials and intermediates.

In the twenty-year postwar period, the industry accomplished a major decrease in personnel by absorbing losses from deaths, retirements and resignations without bringing in any significant number of new employees. As a consequence, the average refinery worker age has climbed steadily until today in the older refineries the average age is from 45 to 50 years. This means that over the next 10-15 years there will be a major replacement of the refinery work force which will provide the industry with an opportunity to introduce new training methods and new work practices to reach a new high in development of the skill and flexibility of the refinery worker.

In the future we can expect a continuation of this same trend of increased barrels of capacity per employee and less total employees. As old units use up their economic lives, they will be replaced by new units of larger capacity, designed to make full use of all the latest advances technology can offer. These units will be operated by certainly no more operators than were comparable smaller units, and in most cases by less.

SECTION 3—Average Hourly Rates

The average hourly earnings of production workers in petroleum refineries are higher than those in all other manufacturing industries. Not only hourly earnings, but also payment for fringe benefits in the petroleum industry exceeds the average of all manufacturing industries. The following table shows a comparison of the average hourly earnings and fringe benefit payments of production workers in the U. S. refining industry compared with the average earnings of all manufacturing workers during the 20-year period 1946 through 1965. In this table, fringe benefits include vacations, holidays, pension, life insurance, hospitalization insurance, rest periods, social security, etc.

AVERAGE HOURLY EARNINGS OF PRODUCTION WORKERS
1946 - 1965

	PETROLEUM INDUSTRY			ALL MANUFACTURING INDUSTRIES		
	HOURLY EARNINGS	FRINGE BENEFITS	TOTAL	HOURLY EARNINGS	FRINGE BENEFITS	TOTAL
1946	$1.43	$ .36	$1.79	$1.08	$ .20	$1.28
1950	1.94	.54	2.48	1.44	.26	1.70
1955	2.47	.68	3.15	1.86	.47	2.33
1960	3.02	.95	3.97	2.26	.63	2.89
1965	3.47	1.16	4.63	2.61	.88	3.49

Source: Bureau of Labor Statistics, "Employment and Earnings Statistics for the United States 1909-1965," pp. 41, 547. U. S. Chamber of Commerce, "Fringe Benefits," 1965.

Thus, total average earnings in the petroleum industry have remained about one- third more than the average of all manufacturing industries since World War II.

The following table indicates the labor costs as a percent of the total operating costs of U. S. refineries for the period 1946 through 1965.

LABOR COSTS AS A PERCENT OF TOTAL OPERATING COSTS OF U. S. REFINERIES
1946-1965

1946	49.2%
1950	45.6%
1955	42.0%
1960	39.6%
1965	36.1%

Source: API, *Petroleum Facts and Figures*, 1965, p. 82.

Even with the highest average hourly earnings for production workers, the petroleum refining industry has been able, through advancements in technology, to reduce the percentage of labor costs to the low of 36.1 percent in 1965.

SECTION 4—Productivity

During the 20-year period 1946 through 1965 the productivity in the U. S. petroleum refining industry expressed as the number of barrels of refinery output per production worker manhour has increased substantially. Advancements in technology which enabled construction of units having high throughputs, long run-lengths, and making extensive use of automatic control instruments have made this possible. These larger, more complex plants have also substantially increased the capital investment per worker necessary to construct modern refining facilities. The improvement realized in productivity through these investments from 1947 through 1965 is shown in the table below. Data prior to 1947 are not available.

PRODUCTIVITY AND INVESTMENT IN THE U. S. PETROLEUM INDUSTRY

	TOTAL REFINERY OUTPUT, MILLION BARRELS	TOTAL REFINERY INVESTMENT $, MILLIONS	INVESTMENT WHEN ADJUSTED TO 1965 DOLLARS $, MILLIONS	TOTAL REFINERY PRODUCTION WORKERS, THOUSANDS	REFINERY OUTPUT PER WORKER, BBL./YR.	INVESTMENT PER PRODUCTION WORKER, 1965 $
1947	1,923	3,600[pc]	6,100[pc]	145	13,300	42,000
1950	2,190	4,600[pc]	6,780[pc]	140	15,600	48,000
1955	2,857	6,000	7,500	138	20,800	54,000
1960	3,119	8,400	9,350	114	27,400	83,000
1965	3,639	9,450	9,450	90	40,300	104,000

(pc) Includes some investment in petrochemicals. Separate investment data for refineries ex petrochemicals not available prior to 1955.

Sources: API, *Petroleum Facts and Figures,* 1959 Centennial Edition, pp. 110, 111.
API, *Petroleum Facts and Figures,* 1965 Edition, p. 82.
Bureau of Labor Statistics, "Employment and Earnings Statistics for the U. S. 1909-1965," pp. 546, 548.
Frederick G. Coqueron, Petroleum Analyst, Chase Manhattan Bank. "Annual Financial Analysis of the Petroleum Industry for 1955, 1965,"

These data show that both output per worker and investment have about tripled since 1947. Total industry investment is now over $100,000 per worker, or about $700 per daily barrel of throughput.

SECTION 5—Safety

The petroleum refining industry has long concentrated on safety programs. The frequency rate in 1965 of disabling work injuries per one million employee hours worked in refineries was 5.58, or less than half the average of 12.9 attained by all manufacturing industries.

CHAPTER THIRTEEN—STORAGE AND TRANSPORTATION

Petroleum gains much of its value to society by being the most portable form of stored energy. For full utilization by the public of this portability, it is essential that petroleum products be widely available at low cost. An efficient, broadly based and extensive distribution system is the key to supplying adequate amounts of gasoline and oil throughout the nation at minimum expense. Most technological advances in petroleum storage and transportation have been to improve efficiency, safety and convenience of the distribution system.

Storage and distribution systems and three specific means of transportation—tank trucks, barges, and tank cars—are discussed in this Chapter. Pipelines and tankers, which are most important means of transportation, are taken up in Chapter Six of Part I.

SECTION 1—Storage

About one month's supply of crude oil and petroleum products is normally maintained in storage by the industry to provide the working stocks to operate an efficient distribution system. It is customary to accumulate stocks ahead of peak demand periods, e.g., fuel oil is stored in late summer and fall to supply high demands in the winter, and gasoline is accumulated in late winter and spring to supply summer requirements. Storage is also provided to counteract the weather's interference with supply, e.g., extra storage for winter is installed in northern Great Lakes terminals that may be closed to tanker deliveries by ice.

While various forms of storage such as wooden tanks and earthen pits were once common, steel tanks have long been the main form of petroleum storage. However, changes in storage technology have been taking place as the industry searches for cheaper, safer, cleaner ways to store the necessary inventory of crude and products. Not only have new forms such as underground caverns and refrigerated storage appeared since 1945, continued improvements in design and construction of steel tanks have taken place.

A. Steel Tanks

While welded tanks had become the standard by the end of World War II, improvements in materials, design and construction techniques have helped to keep the cost of storage down while improving its quality. Higher strength steels have made possible larger tanks; the largest now constructed has more than 600,000 barrels capacity. Development of field X-ray techniques, which made high-quality field weld inspection possible, has led to use of high-joint efficiency in design and hence to savings in metal required for a given tank. Improvements in the design of floating roof tanks and in particular the development of internal floating roofs for cone-roof tanks have enhanced the ability of steel storage to conserve the value of products stored. Highly superior exterior and interior protective coatings have appeared since the war. The coatings not only reduce the cost of corrosion, but also assist in the protection of quality of sensitive products such as aviation turbine fuel.

B. Underground Storage

Volatile products such as propane and butane have come into widespread use for heat and petrochemical feedstocks since 1945. As a result, the industry has had to develop economic means of storing these products. Since propane and butane have high vapor pressures at atmospheric temperatures, high-pressure storage vessels are required. Large steel tanks for these pressures (up to about 250 psig) are expensive, and it became clear early that new storage technology would be required. The first method developed was to store these materials as liquids under pressure in caverns in the earth's crust, i.e., in a situation not wholly unlike that in which nature had produced them. Large caverns, up to 800,000 barrels, have been produced. Most of these have been formed by leaching of salt beds or domes. In areas where suitable salt layers are not available, caverns have been mined in limestone, shale, and granite. In addition, some naturally porous media such as depleted oil and gas sands or water sands are being used.

C. Refrigerated Storage

A second method of storing the highly volatile products such as propane and butane and even liquefied natural gas is to cool them sufficiently so that they are liquid at atmospheric pressure; low-pressure vessels of appropriate design will then be adequate. Two basic types of vessel for this purpose have been designed: insulated double-walled aboveground steel vessels up to 250,000 barrels capacity and frozen earth pits up to 500,000 barrels capacity. For the aboveground case, appropriate steels and superinsulations are used to construct storage tanks in which the evaporation losses are acceptably low. In the frozen pits, a refrigeration system is used to freeze the soil surrounding the pit into an impermeable layer. The cold liquid then maintains the soil frozen. In both types of storage, the evaporation of a portion of the liquefied gas serves to chill the remainder of the liquid. Sometimes refrigeration plants are provided to recondense the evaporating vapors; in other cases, the vapors are fed directly into a gas transmission system.

The advantages of these new types of storage are illustrated by the table below.

PROPANE—BUTANE STORAGE

TYPE OF STORAGE	INITIAL COST RANGE $/BBL.
Leached salt	1-2
Mined caverns	4-8
Frozen earth pits	6-11
High-pressure steel tanks	16-25

Source: Bizal, R. B., *Oil and Gas Journal*, October 29, 1962, p. 130.

D. Automation

Major savings in the operation of tank farms in refineries and terminals have come about through application of automatic and remote supervisory control systems. By their very nature, large storage facilities are spread over large areas with individual units widely spaced. Many men are required to gauge tanks and to operate valves and pumps because of the dispersion of the equipment. Such installations lend themselves to large savings by installation of remote reading gauges and remote controls for operating valves and pumps. The industry has been eager to garner these savings and consequently automation has been and is being widely applied to tank farm operation.

E. Conservation

For some years prior to World War II, the industry had realized that important product values could be lost through evaporation while crude or products were in storage. The value of reflective paint in reducing tank temperatures had been recognized, but not widely adopted since adequate paints were not available. Floating roof tanks, in their more primitive forms, had been introduced. Open storage was already disappearing.

After the war, the trend toward product conservation was greatly accelerated. Tank designs were improved and adequate paints developed. New vapor conservation systems were introduced and in some cases compressors were installed to recover quantitatively all vapors from the storage tanks. While the floating roof tank had already been introduced for storage of volatile crudes and products, it was at war's end not nearly so highly developed as it is today. Better flotation systems, drains, and edge seals have been introduced in the last twenty years. Some of these, such as better edge seals, have depended on the postwar development of new materials of superior quality. Internal floating roofs of plastic or aluminum are now in use in cone-roof tanks. These designs bring the advantages of the floating roof to the many cone-roof tanks already in existence. Furthermore, they allow the combination of the conservation characteristics of the floating roof with the quality preservation characteristics of a fixed roof.

Vapor conservation systems have been developed since the war. These are of two general types: the gasholder and the compressor systems. In the gasholder types, a variable volume vapor space is provided so that vapors from one or more tanks may be displaced into and out of this space as the tanks are filled or emptied or change temperatures. Both rigid gasholders similar to those used in the gas industry and flexible membranes in hemispherical domes on the tank roof are used. In other cases the vapors are removed to a compressor which reliquefies them and injects them into a suitable reservoir or stream. In most cases, the added cost of the compressor system is borne as an antipollution cost rather than being justified by the value of the additional product recovered.

F. Product Quality Preservation

The rise in the use of aviation fuels following the war imposed new demands on storage facilities. Aviation turbine fuel must be delivered in much cleaner form than was allowable for prewar aviation products. New storage technology had to be developed to protect the product quality. Fully covered internal floating roof tanks are used for this service. Internal tank coatings have been developed to limit the pickup of rust particles by the stored product. Other measures to protect product quality will be discussed in the next section.

SECTION 2—Distribution Systems

This Section includes developments in all parts of the product supply system from refinery storage tank to the customer, with the exception of specific means of transport which are discussed in subsequent sections, or in the case of pipelines and tankers are treated in Chapter Six of Part I.

A. Product Blending

Automatically controlled in-line blending of refinery components to produce specification products was introduced about 1950. Modern control technology and recent advances in instrumentation are causing a new revolution in blending practice. Blenders are now being used both for blending within refineries and for direct blending into pipelines. Another use of the same technology is to blend special products such as solvents directly into the delivery truck.

B. Aircraft Fueling Systems

The development and installation of modern fuel supply systems for the nation's aviation industry has been essential to the growth of that industry. At the end of World War II, practically all aviation fuel was delivered both to airports and to airplanes by truck. The largest aircraft then in commercial service, the DC-4, required only 1,500 gallons per fueling; airport fuelers had capacities of about 2,500 gallons. Today, jet aircraft such as the Boeing 707 require in excess of 20,000 gallons; the fuelers have grown to 10,000 gallons. Future aircraft such as the Boeing 747 and the SST will require 40-50,000 gallons. Not only have the quantities per airplane fueling gone up radically, the number of flights has also vastly increased. An enormous fleet of trucks would have been required, both on the road for transport to the airports and at the airports for fueling, if new technology had not been developed. The cost of aviation fuel (which is approaching half the direct operating cost of a transport aircraft) would be much higher and the growth of the aviation industry would have been retarded.

The large volume supply problem has been solved by adaptation of pipeline technology. Most major airports are, or are being, connected directly to one or more refineries or major ocean terminals by pipeline. The Air Force, which has 57 bases supplied by pipeline, has said that the use of pipelines has reduced cost of fuel delivery by 14 percent during the past 12 years even though the volume has increased by 44 percent.[1] Not only are pipelines more economical, their use removes large numbers of trucks from already crowded highways. At the airports, hydrant fueling systems, much like a fire main system, have been buried beneath the aircraft loading and service areas. Instead of the conventional fueler truck, only a small hose and filter cart is required at each wing of the aircraft. The hydrant mains are fed by large

1. "Air Force Saves Millions by Use of Product Pipe Lines," *Pipe Line News*, Nov. 1966, p. 17.

and efficient pumps located in the storage area. Thus unlimited supplies of fuel can be delivered at high rates to the aircraft with a minimum of equipment at the plane and a minimum of traffic in the vicinity of the plane. Some hydrant systems were built for piston-engine aircraft in the early 1950's, but the method was not widely adopted until the advent of the jet transport.

In addition to the problems created by the large volumes of fuel handled, jet engines are more sensitive to fuel cleanliness than their predecessors, the gasoline engines. Dirt and water (which may form ice crystals) will clog or erode the fuel nozzles in the jet engine. These effects are multiplied by the large quantities of fuel consumed in short time periods. To solve the cleanliness problem many steps have been taken. One, the internal coating of tanks, has already been mentioned. Another is the internal coating of pipelines supplying some of the airports. Internally coated pipes have also been employed in hydrant systems. Efficient separating and filtering equipment has been developed to remove both water and solid matter. It is customary to filter into and out of the airport storage and again at the hydrant cart as the fuel is loaded aboard the aircraft. Effective field test methods have been developed so that positive assurance of fuel cleanliness at the final loading can be rapidly obtained.

C. Bulk Terminal Operations

Automation is also coming to the truck loading rack. Several systems are now in use which permit the truck driver to perform all the necessary functions at the rack. He will identify himself by inserting a punched card into a reader, or a key into a lock. The automatic controls will record his presence and respond to his request for product by opening the proper valves and starting the proper pumps after first checking to see if his load is authorized and if he has grounded his truck. The system will record the quantities issued to the driver and in some cases provide the invoice or bill of lading which accompanies the delivery. The advent of modern solid state electronics has greatly stimulated this development. It is safe to predict that much more work along these lines will be carried out in the near future. Ultimately such systems will be tied into corporate data processing and information systems, so that much of the repetitive handling of figures and paper associated with terminal transactions can be eliminated.

D. Package Goods Handling

Though sometimes obscured by the great technological efforts expended on the manufacture and supply of the large-volume bulk products, many improvements in the methods of transport and supply of packaged petroleum products such as oils, greases, etc., have been made in recent years.

As roads, trucks, and communications have improved, it has been possible to use larger central warehouses which yield the economies attendant to smaller total inventory and better stock control. Frequently, it is possible to locate the central warehouse adjacent to the packaging plant and further economics can be achieved by integrating the operation of the warehouse with the packaging plant.

A technical innovation of recent years which has had an impact in this area is the development of containerization. In a form employed by several companies, the containers are the two halves of a large semitrailer van. The two halves are separately loaded, then locked together to form a single semitrailer. A large tractor unit then delivers the unit to one or two bulk depots which have no local stocks of packaged goods. This long haul is usually made at night when the highways are less congested. At the local depot, the large van is broken into its two halves each of which becomes a semitrailer van which a smaller tractor unit can handle. Deliveries are then made direct from the half-van to the customers.

Improvements in packaging techniques and in packages also have contributed to the continued low cost of petroleum products. For example, typical well-designed canning lines in the late 1940's had speeds of about 200 cans per minute. Speeds of 600 cans per minute are now common and 1,000 cans per minute lines are being installed. A variety of automatic machines has been developed to assist in handling these high rates of output. Machines which unload cans from boxes, load cans into boxes, and stack boxes on pallets with no normal intervention by men are coming into widespread use.

Improvements in steel quality and in tolerances in manufacture of steel sheet have permitted decreases in the thickness required for both drums and cans. This reduces the cost of the container and its weight which in turn reduces its shipping cost. Fiber drums and cans and various composite materials show promise of giving further savings and improvements on this score.

Industry-wide standardization of both drums and drum closures has contributed greatly to economy in packaging and shipping. Drum-handling machinery can be standardized and a standardized drum cleaning and reconditioning industry has arisen. Drums can now be sold on a nonreturnable basis. When the customer is finished with a drum, he sends it to a reconditioner who then returns it to standard condition and supplies it to the packager without regard to its original use.

E. Computer Application

One of the developing technological areas with great impact on distribution is that of mathematics and high-speed computing.

The logistical problems of the petroleum industry lend themselves to computer application. The factors which make high-speed electronic analysis both practical and necessary are: numerous supply and demand points, many possible alternative "routes," and the economic incentives provided by large volumes of movement.

Linear programming is the most widely used mathematical technique. As applied to the cost of resource allocation the objective is to optimize the assignment of scarce resources in a manner which will either minimize costs or maximize profits. The linear program provides a method of systematic search for the optimum or best combination of these resources and their end use.

An area where linear programming has found success is in product distribution. One company uses this technique to optimize its distribution of liquefied propane. Here we are faced with a facilities limitation. The storage and transportation facilities used for liquefied petroleum gas are costly and are subject to seasonal utilization. The linear program provides an optimum answer to the problems of distribution and allocation of these resources. It balances the cost of additional facilities (large pressurized tank cars and cavern storage) with the cost of alternative means of distribution. In this application, the linear program provides answers to the questions of how many tank cars, where should they be assigned, and what is the cost of distribution. In a similar application, another company optimizes the blending and distribution of its lubricating oils.

A special case of the linear program has been the basis for a computer program used by several oil companies. The technique called the Transportation Method of Programming solves a problem common to all large oil companies; the assignment of demands to supply points. The assignments are made on the basis of two criteria: costs from each supply to each demand, and the capacity of each supply point.

One of the prime requirements for the successful use of any of the above-mentioned logistical optimization programs is an information system to provide accurate up-to-date input data. Computers are now being used extensively to compile, maintain and update transportation rates and records of performance. These are used by management in monitoring the efficiency of transportation facilities as well as providing input to other systems. For example, tank car inventory programs provide traffic management with keynote reports listing tank cars which have remained idle for extended periods. This type of exception reporting is the key which will unlock the door to significant returns from electronic data processing.

Mathematics have been used to help predict and schedule the distribution systems. The degree-day system for home fuel oil delivery scheduling is rather widely in use. Similar and more sophisticated forecasting systems are being developed for predicting demands of other customers such as service stations.

Computer oriented mathematical models are used to establish inventory requirements, production schedules, and warehouse locations. Recently an analog computer was used to determine optimum sites for packaged products warehouses.

SECTION 3—Transportation

Three specific modes of transportation—tank trucks, barges and rail tank cars are discussed in this Section. Pipeline and tankers are discussed in Chapter Six of Part I.

A. Tank Trucks

During the last twenty years delivery trucks have evolved from gasoline powered 1,200-gallon tank trucks and 3,000- to 4,500-gallon tractor-trailers to diesel tractors pulling 8,000-gallon and larger trailers. Aviation fuelers have changed more radically from 2,500-gallon tank trucks and 4,000-gallon tractor-trailers to 8,000- and 10,000-gallon self-contained aircraft fueling service trucks.

Trucks used for petroleum hauling and sometimes for delivery to ultimate consumers have made similar improvements. In addition, the for-hire truck industry has made great strides in developing tank trucks that are readily converted from one service to another; i.e., gasoline to chemicals, or LPG to ammonia, or even liquid to dry products. A truck-cleaning industry has also arisen to assist the convertibility of the trucks. This, of course, helps keep shipping costs down.

The advances in equipment have been accomplished by balancing the design considerations of maximum payload and lightweight equipment against heavy-duty components for long life, reliability, and low maintenance cost. An added factor in the design of the vehicles has been consideration for utmost safety and compliance with the laws and regulations of the government bodies.

The legislative regulations covering vehicle size, weight, and operating speeds have probably been the most significant change that has governed the design of new vehicles. Both length and weight restrictions have been liberalized as road and equipment technology has improved.

Commensurate with the increased allowable weights and sizes, the design trends have been to lighter weight materials. The most significant weight saving has been accomplished with the adoption of aluminum tankage and the various lightweight steels. The elimination of nonfunctional skirting, meters and air eliminators and the use of simplified lightweight piping, valves and manifolds have all reduced the weight of the tanks, resulting in increased payload. Aluminum and other lightweight components have become standard items offered by the tractor and chassis manufacturers. Engines, transmissions, axles, frames, cabs, brakes, and tires are now manufactured of high-strength lightweight materials which again allows greater payload capacities.

The weight savings have had to be balanced against greater power, speed and safety requirements. Tractors have evolved from small gasoline engine units to diesel units capable of operating 70,000-pound vehicles at current highway speeds.

Diesel engines have demonstrated their effectiveness over gasoline engines through the reduction of road failures and lost time, lower operating costs and increased life between overhauls. These economic gains in using diesels are, however, in part offset by the increased weight of the tractive units.

Safety has been constantly improved in the development of truck delivery equipment in the last twenty years. Suspensions and tank design have improved stability. Brakes, tires and power steering have been improved for greater safety and reliability in the operation of the vehicle.

Improved efficiency has been accomplished by designing faster loading and unloading systems. Large size piping, high-capacity vents, quick-connect hose couplings, more efficient internal valves and unloading valves have resulted in deliveries up to 600 gallons per minute on gravity unloading systems. Submerged loading and bottom loading have resulted in greater safety and vehicle utilization.

Aviation fueler designs have changed even more radically than the delivery equipment. In the late 1940's, fuelers were used for servicing gasoline-powered propeller aircraft at rates up to 200 gallons per minute. The advent of jet aircraft radically changed fueling requirements. Pumping rates had to be increased to 600 gallons per minute with delivery pressures up to 50 psig. Two fuelers per aircraft is normal practice, thus delivery rates of 1,200 gallons per minute are possible. Other considerations in the design were fuel cleanliness, pressure regulation to prevent damage to aircraft tanks, fuel handling safety, maximum flexibility and safety in servicing the aircraft.

The large jet aircraft fuelers have evolved into 8,000- and 10,000-gallon capacity tanks mounted on three-axle chassis designed for operating with gross loads up to 100,000 pounds. Power to drive and pump fuel was provided by gasoline and now diesel engines coupled to semi- or fully-automatic transmissions.

The second generation of commercial jet aircraft serving smaller airports and the privately owned and operated business jets again has resulted in new designs of smaller fuelers of the 2,500-gallon to 5,000-gallon capacity. These self-contained tank trucks utilize conventional truck chassis; however, again the pumping systems are designed for high flow rates, maximum flexibility and safety in servicing the smaller aircraft.

B. Barges

There are about 25,000 miles of navigable inland waterways in the United States. Barge movements on these waterways represent a most important slice of the nation's traffic and probably its most economical—much of it moving less expensively than by pipeline or by 18,000 dwt tankers in coastwise trade. Some 15 percent of the nation's total intercity freight moves by barge and more than 35 percent of this barge traffic is crude oil and petroleum products. Despite increasing unit costs for labor and equipment, barge rates have been lowered by improvements in productivity which are attributable to technological advances.

Dramatic advances in the design and operation of towboats and tugs have been made since World War II. Just prior to the war, diesel-powered towboats became prominent on the rivers. Modern propeller-driven diesel boats develop about twice the thrust per horsepower as the old steam stern-wheelers. Towboats with powerplants as large as 1,200 HP were relatively uncommon during the war era. Today the average towboat runs about 3,200 to 4,300 HP while the largest has more than 9,000 HP. The average boats push multiunit tows of 15,000 to 25,000 tons, while the larger slower boats can handle up to 30 barges with a total capacity as high as 50,000 tons. Individual barges will vary in capacity from about 1,000 to 3,000 tons.

A major technological breakthrough was the development of improved reduction and reversing gears. These gears made possible the use of high-speed diesel engines which deliver more horsepower per unit weight than low-speed diesels or steam engines. As a result, it has been possible to construct smaller, lighter, and cheaper towboats with greater power.

Many other improvements to take advantage of the higher power available have been made. Kort nozzles which improve propeller efficiency as much as 25 percent have been introduced. Hull shapes have been improved so that it is now possible to use 10-ft. diameter propellers in channels that are only 9 feet deep. Controllable pitch propellers permit attainment of high efficiency at various speeds.

Flanking rudders and bow thrusters have been introduced to assist in controlling the larger tows made possible by the higher powered towboats. The flanking rudders help maneuver the towboat which is at the stern of the tow. The bow thruster, most commonly a remote controlled power unit placed at the front end of the tow, helps to maneuver the tow which is often as long as 1,000 feet.

Higher powered towboats not only allow larger tows, they have also made possible increased speeds. Twenty-five years ago average speeds were 3 to 4 mph. Today upstream speeds of 5 to 8 mph with maximum loads are not uncommon. The increased speed contributed to economy by increasing the annual carrying capacity of the equipment. Other measures to increase utilization of equipment have also been taken. Radar has decreased the idle time caused by fog. Better ship-to-shore communications have expedited movements. Midstream refueling from small fuel barges with their own tugs or towboats has saved time previously required to fuel the towboats. Retractable pilot houses on Illinois River barges have made passage under low bridges in the Chicago area possible without changing towboats. Another important development is fast loading and discharge; integrated 10,000- to 25,000-ton express tows employ powerful pumps and large lines onboard and/or ashore to make loading or discharge within 24 hours possible—an important consideration since these \$2-\$3 million tows cost \$1,200 to \$1,800 per day to operate.

Advantage of modern automatic control techniques has been taken to ease the burdens of the pilots and to make possible operation of the tows and towboats with a minimum of manpower. Automatic steering devices and automatic engine controls have been developed. Depth finders and swing meters are in widespread use.

Economies have been achieved in some areas, chiefly New York Harbor, by utilizing 300 to 400 HP diesel propulsion units mounted directly on the barge. For short hauls these self-propelled barges have proven very beneficial.

Along with the increase in power of the prime movers, barges have increased in size and improved in hydrodynamic design. At the end of World War II, standard barges were 175′ x 26′ or 195′ x 35′; now they are 290′ x 50′; in capacity they have jumped from 1,000 tons to 3,000 tons.

The concept and use of the integrated tow has become increasingly common since the war ended. Integrated tows are made up so that the underwater portion of the string of barges forms a cleanly streamlined object. This minimizes the effect of water resistance and increases the efficiency of the tow. Older barges were double raked, i.e., both ends of the hull sloped upward. Modern barges, which are intended for use in integrated tows, are either single raked, i.e., sloped at one end and square at the other, or box barges, i.e., square at both ends. The single-raked barges are used on each end of the barge string and the box barges are used in the middle. Capacity of the tow can readily be changed by increasing or decreasing the number of box barges. Capacity can be doubled or more by making up a tow of parallel strings of barges.

Another significant trend of recent years is the introduction of barges tailored to a specific trade. Barges to move products such as liquid methane at −258°F, refrigerated ammonia at −28°F, and molten sulfur at +300°F have been put into service. Barges with organic, inorganic, or metallic internal coatings and double hulls to handle sensitive products and chemicals have been built. There are also double-hulled dual-purpose barges that carry one product in the inner hull on the outward trip and another product in the outer compartment on the return trip, thereby avoiding cleaning costs while eliminating empty return voyages.

Unmanned barges for ocean towing service are undergoing similar developments. Such barges towed by tugs vary in size up to about 18,000 tons. Bulk commodities such as cement and ore are carried in such vessels. Petroleum, while presently carried in somewhat smaller barges, will likely also be transported in large ocean-going barges.

Just as the equipment has improved, so have the waterways over which the barge traffic moves. Continuous improvements in channel conditions and extensions of the navigable waterway system have been made. A notable current project is the simplification and expansion of the locks and dams on the Ohio River system, one of the busiest of our waterways. The system in being at the end of World War II consisted of 46 low-lift dams, each with a single 600 foot lock. It is being replaced by a system of 19 high-lift dams each with dual locks, one 1,200 feet long, the other 600 feet long. The smaller number and larger size of the locks will reduce the voyage times, thereby decreasing the cost of barge transportation.

The general theme of improvements in barge technology has been the application of the most advanced engineering developments to reduce the unit cost of transportation. This has been achieved by increasing the speed and size of the tows and decreasing the manpower required to operate them by providing the mechanical and electrical devices to assist the men. Great effort is being expended to maximize the percentage of the time that the barges are moving loaded. This increased utilization has been important in keeping barge transportation costs low.

The trend toward increased utilization and toward development of specialized barges is expected to continue.

C. Tank Cars

The tank car fleet, while declining in volume of petroleum carried, maintains an importance in the overall transportation scheme because the cars are ideally suited to movement of special, limited-volume products from various origins to diverse destinations. Improvements in the technology associated with rail tank cars and their movement have been involved in lowering costs for transportation of petroleum products.

Size of rail tank cars has increased steadily since the war. Car size has grown and carrying capacity has increased. Gasoline and distillates formerly moved in 8-10,000-gallon capacity cars and now move in many instances in cars of capacities between 20,000 and 30,000 gallons. Practical liquefied gas car capacities have been stepped up from around 11,000 gallons to 30-33,000 gallons. A 50,000-gallon car has found limited use in this latter category.

Various means to improve payload and lower construction cost have been adopted. Use of new materials, such as aluminum and high-strength steels, has lowered the weight of the bare car thus increasing the allowable payload. A raising of the required center of gravity has permitted the construction of large-volume cars of single diameter instead of having to use multiple diameters to achieve large volumes. The use of the tank body as the horizontal strength member of the car has eliminated the bulky underframe common in older cars; this, of course, lowers the empty car weight and raises the allowable payload.

The ability of tank cars to handle specialized cargoes has been greatly improved. Use of special materials or linings for tank bodies and interiors is growing. Cars suitable for liquid hydrogen at very low temperatures and for molten sulfur at very high temperatures have been built. While cars with internal heating coils have been common for some time, cars with coils welded to the outside of the tank body have been used with more frequency. These cars have the advantage of being heated while retaining smooth interiors which facilitate drainage. The tank car builders have taken advantage of the newer insulations to reduce the cost of handling extremely cold or hot products.

It is expected that the trend to specialized tank cars will continue. The particular utility to the petroleum industry of rail tank cars is an advantage that is shared in many ways with tank trucks. It is important that continuing improvements be made in the economy of railroad tank car use. Tank cars along with other rail equipment move only a small part of the time. Greater utilization of the cars would help to keep them competitive with other transport means.

CHAPTER FOURTEEN—PETROLEUM PRODUCTS DEMAND

SECTION 1—Products Demand Since World War II

Petroleum is basic to the transportation of all goods and to the production of most products throughout our economy. It provides the mobility required for national security and contributes greatly to income, growth and welfare of the people.

The demand for petroleum in the U. S. has grown substantially in the postwar period. This rapid growth is summarized for all petroleum products in Table XXVI. In 1946, total demand for oil was less than 5,000,000 B/D and gasoline demand was about 2,000,000 B/D. By 1965, total demand increased to 11,300,000 B/D and gasoline increased to 4,860,000 B/D and will exceed the 5,000,000 B/D level in 1966—equivalent to the total oil product demand in 1946. This represents a large increase in per capita consumption of oil from 530 gallons/year to

U. S. DOMESTIC OIL DEMAND BY USES
1,000 B/D

	1946	1950	1955	1960	1965	AVG. ANNUAL 1965/1946	INCREASE, % 1965/1960
GASOLINE							
Automotive	1,920	2,534	3,353	3,845	4,592	4.7	3.6
Aviation	35	108	192	161	120	6.7	(5.7)
Special Naphthas[a]	60	82	110	124	147	4.8	3.5
Total Gasoline	2,015	2,724	3,655	4,130	4,859	4.7	3.3
JET FUELS							
Naph-Type	—	—	154	280	271	—	(0.6)
Kero-Type	—	—	—	91	333	—	29.5
Total Jet Fuels	—	—	154	371	604	—	10.2
INTERMEDIATES							
Kerosene (ex Jet)	244	323	320	271	267	0.5	(0.3)
Distillate							
Heating	406	646	978	1,195	1,304	6.3	1.8
Diesel	148	287	464	563	718	8.7	5.0
Other Distillate	111	149	150	114	104	(0.3)	(1.9)
Total Distillate	665	1,082	1,592	1,872	2,126	6.3	2.6
Total Intermediates	909	1,405	1,912	2,143	2,393	5.2	2.2
RESIDUAL							
Heating	136	199	236	342	428	6.2	4.0
Other Residual	1,179	1,318	1,290	1,186	1,179	—	(0.1)
Total Residual	1,315	1,517	1,526	1,528	1,607	1.1	1.0
LUBRICANTS	96	106	117	117	129	1.6	2.0
ASPHALT & ROAD OIL	135	179	254	302	368	5.4	2.3
LPG							
Chemical Use	20	41	97	196	343	16.1	11.8
Residential and Commercial Use	49	132	183	275	312	10.2	2.6
Other LPG	40	61	124	150	186	8.4	4.4
Total LPG	109	234	404	621	841	11.4	6.3
ALL OTHER	333	342	438	449	503	2.2	2.3
Total Domestic Demand ALL OILS	4,912	6,507	8,460	9,661	11,304	4.3	3.2
Net Imports	(42)	545	881	1,604	2,282		
Imports as % of Total		8.3	10.4	16.6	20.2		

a—1965 includes naphtha 400° for petrochemical use—65 MB/D. Earlier years estimated @ 3% of total gasoline demand.

Sources: U.S. Bureau of Mines—Monthly & Annual Petroleum Statements; Annual Sales of Fuel Oil & Kerosene; Annual Sales of Liquefied Petroleum Gases.

890 gallons/year as shown by Figure 110. The total oil demand in gallons in 1965 came to a staggering 173 billion gallons versus only 75 billion gallons in 1946. This growth has required an enormous expansion in transportation facilities since each gallon of gasoline has traveled about 1,000 miles while en route from the crude field to the refinery and to the ultimate consumer.

The chief factors contributing to this increased demand for oil in the U. S. have been the population growth, the rise in real per capita income, and the rise in industrial production.

In the postwar years, these factors resulted in large increases in vehicle registrations, air passenger and cargo miles, and in central oil burners for home heating. Salient statistics are tabulated below.

Since 1946, population has increased from 142 million people to 195 million people or 37 percent, equivalent to 1.7 percent per annum versus annual growth rates in GNP of 6.3 percent and FRB of 4.3 percent. The per capita income in the U. S. has nearly doubled, rising from $1,500 in 1950 to about $2,750 in 1965. This gain in per capita income comes partly from inflation but chiefly from increased production, improved technology and new capital equipment with the resulting rise in productivity.

Looking at the major oil product, gasoline, we can explain the growth in demand as follows:

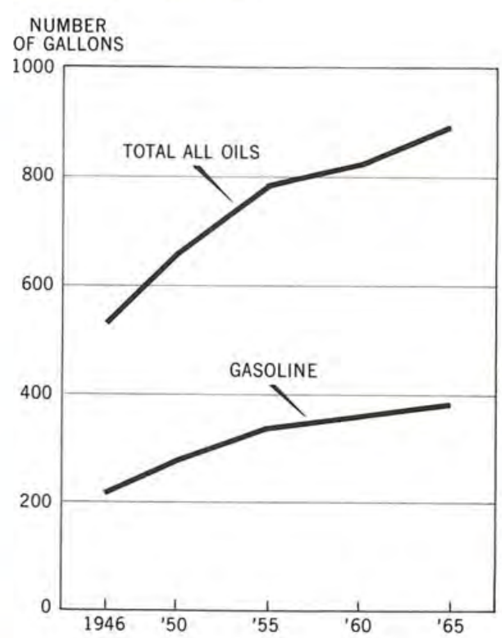
After the war, the number of operating automobiles was equivalent to one for every five people in spite of the fact that car production had been stopped during the war. By 1950, the increase in unit car

FACTORS AFFECTING OIL DEMAND

UNITED STATES	1946	1950	1955	1960	1965
Total Population (000's)	141,936	152,271	165,931	180,864	194,572
Per Capita Income Current $	1,249	1,496	1,876	2,215	2,746
Per Capita Income Constant 1958 $		1,810	2,027	2,157	2,507
GNP [a]—Billion Current $	211	285	398	504	676
GNP—Billion Constant 1958 $	313	355	438	488	610
FRB[b] (1957-9=100)	60	75	97	109	143
Motor Vehicle Registration (Millions)	34.4	49.2	62.6	73.7	90.1
Cars	28.2	40.3	52.0	61.5	75.1
Trucks and Buses	6.2	8.9	10.6	12.2	15.0

a—Gross National Product—a measure of total goods and services produced by the nation.
b—Federal Reserve Board Index—a measure of the nation's industrial production.

FIGURE **110**
U.S. Per Capita
Use of
Oil Products



registrations over 1946 was greater than the gain in the number of people during the same period. As a result, there was one car for every 3.8 people in 1950. By 1965, car registrations grew to the point where there was one car for every 2.6 people and many households had two or more cars. This is shown in the tabulation below and a prediction is made for the year 1975.

driving age. Thus while U. S. population growth between 1946 and 1965 was 37 percent the growth in car registrations from 28.2 million to 75.1 million was a 166 percent increase and the gain in gasoline consumption from 2,015,000 B/D to 4,859,000 B/D was a 141 percent increase.

The U. S. has become a nation on wheels. Four out of every five workers use an automobile for commuting to and from work. One-fourth of the workers belong to a car pool. More than 80 percent of the vacationing public use their own automobile for transportation. Almost one-half of all automobile

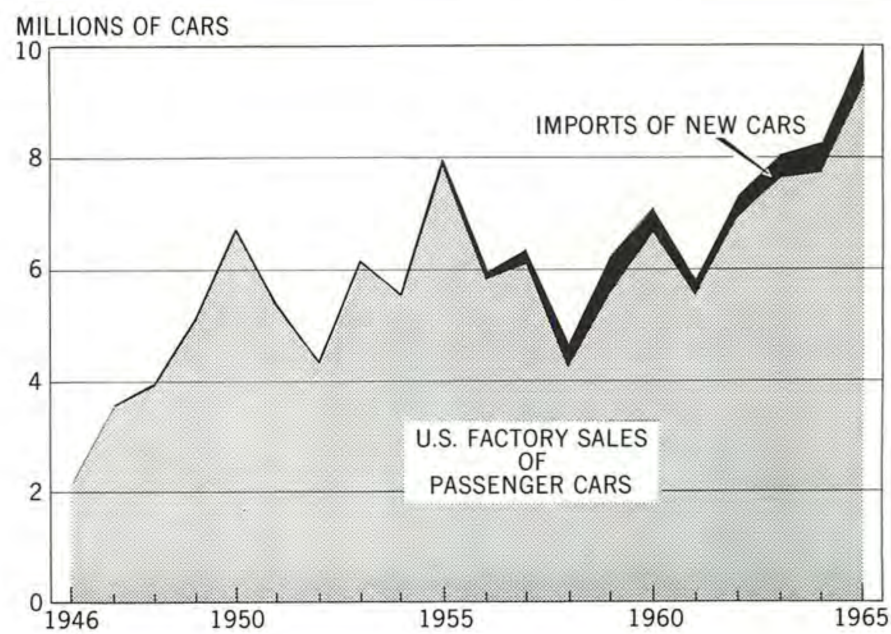
FACTORS AFFECTING GASOLINE DEMAND—TOTAL U. S.

	1946	1955	1965	1975[a]
Automotive Usage				
Bbls. per person	4.40	7.90	8.60	10.30
Bbls. per household	19.20	27.40	28.70	32.20
Bbls. per car[a]	16.74	16.24	15.26	15.03
No. of Cars, Millions, Year End	28.2	52.00	75.10	103.20
Persons per Car	5.05	3.20	2.61	2.15
Cars per Household	0.75	1.07	1.29	1.46
Gasoline Demand (MB/D per Billion $ GNP)	9.55	9.18	7.19	5.61
Population (Midyear Millions) Total	141.9	165.90	194.60	220.10

a—Estimated

Increases in income and availability of credit permitted many families to own a car who previously could not. A further stimulus to increasing car ownership has been the large gain in people reaching

FIGURE 111
Passenger
Car
Sales



Source: *Automobile Facts and Figures, 1966 Edition* travel is used for the purpose of earning a living. One-third of automobile travel is used for family (shopping, medical, etc.) business, while remainder is for family, social and recreational activity. The automobile industry is one of the most important in the nation. It uses a large share of many raw materials, such as rubber, glass and steel and half of such finished products as radios. Figure 111 shows car sales since 1946 with an increase from 2.2 million to 9.3 million units per year.

The total mileage traveled has increased in a direct ratio to the number of cars since the mileage per automobile has not changed much over the years. This has caused some congestion on the highways and city parking problems; nevertheless, automobile travel continues to grow. When all of the new federal highways are open, greater travel, including farther away vacation trips, seems likely. While the annual growth in gasoline is affected by general business, there has not been a decline in demand in any year since the war in spite of several recessions.

During the postwar period, truck usage rose sharply on the highway, on the farm and for city delivery. Truck registrations increased from 6.0 million in 1946 to 14.8 million in 1965.

Air travel developed rapidly after the war causing substantial increases in demand for aviation gasoline. This demand jumped from 35,000 B/D in 1946 to 192,000 B/D in 1955. Then the jet age in domestic airline travel began, creating a need for an entirely different fuel in the aviation business with turbine fuel. Faster and larger commercial planes have continued to increase demands. Private and business planes have grown substantially and there were about 88,000 planes in the "general aviation" category at the end of 1965.

The kerosene/turbine fuel demand in 1965 reached 333,000 B/D, up from nothing ten years prior and 91,000 B/D in 1960. U. S. passenger miles traveled came to 71,800 million compared with 25,200 million in 1955 and 10,700 million in 1950. World travel amounted to 105,000 million in 1964. Thus, the U. S. total was 58 percent of world travel in that year whereas our population is only 6.5 percent of the world. Even with Americans traveling more than the rest of the world combined, air travel in the U. S. is still in the early stages of growth. The annual consumption of turbine fuel in 1965 amounted to 25 gallons per person—enough for only one hour of flying time per year.

Heating demand for distillates increased sharply after the war, chiefly because of a switch from coal in existing homes. The postwar gain averaged 6.3 percent per annum between 1946 and 1965. This rate slowed down to 1.8 percent per annum between 1960 and 1965. At the end of 1946, there were 2.7 million homes in the U. S. centrally heated with oil. This number jumped to 7.9 million in 1955 and to 10.4 million in 1965. In addition, many homes are heated with space heaters. In 1965, almost one out of three homes was heated by gas.

Diesel demand has shown great increases since the war. In 1946, it amounted to about 150,000 B/D for all uses. By 1965, the demand climbed to about 720,000 B/D. The chief uses were 200,000 B/D for trucks and buses on highways, 210,000 B/D for nonhighway stationary diesel engines that are used for road and building construction, etc., and 230,000 B/D by the railroads.

Heating demand for residual oils in large office buildings, apartments and hotels rose substantially after the war because of the large increase in office space and large apartment buildings. In 1946, consumption for heating averaged 136,000 B/D and by 1965, the volume increased to 428,000 B/D, a gain of 6 percent per annum. Demands for uses other than heating have not increased chiefly because of the elimination of railroad usage due to the postwar switch from steam engines to diesel locomotives. In 1946, railroads consumed 275,000 B/D of residuals and this declined to 11,000 B/D in 1965.

While the demand for lubricants is small as compared with gasoline, lubricating oil and grease demand increased from 96,000 B/D in 1946 to 129,000 B/D in 1965. The growth rate here has not been as large due to improved efficiency in use. In 1966, over 55 percent of the cars had a 30,000 mile chassis lubrication life as compared with about 20 percent in 1961. Many cars now require an oil change every 6,000 miles versus the conventional 1,000 miles in the earlier postwar years.

Asphalt is an important oil product and it has played a large role in the postwar highway construction program. In addition, it is used extensively in roofing materials and in building runways at airports. The postwar growth rate for this product has exceeded 5 percent per year and the volume has risen from 135,000 B/D in 1946 to 368,000 B/D in 1965

LPG (liquefied petroleum gas) is a large volume product that has experienced an overall growth rate of over 10 percent per annum since World War II and 6 percent since 1960. Demands for LPG as raw material for petrochemical manufacture have been increasing at a 16 percent rate per annum since World War II or 7 percent since 1960. Residential and commercial space heating and cooking usage has grown at a 10 percent rate.

SECTION 2—Future Projections to 1975

The growth rate in oil demand over the next ten years is estimated at 3 percent per annum, the same rate as prevailed in the previous decade. However, since the growth rate starts at a higher volume level, the anticipated volume gain in 1975 versus 1965 is 3,900,000 B/D versus 2,800,000 B/D in the 1955-1965 decade. The growth of two major products in transportation, gasoline and jet fuel, is shown below.

GASOLINE AND KERO-JET FUEL DEMANDS

	DEMAND [a] MM-B/D		POPULATION [b] MILLIONS	PER CAPITA USE BBLS/YEAR	
	GASO	KERO-JET		GASO	KERO-JET
1920	0.3	—	108.5	1.03	—
1930	1.1	—	123.1	3.22	—
1940	1.6	—	132.6	4.45	—
1950	2.7	—	151.7	6.55	—
1955	3.6	—	165.3	8.04	—
1960	4.1	0.1	180.7	8.28	0.23
1965	4.8	0.3	194.6	8.99	0.62
1970	5.6	0.6	206.1	9.91	1.13
1975	6.4	1.0	220.1	10.65	1.67

a—U. S. Department of Interior—Bureau of Mines data through 1965. 1970 and 1975 data estimated from past trends.
b—U. S. Department of Commerce—Census Bureau. 1970 and 1975 projections from Series P-25, No. 286, July, 1964.

Gasoline will continue to be the principal petroleum product and demand in 1975 may equal 6,-500,000 B/D with a growth rate of 3 percent per annum. The anticipated volume gain during the decade ahead is one-third more than occurred in the past decade. Car registrations in 1975 are projected at the 100 million level; and in addition, there will be some 20,000,000 trucks. Although the growth in population is projected at a somewhat lower rate than that prevailing in the 1955-1965 decade, gasoline demand should increase with more families having two or more cars. A super highway system, shorter work week, higher pay, longer vacations, earlier retirement and longer life are all plus factors favoring a good continued growth in gasoline demand.

The commercial turbine fuel demand is forecast to show sizable gains in the decade ahead. A conservative growth rate would be 10 percent per year and this rate could be exceeded considerably in the immediate years ahead. The rise in pleasure travel should be substantial both abroad and at home. More and more families will be traveling as a group as higher incomes and special fares will permit and encourage such travel. By 1975, commercial kerosene turbine demand will probably exceed 1,000,000 B/D.

Oil consumption for home heating is not expected to grow appreciably. The gain in home heating demand may not exceed one percent per annum in the 1965-1975 period.

Diesel fuel usage should continue to expand, particularly highway truck usage. The annual gain through 1975 should average 5 percent per annum, with smaller gains in stationary diesel usage and by railroads.

Residual fuel oil should show only minor gains in the years ahead. It faces competition from coal and gas and from nuclear plants in the case of electric utilities. Accordingly, a gain of 1.5 percent per annum in total residual fuel oil demand includes a larger gain for heating large buildings and no gain in utility usage.

Liquefied petroleum gas demand is forecast to rise 5 percent per year while petrochemical feedstock requirements may show an 8 percent gain per year.

Asphalt demand is forcast to show a 3 percent gain per annum through 1975, and coke is forecast to gain at a similar rate.

The general economy assumptions to support the future petroleum demands just outlined are:

	1965 LEVEL	1975 LEVEL	PER ANNUM % GAIN 1975/65
Population, midyear millions	194.6	220.1	1.3
Households	57.3	70.0	1.9
Gross National Product, Billion $	676.0	1,174.0	5.7
Federal Reserve Board Index of Industrial Production, 1957-1959=100	143.0	220.0	4.4

CHAPTER FIFTEEN—TECHNICAL ASPECTS OF GOVERNMENT AND COMMUNITY RELATIONS

The oil refining industry, like all manufacturing industries, has frequent contacts with the public and with state and local governments in the areas in which it operates, and oilmen have followed a policy of being good citizens of the community in which they live and work. The industry also is subject to many forms of federal regulations. Some of these, such as the Oil Import Control Program, the National Labor Relations Board, the Walsh-Healey Act, etc., are primarily economic and political in character and involve refining technology only incidentally.

Therefore, three fields have been considered in which there are close relationships between refining technology and the interest of the government and public. These are National Defense, the industry's safety program, and the many problems which arise in the fields of air and water conservation.

SECTION 1—National Defense

Petroleum is an essential requirement for any country to maintain a strong national defense system. This means not only an adequate supply of crude oil but it means the refineries and technical knowledge necessary to make the sophisticated products required for modern warfare.

A. Wartime Administration

In order to understand the refining industry's support of our defense programs, it is necessary to review briefly the program during World War II. When the war broke out, the future of the refining industry was full of unknowns. Normal methods of transporting crude and products were disrupted by the submarine attacks along our East Coast. Future military requirements for petroleum products were indefinite. For example, the initial goal for 100 octane gasoline was set at 120,000 B/D late in 1941, a staggering figure considering that the production at that time was somewhat less than 40,000 B/D. Three years later, the requirement for 100 octane gasoline was more than 600,000 B/D.

The President designated the Secretary of the Interior as Administrator of the Petroleum Administration for War. PAW, as it was more commonly known, was staffed with oil industry men and, in a short time, companies made available to PAW and to their competitors, their most choice secrets of technical know-how. They pooled their facilities, their technical information and their products and, under PAW direction, ran their refining activities as if they were component parts of one huge refinery. With such cooperation, production of petroleum products reached levels never before attained—levels without which the war might have been greatly prolonged.

Industry committees, such as the Aviation Gasoline Advisory Committee and the Technical Advisory Committee, held national and district meetings at which technical and operating developments were freely discussed. Technical subcommittees of the industry collected and analyzed operating data and presented to the industry recommendations and suggestions which were invaluable in maintaining an increasing production of 100 octane gasoline and its components. In addition, the petroleum refining engineering firms gave freely of their knowledge and manpower to increase the production of aviation gasoline. The whole program of aviation gasoline was an example of what teamwork can accomplish.

B. Postwar Reorganization

The government-industry cooperation in petroleum matters had been so effective during the war that officials of the United States Government wished to maintain it in peacetime. When President Truman issued the order terminating PAW in May, 1946, he at the same time directed the Secretary of the Interior to establish a national council of petroleum industry representatives following the same general pattern in which the Petroleum Industry War Council operated so successfully. The Secretary of the Interior responded to this suggestion by establishing the National Petroleum Council to advise, consult and make recommendations to him on oil and gas matters when he so requested.

C. Office of Oil and Gas

Also, responsive to the President's suggestion, the Secretary of the Interior, in 1946, established within the Interior Department a special "Office of Oil and Gas" which "took over" from PAW. The Office of Oil and Gas serves as the agency in the Federal Government having primary responsibility for leadership and information on petroleum and gas, and also serves as the principal channel of communication with the petroleum and gas industries. Additional defense planning responsibilities were subsequently assigned to the Office of Oil and Gas. It retains on its staff, at all times, one or more qualified refining specialists.

D. Petroleum Administration for Defense

United States mobilization for the Korean War occurred under the Defense Production Act, which was enacted in September, 1950, and which still exists in amended form. The Petroleum Administration for Defense was established in October—the Secretary of Interior, being its Administrator. An oilman was appointed Deputy Administrator, and an organizational pattern similar to that of the World War II organization was adopted. Industry experts recruited for the agency staff were, in the first recruitment, largely individuals who had served in similar positions in PAW and who had been active in the work of the Military Petroleum Advisory Board. There was no real delay in the mobilization. The MPAB had been working for years with the Defense Department on a mobilization exercise. Logistical considerations applicable to either a limited war, such as occurred in Korea, or to a worldwide conflict were well understood. During the fall of 1950, the National Petroleum Council and its committees were in frequent session. The experts on the subcommittees of MPAB dropped all other activities and were in continuous session in the Office of Oil and Gas. The OOG formed the first cadre of personnel for PAD. As PAD became active, the volunteer work of MPAB committeemen was absorbed and MPAB became inactive.

By June, 1952, the new Petroleum Administration for Defense had attained the full size and activity needed to cope with the problems of sustaining the Korean War. Had the war widened, it was prepared for the larger problems as well. Since a world war was avoided, PAD did not expand further. After another six months, some of its activities were lessened and some abandoned. Then, after a further period of months, PAD was abolished and its residual responsibilities and files were turned back to the Office of Oil and Gas of the Department of the Interior.

E. Present Organization

The cooperation between the oil industry and the government, which began under the pressure of World War II, has continued in the same basic pattern in the postwar years.

Pursuant to a Presidential Executive Order assigning to him emergency preparedness functions for oil and gas, the Secretary of the Interior established in 1963 a standby organization, the Emergency Petroleum and Gas Administration (EPGA). The EPGA is designed to meet the need for an emergency organization ready and authorized in the event of a national emergency. It will coordinate and direct, to the extent necessary, the operations of the petroleum industry in mobilizing the U. S. oil and gas resources.

The EPGA is patterned after PAW of World War II and PAD of the Korean Conflict mentioned above. It differs from its predecessors, however, in that it is organized and staffed on a standby basis preemergency and allows for a large degree of decentralized operations to permit an immediate and flexible industry-government response to a nuclear attack. It consists of a National Headquarters, eight Regional offices, nine gas group offices and such state and local subordinate offices as may be required. The EPGA structure parallels the functional lines of the petroleum industry with staff and line units comparable to those found in a typical large vertically integrated organization.

The EPGA, on activation, like PAW and PAD would be an independent agency headed by a National Administrator, the Secretary of the Interior. Other positions are filled primarily by petroleum and gas industry personnel who, prior to activation, are designated members of the Petroleum and Gas Unit of the National Defense Executive Reserve.

The industry, working through the National Petroleum Council and the Emergency Advisory Committee for Natural Gas, as requested by the Interior Department, recommends such government-industry organization, procedures and policies as would best meet the needs of a future war emergency. The NPC examined in 1964 the adequacy of the government's plan of organization for an emergency and made 31 recommendations related to basic principles, organization structure, techniques of staffing and training and clarification of relationships with other government departments so as to avoid conflict of authority. All recommendations were accepted by the government. One of these recommendations was the preparation of detailed operating manuals covering the 20 divisions and staff offices of EPGA. This monumental task was completed by the NPC in 1967, enabling the Interior Department to distribute copies to key EPGA Executive Reservists and to government agencies. Included in this set of emergency operating manuals is one covering domestic refining operations.

Various other studies of a more specific technical nature, yet related to defense needs, were requested of the industry by the Interior Department. Among such studies prepared by the NPC were: "Critical Materials Requirements for Petroleum Refining" (1966); "Civil Defense and Emergency Planning for the Petroleum and Gas Industries" (1964); "Petroleum and Gas Industries Manpower Requirements" (1963); and "Maintenance and Chemical Requirements for U. S. Petroleum Refineries and Natural Gasoline Plants" (1961). The refining segment of the industry plays a major role in cooperating with the government to provide the technical advice, information and talent needed to better meet the country's requirements whatever future emergency may arise.

The oil industry also has continued to offer its services to the Defense Department. The quality of petroleum products required by the military services has gone up each year—and it is still going up. These improvements have been achieved by informal cooperation between industry technical experts and their military counterparts.

This cooperation has made it possible to achieve a balance between the quality desired and the ability of the industry to meet these higher standards at reasonable cost. It is worthy of note that the petroleum industry is unique among the important suppliers of military requirements in that the research and development work necessary to meet military needs has been carried out almost entirely by the oil industry at its own expense.

The major portion of this burden has been borne by the larger companies which have the research and the technical personnel necessary to develop the sophisticated products required by the military services. The smaller refiners have participated to a large extent, however, and many of them have become important suppliers of jet fuel. There are a number of smaller refiners which have been able to make an important contribution to the Defense Program in the development of certain specialty items, particularly lubricating oil. One of the smaller refiners today is the principal supplier of reference fuel which is used by the military services and by aircraft engine builders.

F. Coordinating Research Council

This informal cooperative program sometimes is done through more formal organizations, an outstanding example of which is the Coordinating Research Council (CRC), which provides an effective forum for the various segments of the automotive and petroleum industries to work together in noncompetitive problem areas. The Council is jointly financed and administered by the API and the Society of Automotive Engineers. As a result of the many CRC projects undertaken over the years, knowledge of the mutual adaptation of fuels and lubricants, with the equipment (aviation, diesel, motor) in which they are used, has advanced to a high level of proficiency and flexibility. An indication of the importance of this work to the military services is the fact that, during the Korean War in 1950 and 1951, approximately two-thirds of the CRC work was being carried on at the specific request of the military services. It was expected that the military program would be reduced after that time, but, even as recently as 1964, approximately 56 percent of CRC activity was expended for the Air Force, U. S. Army Materiel Command, U. S. Navy Bureau of Ships, and the U. S. Navy Bureau of Naval Weapons.

The organizational structure of the CRC is designed to afford a straightforward method for accepting problems, developing the necessary information and research test techniques for their solution, and distributing the results of those interested as expeditiously as possible. To insure that work on each project is progressing towards its assigned objective, three Technical Committees—Aviation Fuel, Lubricant, and Equipment Research Committee (CRC-Aviation), Diesel Vehicle Fuel, Lubricant, and Equipment Research Committee (CRC-Diesel), and Motor Vehicle Fuel, Lubricant, and Equipment Research Committee (CRC-Motor)—supervise all the fuel and lubricant activities within their respective equipment fields. Each year the work of the Technical Committees is reported to the American Petroleum Institute, Automobile Manufacturers Association, Aerospace Industries Association, and Compression Ignition Engine Advisory Committee.

After the technical merits of a proposed project have been established by the appropriate Technical Committee, the CRC Industry Committee determines whether the activity lies within the CRC scope, and if it will receive the necessary support in funds and personnel from the cooperating equipment and petroleum industries. In its turn, the CRC Coordination Committee provides for the functioning of a coordinated policy by the three Technical Committees and for supervision of those activities which, due to overlapping interest or security classification, do not fall within the jurisdiction of a particular committee.

SECTION 2—Safety Regulation

Government regulation of industrial safety historically has been a function of the state governments. The Federal government has no general authority over industrial safety except in industries such as railroads, airlines, etc., which are engaged in interstate transportation.

The Federal government, however, does have the power in its capacity as a buyer to establish conditions which must be met by contractors supplying product to the government. This power has become of increasing importance as the purchases of the Federal government have increased in volume. The most important use of this power is through the Walsh-Healey Act under which the government establishes minimum wages and other conditions for employment. One of these other conditions is the authority to regulate safety. The industry has suggested through the American Petroleum Institute and National Petroleum Refiners Association that the government make use of the many safety codes which had been prepared by experts in their particular field and already are widely accepted in the industry (such as those published by the National Fire Protection Association, the American Standards Association, the American Petroleum Institute, the National Board of Boiler and Pressure Vessel Inspectors, etc.) and provide that compliance with these codes shall be deemed compliance with the statute.

SECTION 3—Air and Water Conservation

In recent years, the public and government authorities have become increasingly concerned with air and water pollution. These are problems which are the result of urbanization and increased industrial activity in urban areas. In certain cities the air pollution problem has been aggravated by the tremendous increase in the automobile population.

The state and federal programs dealing with water pollution are of more direct concern to the oil industry because refineries are large users of water and most refineries are located on navigable waters. The oil industry has been actively engaged in air and water research and conservation treatment for nearly 40 years. As far as water pollution abatement at oil industry facilities is concerned, technology and procedures are well advanced.

The public concern with air pollution has come about in recent years, and thus far it has not had as great an impact on the technology of oil refineries as the water conservation program. The potential impact of programs designed to reduce air pollution, however, may have an even greater ultimate impact on the technology of the industry because, in addition to dealing with refinery emissions, many of them deal with the industry's products which are used in internal combustion engines, as fuel in stationary installations and as industrial solvents. Another great difference between air and water conservation problems is that the causes of air pollution still are not fully understood. Much of the industry's government and public relations activity in this field has been directed toward encouragement of research to determine the causes of air pollution and to establish reasonable criteria for air quality. A vast amount of research must be conducted before we can reach a sound understanding of the cause-and-effect relationship between air pollutants and their effects—an understanding which must be reached if we are to provide the basis for good pollutant control. Oil industry expenditures on conservation, research and pollution control equipment have exceeded $220 million for air since the Federal Clean Air Act was passed in 1955.

During 1966, the oil industry increased its budget substantially, and will spend more than $43 million on air conservation alone. These are investment figures only; figures on operating costs are not available but they have been substantial.

A. Water Pollution

The oil industry has been concerned with water conservation for many years. As far back as 1927, when this was not as widely publicized an issue as it is today, the American Petroleum Institute made a survey of the practices being followed by oil companies to curb water pollution. This study laid the foundation for programs that have been pursued ever since by the various branches of the industry.

One effort that deserves special notice is the "Manual on Disposal of Refinery Waste" prepared by the Refining Division of the API. It is a definitive work on this subject, and is regarded as a bible, not only in our industry but in other enterprises as well. The manual now is in six volumes: two deal with water pollution, one with chemical waste, two with air pollution, and the latest part just issued three years ago deals with solid waste disposal.

B. Air Pollution

The subject of air pollution has attracted great public interest in recent years. Representatives of the oil industry have been active in discussing and searching for solutions to this problem. Although interest in this field is of recent origin, as compared with the long history of dealing with water pollution problems, the oil industry's expenditures for research and for new technology in this field already are greatly in excess of the amount being spent on water conservation. As pointed out above, there are two differences between the industry's approach to the air pollution problem and the control of water pollution. The first of these is that in the water field we are concerned with the use of water by the oil industry itself. In the field of air pollution the serious problem exists, not with the oil industry, but with the emissions created by the use of its products.

The second difference is that, while refineries have a long background in the study of water pollution and a good understanding of its causes and cures, the industry does not have similar knowledge for air pollution. In fact, the form of air pollution which causes the greatest amount of discomfort to human beings, photochemical smog, was first detected in the Los Angeles area in the mid-1940's, but it was not until about 10 years later before the causes of it were known and the role of the automobile in causing smog was understood.

The problem of air pollution and the industry's efforts to deal with it can be divided into three subjects: (1) the emissions of the plants of the oil industry itself; (2) the burning of fuel oils under boilers; and (3) the use of petroleum products in the internal combustion engine.

With respect to the first of these, refineries were once considered as major sources of pollution. As further research in this field has developed, however, it has become clear that they are not the major contributors to air pollution. Since this problem is a local one, refiners have continued to work with government agencies in their localities to control the emission from refineries.

The second problem, the discharge of sulphur dioxide from plants burning fossil fuels, is a complex one. The removal of the sulphur dioxide from the stack gases, and the removal of the sulphur from the fuel before it is burned, are both technically possible, but until recently have been considered too costly for general use. A considerable amount of research is being carried on by individual oil companies and by API contractors to find an economic way to reduce sulphur emissions from residual oil. Any government regulation in this field involves the competition between oil and coal, the competition between oil and natural gas, and even between oil from different fields when there is a difference in the sulphur content of the crude oil used.

The third area of concern is the use of petroleum products in internal combustion engines. This is the newest problem because the role of the automobile, and particularly the photochemical smog for which the motor vehicle is primarily responsible, in contributing to air pollution, was not known until recently. This knowledge provided the basis for action to control smog by controlling automotive emissions. The first efforts were devices to control crankcase "blowby," since about 25 percent of an automobile's hydrocarbon emissions are discharged from crankcases. These devices have been in use nationwide on all new cars for several years. Another important step to control exhaust emissions was taken with the development of exhaust control systems which are now required on all 1966 model cars registered in California, and, beginning with the 1968 model, new federal standards will require similar devices on all automobiles.

There is still need for a good deal of research in this field, and the oil industry is actively concerned with the search for more information. For example, the API is sponsoring a $480,000 technical project which is underway at the Bartlesville, Oklahoma, laboratories of the U.S. Bureau of Mines. The purpose of this research is to determine what effect, if any, on the evaporative and exhaust emissions of automobiles would be brought about by varying fuel composition and volatility, and by blending gasoline with and without lead.

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GLOSSARY

Additives—Any materials incorporated in finished petroleum products for the purpose of improving their performance in existing applications or for broadening the areas of their utility.

Alkylation—A refinery process for chemically combining isoparaffin with olefin hydrocarbons. The product, alkylate, has high octane value and is blended with motor and aviation gasoline to improve the antiknock value of the fuel.

Ambient—A term usually referring to surrounding conditions.

Amine—A class of organic compounds of nitrogen that may be considered as derived from ammonia (NH_3).

Analog Computers—A computer that operates with numbers represented by directly measured quantities.

Antiknock—A quality to reduce autoignition knock in gasoline engines.

Aromatic Hydrocarbons—Hydrocarbons characterized by unsaturated ring structures of the carbon atoms. Commercial petroleum aromatics are benzene, toluene, and xylenes.

Ash—The amount of ash or nonvolatile, incombustible content left from heating petroleum oils to the point of complete burning of the oil.

Asphalt Cement—A refined asphalt, or combination of refined asphalt and flux, of suitable consistency for paving purposes.

Base Oils—A refined or untreated oil used in combination with other oils and additives to produce lubricants.

Biodegradable Detergents—Detergents susceptible to destruction by bacteria especially in sewage treatment plants.

Blending—The process of mixing two or more oils having different properties to obtain a product of intermediate properties.

Bright Stocks—High viscosity, fully refined, and dewaxed lubricating oils produced by the treatment of residual stocks and used to compound motor oils.

Carbon Residue—The amount of carbonaceous material left after evaporation and pyrolysis of an oil.

Catalytic Reforming—A catalytic process to improve the antiknock quality of low-grade naphthas and virgin gasolines by the conversion of naphthenes (such as cyclohexane) and paraffins into higher octane aromatics (such as benzene, toluene, and xylenes). There are about 10 commercially licensed catalytic reforming processes.

Cetane Number—A term for expressing the ignition quality of a diesel fuel.

Chelating Agents—A metal deactivating additive that chemically combines with a metal to make it inactive. Especially useful where metals may be present in extremely small quantities.

Cloud Point—The temperature at which paraffin wax or other solid substances begin to crystallize out or separate from solution when an oil is chilled under specified conditions.

Coke—The solid residue remaining after the destructive distillation of crude petroleum or residual fractions.

Compound—Chemically speaking, a distinct substance formed by the combination of two or more elements in definite proportions by weight and possessing physical and chemical properties different from those of the combining elements.

Cracking—Process carried out in a refinery reactor in which the large molecules in the charge stock are broken up into smaller, lower boiling, stable hydrocarbon molecules, which leave the vessel overhead as unfinished cracked gasoline, kerosenes, and gas oils. At the same time, certain of the unstable or reactive molecules in the charge stock combine to form tar or coke bottoms. The cracking reaction may be carried out with heat and pressure (thermal cracking) or in the presence of a catalyst (catalytic cracking).

Crankcase "Blowby"—Engine combustion gases that do not leave the cylinder through the exhaust manifold but leak into the crankcase.

Cryogenic Fuels—A fuel that must be maintained at extremely low temperatures to remain liquid; i.e., liquefied hydrogen, methane, propane, etc.

Cycle Stock—Unfinished product taken from a stage of a refinery process and recharged to the process at an earlier period in the operation.

DDC—Direct digital control. A process control system using a computer connected directly to the process controls without using conventional control instruments for maintaining preset variables.

Deactivators—A chemical added to oils and fuels to suppress a reaction or make another chemical inactive.

Deasphalting—Process for removing asphalt from petroleum fractions, such as reduced crude. A common deasphalting process introduces liquid propane, in which the nonasphaltic compounds are soluble while the asphalt settles out.

Desalting—Removing calcium chloride, magnesium chloride, and sodium chloride from crude petroleum.

Detergent—A substance having the properties of washing away undesirable substances through lowering of surface tension; wetting, emulsifying, and dispersive action; foam formation. Soaps are natural detergents. In a lubricating oil, the property which prevents the accumulation of deposits in engine parts.

Detergent Additive—A substance incorporated in lubricating oils which gives them the property of keeping insoluble matter in suspension and preventing its deposition where it would be harmful. Such oils are referred to as detergent oils.

Dilution—In motor oils in use, the contamination of oil in the crankcase with some of the less volatile portions of the fuel which have passed unburned into the crankcase.

Dimer—A molecule formed by union of two simpler molecules; i.e., isobutane dimer is a combination of two molecules of isobutane.

Diolefins—A type of open-chain, hydrogen-deficient hydrocarbons which oxidize easily in air and form gum in petroleum products during storage.

Dispersants—An additive used to prevent lubricating oil impurities (usually oxidation products) from adhering to each other and forming sludge.

Distillation—The general process of vaporizing liquids, crude oil, or one of its fractions in a closed vessel, collecting and condensing the vapors into liquids.

Emulsification—The phenomenon of fine dispersion of one liquid held in suspension in a second liquid in which it is partly or completely immiscible.

Endothermic Fuels—A fuel that absorbs heat when thermally or catalytically cracked.

Engine Oil—Generic term applied to oils used for the bearing lubrication of all types of engines, machines, and shafting and for cylinder lubrication other than steam engines. In internal combustion engines synonymous with motor oils, crankcase oils.

EP (Extreme-Pressure) Lubricants—Lubricants which have the property of imparting to rubbing surfaces the ability to carry appreciably heavier loads than would be possible with ordinary lubricants without excessive wear. This property is usually imparted by additives.

Flash—The lowest temperature at which vapors from an oil will ignite momentarily on application of a flame.

Floating Roof—Special type of steel tank roof which floats upon the surface of the oil in the tank, thereby eliminating tank breathing and reducing evaporation losses.

Flowers of Sulfur—The element sulfur in its free state. Sometimes called sulfur flour, sulfur flowers or brimstone.

Flue Gas Expanders—A turbine used to recover energy where combustion gases are discharged under pressure to the atmosphere. The pressure reduction drives the impeller of the turbine.

Fractions—Refiner's term for the portions of oils containing a number of hydrocarbon compounds but within certain boiling ranges, separated from other portions in fractional distillation. They are distinguished from pure compounds which have specified boiling temperatures, not a range.

Fuel Oils—Any liquid or liquefiable petroleum product burned for the generation of heat in a furnace or firebox or for the generation of power in an engine.

Gas Oil—A fraction derived in refining petroleum with a boiling range between kerosene and lubricating oil.

Gear Oils—Lubricating oils for use in standard transmissions, most types of differential gears, and gears contained in gear cases.

Grease, Lubricating—A solid to semifluid product of the dispersion of a thickening agent in a fluid lubricant. Other ingredients may be added to impart special properties.

Heat Sink—A mass used to absorb heat. In jet aircraft the fuel may be used for this purpose.

Heating Oils—Trade term for the group of distillate fuel oils used in heating homes and buildings as distinguished from residual fuel oils used in heating and power installations. Both are burner fuel oils.

Heavy Ends—The highest boiling portion of a gasoline or other petroleum oil.

Hydraulic Fluid—Liquid of petroleum or nonpetroleum origin used in hydraulic systems. Low viscosity, low rate of change of viscosity with temperature, and low pour point are required characteristics.

Hydrocracking—The cracking of a distillate or gas oil in the presence of catalyst and hydrogen to form high-octane gasoline blending stocks.

Hydrogenation—A refinery process in which hydrogen is added to the molecules of unsaturated (hydrogen-deficient) hydrocarbon fractions. It plays an important part in the manufacture of high-octane blending stocks for aviation gasoline, and in the quality improvement of various petroleum products.

Hypoid Gears—Automotive differential gear system designed to lower the height of the passenger car by having the driveshaft pinion gear meet the axle gear at a point below the centerline. To mesh at this point the gears must have teeth in a shape which resembles a hyperboloidal curve. This causes the teeth to slide together with high friction as they mesh which makes lubrication of this type gear very critical.

Inhibitor—An additive substance which, when present in a petroleum product, prevents or retards undesirable changes taking place in the product, particularly oxidation and corrosion.

Isomerization—A refining process which alters the fundamental arrangement of atoms in the molecule. Used to convert normal butane into isobutane, an alkylation process feedstock, and normal pentane and hexane into isopentane and isohexane, high-octane gasoline components.

Isomers—In petroleum, different compounds composed of the same amounts of carbon and hydrogen but differing in physical properties owing to variation in molecular structure.

Kinematic Viscosity—The absolute viscosity of a liquid (in centipoises) divided by its specific gravity at the temperature at which the viscosity is measured. See Viscosity.

Knock—The sound, or "ping," associated with the autoignition in the combustion chamber of an automobile engine of a portion of the fuel-air mixture ahead of the advancing flame front.

Lead—Industry parlance for the motor fuel antiknock additive compound tetraethyl lead.

Lead Susceptibility—The increase in octane number of gasoline imparted by the addition of a specified amount of tetraethyl lead.

Linear Programming—Instructing a computer in mathematical language to perform some action under certain conditions.

Lithium-base Grease—A lubricating grease prepared from lubricating oil and a lithium soap.

Lube Stocks—Refinery term for fractions of crude petroleum of suitable boiling range and viscosity to yield lubricating oils when further processed and treated.

Mercaptans—Compounds of sulfur having a strong, repulsive garliclike odor. A contaminant of "sour" crude oil and products.

Metal Deactivators—Organic compounds sometimes added to gasoline to suppress or overcome the tendency of metal compounds in the gasoline to form gum. The metal compounds result from copper-treating the gasoline or from other catalytic metals.

Methyl Ethyl Ketone (MEK)—Colorless liquid obtained from petroleum derivatives. A component of a solvent used in dewaxing lubricating oils, also as a chemical intermediate.

Microcrystalline Wax—Plastic, high melting point petroleum wax obtained by removing most of the oil from petrolatum by solvents or other means.

Mineral Oil—Generally speaking, referring to the wide range of products derived from petroleum and within the viscosity range of products spoken of as oils.

Motor Octane Number—An expression for the antiknock value of gasoline. Accepted as the guide of antiknock quality under high engine speed or heavy load conditions.

Naphtha—Liquid hydrocarbon fractions, generally boiling within the gasoline range, recovered by the distillation of crude petroleum. Used as solvents, dry-cleaning agents, and charge stocks to reforming units to make high-octane gasoline.

Noble Metal—Metals that are chemically inert or inactive especially to oxygen. These include gold, silver, mercury, platinum, and palladium.

Octane Number—The antiknock quality of motor and aviation gasoline below 100 octane is expressed by a numerical scale which is based on the knocking tendencies of two pure hydrocarbons. One, normal heptane, has an assigned value of zero in the knock rating scale. The second, isooctane, has an assigned octane number of 100. In a standard engine laboratory test, the octane number of the fuel under test is the percentage by volume of isooctane in a blend with normal heptane that knocks with the same intensity as the fuel under test.

Octane Requirement—The octane number of the reference fuel used in an engine test of a motor fuel which produces a barely audible knock.

Olefins—A class of unsaturated (hydrogen-deficient) paraffinic hydrocarbons recovered from petroleum, of which butene, ethylene, and propylene are examples.

Oxidation—The process of combining substances with oxygen, generally taken from the air. All petroleum products are subject to oxidation.

Paraffin—A white, tasteless, odorless, chemically inert, waxy substance obtained from some petroleum oils.

Paraffin Distillate—At ordinary temperature a crystalline product ready for pressing which serves as the base for paraffin wax and paraffin oils.

Phenol—White crystal solid made by oxidation of cumene or from benzene. Used in manufacturing phenolic resins, weed killers, solvents in petroleum refining, synthetic detergents, chemical intermediates.

Photochemical Smog—An atmospheric condition of heavy fog caused by the reaction of chemicals in the presence of sunlight (radiant energy).

Polymers—A product of the polymerization of normally gaseous olefin hydrocarbons to form high-octane hydrocarbons in the gasoline boiling range.

Polymerization—The process of combining two or more simple molecules of the same type, called monomers, to form a single molecule having the same elements in the same proportion as in the original molecule but having different molecular weights. The product of the combination is a polymer. The combination of two or more dissimilar molecules is known as copolymerization. The product of this combination is a copolymer.

Pour Depressant, Pour Point Depressant—An additive which lowers the pour point of a lubricating oil. Also pour point inhibitor.

Pour Point—The lowest temperature at which an oil will pour or flow when chilled, without disturbance.

Raffinate—In solvent refining, that portion of the oil which remains undissolved and is not removed by the selective solvent.

Reference Fuel—A standard fuel used in testing performance quality of fuel products.

Refluxing—In fractional distillation, the return of part of the condensed vapor to the fractionating column to assist in making a more complete separation of the desired fractions. The material returned is reflux.

Reformate—The high-octane product from reforming a naphtha.

Reforming—The mild thermal cracking of naphthas to obtain more volatile products, such as olefins, of higher octane values; or catalytic conversion of naphtha components to produce higher octane aromatic compounds.

Research Octane Number—An expression for the antiknock rating of a motor gasoline. Accepted as the guide to the antiknock qualities of fuels when vehicles are operated under mild conditions associated with low engine speeds.

Residual Fuel Oils—Topped crude petroleum or viscous residuums obtained in refinery operations. Commercial grades of burner fuel oils Nos. 5 and 6 are residual oils and include Bunker fuels.

Road Octane—A numerical value based upon the relative antiknock performance in an automobile of a test gasoline as compared with specified reference fuels. Road octanes are determined by operating a car over a stretch of level road or on a chassis dynamometer under conditions simulating those encountered on the highway.

RVP (Reid Vapor Pressure)—The method of measuring vapor pressure. See Vapor Pressure.

SAE Numbers—A classification of motor, transmission, and differential lubricants to indicate viscosities, standardized by the Society of Automotive Engineers. They do not connote quality of the lubricant.

Scale Wax—The paraffin derived by sweating the greater part of the oil from slack wax. It contains up to 6 percent of oil. Also called crude scale.

Shear—Rate of shear is the ratio of flow rate or velocity (of a lubricant) to the clearance between two parallel surfaces moving in opposite directions. For practical purposes, shearing stress may be considered as the pressure to cause flow and rate of shear as the rate of flow.

Slack Wax—Soft crude wax obtained from pressing paraffin distillate or wax oil.

Solid State Electronics—Low voltage electrical circuiting using transistor-type components. Very rugged and durable with no vacuum tubes or parts susceptible to vibration damage.

Solvent—A substance, usually a liquid, capable of absorbing another liquid, gas, or solid to form a homogeneous mixture.

Solvent Extraction—The process of mixing a petroleum stock with a selected solvent, which preferentially dissolves undesired constituents, separating the resulting two layers and recovering the solvent from the raffinate (the purified fraction) and from the extract by distillation.

Stability—In petroleum products, the resistance to chemical change. Gum stability in gasoline means resistance to gum formation while in storage. Oxidation stability in lubricating oils and other products means resistance to oxidation to form sludge or gum in use.

Stocks—Petroleum in storage, both crude and refined products; includes crude awaiting processing and products awaiting transfer to the point of utilization.

Succinimide—An organic compound combined with nitrogen used in the manufacture of lube oil additives. Chemically the compound is 2.5-diketopyrrolidine $C_4H_5O_2N$.

Sulfonates—A group of petroleum hydrocarbons resulting from treating oils with sulfuric acid. Used as synthetic detergents, emulsifying and wetting agents, and chemical intermediates.

Surfactant—A substance which, when in a pesticidal formulation, imparts emulsifiability, spreading, wetting, dispersibility, or other surface-modifying properties.

Sweetening—The process of improving petroleum products in color and odor by converting the undesirable sulfur compounds into less objectionable disulfides with sodium plumbite or by removing them by contacting the petroleum stream with alkalies or other sweetening agents.

Synthetic Detergents—Liquid or solid materials capable of dissolving oily materials and dispersing or emulsifying them in water. Petroleum sulfonates are examples of synthetic detergents.

Synthetic Lubricants—A group of products, some of which are made from petroleum hydrocarbons, natural gas, or refinery gases, which are used as oils or lubricating greases where heat, chemical resistance, and other requirements can be better met than with straight petroleum products.

TCP, Tricresyl Phosphate [$PO(OC_6H_4CH_3)_3$]—Colorless to yellow liquid used as a gasoline and lubricant additive and plasticizer.

TEL, Tetraethyl Lead [$Pb(C_2H_5)_4$]—A volatile lead compound which is added in concentrations up to 3 cc. per gal. to motor and aviation gasoline to increase the antiknock properties of the fuel.

Thiophosphates—Lube oil additives formed by the combination of sulfur and phosphorus. Usually P_2S_5, phosphorus pentasulfide, sometimes called phosphoric sulfide, phosphorus persulfide or thiophosphoric anhydride. These additives are usually supplemented by more conventional additives, i.e., barium salts.

TML, Tetramethyl Lead [$Pb(CH_3)_4$]—A highly volatile lead compound added to motor gasoline to reduce knock. May be used alone or in mixtures with TEL.

Topped Crude—A residual product remaining after the removal, by distillation or other artificial means, of an appreciable quantity of the more volatile components of crude petroleum.

Topping—The distillation of crude petroleum to remove the light fractions only.

Trace Contaminants—Impurities present in such small concentrations that conventional analytical methods cannot measure their quantity.

Trimer—A molecule formed by union of three simpler molecules of the same compound.

Unsaturates—Hydrocarbon compounds of such molecular structure that they readily pick up additional hydrogen atoms. Olefins and diolefins, which occur in cracking, are of this type.

Vacuum Distillation—Distillation under reduced pressure, which reduces the boiling temperature of the material being distilled sufficiently to prevent decomposition or cracking.

Vapor Lock—The displacement of liquid fuel in the feed line and the interruption of normal motor operation, caused by the vaporization of light ends in the gasoline. Vaporization occurs when the temperature at some point in the fuel system exceeds the boiling points of the volatile light ends.

Vapor Pressure—The pressure exerted by the vapors released from an oil at a given temperature when enclosed in an airtight container. For motor gasoline a criterion of vapor-lock tendencies; for light products generally an index of storage and handling requirements.

Virgin Stock—Oil processed from crude oil which contains no cracked material. Also called straight-run stock.

Visbreaking—Lowering, or breaking, the viscosity of residuum by cracking at relatively low temperatures.

Viscosity—The measure of the internal friction or resistance of an oil to flow.

Viscosity Index (V. I.)—A scale showing the magnitude of viscosity changes in lubricating oils with changes in temperature.

Volatility—That property of a liquid which denotes its tendency to vaporize.

Wax—A term used loosely for any of a group of substances resembling beeswax in appearance and character and, in general, distinguished by their composition of esters of the higher alcohols and by their freedom from fatty acids.

Yield—In petroleum refining, the percentage obtained of product or intermediate fractions of the amount of crude charged to the processing operation.

Zeolitic Catalyst—A porous cracking catalyst base having very uniform size pores. Usually sodium or calcium aluminosilicate.

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