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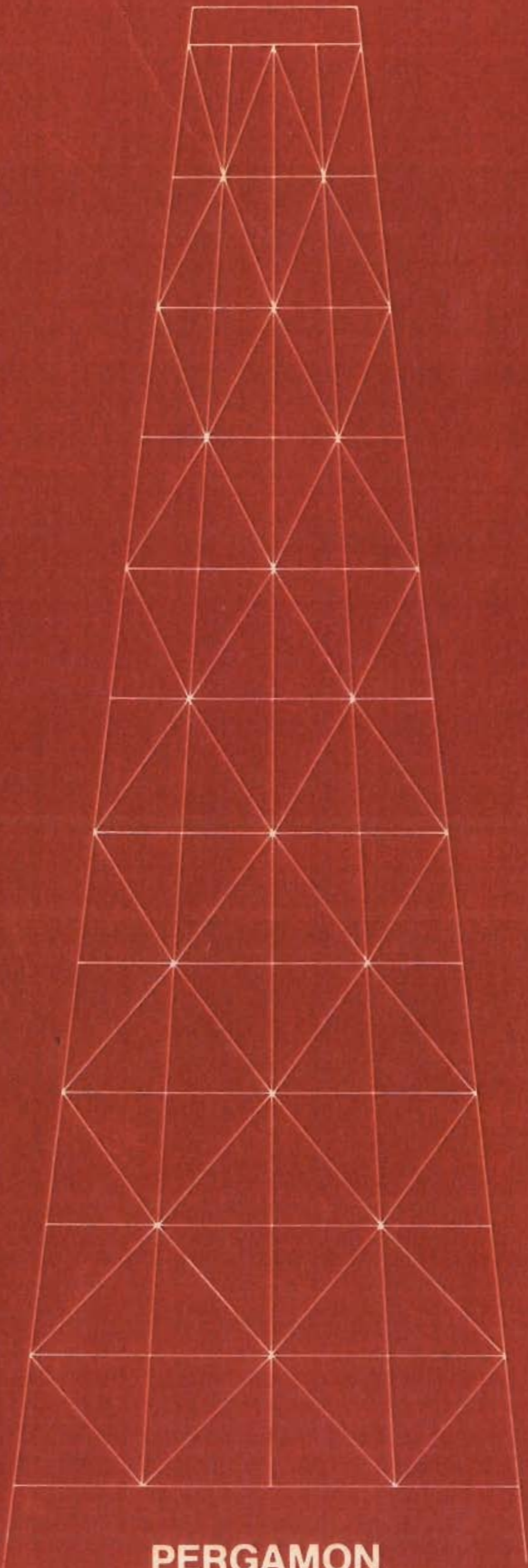

THE FUTURE SUPPLY OF NATURE-MADE PETROLEUM & GAS

A Conference Jointly Organized as
First UNITAR Conference on Energy and the Future
Second IIASA Conference on Energy Resources

5-16 July 1976 Laxenburg, Austria

PERGAMON

The Future Supply of Nature-made Petroleum and Gas Technical Reports

An International Conference Sponsored by
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As

The First UNITAR Conference on Energy and the Future
and
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5-16 July 1976
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J. Barnea and M. Grenon
Scientific Secretaries

R.F. Meyer
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FOREWORD

Philippe de Seynes[1]

The topic of energy is so central to the world predicament that no institution looking at the future or at the complex interactions of global problems can fail to deal with it in one or the other of its aspects. IIASA, as a major exponent of systems dynamics, an approach to problem solving which seeks to broaden the traditional information base and to delve into the complex structure of the policy-making process, and UNITAR, as an arm of the United Nations, which has recently initiated a Programme of Future Studies, largely oriented toward the creation of a New International Economic Order, are currently devoting to energy a substantial part of their efforts. The papers reproduced in this volume were presented at a conference jointly organized by these two institutions and held in Laxenburg from July 5 to July 16, 1976.

During the early 1970's, the attention of the world was focused, as never before, on the problems of natural resources and energy. Both the new strategy of OPEC countries and the dramatic warnings of the Club of Rome, induced governments and private institutions to take a hard look at the long-term availability of natural resources. As the world awakened to the notion of "physical limits" and the "carrying capacity of the planet," many took a big leap toward sweeping conclusions on the basis of scanty data and inadequate understanding of empirical relationships between various phenomena. Thus, hasty generalizations may already have been translated, at least marginally, into public policies or investment decisions.

Yet, in the context of the high level of controversy which accompanied the launching of Limits to Growth[2] in 1972, it became clear that the findings of global computerized models could hardly be invoked for policy guidance unless the empirical

[1]Director, Programme of Future Studies, UNITAR.

[2]Meadows, Dennis L., and Donella H., Limits to Growth. Report to the Club of Rome (MIT, Cambridge, Mass., 1972).

knowledge on which they were built was significantly improved. It appears at this stage essential to probe current hypotheses and evaluations regarding supplies of depletable resources, and to make a serious attempt to come closer to a consensus in this regard. It seems particularly timely to look at Nature-Made Petroleum and Gas, as the recent sharp increase in prices could not fail to enlarge significantly the volume of resources recoverable under the new economic conditions. Oil and gas are unique resources which alone among energy sources can be used for all purposes, and there was a certain confidence on the part of the two organizations sponsoring the Conference, that its future is brighter than is currently admitted in most of the pronouncements about the future of energy.

With the availability of a variety of unconventional sources of petroleum and gas, the "age of petroleum" may be considerably extended--nature-made hydrocarbons may play a most important role in the difficult transition to a new energy economy, hopefully based on renewable resources. The conditions under which such a transition will be managed are today raising momentous issues: For almost a quarter of a century nuclear energy had been seen in many circles as the natural successor to petroleum and gas. But the perspective of the proliferation of atomic reactors is now generating a widespread and deep "malaise" as the assumptions in regard to safety and costs on the basis of which the nuclear option had been so widely supported, are increasingly challenged.

The Conference was conceived and convened as a technological encounter, bringing together outstanding experts to compare their experience and knowledge and to explore the present "state of the art," in relation to the totality of known petroleum and gas resources and their future availability in the light of new technologies, as well as time and cost constraints. While the Conference did not answer all questions involved in the search for alternative energy sources, it was able to draw a comprehensive picture in regard to petroleum and gas, and it represents a useful "building block" in the vast effort on which mankind is now embarked.

Furthermore, the discussions revealed a number of broader problems which directly condition the development of new resources and which policy makers should now begin to tackle vigorously. The institutional frameworks within which new endeavors in the field on energy resources are taking place do not appear to afford the optimum context in which early breakthroughs can be expected. One striking aspect of the present situation, which became obvious at the very outset of the Conference and was confirmed during its 2 weeks of deliberations, is the lack of communication in regard to Research and Development. Experts in some 20 types of oil and gas resources were apparently meeting for the first time in an international gathering. This state of affairs is not solely due to a certain inertia or to the natural compartmentalization of Research and Development activities. The principle of confidentiality conditions public as well as private enterprises when new and innovative technologies are at stake. Its importance must be recognized, and in the light of the achievements of the last quarter century, it could hardly be said that it has thwarted technological progress. Yet, in the face of possible scarcities, it must also be acknowledged that a strict application of the principle results in a needless multiplication of inherently large expenditures and in the inevitable lengthening of the lead time necessary for the maturation of new technologies. New ways of combining cooperation and competition seem to be called for. Indeed, the institutional system for Research and Development is already visibly changing and becoming more diversified. The rapid build-up of the Energy Research and Development Administration in the United States, for example, may epitomize a new trend.

This is only one aspect of the broader question anxiously asked today in so many quarters: whether and how Research and Development should be more efficiently oriented toward the basic needs of mankind. The market does not give reliable signals when there is great uncertainty about available resources and when environmental considerations significantly influence the decision-making process. One may then well wonder what there is in the past and present institutional arrangements, or in the behavior of the techno-structures which has caused, for so long, a serious imbalance in Research and Development programs, with their heavy concentration on nuclear power.

The international aspects of the energy problem must also be faced. Those nations best equipped financially and technically to conduct Research and Development on new types of resources are not those most in need of them. They have other cards to play. Yet the rise in energy prices imposes an increasing burden on the already strained balance-of-payments of many small and less developed countries. The case for international programs of Research and Development, as well as training on a broad scale, would appear to be overwhelming.

New dimensions and complexities are constantly being imparted to the ancient effort of mankind to elicit from this planet the means of survival and the achievement of steady progress. In the field of resources, as in many others, one of the answers is to explore and delineate alternative paths. It is important for many countries at various stages of development, and it is fundamental for those of the Third World nations which live on a dismally small and precarious margin of resources, that the range of options open to them be widened and that the technologies appropriate to their conditions be developed.

This is the vast problem to which the UNITAR/IIASA Conference on Nature-Made Petroleum and Gas attempted to give a very partial answer. In so doing it may hopefully have laid the ground for future encounters designed to assist in the advancement of knowledge and understanding. The two sponsoring organizations are deeply indebted to all the participants, whose contributions were of very high quality, and to the academic and governmental institutions which greatly assisted in making the Conference a success. A special word of gratitude is due to Dr. Richard F. Meyer of the U.S. Geological Survey who undertook the formidable task of editing an impressive number of difficult technical papers in a very short period of time.

PREFACE

Michel Grenon[1]

Looking at long-term energy perspectives--say 50 years or more--we must hope that energy consumption will continue to grow on a global basis to match a growing world population as well as provide a more equitable distribution between the various individuals within the nations and the world. Although forecasting this energy demand is essentially a difficult task, reasonable projections arrive at a possible global consumption of maybe 20 or 40 x 10^9 tons of oil equivalent per year at equilibrium in a few decades, compared to about 5.5 x 10^9 tons of oil equivalent today. At such levels, present known reserves of oil and gas would hardly last more than a very few years and known coal reserves, although much greater than hydrocarbon reserves, would, at best, last for a few decades. Hence, in such a long-term perspective, it will be mandatory to shift some day to non-fossil resources. Four of these have been identified: nuclear fission, nuclear fusion, solar energy, and possibly geothermal energy. But none of these new energy resources is fully ready to be applied on such a broad scale, and the transition will necessarily take time.

One of the characteristics of these new energy resources will be to impose enormous changes on all our energy industries, not only at the primary production level but at all levels, from the conversion to the transportation and to the final utilization. In this connection, a very important question is: How long, in fact, could or must the transition period last, and what is the potential of being able to rely for as long as possible on oil and gas resources during this transition period because of their astounding adaptability to our industrial societies as well as for new developing societies?

One possibility to so extend the "oil era" is to utilize "unconventional" oil and gas resources, which are indeed

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[1]IIASA, Laxenburg, Austria.

plentiful, from enhanced recovery of oil to oil shales or tar sands, from gas in tight formations to geopressured zones or the "mysterious" gas hydrates. The few studies--mostly in the United States, where the oil and gas situation is becoming more and more severe, but also where the most expensive technological know-how is capitalized--already published previously to the IIASA-UNITAR Conference have shown that these additional resources have a very attractive potential. But unfortunately, they are, up to now, very badly known, a statement which is also true, generally, for many, if not all the energy resources.

The Energy Program of the IIASA is devoted to such a study of long-term energy alternatives. The Resources group, in the Energy Program, is especially concerned with the assessment of energy resources, and with the systems aspects of their harvesting. It was natural, therefore, within the framework of annual conferences,[2] to devote this second IIASA Conference on Energy Resources to the possible future supply of nature-made oil and gas, and to organize it jointly with UNITAR, which has similar interests.

The various contributions and the extensive discussions during the IIASA-UNITAR Conference confirmed the high potential of the numerous additional hydrocarbon resources, but also highlighted the difficult problems which have to be resolved before their possible harvesting. The most urgent problems are probably posed by the requirements for much more exploration and a true assessment of the resources on a global scale. It is doubtful whether these resources are exclusively concentrated in North America and in the Soviet Union, where they have been generally identified. But confidence in this fact is not sufficient for us to be able to speak of them as valuable global energy options for the future. Many of these resources have been geologically "surmised" or found--but not really identified <u>and</u> measured, and

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[2]The first IIASA Conference on Energy Resources was held in May 1975 in Laxenburg, Austria, and was concerned with models and methods for assessing energy resources (Proceedings available from IIASA). The third Conference, on coal resources, is planned for the end of 1977 and will probably be held in the Soviet Union.

considerable work remains to be done. Their potential and their prospects, their possible role on the energy scene, together with the availability of more and more sophisticated exploration tools (such as remote sensing by means of earth satellites) are important factors which, hopefully, will positively and decisively influence future exploration programs.

But the problems of harvesting such resources are also so considerable that they almost lend a new dimension to the energy situation. Many of these resources, such as some oil shales or gas in geopressured zones, are, at the same time, scattered and known to exist in giant, even supergiant, deposits of the size of the "Ghawar" fields. This means that their extraction will interfere on a major scale with the other natural resources, surface water and underground water resources, land and other mineral resources (through various materials requirements) and, of course, will also require large amounts of manpower. Let us just mention that in order to explore these problems in detail, an analytical method of analysis of the impacts on natural resources has been developed at IIASA and is called the WELMM approach (standing for Water, Energy, Land, Materials, and Manpower analysis). Such a method seems well suited to a comparison between these various additional oil and gas resources, or to such other resources as coal, uranium, and solar. In this respect, the IIASA-UNITAR Conference provided some highly valuable pieces of information.

It is somewhat paradoxical, during a period of energy crisis, to speak of abundance, possibly over-abundance of energy resources (and even of oil and gas resources. . .). But we are convinced that the bottleneck lies not at the level of the occurrence of the resources in the ground, but more and more in their institutional aspects, whether economical, environmental, or political.

One obvious conclusion of the IIASA-UNITAR Conference was the growing awareness of the necessity to deal with these energy matters, and especially with these so very promising additional oil and gas resources, on an international basis. The wish to develop one or another on a purely national scale could fairly well result in the fact that none of them will be finally developed, and will thus remain in the ground forever.

LIST OF SYMBOLS, ABBREVIATIONS, AND CONVERSION FACTORS

Atmospheres	at	in x 2.540 = cm
British thermal unit	Btu	cm x 0.394 = in
Centimetre	cm	ft x 0.305 = m
Cubic centimetre	cm^3	m x 3.281 = ft
Cubic foot	ft^3	ft^2 x 0.093 = m^2
Cubic foot x 1,000	MCF	m^2 x 10.764 = ft^2
Cubic inch	in^3	ft^3 x 0.028 = m^3
Cubic kilometre	km^3	m^3 x 35.315 = ft^3
Cubic mile	mi^3	mi x 1.609 = km
Degrees		km x 0.621 = mi
Celsius	°C	mi^2 x 2.590 = km^2
Fahrenheit	°F	
Feet, foot	ft	km^2 x 0.386 = mi^2
Hectare	ha	mi^3 x 4.166 = km^3
Inch	in	km^3 x 0.239 = mi^3
Kilometre	km	acres x 0.405 = ha
Metre	m	ha x 2.471 = acres
Mile	mi	barrels x 0.159 = m^3
Number	No.	m^3 x 6.290 = barrels
Parts per million	ppm	barrels x 0.134 = tonnes of oil (36° API)
Pound	lb	
Pounds per square inch	psi	tonnes x 7.454 = barrels of oil (36° API)
Specific gravity	s.g.	
Square foot	ft^2	at x 14.696 = psi
Square inch	in^2	
Square metre	m^2	
Square mile	mi^2	
Square kilometre	km^2	

1,000,000,000,000 = 10^{12} (trillion)
1,000,000,000 = 10^9 (billion)
1,000,000 = 10^6 (million)
1,000 = 10^3 (thousand)
100 = 10^2 (hundred)
10 = 10^1 (ten)
1 = unity

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R. F. Meyer and C. R. Hocott

INTRODUCTION

In studying the papers in this volume on nature-made petroleum and gas it is evident that the emphasis is on exploration and extraction. This points the way to certain broad conclusions:

1. There is no dearth of petroleum and natural gas resources remaining in the earth. As a matter of fact, there is no foreseen shortage of available supplies by present technology until well into the next century. Such supplies exist in every portion of the globe. There are distribution and dislocation shortfalls in numerous places, however, brought on by economic, institutional, and political forces. It is anticipated that these forces will lessen over the short- or mid-term.

2. There are on the horizon new emerging technologies in various stages of readiness which can bring about a major expansion of the potential resource base of the naturally occurring hydrocarbons from conventional sources. Also, there are vast untapped basins around the globe which, by reason of geologic history, should be petroliferous and can likewise extend the potential petroleum resource base.

3. Further, there is a huge potential for additional resources of these hydrocarbons in unconventional sources widely distributed over the face of the earth. At the present time, these sources contribute very little to world production and are best known in intensely explored countries. Examples include the heavy-oil sands of Canada and Venezuela, the tight gas sands of the United States, and the oil shales of France, the USSR, and the USA. There is, however, nothing to suggest that similar deposits will not be found in less explored areas in the future. All nature-made oil and gas deposits are the result of geological processes and are not geographically unique.

4. Petroleum extraction technology, like that of every other natural raw material, has always recovered, first, the easiest to reach and least expensive. However, as with other

resources, advancing technology has kept pace with the supply-demand forces except where nontechnological barriers have interfered.

Having stated these conclusions it is essential to bear in mind that a great many things are not considered in detail in this publication. These include the following.

Only a few of the papers develop the economics of exploration, production, and competitive energy sources. Thus, nature-made petroleum economics will be included with the publication of the Proceedings of the Conference at which the papers in the present volume were given.

A further deterrent to full commercial application of high technology resource development in meeting future requirements will be the lack of adequate expert professional manpower. Skilled labor supply will also be short, but technical manpower availability promises to be acute. This is a problem for all concerned but must receive particular attention from both industry and the universities, probably cooperatively.

Additional constraints to nature-made petroleum development will arise from shortages of equipment and chemicals. The latter constraint is mainly applicable to oil recovery and is treated for the U.S. example in Chapter 35. Equipment shortages result from equipment being mislocated geographically, in short supply by type required, and inadequately engineered for new technologies. In all cases equipment and chemical shortages are exacerbated in developing countries.

Although most of the papers devoted to unconventional types of deposits essay attempts to estimate resource levels, this is not true for conventional oil and gas deposits. Estimates are available world-wide for proved reserves and past production but only rarely for subeconomic and undiscovered resources. This is a matter of great importance that deserves a much higher level of priority among petroleum scientists.

The question of environmental constraints was not the subject of any particular paper, although it is considered in some chapters. Such constraints are real and require the strictest attention but perhaps could best be addressed at a separate conference. Few scientists in any country denigrate the importance of environmental concern for petroleum and gas operations but all too often this concern does not find proper expression in presentations to the lay reader. It is evident that the conclusion of the nature-made petroleum and gas energy economy lies at most a half-century away; great care must be exercised not to leave a legacy of environmental disruption for future generations to repair.

At the same time it is evident that nature-made petroleum resources are large--sufficient to permit the world a smooth transition to alternative energy sources. This time must be used to best advantage and not squandered for short-term objectives.

A final consideration must be borne in mind when studying the deposits described for convenience as unconventional. In most cases it will be noted that they are not unconventional in occurrence but present special reservoir-engineering problems related to recovery. The special consideration with respect to these deposits is that of producing capacity. Thus, the total amount of potentially recoverable methane in coal seams in the United States may be as much as 800×10^{12} ft^3 but this gas is at low pressure and will not yield flow rates per well comparable to conventional gas fields. Similarly, the great oil sand occurrences in Canada contain about 1×10^{12} barrels of oil but this oil cannot be produced at rates at all comparable to conventional oil fields because the sands must be mined and retorted, except where in situ extraction is feasible, in order to extract the bitumen content. Therefore, caution must be exercised in equating the quantity of resource known to be in place with the available supply of resource.

CONVENTIONAL OIL AND GAS

This volume is comprised of 57 chapters arranged in nine sections, plus one appendix. Section I, five chapters, deals with world perspectives on the exploration for conventional petroleum deposits and their occurrence. A significant point is raised in Chapter 2 with respect to the relative paucity of drilling in the world outside of the United States. It is, after all, only by drilling wells that the presence or absence of petroleum and natural gas can be proved. An interesting perspective on the cost of drilling for gas relative to the cost of obtaining it as synthetic gas from coal can be gained if the common estimate of $1 x 10^9 is taken for an SNG plant (including mine). It should be considered that this operation, which would yield 250 x 10^6 ft^3 of gas per day, is both labor- and materials-intensive. The plant would be equivalent to recoverable reserves of 2.7 x 10^{12} ft^3 of gas, given a 30-year plant life. This in turn would be equivalent to 3.7 x 10^{12} ft^3 of recoverable conventional gas reserves, at 250 x 10^6 ft^3 per day over 40 years (10-year remaining supply after the same 30-year period). Thus, 1,000 gas wells could be drilled at $1 x 10^6 each to find the amount of gas equivalent to the SNG plant; allowing for dry holes and for risk, as well as credit for any oil found. This is obviously a viable alternative in most areas of the world, including the USA.

Section II and the appendix are devoted to discussions of resource appraisal methods and classifications of reserves and resources. Only the classification scheme used in the USSR is presented in detail (see also Modelevsky and Pominov, 1976, for greater detail). This classification appears not to differ fundamentally from those used in other countries but is rendered difficult to correlate because (1) terms used are not explicitly defined; (2) the differences between the terms reserves and resources are unclear; and (3) only in the table headings (Table 7-3; Modelevsky and Pominov, p. 126) are resources and reserves expressly stated as recoverable. A current U.S. classification is given in Figure S-1, from U.S. Federal Power Commission (1977). This classification is essentially identical with that adopted by the Definitions Committee of the Petroleum Resource Estimation Project of the American Association of Petroleum Geologists, a project still in progress.

It appears that the most likely reconciliation of the two schemes would be as follows. Proved reserves: the recoverable parts of A plus B (step outs); indicated reserves: the recoverable part of C_1 (extension wells plus deeper reservoirs tested by at least one well) plus C_2, the parts of the deeper reservoir in C_1

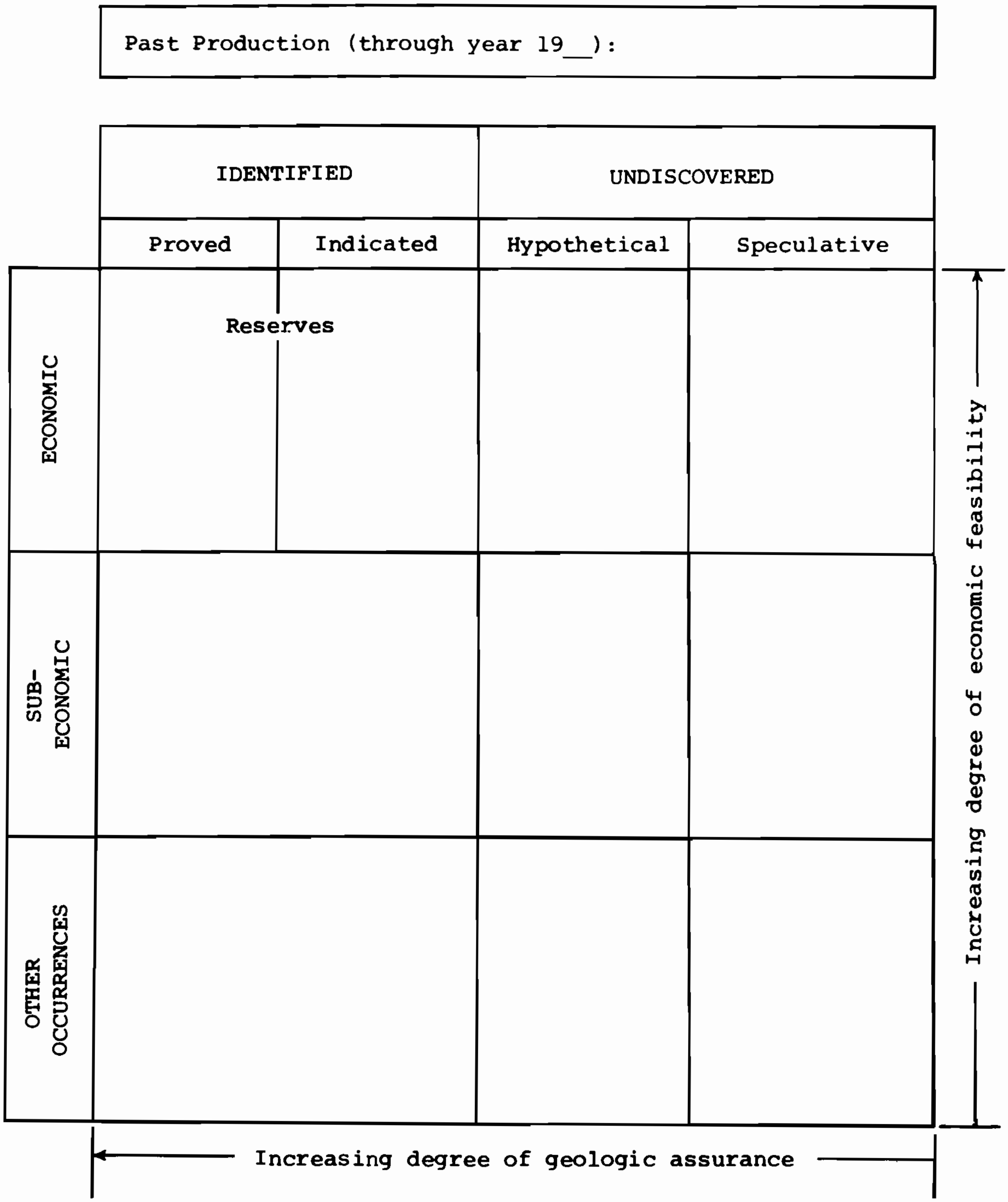

Figure S-1.--Remaining petroleum and natural gas resources of the United States, as of as yet untested by wells, and parts of a structure separated from the drilled part by a saddle; hypothetical resources: D_1; and speculative resources: D_2.

The category of Subeconomic Resources would include the noncommercial reserves of A, B, and C_1; the Soviets do not single out noncommercial reserves for other categories. The Soviet scheme does not take into account the U.S. category of Other Occurrences, which, in the case of conventional oil and gas fields, includes the balance oil-in-place not placed in the categories of Economic and Subeconomic. Furthermore, the system of the USSR does not allow a separate category for the additional oil to be recovered by enhanced recovery methods, presumably because the Soviet engineers institute such methods from the beginning of production and do not distinguish the production.

The 11 chapters in Section III all are devoted to aspects of conventional oil and gas deposits--those recoverable by techniques in common use world-wide. Chapter 15 is concerned with the importance of small deposits, a concern also expressed in Chapters 4 and 6. In more maturely developed areas it is becoming increasingly difficult to locate giant fields but the aggregate contribution of small deposits must not be overlooked as a worthy target for future exploitation. Chapter 19 describes possible future technologies for developing production of oil and gas in water deeper than the usual 200 m depth. If the important offshore areas described in Chapters 5 and 12 are to be exploited, then adequate production technologies must be evolved.

Section IV, on enhanced oil recovery, is comprised of 13 chapters, the most devoted to a single subject. One of these, Chapter 35, describes constraints on future recovery because of materials requirements--sulfonates, CO_2 gas, polymers, alcohols, and the like. Two chapters attempt to clarify the terminology of enhanced recovery operations, and the others describe secondary and tertiary recovery techniques and thus possibilities for increasing future crude oil supplies. One chapter, 27, explains enhanced oil recovery techniques and procedures in the Soviet Union.

The following discussion describes the general conclusions of the sections related to conventional oil and gas deposits.

The Nature and Origin of Petroleum

Although small quantities of a few hydrocarbons of obvious inorganic origin are found in nature, there seems to be little doubt that the bulk of the huge quantities of complex hydrocarbon mixtures found in the petroleum accumulations of the earth are of organic genesis. Most of the petroleum consists of complex mixtures of molecules containing only carbon and hydrogen and existing in two homologous series of hydrocarbons: aliphatic, with a basic straight chain structure, and aromatic, with a closed ring structure. The aliphatics are present in all crude oil, with molecular structures ranging all the way from methane (along with other lower-boiling components existing as dissolved gases) to the high molecular weight, heavily branched paraffins (which are dissolved waxes). When these compounds predominate, the crude is referred to as paraffin-base and has a maximum content of hydrogen.

The crude is referred to as asphalt-base when aromatic constituents are present in a high proportion of the crude volume. The components include saturated ring compounds, starting with cyclopentane, and, usually, unsaturated rings, starting with the familiar benzene and going up to very high-boiling naphthenes. The chemistry of these components determines the physical properties of the petroleum and therefore must be considered in their recovery from the reservoir as well as during later refining into a variety of petroleum products.

Of course, when the low-boiling petroleum hydrocarbons, particularly methane, predominate, petroleum exists in the earth not as crude oil but as natural gas. Existing at high pressures and temperatures in the reservoir, these natural gases may contain significant quantities of the higher-boiling components commonly referred to during production as condensate. When the low-boiling hydrocarbons are essentially absent, crude petroleum may exist as such extremely viscous liquids or solids as natural tar and asphalt.

Organic compounds usually present in crude oil in varying amounts contain within their molecular structures sulfur, oxygen, or nitrogen and metal atoms such as vanadium, iron, or nickel. These provide fingerprints which serve to confirm the organic genesis of petroleum. Nonhydrocarbons such as carbon dioxide, hydrogen sulfide, and ammonia are also frequently included in the petroleum mass.

Most organisms generate small quantities of petroleum in their metabolic processes. Certainly enough such hydrocarbons have been generated in this fashion throughout the earth's history to account for all the petroleum found today and more. However, most of these hydrocarbons, together with other organic matter, are destroyed by aerobic bacterial action; only a small fraction of this organic debris is deposited and buried with sediment in the bays, marshes, and seas of marine or shore-line environments. It seems most plausible that some of this vast supply of organic matter--the lipid fractions--is there transformed, by subsurface heat and pressure under anaerobic conditions, into petroleum, to become available for later migration into petroleum accumulations. Generally, petroleum is postulated to have formed almost exclusively from the lipid fractions of the organic debris.

The Migration and Accumulation of Petroleum

The preponderance of the evidence leads to the conclusion that the organic progenitors of petroleum, together with the fine-grained inorganic debris of the continents, form the shales and mudstones which are the source beds of oil and gas. Although a small fraction of petroleum may have been generated in the more porous or nonclastic rock, most seems to have been formed in these fine-grained source beds following deeper burial and maturation. Heat is thought to be the major source of energy responsible for the transformation of the lipids into petroleum.

Under the pressure attendant deeper burial and consequent compaction, the hydrocarbons are expressed from the source beds into adjacent porous sandstones and limestones, where they are free to migrate under the forces of gravity and thermal diffusion into the geologic traps formed during the sedimentary and structural geologic history of the subsurface rocks. This permits the classification of the traps as stratigraphic, structural, or a combination of the two.

Although there is no reason why petroleum cannot migrate over long distances prior to entrapment, such movement is not required and most gas and oil are thought to have been formed in close proximity to their present location. Similarly, most accumulations are thought to have been transformed from organic matter to petroleum within the adjacent source beds. However, classic examples are known in which oil has migrated along faults associated with the subsequent tectonic history of the area into beds of much younger age. The most striking of these are cases of mixed accumulations of both younger and older oil within the same present-day reservoir.

Assessment of Petroleum Resource Potential

Although all marine deposits of the sedimentary basins of the world must be considered as prime targets for petroleum development, determination of the quantity and quality of source beds is considered essential to the classification of these basins with respect to resource potential. The presence of source beds, even with the uncertainties of their identification, is still one of the most reliable indicators of the resource potential of frontier areas, when coupled with identification of the presence and nature of reservoir rocks.

When these factors are known to be favorable, basin potential may be defined by numerous parametric and analogue techniques whereby unexplored areas are analyzed by comparison with explored and productive areas of similar character. These studies may be further refined by probabilistic methodologies, which necessitate studies of field-size distributions. Basin assessment and comparison have generally suffered from the lack of a commonly accepted methodology and a consistent terminology. Ideally one would like to construct a model based on quantifiable factors; and yet in many vast areas of the earth, knowledge of most of the necessary parameters does not exist in sufficient detail to permit precise assessment. Where geological and geophysical exploration has not been conducted and at least a few stratigraphic wells drilled, quantification of the required parameters for analysis is not possible and attempts at assessment of resource potential are highly speculative. There is a pressing need for a minimum of reconnaissance evaluation of the many readily accessible, potentially productive petroleum basins of the world, as well as some standardization of procedures. In any event, a dynamic model for resource assessment would seem to be indispensable for continual upgrading and revision, as additional facts become known and quantified data become available.

Although statistics suffer badly from lack of common definition and a consistent terminology, the amount of cumulative reserves developed to date, of the order of $1.5\text{-}1.8 \times 10^{12}$ barrels (Btu equivalent) of petroleum, is an adequate estimate for assessment purposes. Furthermore, the more speculative estimate that an equal amount may remain to be discovered is of sufficient magnitude to provide all the incentive that industry, nations, or society at large should need to stimulate exploration.

Compared with the vast untouched basins on the continents, the marine basins are in the infancy of development. The continental shelves have actually been tested in few areas--the continental slopes not at all. Sufficient work has been done to prove that favorable sediments and structures exist worldwide in these marine environments and already have yielded vast quantities of oil and gas. The future looks bright, challenging, and exciting.

Exploration for Petroleum Resources

The first step in exploration is that of basin identification. In the past this has been done by surface geologic mapping, including especially the search for surface manifestations of hydrocarbons. These signs include oil and gas seeps and natural asphalt or oil sand deposits. Next is is common to use reconnaissance geophysics--the airborne magnetometer and the gravimeter--to delineate broad geologic features of interest. In the past all these techniques were enhanced by the use of aerial photographs, both vertical and oblique, to find lineament and fracture zones not apparent on the ground. Now such surveys are enhanced or supplanted by various sorts of imagery obtained from earth-orbiting satellites, which show features, by color contrast, in a detail and on a scale never before believed possible.

When one approaches the problem of exploration in a prospective area, several avenues are available. The identification of structure in the subsurface has been the objective historically of much of the petroleum-exploration effort around the world. Since geologic traps are usually associated with structure, and both geological and geophysical methods are directly applicable for their detection, they remain the explorationists' basic preliminary tools. Where surface expression does not permit definitive geologic surveys, geophysics forms the sole basis for exploratory drilling.

In any event, penetration of the geologic column with the drill bit is the ultimate tool available for exploration. Maximum coring and core analysis, logging and log interpretation, along with correlation with geophysical records and geologic studies are prerequisite to optimal exploration in any frontier area. Even so, one must always be prepared for the unexpected. Some regions thought to be highly prospective have proved to be failures and, happily, the other way around. Success comes in oil finding from perseverance, as in others of life's endeavors.

Frequently, man has been phenomenally successful in finding major oil deposits early in an exploratory effort. The statement is often made that the giant fields are always found first, but this generalization will not stand up to careful study. Notable examples of the late finding of major reserves are the North Sea and Western Canada.

The apparent phenomenally early discovery of major fields seems actually to stem from the philosophy and policy of exploration in a frontier area. A commercial beginning in a new area strategically requires a certain minimum operation in order to justify moving in production materials, facilities, manpower, and the like. Consequently, the tactic of initially seeking only giant traps is the one adopted.

It seems reasonable to assume that, as the price of oil increases, the size of the minimal accumulation to justify moving into an area will decrease. In any event, once the base for production operations is established, the more numerous but smaller accumulations become economically attractive and these can add significantly to reserves. This leads to the conclusion that early exploration should be conducted so as to identify the smaller accumulations, even though they may not be developed in the absence of a major discovery and consequent establishment of gathering facilities.

Estimation of Petroleum Reserves

A vital function in a complete exploration program is the calculation of the quantity and distribution of the original oil-in-place in a newly discovered reservoir. It is true historically that the petroleum industry has been remarkably close in its estimates of reserves recoverable by conventional technology, but as recovery methodology moves into the realm of enhanced techniques it becomes doubly important to know not only that a significant quantity of oil remains in the reservoir after conventional recovery but where this oil resides in the reservoir. Much of this residual oil is geologically controlled and is confined to areas not accessible to the displacing fluids currently used and recovery patterns employed. Unfortunately, most of the world's fields are developed on the basis of geography and not geology. If, however, developmental wells are to be located and drilled to provide optimum access to the in-place oil, the subsurface geologic mapping of reservoirs must be improved. The stratigraphy, lithology, and structure must be finely delineated. Coring and logging of uniformly drilled, widely spaced wells alone will not provide the needed reservoir description. Detailed, quantified, three-dimensional reservoir maps must be prepared, based on information inferred from reconstruction of depositional environments, facies analysis, core analysis, log interpretation, detailed analysis of geophysical (primarily high-resolution seismic) records, and pressure discontinuities between wells, as determined by pulse and interference tests. When this is done early in the development of a field with widely spaced wells, in-fill wells may be placed for more complete displacement of the reservoir fluids. When this is done, not only should enhanced recovery techniques do a better job but conventional recovery should be improved.

Most of the reserve estimates in the United States today are based on average conventional recovery of 30-35 percent of the oil-in-place. Enhanced recovery technology now in the advanced research stage offers promise of increasing this recovery to 40-45 percent. Speculation on future enhanced recovery methods places recovery as high as 50-60 percent of the original oil-in-place. Such an accomplishment not only promises to increase the reserves of currently known fields, but greatly increases the reserve potential of oil from undiscovered deposits around the globe.

In the USSR there is little effort to distinguish primary and secondary recovery, so that average cumulative recovery tends to be in the range of 40-45 percent. It is therefore of greatest importance, when describing levels of recoverable reserves, to state the average recovery factor on which the estimates are based.

With present world crude oil reserves estimated at about 560-590 x 10^9 barrels, increasing the percentage recovery by 10 percent would add about 175 x 10^9 barrels of crude oil to world reserves. The reserves from future discoverable and recoverable resources would be similarly increased.

Status of Petroleum Recovery

Since the early 1930's reservoir engineering has been a mature though, of course, improving engineering science. Oil reservoirs discovered and developed during that period, with rare exceptions, have been produced by the most efficient known technology in a single-stage recovery operation. Where sufficient reservoir energy was not naturally available, it has been supplied by the injection of gas, water, or both to insure maximum efficiency of oil recovery. In the United States, however, most secondary recovery operations commenced after about 1941 and truly widespread application began about 1948.

Where the characteristics of the reservoir rock permit, there is no reason to presume that any significant future reserve will be produced without reservoir energy being augmented or assisted when sufficient energy is not naturally available for efficient recovery. Consequently, additional recovery in the future, beyond water flooding and pressure maintenance, will be confined to the more advanced, sophisticated, or exotic technologies commonly known today as tertiary or enhanced recovery.

Enhanced Recovery

Of the enhanced recovery technologies for oil, only thermal already has been developed to the stage of routine application. Steam injection by both cyclic and continuous-drive methods is commercially applied to the recovery of heavy oils. This technology alone has added significantly to world reserves and vastly expanded potential resources; it should find widespread application around the globe. In Venezuela alone about 4×10^{12} barrels of heavy oil are known to exist in the sandbelt of the Orinoco basin. In situ combustion technology is not so advanced as steam injection and still is hampered by such problems as corrosion and emulsion formation; however, it is well understood and should find ready application where reservoir characteristics are favorable.

The other enhanced recovery technologies now mature enough for commercial application are carbon dioxide and mobility-controlled (polymer-augmented) water flooding. Although much research needs to be done on the phase behavior and displacement characteristics of CO_2-crude oil systems, the method was applied as long as a quarter-century ago; and at least one major field in the United States is today under commercial CO_2 flood. The main hindrance to the application of either method is the availability of ample supplies of necessary materials.

Another widely publicized and intensely researched enhanced recovery technology relies on reduction of interfacial tension between residual crude oils and a surfactant displacing solution. Numerous variations of this physico-chemical technique have been proposed and tested and several are known to move oil and displace it effectively from those portions of the reservoir which are contacted. The results of field tests conducted to date would seem to show that a significant portion of the residual oil remaining after water flood is geologically controlled and resides in the nonconformance areas of the displacement pattern. Low-tension flood undoubtedly attains a lower pattern efficiency than other floods due to the lack of capillary forces and consequently, the technique still lacks full development for commercial application.

A significant problem in the commercial application of surfactant technology will undoubtedly be the availability of raw material. A figure of 10 pounds of surfactant per barrel of oil produced is commonly cited by those who have conducted field tests and manpower, material, and construction delays all pose serious problems. Production costs attributed to published surfactant field-test results range from $15 to $25 per barrel of crude oil.

UNCONVENTIONAL OIL AND GAS RESERVOIRS

Sections V through VIII are concerned with oil and gas occurring in what are termed, as a matter of convenience, unconventional deposits. In most cases the deposits differ from those in conventional reservoirs only in requiring special reservoir-engineering techniques to permit recovery.

The five chapters in Section V discuss the resources believed to be present in tight sandstones and shales, and the techniques to recover these resources. The permeabilities of tight sandstones are in the range of .001 to 1 md and of shales, less than .001 md. The exploitation of such tight formations becomes a matter of developing means for accurate resource assessment, locating areas within the strata where permeability and other reservoir conditions are appropriate, and then successfully fracturing the strata to permit production. The use of nuclear fracturing was tried and then abandoned in the United States for a variety of technological, cost, environmental, and sociological reasons. However, this technology has also been studied in the USSR, and experiments conducted are apparently large scale but the present status of this effort is not known. In the United States present efforts are now directed at a magnified version of conventional hydraulic fracturing known as Massive Hydraulic Fracturing (MHF). Very encouraging results have been obtained in at least one field, where it was found that large treatments--500×10^3 gallons of polymer emulsion and 1×10^6 pounds of sand proppant--yield a payout time for drilling and MHF costs only one-fifth as long as for small (50×10^3 gallons) treatment (Fast, et al., 1977).

Estimates of total resources of recoverable gas in the United States in tight sandstones are as large as 600×10^{12} ft^3 and in shales, 500×10^{12} ft^3. There are no available estimates of resources in other countries; it is obvious the U.S. occurrences are not unique because of the efforts at extraction undertaken by Soviet engineers. Furthermore, the tight formations represent a reservoir engineering problem in rocks of a type that are found in sedimentary basins everywhere.

In Section VI, three chapters are devoted to oil sands (tar sands), two to heavy crude oils in the United States, and three to oil shale. In all cases, the resources are very large indeed, amounting to trillions of barrels of oil, but the recovery technologies are almost equally imposing in their difficulty. These difficulties will be eased where in situ and surface-mining extraction can be applied, but in any case capital and environmental constraints will be severe and water availability may be.

Separating oil (tar) sands from heavy crude oils is an unresolved problem. Ideally the definitions should be based upon specific gravity (stated as degrees gravity API) and viscosity. Information on viscosity is not always readily available so that a convenient definition might consider crude oil heavier than 25^{o} gravity API as Heavy Crude and oil heaver than 7^{o} or perhaps 10^{o} as Oil Sand. Such a definition has the advantage of objectivity and therefore forms a basis for world-wide heavy crude oil and oil sand resource assessments.

Regardless, the heavy crude oil and oil sand deposits of Alberta, Canada, and Venezuela dwarf in magnitude other known deposits of this sort. The oil sand deposits of the United States in total amount to only a fraction of the resources of the giant occurrences and have been exploited only to a limited extent, mostly as road material. The only large-scale attempts to produce the crude oil content are associated with the Albertan oil sands. The resource potential world-wide, however, is enormous and probably not well known even today outside of the few areas listed in Chapter 41.

On the other hand, many heavy crude oil deposits are being developed today, especially by means of thermal recovery methods--steam, hot water, or in situ combustion. Examples are perhaps better known in the United States, as described in Chapters 33, 44, and 45, but obviously heavy-gravity crude oil reservoirs exist wherever oil is being exploited. Because of the indistinct boundary between normally produced and heavy crude oils, precise statistics are impossible to derive. A good indication of heavy oil possibilities can be seen in the fact that oil-in-place in identified reservoirs in the United States amounts to more than 400×10^9 barrels, yet this does not include as much as 150×10^9 barrels of known heavy crude oil deposits.

Oil shales were retorted in Scotland for many years to capture their contained oil. The technology has never been developed, however, to permit large-scale exploitation and the resultant necessary high producing capacity. There is hope that recent research advances in the area of in situ production will overcome many of the obstacles in the way of a viable industry. Such obstacles may include water requirements, mining and retorting technology, environmental concerns, and excessive capital investments. The oil shale resources are well defined in such countries as the United States, Brazil, France, and the western USSR. Large resources may and probably do exist elsewhere but have yet to be described.

Section VII is comprised of two chapters on the possibilities for exploitation of the natural gas resource of geopressured reservoirs. Such zones have long been known from conventional drilling experience. The amount of the natural gas resource appears to be staggering, with estimates as high as 49,000 x 10^{12} ft^3, or about 200 times U.S. presently proved reserves alone. It is also estimated that the gas is dissolved in the water in the amount of about 30 ft^3 per barrel, so that producing the gas will entail producing very large quantities of hot salt water. Production will also necessitate the cost of the water disposal, resolution of thermal pollution effects, and avoidance or mitigation of land subsidence. On the other hand, it may be possible to utilize the water for electric-power generation. The resource target is large, by any estimate, and research may yield ways to attain production of the gas and, perhaps, power generation, while overcoming the environmental concerns.

Section VIII is made up of five chapters directed to other possible sources of nature-made petroleum and gas. These include marsh and landfill gas (Chapters 51, 54, and 55) and methane occurring in the form of hydrates in permafrost areas and on the sea floor (Chapters 52 and 53).

Although large quantities of gas are generated in marsh areas, the means to exploit the gas resource are not obvious. It is not likely to contribute to energy supplies in the near future. Large quantities of gas also are generated in landfills and this sort of occurrence may be of local importance in the near future.

The occurrence of methane hydrates in cold climates and in the deep sea floor is well documented (Chapters 5, 52, and 53). The amount of the resource is not yet determined. The hydrates are crystalline, ice-like solids formed when certain light hydrocarbons and other low-molecular-weight, nonpolar substances are contacted with water (Verma, et al., 1975). The latticework of the hydrate consists of one gas molecule for each six water molecules and molecules larger than isobutane cannot fit in the lattice structure. The earliest work on gas hydrates was concerned with the build-up of such deposits in industrial gas-processing units. Soviet scientists described natural gas hydrates in Arctic areas in 1970 and speculated on their occurrence in oceanic basins earlier. Gas hydrates are commonly found in deep sea cores (Emery, Chapter 5). The fact of their occurrence therefore is no longer in doubt and their significance to exploitation in the Arctic is well documented; the resource is known to be very large but as yet not clearly defined. The extent of such occurrences on the sea floor, that is, the magnitude of the resource, is unknown; perhaps it will acquire further definition as sea floor exploration continues and the scientists involved are fully aware of the potential import of the resource, occurring as it does in the upper layers of sediment close to the water interface.

The sole known unconventional natural gas reservoir not specifically treated in this volume is the coal seam. In the United States alone it is estimated that 850 x 10^{12} ft^3 of methane may be present in shallow and deep coal beds. Of this amount, 300 x 10^{12} ft^3 is found in remaining identified seams, excluding strippable coalbeds, and with an average gas content of 200 ft^3 per short ton (U.S. Federal Power Commission, 1977). There can be no doubt that comparably large gas resources are to be found elsewhere in the world's coal basins, so long as the coal beds have not as yet been mined and a gas migration route to the surface does not exist.

TECHNOLOGY TRANSFER

The final section of the book, Section IX, contains two important chapters on the transfer of technology. Involved here is the exchange not only of technology but of people and ideas. This is of prime importance to the developing nations, which are as yet ill-equipped to provide for their materials requirements for resource exploitation, let alone for needed technological innovation. There is no question but what technology transfer is simpler in theory than in practice. The profit motive, which provides the incentive for technological innovation, is ill-served by a transfer working in one direction only.

RESOURCE RESUME

World consumption of petroleum products has increased 10-fold since 1940, 4-fold since 1955, and has nearly doubled since 1965. It is perfectly obvious from this that representations of petroleum reserves in terms of life indexes, or remaining years of supply, are meaningless. With present total world consumption at 20×10^9 barrels per year and reserves at 659×10^9 barrels, a 33-year supply appears to exist. But consumption is increasing much more rapidly than are new discoveries. It is time, therefore, to direct attention to possible new sources of nature-made petroleum and gas, and to improvements in recovery.

Attention will most obviously be directed to conventional deposits, employing every exploration technique known or under research. Important advances are expected in the interpretation of earth-satellite imagery, the bore-hole gravimeter, and geochemical detection of oil and gas. Price advances permit the exploitation--indeed, the exploration for--smaller deposits. Price, the great equalizer, the ultimate incentive in nearly all societies, will open doors to an enormous variety of exploitable petroleum and gas sources. The most obvious of these will be the oil-in-place in known reservoirs which requires production techniques more advanced than those now routinely practiced.

Of the deposits now considered to be unconventional, it appears that gas in tight sandstone formations and in the hydrated form in Arctic areas may be most amenable to early production. Oil sands are already in production in Canada and it appears that the technology for extracting the material is now sufficiently advanced to permit a viable industry. It will be very difficult, however, to develop a large producing capacity with present methods and this deterrent applies, as well, to shale oil, without a workable in situ recovery technology. In addition, there is already a modest production of methane from coal beds; this process receives added impetus from the need to degas the coal seams prior to mining.

Much further distant, technologically, is the possibility of production of gas from sea-floor hydrates and marshes. By the same token the fuel resources from these deposits and from geopressured formations are potentially so large as to require rethinking of the entire world energy economy. It would seem of critical importance to examine in particular the potential of the geopressured zones; the uncertainties are many but the possible rewards are such as to justify intensive scrutiny.

CONCLUSION

Review of the various chapters should substantiate the premises of the conclusions given in the introduction to this Summary. Unquestionably, there are extremely large quantities of petroleum and natural gas present in nature under various conditions, enough indeed to last for many years. But gaining these resources will not come easily.

A significant hindrance to the rapid development of additional reserves is the nontechnological barriers posed by environmental, political, and other societal issues. National policies in many countries seriously impede, if they do not prevent entirely, the development of petroleum supplies sufficient even for those countries' own internal requirements. It can hardly be expected that policies which inhibit--which, in fact, provide disincentives for exploration and development of conventional resources, will, at the same time, promote necessary research and development of less conventional resources.

Nevertheless, the needs for clean and safe energy sources are very great. The barriers to development are not insurmountable, and the future is hopeful.

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INTRODUCTION

THE FUTURE SUPPLY OF NATURE-MADE PETROLEUM AND GAS[1]

Joseph Barnea[2]

Two events in the last few years have, in the minds of many observers, raised the prospect of a scarcity of petroleum, namely, the publication of the study on "The Limits to Growth" and the emergence of an effective international oil producers group formed by the countries in the Organization of Petroleum Exporting Countries (OPEC). However, this fear of a scarcity of petroleum may be unfounded if we look into the future because there is a large variety of natural petroleum sources and, as the price of petroleum rises, the resource base expands.

This paper deals with the resource-base for nature-made petroleum from the viewpoint of supply, although long-term considerations will also have to take demand into account. The demand for nature-made petroleum is a separate, complex issue because demand is affected by price, by the development of alternative sources of energy, and by changes in end-use technology. Today, petroleum (in end-use technology) has no competition in air travel and shipping and only limited competition for car travel, railway transportation, and petrochemicals. Changes in energy end-use take place only slowly.

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[1]Definitions: The term <u>petroleum</u> is used to refer to a liquid, plastic, solid, or gaseous material similar in organic composition to the conventional crude petroleum found in nature, but not including coal, lignite, or peat.

The term <u>natural gas</u>, when used separately, means natural petroleum gas, marsh gas, or similar methane-rich gases found in nature in gaseous form.

<u>Resource base</u> is the natural material, such as rocks or brines, which contain a desired product and which now or in the near future may be economic to extract. There are many types of natural materials containing desired products in various grades or in different physical forms--liquid, solid, or gaseous. An expansion of the resource base means that additional categories of the natural material shift to the resource base.

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In addition, only nature-produced petroleum is discussed and therefore three important categories of additional sources of supply are omitted. These sources, which might become significant in the future, are petroleum and methane produced from coal and lignite, wood and other renewable sources of cellulose, and urban and agricultural waste material.

THE PETROLEUM RESOURCE BASE

Almost all presently published estimates of petroleum resources refer in practical terms to a very tiny fraction of the total nature-made petroleum base, namely, to primary production of petroleum from conventional oil or gas fields. Thus, for instance, the U.S. Geological Survey in its estimates of recoverable oil and gas resources in the United States (Geological Survey Circular 725, published in 1975) defines crude oil as:

> . . . a natural mixture of hydrocarbons occurring underground in a liquid state in porous-rock reservoirs and remaining in a liquid state as it flows from a well at atmospheric pressure. (p. 9)

Such definitions of crude oil, which are more or less followed all over the world, define hydrocarbon resources as the primary production in conventional oil fields. The range of the primary production is usually between 15 and 30 percent of petroleum in place, therefore the bulk of all crude oil in place is excluded by this definition. This definition also leaves out the many other sources of petroleum, from heavy crude to petroleum in tar sands, oil shales, and so on, as well as small deposits which have traditionally been neglected by the oil companies and by government services. A similarly limited definition is employed for natural gas. The result is that the estimates of recoverable oil which are published cover perhaps 1 percent of nature-made oil in place.

What has to be asked is what information is required, information about the primary crude petroleum reserves, or information about something totally different, namely, what is the spectrum of petroleum resources provided by nature and at what cost and with what technology can these resources be developed? It is obvious from this formulation of the question that the future availability of petroleum is not dependent primarily on geological considerations but much more on technological and economic considerations.

As petroleum prices increase, petroleum resources become more plentiful because petroleum resources that were regarded as uneconomic in the past now become economic. If this analysis is accepted then it has to be realized that many of the present petroleum definitions and petroleum reserve estimates are based on the wrong approach and the famous Hubbert diagram (Fig. 1) is incorrect from an economic point of view. The proper configuration is a triangle which at the top is very narrow and broadens consistently as the price per barrel of oil increases from the top down (Fig. 2). Thus, a price of $2.00 per barrel may indicate the primary recovery from conventional oil fields. A $4.00 per barrel price may already include a substantial proportion of secondary recovery oil, and so on. With the present world market price of oil about $11 per barrel it is obvious that a variety of petroleum sources, depending on location and size of deposits, would be economic to develop, including heavy crudes, some tertiary recovery, and some types of oil shales and tar sands. The diagram also indicates that, as the price rises in the future, the resource base will expand until a price level is reached at which the production of petroleum from coal or renewable resources will become economic. Figure 2, therefore, expresses the fact that there is a very significant relationship between resource availability and price, a relationship which holds not only for petroleum but also applies to all underground resources.

Figure 2 also indicates that the opposite is true, namely, that a sharp fall in the price of oil would reduce resource availability, other factors being equal. The diagram allows for changes in technology. Thus a breakthrough in, say, the technology of extraction of heavy crude, thus reducing the cost, would push up heavy crudes within the triangle. If at any given period of time one had fairly reliable cost estimates for production of the various types of oil, one could establish within the triangle the proper tabulation of the resources according to

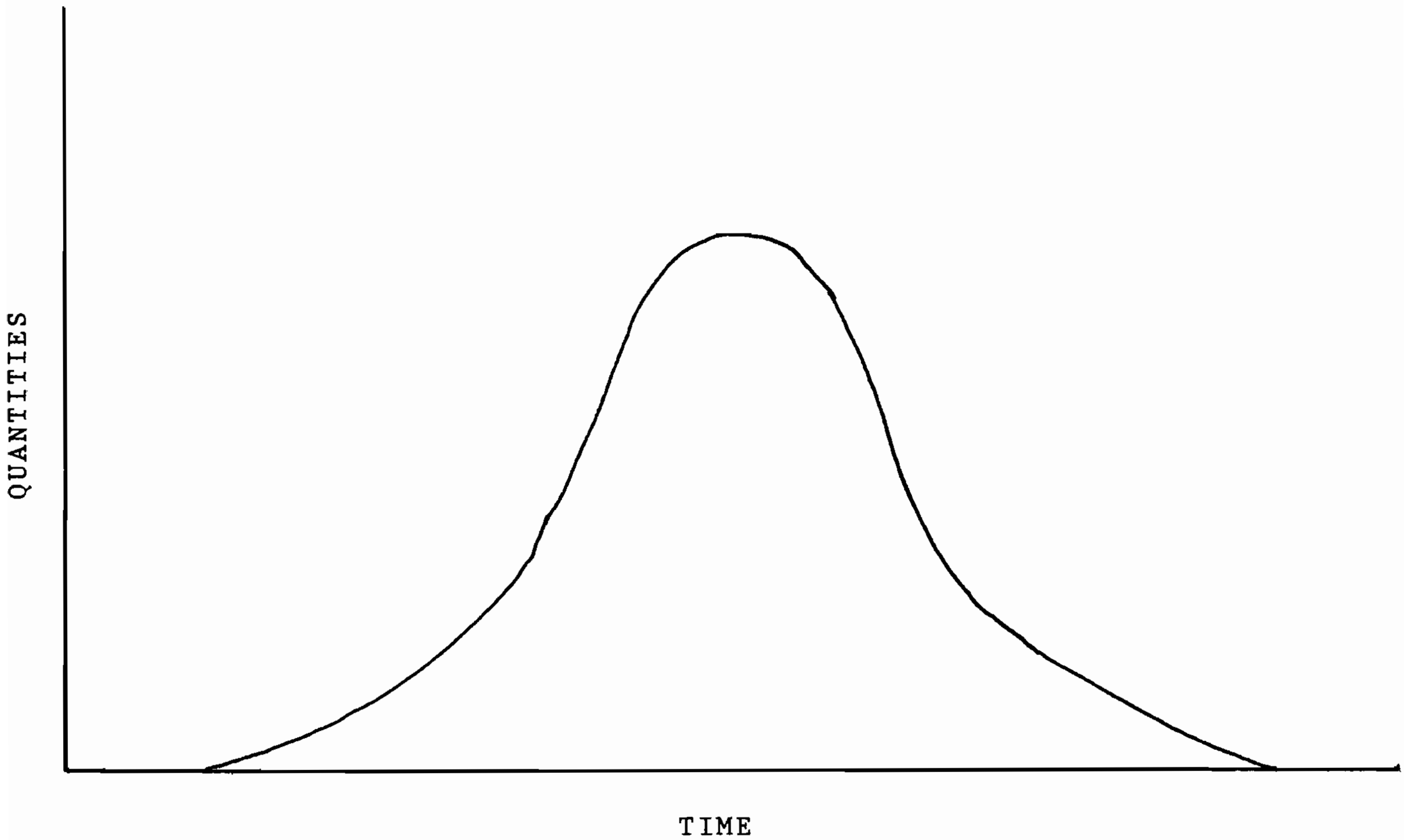

Figure I-1.--Hubbert's famous diagram of world oil availability

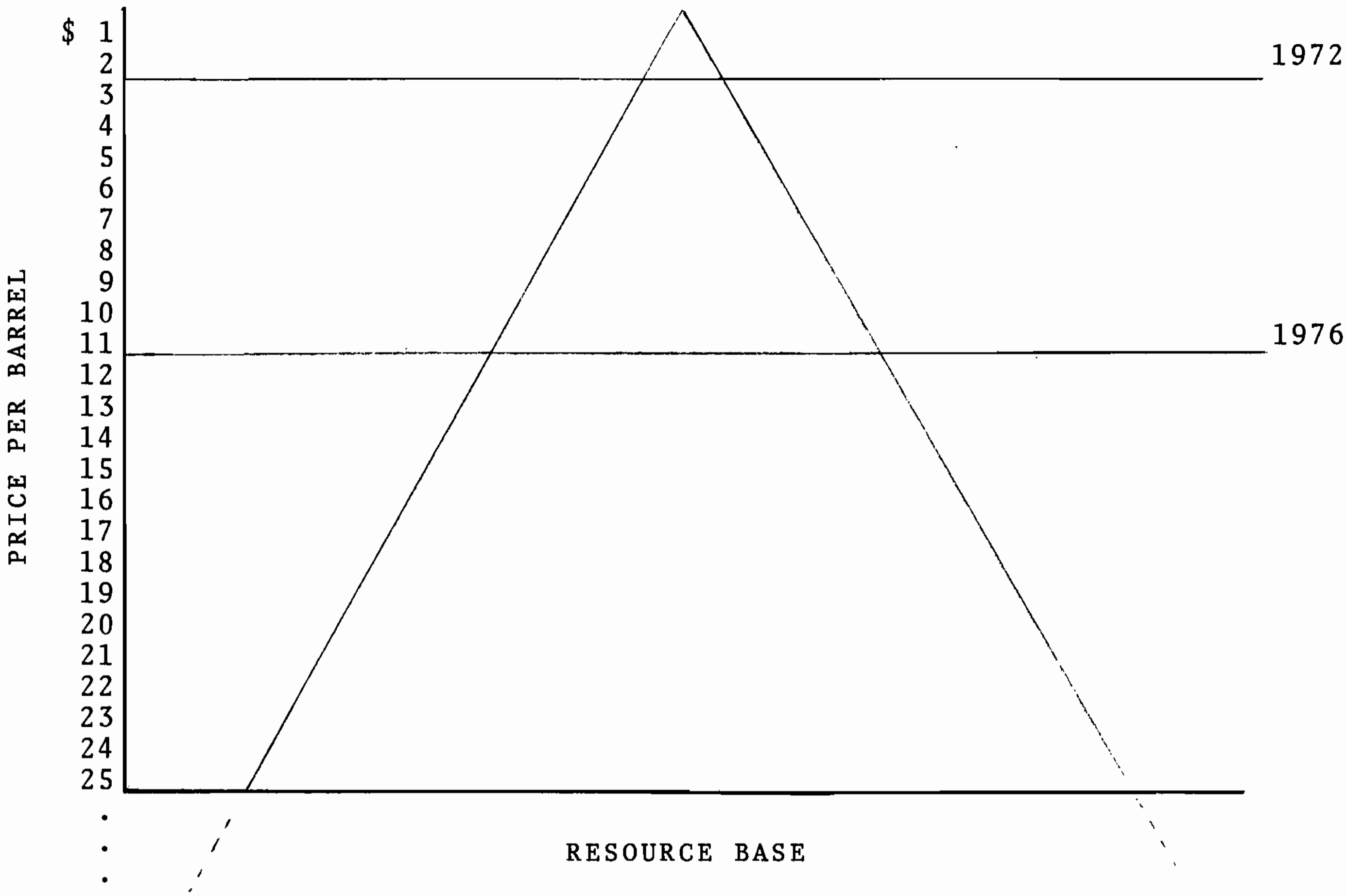

Figure I-2.--Availability of nature-made oil as a function of time the cost level and, as costs changed between the various petroleum sources or types, the tabulation according to cost would change. A similar triangle could be drawn for the 18 types of nature-made gas discussed in subsequent chapters. However, there will be from time to time both in the case of oil and in the case of natural gas, discontinuities or partial disorders in supply which may disturb the symmetries. Thus, it may occur that a man-made petroleum or gas source may become available at a price lower than some of the nature-made sources. For instance, in May 1976, the U.S. Federal Power Commission (FPC) approved the purchase of methane at a price of $1.33/1,000 ft^3 from a large-scale biodigester operation in Oklahoma. The FPC said that its studies have indicated that this biodigester methane was cheaper than imported liquefied natural gas and coal-produced gas. In addition it may be cheaper than some of the nature-made gas described in later chapters of this volume. However, the total quantity of biodigester gas that will be available in the United States in the near future is so limited that it will not drive out nature-made gas from most of the market. In general, it is assumed that practically all nature-made oil and gas in most locations will become available at a cost lower than that of man-made oil and gas. However, if man-made oil and gas were to be produced in large quantities at a cost below that of some of the nature-made oil and gas, then the higher cost nature-made oil and gas resources would remain economically unusable until the demand for oil and gas exceeded the production capacity of the cheaper man-made sources.

One of the purposes of this conference is a detailed study of this cost-price resource relationship. The relationship is complex and involves a variety of factors. Looking at petroleum resources as a whole and leaving out, as stipulated in the introduction, the demand side with all its factors, the six main factors involved are: (1) the type of deposits; (2) the size of the deposits; (3) the location of the deposits; (4) exploration technology; (5) extraction technology, including refining; and (6) transportation technology.

Until today the dominant trend of activities in petroleum exploration and development has been to find conventional petroleum deposits, of large size, located in accessible areas and explored for mainly by the application of subsurface geology, seismic geophysics, and drilling, using production technology to extract free-flowing crude, which could be transported by pipelines, or tankers, to markets. This traditional approach to exploration and development was justified during a period of low oil prices, when companies and most governments regarded the exploitation of other than conventional petroleum deposits as uneconomic and when extraction technology for other types of petroleum resources, except for certain types of heavy crude and oil shales in the USSR, was neglected. But if one wishes to look at the future availability of petroleum from natural resources, at prices which it is assumed will be higher in the future than today, one has to look at the variety of possible, naturally occurring petroleum resources, how to explore for them, and how to extract the oil and gas.

There will be no generally applicable answers, because each type of resource has a wide range of characteristics. Oil shale resources, for example, may be low or high in grade, may be minable through surface mining or in situ mining, or may be too deeply buried for existing technology. Similarly, extraction technology which may work well for one type of resource in a given geological environment with a given chemical composition of the host rock and of the petroleum, may not work for the same type of resource with a different host rock and different chemical composition. Some types of resources may involve political considerations, thus, the large-scale sedimentary basins on the margins of the continental shelf are beyond territorial waters and will require a solution to the problem of the management of the resources of the deep ocean.[3] Similar political considerations may also apply in connection with the petroleum resources in the Antarctic.

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[3]Some scientists believe that half the global sedimentary volume may be located in or on the margins of the continental shelf; see Dr. Kenneth Emery in Technology Review, March/April 1975, p. 32.

Another problem is the neglect of small deposits, which may be very numerous. Historically, companies and governments neglected small deposits because it was not economic to build pipelines for small oil and gas deposits. However, when the price is high enough and an area has a nearby demand, small deposits may become very attractive and may begin to play an important role. What is happening now in Ohio and several other states of the United States where industrial enterprises and farmers are exploring for shallow deposits, indicates the potential significance of such small deposits, provided that the price and the density of economic development in the area are attractive. There are no detailed studies on the relationship of small deposits to medium- or large-scale deposits other than empirical data in a few countries. But all those relationships are based on economic evaluations at the time of exploration and are therefore subject to change as prices, costs, and other conditions change.

The aspect of the petroleum resource base which especially needs study is existing knowledge of sedimentary areas and the volume of those sedimentary areas, especially in developing countries. Based on present geological concepts and experience, all the nature-made hydrocarbons are to be found in sedimentary areas only. The depth and distribution of sedimentary areas is therefore quite significant. With the discovery of geopressured zones and their contents of dissolved natural gas a further dimension is added because geopressured zones may be very deep. Sedimentary basins in certain cases may go deeper than any holes drilled so far and the resource potential of such very deep basins is largely unknown. On the other hand, there is a substantial body of experience which indicates that oil is not found in excess of a temperature of 200-250^{o}C so that, on the basis of present experience, crude oil may not be expected to be found below about 17,000 ft, but it is not known whether that also applies to oil shale, tar sands, and other types of hydrocarbons. There are large known quantities of natural gas dissolved in Lake Tivu in Africa and there may exist similarly large resources of natural gas in other lakes and marsh areas. It is also known that there is frozen natural gas in certain Arctic areas and gas hydrates in the oceans. There are indications of hydrocarbons in certain nonsedimentary areas, but our present knowledge is too limited to consider this of significance for the future, because nonsedimentary areas are far less explored and far less known. However, restriction of assessment of the hydrocarbon resource base to sedimentary areas is a function of our present knowledge; it is not necessarily something that will hold true in the future.

ECONOMICS OF EXTRACTION

In general the economics of petroleum exploration, development, and production is extremely complex. The wide range in exploration costs, the wide range of production per well, and the wide range in taxes on different types of petroleum, lead to the result that a precise cost comparison is almost impossible. Whereas, in the countries around the Persian Gulf estimates of the cost of oil, often placed at U.S. $.10-.20 per barrel, are based exclusively on the direct cost of exploration and production, such cost estimates are calculated in other countries by including very many more factors with the result that cost comparisons are almost impossible. In the United States for instance, on Federal land, leases are auctioned before exploration and the cost of the lease, in addition to Federal royalties and other taxation, becomes part of the production costs. On private land and State land in the United States, State taxes may also be applicable.

As a result of these difficulties in comparing costs, it is preferable to restrict cost comparisons exclusively to the direct cost, leaving out all taxation, whether Federal, State, or local. If this is done it will be found that the cost, in the case of normal oil fields, is primarily determined by the out-put per well and the depth of the well. In this connection, it has to be recognized that the range of production per well is very great. Production ranges from about 5,000 barrels per day around the Persian Gulf down to about 250 barrels per day in Venezuela. In the case of stripper wells in the United States the production per well is below 10 barrels per day. Where wells are very shallow and cost only a few thousand dollars to drill, the cost per barrel may be low even if the out-put per well is quite small.

There are economic studies especially for oil shale and tar sand which take into account the rate of interest at the 1974 level and thus show that the cost of the oil extracted would be very high. In some of these studies interest rates up to 15 percent are taken into account. It is obvious that high interest rates will, over a period of 20 or 25 years yield very much different results from normal interest rates, such as 6 to 8 percent. It is important therefore, for uniformity of comparison, to apply to investments a uniform, long-term, reasonable rate of interest.

Even more important than our assumptions about future long-term rates of interest are our assumptions about the future price of oil. It is assumed here that the present prices will not decline, because there is an effective oil producers group formed by sovereign governments interested in keeping prices high and capable of doing so by production restraints. Looking ahead to the year 2000 it should also be assumed that it is most likely that oil prices will continue to rise. In Table 1, future oil prices have been calculated assuming various annual rates of possible price increases. At a rate of increase of 5 percent per year, the price of oil at U.S. $11 per barrel today would rise to $17 by 1985, to $22 by 1990, and to $35 by the year 2000, only 24 years away.

TABLE 1.--Future possible price ranges for crude petroleum
(Based on $11 per barrel in 1976)

Year	Increase in compound rate of interest		
	5 Percent	7 Percent	10 Percent
1985	$17.064	$20.223	$25.937
1990	21.778	28.363	41.772
1995	27.795	39.780	67.274
2000	35.474	55.874	108.344

If an annual rate of petroleum price increase of 7 percent per year is assumed the price of oil would rise to $56 by the year 2000. The case of a 10 percent annual raise would rise to $106 per barrel by the year 2000.

There are very few published forecasts of future oil prices. One of the few is a forecast by the Henley Centre for Forecasting in England which has predicted a $16.00 price per barrel by 1981 and a price of between $22.00 and $28.00 per barrel by 1991.[4]

These forecasts for future oil prices are not more than guesses; with the existence of a producers group formed by governments, political factors are predominant in price determination. However, it is believed that the postulation of an upward price trend in the future is unassailable in the absence of some totally unexpected and unpredictable factors.

All these price forecasts are expressed in nominal prices, not only because real prices are practically unpredictable but because in the mining industry prices have always been expressed and forecast in terms of nominal prices. In studies carried out with a view to expressing the price movement for metals and other minerals in real terms, it was found that in real terms metal prices declined until 1972, thus the forecast nominal increase in petroleum prices may be reflected in a much smaller increase in real prices.

The assumption that the present high price of oil will not decline but will continue to rise may be challenged on two grounds, namely (a) normal demand and supply functions, and (b) the possibility of technological break-throughs.

There is no doubt that present petroleum producing capacity is essentially above present production and, under conditions of normal market price formation, the price of petroleum should go down. However, as explained earlier there is an effective petroleum producers group formed by the OPEC countries, and all petroleum exporting countries whether the USSR, China, Mexico, Canada, or others, are following the price leadership of the OPEC countries. It is, therefore, unlikely that the excess petroleum

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[4]See Petroleum Economist, May 1976, p. 195.

production capacity will have a decisive influence on the price of petroleum; unless large-scale petroleum production is rapidly pushed forward in the few remaining countries in which petroleum is produced by private companies and the governments concerned favor production at lower prices. This virtually leaves only the United States, and the present policy in the United States in practical terms does not support the rapid expansion of petroleum production, at least for the next 3 years.

As to the possibility of technological break-throughs this is a more difficult problem. Technological break-throughs which may allow the large-scale production of petroleum from oil shale, heavy crudes, or other petroleum material are a possibility that cannot be ruled out. Cases of technological break-throughs relevant to other natural resources have indeed taken place. The large-scale development of porphyry copper (low-grade dispersed copper) has indeed prevented copper shortages and has changed the long-term trend of copper prices. There are other examples of similar development of low-grade resources, therefore careful consideration needs to be given to this technical possibility.

A very recent example is the break-through in solution mining of low-grade uranium, uneconomic to mine by any other method. This follows the earlier development of solution mining for sulphur and more recently for potash. All these solution mining processes are applicable only in sedimentary areas.

It should be noted that oil shale, tar sands, heavy crudes, and so on, are available in large quantities in many countries which are today petroleum importing countries. The effect of such a technological break-through, therefore, could lead not only to a slowing down in the rise of prices of petroleum (perhaps even to a decline in prices for a period), but it could also change substantially the present pattern of international petroleum trade. Whether such a technological break-through is likely in the near future is one of the subjects of the present volume of technical reports. If, however, as appears likely at this stage, oil produced from oil shale, heavy crudes, and so on, will require present prices for economic extraction or some price increase for expanded production, then the effect of a technological break-through may be restricted to a slowing of the price rise in the future. A policy alternative that has been discussed in some papers does not seem to merit serious attention. That policy alternative holds that the OPEC countries would reduce their prices in order to prevent capital investment in alternative sources of petroleum. Such a policy appears not to be in the long-term interest of the OPEC countries because all of them will in time experience sharp increases in the cost of producing petroleum as they move from primary production to secondary and tertiary production.

The extraction of petroleum from any of the various petroleum sources must at any given time in the future be economic, and the economics of any given time must yield a ton of oil which costs less to produce than the prevailing market price. Consequently petroleum, which through lack of proper technology, or because of location or depth, cannot be produced below the prevailing market price, is uneconomic to produce at a given time. A price definition is therefore essential, and it cannot satisfactorily be replaced by <u>energy in-put</u> or some other yardstick. In theory, it might be argued that if one could determine the direct and indirect energy in-put for the production of a ton of oil from oil shale or from tertiary recovery from a conventional oil field, that would indicate the limits of the economic extraction of such hydrocarbons. There is, however, no uniform yardstick for measurement of energy because energy is a concept and not a commodity. There are very many different energy resource commodities at different prices and this will continue in the future. Thus, in some countries a British Thermal Unit (Btu) of energy from geothermal sources may be very cheap, in others it may be very cheap from coal, in yet others it may be very cheap from hydropower, while in the same countries a Btu from oil may be very high in price. In those countries it would make sense economically to put into the extraction of petroleum the same amount of Btu's in the form of geothermal, coal, or hydro energy if the result would be that an equivalent or even smaller amount of Btu's in oil were obtained that would have a very much higher market value.

There is then no better method available for price definition than true market price, though in some countries with widespread price control this method may not work too well. For instance, in the United States where natural gas is price-controlled at a very low level, if natural gas were to be used for the extraction of oil it might make sense in financial terms but it would not make sense from a long-term resources point of view. In summary, therefore, we may conclude that for all future petroleum extraction, the cost of extraction must be below the expected market price, assuming that the cost-price relationship will at a given time be the correct yardstick.

This discussion on the relationship in the future between cost and prices does not mean that cost and prices must be equal all over the world or that they will be equal. For example, oil produced near a consuming center, and thus bearing very little in transport costs, can be produced at a higher cost, other things being equal. However, more important is the recognition that each underground resource has its own characteristics relating to size, depth, location, and quality, with the result that for each type of petroleum resource there will be a range of production costs, and with the different types of petroleum resources which will be exploited, the range of cost per type may overlap the range of cost of other types of petroleum resources. How much of each type will be produced at a given time will be a function of the price of petroleum and the supply at various costs from the different types of petroleum resources. As a result, it is difficult to forecast conditions under which petroleum from any particular type of resource will always be economic and will find a market. In an extreme case, even oil from primary production from a conventional oil field may not be able to compete with oil produced from another type of petroleum resource, if the oil from the primary production is from a small field in an isolated area and involves high transport costs. The conclusion is that though studies can indicate the broad parameters expected for petroleum in the future, such analysis will not replace the necessary individual petroleum resource analyses as to cost, prices, and future marketability prospects.

One further conclusion to be drawn from this analysis is that the emphasis in petroleum development will shift in the future from the discovery of conventional oil and gas to the extraction of oil and gas from many different kinds of sources. Rapid expansion in the engineering manpower needed for the new developments will therefore be required. The future will also see the beginning of a new nature-made petroleum exploration concept in which there will be exploration and drilling for all types of nature-made oil and gas resources instead of the present single-purpose exploration for liquid oil and natural gas only. This may reduce the number of dry holes and reduce the cost of exploration in the future.

This study has not discussed the relationship between oil and gas, although the relationship between them may have an impact on the various types of both oil and gas resources in the future. Oil is much easier to transport than natural gas and consequently large quantities of natural gas were flared off in the past, and are still flared off in some countries. In some countries the price of natural gas is now much higher in calorific terms than the price of oil. This review assumes that because natural gas is a clean fuel the demand for it will continue to rise. Given the fact that there are many sources of methane, as described in subsequent chapters, it may be that the expanded availability and use of gas might reduce the demand for oil in the future. This inter-relationship may have implications for the future but cannot be pursued further here. Another relationship which might become significant for some resources is multipurpose or joint production of oil and other minerals, as in the case of some tar sands and some oil shales. If either or both of the joint products should rise in price, this might make the exploration of an oil resource economic although on the basis of a single product development it might be uneconomic. Such a possibility again complicates the evaluation process but is a fact which applies also with regard to a number of other natural resources, especially lead, zinc, copper, silver, and gold.

TECHNOLOGY OUTLOOK

In general, the higher the value of a mineral the greater the amount of technology that can be employed in its extraction. Thus, for copper, nickel, and similar high-value metals, each with a price exceeding a $1,000 per ton and often very much higher, the large-scale application of technology is obviously justified. Doubts may linger as to petroleum, when even now the price of a ton of oil is between only U.S. $80-90. However, as the price of oil has jumped from U.S. $3.00 to $11.00 per barrel, petroleum has become more valuable, and the more valuable it becomes the more technology can be afforded for its extraction. On the other hand, water, which in most parts of the world has a price of U.S. $.05-.10 per ton, is now undergoing large-scale technology application without unduly raising the cost of the reprocessed water.

This study assumes a growing large-scale application of new technology to the variety of petroleum resources that we already know to exist as well as to the further types of petroleum resources that may become available in the future. How can one be sure that large-scale application of modern technology to the various types of petroleum resources will occur and that such an application will yield petroleum at prices applicable in the future? There are two important new developments that need to be noted in this connection. One is a very large effort on the governmental level, in terms of funds and manpower, going into the study of modern technology for petroleum extraction from a variety of sources. This is especially true in the United States (through the Energy Research and Development Administration (ERDA)), but it also applies to other countries. In addition there is the vast effort by private companies using their own staff and their own laboratories, although this is little publicized. Large-scale investment in the petroleum technology of the future is therefore underway. The other new development that should be noted is that more and more, when dealing with applied research, it is possible to define goals and to plan to achieve these goals over a given time period. A recent example of this type of applied technology planning in the energy field is the

U.S. Energy Policy and Conservation Act passed in December 1975. In this act new automotive efficiency standards are prescribed by law for a technology to be developed within a specified time frame in the future.[5]

There is, therefore, little doubt that the large-scale application of modern technology to the various petroleum resources will, given the necessarily large and long-term supply of capital, produce a variety of improvements and possible breakthroughs in the technology of petroleum extraction. This conference will review the ongoing applied research insofar as information will be made available, within a framework for the future, where slowly rising petroleum prices are assumed. There is very little doubt that some of the processes are economic now. For example, secondary recovery of oil is already economic onshore in most countries of the world. The same may apply to certain types of heavy crude oil and certain types of shale oil. Were it possible to estimate the range of extraction costs for various types of petroleum resources over the next 25 to 30 years, on the basis of a technology that is now under development, then some important conclusions could be drawn: certain types of petroleum resources widespread in nature, for example oil shales within certain grades, may become economic to extract in, say, 10 to 20 years. Such knowledge would indicate that there is no need to worry about petroleum resources, if presently proved petroleum reserves in conventional oil fields should last only 30 years, because it then would be evident that there are other types of petroleum resources for which extraction technology will be ready and economic at the prices expected in the future. The same expectation with regard to technology can most likely be applied to the bulk of the oil that remains in conventional oil fields after primary production--such fields being petroleum sources that require no further exploration. Furthermore, such expectations about technology will help to destroy the myth that the petroleum resources of the petroleum

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[5]The law prescribes a fuel economy standard of 27.5 miles per gallon for 1985 and prohibits the manufacture of any car in the United States after 1985 which does not achieve this standard.

exporting countries will come to an end with the end of the primary oil production. With rapid development of extraction technology, oil countries will gradually shift from their low-cost primary production to higher cost production, but they will remain petroleum producing countries. In short, the assessment of the rate, time frame, and cost of the application of modern technology to petroleum extraction can lead to basic changes in the evaluation of the future availability of oil.

CONCLUSION

The main purpose of this Conference on Nature-Made Petroleum and Gas was to conduct a new, broad, and well-informed review of the variety of petroleum resources on the globe, coupled with a detailed discussion of existing and expected extraction technology expressed in cost estimates based on uniform standards. When such cost estimates become available, and with an assumed range of future oil prices, it will become possible to estimate at what price level (and time period) the various technologies will become economic. It finally will become possible, on the basis of such data and estimates, to define and compile new petroleum resource and reserve definitions, based on the principle that a type of petroleum resource must be added to the resource base when the extraction cost falls below the expected price.

SECTION I. WORLD PERSPECTIVES ON CONVENTIONAL PETROLEUM

CHAPTER 1

OCCURRENCE OF PETROLEUM

John D. Haun[1]

INTRODUCTION

The occurrence of petroleum (oil and gas) is the result of chemical, physical, and geological factors that control origin, migration, and entrapment. To understand the distribution of known oil and gas accumulations and to predict the location and volume of undiscovered accumulations, a knowledge of these factors is necessary. The purpose of this paper is to review the principles of petroleum geology and to indicate how these principles affect exploration and estimation of undiscovered resources.

DEFINITION AND COMPOSITION

Petroleum is a naturally occurring liquid, gas, semisolid, or solid mixture of hydrocarbon and nonhydrocarbon molecules. Crude oil (unrefined oil) is the liquid form of naturally occurring petroleum. Natural gas is composed largely of methane (CH_4) and contains lesser quantities of ethane (C_2H_6) and heavier hydrocarbons. Semisolid and solid petroleum (bitumen, asphalt, tar, pitch, gilsonite, albertite, grahamite, and similar materials) are composed of heavier, more complex hydrocarbon and nonhydrocarbon molecules. Oil-saturated sandstones (tar sands, bituminous sands) are the surface or near-surface occurrences of oil accumulations that have been brought to the

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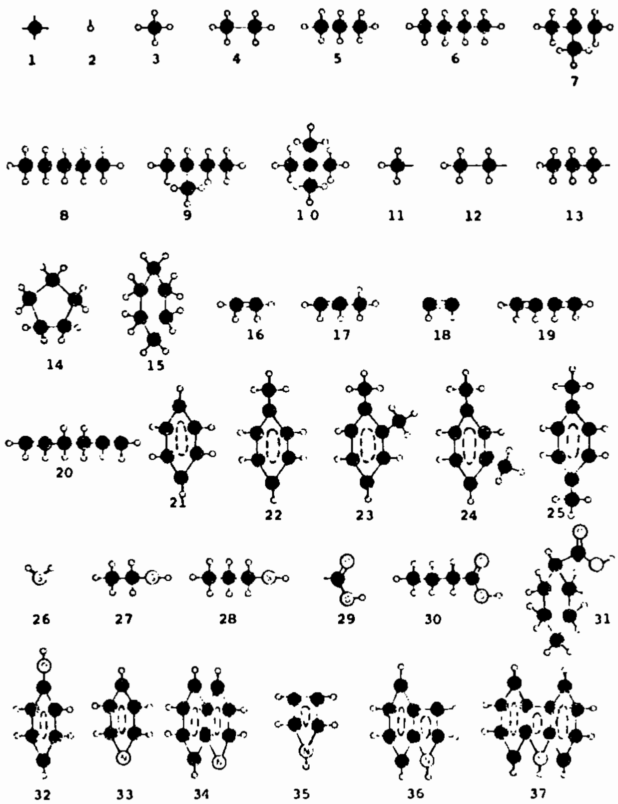
surface of the earth by structural uplift and erosion, or by seepage, and have lost the lighter, less complex components by evaporation, oxidation, and bacterial degradation.

Hydrocarbon molecules are composed entirely of hydrogen and carbon. Nonhydrocarbon molecules contain sulfur, oxygen or nitrogen atoms, in addition to hydrogen and carbon, within their molecular structure. Some metals, especially vanadium and nickel, are contained in the molecular structure of some nonhydrocarbons. Other constituents, such as free sulfur, hydrogen sulfide, free oxygen, free nitrogen, sodium chloride, carbon dioxide, and helium, are commonly present in small amounts in petroleum liquids and gases. Natural gas and petroleum solids are present in dissolved form in most crude oils.

Figure 1-1 illustrates some of the organic compounds found in petroleum. Most hydrocarbons are classified in four <u>series</u>: <u>paraffin</u>, <u>naphthene</u>, <u>olefin</u>, and <u>aromatic</u>. The first three are called <u>aliphatic</u> and are considered as a class distinct from the aromatic hydrocarbons. Each of these series consists of a group of hydrocarbons having a similar basic structure and having similar chemical characteristics. If the hydrocarbon molecule contains the maximum number of hydrogen atoms, all valence shells are filled with shared electrons (single covalent bonds), and the hydrocarbon is considered <u>saturated</u>. If some of the carbon atoms in the molecule are connected by double covalent bonds, the hydrocarbon is <u>unsaturated</u> and atoms may be added to the molecule. Unsaturated hydrocarbons are, therefore, more reactive than saturated hydrocarbons. Paraffins and naphthenes are saturated; olefins and aromatics are unsaturated.

Carbon atoms form either a straight-chain structure, in the <u>normal paraffins</u> (<u>n</u>-pariffins), or a branched-chain structure in the <u>isoparaffins</u> (isomers). At ordinary temperatures and pressures the paraffins with one to four carbon atoms are gaseous. Methane is formed in swamps, is a constant problem in coal mines, and is the chief constituent of natural gas. Ethane is also a component of natural gas. The heavier gases, propane, butane, and isobutane, are compressed into liquefied petroleum gas (LPG). Paraffins with 5 to 15 carbon atoms are liquids and are the chief



1, carbon; 2, hydrogen.
Aliphatic hydrocarbons, paraffin (alkane) series, C_nH_{2n+2}:
3, methane; 4, ethane; 5, propane; 6, *n*-butane; 7, isobutane; 8, *n*-pentane; 9, isopentane; 10, neopentane.

Substituent radicals: 11, methyl; 12, ethyl; 13, propyl.
Naphthene (cycloparaffin) series, C_nH_{2n}: 14, cyclopentane; 15, cyclohexane.
Olefin (alkene and diene) series; mono-olefins, C_nH_{2n}:
16, ethene; 17, propene; 18, acetylene (an alkyne, C_nH_n, not found in petroleum); diolefins, C_nH_{2n-2}:
19, butadiene; 20, hexadiene.
Aromatic hydrocarbons, benzene series, C_nH_{2n-6}: 21, benzene;
22, toluene; 23, *o*-xylene; 24, *m*-xylene; 25, *p*-xylene.
Nonhydrocarbons (sulfur, nitrogen, and oxygen compounds):
26, hydrogen sulfide; 27, ethyl mercaptan (ethanethiol);
28, propyl mercaptan (propanethiol); 29, carboxyl group (of fatty acids, naphthenic acids, etc.); 30, butyric acid;
31, cyclohexane carboxylic acid; 32, phenol (carbolic acid);
33, pyridine; 34, quinoline; 35, pyrrole; 36, indole;
37, carbazole.

FIGURE 1-1.--Organic compounds in petroleum components of straight-run (uncracked) gasoline. Paraffins with over 15 carbon atoms are waxes which, if they occur in large quantities in crude oil, may cause production problems. Hydrocarbons of the paraffin series are the most common constituents of petroleum.

Carbon atoms in naphthene molecules are joined in closed rings. Cyclopentane and cyclohexane are the most common members of the series. Naphthenes are similar to the paraffins in their chemical characteristics and they are second in importance as constituents of petroleum. A crude oil that contains a high proportion of complex asphaltic naphthenes (multiring structures) in the residue of high-boiling fractions is called an asphalt-base crude and is thereby distinguished from paraffin-base crudes. Paraffins, however, are still the major components of asphalt-base crudes. Intermediate crudes that contain significant proportions of both wax and asphalt are considered mixed-base.

Olefins are present in only small quantities in crude oil. They are very reactive and form the chief raw materials of petrochemicals; also, they react with each other to form gums.

Aromatics comprise a large percentage of some crudes from California and Indonesia. They are chemically active and are basic to the manufacture of many synthetic chemicals. Aromatic oils are more easily oxidized than are paraffinic or naphthenic oils.

The nonhydrocarbon components of petroleum are important from a refining standpoint and also are important to an understanding of the origin and geologic history of petroleum. Some of these compounds decompose easily when petroleum is distilled and, therefore, are difficult to identify. Sulfur, nitrogen, and oxygen atoms in compounds form polar molecules, that is, the center of positive charge does not coincide with the center of negative charge and, although the molecules contain an equal number of positive and negative particles and are neutral electrically, one end of each molecule is negative and the other end is positive. Because of their polarity, they probably play an important role as surface-active agents in the reduction of surface and interfacial tension. Reduction of interfacial tension is of primary concern in secondary and tertiary recovery technology.

The chemistry of petroleum determines its physical properties and, in turn, the mechanics of migration and entrapment.

ORIGIN

A theory of petroleum origin must account for movement of petroleum molecules from the point of origin into a porous reservoir rock (primary migration). In some cases petroleum may originate in the reservoir rock and require no primary movement, but this probably is not common. After its arrival in the reservoir rock, petroleum may move by several mechanisms (secondary migration) and this may be repeated several times during the geologic history of a petroleum accumulation. The common textbook subdivision of the natural history of petroleum into distinct periods or stages of (1) origin, (2) primary migration, (3) secondary migration, and (4) entrapment is misleading because the first two "stages" are parts of the same unified process. The relationship between petroleum and rocks especially rich in organic matter, such as coals and oil shales (pyrobitumens), is also of interest.

Theories of inorganic origin of petroleum are of historical interest. Several adherents of inorganic theories publish serious papers, but they avoid some of the major evidence and their ideas can easily be discredited. Some arguments for inorganic origin have been based on the fact that hydrocarbons may be formed in the laboratory by combining alkali metal, carbon dioxide, and water, or by combining metallic carbides and water or acid. Hydrocarbons in the atmospheres of planets, in meteorites, in igneous and metamorphic rocks, and in the gases of volcanoes have been used as evidence for inorganic origin. It is probably true that the nonhydrocarbon gases, nitrogen, helium, and some carbon dioxide originated through inorganic processes.

Overwhelming evidence requires that petroleum originate from organic matter. Perhaps any single argument could be debated, but taken as a group the arguments for organic origin are too numerous and too powerful to be countered successfully. The following observations are at the same time arguments for organic origin and against inorganic origin: (1) The homologous series of hydrocarbons found in petroleum are found elsewhere only in organic matter and in obvious organic derivatives such as coal and carbonaceous shale. (2) Nitrogenous compounds, especially plant-derived porphyrins, comprise a small but significant portion of petroleums; elsewhere, porphyrins are found only as derivatives of chlorophyll and hemoglobin. (3) The range of carbon-isotope ratios (C^{13}/C^{12}) in petroleums is within the ranges of natural carbonaceous materials and is unlike such ratios in most inorganic matter. (4) Optical activity is a property of most crude oils and is found also in compounds derived from living organisms. (5) High temperatures necessitated by most inorganic theories will destroy nitrogenous compounds (including some porphyrins), will eliminate optical activity, and will decompose (crack) the more complex hydrocarbons into simpler compounds. Observed temperatures in oil-producing areas, usually less than 100° C, support this contention. (6) Most petroleum is associated with sedimentary rocks, and organic-rich source material is usually present in the same rock sequence. This is certainly strong circumstantial evidence that inorganic processes are not operative. Most petroleum occurrences in igneous or metamorphic rocks may easily be explained by migration from sedimentary rocks. The general lack of petroleum in basement rocks and shield areas leads to the same conclusion. (7) Small quantities of hydrocarbons in recent sediments, in a variety of environments, lead to the conclusion that the formation of petroleum is a normal, continuing process that has been in operation since the beginning of life and is not a process that requires a fortuitous or severe set of physicochemical conditions. (8) Most organisms, especially some microscopic plants (diatoms), contain hydrocarbons.

Certain additional facts serve to define the chemical environment in which petroleum originates and is preserved. Most of the components of petroleum and organic matter are destroyed under aerobic conditions that promote the growth of oxidizing bacteria. The end products of bacterial degradation are carbon dioxide and water. This destructive process can take place at any stage of petroleum formation or at any time after the petroleum is formed and is subjected to an aerobic environment. It is apparent, then, that petroleum must originate and must be preserved in a reducing environment.

Much has been written about the possible sources of energy believed necessary for transformation of organic matter into petroleum. In general, bacteria change organic matter into a more petroleum-like substance and anaerobic bacteria probably play a significant role in the formation of petroleum. Bacterial production of methane is a commonly observed occurrence in mud bottoms of swamps and in soils. In the laboratory, bacteria have been observed to produce methane and hydrogen.

Methane and other molecules in petroleum also are produced by nonbacterial cracking of organic substances (including previously formed oil) in sediments and sedimentary rocks. Recent deep drilling (5,000 to 7,000+) has established the fact that deeper exploration has a statistically higher chance for gas discovery than for oil (Landes, 1966). Age and temperature of the rocks increase with depth and probably a parallel increase in the production of gas by thermal and catalytic cracking processes takes place. There is no well-defined relationship between the volume of natural gas in a geographic area and the volume of liquid hydrocarbons (oil) in the same area. Methane is thermodynamically stable, with respect to heavier hydrocarbons, and is the natural end-product of bacterial and thermal reactions.

Subsurface heat and pressure, with geologic time as a factor, cause chemical changes in organic matter and petroleum that could only take place at excessive temperatures or pressures in a short-time experiment in the laboratory. Catalysts, such as trace metals, clays, and enzymes, are always present in sedimentary rocks and would make low-temperature chemical reactions more probable. Differences in the chemistry of petroleums are the result of such factors as differences in the original organic matter, depositional environments of the sediments, thermal history, migration distances, and hydrodynamic conditions.

Most of the world's petroleum is associated with sedimentary rocks that were deposited in marine or shore-line environments. There are also very large accumulations of petroleum in nonmarine, especially lake, environments. Fresh waters associated with some petroleum-producing areas have, in the majority of cases, been introduced into reservoir rocks exposed at the surface of the earth during a period of uplift after the petroleum was formed.

Petroleum originates in a chemically reducing environment, in organic-rich shales or carbonates (source beds) that were deposited as muds. Petroleum may also originate in sediments that would not be considered especially rich in organic matter. But petroleum is found today in porous and permeable strata (reservoir rocks) that were most commonly deposited in well-oxygenated environments from which muds were removed by wave and current action. A paradox is found in the fact that the source beds act as barriers to migration after they have been lithified to shales!

With the exception of bacterially-formed methane, it is believed that heat is the primary energy source in the formation and primary migration of petroleum. Thermal maturation of organic matter, followed by solubilization of hydrocarbon and nonhydrocarbon molecules in subsurface waters, may account for petroleum origin and primary migration. Vast quantities of methane and heavier hydrocarbons are dissolved in pore waters of subsurface formations throughout the world. Microfractures and phase-continuous "stringers" of petroleum also may play a role in the process.

SOURCE-BED IDENTIFICATION

Determination of the presence and quality of source beds in an unexplored or little-explored area of the world is a routine technique in modern petroleum exploration. The major problem in source-bed identification is the uncertainty that the organic content measured today is indicative of the chemistry of the derived petroleum. Certainly the removal of selective portions of the original organic matter will leave an altered residue. The question then is whether or not the residual organic matter has been modified during primary migration, or by post-migration processes, to such an extent that its identification as petroleum source material can be verified. After the formation of protopetroleum (and primary migration) it is reasonable to expect that organic matter remaining in the source beds should contain a residual component of hydrocarbons or petroleum-like organic material; the process of protopetroleum removal surely is not 100 percent effective. Provided metamorphic processes have not advanced too far, it should be possible to identify the petroleum-like components. Chemical alterations of petroleum during secondary migration and after entrapment add to the complexity of correlating individual petroleums with specific source beds.

The following criteria are used in source-bed identification:

1. The total organic carbon (TOC) is measured; it is the percentage (by weight) of organic carbon in a rock sample. Total organic matter (or kerogen) is cited by various authors to range from 1.2 to 1.6 times the TOC. The minimum TOC of source beds has been estimated to be 0.4 to 1.4 percent (Ronov, 1958), 1.5 percent (Schrayer and Zarrella, 1963), and 0.5 percent (Welte, 1965). Hunt (1972) has estimated that only 0.01 percent of the organic carbon in sedimentary rocks is in the form of petroleum.

2. Most geochemists believe the volume and character of extractable organic matter (EOM), both hydrocarbons and non-hydrocarbons, is more important than TOC in the definition of source beds. According to Hunt and Jamieson (1956), source beds should contain soluble hydrocarbons, soluble asphalt, and insoluble kerogen (pyrobituminous material). In general, source-bed extracts should contain significant quantities of the major constituents of crude oil (Erdman, 1961).

3. The EOM/TOC ratio may be more significant than either quantity alone in the characterization of source beds. Erdman's opinion (1964) is that the EOM/TOC (oil/kerogen ratio) is too low in coals and oil shales, but a minimum amount of kerogen is

necessary in source beds to provide primary migration paths. Welte (1965) states that "the ratio of the extractable amount of organic carbon to the residual organic carbon" is an indicator of hydrocarbon generation. Philippi (1965) believes that the critical ratio in the Ventura and Los Angeles basins is in the range of 0.030 to 0.120.

4. In living organisms and in recent sediments, n-paraffins in the approximate range of C_{21}-C_{37} have a larger quantity of odd-numbered than of even-numbered species. The ratio of the volume of odd- to the volume of even-numbered n-paraffins is termed the carbon-preference index (CPI). In most ancient sediments the CPI value approaches unity and most crude oils have a CPI between 0.90 and 1.15. Bray and Evans (1965) determined the CPI of 77 recent sediment samples and 241 ancient shale and mudstone samples, and compared these with CPI values of 40 crude oils. They found that CPI values of approximately 30 percent of the ancient samples correspond to the range of CPI values of crude oils. The inference, therefore, is that CPI values of source beds should be less than 1.15 (similar to petroleum) and should correspond approximately to the CPI of the derived crude oil. The results of Bray and Evans' (1965) work are illustrated in Fig. 1-2.

5. The range of carbon-isotope ratios (C^{13}/C^{12}) among various petroleums is approximately 1 percent (0.0109-0.0110). A summary of ranges of carbon-isotope ratios of various organic materials compiled by Silverman (1973) indicates "that petroleums are derived almost exclusively from the lipid fractions of organisms, whereas coals are derived principally from (land) plant cellulose." As a source-bed indicator, it is assumed that the C^{13}/C^{12} ratio of the source material should be essentially the same as the C^{13}/C^{12} ratio of the derived petroleum.

6. Regional and vertical changes in density and other chemical characteristics of petroleum have been described by many workers. Landes (1966 and 1967) has used the term "eometamorphism" to describe the relatively low-temperature transformation of organic matter resulting from increasing burial depth (and pressure) of sedimentary rocks. Geologic time is believed

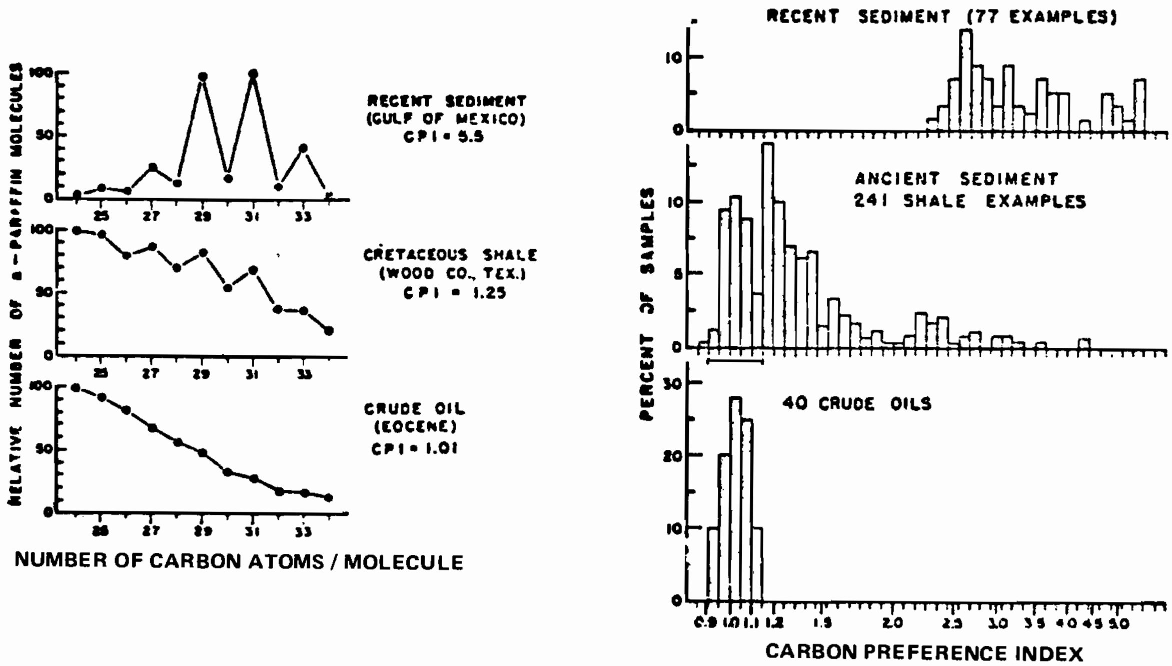


Figure 1-2.--Carbon preference index (CPI)
(Bray and Evans, 1965)

to be a substitute for the extreme temperatures that might otherwise be necessary to form protopetroleum, facilitate primary migration, and alter petroleums in reservoir rocks or traps. The relationship between depth, geothermal gradient, and petroleum occurrence, as determined by Landes (1966), is illustrated in Fig. 1-3.

The level of thermal maturation (LOM) of a sample may be measured by (1) carbon ratios (fixed carbon/fixed carbon plus volatile matter), (2) vitrinite reflectance (measure of the ability of coaly particles to reflect light), (3) loss of porosity of reservoir rock in response to burial depth and geothermal gradient, (4) maturation of petroleum by thermal cracking, and (5) thermal index (visual color classification of pollen and other organic matter).

Powers (1967), Burst (1969), Johns and Shimoyama (1972), and others have established a relationship between the temperature-dependent explusion of interlayer water from montmorillonite (and subsequently from mixed-layer clay) and thermal alteration and desorption of protopetroleum. The critical temperature of 200-230^{o} F is attained at various depths depending on the geothermal gradient. The implication of these various studies, with regard to source-bed identification, is that the present content of montmorillonite, illite, and mixed-layer clays may be indicative of the thermal history and petroleum generation capacity of the rock.

SECONDARY MIGRATION AND ENTRAPMENT

Hydrocarbon molecules tend to coalesce readily into petroleum globules, and if this occurs, they lose their mobility, in comparison with water, and are trapped in the small pores of the rock. For globules (slugs) of petroleum to move, their buoyancy must exceed the entry pressure of the pore connections. Entry pressure is the minimum capillary pressure necessary to force entry of a nonwetting fluid into a capillary opening. A petroleum slug with considerable vertical continuity is necessary to produce the buoyancy that will force entry into the capillary openings of a reservoir rock. After movement has taken place,

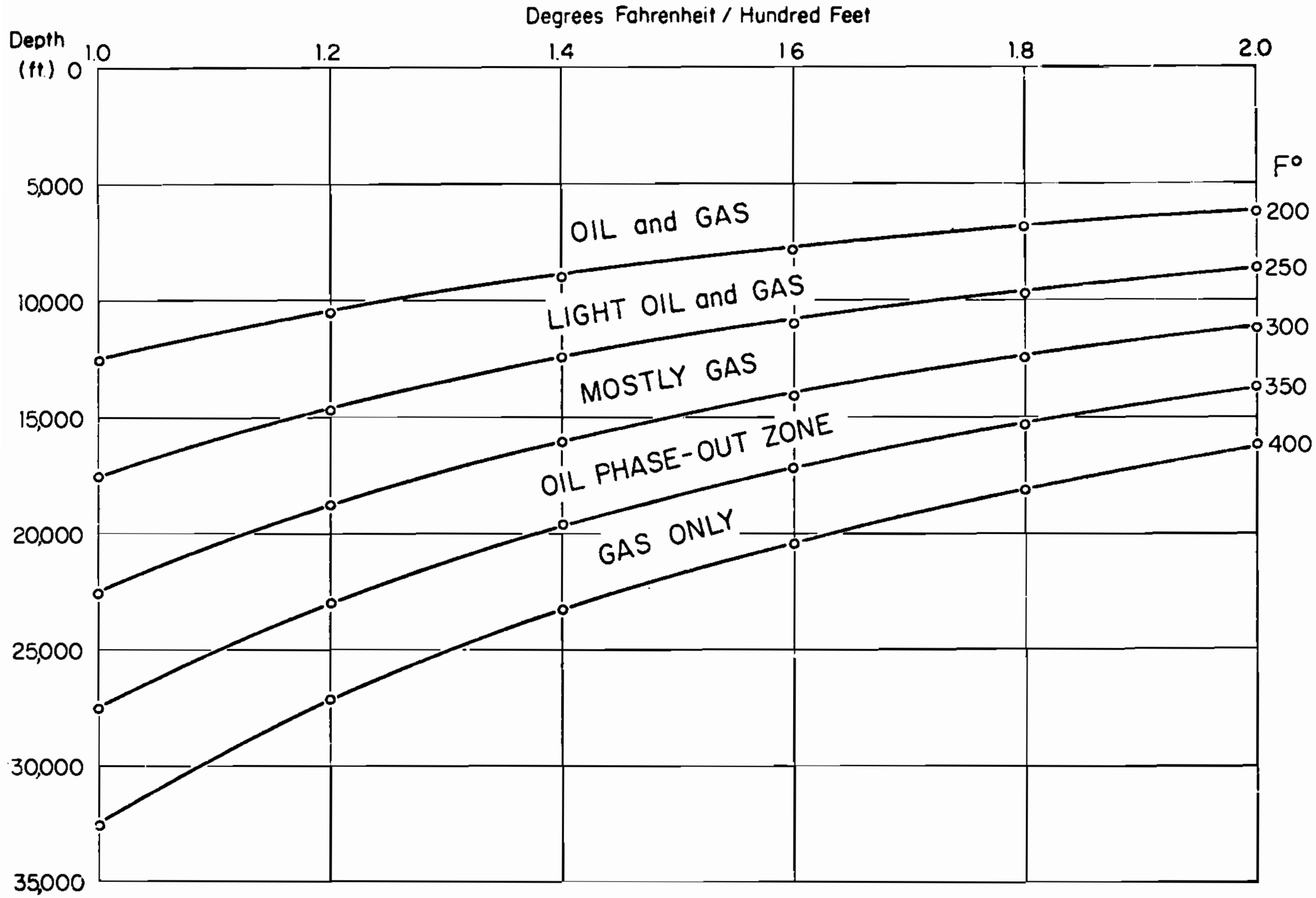


Figure 1-3.--Depth, geothermal gradient, oil, and gas (Landes, 1966)

there should remain a high petroleum concentration; just below that necessary to begin or continue movement. Migration usually is in a direction that has an upward component. Hydrodynamic conditions may modify the normally upward direction of movement. When the oil or gas in the reservoir rock reaches a position beyond which it cannot penetrate it may accumulate into an economically significant concentration. The end of the migration path is a trap.

Complex classifications of traps have been proposed. In the simplest scheme, traps are classified into three groups: (1) structural, (2) stratigraphic, and (3) combination. Structural traps are the result of rocks being folded into domes or anticlines, or are the result of faults in the rock sequence. Stratigraphic traps are the result of events during the deposition of sediments (channels, beaches, reefs, etc.) or during development of an unconformity (uplift and erosion, followed by renewed deposition). Combination traps contain elements of the two basic trap types.

Structural traps have been the objective of most of the world's petroleum exploration because they are relatively easy to discover by geological or geophysical methods and they have the potential for multiple producing formations. Stratigraphic traps are more difficult to find and the potential for more than one producing formation in an exploratory well is low. Closely related petroleum accumulations throughout the world, whether structural or stratigraphic, are characteristically lognormally distributed with regard to producible reserves.

SUMMARY

The occurrence of oil and natural gas is controlled by the depositional environments of sediments, the geologic and thermal history of the enclosing rocks, and the conditions of fluid movement within areas of traps. Anaerobic chemical environment, rapid deposition of organic-rich sediments, a moderately high geothermal gradient, regionally extensive or discontinuous reservoir rocks (sandstones and carbonates), and development of a significant number of traps characterize the world's most petroleum-productive areas.

Factors that control petroleum occurrence in a moderately to well-explored area may be used to predict the undiscovered oil and gas potential of the area. Unexplored frontier areas are analyzed on the basis of analogy with explored areas. Geological and geophysical knowledge of structural configuration and wells drilled to determine the presence or absence of source and reservoir rocks are necessary for estimates of undiscovered potential in frontier areas. Various statistical methods have been applied (Haun, Ed., 1975), but knowledge of the principles of petroleum geology are the basic theme in all methods.

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CHAPTER 2

THE PETROLEUM EXPLORATION CHALLENGE WITH RESPECT TO THE DEVELOPING NATIONS

Bernardo F. Grossling[1]

INTRODUCTION

About 2 years ago I was asked by an international lending organization to assess the petroleum potential of developing nations throughout the world. Until this question was posed to me, I had accepted the view that the petroleum potential of areas like Latin America and Africa was much lower than that of the United States, and if they had produced so little oil it was simply because there was not much oil there.

However, I had to reexamine the problem and so I did. The first question I asked myself was how intensive drilling had been in various areas of the world. Inquiries to knowledgeable experts and search of the literature disclosed the fact that such totals had not been either compiled, or if compiled had not been published. Because of the limited time I was allowed for the study I developed a strategy of estimating these numbers from industry and professional journals on petroleum exploration and development. The numbers thus compiled, quickly began to reveal the surprising fact that the bulk of the past drilling for petroleum in the world had been concentrated in the United States, and that even now it continued to be so concentrated, year after year.

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Then I reviewed the broad geologic conditions of the various continents to see what factors could explain the alleged remarkable productivity of the United States, and of the Middle East. For the Middle East these geologic factors can readily be found, but they do not appear to single out the United States as a nation more favored with oil than others with a similar tectonic framework.

THE OUTCOME OF PAST PETROLEUM DEVELOPMENT

First, I would like to briefly highlight the outcome of past petroleum exploration throughout the world:

1. Of all past production the United States accounts for 34.9 percent of the oil, and 59.5 percent of the gas.

2. Seven countries (USA, USSR, Venezuela, Saudi Arabia, Iran, Kuwait, and Iraq) account for about 80 percent of the cumulative oil production; and four countries (USA, USSR, Canada, and Venezuela) for about 80 percent of the cumulative gas production of the world.

3. By comparison, the non-OPEC developing countries including the Peoples Republic of China, account for 6.0 percent of the cumulative oil production and 4.9 percent of the cumulative gas production of the world.

The current petroleum stance can be highlighted as follows:

1. Eight countries (USSR, USA, Saudi Arabia, Iran, Venezuela, Iraq, Kuwait, and Nigeria) account for about 73 percent of current world oil production; and five (USA, USSR, Canada, Netherlands, and Iran) account for about 71 percent of current world gas production.

2. By comparison, the non-OPEC developing countries including the Peoples Republic of China, account for 7.5 percent of current world oil production and 7.1 percent of current world gas production.

The short-term outlook, which could be gauged by the proven reserves as of the end of 1975 can be highlighted as follows:

1. The OPEC countries account for 67.6 percent of the oil proven reserves, and for 34.8 percent of the gas proven reserves of the world.

2. The USSR and the United States account for 17.2 percent of the oil proven reserves, and for 45.6 percent of the gas proven reserves of the world.

3. By comparison, the non-OPEC developing nations including the Peoples Republic of China, account for 7.9 percent of the oil proven reserves, and for 6.0 percent of the gas proven reserves of the world.

A simplistic interpretation of such past outcome could be misleading to judge the potential of improperly explored areas.

SCHEME FOR ASSESSING PETROLEUM OPPORTUNITIES

For assessing the remaining petroleum opportunities among the various countries, I have chosen a dual partition system. First, I have classified them in two groups: (1) developed countries or regions, and (2) developing countries. This classification is a recognition of the great difference in petroleum supply-demand posture between developed and developing economies.

The first group (developed countries) is further subdivided in: USA, USSR, Canada, Japan, Australia and New Zealand, and Western Europe. The first four subdivisions correspond to the largest single-country developed economies, and the last two correspond to convenient groupings of countries with rather similar energy supply-demand positions. In Western Europe, I have included all European countries, with both market and socialist economies, other than the USSR which is analyzed by itself.

The second group (developing countries) is subdivided in four: Africa and Madagascar, Latin America, South and South East Asia, and the Peoples Republic of China. In Latin America I have included, with minor exceptions, all of the countries south of the United States. That is, it includes: Mexico, Central America, Caribbean, and South America. Because of the richness of its current petroleum resources the Middle East is set by itself; and I have included in it Turkey and Israel. In the category of South and South East Asia I have included mainland countries east of the Middle East and south of China as well as the islands of Oceania, other than Japan, Australia, and New Zealand.

The Middle East, which strictly speaking is a developing area, is to be handled separately because of the current importance of its petroleum proved reserves.

The above scheme essentially encompasses all the world areas which are under national control. It does not include Antarctica, the continental margins beyond the edge of the continental shelves, nor a few areas around some small oceanic islands.

Ideally, to gauge the petroleum potential of given areas one would like to construct a measure built with quantifiable factors (such as sedimentary area, sedimentary volume, thicknesses, lithology, structure, and the like). Yet actual knowledge of most of the factors one would like requires prior geological and geophysical exploration as well as drilling in an area. There are vast areas of the world which are still inadequately known, with none or insufficient drilling, or the knowledge about them may not have been generally disclosed. Therefore, to obtain a worldwide overview of opportunities one has to retrench to a very few factors. I have selected for this presentation one of them, namely the extension of sedimentary basins. Such basins have been defined, for instance, in the regional evaluations published by the American Association of Petroleum Geologists.

Although, in general, there is already a rather good definition of these sedimentary areas throughout the world, there is still an element of surprise. Recent developments in south and southeastern Sudan provide one example of how incomplete the knowledge of the extent of sedimentary areas in regions with incipient exploration has been. In 1974, an oil company began to explore interior basins of Sudan covering about 200,000 mi^2 in a region which previously had been presented in some of the literature as of no interest for petroleum exploration. Also there appear to be other areas in northern Sudan with possible petroleum interest.

PETROLEUM PROSPECTIVE AREAS

Utilizing various published data, and personal knowledge of these areas, I have made the estimates of the extent of the sedimentary areas in various countries or regions, which are summarized in Table 2-1. In general, a minimum sedimentary thickness of 1,500 ft has been required to define the edges.

It is observed that the developed countries possess about 45.1 percent of the total prospective area, the Middle East countries about 4.9 percent, and the developing countries, other than the Middle East, about 50 percent.

CUMULATIVE PETROLEUM DRILLING IN VARIOUS REGIONS

Now we come to the question of what has been done about these prospective areas. There are several measures of activity one could use, but I have singled out only drilling. As for drilling one could consider: cumulative number of wells drilled, cumulative number of exploratory wells drilled, and cumulative drilling footage. The problem again is the lack of adequate published drilling statistics worldwide. Some countries consider petroleum drilling to be a state secret, others have inadequate published records of drilling.

The estimates which I have made, in collaboration with Diane T. Nielsen, Computer Specialist, of the total number of wells drilled in various world regions up to 1975 are summarized in Table 2-2. Because the conclusions to be drawn hinge on the inadequate past drilling in certain areas, an upper bound estimate for the drilling in these areas has been sought in these estimations.

The drilling figures show that the overwhelming majority of all past petroleum drilling is concentrated in a few developed countries, and mainly in the United States. By contrast, in the developing countries only about 4.2 percent of past drilling has taken place.

Next we may consider the number of exploratory wells rather than total wells. My estimates of these numbers are summarized in Table 2-3. Again the fact emerges that exploratory drilling

TABLE 2-1.--Resume of world petroleum prospective areas
(Onshore + offshore to 200 m water depth)

Developed countries or regions	Area (mi^2)
USSR	3,480,000
USA	2,470,000
Canada	1,887,400
Australia and New Zealand	1,545,000
Western Europe, market economies and socialist	1,322,500
Japan	256,200
	10,961,100
	(44.7%)
Developing countries or regions, other than Middle East	
Africa and Madagascar	5,004,690
Latin America	4,804,600
South and South East Asia	1,636,500
China, P.R.	900,000
	12,345,790
	(50.4%)
Middle East	1,200,000
	(4.9%)
World Total:	24,506,890
	(100%)

TABLE 2-2.--Resume of world petroleum drilling
(As of end of 1975)

Developed countries or regions	Number of wells	
USSR	about 530,000	
USA	2,425,095	(75%)
Canada	about 100,000	
Australia and New Zealand	about 2,500	
Western Europe	about 25,000	
Japan	about 5,500	
	3,088,095	(95.5%)
Developing countries or regions, other than Middle East		
Africa and Madagascar	about 15,000	
Latin America	about 100,000	
South and South East Asia	about 11,000	
China, P.R.	about 9,000	
	135,000	(4.2%)
Middle East	about 10,000	(0.3%)
World Total:	3,233,095	(100%)

TABLE 2-3.--Resume of world exploratory petroleum drilling
(As of end of 1975)

Developed countries or regions	Exploratory wells	
USSR	about 100,000	
USA	about 482,000	(74.7%)
Canada	about 20,000	
Australia and New Zealand	about 500	
Western Europe	about 12,500	
Japan	about 1,000	
Total	616,000	(95.4%)
Developing countries or regions, other than Middle East		
Africa and Madagascar	about 6,500	
Latin America	about 14,000	
South and South East Asia	about 5,000	
China, P.R.	about 2,000	
Total	27,500	(4.3%)
Middle East	about 2,000	(0.3%)
World Total	645,500	(100%)

is concentrated in a few developed countries. And in the developing countries only about 4.3 percent of the exploratory drilling has taken place.

The last factor we want to consider, as to drilling as a measure of activity, is the drilling footage. If the average well depth were the same for all regions then the number of wells would be equivalent to using the total drilling footage. The question then resolves to the variability of the average depth from region to region. Some estimates of the average depth of all past drillings are as follows:

	Ft	Relative
USA, 1949-1972 av.	4,231.2	1
Canada, 1945-1974 av.	4,055.6	0.96
Australia and New Zealand, 1945-1974 av.	5,097.0	1.20
Western Europe, market economies, 1945-1974 av.	5,393.3	1.27
Japan, 1945-1974 av.	4,147.8	0.98
Africa and Madagascar, 1946-1974 av.	4,005.4	0.95
Latin America, 1949-1972 av.	4,448.0	1.05
South and S.E. Asia, 1951-1972 av. (est.)	4,200.0	0.99
Middle East, 1946-1974 av.	6,293.6	1.49

To take into consideration average well depth we could, for instance, take the U.S. average well depth as a reference and increase the numbers of wells in Latin America by 5 percent, in Africa and Madagascar decrease by 5 percent, and in South and South East Asia decrease by 1 percent. But the relative discrepancies of drilling densities between the very few densely drilled countries and the developing countries are so much greater, such corrections would not substantially decrease the differences.

DENSITY OF PETROLEUM DRILLING IN VARIOUS REGIONS

Utilizing the two previous sets of estimates, I have calculated the density of petroleum drilling, in wells per square mile of prospective area. Table 2-4 gives for the countries or regions considered both the total wells per square mile, and the exploratory wells per square mile. The values are arranged in decreasing exploratory drilling density.

TABLE 2-4.--Density of petroleum drilling
(As of end of 1975)

Country or regions	Wells/mi^2	Exploratory wells/mi^2
USA	0.98	0.20
USSR	0.15	0.029
Canada	0.053	0.011
Western Europe	0.019	0.0094
Japan	0.021	0.0039
Australia and New Zealand	0.0016	0.0032
*South and South East Asia	0.0067	0.0031
*Latin America	0.0021	0.0029
*China, P.R.	0.010	0.0022
*Middle East	0.0083	0.0017
*Africa	0.0031	0.0014

*Developing area.

It is quite clear that in the developing countries the drilling density is about two orders of magnitude smaller than in the United States, and about one order of magnitude smaller than in the USSR. The developing countries are on the bottom of the list of exploratory drilling density.

WINDOW ON OIL CHART

To visualize these questions I have prepared Fig. 2-1, Window on Oil, which was based on the previous estimates that I had made of the size of the prospective areas and of the cumulative petroleum drilling.

The areas within the black rectangles of the chart correspond to the relative areas of the petroleum prospective regions indicated. The total prospective area of the earth--onshore and offshore to the 200-m water depth--is represented by the entire

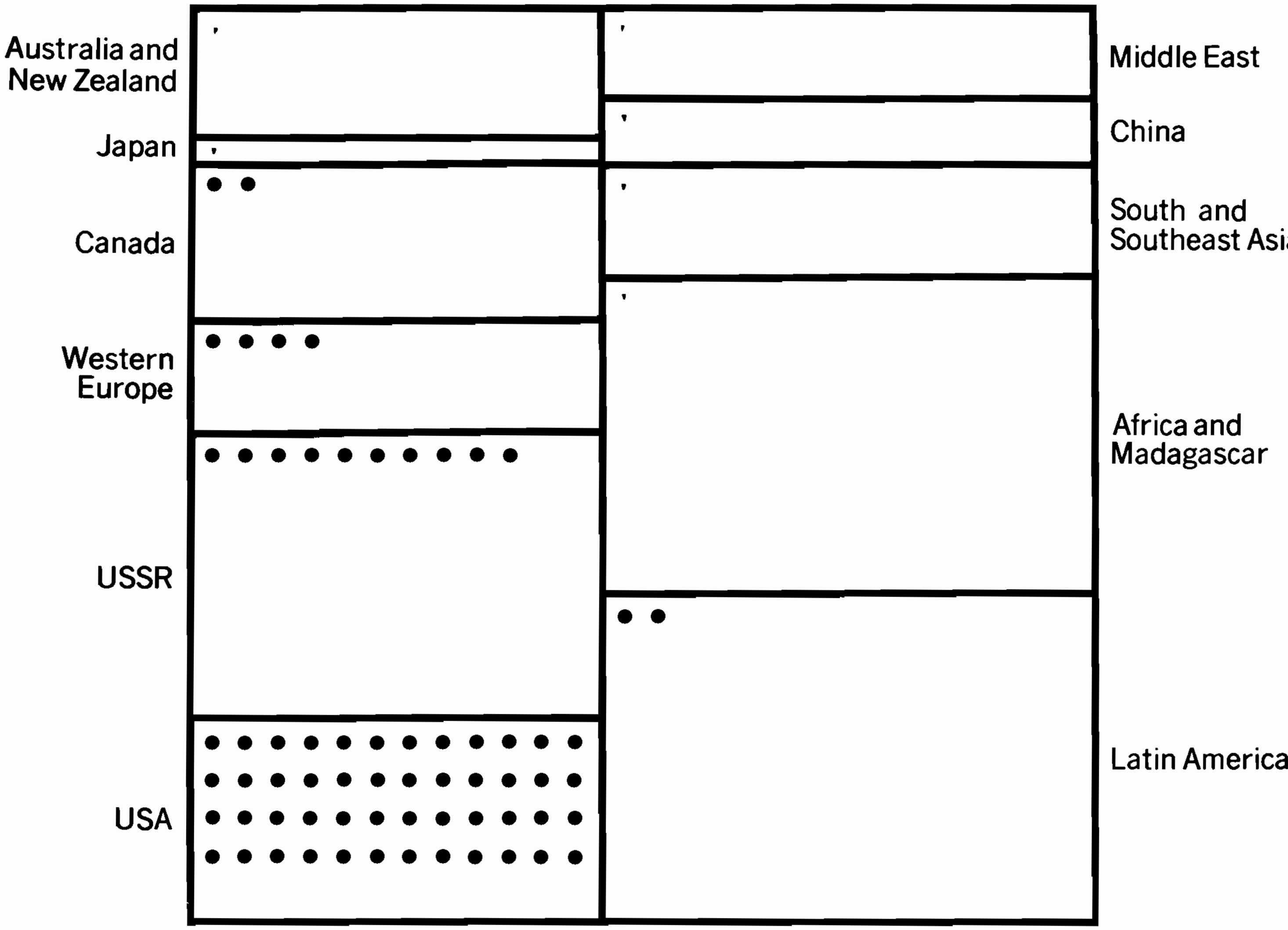

Figure 2-1.--Window on oil. Areas within black bars represent, to scale, the extent of the petroleum prospective areas (onshore and offshore to 200 m water depth). Each full black circle represents 50,000 wells (exploratory and development) drilled in each portion of the chart. Numbers of wells smaller than 50,000 are approximated by segments of the full black circles.

square. The six partitions on the left of the figure correspond to the developed countries: USA, USSR, Western Europe, Canada, Japan, Australia, and New Zealand. In Western Europe, as used here, are included both market-economy and socialist countries.

The developing countries or regions are shown on the right side. They are: Latin America, Africa and Madagascar, South and South East Asia, Peoples Republic of China, and the Middle East. The developed countries control 45 percent of the total prospective area; the developing countries, including the Middle East, 55 percent.

Also shown in the chart is the cumulative drilling in each of the regions or countries shown. Each full black circle represents 50,000 wells. There are 65 full black circles in the figure, 48 of which are in the United States, 10 in the USSR, 4 in Eastern Europe, 2 in Canada, and 2 in Latin America. As in none of the other areas are there 50,000 wells, only a proportional sector of the full circle has to be used.

The additional drilling, both exploratory and development, which might eventually be attained in the United States may be of the order of 600,000 to 800,000 wells, that is, 12 to 16 full black circles in the figure. Therefore, one would have to cluster the existing 48 a little closer to allow for the 16 additional full black circles.

FINAL COMMENTS

The previous analysis demonstrates that there is a substantial petroleum drilling gap in the developing countries of the world. Moreover, the non-OPEC developing countries of the world possess about half the world petroleum prospective area. An opportunity for substantial discoveries in Latin America, Africa and Madagascar, and S. and S.E. Asia is apparent.

Obviously, there is much need for a refined evaluation of petroleum prospective areas throughout the world. This would be facilitated by the disclosure of more information about petroleum exploration in the various countries.

Economic and political conditions in the past readily explain how this drilling gap came about. But the sense of urgency brought about by the energy crisis should help to resolve these economic and political impediments.

Notes on Sources of Information Utilized: The basic sources of information utilized for the oil and gas annual production, and for proven reserves have been statistical data published in issues of the Oil and Gas Journal and the World Oil, and statistics published by the U.S. Bureau of Mines.

For the cumulative oil and gas production the main source has been the "Summary of 1972 Oil and Gas Statistics for Onshore and Offshore Areas of 151 Countries" by S. E. Frezon, U.S. Geological Survey Professional Paper 885, 1974.

The size of the prospective areas has been measured on published maps of individual countries or regions in issues of the Bulletin of the American Association of Petroleum Geologists.

The main source of information about the drilling for petroleum has been the annual Foreign Developments issues of the American Association of Petroleum Geologists, statistics published in the World Oil, information obtained from many geologic papers on specific regions, and estimates by the author.

CHAPTER 3

TOTAL ENERGY RESOURCE EVALUATION AS PART OF FUTURE OIL AND GAS EXPLORATION[1]

Alan Lohse[2]

Technology exists to examine the crust of the earth in search and evaluation of all the earth's known forms of energy resources. Technology increasingly evolves to find these resources in greater detail and to produce them in a more cost-effective manner.

Higher levels of exploration technology do not, however, negate the essential human input of scientific knowledge and imagination applied to interpretation of technical data. A famous United States industry oil finder once said that "oil is found in the minds of men." That statement of three decades ago is no less true today.

Better exploration and production technologies can be likened to computer technology. Very few if any computer applications reduce the total amount of work to be done by man.

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[1]Presentation of this paper at the UNITAR-IIASA Conference was based largely upon colored slides to illustrate each of the technologies and tools referred to. As a result of nonuse of color reproduction, this text is abbreviated and condensed from the original paper.

Reference to specific companies, products, or services is made only to cite examples of technologies that are presently available, as illustrated in the original presentation. These references in no way imply that similar or identical services or products are not available elsewhere.

[2]Gulf Universities Research Consortium, 5909 West Loop South, Suite 600, Bellaire, Texas 77401.

Instead, computers create more work to be done by more men. The work can be done either better and faster than before computers or worse and faster, depending upon the men themselves.

As more diverse data are available through computer applications, the human mind is increasingly required to analyze, synthesize, and interpret these data into useful forms of information, and, ultimately, into knowledge that expands man's needs for more data to be applied to newly defined and complex problems.

In similar fashion, present-day exploration for oil and gas, ranging from satellite imagery and computerized data processing to conventional field work from desert to jungle, can be expanded through careful planning to include evaluation of the total potential energy resource of any nation.

Exploration for fossil energy resources can be represented by an inverted cone pointing downward from broad reconnaissance conducted high above the earth to geophysical and geological field work leading to drilling at specific sites. As the cone converges upon specific locales and prospects, areas of coverage decrease but costs of exploration generally increase. The objective of a well-planned exploration program, therefore, is to identify multiple targets in the broadest and least expensive reconnaissance work and to use more restricted and expensive detailed work to focus upon specific prospects within those target areas.

The upper level of reconnaissance presently exists through satellite imagery. This imagery provides broadest coverage at least cost to the private consumer and operates independently of geopolitical control.

Reference is made to the article by Michel T. Halbouty in the May 1976, Bulletin of the American Association of Petroleum Geologists for a detailed description of the imagery and examples of its worldwide application.

Satellite data are not an entire answer to exploration, nor does any unique answer exist. They are, however, a new element of information providing worldwide coverage, to be combined with other techniques leading to recognition of multiple target areas for further evaluation.

Satellite data are obtained from the Earth Resources Technology Satellite (ERTS) renamed LANDSAT. The first satellite was launched July 1972, followed by the second launch in January 1975. The LANDSAT spacecraft follows a circular orbit 920 km (570 mi) above the earth's surface. It circles the earth every 103 minutes, which is about 14 times per day. It covers the entire globe, except the poles, every 18 days and crosses the equator at 0930 local time each day.

Each standard spacecraft image covers an area of 34,385 km^2 (185 km by 185 km), which is 13,225 mi^2 (115 mi x 115 mi). The images are available in digital form on standard magnetic Computer Compatible Tape (CCT) with four CCT's per image. The data are available to anyone in the form of processed black-and-white or color photographic images, or the CCT's.

Processing of data is constantly improved by various contractors, and is available experimentally with ground control within 1 meter horizontally and vertically.

Conventional color processing of imagery data produces "false color" images in which vegetation appears red, water appears black, and urban areas together with shallow or silty water appear blue.

Halbouty's (1976) article contains a number of displays showing the geological and/or cultural interpretations that have been made on various LANDSAT images to provide detailed geological structural and stratigraphic information, as well as the location of regional features not recognized heretofore. One illustration shows the possible location of gas seeps in the North Slope of Alaska, as interpreted from successive overflights showing anomalous snow-free areas.

Within the cone of exploration between satellite imagery from the sky and field work upon the surface, airborne radar provides another form of imagery that is useful either in combination with satellite reconnaissance or as an initial reconnaissance tool.

Since about 1971, side-looking airborne radar (SLAR) has matured from an experimental commercial system to a proven geophysical tool.[3] This system represents the most advanced land-based, commercial, all-weather mapping system in the world.

As exemplified by equipment and service of the Aero Service Corporation, the Goodyear synthetic aperture X-band radar system maps a swath of terrain 20 nautical mi (37 km) wide. The swath is offset 5 nautical miles from the ground tract of the aircraft as a characteristic of the side-looking airborne radar (SLAR) installation. The synthetic aperture concept allows a uniform resolution of about 40 ft (16 m) every place on the imagery.

The relatively long wave length of 3.12 cm penetrates all but the most severe weather and exceeds the quality of satellite imagery in this respect. The normal flight altitude of 40,000 ft and parallel 8-nautical-mile line spacings yields 60 percent overlap radar for stereo-viewing and stereo-metric photography.

During 1971 and 1972, a SLAR aircraft mapped more than 5×10^6 km^2 in northern South America. The SLAR programs acquired detailed near-orthographic imagery over areas heretofore unmapped and mostly unphotographed except in satellite imagery.

Through geological interpretation of SLAR imagery, the Guayana shield of northern South America and sediments to the west of the shield toward the Andes were differentiated into intrusives, volcanics, metasediments, and sediments, together with the mapping of regional and some local faults and structural folds. This interpretive work was accomplished despite dense vegetation cover of the majority of the area.

Several South American countries have contracted for radar coverage of undeveloped areas for the purposes of mineral exploration and planning of general resource development.

A regional mapping program conducted by the Department of Mineral Production, Ministry of Mines and Energy, the Republic

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[3]In the spring of 1971, a Goodyear GEMS radar system, inertial navigation SHORAN/HIRAN guidance system, radar profiler metric mapping and multi-spectral cameras were installed aboard a CARAVELLE twin-jet aircraft owned by Aero Service Corporation, Houston, Texas, and readied for commercial contract work.

of Brazil, exemplifies the use of airborne radar mapping together with selected low-level oblique photography to identify and delineate a variety of natural resources (Projeto Radam, 1973).

Projeto Radam produced a series of maps of soils, land forms, areal geology with generalized subsurface cross-sections, vegetation, and interpretative maps of optimum land use development, all of which provide valuable basic information for regional resource evaluation and development planning.

Geological coverage from a program such as Brazil's Projeto Radam is the beginning of a knowledge base for locating stratigraphic and structural traps for oil and gas and other fossil energy resources.

In some areas, low-altitude oblique photography complements the radar imagery by providing surface information to relate vegetation and soil characteristics to subsurface stratigraphy. Geological data derived from this combination of survey data can provide the basis for initial stratigraphic interpretation and further program planning to distinguish between oil-bearing marine lithofacies; coal, oil, shale, and tar sand-bearing transitional lithofacies; and terrestrial lithofacies, which, in the United States, contain a large percentage of the uranium ores.

Geological and geophysical field work, including core drilling, are most effectively used to confirm and evaluate specific targets leading to location of sites for exploratory drilling. The utility of geophysical programs is greatly enhanced in this decade by a variety of data processing techniques developed principally by contractors in a competitive marketplace for services.

As exemplified by the work of SEISCOM DELTA, Inc.,[4] conventional black-and-white reflection seismic display can be improved by systematic vertical exaggeration that enhances geological rock and stratigraphic variations, fault patterns, and

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[4]Principal offices located in Houston, Texas.

structural anomalies. The use of colors in displays of seismic data such as reflection strength (amplitude) independent of phase (peak or trough) displayed in colors representative of rock density and porosity, not only assist in geological interpretation but in semi-quantitative evaluation of hydrocarbon accumulations.

Improvements in geophysical data processing through computer programs are advancing rapidly in the competitive marketplace. For example, some processing makes possible not only the ready identification of low angle unconformities resulting from ancient orogenies, but also the distinction between various rock types, as between sandstones whose intermediate amplitudes are automatically processed and displayed as yellow color and limestones whose high amplitudes are displayed as gray-blue colors.

As these capabilities are combined with identification of coal beds, tar sands, and even possibly interbedded sandstone-shale sequences within terrestrial lithofacies that contain the roll-fronts of high grade uranium ore, a total fossil energy exploration program becomes routinely feasible.

It has been said many times that the ultimate test of an exploration program is reached through the drill bit. This is no longer true in those geological provinces characterized by "tight" gas-reservoirs or low oil saturations.

Modern energy resource exploration and evaluation require (a) a sophistication of formation evaluation techniques that did not exist in the decades of 1950's and early 1960's, and (b) improved production technologies that, for many applications, are in research but not yet commercially feasible.

The goals of formation evaluation and resource production may be thought of as a second cone standing upright within the earth's crust, whose apex is the earth surface site of the borehole and which extends downward and outward to encompass as large a volume of rocks as the state-of-the-art allows.

Formation evaluation through the combined use of logging methods and cores exists as a high state-of-the-art. (See E. H. Koepf, Chapter 11.) Quantitative determinations of in situ resources can be made within plus or minus 2 or 3 percent.

Better formation evaluation tools of different kinds are forthcoming, as, for example, the borehole gravity meter (BHGM). Although the scope of BHGM application needs to be improved, as in its limited tolerance to heat and motion, the BHGM has demonstrated the capability of improved determinations of fluid densities beyond the invaded zone of drilling mud filtrate, better gas-detection, detection of reservoir fluids behind casing, and differentiation of rock porosities laterally from the well bore at sufficient distances to facilitate identification of changing rock facies and extents of ore bodies. (Jageler, 1976; McCulloch, et al., 1975.)

Production technologies have improved within the past decade beyond conventional oil and gas well systems and underground or open pit mining, as exemplified in the solution mining of uranium "yellow cake" ore in South Texas which not only produces the ore through the borehole but eliminates one step in surface processing.

Research is being applied in situ production methods for coal reserves and for tar sand or heavy oil deposits, but not with sufficient priority, in my opinion, to provide sufficient short-term or mid-term levels of production technology for these fossil fuels.

Development of cost-effective technologies for in situ production of energy resources through the borehole, with minimum surface impact and with reduced processing of the resource in surface plants, can provide the greatest overall benefits of any production research now in progress.

An additional aspect of energy resource evaluation is prediction of future reserves. Many references are made to Dr. M. King Hubbert's use of the bell-shaped curve to predict the quantity of an exhaustible natural resource such as oil or gas, as shown in one of his early publications (Hubbert, 1958) and numerous later references. Dr. Hubbert originally used this curve to estimate the rate at which new discoveries and new reserves could be expected <u>when the quantity of a resource is known</u>.

Too much is made of the original Hubbert technique to predict the quantity of ultimate recovery. The area under the curve, representing cumulative production of the resource, is determined by man and not by nature. Nonliving earth resources do not become extinct, as did the ancient dinosaurs, but become progressively scarce until their finding and production costs can no longer compete with an alternative resource. It is, therefore, fallacious to use the shape of the back side of a symmetrical bell-shaped curve to predict decline of availability of the resource when the back side is determined by economics and national policies in future decades that are significantly different from those that determined the front of the curve in past decades.

Technology and human "know how" exist to find any energy resource within or upon the earth for which there is sufficient demand in a viable economic marketplace. Any necessary supplementary technologies will be forthcoming as the marketplace requires. A basic tenent of the industrial world is that technology follows economics, just as certain qualities of life such as freedom from endemic disease, reduced infant mortality, and increased longevity of life are related to availability of low-priced energy.

Future supplies of energy resources are not dependent upon technology but upon whether governmental policies that impact the marketplace as economic and regulatory incentives or disincentives.

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CHAPTER 4

IMPLICATIONS FOR FUTURE PETROLEUM EXPLORATION

Orlo E. Childs[1]

INTRODUCTION

Exploration for petroleum has long been one of the most exciting activities of the geologists and oil industries of the world. The finding of commercial accumulations of oil and gas in the subsurface has been a remarkable success story, throughout the world, during the past half century. From this endeavor has come a great supply of natural resources that undergirds the energy needs of a growing civilization. Locating these deposits has never been direct and simple, and the spectre of failure has always been a part of the economic risk to be assumed. Secondary geologic features associated with and in some places indicative of oil accumulation are often the only ones available to geologists, and the process of exploration is crowded with inference and implication. Courage of conviction, based on careful inductive reasoning, is required in the ultimate test of a working hypothesis that oil and gas have accumulated at a given site. The first step in this test is to determine whether certain physical conditions are present. These are common to most successful petroleum exploration, and are as follows: (1) There must be evidence of source materials from which oil and gas might be derived. Rich organic constituents of regional sedimentary rocks must be expected at a given site. Often the occurrence of oil seeps, mud volcanos, or proven production in the

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[1]Texas Tech. Univ., Lubbock, TX, USA.

region help in establishing that petroleum may, in fact, exist in the subsurface rocks. (2) Rock characteristics, such as porosity and permeability, must be present to control the ease of fluid migration. There must be reason to expect that certain layers in the subsurface are made of rocks through which fluids can move in response to differential pressures. (3) It should be demonstrable that geologic conditions exist which interrupt movements of oil or gas. Structural entrapment, or lateral change of permeability must be expected.

In the past, energy uses increased constantly, encouraged by ready availability of newly discovered oil and gas. Costs of exploration for oil were moderate. Wildcat well-drilling could be expected to be shallow and relatively free of mechanical difficulties. Only a few wells reached costly depths. The ratio of successful wells to dry holes reflected an acceptable risk, and the long-term economic success associated with successful wells overshadowed the losses from unsuccessful drilling projects. The geological characteristics in the shallow subsurface of well-known producing provinces were extended to new areas with a surprising degree of confidence. Economic relations between cost and the price of products could be foreseen with acceptable accuracy. Stable (or gradually increasing) costs of drilling and exploration were a part of the operating environment, and reasonable forecasts could be made. Undue geological complexity was avoided as too costly, and there always seemed to be less expensive alternatives available for testing. The oil-seeker could choose high-risk or low-risk areas to match a myriad of expected economic incentives. The long-term role of government regulation was understood, and drastic change was not anticipated.

Often there was a conscious effort to minimize the exploration steps before drilling. The resulting cost reduction was a respectable measure of the skill and success of the explorationist; for an exploration geologist to be called an "oil finder" was a high accolade. It meant he had become so skilled as to reach his target without the frills of "unnecessary geology for geology's sake." If the wildcat well was successful, subsequent development wells would eventually answer the unknowns of the wildcat venture. If the drilling did not succeed, many were pleased by all the money that had been saved in the effort. It seemed not important to spend valuable time to investigate, and explain in detail, why one well produced oil in economic quantities and another did not. Autopsies of dead projects were brief, and often looked upon as "throwing good money after bad." The dominant target of a successful oil or gas producing well was so important to explorationists and to their companies that other energy sources such as coal, tar sands, oil shale, and gilsonite were interesting, but not really important. They were hardly ever considered a part of the excitement of the economic present; rather, they were relegated to some remote future economy and some imagined future need.

Now we must look at a new set of needs and a future laden with new threats and new promises. Can we simply enlarge the exploration target of natural liquid petroleum, using general exploration techniques to seek out all sources of oil and gas, or will each new source require its own specially-targeted efforts? What is common to all such exploratory efforts, and what specialties must emerge? Has the pendulum of exploration specialization swung so far from generalization as to be self-defeating? Can a viable exploratory policy take both approaches into account, and still answer contemporary needs within a reasonable timeframe? There are ample questions, but no panacea. With the easy recovery of obvious resources already near completion, we must turn to less accessible sources, with their hitherto-ignored complexities. We must also face the economic and technological costs those complexities entail.

After three decades of extensive exploration for oil and gas, the geologist now finds himself in a new era of activity. No longer are exploration costs moderate. They have now escalated to ever-changing new peaks, controlled not only by the economy (and political decisions), but also by the remote areas that must now be investigated. Wells can no longer be shallow; we must now expect to drill deeply, in hostile environments where structural complexities challenge interpretation.

M. King Hubbert (1967) has documented the relationship between successful discovery of petroleum and the accumulated footage of exploratory drilling. He notes that in the period of 1928 to 1937, 276 barrels of oil were found for each foot of exploratory drilling. Then he records a rather "spectacular decline" in discoveries-per-foot-of-drilling until, in 1965, the average rate was 35 barrels of new oil discovered per foot of drilling. It is rather remarkable that the figure of 35 barrels per foot has remained somewhat constant for the past 20 years varying between a minimum of 28 and a maximum of 40 barrels per foot. Hubbert's (1972) analysis of these statistics deserves attention,

> The fact that this decline in the effectiveness of exploratory activities occurred during the period of the most intensive research and development of improved methods of petroleum exploration and production can hardly have any other significance than that the diminishing supply of undiscovered oil is becoming increasingly difficult and expensive to find.

Along with the technical difficulty of oil exploration, there are important ambiguities involved in foreseeing the change of economic conditions. The future economic relations among costs of exploration, development, and production, compared to the expected price of the end products, are anything but clear. Oil seekers today no longer have the luxury of choosing low-risk areas for exploration. Avoidance of complex geology in drilling prospects is no longer feasible. The degree of expected government regulation of (or intervention in) both exploration and production is so changeable as to defy estimation.

Yet, the seemingly insatiable demand for petroleum products to meet an escalated worldwide energy requirement dictates that we must accelerate the process of exploration. It must be anticipated that the additional costs and requirements of success can only result in the intensification of effort. Regional geological understanding is mandatory, and as exploration continues for other materials (such as oil shale, tar sands, and coal), these cannot be simply a byproduct in the process of looking for liquid petroleum. They must become equal targets in the effort involving their own specialized exploration techniques.

The complexities of geological and economic conditions, one unique set for each of these energy sources, are such that the differences among these sets require individually targeted efforts. It is inconceivable that any single planned approach for seeking all these natural resources can immediately bring to the energy developer new opportunities for extraction and utilization of these materials. There must be achieved in the future a high level of coordination of all general and specialized methods of exploration, and this must be coupled to continual development of new techniques.

RESOURCES AND RESERVES OF PETROLEUM

As an important ingredient in any long-range plan for answering the energy requirements of the world, it is necessary to make a reasoned estimate of the oil and gas available for production and use. Particularly is this true when the resource involved is finite in quantity. Over the years, many students of energy resources have attempted to foresee the quantity of oil and gas that might be made available. Individual estimates have not always included consideration of the same areas, or the same degree of expectation of production, and there has resulted a great deal of confusion of what has been included in these estimates. One of the problems is that terms such as "reserves" and "resources" have been used interchangeably, when they are by no means synonymous. There has, however, been at least one attempt at clarification. United States Geological Survey Circular 725, written by Betty M. Miller, et al. (1975) has attempted to gather together many of the estimates of undiscovered recoverable oil and gas in the United States. An attempt has been made to derive agreement of definitions, which will allow a reasonable comparison of the figures that have been published. The government geologists have stated a reasonable definition of "resources" and "reserves" which is in common usage within the oil industry and its agencies, but it proves to be not at all consistent with the usual press releases published in the United States:

> Reserves are identified resources known to be recoverable with current technology under present economic conditions. Undiscovered recoverable resources include deposits that are yet to be discovered but are assumed to be economically producible. Resources also include deposits that have been identified but cannot now be extracted because of economical or technological factors as well as some economic deposits that are yet to be discovered.

From the United States, including Alaska and offshore areas to a water depth of 200 m, there have been produced to date a cumulative total of 106 x 10^9 barrels of oil. Reserves, both demonstrated and inferred, are estimated to be 62 x 10^9 barrels. To this must be added the undiscovered recoverable oil resources, which are estimated to be in a range of 50 and 127 x 10^9 barrels of oil. (The lowest value of the range is considered to have a 95 percent probability of being correct, while the highest value of the range is expected to have a 5 percent probability.) The mid-point of the range (88.5 x 10^9 barrels), when added to the reserves, indicates a possible future supply of 150 x 10^9 barrels, or about half again as much as the 106 x 10^9 barrels of cumulative production. Since this future estimate includes varying degrees of probability, the authors make it apparent that we are now somewhere near the mid-point of ultimate recovery of the available resource of petroleum within the United States. Thus, we may have discovered, produced, and used 40 percent of the oil available for our use. At the end of 1974 in the United States the cumulative production of natural gas has amounted to 481 x 10^{12} ft^3. The reserves, those demonstrated and inferred, total 439 x 10^{12} ft^3. It is estimated that the undiscovered recoverable resources will add an amount in the range of 322 to 655 x 10^{12} ft^3 of gas. Using the mean of the undiscovered recoverable resources, together with the reserves that have been estimated, it is anticipated that there may still be 927 x 10^{12} ft^3 of natural gas. This figure might be compared with the 481 cumulative production to date. Others (such as Hubbert, 1972) have estimated that the mid-point of gas production, as compared to expectable recovery, will occur approximately in the early 1980's, a short 6 or 7 years in the future.

The United States was one of the early major producers of petroleum. As such it is an area where we know a great deal about the structure and sedimentary rock environment from which oil and gas are derived. Understandably, the confidence of our estimates is at a fairly high level. This is not the case once an attempt is made to foresee the dimensions of available oil and gas resources worldwide. There are great differences among the published estimates of the ultimate production of petroleum liquids. However, one of the most frequently quoted estimates is that of M. King Hubbert (1969). He has stated that the ultimate world crude oil production will lie in the range of 1,350 and 2,100 x 10^9 barrels of oil. In commenting on the differences between estimates that have been made by various students of the subject, Dr. Hubbert, in his 1974 testimony to the United States Senate Committee on Interior and Insular Affairs, made the statement that recent estimates of ultimately recoverable oil "show a convergence toward a range of from 1,800 to 2,100 x 10^9 barrels." As estimates of world ultimate oil recovery have been done during the past 35 years, it is interesting to note that increased technology, along with increased knowledge of regional geology, have brought with them a steady increase in expectation of crude oil recovery. However, the last 10 years of this period of estimation have begun to show a rather consistent expectation. Warman (1973) has provided a partial list of the published estimates of a number of authors. That list follows:

ESTIMATES OF WORLD ULTIMATE RESOURCES OF CRUDE OIL FROM CONVENTIONAL SOURCES (10^9 barrels)

1942	Pratt, Weeks, and Stebinger	600
1946	Duce	400
1946	Pogue	555
1948	Weeks	610
1949	Levorsen	1,500
1949	Weeks	1,010
1953	MacNaughton	1,000
1956	Hubbert	1,250
1958	Weeks	1,500
1959	Weeks	2,000
1965	Hendricks (U.S. Geological Survey)	2,480
1967	Ryman (Esso)	2,090
1968	Shell	1,800

1968	Weeks	2,200
1969	Hubbert	1,350-2,100
1970	Moody (Mobil)	1,800
1971	Warman (British Petroleum Co.)	1,200-2,000
1971	Weeks	2,290
1972	Warman	1,900
1972	Bauquis, Brasseur, and Masseron (Inst. Franc. Petr.)	1,950

Although the thought is sobering, and may be overly pessimistic, Dr. M. King Hubbert (1972) presents a graph of an expected complete cycle of world crude oil production which anticipates that, in the decade prior to the year 2000, we shall reach maximum world crude oil production. At that time he believes we will have discovered, produced, and used half of the recoverable petroleum resources of the world.

It seems reasonable, then, to expect that in the United States we have now reached the position of having discovered and produced approximately half of the oil and gas we will ultimately find in our country. After the next two decades, we may be in the same position relative to the entire world. The oil and gas that can be easily and inexpensively found have already been discovered. The difficult (and therefore expensive) oil and gas yet to be found will provide a formidable practical challenge to the technologies now developing in petroleum exploration. Extensive--and therefore costly--analysis of all geological parameters must become a part of exploration for petroleum. The methods of exploration must be expanded beyond the typical approaches of the past. Economic limits must be loosened, and the geologist must have far more data available than he has had traditionally. Exploration data and techniques are becoming interdependent. No longer can we hope to find petroleum deposits by strictly geophysical, structural, stratigraphic, or geochemical approaches.

INTERDEPENDENT EXPLORATION TECHNIQUES

For some time after geophysical methods of exploration were introduced into the search for petroleum, those methods were used as a separate and independent check of the conclusions reached by traditional geological studies. Thus, questions derived from geological investigation were seldom addressed by geophysical measurements, and conversely the structural patterns indicated by some geophysical interpretations were quite at variance with regional structural implications. Over the past 30 years, application of geophysical-scientific techniques to the problems of exploration have resulted in many refinements in the problem. Recently the team approach of geologists and geophysicists has become more and more a working partnership. A far more useful and accurate interpretation of geophysical data has been the result. Interdependence between regional geological findings and geophysical measurements has been well-recognized and intensified. It is to be anticipated that the future will see even closer coordination of these disciplines, because they are interpreting the same natural phenomena. Thus, petroleum exploration involving deeper prospective horizons in the earth's crust must involve even closer coordination of geophysics and geology. Deeper accumulations of oil and gas entail greater complications in geological structure and stratigraphic rock changes than those we have seen in the near surface. At shallow depths reasonable projections of surface observations were often reliable. But deep well penetrations in search of oil and gas involve problems of a kind entirely different from those attending the recovery of shallow deposits of coal, tar sands, and oil shale. It is only as the methods of in situ gasification of coal and in situ retorting of both oil shale and tar sands reach a practical level of operation far beyond the present technology that any common exploration techniques for alternate sources of petroleum materials can be expected.

Geophysical Exploration Techniques

As satellite imagery (derived from using various parts of the energy spectrum in scanning the surface of the earth) is beamed to the surface, and reproduced by surface instruments, we have obtained a new and exciting view of the geology of the earth's surface. This remote sensing has allowed a new approach to exploration, involving important regional continuity in representing our analysis of the structure of the earth's crust.

Already we are beginning to recognize certain subtle color tone changes and lineaments that are not entirely understandable at present, though these seem related to mineral deposits and possible subsurface accumulations of oil and gas. As an adjunct to other exploratory techniques, this important scanning of the earth's surface will help tremendously in future petroleum exploration. This is particularly true in areas where surface geology has not been extensively studied, in countries where surveys have been done only as general reconnaissance. However, it should be clear at the outset that the use of remote sensing demands a careful tie to what is termed "ground truth." Thus, the interdependence among remote sensing, geological surface studies, and possible geophysical measurements, is readily recognizable, even as we are just now becoming proficient in the analysis of remote sensing surveys.

As the regional framework of large features of the earth's crust (such as mountain and basin blocks) is evaluated, the geophysical methods of gravimetry and magnetometry become very important exploration tools. These methods are frequently used in new approaches to relatively unknown areas. Again, these involve interdependence with ground studies (which deal with the exposed geology of the region), and this becomes extremely important in interpreting the features of these geophysical surveys. To date these have been reconnaissance tools, but the possibility is emerging that more refined basin evaluation can come from the useful extension of newly developed interpretive skills. The role of structural evaluation by gravimetry is enhanced as new developments have allowed greater portability of equipment; this portends even better applications in future exploratory programs.

The use of the reflection seismograph has long been recognized as one of the most important catalysts of modern petroleum exploration. Interpretation of the hidden subsurface geological structure is of vital concern in the analysis of possible fluid migration, and of the entrapment which results. Wherein this is particularly applicable to oil and gas, the importance of this type of interpretation may be less obvious in future exploration for deep coal seams, oil shale, or tar sands. Yet, the interpretation of subsurface structure is mandatory in the search for possible entrapment of fluids such as oil and gas.

During the past two decades, the utilization of seismology has been especially important in the interpretation of oceanographic data. Important new concepts of worldwide plate tectonics have resulted from the wealth of seismic data accumulated by oceanographic fleets. In addition to this general framework concept, the location of extremely important structural features has allowed the discovery of important new oil and gas accumulations on the continental shelves of many nations. Many new frontiers of petroleum exploration will be studied in detail as the result of future applications of seismology. Seismic reflections of energy induced from a variety of sources, explosive, electrical, or physical, are used in sophisticated shipboard seismic studies. As important as this exploratory tool is to future petroleum exploration, it is by no means independent from the important information to be derived from sampling techniques, in particular the samples and cores from ship-based drilling operations, drilling platforms, and man-made drilling islands. Again, interdependence is clear. We must know not only the structural attitudes of rocks beneath the sea, but we must also know the source bed and reservoir characteristics of the rocks beneath the oceans. This is expensive exploration, but nevertheless it carries the greatest potential for future success that we now recognize.

When natural gas has accumulated in the porous spaces in layers of reservoir rock, the passage of seismic energy through that accumulation differs from the normal velocities shown in the layers above and below the accumulation. The existence of the gas provides a lessened overall density, compared to the surrounding materials, and so provides for a marked decrease in seismic velocities. These so-called "bright spots" are recognizable in modern, computer-aided recording of seismic reflections. A number of natural gas deposits have been located as a direct result of the study of these features. However, other changes in rock characteristics can result in the focusing of seismic waves in such a way as to duplicate the bright spot phenomenon, hence the method is not infallible. However, it does represent an extremely important aspect of future studies, and future exploration for natural gas accumulations. It is interesting to note that coal beds at depth can provide recognizable bright spots on the seismic record. Current studies indicate that it might be possible to induce seismic energy from sources suspended in wells (at the depth of coal seams) and that the lateral passage of seismic waves to a recording in another well might make it possible to depict the lateral coal extent and thickness with surprising accuracy. This could be of great importance to the estimation of coal reserves in deep layers, particularly if a given coal deposit is to be considered for possible in situ gasification. This is an example of a specifically-targeted geophysical study, associated with coal exploration. Still, it has little application to exploration for oil and gas, and would undoubtedly be excluded from normal geophysical studies tied to petroleum exploration projects. As an example of the specific application of geophysics to coal exploration, Hasbrouck and Hadsell (1976) have reported on a geophysics research program applied to strippable coals of western United States. Among other conclusions, they identify four specific applications of geophysics:

> (1) High precision gravity surveys can be used to locate cut outs of thick coal seams; (2) burn facies can be mapped effectively and quickly with magnetic methods; (3) seismic seam waves can be observed when seam boundaries are well defined; and (4) combination of bore hole logging, seismic seam wave certification, and shallow seismic reflection techniques is the preferred geophysical exploration method when precise mapping is required.

Seismic studies have covered large areas of possible petroleum-producing regions in the United States. However, in this coverage there are vital regions covered by thick gravel deposits or lava flows, which have previously resulted in no recoverable data. It is to be expected that in the future these areas will be restudied, but only in the light of a future technology sufficiently advanced to render such studies economically feasible. Here again, interdependence with subsurface data from drilled wells will undoubtedly be demonstrated.

Undoubtedly many important oil and gas accumulations of the future will be closely tied to lateral changes in rock porosity and permeability. The identification of stratigraphic facies change (and the resultant entrapment of fluids that have migrated through layers of sedimentary rock) has been an understandable objective of many geologic regional studies. The use of geophysics in this study has long been sought as an important and valuable adjunct to information derived from subsurface wells. Important applications of geophysical research have centered around the possible location of subsurface reefs and other areas of unusual porosity and permeability. To date these efforts have not been totally successful, but it is certainly to be anticipated that more important technological research achievements can be expected as a part of future exploration techniques. Continued efforts toward the improved resolution of seismic signals are an important part of most geophysical research going on at present. Successful results will undoubtedly be a part of future exploration efforts.

Regional Stratigraphic and Structural Studies

It has long been recognized that a single oil and gas prospect cannot be evaluated independently of the regional stratigraphic and structural framework of which it is a part. In the United States, where extensive oil exploration has been going on for many years, this regional concept has always been a part of the exploration base. Active cooperation between industrial and government scientists has resulted in extensive documented knowledge about the regions of our country. This, of course, is one of the strongest points of emphasis in the work of the United States Geological Survey: Mapping of vast surface areas, together with an insistence upon regional interpretation, has long been the hallmark. Industrial geologists have added to this extensive surface information the extra dimension of subsurface conditions. The subsurface is interpreted from the vast amount of geological data provided by drilling and geophysical surveys. Regional interpretation of the stratigraphic and structural events in the history of an area is intimately involved with the anticipation of stratigraphic changes in the subsurface. These latter are very important in anticipating the blocking of permeability that results in stoppage of oil and gas migration, which in turn may result in commercial accumulation. It is this regional emphasis in geologic studies that has been such an important aspect of petroleum exploration, not only in the areas of extensive exploration (such as the United States), but also throughout the world. Thus, as new areas come to be better known, and geological interpretations are constantly improved by surface and subsurface geological data, the inclusion of geophysical information in future exploration of new frontier areas will be very effective in finding new petroleum deposits.

The slow (and sometimes costly) accumulation of regional information, along with the understanding of geological interrelationships within those areas, has sometimes been considered overly time-consuming, even unnecessary. However, as we face a future in which new oil and gas accumulations are increasingly difficult to find, the reliance on regional geological concepts will become even more necessary than it is now. Thus, the close tie of stratigraphic constituents and structural evolution must be studied and even be extended as background understanding upon which concepts can be projected into unknown frontiers of oil and gas exploration.

Extensive geophysical logs of wells have proven of great value in the interpretation of subsurface geology. Due to the great reliability and usefulness of this tool, actual rock samples might be ignored. In the past we have often felt that the high cost of storage of core and sample rock materials from wells that had been drilled did not justify the expenditures involved. Core and sample libraries already established have either been abandoned, or subjected to such curtailment that important materials have been lost. Neither government nor industry has been willing to face the prohibitive cost of space and curatorial service for subsurface rock samples that have accumulated over the years. Already great bodies of important information have been lost as a result of this practice. In the future it may become even more apparent that we must face the cost of systematic preservation (and therefore future availability) of vital subsurface information available only from cores and rock samples that were collected from drilling operations. This may well be a future cost that somehow must be a part of the urgent petroleum exploration we will face in the decades to come.

Geochemical Exploration

In the past, very interesting changes have been observed in soils and in the rocks outcropping at the surface above known oil and gas accumulations. Yet these changes have not been consistent enough for this exploration technique to be used widely. However, there are enough cases already identified to prove it obvious that geochemical exploration cannot be ignored in future exploratory efforts. Lithologic changes due to reduction of cementing materials in sandstones, color changes identifiable even from remote sensing imagery, and other alterations associated with gas emanations from the subsurface may be far more extensive than is now recognized. Only a few cases have been identified at the present, but they are indeed interesting ones. For some time the study of plant assemblages has indicated several, but nevertheless recognizable anomalies which can be attributed to the emanation of natural gas through the surface soils. It seems reasonable to expect that in the future exploration for petroleum, geochemical evaluations will become even more important than they have been in the past. Inasmuch as future exploration for tar sands, oil shales, and coal will become increasingly important as a source for petroleum, geochemical exploration will be of particular importance; many of these deposits will be near the surface, and hence have an important influence upon geochemical changes that might be identified at the surface.

ECONOMICS AND GOVERNMENT INVOLVEMENT

That the amount of oil and gas available for human use is in finite supply is an inescapable realization. As we approach the time when we have produced half of the oil and gas there is to be used, we must look with careful planning at the future availability of the remaining oil and gas, despite the greater difficulty of discovery. This means that there will be a new set of values in both economic terms and in the involvement of world governments. Industrial and public dependency on the energy derived from petroleum has grown worldwide in the past half century. Much of this needed energy can be found from alternate sources, but until this new energy derivation has been perfected, there is no escape from the current dependency on petroleum. Government involvement in production and utilization of petroleum can be expected at an even higher level than it has been in the past, since so many aspects of the national economy, the public standard of living, and national security are deeply involved in the availability of energy sources.

The scientific method of studying a given problem is common to all students of earth science who employ these methods in the exploration for petroleum. The collection of data, measurements, and observations represent the first step before the invention of causative concepts by induction. Concepts of stratigraphic and structural relationships delineate possible areas where oil and gas may have been entrapped, and so guide the drilling of a test well to determine whether or not the entrapment has taken place. This is the truest type of deductive test of the concepts derived. This has given rise to the oft-quoted comment that "oil is found in the minds of men." Future petroleum exploration into geological situations of greater and greater complexity will require more complete data accumulation than has been the habit in the past. No longer can we afford expensive drilling operations on the basis of limited subcritical data accumulation that might well result in premature and wasteful economic decisions. Costs of exploration, therefore, must be expected to increase, and the employment of capital in exploratory efforts will be at a new scale of risk, because many more wells can be expected to prove unsuccessful in the future. This exploratory activity must continue, yet we must not allow the urgency of need for future supply to force premature drilling. A corollary to this exploratory activity is that we must not permit one or two unsuccessful wells to prejudice our attitude toward large areas. In the past, one or two dry holes have tended to condemn the oil prospects of rather large areas. Once we had the option of seeking new and less risky areas; now this is a luxury we no longer have. Premature abandonment of areas, in the new frontiers of exploration, simply must not happen if we are to provide the future supplies of petroleum the world needs.

The basic economics of cost-of-exploration vs expectation-of-return has long been an integral part of the exploration decision. As long as the price of energy from petroleum is held at an artificially low level, the only manner in which private enterprise has thus far been able to respond is to select targets of large potential production. If the future economics of petroleum utilization will allow exploration for smaller accumulations, there may be many areas to be restudied and retested for smaller objectives than have been the predeliction of the past. Estimates of the ultimate size of an accumulation of oil and gas that has not yet been found often have been made on the basis of insufficient preliminary data. Pessimistic assumptions have often resulted in the death of a program before exploration has truly begun. Or, on the other hand, ill-conceived exploration programs have been based on vague assumptions and the resultant lack of success has prejudiced future exploration in the region. Of course, these problems have always been a part of the explorationist approach to the search for petroleum. The future may loosen some of the bonds of future decision, but the problem will never be totally solved. It is this practice of prior assessment of the size of the exploration target which has encouraged many small independent oil producers to seek rewarding success in aiming for smaller targets. There is always the hope that the ultimate producing area could be larger than originally estimated. This contentment with a small target, which has proved quite successful in many parts of the United States, may become a worldwide phenomenon as petroleum becomes more and more difficult to find. However, the precise way in which this occurs will be controlled by a traditional trade-off: the balance between the cost of exploration and the expected financial returns. Thus, economics on a worldwide base will be the ultimate limiting factor on the mode--and even the act--of exploration in the future.

The financial incentives for future exploration are strongly affected by government involvement. Some assurance of the continuance of certain fiscal and tax parameters must exist, if the long-range planning of exploration and possible returns from production are to be meaningful. Therefore, relatively stable government attitudes toward pricing and tax assessments stand as important controlling elements in the process of exploring for new petroleum reserves, and may determine whether such reserves will even be sought.

Most long-range energy alternatives to oil and gas seem, at this point, to belong to the next century. The social problem the world faces is whether or not oil and gas availability will fill the span of time between the present and future availability of these energy sources. Somehow, through conservation and successful exploration for new oil and gas deposits, the vital time link must be made. Economic and government allowance of petroleum exploration must be a part of the immediate future, rather than a desperate and inadequate response to an even deeper energy crisis than the present one. It would be well to keep in mind that such a crisis is a virtual inevitability, if we fail to make full use of the time we have.

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CHAPTER 5

THE POTENTIAL AND TIME FRAME FOR THE DEVELOPMENT OF PETROLEUM IN THE DEEP OCEAN

K. O. Emery[1]

ABSTRACT

Petroleum has been produced in quantity for several decades from the continental shelves of the world, but much of the shelf area remains to be explored and drilled. Additional supplies of oil and gas probably occur in deeper waters beyond the shelf--in small marginal basins, continental rises, abyssal plains, and deep-water salt diapirs. Essentially no drill-hole data for these regions is available, and so estimates of oil and gas resources from the deep-ocean floor are meaningless. As the sediment volume of the deep ocean is enormous, perhaps half the total volume of all the world's sediments, it is imperative that deep-ocean drilling soon be organized for a first-order evaluation of their potential oil and gas to augment future supplies of energy and industrial feed stocks.

CONTINENTAL SHELVES

Tar has been recovered from the ocean floor for thousands of years, because its low density allows it to periodically break away from the bottom and float to shore. However, oil is much more difficult to obtain, and the first offshore drilling for petroleum started in California only during 1896, with significant oil production reached only about 1950--in Louisiana,

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California, and the Caspian Sea. During the past decade about one-sixth of the total world oil has come from the continental shelves and other underwater areas such as Lake Maracaibo and the Caspian Sea. The major sites of offshore production are indicated in Fig. 5-1; additional small production comes from the shelves off Argentina, Ecuador, Gabon, Greece, Italy, Japan, New Zealand, Tunisia, and probably other countries. Since 1973 world offshore production declined while onshore production increased; presumably, this difference is due to reduced demand in the face of increased oil prices magnified by the greater costs of finding and producing offshore oil. Intensified offshore production can be expected when the demand again increases and old fields on land pass their peak production and new fields are found less frequently than in the past.

Only a few percent of the total area of the world's continental shelves have been thoroughly explored and drilled for oil and gas. Most of the black area on Fig. 5-1 denotes shelves that have not been drilled but that appear to be favorable on the basis of their general stratigraphy and structure. Some areas remain untested because of severe weather (icebergs, thick ice-floes, and storms at high latitudes) or unsuitable concession terms.

Nearly all offshore oil and gas production to date has come from simple oceanward extensions of known structures and producing fields ashore. Other offshore fields are parts of a pattern of fields ashore--such as belts of salt diapirs on the Gulf Coast of the United States and folded basin fill off southern California. Very few oil and gas fields on the continental shelf completely independent of ones on the adjacent land have been found. Among these few are Bass Strait off Australia, Cook Inlet, and the oil traps of the North Sea, and perhaps eventually the basins of the East China Sea between Japan and Taiwan, the Gulf of Thailand, Georges Bank off eastern United States and Canada, and the shelves off Labrador and western Greenland.

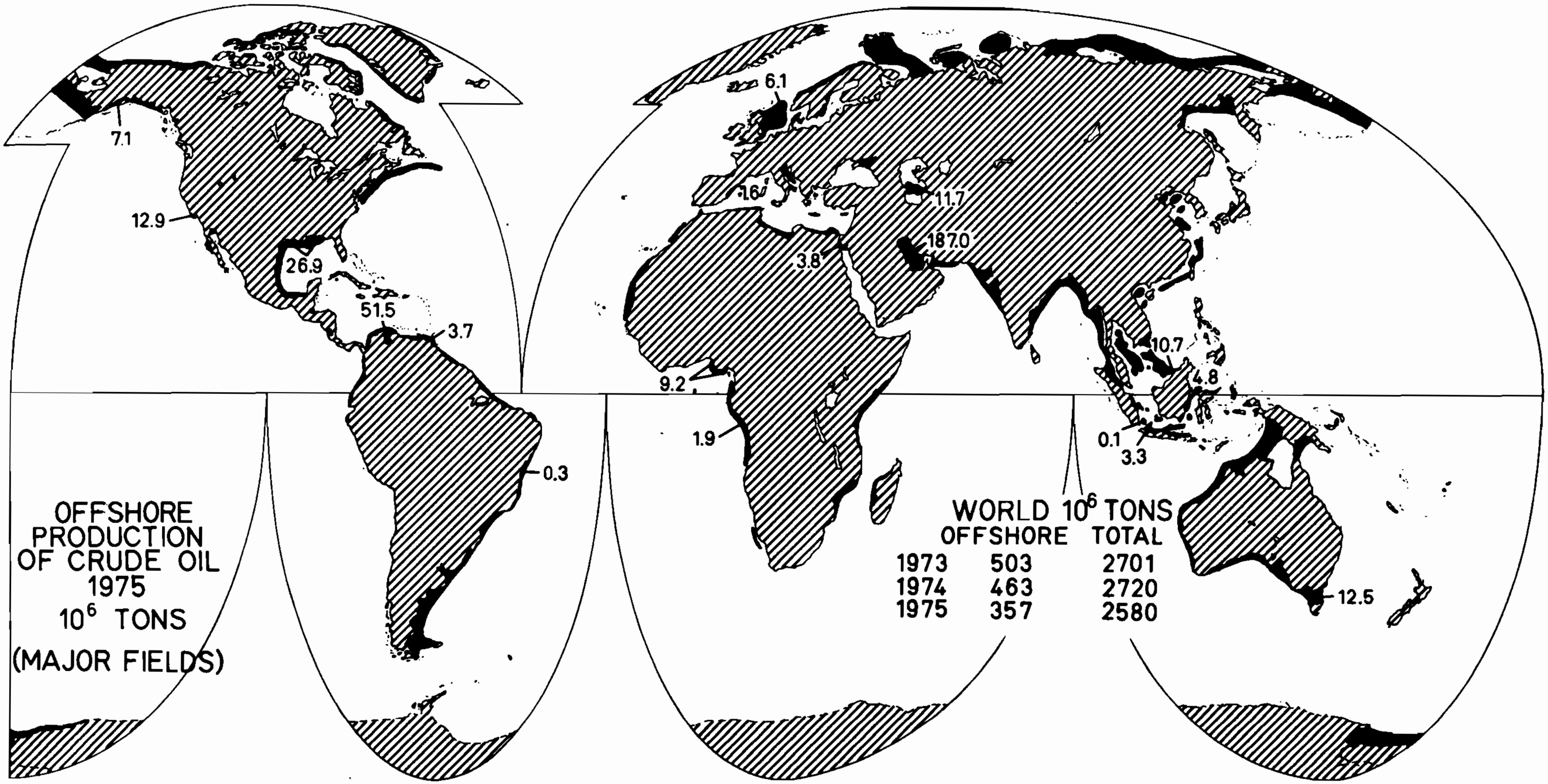

Figure 5-1.--Continental shelves of the world believed to be favorable for oil and gas (black), and production of oil during 1975 in largest offshore fields. Table shows world offshore and total production of oil for 1973, 1974, and 1975.

SMALL MARGINAL BASINS

Small basins are widespread around the perimeters of continents particularly landward of island arcs and their deep-ocean trenches (Fig. 5-2), and most of these basins have floors at intermediate ocean depths. Because these marginal basins adjoin the continents, they are in positions to intercept much of the sediment that is contributed by rivers and shore erosion. Their positions also permit inclusion of such organic matter provided by photoplankton growth that is enhanced by high concentrations of nutrients from stream discharge and upwelled deep waters of the oceans. As a result, rich source beds are present and are interleaved with reservoir beds in the form of sands brought and deposited by turbidity currents from submarine canyons and upper continental slopes of the nearby land areas. Enough is known about the sediments in these basins from detailed studies of the small ones off southern California and northwestern Mexico, the Mediterranean Sea, the Black Sea, and other areas that we can have some confidence in our knowledge of pertinent sedimentary processes. Many of the basins also have a much higher heat flow than is typical of the deep-ocean floor because of the particular origin of the marginal basins and the nature of their igneous basement. The high temperatures speed the conversion of sediment organic matter into oil and gas and make these basins especially promising.

CONTINENTAL RISES

Continental rises (Fig. 5-3) cover a much larger area of the deep-ocean floor than do marginal basins. In general, the rises also occur in different regions than the marginal basins, because they cannot develop where underthrusting of oceanic crust is active in deep-ocean trenches. Small continental rises, however, are present on the floors of some larger marginal basins. The sediments in continental rises come from the same land and biogenic sources as those of marginal basins, but the sediments generally have been received for such a long time that the continental rises have coalesced along the continents, have

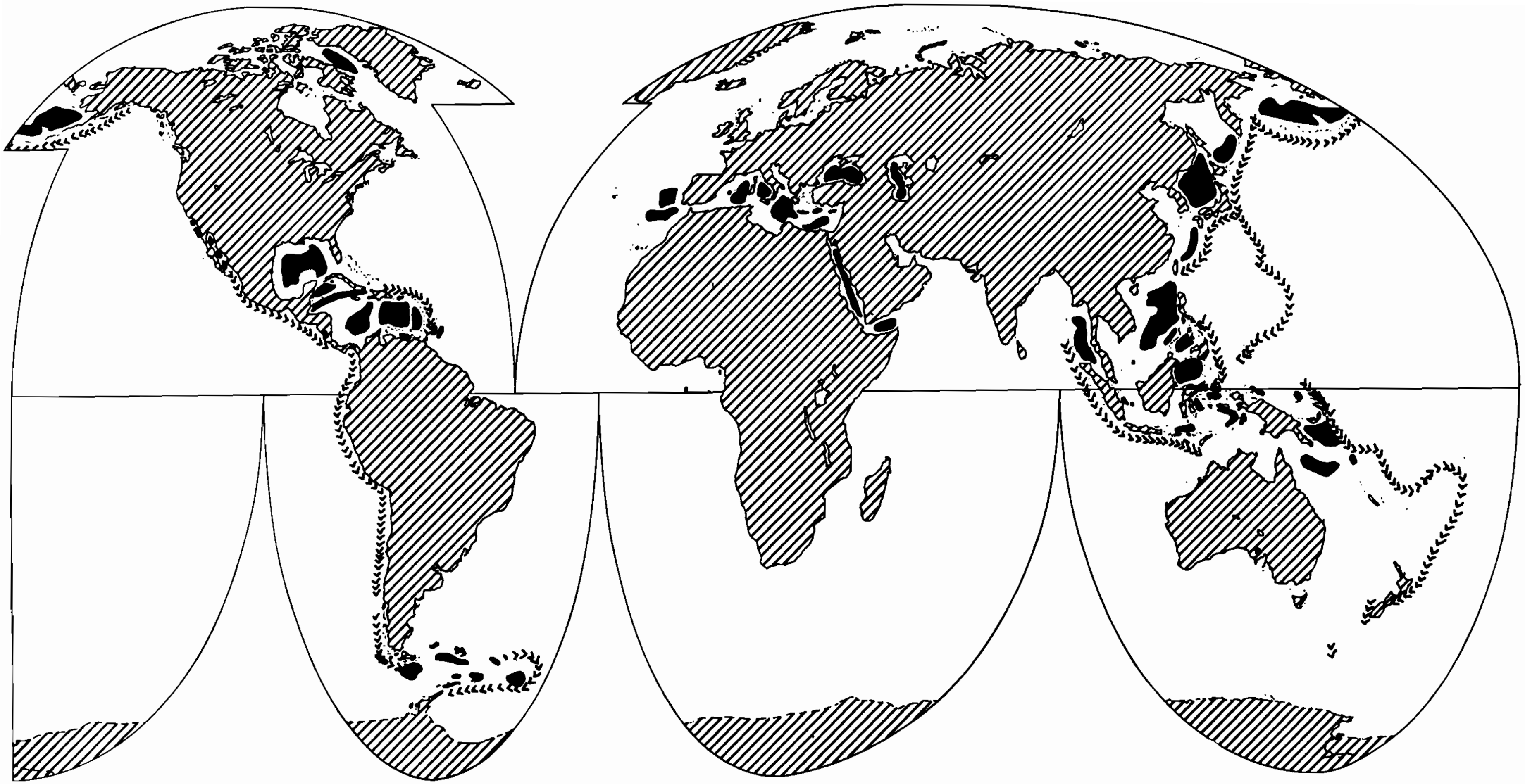

Figure 5-2.--Small marginal basins of the world (black). Note that most are in regions of island arcs landward of deep-ocean trenches (chevrons).

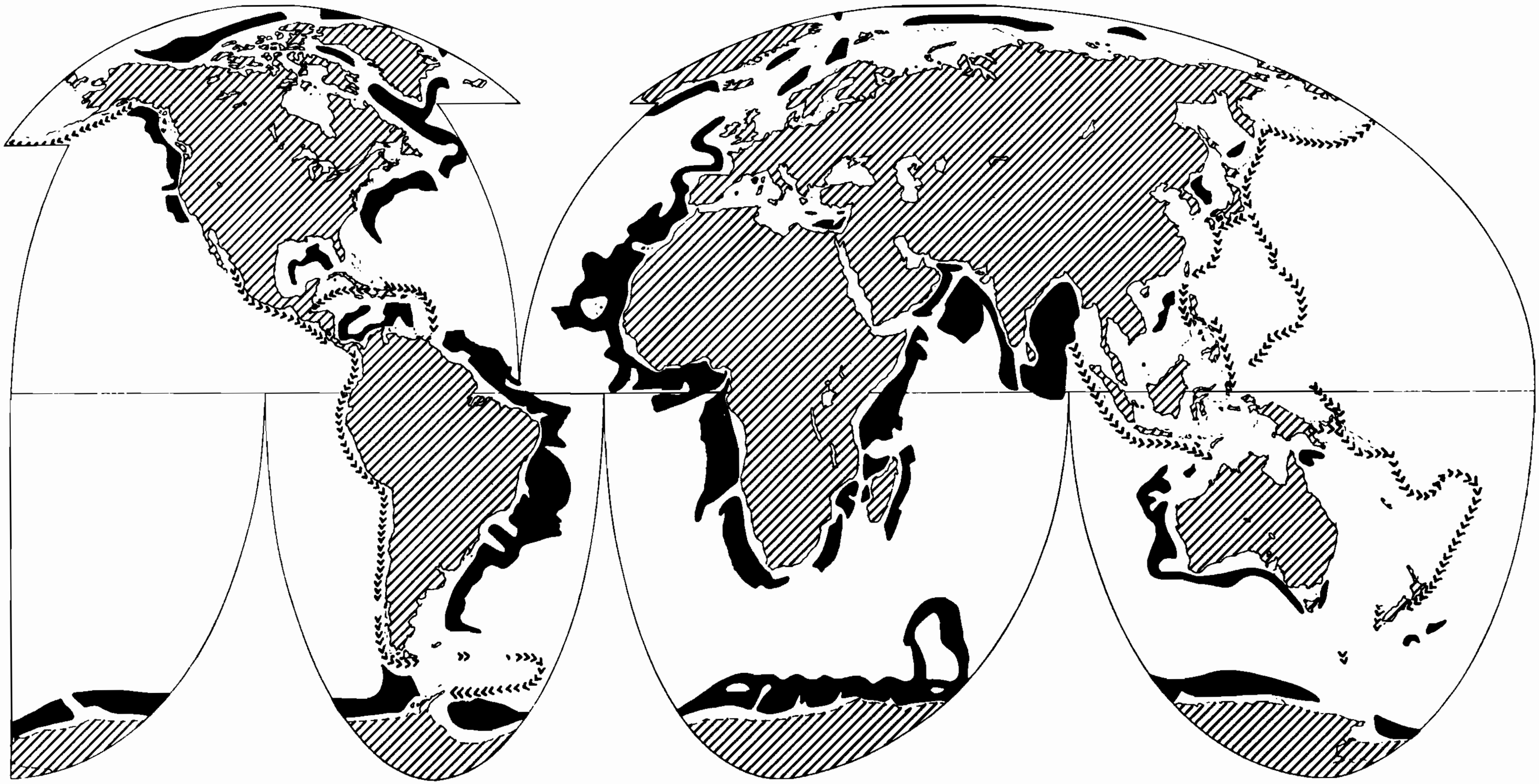

Figure 5-3.--Continental rises of the world (black). These occur only in regions devoid of deep-ocean trenches (chevrons), where underthrusting of ocean floor beneath continents prevents their growth.

prograded far oceanward, and are very thick. The top surface of the continental rises slopes smoothly oceanward between the base of the continental slope and the gradual transition into deep abyssal plains. For about one-third of their width the rises thicken oceanward in response to deepening of the underlying oceanic basement. Farther oceanward, the basement is shallower, and the continental rises thin.

Seismic reflection records reveal the presence of many internal acoustic reflectors that probably mark the tops of sands that have been deposited by turbidites and reworked by bottom contour currents. These sands can serve as reservoir beds, particularly where they are thickest and coarsest-grained off the mouths of submarine canyons. Source beds probably are not so common in continental rises as in marginal basins, because most organic matter from the ocean surface becomes oxidized while falling through the deeper water and before slow burial on the bottom. However, great volumes of bottom sediments slide down the unstable continental slopes to the rises, bringing with them much organic matter that had been preserved from complete oxidation during their deposition in the oxygen-poor waters that lie at mid-depths on most continental slopes. These slides may provide the source beds needed for oil and gas in the continental rises. Another source bed that is receiving increasing attention is the anoxic organic-rich Lower Cretaceous strata of the Atlantic deep-ocean floor that has been sampled in many Deep Sea Drilling Project holes. Faults and folds have been found on continental rises, but probably most oil accumulations occur in stratigraphic traps--where sands pinch out on the landward side of the continental rises.

ABYSSAL PLAINS AND LOWER CONTINENTAL RISES

During the past 5 years seismic reflection records from various deep-ocean environments have shown intriguing pictures of stratigraphic features due to possible cementation by clathrates (or methane hydrates). Among the most persuasive are acoustic reflectors that cross the normal stratigraphic reflectors in a band that is parallel to and a few hundred meters below the sediment surface. Another example of cementation by clathrates may be "pagoda" structures found in the topmost 50 m of the abyssal plains and lower continental rises off western Africa and elsewhere. Sampling is difficult because the decrease in pressure and increase in temperature that necessarily occur during hoisting of samples to the ship cause the presumed methane hydrate to change from ice to gas.

Light hydrocarbon hydrates have been discovered in the subsurface of the Mackenzie Delta and beneath permafrost in Siberia. On the deep-ocean floor the gas may have become concentrated at the depth of the most favorable part of the pressure-thermal gradients after diffusion from deeper strata. When more is learned about both ocean-floor and land deposits of the clathrates, they may prove to be an easily recoverable nonpolluting energy source.

DIAPIRS

Diapirs are masses of low-density salt or mud that have risen through overlying denser sediments generally as bulbous units. Many are present on land, where they and the upturned adjacent strata serve as traps for oil and gas accumulations. Others lie beneath continental shelves (and the shallow Persian Gulf), but the diapirs of interest here are those on the deep-ocean floor (Fig. 5-4). Some consist of mud, particularly those off large river deltas: Mississippi, Magdalena (off Colombia), Amazon, and Niger. The others, and possibly some beneath the Niger Delta, consist of salt and related evaporites, as judged by drill-hole samples, continuity with known diapir belts ashore, seismic velocities, solution of the tops to produce topographic depressions over the diapirs, and similarity in age of disturbed overlying strata with those ashore. The presence of still other salt diapirs has been verified by sharp increases in the concentrations of chloride, potassium, and bromine near the bottoms of drill holes that were not quite deep enough to reach the diapir itself. Preliminary reports suggested that some other features far from shore off northwestern Africa were salt diapirs, but

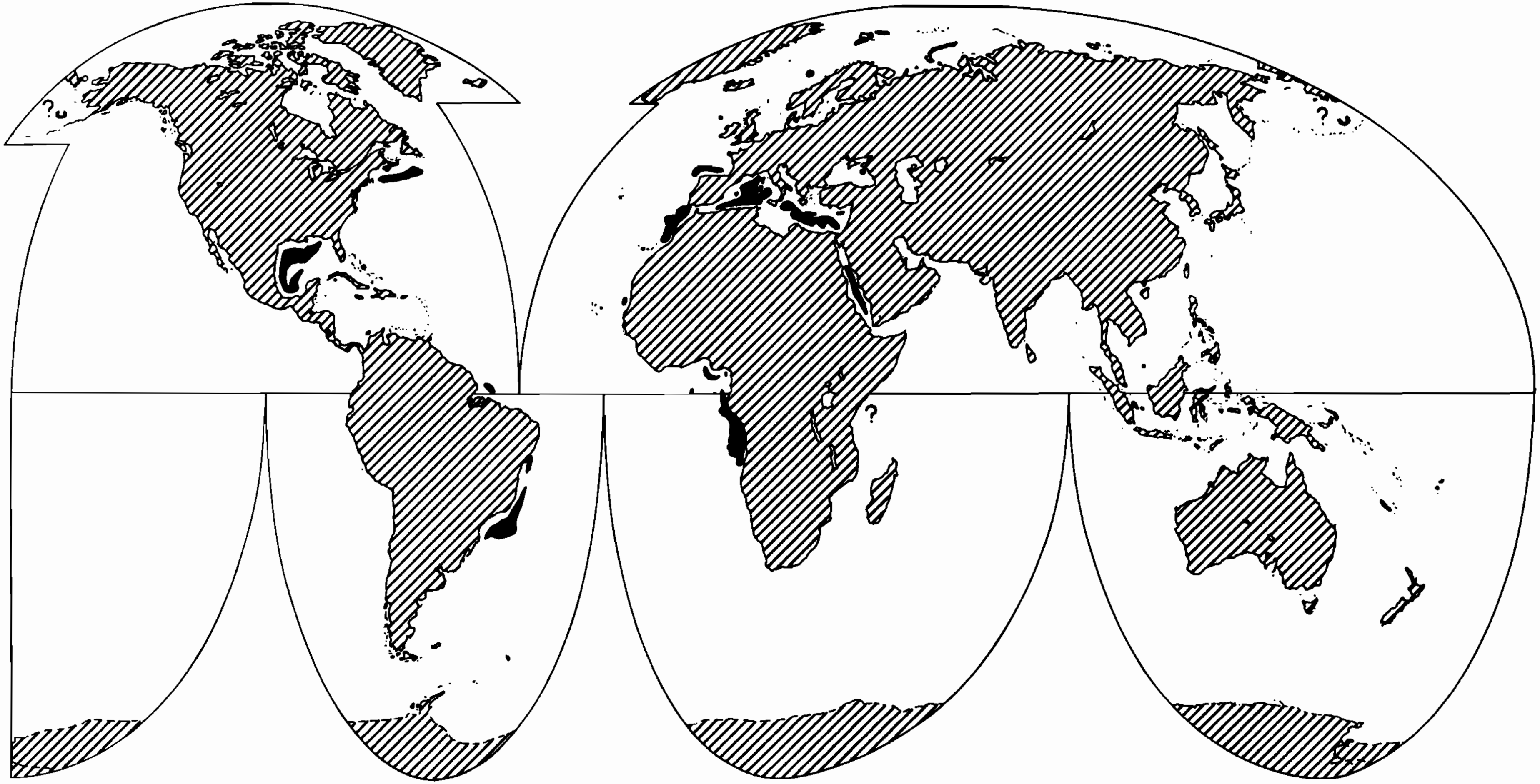

Figure 5-4.--Deep-ocean diapirs (black) mostly consisting of salt. Diapirs have risen through denser overlying sediments, disrupting them enough to provide many traps favorable for oil and gas accumulations.

later work showed them to be pinnacles of igneous rock; the same may be true of diapirs in the Gulf of Alaska shown in Fig. 5-4.

Just as on land, the diapirs of the deep-ocean floor have provided structures in overlying sediments (doming, up-tilted adjacent strata, faults) capable of service as traps for oil and gas accumulations. Source beds can be organic-rich muds of the continental slope and upper rise, and perhaps especially important, the anoxic Lower Cretaceous sediments of the deep Atlantic Ocean.

CONCLUSIONS

During the past decade 400 holes during 48 cruises of GLOMAR CHALLENGER under the auspices of the Deep Sea Drilling Project have been drilled in the ocean floor through sediments as thick as 1.7 km in water depths as great as 5 km. Many of the cores contain methane, but only a few samples have been analyzed for other hydrocarbons. Those few show the presence of both light and heavy hydrocarbons in such diverse regions as the Challenger Knoll in the Gulf of Mexico, the Balearic Basin in the Mediterranean Sea, the floor of the Red Sea, the Bengal Basin, Shatsky Rise in the North Pacific, and off northern California. Accordingly, no holes have been drilled very deeply into smaller marginal basins, continental rises, or salt diapirs for fear that the drill might tap a large accumulation of oil that could escape in the absence of expensive control equipment aboard the scientific drilling ship. As a result, we still know nothing about the oil and gas potential of either marginal basins, continental rises, or deep-ocean salt diapirs except what can be inferred from indirect geophysical measurements, geological processes, and extrapolation from oil fields ashore. This lack of direct information about potential energy resources soon to be greatly needed can be overcome only if funds can be found for deep-ocean drilling using blow-out controls and probably return circulation of drilling mud and cuttings aboard the ship.

Progress from test drilling to actual production of oil and gas from the deep-ocean floor may require much more time than has been required for continental shelves because of probable higher costs of drilling and production. Moreover, the potential oil and gas structures of the deep-ocean floor are completely independent of those on the continental shelves, where nearly all production has come from extensions of structures and fields on land. Twenty-five years of effort have resulted in exploration of only a few percent of the total area of continental shelves; much of the time has been used in developing methods, but new methods also must be developed for the deep-ocean floor. Clearly, the time can be shortened by increased effort--meaning increased funding. Costs for the present Deep Sea Drilling Project that has operated for nearly a decade are now about $14 million per year and were supplied mainly by the United States. During 1976, England, France, Germany, Italy, Japan, and the Soviet Union have supported the program with contributions of about $1 million each. An expanded program of investigating the oil potential of the deep-ocean floor using proper environmental safeguards is likely to cost about twice as much. Supplementary funds have been required for laboratory studies of the core samples and will be needed for future ones.

Is an initial evaluation of the oil and gas potential of the deep-ocean floor by drilling worth $30 million per year for several years? If so, who will supply these funds? Until this drilling is done, let us not make absurd speculations about how much oil and gas may or may not be present on the deep-ocean floor.

SECTION II. PETROLEUM RESOURCE CLASSIFICATION

CHAPTER 6

IMPLICATIONS OF CHANGING OIL PRICES ON RESOURCE EVALUATIONS

Richard G. Seidl[1]

INTRODUCTION

In other chapters it is described:

- That additional percentages of oil could be recovered from already known reserves by applying, at a cost, enhanced recovery techniques;
- That additional amounts of the resource base could be converted into reserves by extending our exploration efforts to as yet unexplored areas;
- And that, finally, additional types of resources, like tar sands, oil shales, and gas from geopressured zones could become economical to produce and thus could also contribute to the amount of oil and gas which remains available.

Each one of these developments reflects both advances in knowledge and expertise which make resources accessible that were not even considered a decade ago; and a change in the economic climate as a consequence of the change in oil prices which renders resources economical, which could not have been considered before this change in oil prices occurred.

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[1]IIASA, Laxenburg, Austria.

THE HISTORY OF RESOURCE ESTIMATES

A large number of researchers have attempted, in the last few decades, to evaluate the amount of oil and gas that would be ultimately recoverable from the overall resource base. Although it is not always expressly stipulated, these estimates are subject, apparently, to a certain set of assumptions of how much of the resource could eventually be discovered and how much of that amount could be economically recovered.

With increasing geological knowledge and production experience, these estimates tended to increase. In 1972, Warman [1] published 18 selected estimates of ultimately recoverable resources of crude oil from conventional sources (Table 6-1), amended with some additional estimates [2, 3, 4].

TABLE 6-1.--Estimates of world ultimate reserves of crude oil from conventional sources

Year	Source	Ultimate reserves (10^9 barrels)
1942	Pratt, Weeks & Stebinger	600
1946	Duce	400
1946	Pogue	555
1948	Weeks	610
1949	Levorsen	1,500
1949	Weeks	1,010
1953	MacNaughton	1,000
1956	Hubbert	1,250
1958	Weeks	1,500
1959	Weeks	2,000
1965	Hendricks (USGS)	2,480
1967	Ryman (Esso)	2,090
1968	Shell	1,800
1968	Weeks	2,200
1969	Hubbert	1,350-2,100
1970	Moody (Mobil)	1,800
1971	Warman (BP)	1,200-2,000
1971	Weeks	2,290
1971	U.S. National Petroleum Council	2,670
1972	Linden	2,950
1972	Weeks	3,650

Commenting on these figures, Warman [1, p. 292] states:

> It is interesting to note that estimates have increased with time and it is fair to ask whether we are still underestimating. There are some good reasons for believing that during the time span of these estimates our knowledge has increased to a point where future continued expansion on the same scale seems unlikely. Not only has there been a great increase in the amount of oil exploration during the time in question, but also its geographical distribution and effectiveness.

And he concludes:

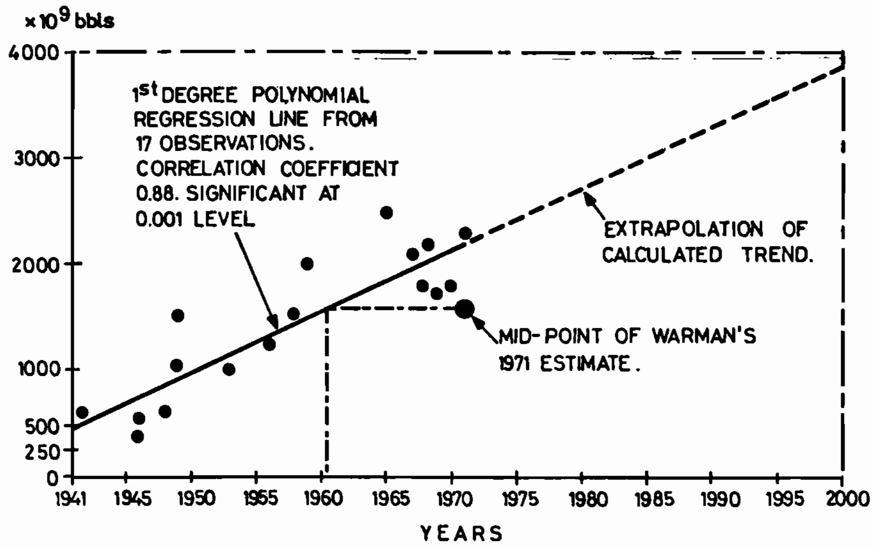
> . . . a reasonable consensus of opinion favors an ultimate reserve of recoverable oil between 1600 and 1800 x 10^9 barrels . . . but independent work by my colleagues in British Petroleum and by myself suggests a figure around 1800 x 10^9 barrels to be a reasonable maximum.

This conclusion has been vigorously attacked by Odell [5] for reasons both of statistics and interpretation. Odell submits the figures quoted by Warman to some statistical analysis, extrapolates the trend and concludes [5, p. 454]:

> . . . the resource base, . . . given the extrapolation of the calculated trend, would reach almost 4,000 x 10^9 barrels (Fig. 6-1) by the year 2000. In brief, the oil resource base in relation to reasonable expectations of demand gives very little apparent cause for concern, not only for the remainder of this century, but also thereafter well into the twenty-first century at rates of consumption which will then be five or more times their present level.

The controversy flared up again in 1975 in the Petroleum Times [6] and prompted the editor to note:

> When faced with two highly expert groups battling on a complex technical issue, there is a terrible temptation to assume that the truth lies somewhere between them and that the rest of us can sit back and simply enjoy the spectacle. Attractive though this course might be, it is too much of a luxury to be tolerated in the circumstances of the present controversy.
>
> The political and economic decisions on energy which will determine the levels of industrial activity and standards of living in the early years of the next century must be made now, and the decision-makers are



REPR. FROM : PETER R. ODELL
'THE FUTURE OF OIL : A REJOINDER'
GEOGRAPHICAL JOURNAL, VOL. 139, OCT. 1973

Figure 6-1.--Projections of trend of ultimate oil recovery

> totally dependent on the advice of experts such as those who are party to this dispute.
>
> If the right approach cannot soon be proved--the gap is too wide for compromise--minds will be made up on incomplete and possibly erroneous data with unguessable consequences for millions of people. There is far too much at stake for this argument to be considered simply as an academic exercise.

I think we all agree on that, but what is the "right approach"?

THE RESOURCE CUBE CONCEPT

A very substantial amount of the work done at IIASA is concerned with problems of energy. In the context of this basic research program, the question of fossil fuel resources is but one issue, but an extremely important one. On it hinges the question of the time for transition we can foresee to move from an economy based nearly exclusively on nonrenewable fossil fuel resources into an economy based on renewable (or, for practical purposes, unlimited) energy resources like solar energy or nuclear fusion. And the duration of this transition period, by all accounts, will have to be measured in decades rather than centuries.

To coordinate the various estimates for various resources, we use a concept which we call (for want of a better term) the Resource Cube Concept (Fig. 6-2). It is built around three axes formed by:

- The resource base line,
- The discovery line, and
- The recovery line.

Along the resource base line we group all the known hydrocarbon resources:

- Coal,
- Lignite,
- Oil shales,
- Tar sands,
- Heavy crudes,
- Crude oil, and
- Natural gas.

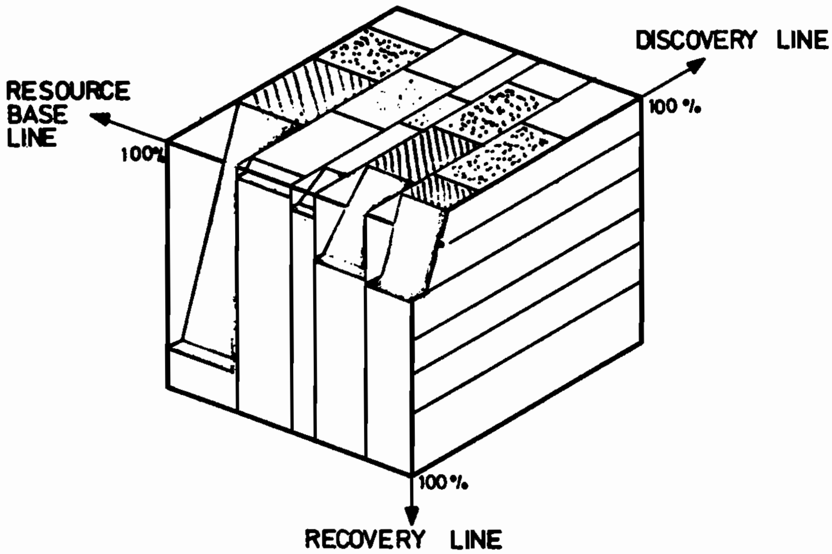


Figure 6-2.--The resource cube

Along the discovery line we indicate (in percent) which fraction of each resource:

- Has largely been used,
- Has been proven (but is still in the ground),
- Is likely to be discovered, and
- Could ultimately be discovered as assumed by various authors.

Along the recovery line, finally, we attempt to show (in percent again) the fraction of the discovered resource which is considered to be recoverable under varying economic conditions.

How far and how fast we can progress at a given point in time along any one of these axes, is obviously subject to political, technological, and economic conditions.

A few examples may illustrate this.

DISCOVERY RATES

If we look at the amount of reserves (Fig. 6-3) [7, 8, 9, 10] proved at the end of each year during the last 25 or 30 years, and compare this with the amount of crude produced during each year [11], we note that worldwide, the amount of proved reserves rose faster than production (Fig. 6-4). Plotted against various Reserve/Production ratios (Fig. 6-5) we note that the proved reserves, after passing the 20-year line in the early forties and the 30-year line in the mid-fifties, stand now at about 32 years.

This development was anything but uniform, however, in various parts of the world. If we look, for instance, at the amount of reserve proved annually in the United States on the one hand, and in the rest of the world on the other, we notice that the rate of discovery continuously decreased in the United States, while it continuously increased in the rest of the world (Fig. 6-6). As a consequence, proven reserves within the United States, which still amounted to about 32 percent of the world total in 1950, dropped to about 12 percent by 1960, 5.4 percent by 1970, and at the beginning of 1975 stood at less than 5 percent of the world total (Fig. 6-7).

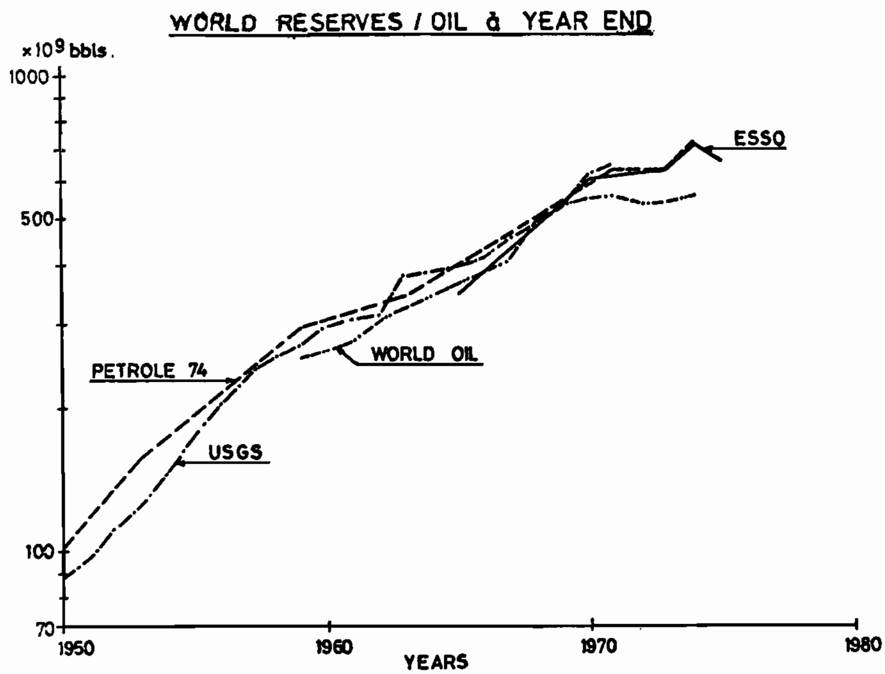


Figure 6-3.--Estimates of world proved crude oil reserves by year

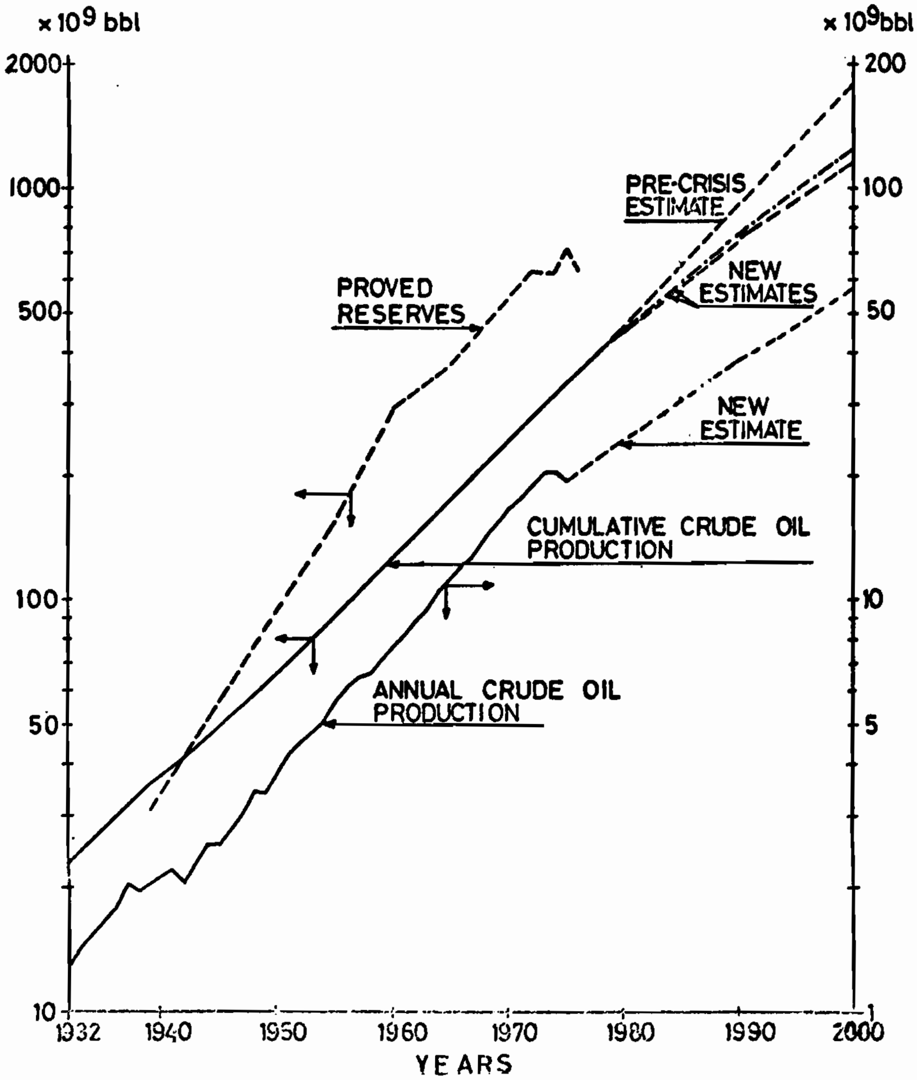


Figure 6-4.--Global "proved reserves" at year end, and annual and cumulative crude oil production (10^9 barrels)

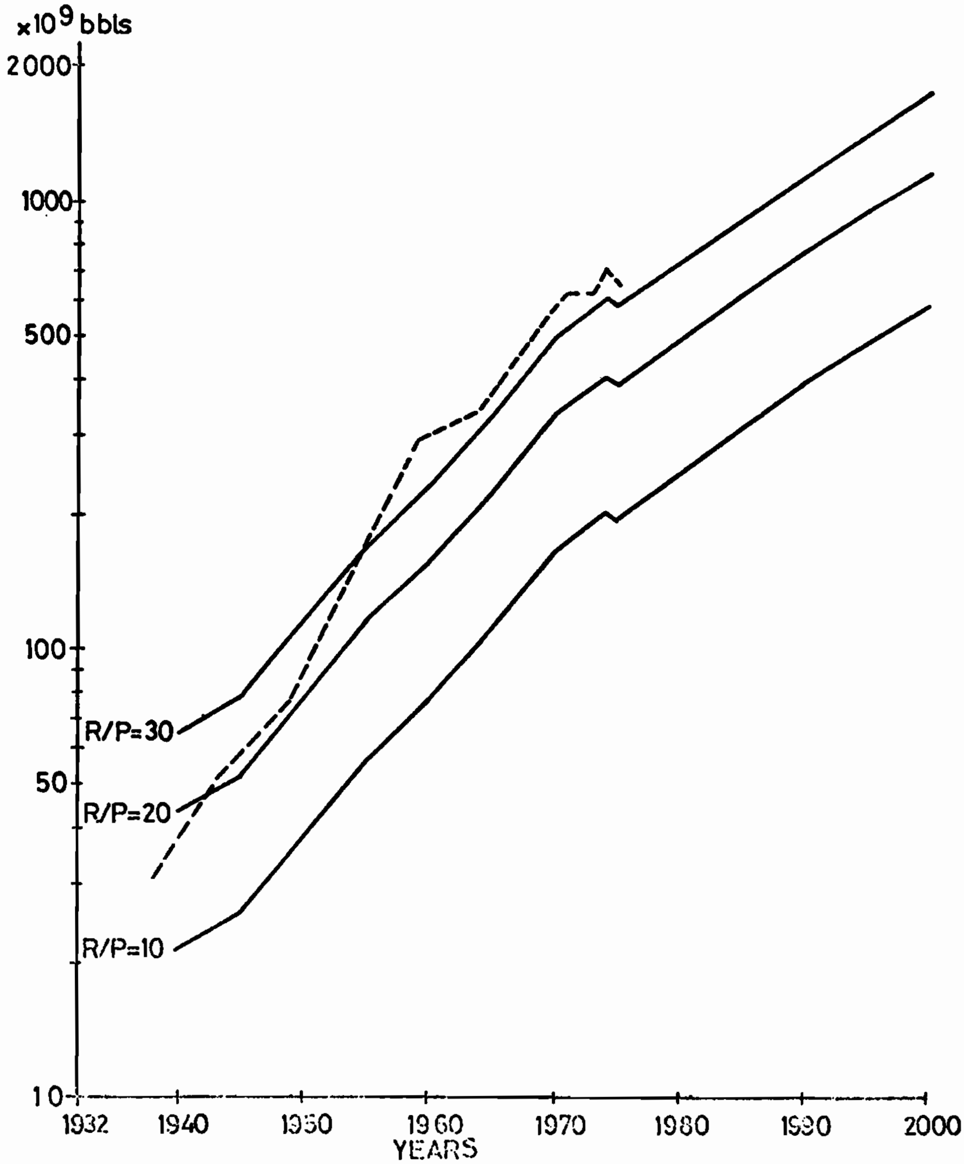


Figure 6-5.--"Proved reserves" at year end vs. various R/P ratios

Figure 6-6.--"Reserves" proved annually in USA and world (10^9 barrels)

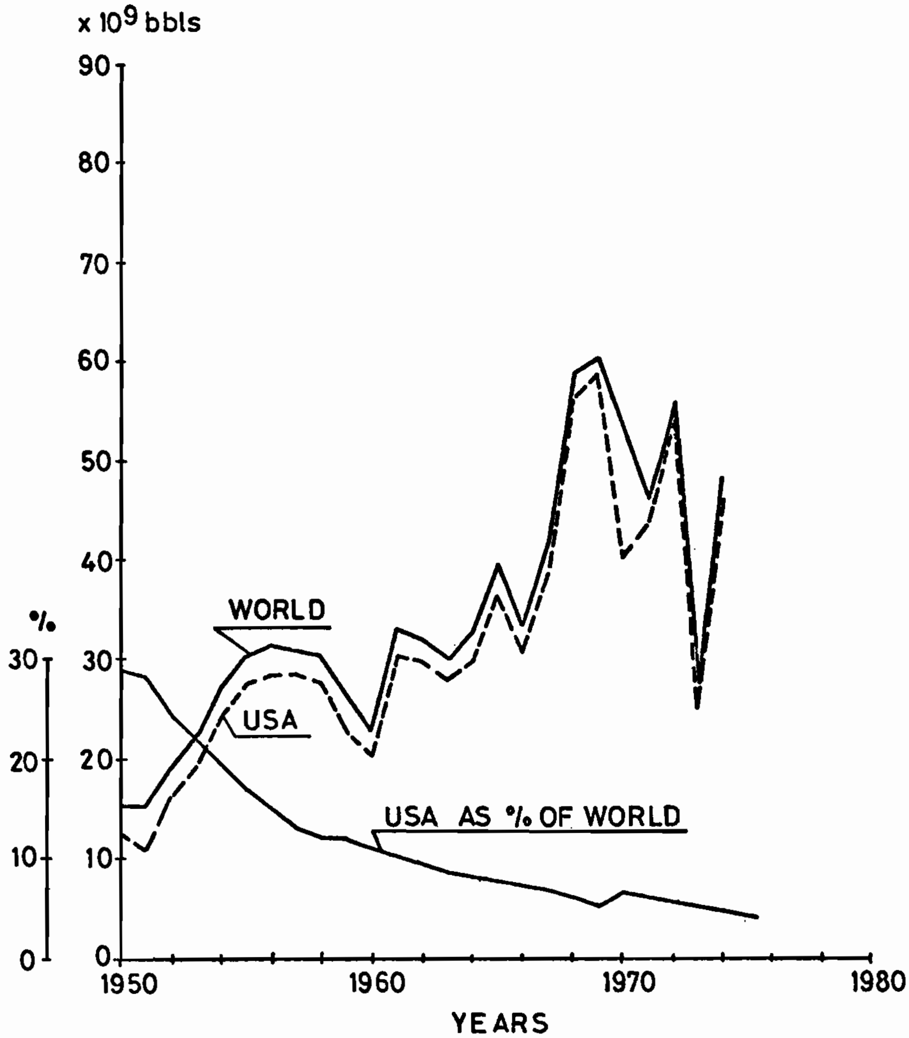


Figure 6-7.--Reserves proved annually, USA and world, vs. USA proved reserves as percent of global proved reserves

THE RELATIONSHIP BETWEEN EXPLORATORY EFFORT AND AMOUNT OF PROVED RESERVES

It has frequently been stated that this decline in discovery rate is a consequence of the fact that the more of the resource base that has already been discovered, the less there remains to be discovered. M. King Hubbert, in a number of well-publicized statements [12, 13, 14], has in fact attempted to forecast ultimate discoverable reserves on the basis of discovery history. Although there is undeniably much to be said for this approach, there are other ways of looking at the history of oil discoveries.

Taking the United States as an example again and looking at the amount of money spent to drill for oil (including a proportional amount of dry holes) in comparison to the amount of oil found, the following facts become apparent:

- If we express the money spent for drilling in barrels at going U.S. crude prices at any time during the last 15 years, and compare that figure with the amount of reserves proved, we find that, on the average, the equivalent of some 0.2 to 0.25 barrels had to be spent to discover one additional barrel of crude (Fig. 6-8).
- Obviously a smaller and smaller number of sites offered the prospect to find 4 or 5 barrels of crude oil for each barrel (equivalent) spent, so the number of wells decreased substantially (Fig. 6-9) as the cost of drilling increased.
- Consequently, the amount of money spent for drilling within the United States, if expressed as a percentage of the value of total U.S. production, decreased from 26 percent in 1960 to less than 12 percent in 1974 (Fig. 6-10).
- The amount of crude which was added, on the average, to proved reserves by each well, however, stayed pretty much constant during all these years, if we allow for the retarded announcement of the Alaskan discoveries, at about 95,000 barrels/well (Fig. 6-11).

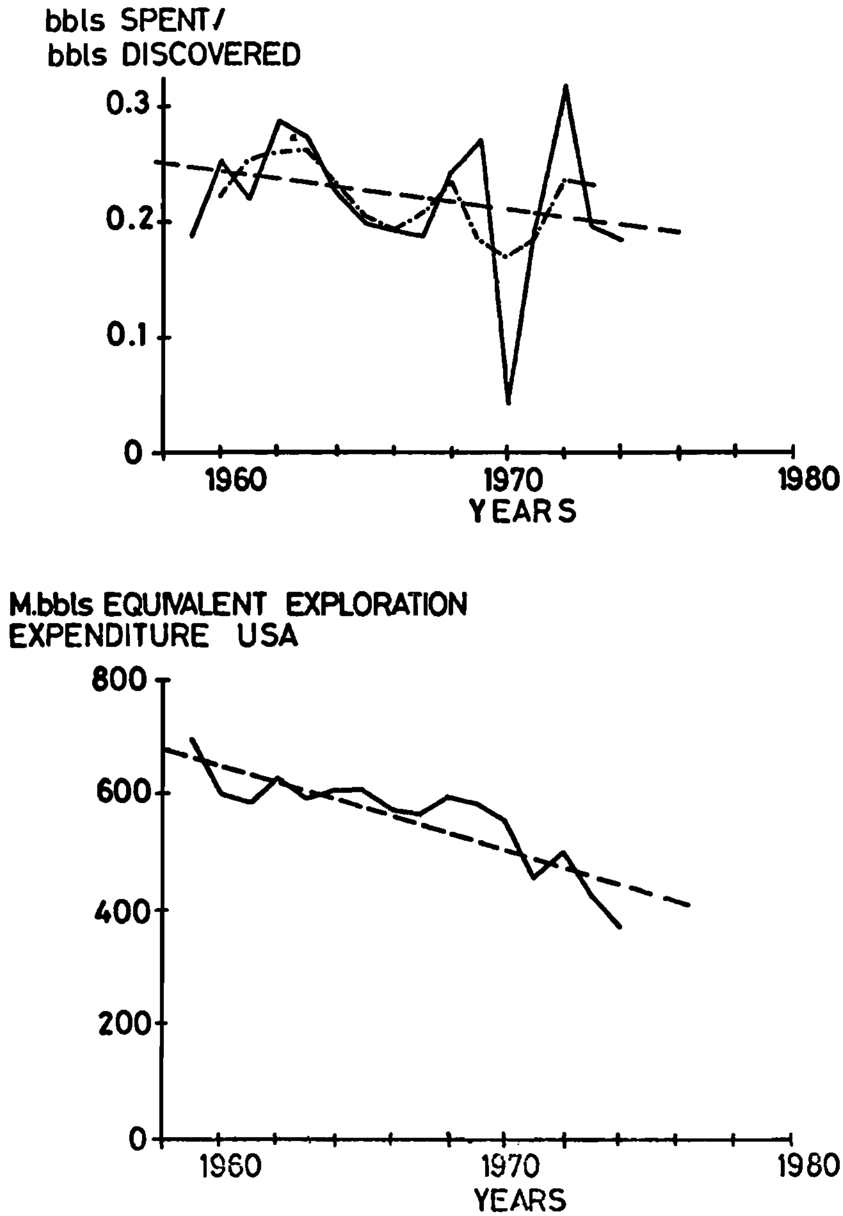


Figure 6-8.--Exploration effort (total cost of drilling and equipping new oil wells plus percent of dry holes in USA, expressed in barrels of oil at going crude oil prices) vs. barrels of proved reserves

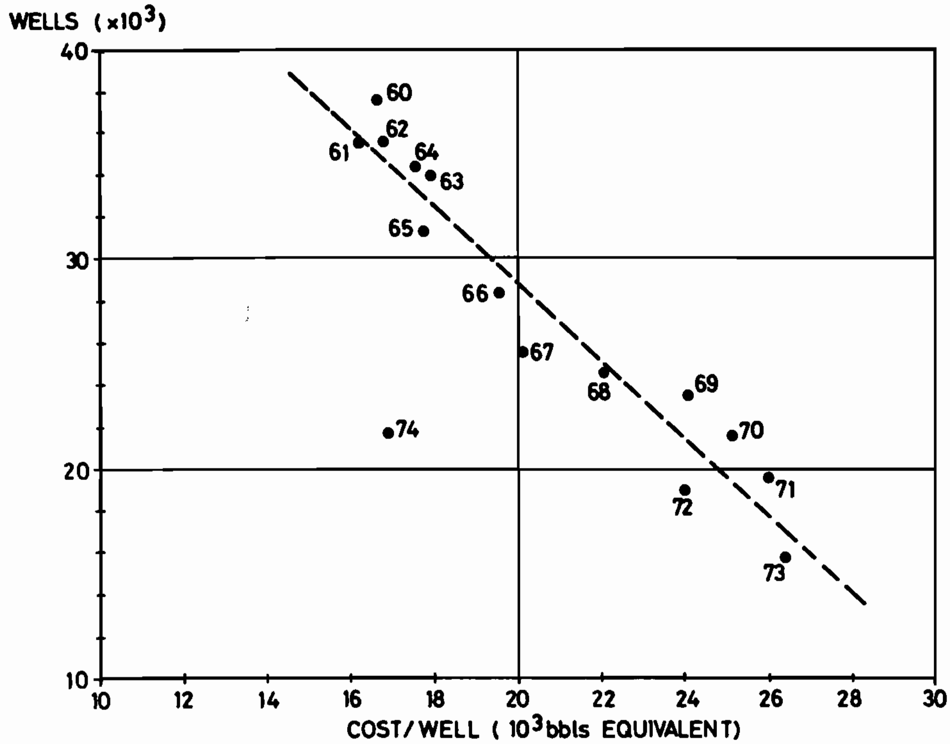


Figure 6-9.--Oil wells (plus percent of dry wells) drilled vs. cost per well in barrels (at average U.S. crude oil price) lagged by 1 year

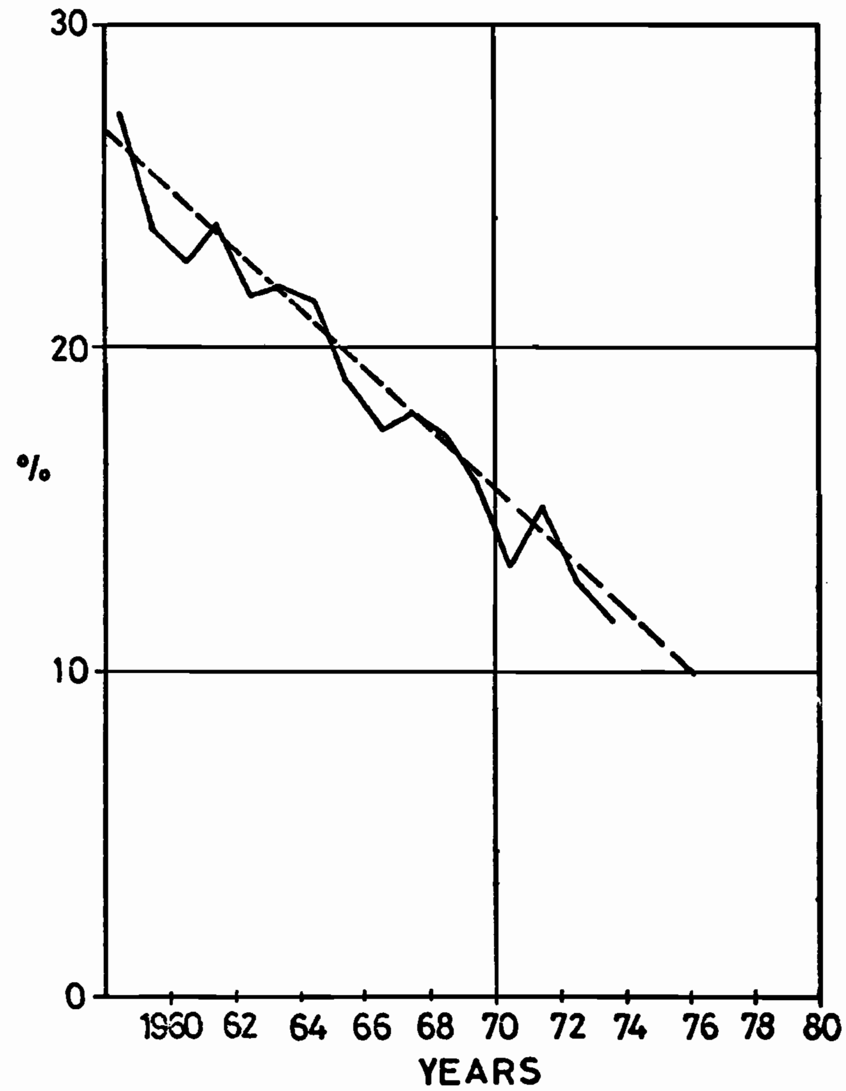


Figure 6-10.--Exploration effort (total cost of drilling and equipping new oil wells plus percent of dry holes in USA, expressed in barrels of oil at going crude oil prices) as percent of U.S. production

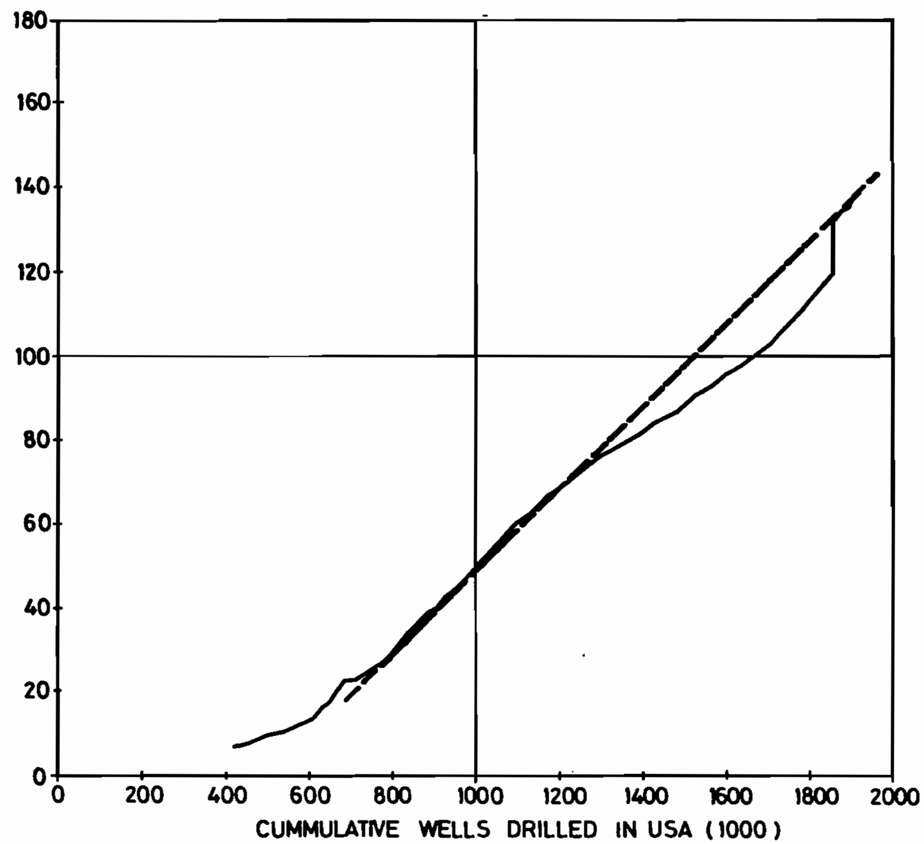


Figure 6-11.--USA cumulative proved reserves vs. cumulative oil wells drilled (including dry holes)

Throughout the rest of the world, the number of oil wells drilled was only a fraction of the United States. Although the percentage has gradually decreased during the last 15 years, the number of oil wells drilled in the United States still amounted to nearly 75 percent of all oil wells drilled in 1973, and increased again to more than 80 percent in 1974, with more than 21,000 holes drilled versus 5,000 holes in the rest of the world (excluding the Socialist areas). The amount of oil proved by each one of these few wells, however, was about 30 to 60 times greater than in the United States and showed a tendency to increase even further (Fig. 6-12).

RECOVERY RATES

The percentage of crude which was actually recovered from a deposit increased but little since secondary recovery techniques became firmly established during the fifties, yielding cumulative recovery factors of about 34 percent at a cost of well below 50 cents/barrel [15] which, at the going prices of the time, was equivalent to the value of about 0.2 barrels of crude; thus, these secondary recovery techniques could start to compete with additional discoveries at approximately the same cost.

Cost figures quoted for enhanced recovery techniques range from about $3/barrel to about $20/barrel. For these techniques, recovery factors are quoted in the order of magnitude of about 45 percent to about 75 percent of total oil in place.

THE CHANGE IN OIL PRICES

During the past few years, the value of crude has increased substantially both within the United States and in the rest of the world.

Within the United States, the average price of crude at the well head increased from around $2.50/barrel in the fifties to around $2.90/barrel in the sixties and is now (1976) estimated at around $7.50/barrel (Fig. 6-13).

Outside of the United States, the increase was even more pronounced. For various reference crudes, prices increased from

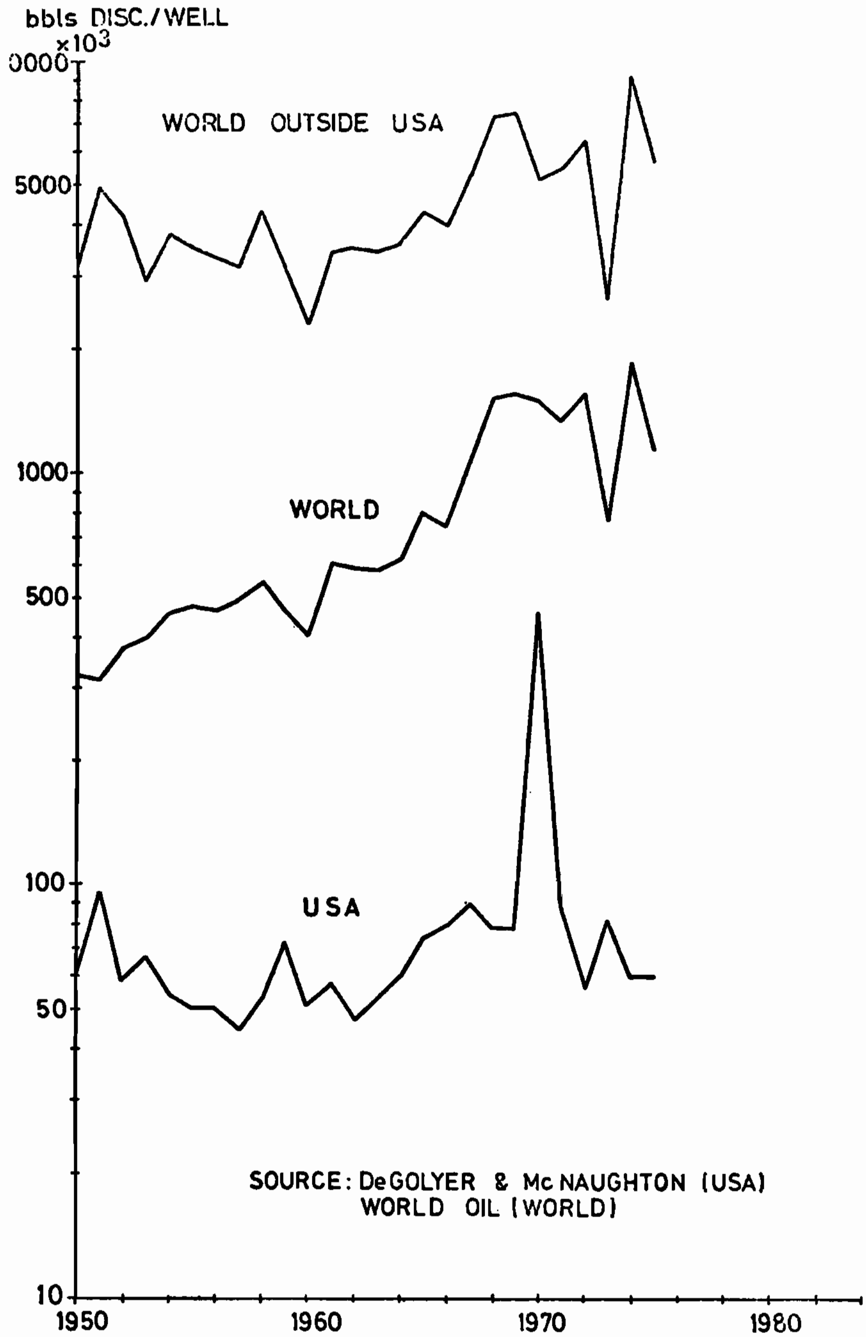


Figure 6-12.--Reserves proved annually per well (all wells)

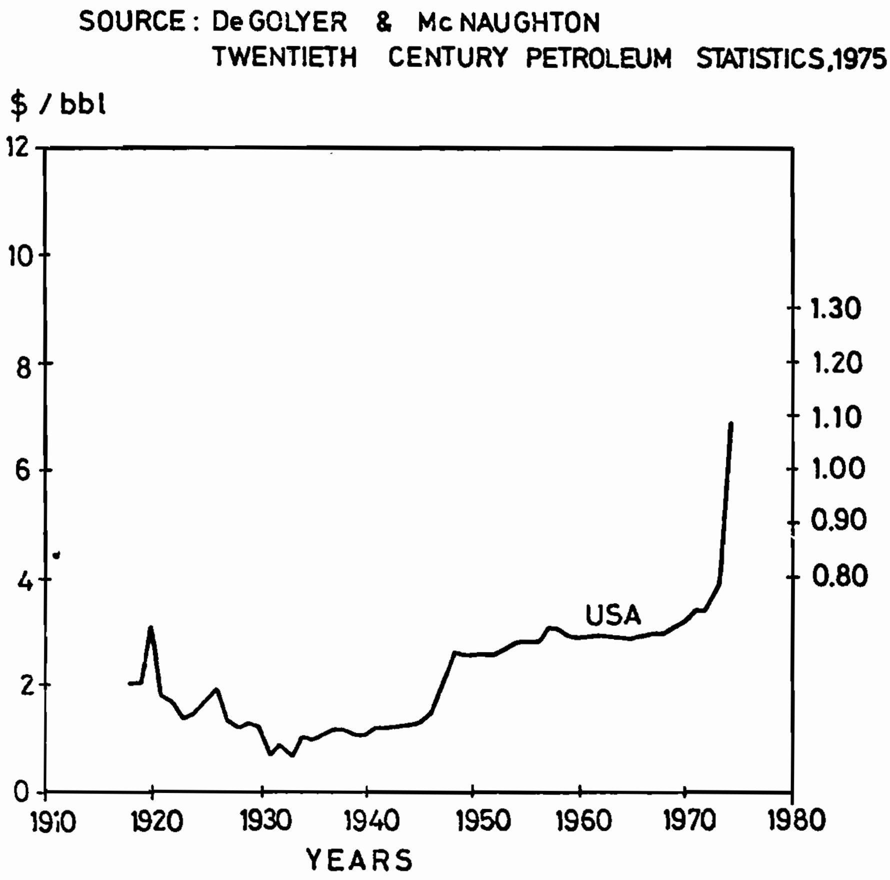


Figure 6-13.--Average prices of crude petroleum in the USA

about \$1.80/barrel in 1970 to about \$11.25/barrel in November 1974 (Arabian Light, Ras Tanura), or from \$2.37/barrel in 1970 to about \$13.25/barrel in November 1974 (Arabian Light, Sidon), if we use posted prices for comparison. Using theoretical prices calculated from product prices, we arrive at similar increases ranging from about \$2.20/barrel (Persian Gulf) or \$2.60/barrel (Far East) to about \$10.60/barrel (Persian Gulf) or \$11.30/barrel (Far East) (Fig. 6-14) [16].

POTENTIAL EFFECT ON DISCOVERY AND RECOVERY RATE

If the basic relationship between the value and the amount of money spent on discovering and recovering crude oil, which we discussed earlier, continues to hold, this change in oil price should affect very substantially both discovery and recovery of crude oil. Indeed the number of wells drilled in the United States, after nearly two decades of constant decline, has already increased by nearly 20 percent from 26,244 in 1973 to 31,481 in 1974 [17].

Although the effect on the amount of reserves has yet to be seen, it seems fairly obvious that the increase in U.S. oil prices of (roughly) 250 percent makes it economically possible to drill for substantially smaller prospects. Similarly, some of the enhanced recovery techniques which were simply uneconomic just 2 or 3 years ago have either become economical or at least marginal by now, depending on the merits of the individual case.

In addition, and not yet mentioned, the economics of alternative hydrocarbon resources like oil shales and tar sands will have to be completely reconsidered. Quite a sizeable amount of these may be on the verge of becoming economically recoverable.

CONCLUSION

Let me finish with a brief example, hypothetical so far, of what is implied. The increase in oil prices has not only increased the amount of economically recoverable resources, it has, at the same time, worked to reduce the increase in consumption. Before 1974, the average annual increase in world crude oil

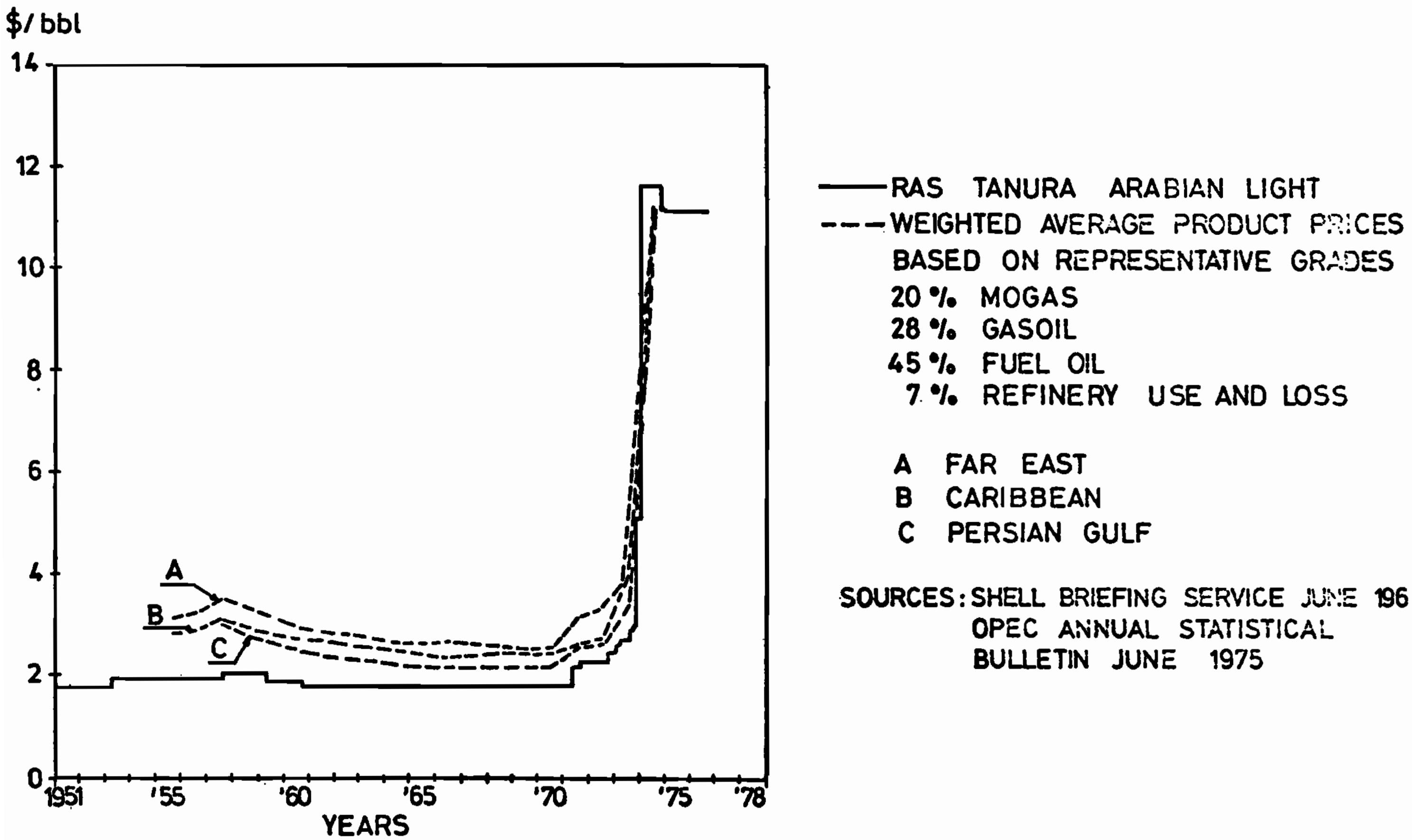


Figure 6-14.--Posted prices of some crude oils

production ran around 7 percent and was expected, basically, to continue somewhere along this line. Estimates produced after 1974 assume about half that figure only [18].

Taking the 1973 crude production of about 20.4 x 10^9 barrels as a basis, present proved reserves of around 650 x 10^9 barrels would have lasted about 17 years. At a reduced rate of consumption increase of, say, 3.5 percent, it could last some 22 years. If during this time, however, the recovery factor of these reserves could be increased from about 33 percent to, say, 45 percent, this would already extend the usefulness of these reserves, without any new discoveries, to 27 years, that is, just beyond the end of this century. Obviously, additional reserves will be discovered concurrently. If we take, following Odell, a figure of a total of some 4,000 x 10^9 barrels of ultimately recoverable oil, again apply an average recovery factor of 45 percent instead of 33 percent, and an average annual increase in consumption of 3.5 percent (although, of course, it is getting increasingly more unrealistic to use exponential growth rates the further we proceed into the future), we already arrive at more than 70 years supply, and, increasing the recovery factor to 60 percent, at 75 years versus 39 at the original growth and recovery rates. (Incidentally, Odell's estimate sits in very well with an estimate of just over 12,000 x 10^9 barrels of original oil in place elaborated by I. I. Nesterov and F. K. Salmanov (Chapter 10). This, for policy decisions, is a large difference indeed, which may substantially change the outlook on available energy alternatives.

In light of these considerations, past resource estimates will therefore have to be reworked to a very considerable extent. To make them more comparable and, thus, more useful for future policy considerations, it would appear highly desirable that assumptions on future discoveries of conventional resources of naturally-occurring oil and gas be complemented by explicit assumptions on future recovery rates. In addition, estimated recovery from nonconventional resources will increasingly have to be considered to arrive at, ultimately, a consolidated overall estimate.

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CHAPTER 7

METHODS USED IN THE USSR FOR ESTIMATING POTENTIAL PETROLEUM RESOURCES

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A.E. Kontorovich, Yu. Ya. Kuznetsov, S.P. Maksimov,
M. Sh. Modelevsky, and I.I. Nesterov[1]

INTRODUCTION

Solution of the problem of production, distribution, and maximum utilization of all mineral and raw material resources, with oil and gas being most important, is one of the principal tasks of the development of the USSR industry. Planning and prospective forecasting are getting considerable attention as volume of all spheres of production and their coordination are increasing. With this in view, further growth of the rate of verification of hydrocarbon resource estimations, which are the basis for long-term development of energy systems, is projected.

To plan the development of the petroleum industry it is necessary to have rather well-grounded ideas of the amount of crude oil, natural gas liquids (NGL), and nonassociated and associated gas, not only as explored reserves and those prepared for production, but also as undiscovered (probable and speculative) ones. The explored reserves provide the principal source of current production level of the commercial minerals and planning for the near future. The long-term planning of production is mainly based upon estimates of undiscovered reserves. Large districts (zones, regions, areas, provinces) usually furnish the basis of these estimations for promising territories and water

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[1]USSR.

areas of individual complexes of deposits within the limits of these districts. The quantitative estimating of petroleum potential (estimating of future petroleum reserves) is usually performed for such objectives where the qualitative estimating of this potential has been completed previously, i.e., on the basis of geological, geophysical, and geochemical information, including drilling data (provided that drilling has been performed) and the areas have already been allocated on which the commercial petroleum deposits are expected to be discovered with a high or low degree of probability. For such areas the quantitative estimating of petroleum potential has to answer the question: what amount of hydrocarbon reserves is to be discovered in the final analysis and in what ratios the reserves of liquid and gaseous hydrocarbons will be?

Total amount of petroleum which can be contained in the interior of the promising petroleum-bearing territories and water areas is called "ultimate (or initial) potential geological[2] resources" (UPGR) irrespective of technical-economical possibilities for their extraction and use. If, within the limits of promising territory or water area, oil or gas is already being produced, the part of ultimate potential resources still contained in the interior of the earth is called "current potential resources" (CPR). So, "resources" is the most common all-embracing term.

In every particular case estimating of resources is a function of the degree of geological knowledge of the object under estimation. As accumulation of knowledge proceeds concerning regularities of distribution of deposits, increasing the amount and perfecting the exploration methods, the estimating becomes more and more accurate, i.e., it will approach the petroleum quantity actually to have been accumulated in the interior of the earth in the territory or water area under study.

The UPGR at any time, i.e., at any degree of exploration of promising area, may be divided into two parts--discovered and undiscovered. The discovered part of resources is called

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[2]The same as "in-place."

"ultimate (or initial) discovered reserves" and comprises all the reserves discovered at known fields including the amount of oil or gas which has already been produced from these fields (cumulative production). The part of ultimate discovered reserves which still occurs in the interior of the earth is called "current discovered reserves" (CDR). From the economic point of view they are divided into commercial reserves, the development of which is considered to be advisable under existing technical-economical conditions, and noncommercial ones, the development of which is unprofitable under these conditions. According to the degree of exploration of the reserves to be estimated and degree of reliability of this estimating, the CDR are divided into three categories--A, B, and C_1 (in decreasing order of degree of exploration and reliability). Undiscovered part of the UPGR is divided into "prospective reserves" (category C_2) and "forecasted reserves" (group D).

The category A is computed only during the process of exploitation of the fields and is studied to such degree only when all factors (conditions) influencing commercial production are fully determined, including reservoir properties and their changes, fluid chemical composition and saturation, and also parameters determining the type of reservoir drive. Reserves of this category serve as a basis for designing and constructing field gathering systems and equipment for production, for oil and gas refining and transport, and for determination of present and planned production.

The category B is computed for reserves within the areas with commercial capacity proved by flow tests in wells which met the reservoir at different hypsometric levels, and by favorable logging-coring data. The conditions of the petroleum occurrence, basic parameters, and drive-mechanism can only be studied approximately. The prerequisite is a pilot exploitation of oil or gas wells and detailed knowledge of petroleum composition. The data are sufficient to start development designing.

The category C_1 is justified in known fields when some wells are proved to be commercial and others are characterized by favorable logging evidence and reservoir parameters. Also falling into category C_1 are the reserves directly adjacent to blocks where the higher categories (A and B) are present in the same pool. Category C_1 reserves serve as the basis for the extension of field exploration.

The accuracy of determining the basic parameters used in calculation of petroleum reserves by the volumetric methods may be in the range of ± 10, 15, and 50 percent for the categories A, B, and C_1 respectively.

Reserves which can be explored in known fields (in untested horizons, separate blocks and so on) and reserves which can be discovered on new structures prepared for wildcat drilling are included in category C_2. Estimation of this category of reserves is usually performed by the volumetric method with the use of geophysical data for mapping of possible oil and gas-bearing horizons. With this data as the basis, the exploration program for structure and its components is composed.

According to degree of validity of estimating, forecasted reserves are divided into two subgroups--(D_1) more reliable and (D_2) less reliable.

Forecasted petroleum reserves having been calculated regarding the promising areas or complexes within the limits of which commercial oil and gas fields have already been discovered fall into D_1 subgroup. These reserves are calculated as follows:

1. on expected anticlinal and stratigraphic traps prepared for wildcat drilling but not estimated regarding C_2 category (for example, in connection with doubtfulness of direct analogy in structure of the area under consideration with that of the known fields);

2. on expected traps supposing they exist according to the geological-geophysical data, but are not prepared for wildcat drilling;

3. expected traps supposed to exist based on regularities of distribution of local structures on adjacent areas studied in detail in those cases when petroleum-bearing capacity of such traps in the area being forecasted is not doubtful.

Forecasted reserves calculated by areas and deposition complexes related to large tectonic forms within the limits of which oil and gas fields have not been discovered yet but the geological structure of which bears resemblance to that of the tectonic forms with petroleum-bearing potential already ascertained fall into D_2 subgroup. Forecasted reserves calculated for such zones of distribution of regional petroleum-bearing complexes which occur much deeper than brought in by drilling fall into this subgroup.

Taking into consideration the value of recovery factors of oil, NGL, nonassociated and associated gases calculated as of the date of estimation or probably to be achieved in the future, the recoverable part (recoverable resources and reserves) may be ascertained in the total UPGR and may form the basis for discovered, prospective and forecasted reserves categories.

General structure of the ultimate potential petroleum resources is shown in Table 7-1.

In many countries, the classification of petroleum reserves which has been worked out by the American Petroleum Institute (API) and the American Gas Association (AGA) and the classification of resources proposed by U.S. Geological Survey, are popular. The correlation between these classifications and the classification adopted in the USSR is tabulated in Tables 7-2 and 7-3.

Undiscovered petroleum resources are calculated either directly on the promising but poorly studied area or complex or are calculated as the difference between previously calculated UPGR of this area or complex and commercial reserves that have been discovered by the date of estimating within the limits of a part of this area or complex. If it is possible to take into consideration also the prospective reserves (C_2 category), the result of estimating is forecasted reserves only.

In the USSR several methods of estimating the ultimate potential resources (UPR) and forecasted reserves (FR) of petroleum have found application. The majority of methods are based upon the principle of geological analogy, where the values of specific petroleum reserves accounted for in one unit of area or one volume of rocks, or in natural reservoirs or single structures (fields) are calculated over a very well studied

TABLE 7-1.--Ultimate (initial) potential petroleum resources (UPGR)

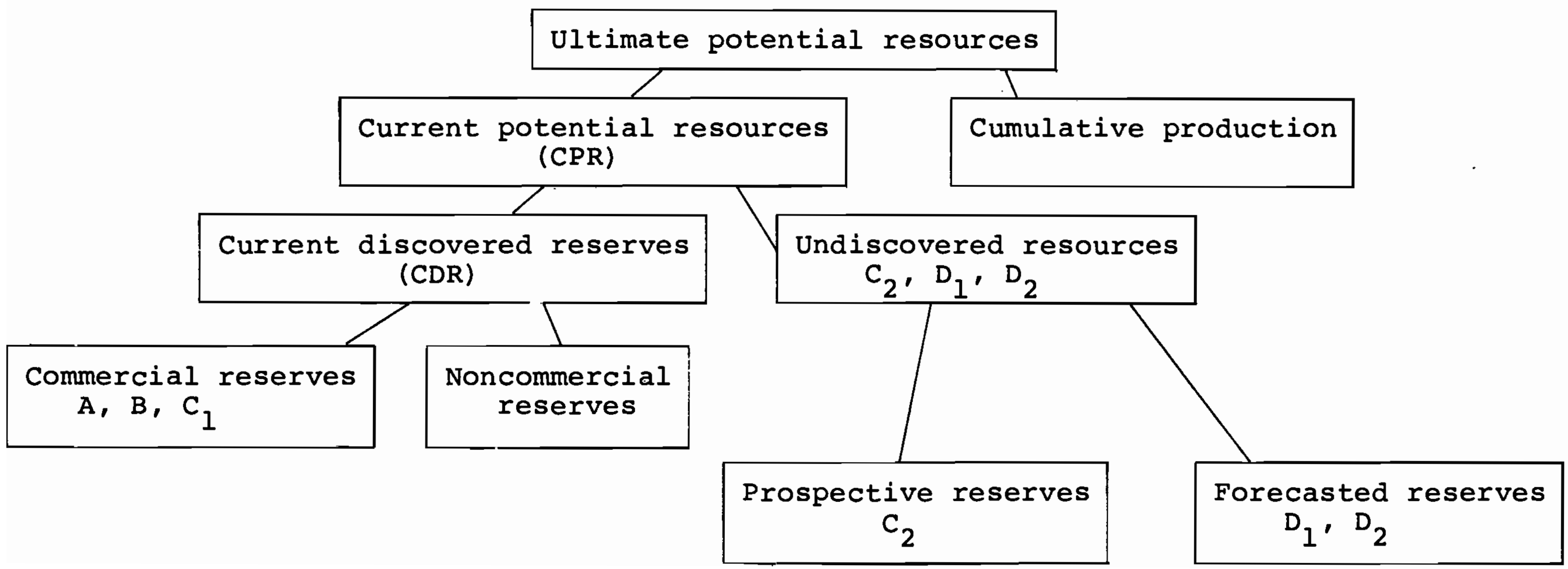

TABLE 7-2.--Comparison of classifications adopted in the USSR and in other countries

Groups of reserves in the US classification	Categories and groups from classification adopted in the USSR							
	USA and Canada	India	Iran	Malaysia	France	Netherlands	Federal Republic of Germany	North African countries
Proved	A, B, partly C_1	A, B	A, B	A, B	A, B, partly C_1	A, B, partly C_1	A+B partly C_1	A, B, C_1
Probable	C_1, C_2	C_1, C_2	C_1	C_1	C_1 and partly C_2 in known fields	mainly C_1	C_1 and some times C_2 in known fields	
Possible	D_1, partly D_2	--	C_2 in known fields	C_2 in known fields	C_2 in prospective undrilled areas	C_2 in known fields	C_2 in prospective undrilled areas	--
Speculative	D_2	D_1	--	--	--	--	--	--

TABLE 7-3.--Comparison of classifications of resources and reserves in the USSR and suggested by U.S. Geological Survey

Groups of mineral resources and reserves by U.S. Geological Survey classification	Categories and groups of recoverable petroleum resources and reserves in the USSR
Total resources	Original (ultimate) potential resources
Identified reserves	A, B, C_1, C_2
Measured reserves	A, B, partly C_1
Developed reserves	A
Undeveloped reserves	B and partly C_1
Indicated reserves	C_1 and C_2 in known fields
Inferred reserves	C_2 in prospective areas and partly C_1 and C_2 in known fields
Undiscovered economic resources	D_1, D_2
Hypothetical resources	D_1
Speculative resources	D_2
Identified subeconomic resources	Noncommercial reserves of categories A, B, and part of C_1 (noncommercial part of categories C_2 in the USSR not being singled out).
Undiscovered subeconomic resources	Not singled out

(reference) area and extended by analogy to cover the areas under estimation (forecast areas). On the other hand, variations of direct estimation of amount of petroleum have been proposed, in which the petroleum formed in the source rocks, migrated from them to the reservoirs, and accumulated within the limits of the areas under estimation (volumetric-genetic method) is calculated. In another method of estimation of petroleum reserves, data are used which characterize the dynamics of production and the increase of petroleum reserves or effectiveness of wildcat drilling over a long-term period (historical-statistical method).

METHODS BASED UPON THE ANALOGY PRINCIPLE

To estimate the UPR or FR on the principle of geological analogy it is essential that an area studied in detail is selected within the limits of which a considerable number of commercial oil and gas fields have been discovered and which has similar features of geological history to the area under estimation. The better a reference area is explored and the more complete the analogy is drawn between it and the area under estimation, the more reliable will be the results of the forecasting estimation. However, in nature, a complete analogy between two areas is never met. In connection with this fact, the "analogy ratio" is introduced into calculation, taking into consideration differences in thickness of complexes compared, reservoir properties, types of traps, nature of overburden, conditions of conservation, and related factors. Calculation by the method of specific reserves accounted for by a unit of promising area is performed in the following way:

$$UPR = S \cdot q_s \cdot K_a$$

where UPR is ultimate resources of oil, gas, or sum total of hydrocarbons in oil equivalent, 10^6 tons or 10^9 m^3; S is surface area under estimation, km^2; q_s is specific reserves of oil, gas, or sum total of hydrocarbons calculated over a reference area, 10^6 tons/km^2 or 10^9 m^3/km^2; K_a is the analogy ratio, fractions of a unit.

Calculation by the method of <u>specific reserves accounted for by a unit of promising rock volume</u> is performed from the formula:

$$UPR = V \cdot q_v \cdot K_a$$

where V is volume of rocks composing the area under estimation or an individual promising complex within the limits of this area, km^3; q_v is specific reserves of oil, gas, or sum total of hydrocarbons in oil equivalent, calculated over a reference area, 10^6 tons/km^3 or 10^9 m^3/km^3.

Calculation by the method of <u>average reserves accounted for by one field</u> ("averaged structure") is performed by equation:

$$UPR = N \cdot q_f \cdot K_s \cdot K_a$$

where N is expected number of structures (structures on which wildcat drilling can be accomplished) in an area under estimation; q_f is average reserves of oil, gas, or sum total of hydrocarbons in oil equivalent accounted for by one field in the reference area, 10^6 tons or 10^9 m^3; K_s is success ratio of wildcat drilling, fractions of a unit.

Expected quantity of structures in an area under estimation is determined in the following way. First, the area of the reference territory is divided into total number of local areas, i.e., the average area of one structure is determined. Then the area of the territory under estimation is divided by this index.

The success ratio of wildcat drilling is determined by dividing number of oil fields to have been discovered in the reference area by total number of local areas on which the wildcat drilling was completed.

Calculation by the method of <u>specific volume of oil and gas accounted for by a unit of volume of promising reservoir rocks</u> is accomplished by the equation:

$$UPR = V_r \cdot q_r \cdot \gamma \cdot 10^3$$

where V_r is the volume of promising reservoir rocks in the area, km^3; q_r is average specific volume (concentration factor) of sum total of hydrocarbons in oil equivalent in reservoir conditions, fractions of a unit; γ is average specific weight of sum total of hydrocarbons, gr/cm^3.

In case of estimating the oil resources UPR_o in advantageously oil bearing area or gas resources UPR_g in advantageously gas bearing area this equation will be as follows:

$$UPR_o = V_r \cdot q_r^o \cdot \gamma_o \cdot 10^3 \ (10^6 \text{tons})$$

$$UPR_g = V_r \cdot q_r^g \cdot F \ (10^9 \ m^3)$$

where q_r^o and q_r^g are respectively oil and nonassociated gas concentration factors, γ_o is average specific weight of oil; F is volume ratio of nonassociated gas (to transform gas volume in reservoir conditions into gas reserves at surface conditions).

The volume of reservoir rock is calculated by multiplying the area of promising deposition by the average thickness of the permeable part of the section enclosed between regional fluid-tight (impermeable) beds. Ratio between this volume and the total complex volume is called an "effective capacity factor" (K_e). The volume of effective reservoirs does not include those parts of section which are composed of permeable rocks without an overlying seal, as well as thick reservoir rock masses which exceed 60 to 70 percent of total thickness of the complex under estimation (such rock masses usually are actively washed by the underground waters). K_e value can be calculated from the data of individual boreholes if such boreholes have been drilled within the limits of the area under evaluation or are accepted by analogy with the areas studied in detail. All things being equal, average values of the effective capacity factor amount to: 15 to 30 percent for marine clastic deposits, 5 to 15 percent for carbonate (up to 40 percent for reefogenous) and of the order of 20 percent for mixed (clastic-carbonate) ones. Smallest values of K_e are typical of rock masses of essentially halogenous composition (10 percent an average) as well as continental and continental-marine formations, especially rudaceous and medium-detrital molasse formations for which this factor does not exceed 5 percent is usually 1 to 3 percent. Consequently, when calculating the volumes of natural reservoirs, effective capacity factors can be selected taking into consideration the general lithological characteristics of the sedimentary cover as well as the ascertained or expected proportion of deposits of various lithologies in the total thickness of the section. To select the effective capacity factors for carbonaceous rock masses consideration must be given to the data about presence of zones of reefs as well as zones of increased jointing, considerable clayiness in carbonate rocks, and so on. Thus, in some cases it is advisable to increase the K_e value, in others to decrease it.

Concentration factors of oil, gas, or total hydrocarbons are selected for every area under estimation, proceeding from the available data concerning relations between discovered hydrocarbon reserves and volumes of reservoir rocks within the limits of reference areas, as well as volumes of reservoir rocks in the area to be estimated. In addition, the number of prospects expected from the results of preliminary qualitative estimating should be taken into consideration.

In the beginning, the volumes of reservoir rocks are calculated over reference areas. Then, oil, natural gas liquids, and nonassociated and associated gas reserves discovered within the limits of these areas are calculated into volumes which these reserves can occupy under reservoir conditions in the reference area (in this particular case calculations are to be made with geological but not recoverable reserves. By division of hydrocarbon volumes by volumes of natural reservoir rock, q_r^o and q_r^g (concentration factors) are obtained which can be used in calculating FR for the areas under evaluation.

VOLUME-GENETIC METHOD

Various versions of this method have been advanced. The essence of the method is to calculate the probable quantity of liquid and gaseous hydrocarbons which could originate in the source rocks as a result of katagenic transformation of the organic matter dispersed in the rocks under the conditions of temperature and pressure which existed in the interior of the earth of the area under estimation during the process of its geological evolution. Then the probable quantity of liquid and gaseous hydrocarbons which migrated out of the source rocks into reservoirs (ratio between this quantity and total amount of hydrocarbons to have been formed is called the "migration factor")[3] is determined. Finally, taking into consideration probable losses of hydrocarbons during the migration process, that quantity of hydrocarbons is calculated which would have accumulated in the deposits (ratio between this quantity of hydrocarbons and total quantity of hydrocarbons estimated to have migrated is called the "accumulation factor")[4].

Specifically, the quantity of liquid hydrocarbons (Q_{em}), that migrated out of the source rocks into reservoirs can be determined by equation:

$$Q_{em} = \frac{1.3 \cdot K_{em} \cdot \lambda \cdot h \cdot S \cdot b \cdot 10^4}{1 - K_{em}} \text{ (tons)}$$

where K_{em} is the migration factor, fractions of a unit; λ is the density of argillaceous rocks considered to be the source rocks, gr/cm^3; h is thickness of these rocks, m; S is area of their occurrence, km^2; b is average content of residual bitumen in these rocks, %; 1.3 is a correction factor taking into account the losses of benzine and kerosine fractions when accomplishing extraction of bitumen in laboratory conditions.

Having multiplied the calculated results by the accumulation factor one can obtain the value of forecasted geological petroleum reserves. It is desirable in every particular case to calculate the values of this index for a number of reference areas studied in detail (comparing the calculated values of Q_{em} with the actually explored reserves), and then to utilize those values when performing calculations of UPR for the areas under estimation having similar geological structure.

HISTORICAL-STATISTICAL METHODS

These methods are based upon the analysis of changes over a long-term period of such indices as the annual production of oil and gas, the average annual increase of petroleum reserves, or

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[3] 10 to 20 percent in general.

[4] 1 to 5 percent for oil and 1 to 3 percent for gas in general.

the specific increase of reserves (meters of reserves per meter of drilling or per unit of expenditures). In the case of availability of rather representative data one could plot curves in coordinates: production-time, increase of reserves--volume of drilling, and so on, then reveal statistical dependences between these indices and utilize them for estimating FR.

For example, it is known from more than one hundred years of development of the petroleum industry that in a common case, if there are no reasons retarding the development of petroleum production, it has to change according to the law close to the normal one, i.e., the production increases approach some maximum, then fall to zero. The total petroleum production for the whole period of development of oil fields actually represents the general value of the recoverable part of ultimate potential petroleum resources. One may obtain rather precise values of recoverable UPR if the curve "production vs time" is plotted and integrated from the moment of beginning the development of oil fields up to the expected moment of their completion. Having subtracted from it that part of petroleum, which has already been discovered and recovered, we should obtain the value of recoverable forecasted reserves. The most reliable FR estimations by this method could be performed on areas in which most oil fields have already been discovered and the total annual production has reached or passed the maximum level.

CONCLUSION

The quantitative evaluation of petroleum possibilities may be accomplished at different stages of development of promising regions or at various stages of exploration, and consequently the degree of reliability of these estimations also should vary. That is why calculations UPR and FR should be performed systematically and evaluations corrected as new data are accumulated. It is advisable to make good use of a combination of different methods of UPR and FR evaluations. The obtaining of similar results by using two or three various methods may indicate the objectivity of calculations.

UPR and FR calculated on different commodities are to be assumed for different geological structures (districts, basins, provinces, and so on), or administrative units (regions, countries, and so on). The final results of the quantitative estimating of petroleum-bearing prospects are expressed on tables and maps. On maps the average density of forecasted reserves or ultimate potential resources is usually represented schematically, and is obtained by division of total value of FR or UPR, calculated for any geological structure, by the area of the promising part of the structure.

CHAPTER 8

STUDY OF PETROLEUM ZONES: A CONTRIBUTION TO THE APPRAISAL OF HYDROCARBON RESOURCES

G. Gess[1] and C. Bois[1]

INTRODUCTION

The aim of this study is to help the geologists to appraise the potential of an area more or less unexplored using the geological parameters which are known in the early state of exploration.

We will discuss successively:

- The concept of petroleum zone;
- The parameters involved in the study;
- The similarity and the correlations;
- In conclusion we will discuss an actual example of area appraisal.

THE PETROLEUM ZONE

The petroleum zone (Fig. 8-1) is a continuous part of the sedimentary space containing hydrocarbon pools which have in common:

- Reservoirs belonging to the same productive series (same age and lithology);
- Traps belonging to a small number of types;
- Hydrocarbons of a similar chemical nature.

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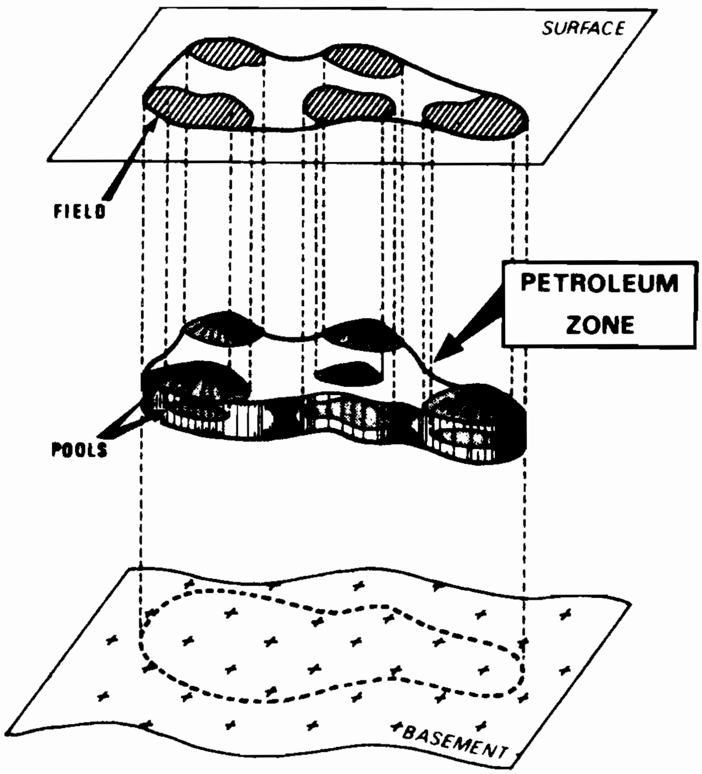


Figure 8-1.--Concept of petroleum zone

In other words, a petroleum zone is what is often called a "play."

Figure 8-2 is an example of petroleum zones in the Middle East.

In Saudi Arabia, the HASA zone produces from the Upper Jurassic carbonates of the Arab zone formation; in Kuwait and Safaniyah the pools produce essentially from the Lower and Middle Cretaceous; in the Dizful zone the production comes mainly from the Asmari limestone, Oligo-Miocene in age. Within each of these sets of pools the traps belong to the same type but important variations may occur from one set to another. The same distribution appears concerning hydrocarbon.

We have 126 petroleum zones in our file. We estimate the number of worldwide petroleum zones to be around 350.

PARAMETERS OF PETROLEUM ZONES

To describe the petroleum zones of the file we use three kinds of parameters (Fig. 8-3):

- The original parameters, those which are directly collected by the geologists. They are 153 distributed in different chapters such as stratigraphy or structure;
- The calculated parameters which are 76 in number. They are a combination of the original ones such as richness which is the ratio of reserves by square kilometers or rate of sedimentation which is the thickness of sediments by million of years;
- The transformed parameters (106) are qualitative parameters which need to be transformed in order to be processed. For example each lithology is expressed by one of the four percentages 0, 33, 67, 100 percent, meaning that this lithology is absent, present but not very important, present and important or is the only lithology present in a stratigraphic unit.

The total amount of parameters of the file is 335.

We assume that it should be easier to find out relationships between geology and hydrocarbon occurrences within homogeneous habitats of oil rather than within the whole file which groups different types of geological situation. Therefore, we have followed two directions:

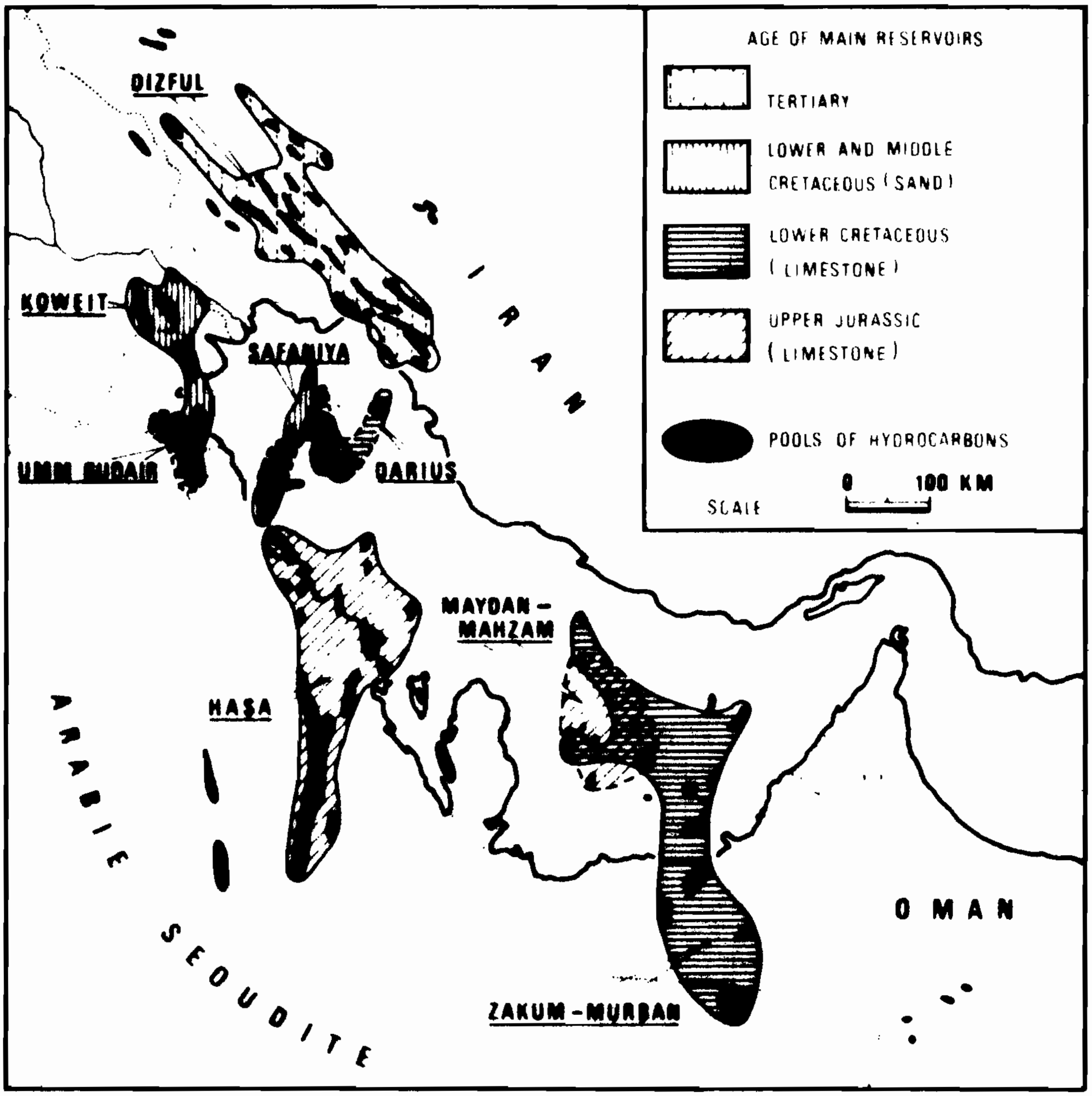


Figure 8-2.--Principal petroleum zones of the Persian Gulf

- DISTRIBUTION OF PARAMETERS -			
ITEMS	Amount of parameters		
	original parameters	calculated parameters	Trans-formed parameters
IDENTIFICATION	3		
CO.ORDINATES	12		
PETROLEUM RESULTS	6		
STRATIGRAPHY	28	22	36
STRUCTURAL GEOLOGY	14	8	28
RESERVOIR GEOLOGY	19	9	15
CAP ROCKS	7	5	5
TRAPS	15	4	14
SOURCE ROCKS	13	4	6
RESERVOIR ENGINEERING	5		
NATURE OF HYDROCARBON	13		2
RESERVES AND FIELDS	18	24	
TOTAL	153	76	106

Figure 8-3.--Parameters of a petroleum zone

- Research of relationship between the petroleum zones: this is done by the study of the similarity;
- Research of relationship between the parameters: this is the study of correlations.

SIMILARITY STUDIES

Let us consider the distribution of the porosity of the file; m is the zone bearing the minimum porosity and M, the zone having the highest porosity. A, B, C, are three zones of the file with porosity of 10, 20, and 25 percent. The distance between B and C is shorter than between A and B. These distances can be expressed in function of the distance mM; then it comes: AB = 40 percent and BC = 20 percent. The same results can be expressed by the similarity which is equal to 100 percent less the distance. So the similarity between B and C is 80 percent and between A and B is 60 percent. Between nM the similarity is 0 percent. (Fig. 8-4)

This calculation generalized for several parameters and for any couples of zones gives an average similarity which takes into account the whole set of processed parameters. Then we obtain a matrix of similarity between the petroleum zones of the file. This matrix of similarity has been studied by cluster analysis by complete linkage which permits showing the results on a dendrogram.

On this dendrogram (Fig. 8-5) done with only geological parameters we can see the scale of similarity and the zones which are identified by numbers; the similarity between two zones of a couple, 34 and 35, is 93 percent and between the zones of a larger group (nos. 33 to 37) is 83 percent. The dendrogram allows us to define easily a number of classes in which the petroleum zones have important geological similarities.

Figure 8-6 shows how the dendrogram comes out from the computer.

The names of the zones (Fig. 8-6) are on the right side and the scale of similarity is on the top increasing from left to right.

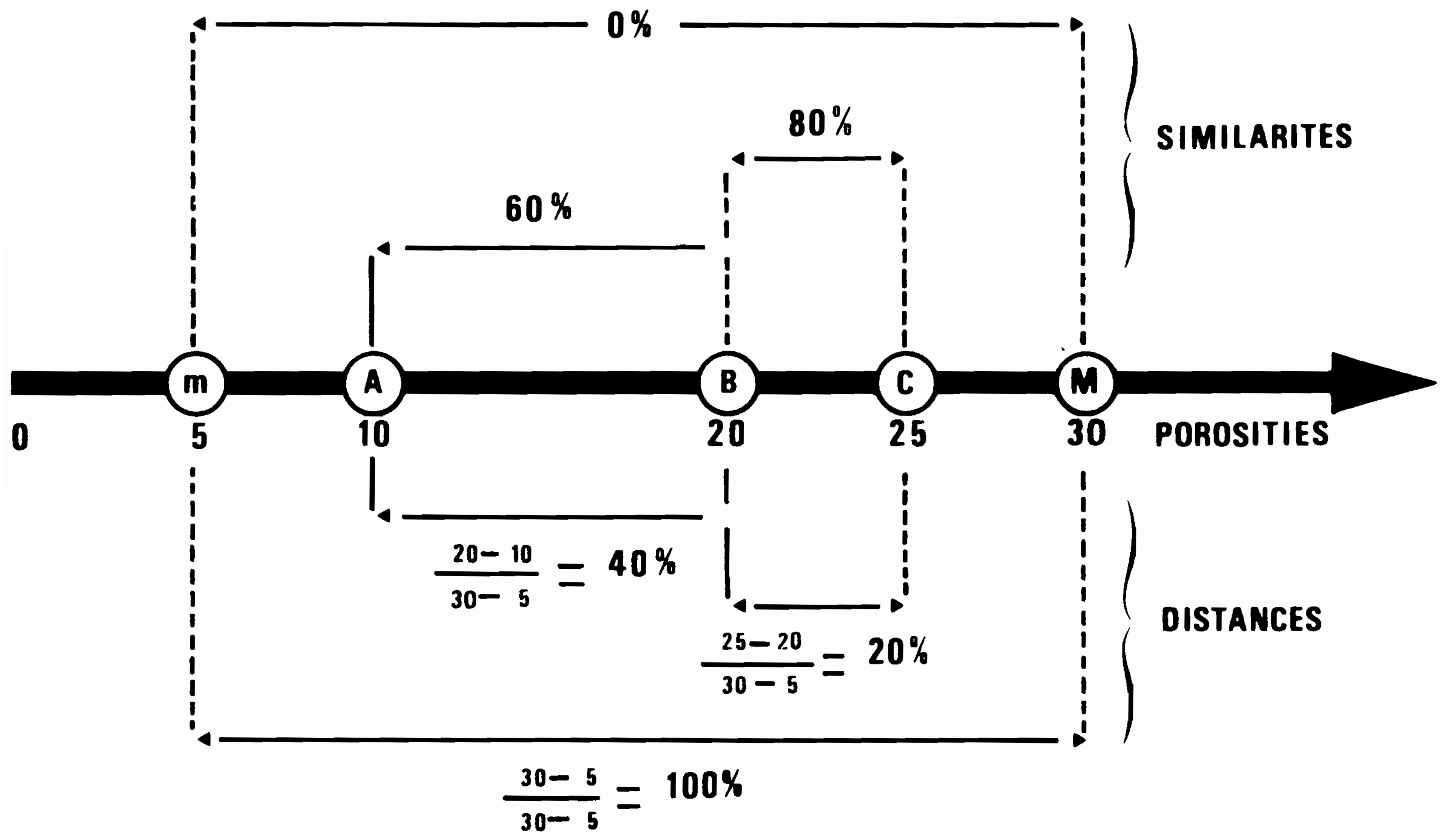


Figure 8-4.--Calculation of similarity of zones

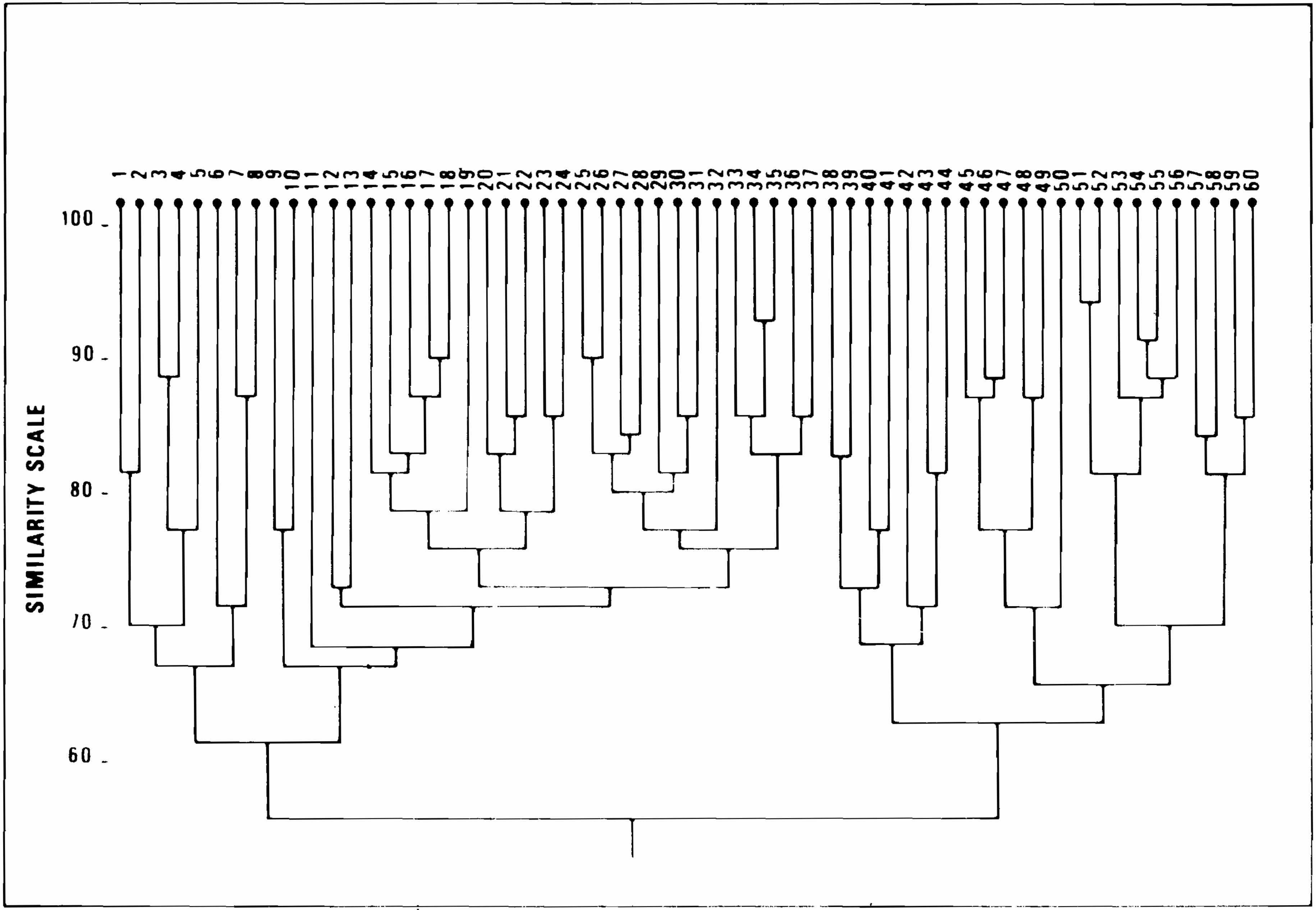
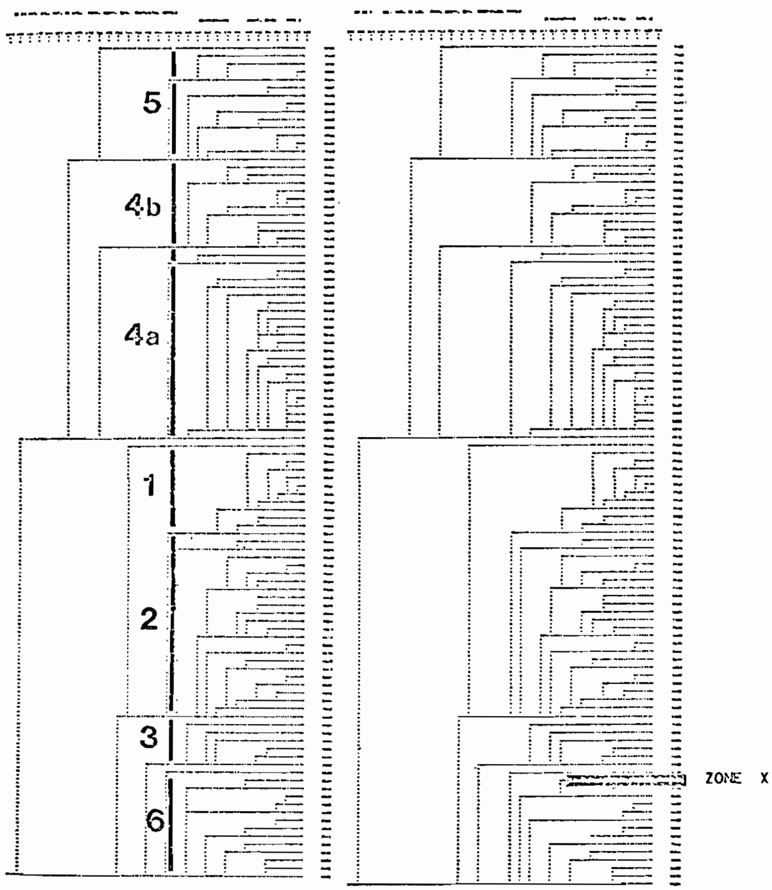


Figure 8-5.--The petroleum zone dendogram



DENDROGRAMME GEOLOGIQUE DE 105 ZONES PETROLIERES
- à gauche un exemple de classification
- à droite un exemple de calcul avec une Zone "X" à étudier.

Figure 8-6.--Dendrogram for 105 petroleum zones

In fact the similarities, and of course the classification, depend on several factors: choice of the coefficient of similarity, choice of the parameters, the way the parameters are expressed and weighted, the relationship between parameters etc. We have got round the difficulty by making several classifications using different sets of parameters with different weighting. We did about 20 dendrograms; they are more or less the same with small differences in the detail of the composition of the classes.

We have then located which zones were more often in the same class within the different dendrograms and we have established the definitive classes of petroleum zones according to their geological similarity.

Figure 8-7 is a tentative sketch trying to show in two dimensions the seven classes and a few isolated zones more or less closely related.

The big circles numbered 1 to 8 are the classes, the smaller are the zones which cannot be included in a class.

Each class has an internal cohesion which is the average of the similarity between any couples of the class. Smaller is the circle representing the class, higher is the cohesion (similarity = 1,000 - distance). Out of 105 processed zones, 95 are included in classes and 10 are isolated either because they are too far from any class (zone 9) or because their similarity is quite the same with several classes (zone 13).

The classes (Fig. 8-8) coming out from this classification have geological characteristics which are summarized in the table here below:

Class 1 (8 PZ)	:	Carbonated paleozoic platform containing the petroleum zone, overlaid by foredeep deposits. Reservoirs are carbonate and the traps are stratigraphic. Ex.: Alberta.
Class 2 (21 PZ)	:	Platform containing the petroleum zone overlaid or not by foredeep deposits. Carbonated reservoirs. Structural traps. Ex.: Middle East.

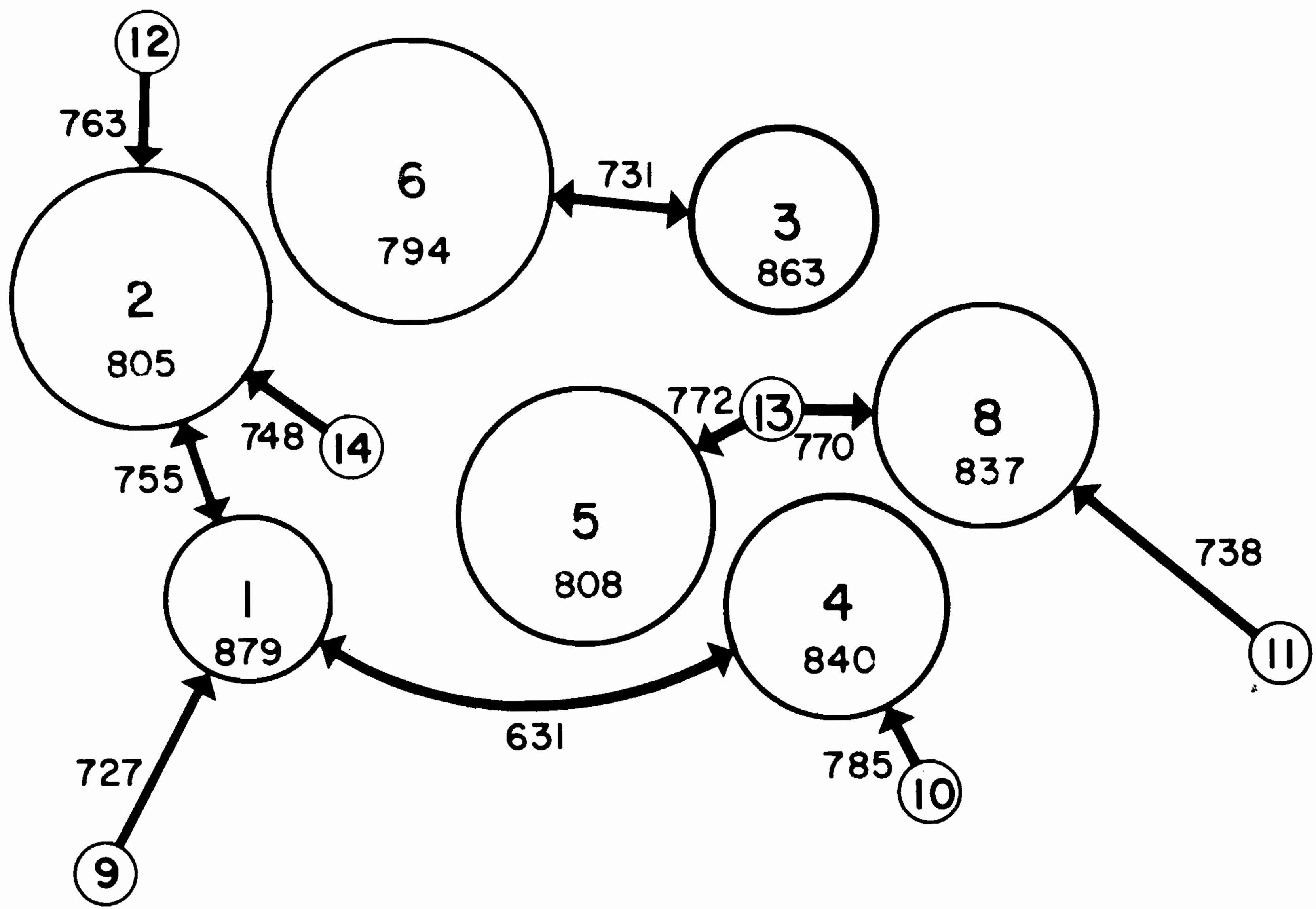


Figure 8-7.--Relationships among classes and zones
(similarity in percent)

GEOLOGICAL CHARACTERIZATION	Class n° 1	Class n° 2	Class n° 3	Class n° 4	Class n° 5	Class n° 6	Class n° 8
Geotectonic types (Youngest / Oldest)	Foredeep / Platform	Variable / Platform	Plateform / Mobile	Troughs	Foredeep / Platform	Variable / Platform	Foredeep / Platform
Rate of sedimentation (meter/10^6 years)	23	23		107	28	17	27
Age of Petroleum Zone	Paleoz.	Variable	Jur.-Cret.	Tert.	Variable	Variable	J.Cret.
Geotectonic type of Petroleum Zone	Platform	Platform	Platform	Mobile	Mobile	Platform	Mobile
Lithology of reservoirs	Carbon	Carbon	Sandst.	Sandst.	Sandst.	Sandst.	Sandst.
Porosity % (F=Fracturation)	9 (F)	2-23(F)	23	23	9-25	17	17
Reservoir thickness/PZ thickness	82%	Variable	43%	21%	18%	Variable	21%
Type of traps	Strati.	Struct.	Variable	(Struct)	(strati)	Struct.	Struct.
Example of Petroleum Zones	LEDUC PEKISKO	MARA DIZFUL ZAKUM	HOLSTEIN CHATEAU-RENARD	BORNEO SAVE BAJOS	OFICINA MESAVERDE	MESSAOUD RENO LEMAN	BIGHORN NEUQUEN

Figure 8-8.--Geological characterization of the classes

Class 3 (7 PZ) : Platform containing the petroleum zone, overlying an ancient mobile area. Reservoirs are sandstone, traps are structural and stratigraphic. Ex.: Germany.

Class 4 (27 PZ) : Intramontane or backdeep containing the PZ. Reservoirs are sandstone, generally lenses, or structural traps. Ex.: Indonesia-Central Europe.

Class 5 (13 PZ) : Platform overlaid by external part of a foredeep which contains the petroleum zone. Sandstone and three kinds of traps. Ex.: Eastern Venezuela.

Class 6 (14 PZ) : Platform containing the PZ. Reservoirs are sandstone, traps are mainly structural. Ex.: Sahara.

Class 8 (5 PZ) : Platform overlaid by a post-tectonic filling containing the PZ. Reservoirs are sandstone and mainly structural traps. Ex.: Argentina.

We know that the number of zones within each class is not very high and with regard to the statistics we are open to the criticism; but, we know also that sometimes the number of actual cases is very low; for example the producing deltas in the world are less numerous than the fingers of the hand, and in that case we are well obliged if we want to discover relationships in this type of habitat of oil, to argue about a very few individuals.

We will see now how the petroleum characteristics within these geological classes of petroleum zones are distributed.

Figure 8-9 shows that classes 3, 8, 1, and 4 (90 percent of the distribution) have little chance of yielding big reserves, which are preferentially in classes 5, 6, and 2. The PZ of Middle East are within classes 6 and 2.

Figure 8-10 shows the distribution of the reserves within the different classes.

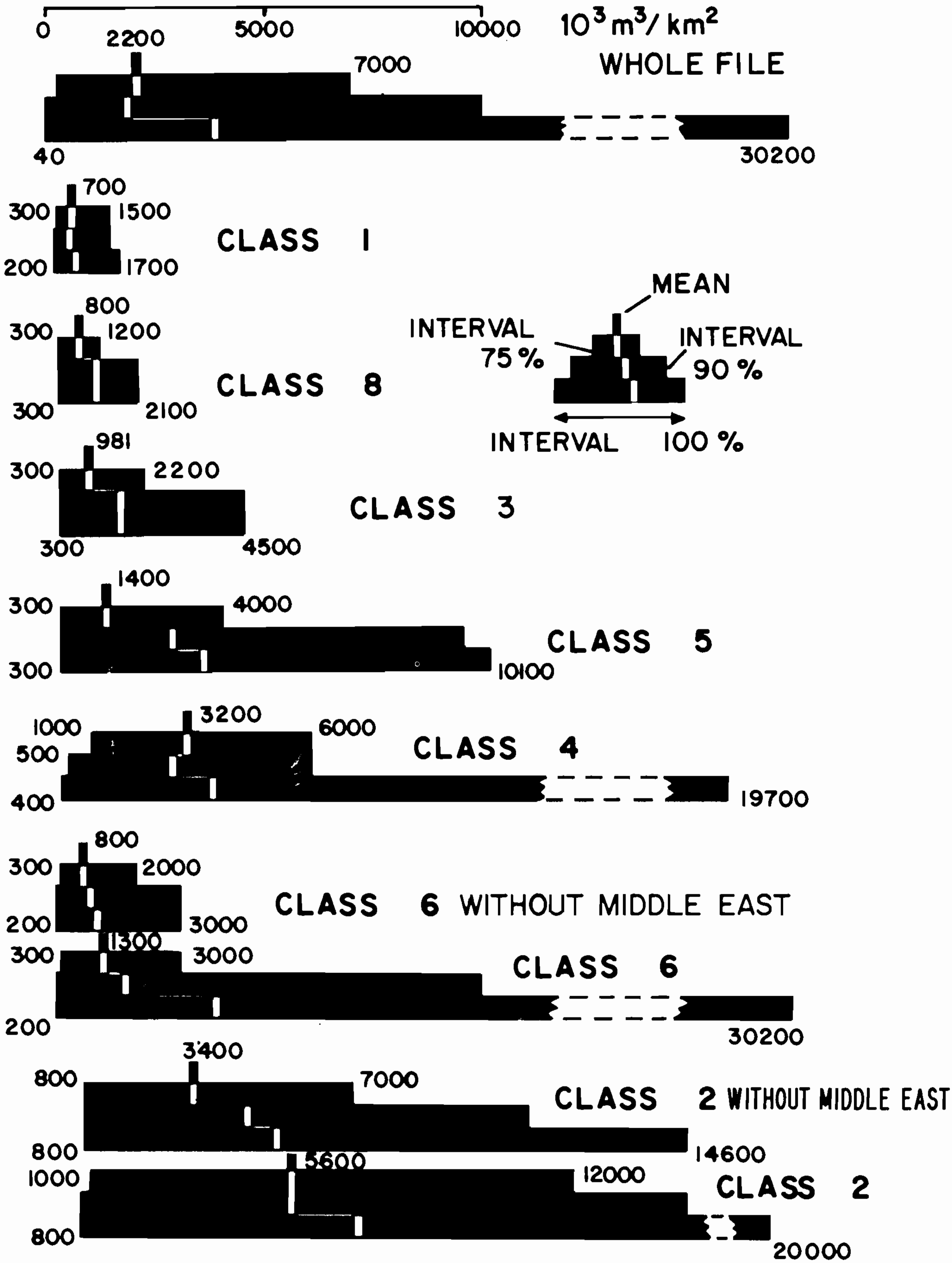


Figure 8-9.--Total oil reserves in-place, by class (10^6 m^3)

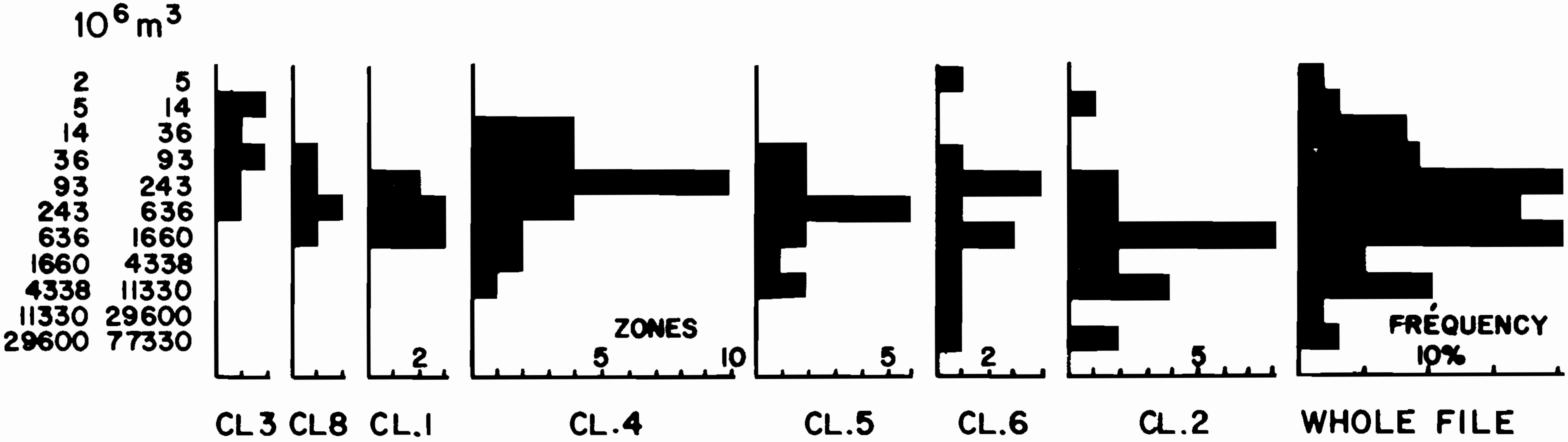


Figure 8-10.--Total in-place reserves (10^6 m^3)

Figure 8-11 shows the in-place richness of fields in thousand cubic meters of hydrocarbon by square kilometer of field.

Class 2 gives the best results even without the Middle East but class 4 and class 5 are better than class 6 without the Middle East.

Figure 8-12 shows these distributions within the classes.

CORRELATION STUDIES

We will discuss successively and briefly:

- The single correlations;
- The multiple correlations.

Generally speaking the coefficients of correlation between petroleum and geological parameters are significantly better within the class of zones than within the whole file of petroleum zones in which there is a mixture of nonhomogeneous types of oil habitat. Figure 8-13 shows an inverse correlation between the rate of sedimentation within the PZ and below the PZ and the rate of filling of a structure which is the ratio: column of hydrocarbon versus the closure.

These single correlations may allow prediction of the petroleum parameter, when knowing the geological one, in well-defined geological situations.

MULTIPLE CORRELATIONS

High coefficients of correlation obtained from single correlations are not many. Most probably, the relationship between geology and petroleum is complex. Therefore we have replaced the single geological parameter by a set of five geological parameters and we have computed the multiple correlations between the petroleum parameter and this set of geological parameters.

Table 8-1 shows us that we have better results, much higher coefficients of correlation, within a class than within the whole file of heterogeneous petroleum zones. The coefficient of correlation is generally higher when the population is smaller, but the difference here is too big to be imputable to the sole difference in size of the two populations.

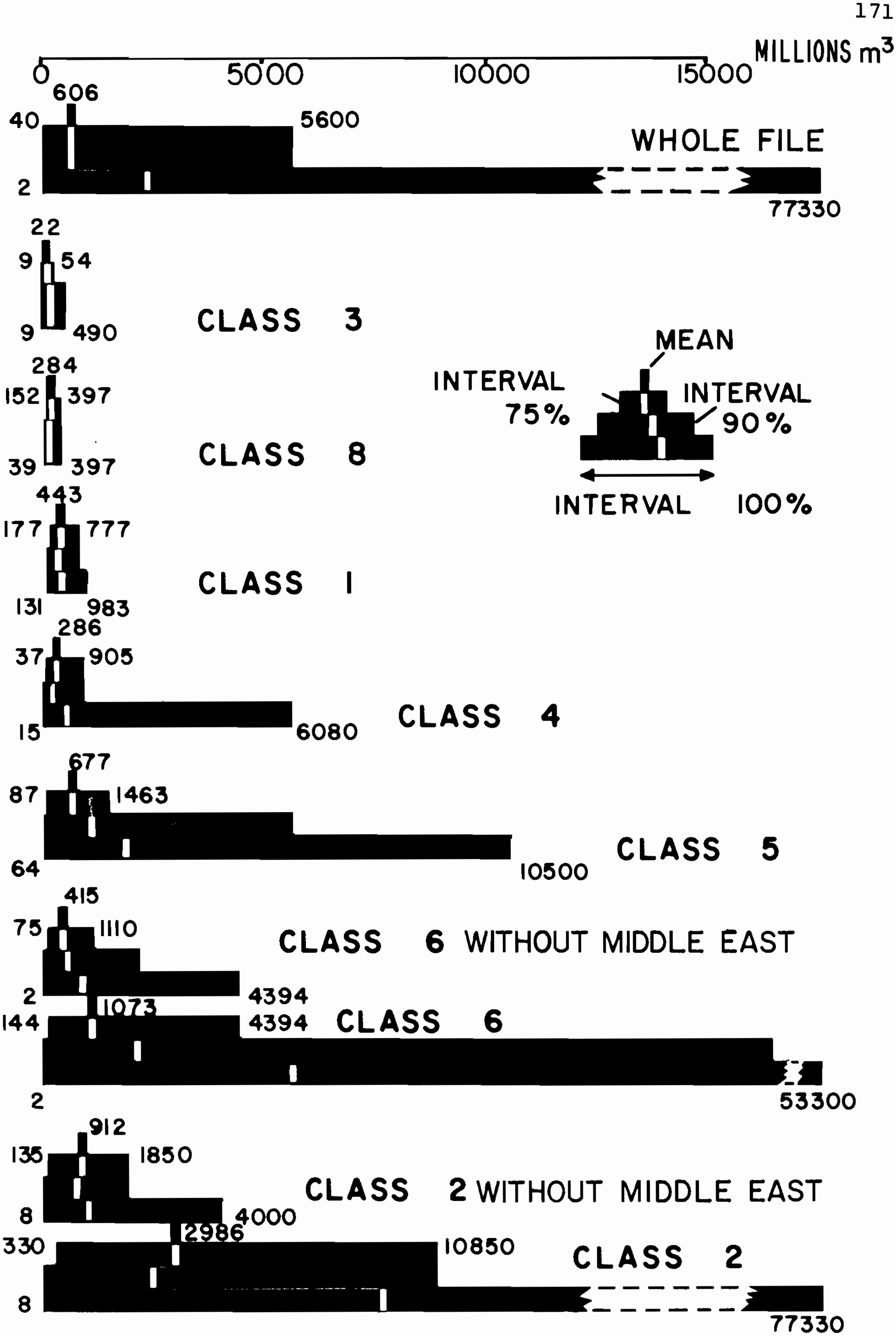


Figure 8-11.--Richness of fields (oil-in-place, 10^3 m^3/km^3)

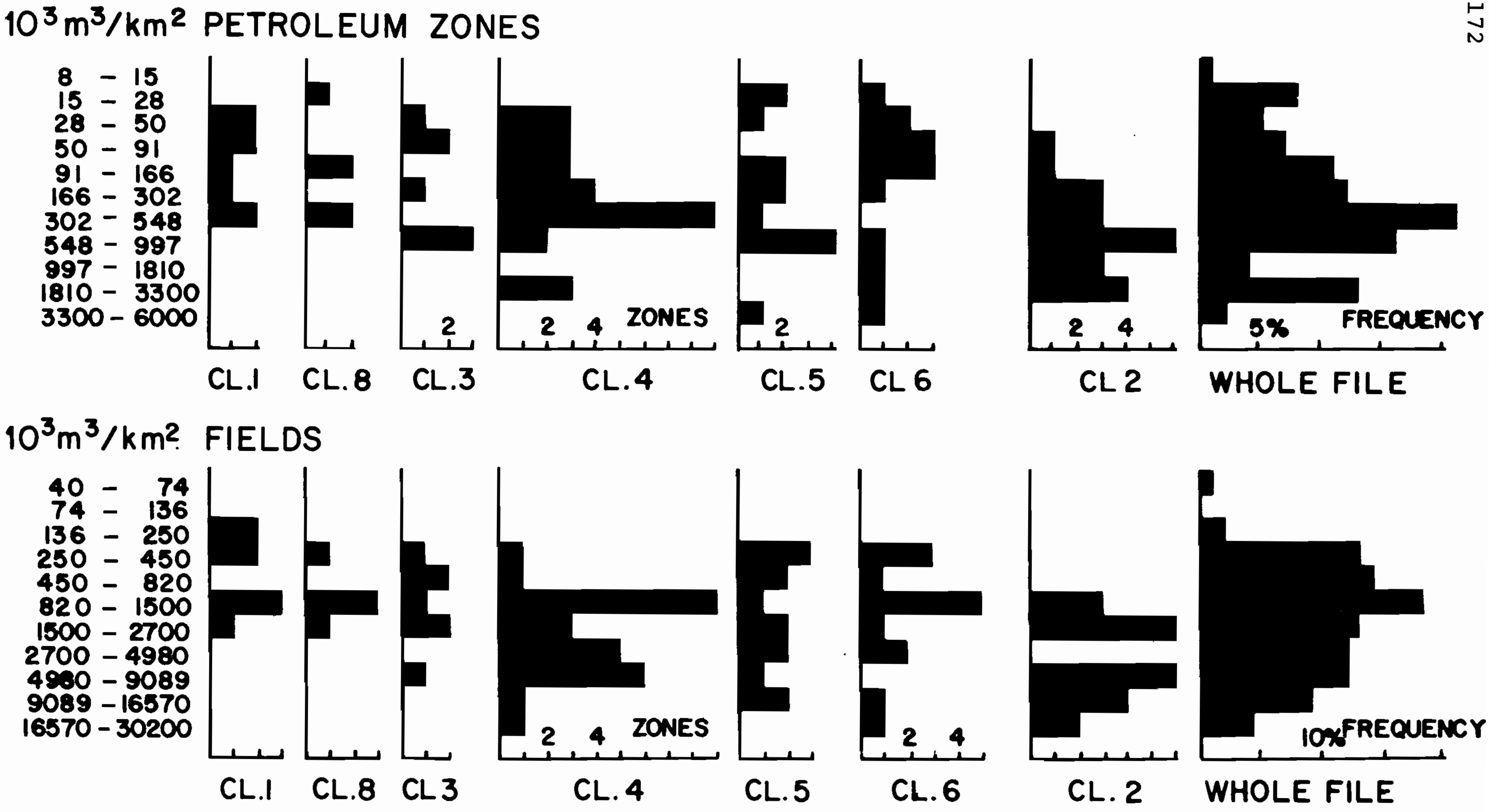


Figure 8-12.--Richness of oil-in-place, by class (10^3 m^3/km^2)

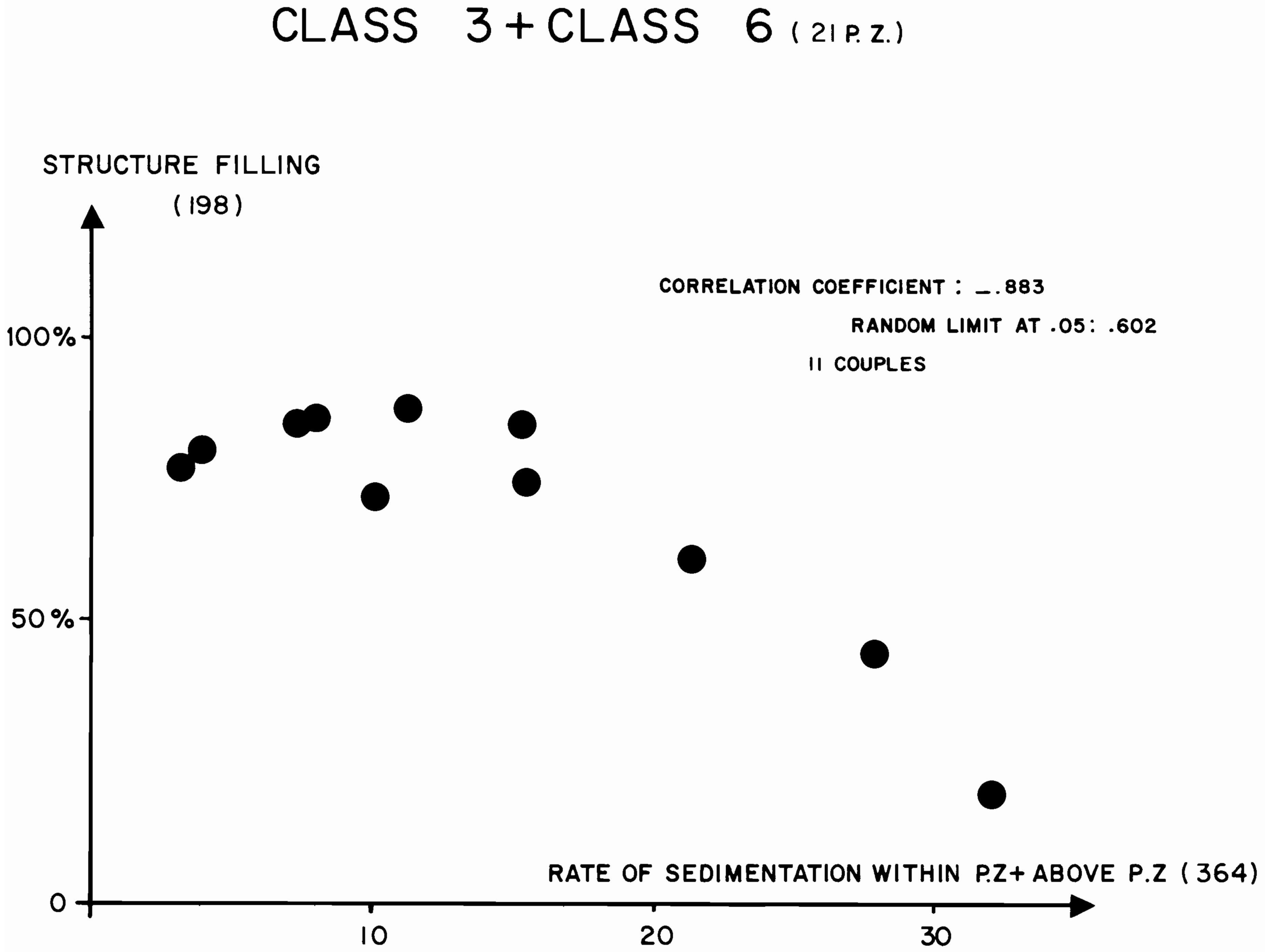


Figure 8-13.--Correlation coefficient of rate of sedimentation and structural growth

MULTIPLE CORRELATIONS

TABLE 8-1.--Coefficient of correlation given by a set of five geological parameters

Petroleum Parameters	105 PZ	Class 2
Hydrocarbon Column	69.3 %	95.5%
Initial Productivity	68.7 %	90.9%
In-Place Oil Reserves	61.0 %	86.1%
Richness of Fields	66.33%	91.2%
In-Place Reserves by Field	58.3 %	91.5%
Richness of PZ	62.3 %	86.8%

Table 8-2 is an example of a multiple correlation between the in-place reserves of a field and 12 geological parameters.

We see that the first five parameters bear the maximum information. The following parameters do not give significant information.

We will end now with an example of appraisal of an actual case given to us for test. After collecting the geological parameters, the first step was to find out to which class of zones belongs the test zone.

APPLICATION OF THE PZ STUDY

We have here the similarity between the zone to be tested and the different classes (Fig. 8-7). The calculation of similarity was done with three ways of calculation using 120 parameters, 47 parameters, and 20 parameters. The weighting was different in each case. (In fact, in the first one the parameters have the same weight.)

The highest similarity in the three calculations was with class 2. To know if the zone could be included in the class 2 we calculated the difference:

Internal Similarity of the Class - Average similarity of the test zone with all the zones of the class

TABLE 8-2.--Multiple correlations in Class 2 (in-place reserve of field)

Geological parameters correlated	Coefficient of multiple correlation successively obtained
Fracturation of reservoirs	61.1%
Number of source rocks within PZ	74.6%
Reefal environment of reservoirs	81.4%
Maximum burial of main source rock	88.5%
Cap rocks thickness/Reservoirs thickness	91.0%
Evaporites thickness under PZ	91.6%
% of sandstone in Tertiary	92.7%
Rate of sedimentation within and below PZ	94.6%
Age of bottom of PZ	95.1%
% of reservoirs in contact with unconformity	95.9%
Reservoir thickness/PZ thickness	96.1%
Number of orogenesis/time of sedimentation of PZ and above	96.2%
Presence of a foredeep	96.2%

If this difference is zero, that means that the zone is on the fringe of the circle representing the area in which are the zones of the class; if that difference is positive, the zone is out of the circle; and if it is negative, the zone is inside the circle, that is to say, within the class.

According to the results you have here (Table 8-3), we can say that the zone belongs to class 2. This is confirmed by the similarity between the zone and the individual zones of the whole file. As we can see here, the five more similar zones belong to class 2.

TABLE 8-3.--Appraisal of hydrocarbon resources: comparison of a test zone (PZ 6198) to the zones of the file

			120 param.	47 param.	20 param.	Average	Rank
Similarity with classes	Cl. 2		809	818	884	836	1
	Cl. 1		732	693	821	749	2
	Cl. 6		743	705	785	744	3
	Cl. 3		764	684	727	725	4
$S_2 - S_2$/Test			- 4	9	- 13	- 3	1
$S_6 - S_6$/Test			51	142	79	91	2
$S_3 - S_3$/Test			99	179	165	148	3
$S_1 - S_1$/Test			147	175	125	149	4
Similarity with zones	zones	class					
	4112	2	897	891	936	908	1
	5101	2	840	881	906	876	2
	5102	2	835	865	920	873	3
	4113	2	823	887	887	865	4
	5103	2	810	827	922	853	5

We are now sure that the test zone belongs to class 2 and we apply the petroleum characteristics of class 2 to the zone.

For example, we can go back to single correlation and multiple correlations and regressions to appraise some petroleum parameters.

From Fig. 8-14, knowing the most frequent area of closure of the structures which is 10, we can infer that the distance between fields could be about 8 to 12 kilometers.

Of course, we use too the multiple correlations and regressions obtained in class 2 to appraise reserves, richness, etc., from the five highest correlated geological parameters.

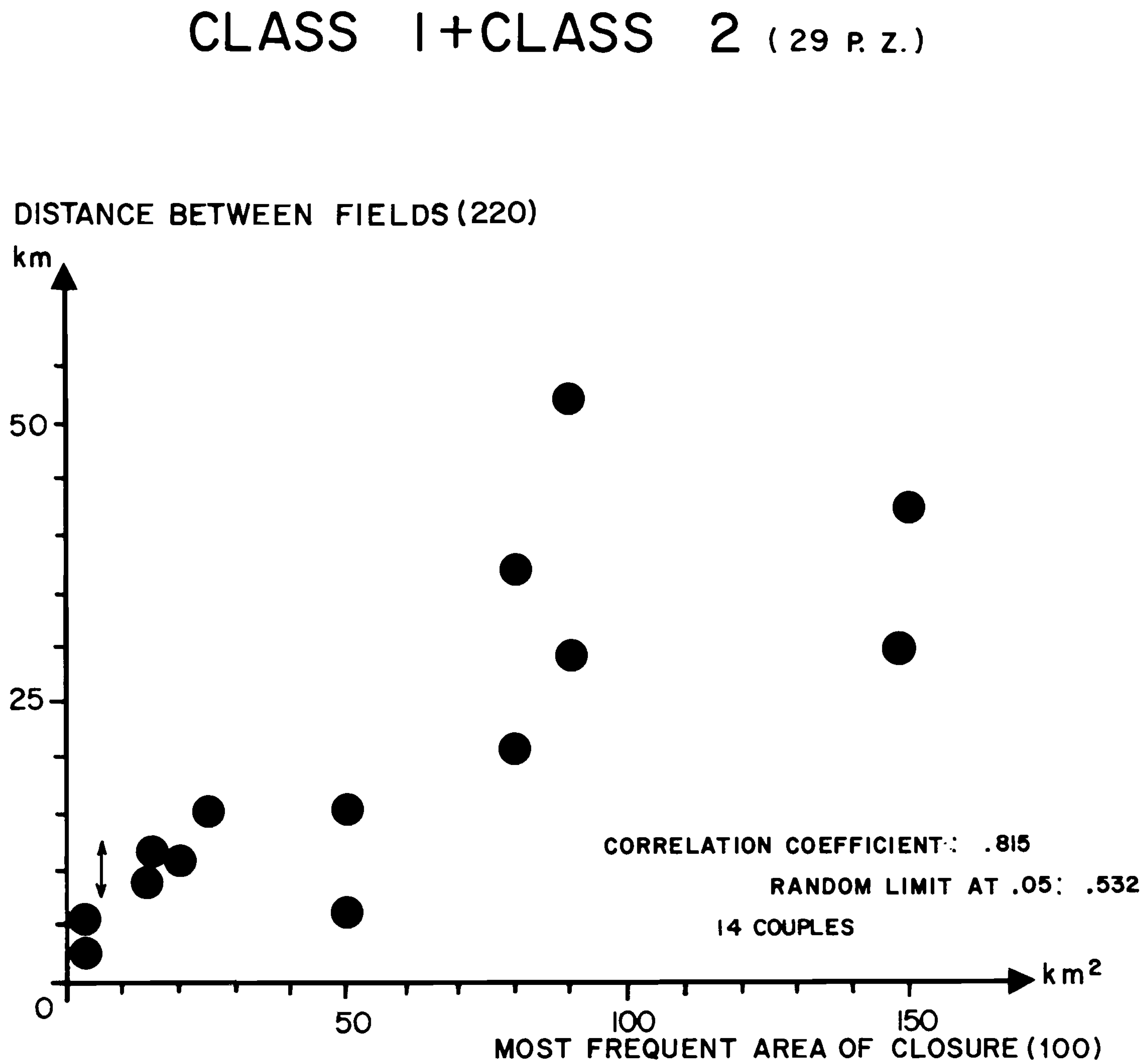


Figure 8-14.--Graph demonstrating distance between fields

CONCLUSION

The aim of this study is to give an additional tool to help explorationists when a decision has to be taken by characterizing a play by analogy with the petroleum zones of the file.

From this study the geologist can get a number of ideas by knowing to what class or zone(s) of the reference file the play has the greatest similarity; from there he may deduct what reasonably can be expected in terms of petroleum parameters within this new area.

But, when the decision has to be taken, the computer cannot get its feet wet, for the only thing which is expected from it is to be only a tool, but a good and fast tool.

CHAPTER 9

UNITED NATIONS ACTIVITIES IN THE CLASSIFICATION AND MEASUREMENT OF OIL AND GAS RESOURCES

Gilbert H. Royer[1]

INTRODUCTION

The United Nations has been concerned for a long time with the complex problems of natural resources and energy development. Over the last 25 years, numerous conferences and seminars have been organized on a variety of natural resource and energy-related problems. An important objective of these activities has been to facilitate exchange of views among specialists and policy-makers of all nations and to expand the information base especially for the benefit of policy-makers in the developing countries. In the field of hydrocarbons, United Nations' activities have included the organization of conferences, collection and publication of statistics, the preparation of special studies, and the provision of help to developing countries either through preinvestment studies or through technical assistance and training of local technicians.

CLASSIFICATION OF HYDROCARBON RESOURCES AND RESERVES

The recent changes in energy prices, the intensified concern with the long-term future, and the present array of predictions have led to increased efforts to evaluate resources* of hydrocarbons both at the national and international level. The task

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[1]UN-CNRET, New York, N.Y., USA.

*The term resources is used here in a generic sense to cover the entirety of reserves and resources.

is difficult because of variations in economic systems and the heterogeneity of input data.

In addition, the breadth of the international interest in undeveloped and undiscovered oil and gas resources compels specialists to seek a better understanding of the physical dimensions of the world's resources. A prerequisite is to reach a common understanding of the concepts that underlie the use of resource terminology. From that point one can move toward the matching of resource classification systems with existing methodologies of measurement.

Furthermore, the needs of industry with regard to the delineation and measurement of petroleum occurrences differ from those of national policy-makers and planning experts. The industry very often uses the word "reserves" in a restrictive sense and is primarily interested in immediate technological and economic problems of production. This limitation is understandable in their perspective. In contrast, government institutions charged with policy making and economic planning have a broader interest in taking into account not only oil and gas in known fields and under specific conditions of exploitation, but in making serious efforts to estimate what may be found in undiscovered fields, regions, and nations.

ACTIVITIES IN THE CLASSIFICATION AND MEASUREMENT OF OIL AND GAS RESOURCES

No organization, national or international, currently engaged in consideration of the nature of the world's nonrenewable resources can avoid an awareness of the problems of communication and data collection that are constantly faced. The changing regional centers of energy production and sharp escalation in the costs of energy in recent years have brought a renewed interest on the part of all groups engaged in resources work to bring information on reserves and resources into sharper focus through greater effort to define clearly what has been measured, to classify it in an orderly manner, and then to identify the results in a fashion which encourages proper understanding and use.

Under Resolution 1761 (LIV) B of the Economic and Social Council, the United Nations is engaged in the collection, analysis, and dissemination of data on reserves and resources. It has a role to play toward the improved understanding of resource classification, terminology, and measurement for the benefit of all groups engaged in the analysis and interpretation of mineral resource data. The Centre for Natural Resources, Energy and Transport is already proceeding under Resolution 1954 (LIX) B of the Economic and Social Council to review the definitions and terminology for mineral resources, production, and consumption. In addition, the Centre has had a long-standing interest in the parallel problems of the classification and terminology employed for oil and gas resources.

Therefore, the Centre has included as a part of its total program in this area an examination of the problems and possibilities for improved international collection and dissemination of oil and gas resources data. Centre staff and consultants have examined extensively the current systems of classification used by various nations and transnational companies in presenting data on oil and gas resources. Based on that effort, the Centre is now prepared to bring together a small working group of experts to discuss a series of basic questions that relate to the international classification and measurement of oil and gas resources.

The series of topics to be considered by this working party have been designed to lead the members through the series of key conceptual and definitional considerations which form the basis of most resource classification schemes. The intent is to identify those essential characteristics that could form the basis upon which nations can work together to formulate a more uniform international exchange of information on oil and gas resources.

The goal of the working group is to arrive at a general classification for oil and gas resources that would improve both data collection and dissemination of oil and gas resource information to the ultimate users of these data. At the minimum, the working group should be able to identify the disparities among the various oil and gas producing nations as to the manner in which they measure, collect, and report on their oil and gas resources. Given that information, the panel is to be asked to propose an agenda for further study and action directed toward providing a means for either eliminating these disparities or dealing with them when data from a variety of national sources are utilized.

The Centre recognizes that it is not alone in its concern about oil and gas resource data or in its effort to generate discussion about the problem and its solution. Among other groups, the International Institute for Applied Systems Analysis and the World Energy Conference are engaged in consideration of the situation. It is expected that the working group will provide the UN a medium of exchange among experts that deal with oil and gas resource statistics.

In this connection, I would like to offer some personal views on the problems of the classification and measurement of oil and gas resources.

In principle, after establishing the kind of classification that may be acceptable to countries concerned with oil and gas resources and reserves, with appropriate definitions, it would be useful to review the various methodologies of resource estimation, their scientific basis, and their relative accuracy. It would be helpful if such methodologies could be classified in terms of the sequence of their use in field petroleum reconnaissance, exploration, and exploitation. As a further step, it would be useful if we could arrive at a classification and definitions of resources and reserves which must accompany petroleum reconnaissance, exploration, and exploitation, as calculations and decisions are made at each one of these levels of activity.

This kind of link obviously is a part of field management but is not always reflected in international statistics. What is suggested, if acceptable by countries, is that an attempt be made to use this "natural link" to generate resources and reserves data calculations keyed into the natural sequence of petroleum exploration and development work.

Since economics is such a pervasive element in resource estimations and may be a major element in one of the dimensions of the classification system under consideration (for instance, the classification of resources as economic, subeconomic, or other occurrences) a brief review of the economic factor as an important aspect of the national and international assessment of energy resources is essential. The first stage of economic influence in reserves calculation is the initial discovery well which leads to the first decisions concerning future development and exploration work. The final stage in decision-making is determining the termination of production based upon the extrapolation of a production decline curve. These various economic decisions are of concern to all parties involved in the energy sector: international institutions, governments, state entities, and private companies.

CONCLUSIONS

An international institution like the United Nations is a focal point for the collection and dissemination of information and strives to provide countries with an objective statistical picture of the global economic environment. In addition, the United Nations has a natural concern with the problems affecting man's long-term future, of which energy now forms a crucial part. Consequently, the evaluation of resources and reserves relevant to the United Nations' concerns tends to be broader than that of individual states and private companies.

As reserves are calculated it is possible to adjust, as necessary, the amounts in accordance with the economic environment at the time. In fact, it has become obvious in recent years that the international petroleum economy can change suddenly and what was considered as economically unlikely yesterday can become possible today.

The CNRET effort described will certainly be far from a definitive study. But it will attempt, through collective effort, to promote necessary improvements in classification and ultimately improve the calculation of reserves. This is urgently needed in the face of the future world-wide demand for energy. It will require an international effort to refine reserve statistics and to make them as accurate as possible. This is necessary if we are to use them in the development of harmonious energy policies.

CHAPTER 10

PRESENT AND FUTURE HYDROCARBON RESOURCES OF THE EARTH'S CRUST

I.I. Nesterov and F.K. Salmanov[1]

Any natural compounds containing carbon or hydrogen are assumed to be hydrocarbons irrespective of current technological or economic aspects of their recovery or conversion into liquid or gaseous hydrocarbons. The purpose of this article is to show the variety of natural compounds containing carbon or hydrogen and to emphasize the urgency of research aimed at the increased extraction and utilization of these elements or their compounds for energy, refined hydrocarbon products, or petrochemicals.

Table 10-1 shows the initial geological, and recoverable, carbon and hydrogen reserves in different natural compounds of the earth's crust.

The initial geological potential reserves are the total amounts of carbon and hydrogen in the corresponding natural compounds and include the volumes already extracted. The initial recoverable potential reserves are the amounts of these materials from which energy and refined products can be economically extracted with existing technology. These amounts also include already recovered reserves. Table 10-1 gives current estimates of potential hydrocarbon products and their prospects as of Year 2000.

All the resources of hydrocarbon materials are divided into two groups--organic and inorganic. Both groups are subdivided into mobile and immobile components.

[1]The Academy of Sciences, Moscow, USSR.

TABLE 10-1.--Initial potential hydrocarbon resources of earth's crust (n x 10^{12} tons)

RESOURCES	GEOLOGICAL RESOURCES		RECOVERABLE RESOURCES 1975		RECOVERABLE RESOURCES 2000	
	C	H	C	H	C	H
1	2	3	4	5	6	7
I. Organic	24,257.16	1,993.70	12.80	1.09	15.27	1.35
A) Mobile organic	1,289.63	158.39	1.47	0.33	2.24	0.47
1. Liquid hydrocarbons	1.55	0.18	0.54	0.06	1.11	0.13
2. Liquid hydrocarbons sorbed by:	1,270.43	152.96	--	--	--	--
- clays	1,250.00	150.50	--	--	--	--
- carbonates	12.88	1.55	--	--	--	--
- sandy rocks	7.47	0.90	--	--	--	--
- evaporites	0.08	0.01	--	--	--	--
3. Asphaltic compounds	0.21	0.02	--	--	0.02	--
4. Liquid hydrocarbons included in natural gases	0.10	0.02	0.05	--	0.08	0.01
5. Natural gases	15.19	4.89	0.88	0.27	1.03	0.33
- included in oil	0.12	0.03	0.05	0.01	0.09	0.03
- free in deposits	1.03	0.33	0.83	0.26	0.94	0.30
- included in underground waters	11.88	3.79	--	--	--	--

TABLE 10-1.--Initial potential hydrocarbon resources of earth's crust (n x 10^{12} tons)--Continued

RESOURCES	GEOLOGICAL RESOURCES		RECOVERABLE RESOURCES			
			1975		2000	
	C	H	C	H	C	H
1	2	3	4	5	6	7
5. Natural gases (continued)						
- sorbed by rocks	1.34	0.47	--	--	--	--
in clays	1.33	0.47	--	--	--	--
in carbonate and sandstone rocks	0.01	--	--	--	--	--
- hydrated	0.82	0.27	--	--	--	--
6. Hydrosphere dissolved and suspended organic matter	2.15	0.32	--	--	--	--
B) Immobile organic	22,967.53	1,835.31	11.33	0.76	13.03	0.88
1. Peat	0.48	0.06	0.12	0.01	0.19	0.02
2. Brown coal and lignites	6.11	0.48	3.65	0.29	4.28	0.34
3. Pit coal and anthracites	11.30	0.66	6.97	0.41	7.90	0.46
4. Disseminated organic matter in	22,949.05	1,834.05	0.03	--	0.10	0.01
- oil shales (O.M.>10%)	0.17	0.02	0.03	--	0.07	0.01
- bituminous clays (O.M.=3-10%)	0.56	0.07	--	--	0.03	--

TABLE 10-1.--Initial potential hydrocarbon resources of earth's crust ($n \times 10^{12}$ tons)--Continued

	RESOURCES	GEOLOGICAL RESOURCES		RECOVERABLE RESOURCES			
				1975		2000	
		C	H	C	H	C	H
	1	2	3	4	5	6	7
4.	Disseminated organic matter in (continued)						
	- clays (O.M.<3%)	22,575.00	1,806.00	--	--	--	--
	- carbonates	232.80	18.60	--	--	--	--
	- sandy rocks	135.00	9.00	--	--	--	--
	- evaporites	4.65	0.30	--	--	--	--
	- lake and ocean silt	0.77	0.06	--	--	--	--
5.	Biosphere organic matter	0.59	0.06	0.56	0.05	0.56	0.05
II.	Inorganic[1]	13,117.75	189,270.98	--	--	--	--
A)	Mobile inorganic	697.75	189,270.98	--	--	--	--
1.	Atmosphere gases	0.75	1.44	--	--	--	--
	- carbon dioxide	0.72	--	--	--	--	--
	- methane	0.03	0.01	--	--	--	--
	- water vapour	--	1.43	--	--	--	--
2.	Hydrosphere gases (CO_2 etc.) and water	57.00	189,203.54				
	- oceans and seas	37.00	150,700.00	--	--	--	--
	- underground waters	20.00	36,300.00	--	--	--	--

TABLE 10-1.--Initial potential hydrocarbon resources of earth's crust (n x 10^{12} tons)--Continued

RESOURCES	GEOLOGICAL RESOURCES		RECOVERABLE RESOURCES			
			1975		2000	
	C	H	C	H	C	H
1	2	3	4	5	6	7
2. Hydrosphere gases (CO_2 etc.) and water (continued)						
- ice	--	2,200.00	--	--	--	--
- rivers, lakes, swamps	--	3.54	--	--	--	--
3. Magmatic rock gases	640.00	66.00	--	--	--	--
- upper crust zone	250.00	30.00	--	--	--	--
- lower crust zone	390.00	36.00	--	--	--	--
B) Immobile inorganic matter	12,420.00	--	--	--	--	--
1. Carbonate rocks	12,420.00	--	--	--	--	--
Total:	37,374.31	191,264.68	12.80	1.09	15.27	1.35

[1]Includes fixed forms of C and H in water and carbonates, which may be used in the future by presently unknown methods and techniques.

The evaluation of hydrocarbon-products reserves was made separately for continental and oceanic crust, with due regard for average carbon and hydrogen content in rocks and natural compounds of geosynclinal, orogenic, and platform areas.

At present the major source of hydrocarbon products is organic mobile carbon and hydrogen compounds. They will be the main supply of basic hydrocarbon products in the current century. By the end of the century a significant part of solid organic compounds can be expected to be involved in hydrocarbon production.

Liquid hydrocarbons are the main source of hydrocarbon products for energy potential and especially for the refining industry.

With existing recovery technology almost two-thirds of liquid hydrocarbon products are left in the earth. To support the present rates of production of liquid hydrocarbons, it is essential that the recovery factor be increased. It is expected that by the end of the century the recovery factor will reach 70 percent. Almost all current experiments on increasing the liquid hydrocarbon recovery factor are based on physical stimulation methods. In time, chemical and physico-chemical methods will appear most effective and their development should be of primary concern.

Liquid hydrocarbons sorbed by rocks represent the major part (more than 98 percent) of all mobile organic resources, but their average concentration is very low (0.06 percent) and therefore for the near future they seem to have no practical value.

Bitumen compounds are rare in nature, but usually form major accumulations. Geological reserves of only two Canadian deposits plus the bituminous belt of the Maturin basin (Venezuela) total 235 x 10^9 tons. Today, the volume of bitumen-deposit production is limited but it is predicted to increase by a factor of ten in the next decade.

Liquid hydrocarbons included in natural gases are valuable products, particularly for the petrochemical industry. By the end of the century their production rate will start decreasing due to natural gas resource depletion.

The economic aspects of the utilization of associated gas are determined by the methods used for the development of the liquid hydrocarbons.

At present, natural hydrocarbon gas deposits are actively produced; their production rate is expected to stabilize by the end of the century.

Natural gases included in underground waters are not as yet used as energy or refined commodities. However, total reserves of these gases are an order of magnitude greater than natural gas reserves accumulated in oil and gas deposits. The amount of hydrocarbon gases included in underground waters varies from a few litres to as much as three m^3 per ton of water. This type of hydrocarbon product will be widely employed in chemical industry after Year 2000. Substantial research and development is needed to develop economically feasible technology to permit large-scale extraction of hydrocarbon gases and other significant products from subsurface water as well as for the reverse pumping of the waste water back into the ground.

Hydrocarbon gases sorbed by rocks occur in small amounts or in disseminated state (0.9 to 1.5 grams per ton) and are of no interest at present and in future.

Natural gases in hydrated form can be found both in subsurface and surface occurrences in zones of extended permafrost and in near-bottom sediments in the ocean. In the next five years some increase of production activity can be expected but only from the near-surface deposits. For the future there is a strong necessity for technological development of hydrated gas extraction from all types of deposits, including near-bottom zones of sea and deep ocean waters.

Dissolved and suspended organic matter in the hydrosphere seems to be of no practical value as a hydrocarbon product.

At this time solid organic compounds containing carbon and hydrogen are used mainly as an energy source. Though all types of immobile organic compounds may be utilized as liquid or gaseous hydrocarbons, liquids and gases are extracted from them only in limited amounts. After Year 2000, solid hydrocarbons will be the main source for liquid hydrocarbon recovery. More than 98 percent of all immobile organic-compound reserves consist of disseminated organic matter in rocks, the content being only 3 to 15 kg per ton. It is likely, however, that in situ conversion processes of some solid compounds into liquid and gaseous hydrocarbons will be developed. This technology should be based on natural-process simulation, resulting in the concentration of liquid and gaseous hydrocarbons in a deposit from their disseminated state.

Inorganic compounds of hydrogen and carbon are contained mainly in water and carbonates. Fractionation of these compounds with subsequent hydrocarbon synthesis requires excessive energy consumption. Thus, in the future these products may be utilized only for hydrocarbon recovery for chemical and refining industries.

The review of possible natural sources of hydrocarbon products shows their variety and emphasizes the wide range of opportunities in their use for continuing economic growth.

CHAPTER 11

NATURE-MADE PETROLEUM AND GAS IN PLACE: METHODS OF MEASUREMENT AND RELIABILITY OF MEASUREMENTS

E. H. Koepf[1]

INTRODUCTION

There are a few cases where crude petroleum is found in caverns or large earth fissures, but essentially all nature-made petroleum and natural gas occurs in the pores of void spaces between the sand grains in sandstone formations; the intercrystalline voids, oolites, fractures, or vugs of carbonates; and the void spaces between the solid materials in conglomerates and unconsolidated sediments. Figure 11-1 presents a schematic representation of the arrangement of sand grains in a consolidated sandstone where the particle sizes vary appreciably. The example represents a normal water-wet condition where the sand grains are wetted by a continuous film of water (reservoir brine). Water may completely fill small pores and spaces at grain contacts. The oil occurs as continuous stringers through the pores or as droplets completely surrounded by water, with a film of water always separating the oil from the rock surface. This type of fluid distribution occurs in most natural reservoirs, but some have been found where the reservoir rock is wetted preferentially by the reservoir oil rather than reservoir brine. In such conditions the relative positions of the oil and the brine of Fig. 11-1 are reversed. The oil "wets" the rock

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[1]P. O. Box 47547, Dallas, TX, USA.

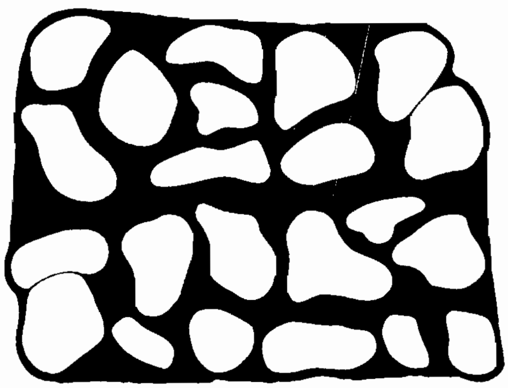

Figure 11-1.--Distribution of water and oil in a porous medium

surface in a continuous film and the connate water is surrounded by oil.

Figure 11-1 represents fluid distribution for a crude oil-water system. If the hydrocarbon portion is a gas condensate or a lean gas, the relative distribution of the water and hydrocarbon phases would be essentially the same, varying in degree only, due to differences in gravity and interfacial tension.

The major sources of nature-made petroleum and natural gas are the conventional deposits in oil and gas fields. Other sources with modest production or which are potentially exploitable include oil in tar sands and oil shale and gas in oil shale, organic shales, or occluded in coal seams. The in-place hydrocarbons from the principal sources can be evaluated with acceptable accuracy early in the life of a new reservoir or source.

DETERMINATION OF IN-PLACE HYDROCARBON RESERVES FOR INDIVIDUAL RESERVOIRS

OIL AND GAS RESERVOIRS

The in-place hydrocarbon resources of naturally-occurring oil (both crude oil and oil from tar sands) and gas are governed by the volume of pore space in the reservoir and the amount of this pore space which is occupied by oil (or gas) and connate water, respectively. Evaluation of resources of oil in oil shale requires laboratory processing of data and its interpretation.

The in-place resources in naturally-occurring crude oil reservoirs are represented by the relatively simple relationship:

$$\text{Stock tank barrels of oil in-place} = \frac{7758\phi(1-S_w)\text{Acre-feet}}{\text{FVF}} \quad (1)$$

WHERE: ϕ = Fractional porosity

S_w = Water saturation as a fraction of pore volume

FVF = Formation volume factor for the oil: ratio of the volume of oil saturated at reservoir pressure and temperature to a unit volume of stock tank oil.

In a similar manner, the in-place resources of a naturally-occurring gas reservoir are represented by the relationship:

$$\text{MSCF (@60°F and 14.73 psia)} = \frac{1538\phi(1-S_w)P \text{ Acre-feet}}{TZ} \qquad (2)$$

WHERE:
ϕ = Fractional porosity
S_w = Water saturation as a fraction of pore volume
T = T°F + 460 (Temperature °Rankine)
P = Reservoir pressure, psia
Z = Gas deviation factor
MSCF = 10^3 standard ft^3

Calculation of oil in-place in tons of gas in-place in cubic meters, or any other desirable units for either, can be accomplished with these basic relationships by use of appropriate unit conversion factors. The evaluation of in-place hydrocarbons in oil and gas reservoirs is reduced to the determination of porosity of the formation, the in-place water (or hydrocarbon) saturation, and a factor or factors relating reservoir volume of the hydrocarbon content to the unit volume as measured at the surface.

Determination of Porosity

The porosity of cores from petroleum reservoirs can be measured by any of several procedures [1]. In-place water (and oil) saturations may be estimated from results of routine core analysis data by correcting for the effects of (1) flushing during coring, (2) gas evolution with expansion and expulsion of fluids while being brought to the surface, and (3) shrinkage of the oil volume due to gas evolution. Reliable values for engineering evaluation are normally obtained from special studies of core samples where pore-size distribution and capillary properties are determined, immobile water and residual oil saturation data are obtained, and special measurements are made to obtain electrical and acoustic properties for use in proper interpretation of down-hole log data.

Down-hole logs and the analysis of their responses constitute a large part of the total effort of formation evaluation. Several logging tools are in widespread use for the determination of porosity: the density, acoustic, and certain neutron devices. Data from still other logging devices are required under some conditions to improve the interpretation and quantification in terms of porosity. The combined use of core analysis data with down-hole log data will, in essentially all cases, permit a more accurate evaluation than can be made with either type of data alone [2].

Core Analysis

The determination of the porosity of a core sample requires measurement of any two of three quantities: Pore volume (PV), bulk volume (BV), and grain volume (GV) for use in the equations:

$$\text{Fractional Porosity} = PV/BV \text{ and } PV + GV = BV \qquad (3)$$

Several acceptable methods of porosity determination for core samples are presented in API Recommended Practices No. 40 [1]. The technique selected in a specific case often depends upon the type of rock being analyzed, the objectives of the core analysis, and the time requirements for the data.

Bulk Volume: Bulk volume of samples is normally determined by volumetric displacement in a calibrated mercury pump or a bulk-volume meter, by caliper, or by water displacement (large samples).

Grain Volume: Grain volume may be measured by utilizing helium in a Boyle's Law-type porosimeter, with errors within ±0.2 percent of the true value. Grain volume may also be calculated from the dry sample weight plus a grain density, if it is available or can be obtained.

Pore Volume: Pore volume may be determined by any one of several methods:

1. Gas extraction by evacuation of the pore space and measurement of the volume removed. This technique requires great operator care and frequent cleaning of equipment.

2. Resaturation of void space of a cleaned and dried sample by evacuation and pressure saturation with a liquid. Failure to completely resaturate may result in appreciable errors.

3. Pressure saturation of nonevacuated pore space with helium in a Boyle's Law porosimeter. This technique is generally considered as a standard for accuracy, and reliable determinations of porosity can be made even on very small samples to within ±0.5 percent porosity. These same factors apply to the determination of grain volume mentioned above.

4. Summation of fluids, a procedure in which the pore volumes occupied by gas, by oil, and by water are determined somewhat independently and summed to obtain a value for total pore volume. Water and oil content are determined by retorting or by vacuum distillation. This procedure is widely used for routine analysis of all types and sizes of core samples. It is adapted to rapid analysis, to provide data on entire cored intervals within 24 to 72 hours. Porosity values accurate to within ±0.5 percent porosity are obtained where suitable oil and water calibrations are made and used.

The number of core samples required to provide a reliable representation of the formation will vary with the thickness of the interval, the homogeneity of the formation, presence or absence of shale streaks or laminar discontinuities, and presence of gas-oil or water-oil interfaces. The complete section from several key wells should be cored, with at least one sample per foot analyzed for porosity, permeability, and fluid saturations. Additional samples from scattered wells may be desirable.

Porosity values as determined by the above procedures represent the sample as measured at surface conditions. A number of workers have pointed out [3,4,5,6] that formation core-samples expand when the external pressure is removed as the core is brought to the surface. As a result, porosity values measured on samples at atmospheric pressure may be appreciably high and lead to overestimation of in-place reserves. Also, the pore volume in the reservoir will decrease with production and reduction of the "net overburden" pressure, and this reduction in pore volume will result in greater volumetric recovery. Such effects are appreciable on poorly consolidated and on deeply buried, normally pressured formations. They are insignificant on many well-consolidated, relatively shallow formations. The importance of this factor should be determined, using the technique of pressure saturation with helium in a Boyle's Law porosimeter, where significant reserve evaluations are being made.

Down-Hole Porosity Logs

Gamma-Gamma Density Log: This tool irradiates with gamma radiation a small volume of formation to a maximum depth of 6 inches (15 cm). These radiations are scattered in the formation by well-defined natural effects which are proportional to the electron density of the zone. The electron density is essentially equivalent to the bulk density of the rock material. The back-scattered gamma radiation that returns to the borehole is sensed, and the intensity computed in terms of bulk density of the zone. The instrument is shielded from borehole effects as much as possible, and the gamma source detectors are focused. Bulk density is related to porosity by the following equation:

$$\phi = \frac{\rho_g - \rho_b}{\rho_g - \rho_f} \tag{4}$$

WHERE: ρ_g = Density of grains or rock solids
ρ_f = Density of fluid in pores
ρ_b = Bulk density

Values for grain density and fluid density are frequently assumed as general average values, and this often limits the application and accuracy of this type of data. Accuracy is improved if grain density values are available from formation samples.

Neutron Log: The neutron logging device irradiates the formation with neutrons to a depth of about 24 inches (0.6 meters). The capture of the neutrons by formation material causes scatter of neutrons and emission of gamma radiation. Detectors are classed as slow-neutron, fast-neutron, and gamma sensors, and each has advantages and limitations. The neutron tools designed for porosity logging are sensitive to the hydrogen concentration in the zone of investigation. Water and liquid hydrocarbons in the pores of the formation are rich in hydrogen, and thus the response of the device can be calibrated in terms of porosity. The tool response from a cored interval should be calibrated with porosity values from core analysis over the interval. Such calibration is frequently necessary and usually very desirable in each field, and sometimes from area to area within a field. A method for correlating neutron-log response with core porosities has been described by Bush and Mardock [7]. Neutron logs are used more extensively in carbonates than in sands, and they can be used qualitatively in cased intervals.

Acoustic or Continuous Velocity Log: A continuous velocity logging tool adapted to formation evaluation purposes allows measurement of the time of travel of elastic or sound waves between a transmitter and a receiver, or between multiple receivers separated by a fixed distance. The time-average equation, popularized by M. R. J. Wyllie et al. [8], relates travel time measured by the logging tool to the porosity of the formation by the equation:

$$\Delta t = \Delta t_f \phi + \Delta t_m (1 - \phi) \tag{5}$$

WHERE: ϕ = Porosity fraction

Δt = Travel time of elastic wave over the specific interval

Δt_f = Travel time of elastic wave through the specific interval or pore fluid only, known as fluid velocity

Δt_m = Travel time of elastic wave through the specific interval of rock solid only, known as matrix velocity

Common practice has been to assume and use published average values for fluid and matrix velocities [8]. The equation assumes a uniform distribution of pores and rock solids. Other variables, such as degree of cementation between grains and rock and pore compressibility, affect this wave velocity. It is desirable to calibrate the acoustic logging tool response with porosity values from core analysis of the cored and logged interval, or to obtain transit-time data from core samples of the logged interval under overburden conditions rather than to use assumed transit-time values. This device works best in porous but not unconsolidated sands, and loses definition in formations, particularly carbonates, of low porosity.

Although each porosity logging device senses a different characteristic of the formation and each has limitations and shortcomings, a simultaneous solution or crossplot of the responses of all the tools will, in many cases, allow interpretation of formation lithology [9,10,11] and estimation of formation porosity within acceptable limits of accuracy. The presence of free gas in the zone of investigation of the density or neutron logging devices will make evaluation of porosity difficult or impossible. The porosity logging devices, when properly calibrated, are believed to sense porosity with errors of less than ± 2 percent porosity, except for reservoirs with a high degree of heterogeneity or other unusual properties.

Determination of Oil Saturation

Core Analysis

Routine Core Analysis: Only under special conditions are the water (or hydrocarbon) saturations determined on core samples representative of the in-place saturation conditions. It is necessary in the majority of cases to deduce the water saturation values from other data and to calculate oil saturation by difference. Empirical correlations have been developed which permit comparative evaluation of intervals and which provide worthwhile approximations of reservoir in-place water saturations, and thus oil saturation by difference. Use of these routine core-analysis data to evaluate in-place oil or gas might result in errors of $\pm$ 10 to 15 percent of the true value.

One method used to determine oil saturation in a virgin reservoir, where the interstitial water saturation has been reduced to an immobile saturation over geologic time, is to core with lease crude or oil-base mud as the drilling fluid. Thus, the fluid filtrate will displace only oil, and the water content, corrected for shrinkage on coming to the surface, will represent in-place water saturation. Fractional oil saturation will then be equal to (1 - fractional water saturation). This procedure can be used with a pressure-retaining core barrel to eliminate bleeding and liquid shrinkage during withdrawal of the core to the surface and provide reliable in-place water saturation data [12].

Capillary Pressure Studies: Most engineering evaluations of in-place reserves and of field performance employ data obtained by special laboratory testing of core samples. Evaluation of oil and water saturations involves study of pore size and pore-size distribution and their effects upon the capillary properties of the formation. Pore size and capillary properties may be studied by one, or a combination of several laboratory methods. The restored-state method [13] is most widely used and is applicable to all except very dense, low-permeability samples, where a mercury injection procedure is used [14]. A third method [15] utilizes a centrifuge technique, principally to obtain indicative data rapidly or to extend the restored-state data with single, end-point values at high pressure differentials.

The capillary pressure data relate water saturation to permeability or porosity, and to height or distance above an oil-water contact in the reservoir. Hydrocarbon saturation is then obtained by difference. This information is used with data on formation areal extent, thickness, porosity, and permeability to calculate hydrocarbons in place. Conversion of the capillary-pressure data to height above the oil-water contact requires knowledge of reservoir oil (or gas) and water densities, estimates of interfacial tension existing between the reservoir fluids, and the wettability preference (water or oil) of the reservoir rock. Reasonable values can usually be assigned for these parameters. Figure 11-2 illustrates a correlation of this type. The correlation requires sufficient capillary pressure data to permit development of curves for selected permeability or porosity ranges. Routine core analysis permeability and/or porosity data can then be related to oil-water-level data to calculate reservoir water saturation versus height. The reliability of the in-place estimates is related to the uniformity of the reservoir rock properties and to the density of sampling. Data on 10 to 15 samples may be adequate for a reliable evaluation of a homogeneous formation, whereas data on 20 to 30 samples in a heterogeneous formation may be necessary to attain good statistical evaluation. The capillary-pressure method must be used for determining formation-water saturation values in cases where formation and hole conditions prevent proper interpretation of logging tool responses. It should be used to corroborate down-hole logging tool data in all fields.

Down-Hole Water Saturation Logs

The responses of resistivity logging devices are the principal means used by the oil and gas industry for in-place water-saturation evaluation. Data from the Spontaneous Potential (SP) and Gamma Ray logs are frequently required to improve interpretation of data from the resistivity logs. Figure 11-3 is a general representation of such logs. Cross correlation of results from several logging tools is frequently used in efforts to develop in-place reserve estimates with confidence.

Several of the commonly used down-hole logs respond to electrical signals, and the amplitude of the signals is determined by the electrical conductivity, or its reciprocal, the resistivity of the formation and its contained fluids. Most connate waters in hydrocarbon-bearing zones are relatively high in salt content and therefore reflect a low resistivity. Hydrocarbons, being nonconductive, reflect a high resistivity. As a result, down-hole logs are used extensively to estimate in situ water saturation. Hydrocarbon saturation as a fraction of porosity is then obtained by difference (1.0 - fractional water saturation).

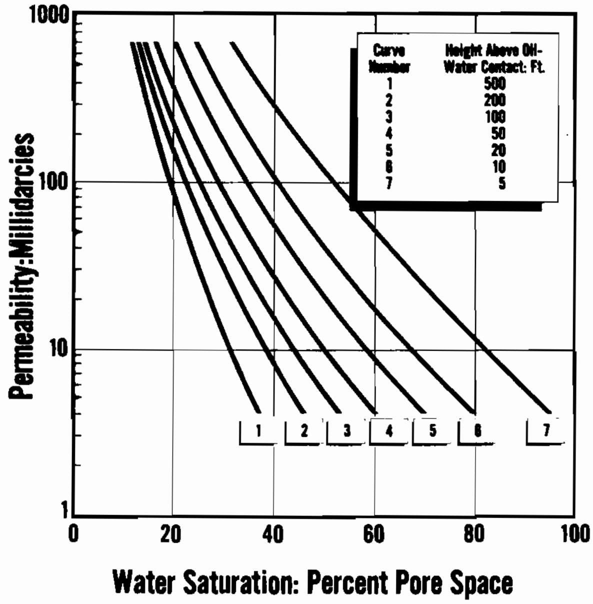

Figure 11-2.--Correlation of connate water saturation vs. permeability and height above a free water level

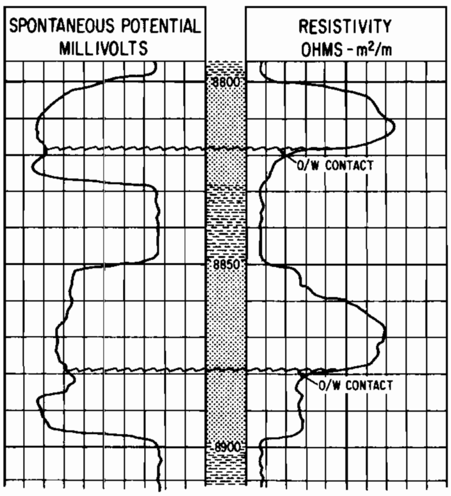

Figure 11-3.--Down-hole water saturation log

Each of the several types of tools has specific purposes and uses, depending upon hole conditions, formation type, drilling mud, bed thickness, and other factors. For determining oil in place from water saturation values, the deep-investigation induction and lateral logs are the principal devices used. They sense the true formation resistivity, R_t, behind the filtrate-invaded zone.

Development of important relationships in the calculation of formation-water saturation of water-wet systems from resistivity log values and porosity values is attributed to Archie [16]. Archie defined formation

resistivity factor, F, as: $F = R_o/R_w = a/\phi^m$ (6)

and resistivity index as: $RI = R_t/R_o = \dfrac{1}{S_w{}^n}$ (7)

which may be rearranged as:

$$S_w = (R_o/R_t)^{1/n} = \left[\frac{FR_w}{R_t}\right]^{1/n} = \left[\frac{aR_w}{\phi^m R_t}\right]^{1/n} \qquad (8)$$

WHERE: R_o = Resistivity of 100 percent brine-saturated sample

R_w = Resistivity of saturating brine

R_t = True resistivity at a given water saturation

ϕ = Fractional porosity

m = Cementation exponent (normal range 1.8 to 2.5)

a = F value at fraction porosity of 1.0 (normal range 0.6 to 1.42)

S_w = Water saturation, fraction of pore volume

n = Saturation exponent (normal range 1.4 to 2.2)

In clean, nonclayey, water-wet sands and carbonate formations, the in-place water saturation can be calculated as a percent of pore space with acceptable accuracy, probably within ± 10 percent of the true value, where the resistivity logging tools are able to sense true formation resistivity, R_t. The calculations require knowledge of the relationship between porosity and formation factor and between water saturation and true resistivity. In other words, it is necessary to know values of a, m, and n for the specific formation being evaluated. Several approximate equations have been used:

$$F = 1/\phi^2 \quad \text{- Archie} \tag{9}$$

$$F = 0.62/\phi^{2.15} \quad \text{- Humble Oil \& Refining Company} \tag{10}$$

$$F = 1/\phi^{1.81} \quad \text{- Rocky Mountain Area} \tag{11}$$

$$S_w = \left[\frac{FR_w}{R_t}\right]^{1/2} \tag{12}$$

Laboratory tests on formation samples can be made to evaluate these factors for specific formations, and the magnitude of possible errors from use of the approximations justifies getting the data if samples are available. These values are sensitive to overburden pressure of deep formations, particularly if porosity is low, and laboratory testing should be conducted under overburden pressure conditions in many cases.

The effect on resistivity logs of the presence of clays in a formation is one of the greatest technical problems encountered in down-hole log analysis. This problem has been studied for many years and is still receiving much attention [17,18,19]; perhaps the most definitive work is that of Waxman and Smits [18] and Waxman and Thomas [19]. The clay mineral surfaces adsorb cations to a high degree. The adsorbed cations, in effect, cause the clays to form an electrically conductive path parallel to the conductive path provided by the brine filling the pores. This causes the clayey or "dirty" formations to exhibit an electrical resistivity lower than if the matrix material contained no clay and thus to indicate high-water and low-oil saturations. The problem is further complicated by the presence of hydrocarbons in such formations. Waxman and coworkers modified the Archie equations [16] to include a clay volume factor, Q_v, and a factor for the equivalent conductance of clay exchange cations (sodium) as a function of the specific conductance of the aqueous electrolyte solution. They define the clay-volume factor Q_v (meq per ml) as:

$$Q_v = \frac{CEC(1-\phi)\rho m}{\phi X100} \tag{13}$$

WHERE: CEC = Cation exchange capacity, meq/100 gms of dry rock

ϕ = Fractional porosity

ρ_m = Matrix (rock solids) density

The existence of hydratable clays, especially in the presence of relatively fresh water, will greatly suppress the resistivity indicated by down-hole resistivity logging devices and will result in significant errors in calculating in-place hydrocarbons. Cation exchange values for each specific formation should be obtained from samples of the formation if it contains significant quantities of clay materials.

The SP log is used as an indicator of several factors, but the determination of brine resistivity and of clay fraction, Q_v, is its most important function in determining hydrocarbons in place. The Gamma Ray logging tool senses natural gamma radiation. Shales and clays normally exhibit more natural gamma radiation than other reservoir rock materials, and the gamma ray log is used in some areas to estimate the clay fraction.

There are no commercially available logging tools which will directly sense hydrocarbons in place. Pulsed neutron logs and nuclear magnetic resonance logs are effective in flushed or invaded zones and are thus useful in determining residual oil at floodout, but not for evaluation of virgin reservoirs. To date these tools have had very limited use.

PVT Characterization of Reservoir Hydrocarbons

After the storage space (porosity) of the reservoir and the percentage of this space occupied by hydrocarbons ($1 - S_w$) have been established, the relationship of a unit volume of hydrocarbon in the reservoir to the surface unit of volume measurement, designated by the denominator of equation (1) and included as the "Gas Law" in equation (2) must be determined on samples of the reservoir fluid (liquid or vapor), computed from vapor-liquid equilibrium ratios or obtained from literature correlations for average values. A reservoir-fluid study can be performed with a high degree of accuracy and is probably the most precise information used in the evaluation of reserves. The limitation on accuracy of the data depends upon the degree to which the sample represents the true reservoir fluid. For a crude oil sample the formation volume factor (FVF) is determined as the ratio of the volume of the reservoir oil at its bubble point to a barrel of stock tank oil recovered under simulated surface separation conditions. The formation volume factor can be determined with an uncertainty of less than 1 percent. An error in formation volume factor translates directly to the same percentage error in calculation of oil in place. If the crude is appreciably undersaturated at initial reservoir conditions, then its coefficient of compressibility is determined and used in developing a true formation volume factor.

If the hydrocarbon is a dry gas containing less than approximately 10 barrels of condensate per $10^6 ft^3$ of gas, then the deviation factor (Z) must be determined. "Z" is the factor with which to correct for the deviation of real gas from ideal gas behavior, and must be included in converting reservoir gas volumes to surface volumes by use of the gas laws.

If the reservoir hydrocarbon is found to be a gas condensate existing as a single phase at a pressure above its dew point, the in-place reserves are calculated in terms of standard ft^3 of gas, as is done with a dry gas. However, considerably more phase-relation data are required to evaluate reserves in terms of both gas and liquid recoveries. The pressure-volume relations of the reservoir fluid and the deviation factor "Z" are determined from initial reservoir pressure and dew-point pressure. The well-stream composition of the gas-condensate fluid at its dew point is determined by analysis, and this composition can then be converted to volumes of separator gas and volumes of stock tank condensate per unit volume of well stream. Thus, the in-place reserves can be evaluated both in terms of gas condensate in-place and in terms of stock tank condensate and separator gas.

It is necessary to recombine separator products to obtain a sample representing the in-place condensate, but subsurface samples are preferred when studying crude oil systems, if reservoir conditions permit. Laboratory results are generally accurate to within less than 1 percent, whereas field measurement of gas-liquid ratio for recombination of separator products to simulate a reservoir sample are accurate to within only 4 to 5 percent under ideal conditions. The accuracy of the formation volume factor for use in equation (1) is normally limited by the suitability of the sample and should be accurate to within ± 0.5 percent of the true value, if obtained on a subsurface sample taken under carefully controlled conditions.

In many instances data from subsurface or recombined surface samples are not available when estimates of in-place reserves must be made. In such cases values from correlations such as those developed by Standing [20] or values computed from vapor-liquid equilibrium ratios must be used. The accuracy of these factors will depend upon the amount of information available on the in-place hydrocarbons, but in most cases they should not introduce errors greater than ± 10 percent of the true value of the formation volume factor.

IN-PLACE RESOURCES OF OIL FROM TAR SANDS

Tar sands occur in many parts of the world and are a very important potential source of nature-made petroleum. The deposits occur at relatively shallow depths and consist of unconsolidated sands held together by tar-like hydrocarbons. Many deposits can be developed by surface mining, but in situ processing will be required for others.

Core samples for analysis and evaluation of in-place hydrocarbons are usually obtained with standard coring equipment modified only slightly to use a rigid plastic sleeve as the inner barrel rather than a metal sleeve. The recovered core may be frozen in the plastic sleeve, cut into desired lengths, and maintained with the recovered fluids undisturbed. A special study [21] has indicated that the most significant source of error in the evaluation of in-place hydrocarbons is the water loss or gain incurred during coring and sampling.

A Dean-Stark procedure [1] involving extraction of the tar by refluxing with hot toluene, measurement of the amount of water extracted, and calculation of the amount of tar by difference between weights of original sample and dry sample plus water, is the most widely used method of analysis. A retorting technique is frequently used for more rapid, comparative evaluations. The empirical corrections for loss of light ends and coking required by the retorting procedure reduce the confidence level of the results.

Calculated results of the assays are based upon the assumption that tar and water occupy 100 percent of the pore space. The sum of tar and water contents provide a minimum porosity value. The results are reported as (1) tar as percent of bulk weight, (2) water as percent of bulk weight, (3) solids as percent of bulk weight, and (4) porosity fraction or percent as the ratio of the sum of tar plus water volumes to the sum of tar plus water plus sand volumes (or total bulk volume).

The study [21] of assays made by a number of both commercial and company in-house laboratories showed that laboratory results within ±3 percent of the true value, with a 95 percent confidence level, can be achieved for rich material (14 to 16 percent grade), and within ±5 percent for most tar sands of current economic interest. The deviation increases with decrease in tar grade and extrapolates to ±10 to 12 percent for 6 percent bulk-weight grade material. The greatest uncertainties are introduced by possible alterations of water content during coring and sampling of the core, which lead to errors in the determination of in-place water content, of porosity as the sum of tar and water content, and of the tar as weight percent of the sample. The errors may lead to either high or low estimation of hydrocarbons.

IN-PLACE OIL RESOURCES FROM OIL SHALE

Naturally-occurring oil shales are made up of an intimate mixture of inorganic material, principally marlstone, and a high molecular weight organic polymer called kerogen. The kerogen decomposes to hydrocarbon vapors on being heated to approximately 940°F (504°C). The heavier hydrocarbon vapors condense into liquid shale oil upon cooling. The light hydrocarbons remain in the vapor phase as product gas. A laboratory procedure developed by the U.S. Bureau of Mines [22,23], with some modifications, has been used for many years in evaluating the yield of oil from oil shale. A slightly different procedure has been proposed by one of the oil shale development groups [24] and is being considered for acceptance as a standard. Also, some service companies have modified oil well core retorting facilities to provide results consistent with and comparable to those obtained by the U.S. Bureau of Mines procedure.

All of these laboratory procedures involve: (1) reducing the sample to a specified sieve size; (2) heating in an overhead delivery retort with heat input controlled to result in a selected rate of temperature increase; and (3) collection of retorted condensate in a double-trap system contained in a bath maintained at a low specified temperature. The noncondensates may be collected and analyzed or they may be reported as gas losses. Results of the retorting are reported as (1) oil content in gallons per ton and weight percent; (2) oil specific gravity 60°/60°; (3) water content in gallons per ton and weight percent; (4) spent shale as weight percent; (5) gas plus losses as weight percent (determined by material balance weight loss); and (6) tendency to coke, by visual examination.

Oil contents as high as 200 gallons per ton, for a deposit in Australia, have been noted, but most deposits of current interest provide 15 to 40 gallons per ton, with an average content of about 25 gallons. Laboratory check results with careful operation show an average standard deviation of about ±0.5 percent on a volumetric basis [24]. However, normal variations for routine analysis by different laboratories is probably between 1 and 2 gallons per ton. The oil content of oil shales varies widely from point to point, even in the same deposit, and varies widely from one deposit to another. Thus a large number of samples covering both the horizontal and vertical extent of the beds is required for statistical evaluation of the laboratory results to provide a reliable evaluation of in-place hydrocarbons.

SUMMARY AND CONCLUSIONS

The foregoing discussion has pointed out that the process of coring a reservoir and bringing the core to the surface alters the fluid content of the formation to such an extent that the fluid saturations in the core, as recovered, are usually quite different from the in-place saturations. As a result, in-place saturations are estimated by applying empirical corrections to routine core analysis data, or they may be determined indirectly and with reliable accuracy from studies of the reservoir rock properties and its contained fluids. Variations in rock properties from reservoir to reservoir result in different degrees of confidence in the evaluation of in-place hydrocarbon content, unless data are available on samples of the specific reservoir. In a similar manner, it has been shown that all down-hole log data for in-place hydrocarbon estimates are based upon indirect measurements and indicators, and that large errors may be introduced by the use of average literature values in the interpretation of the log data. Many factors which affect the down-hole log responses and whose values are required in interpretation of the logs and calculation of in-place porosity and/or saturations are measurable on formation samples. Thus, in essentially all cases, the combined use of routine and special core analysis data with down-hole log data will provide a more accurate evaluation of reservoir properties and in-place petroleum and natural gas than can be developed from either source of data alone.

Data relating volume of reservoir hydrocarbon to normal surface units of measurement are the most accurate data used in the evaluation of in-place hydrocarbons, if the data were obtained by study of subsurface samples. If correlations of data are used, the accuracy of representation of true reservoir values will vary with the amount of information available on characteristics such as gravity, gas-oil ratio, and composition.

The accuracy of the estimation of in-place petroleum and natural gas will vary somewhat with the characteristics of the reservoir or geologic formation in which it occurs and will reflect the degree of effort expended in making the estimate.

If only core analysis is utilized, the estimates should be within ±4 to 5 percent of the true value. If only down-hole log data are used with average literature correlation values, the estimates should be within ±10 percent of the true value. If both core analysis and down-hole log data are used, together with measured fluid properties, and appropriate care is exercised in obtaining the data, the estimates should be within about ±2 percent of the true value.

Present day technology will permit evaluation of in-place petroleum and natural gas resources on a unit reservoir volume basis with sufficient accuracy to justify the long-term planning and investment required for their development and exploitation.

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SECTION III. CONVENTIONAL OIL AND GAS DEPOSITS

CHAPTER 12

WORLD OIL AND GAS RESERVES FROM ANALYSIS OF GIANT FIELDS AND PETROLEUM BASINS (PROVINCES)

H. D. Klemme[1]

INTRODUCTION

Worldwide, the importance of giant oil and gas fields, those fields with over 500 x 10^6 barrels of oil (68 x 10^6 metric tons) or gas equivalent (3.5 x 10^{12} ft^3 or 100 x 10^9 m^3) can be expressed in many ways. One way is that they represent less than 1 percent of the world's fields but 75 percent of the reserves; another way is that they account for 65 to 70 percent of the present production; or in another respect, their discovery is often economically essential before it is possible to consider development of new basins in remote areas and in many offshore areas. Approximately 334 giant fields located in 66 basins comprise the principal source of petroleum energy in the world today.

In view of the importance of giant fields we might review their history of discovery, with particular attention to the last 5 years (1970 through 1975). Cumulative reserves (not showing depletion due to production) from the discovery of giant fields are illustrated in Fig. 12-1. Reserves are taken to mean either oil or gas (not condensate) which are reasonably certain to be recoverable in the future under existing economic and operational conditions. For purposes of this study, oil and gas have been combined, gas being given a ratio of 6,000 ft^3 per

[1]Weeks Natural Resources, Westport, CT, USA.

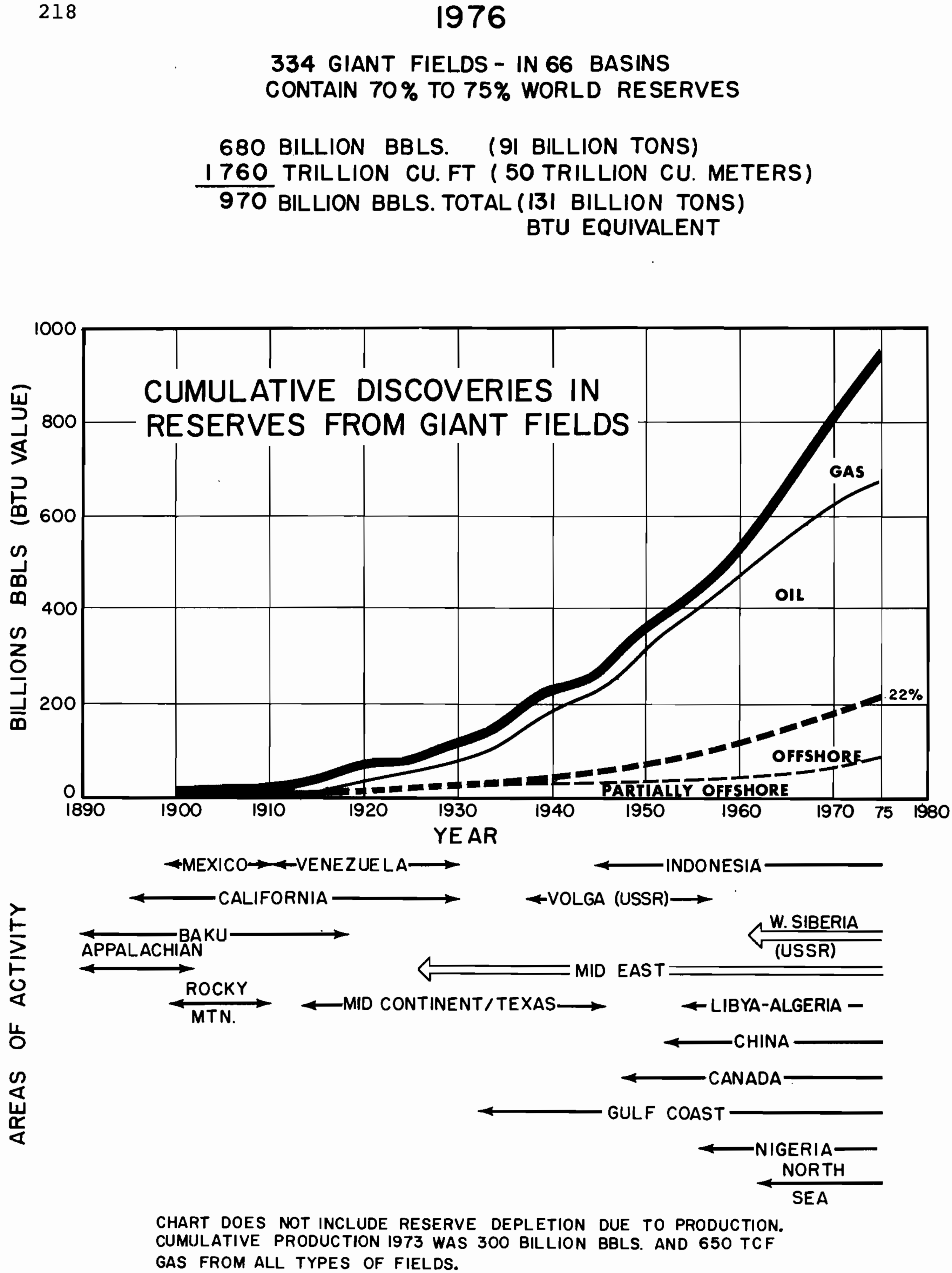


Figure 12-1.--Cumulative discovery of reserves in giant fields

barrel (1,245 m^3 per metric ton) of oil, based on British Thermal Heat Units (Btu equivalents). This ratio tends to upgrade gas reserves in an economic sense, in that many gas accumulations contain a percentage of inert gases and gas processing for shipping involves an appreciable effective loss of recoverable reserves. Under the year of discovery along the horizontal axis in Fig. 12-1 the geographic centers of discovery and development are plotted. Discoveries in the Middle East and West Siberia have been highlighted because they account for over two-thirds of the reserves in the world's giant fields.

On a worldwide basis it is noted that there is no slackening of the addition of reserves from giant fields. The world as a whole has continued to add reserves from giants at the accelerated rate commenced in the mid-1950's; however, the geographic location of these reserves has been shifting, and an increase in the number of giant gas fields, beginning in the 1960's, makes up much of the oil equivalent found in recent years. Until the mid-1950's, giant gas fields accounted for about 10 percent of the total reserves, whereas by 1976 the total was 30 percent. The juxtaposition of these gas reserves and possible markets must be considered in any near-term energy solution. From 1950 to 1960 the dominance of reserves in giant fields in the western hemisphere shifted to the eastern hemisphere (Dunnington, 1975) and this shift has been further accentuated in the last 5 years.

The following observations may be made:

1. Worldwide, on a Btu basis, the cumulative growth rate of reserves in giant fields is continuing. There is no apparent leveling off or drop in the Btu value of hydrocarbon additions.

2. There may be a "topping" out of oil, with a higher proportion of giant gas reserves in the last 10 years.

3. Not shown on the worldwide chart is the ever-changing, disproportionate relation between the geographic location of reserves and the location of "end users."

4. The advent of first onshore giants extending offshore, followed by discovery of giants exclusively offshore is shown at the bottom of the graph in Fig. 12-1. The rapidly-growing

offshore frontier for oil and gas now accounts for 22 percent of the Btu value of all reserves in giant fields.

BASIN CLASSIFICATION AND CHARACTERISTICS

This paper uses one of several possible basin classifications among the many proposed. The classification is based on those basins with giant fields but is also applicable to those lacking giants.

The geological framework or tectonic setting of the world's basins (Fig. 12-2) indicates that on many continents Precambrian shield areas are surrounded by the sialic crustal zones of the craton. Farther out along the continental margin an intermediate crustal zone is present. It lies between the oceanic crust, which averages 3 mi in thickness, and sialic crust of the craton, which averages 20 mi in thickness. The intermediate zone displays variable crustal thickness and often includes the continental slope, shelf, coastal plain, and continental platform, and in many places extends into the mountains bordering the coastal zone.

The classification used herein (Halbouty et al, 1970; Klemme, 1975) involves two general groups of basins, the cratonic and the intermediate crustal basins (Fig. 12-2). Oceanic crustal basins exist, but at present appear to be beyond the depths of effective production, although leasing and drilling is extending into these areas.

CRATONIC BASINS

Figures 12-3 to 12-9 depict the basin types geographically; producing basins with giants are indicated by "G", with no giants by "P", and the stage of exploration in nonproducing basins by 1 (little exploration or drilling), 2 (moderate exploration and test drilling), and 3 (either extensive test drilling or poor results from moderate test drilling). In addition, a schematic cross-section of the prototype of the basin is shown.

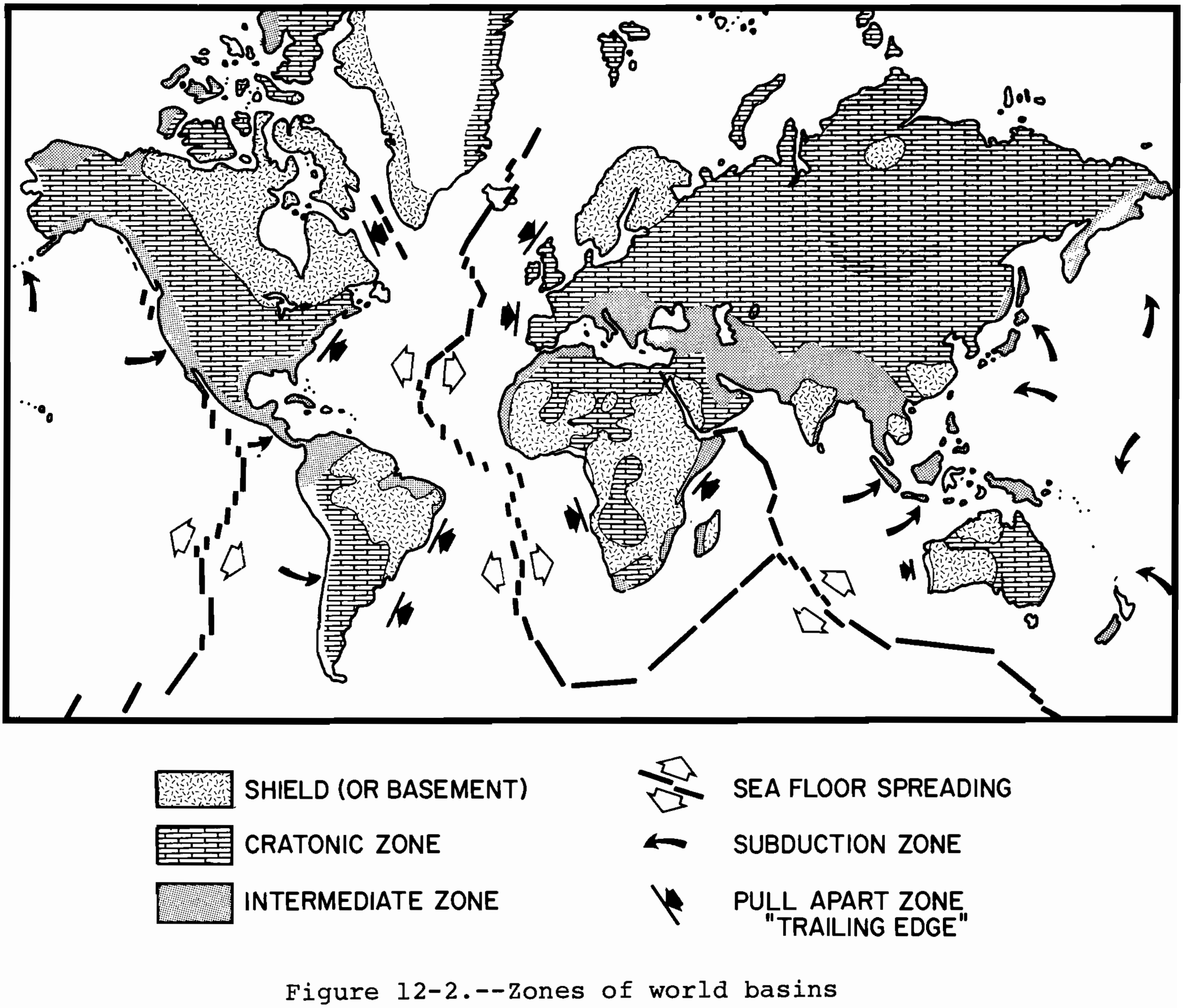


Figure 12-2.--Zones of world basins

Type 1 Basins

Type 1 basins (Fig. 12-3) lie in the interior of cratonic areas. They are flat, single-cycle, saucer-shaped basins generally located near Precambrian shield areas. The sediments consist primarily of Paleozoic platform deposits which display basement-controlled structural and sedimentary traps. Only two basins, the Illinois and the Eromango or Cooper, contain giant fields. In this type of basin, reservoir rocks include both sandstones and carbonates. In general, Type 1 interior basins have low hydrocarbon-recovery rates and entry into them has a 50 percent or less probability of commercial success. The basins are typified by low-sulfur, high-gravity crude oil.

Type 2 Basins

Outward from the interior basins, near the margins of cratons, Type 2 intracontinental composite basins are present (Fig. 12-4). They range in size from subcontinental miogeosynclines to small intermontane basins. Like the interior basins, these multicycle types usually have an initial cycle of Paleozoic platform sediments. In some of them this cycle has been tectonized by Hercynian orogeny; orogenic clastics are often deposited unconformably upon the first-cycle sediments. There are 24 intracontinental basins with 120 giant fields, which represent nearly a quarter of the world's oil and gas reserves. Reservoirs in Type 2 basins are about equally divided between Paleozoic and Mesozoic ages, and are dominantly sandstones. The crude oil types are similar to those in Type 1 basins.

Where giant fields are present, large basins of this type average 120,000 barrels of recoverable oil or gas-equivalent per mi^3 of sediments, while the smaller basins average 40,000 barrels. Basins of this type have better than a 50 percent chance of commercial discovery, and two of three contain giant fields. Most of the world's reserves of Paleozoic oil and gas are found in basins of this type.

Field sizes in the Type 2 basins occur in two general patterns: either one giant or supergiant field which contains over

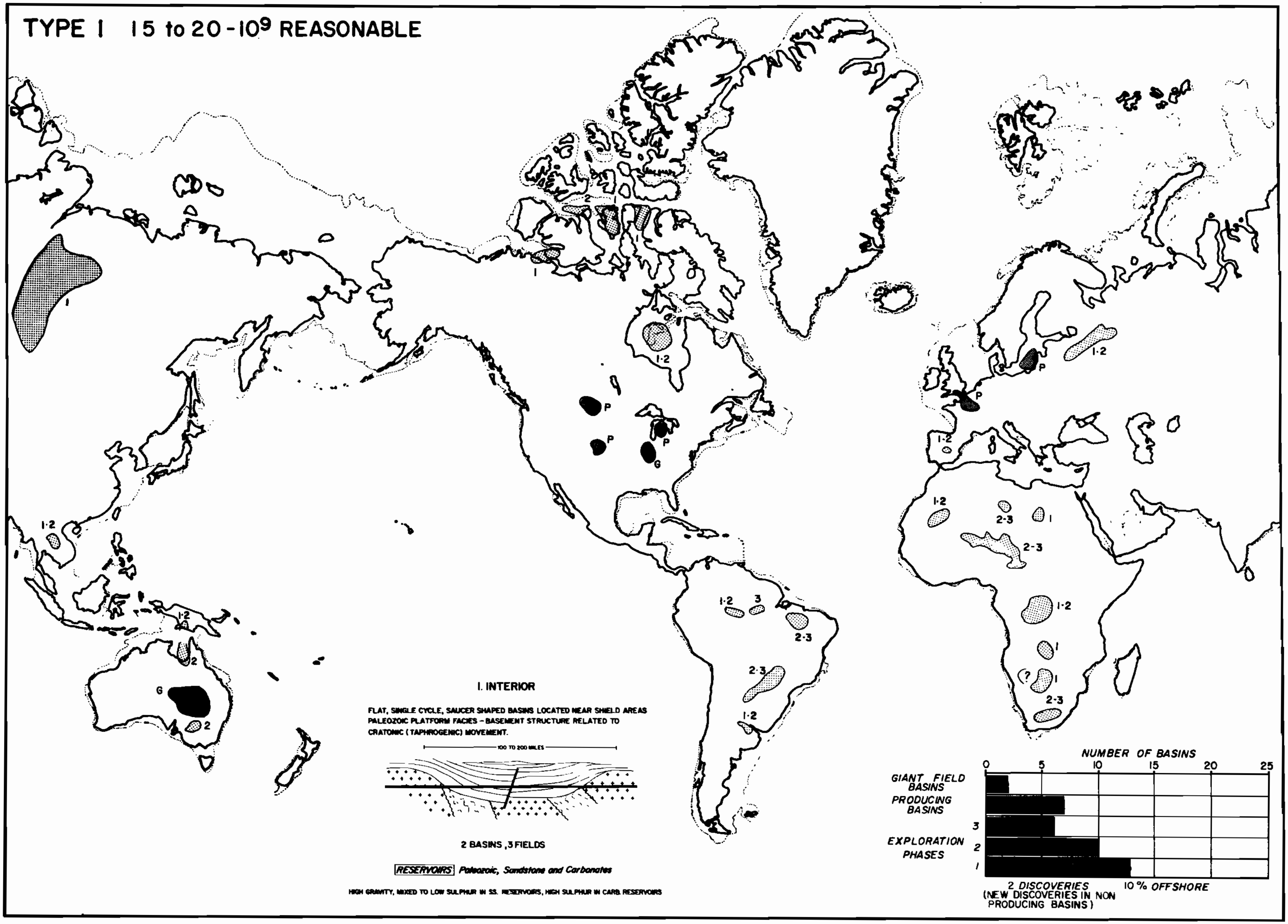


Figure 12-3.--Map of interior basins

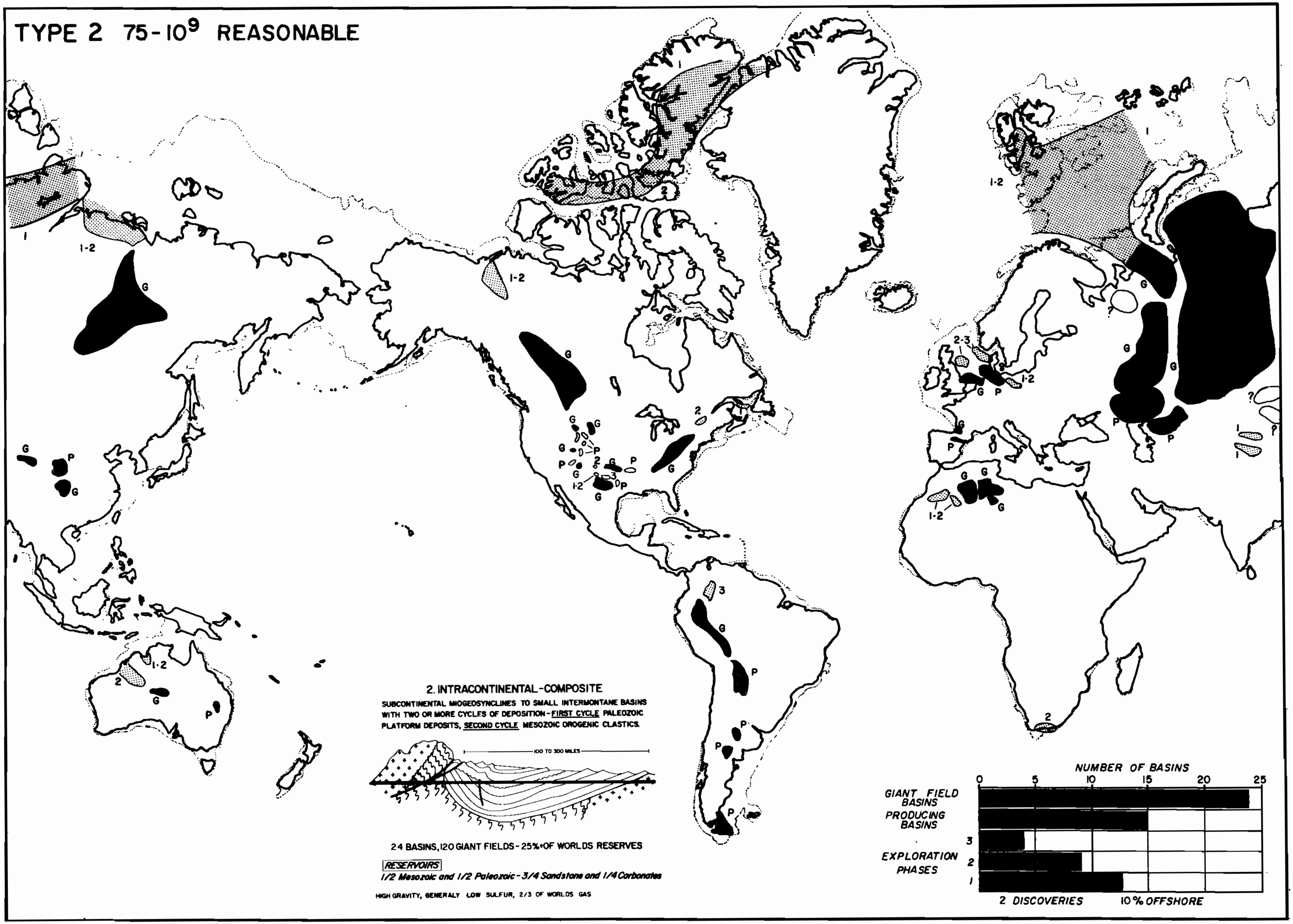


Figure 12-4.--Map of cratonic intracontinental-composite basins

50 percent of the basin's reserves, or in small fields, the largest of which is rarely more than 10 percent of the basin's reserves. Either kind may be relatively rich. The supergiants are associated with the major tectonic arches preserved in many of these basins and this, plus long-distance migration, may account for their presence whereas abundant structural traps with many stratigraphic variations seem to account for the basins with small fields.

Type 3 Basins

Another type of cratonic basin is the Type 3 graben or rift-type basin (Fig. 12-5), which may represent an area of incipient seafloor spreading that has remained dormant. Such basins are of small to medium size, linear, and down-faulted. There are six basins of this type, with a total of 40 giant fields which contain 10 percent of the world's reserves. Reservoirs are about equally divided between sandstones and carbonates, while the crude oil is generally high-gravity and low in sulphur. One out of two basins produces hydrocarbons and one out of two producing basins contains giants.

Type 3 basins with giant fields are fairly rich, averaging 140,000 barrels of oil or gas-equivalent per mi^3 of sediments. Evaporites or thick shale sequences often act as basinwide caprock to trap any oil generated below them. Many of these basins contain almost entirely gas, others mainly oil. Facies appear to control hydrocarbon type. On average, the four largest fields in this type of basin contain from 10 to 20 percent of the basin's total reserves. A high success ratio is experienced in these basins, of which four of the six have been found since World War II.

Some Type 3 basins appear to be superimposed as a third cycle on large Type 2 basins. An example is the Mesozoic-Tertiary graben system superimposed on the North Sea Type 2 basins. This graben system predates the opening of the North Atlantic.

In general, most cratonic basins contain high-gravity crude. They are estimated to contain over three-quarters of the world's

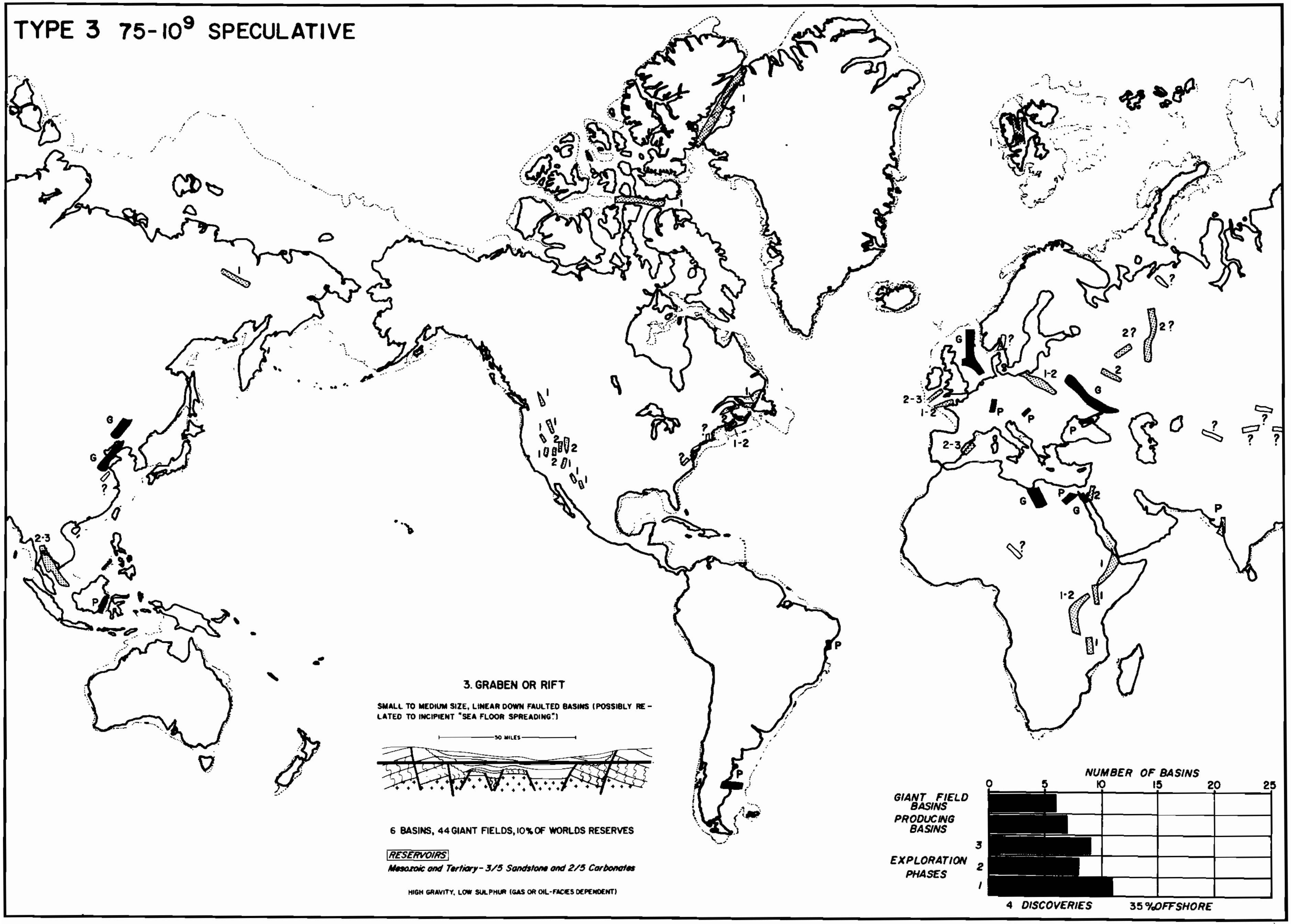


Figure 12-5.--Map of graben or rift basins

gas reserves and 90 percent of total Paleozoic hydrocarbons. They are more predictable in recoverable reserves than are the intermediate crustal basins.

INTERMEDIATE CRUSTAL BASINS (Mobile Zone)

The intermediate crustal zone covers less than a quarter of the land area of the world, but it accounts for more than half of the hydrocarbons. Most intermediate crustal basins appear to be related to the postulated tectonics of sea-floor spreading. Nearly all their reserves are Mesozoic and Tertiary--in other words, formed during the period of theoretical post-Permian sea-floor spreading.

Type 4 Basins

Type 4 extracontinental basins (Fig. 12-6) downwarp into small ocean basins. Some extend all the way to offshore land masses (Type 4A), as in the Tethyan realm of the Middle East Arabian/Iranian basin and in Eastern Venezuela; others are open and appear simply to submerge offshore (Type 4C) as in the Gulf Coast, North Slope, and East Asia. Still others, often termed "foredeeps", are present along the narrow portions of Tethys, such as the Molasse trough, the Indus basin, and Assam (Type 4B). In this basin type the statistics are skewed because of the super-rich Arabian/Iranian basin. Twelve of these basins have 105 giant fields and 50 percent of the world's reserves.

Reservoirs in 4A and 4B types are mainly Mesozoic and are dominantly carbonate, whereas 4C basins are mainly sandstone. They appear to contain average amounts of gas, except for the high gas content in the 4B foredeep subdivision, and intermediate-gravity crude oil with intermediate to high sulphur content.

The risk of exploring in these basins historically appears to entail a 50 percent chance of finding commercial production and a one-in-three chance of finding a giant field.

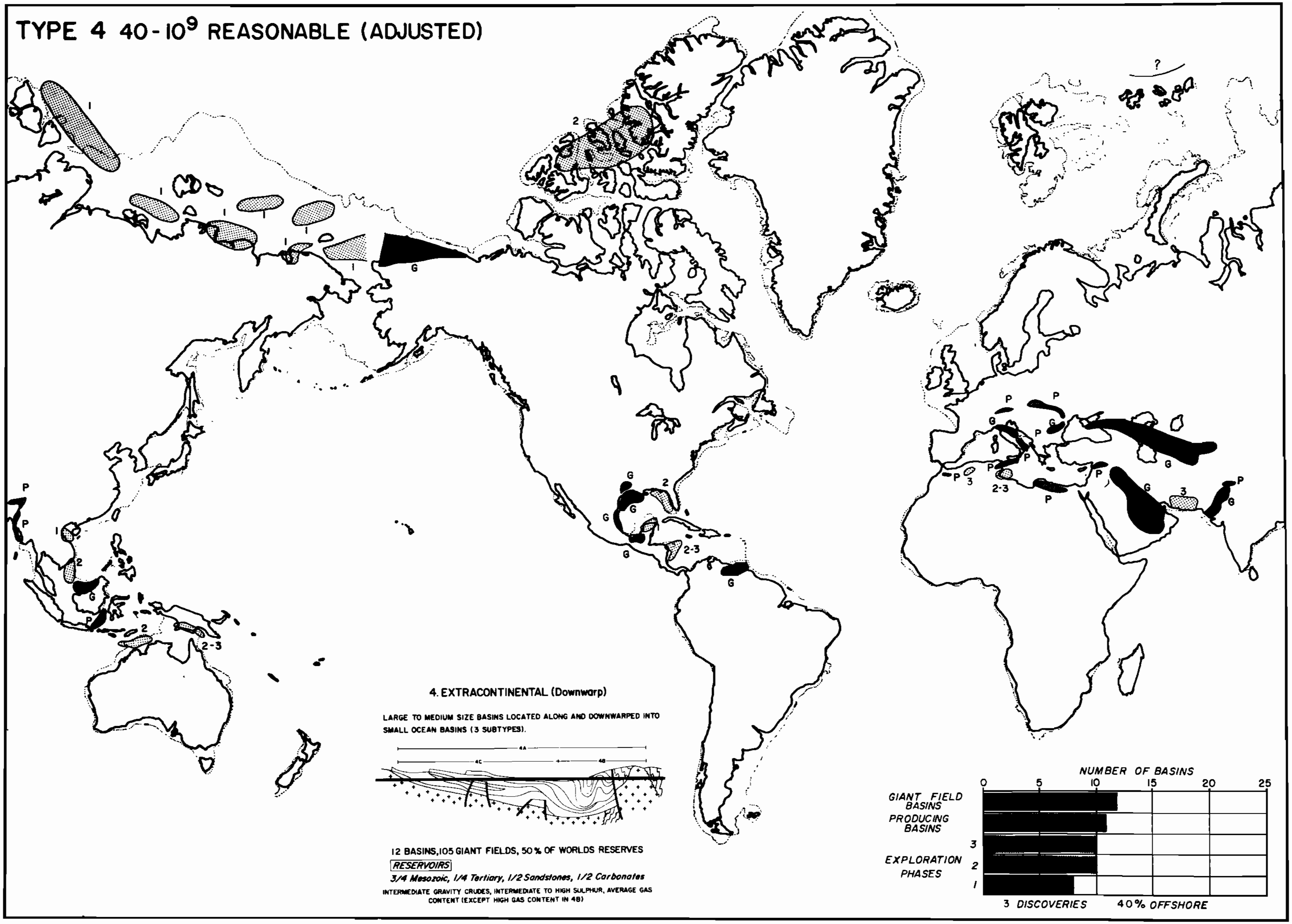


Figure 12-6.--Map of extracontinental basins

Type 5 Basins

Type 5 pull-apart basins (Fig. 12-7) may be the end phase of a Type 3 cratonic-rift basin which has been separated by distances of oceanic scale. It is difficult to determine the time and rate of spreading of some Type 3 rifts if they have passed into Type 5 pull-apart basins. For example, tens of miles of separation are reported to occur in the Red Sea rift, hundreds in the Davis Strait, and thousands in Coastal West Africa and eastern South America. Pull-apart basins are located on both sides of the Atlantic and Indian Oceans and include only four or five giants, located in the offshore lower Congo basin and off the Northwest shelf of Australia. They generally form linear coastal basins characterized by down-to-the-sea tilted fault-block structures containing Mesozoic and Tertiary sediments; these appear to lie along what many marine geologists believe to be the separated margins of continental plates.

The statistical experience factor with these basins does not permit much speculation. To date, the success ratio in significant commercial discovery is about one in three.

There appear to be at least two subtypes of pull-apart basins. One is the parallel pull-apart type of basin, which has often resulted in salt deposition along linear rifts during early stages of development. Mesozoic salt is found offshore in eastern Canada, the United States, Brazil, and west and southwest Africa. The other subtype appears to have been formed by the motion of the east-west transform movements during sea-floor spreading, which formed the basins between northern Brazil in South America and Liberia to Dahomey in Africa. This type seems to lack salt deposition and often displays a different tectonic framework. In addition, many of these basins combine both Type 3 rift and Type 5 pull-apart characteristics as, for example, in the Grand Banks off Newfoundland there appears to be a combination of Mesozoic rift-like horsts and grabens overlain by an Upper Cretaceous and Tertiary seaward-dipping fan of sediments. Dependent on influx of clastic sediments, these basins contain either dominantly sandstone and shale or almost entirely carbonate banks.

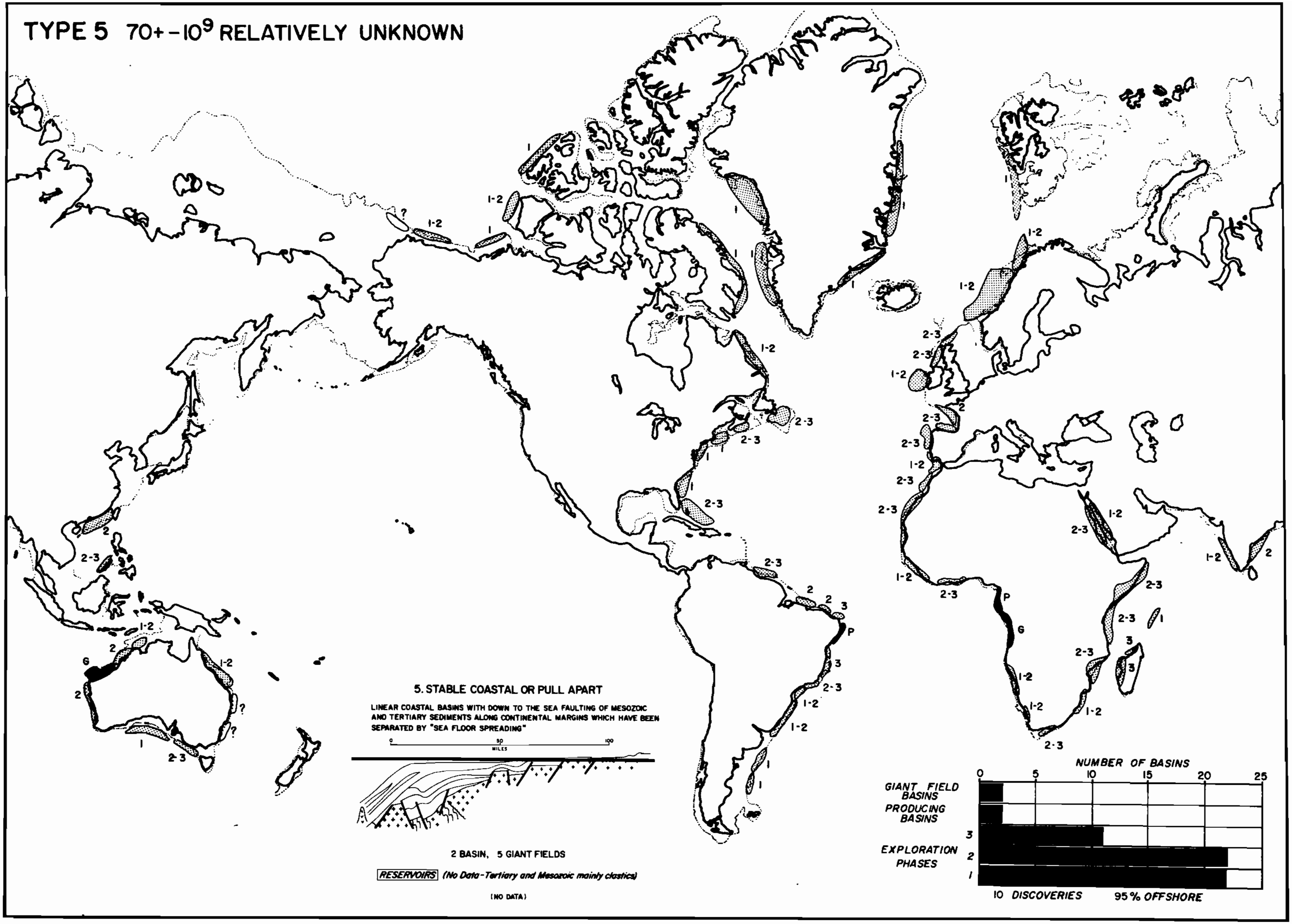


Figure 12-7.--Map of stable coastal or pull-apart basins

Types 6 and 7 Basins

Types 6 and 7 second-cycle intermontane basins (Fig. 12-8) parallel the subduction zones between the continents and ocean basins. They are small, second-cycle Tertiary basins located either transverse to, or along the strike of older deformed eugeosynclines formed previously at the continental margin. Typical of these basins are multi-pay zones of interbedded sand and shale or basal carbonate reefs. Thirteen of these basins contain 40 giant fields and represent 10 percent of the world's reserves. These small, rich basins consist predominantely of Tertiary clastics, with evaporites generally absent. Traps are either combination type or anticlinal uplifts above active basement blocks, formed in what has often been termed rhombochasms located in the crushed zone of actively-moving plates along subduction zones. Generally, the gas content of these basins is below average and their crude oil, although variable, tends toward low to intermediate gravity. Recovery of hydrocarbons, as in the case of other intermediate crustal basins, is highly variable, ranging from small amounts to 4×10^6 barrels per mi^3 of sediments. Offshore extension of production in these basins has occurred in the Caspian Sea off Baku, in the Java Sea, off the Los Angeles and Ventura basins, off Peru, and in the Cook Inlet.

Before World War I, four out of five such basins yielded hydrocarbons in commercial quantities; this ratio is now one out of five. About one out of two of the basins have giant fields.

Type 8 Basins

Type 8 late Tertiary delta basins (Fig. 12-9) with commercial production include the Niger, Mississippi, and Mahakan deltas, to which the Nile delta and portions of the Mackenzie delta appear to be new additions. Discoveries have been made recently in the offshore portion of the Rangoon, Amazon, and Mekong deltas. Statistics are not firm, but there is a remarkable correlation between the Niger and Mississippi basins. In these, there is a tendency for the largest fields to represent

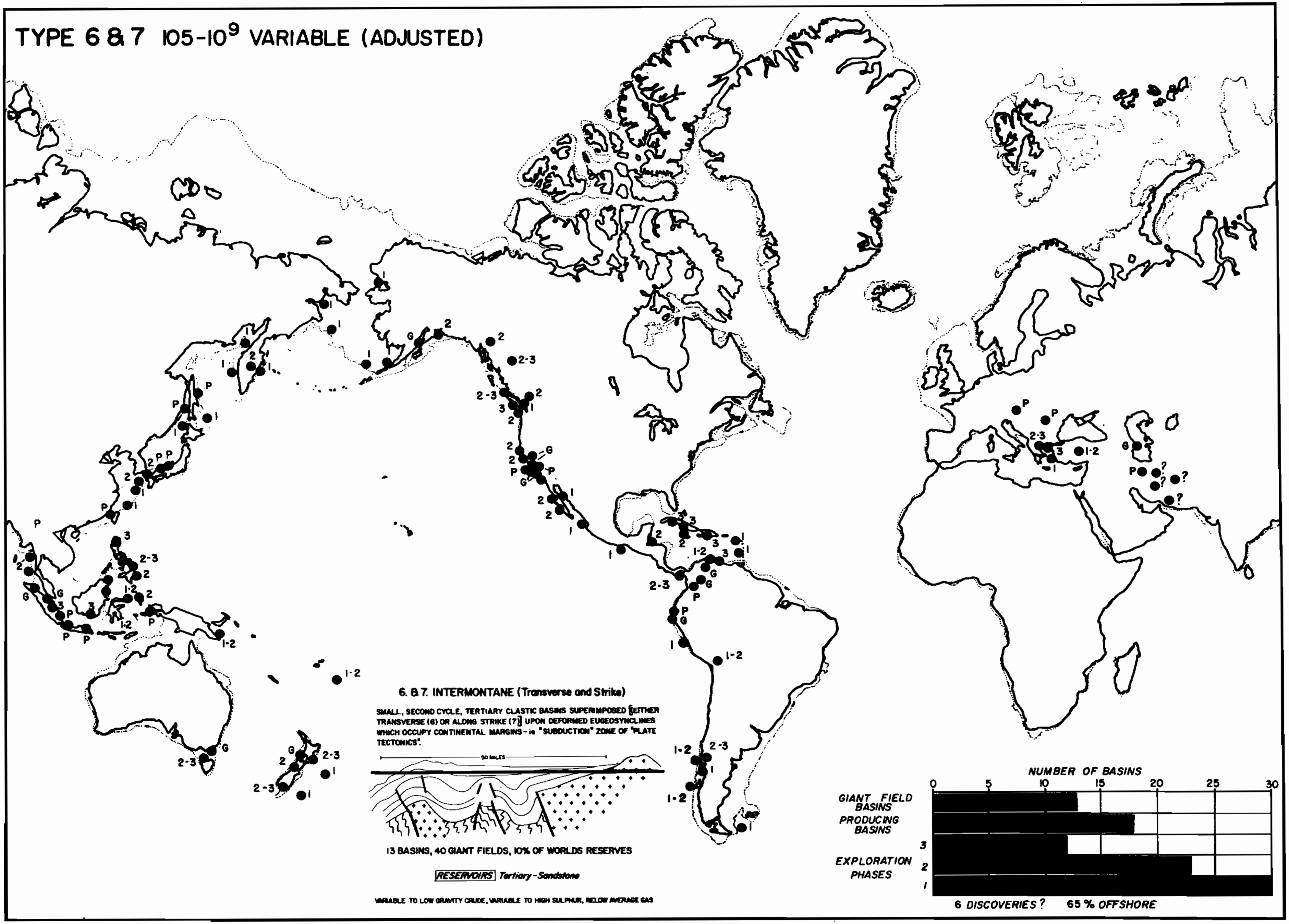


Figure 12-8.--Map of intermontane basins

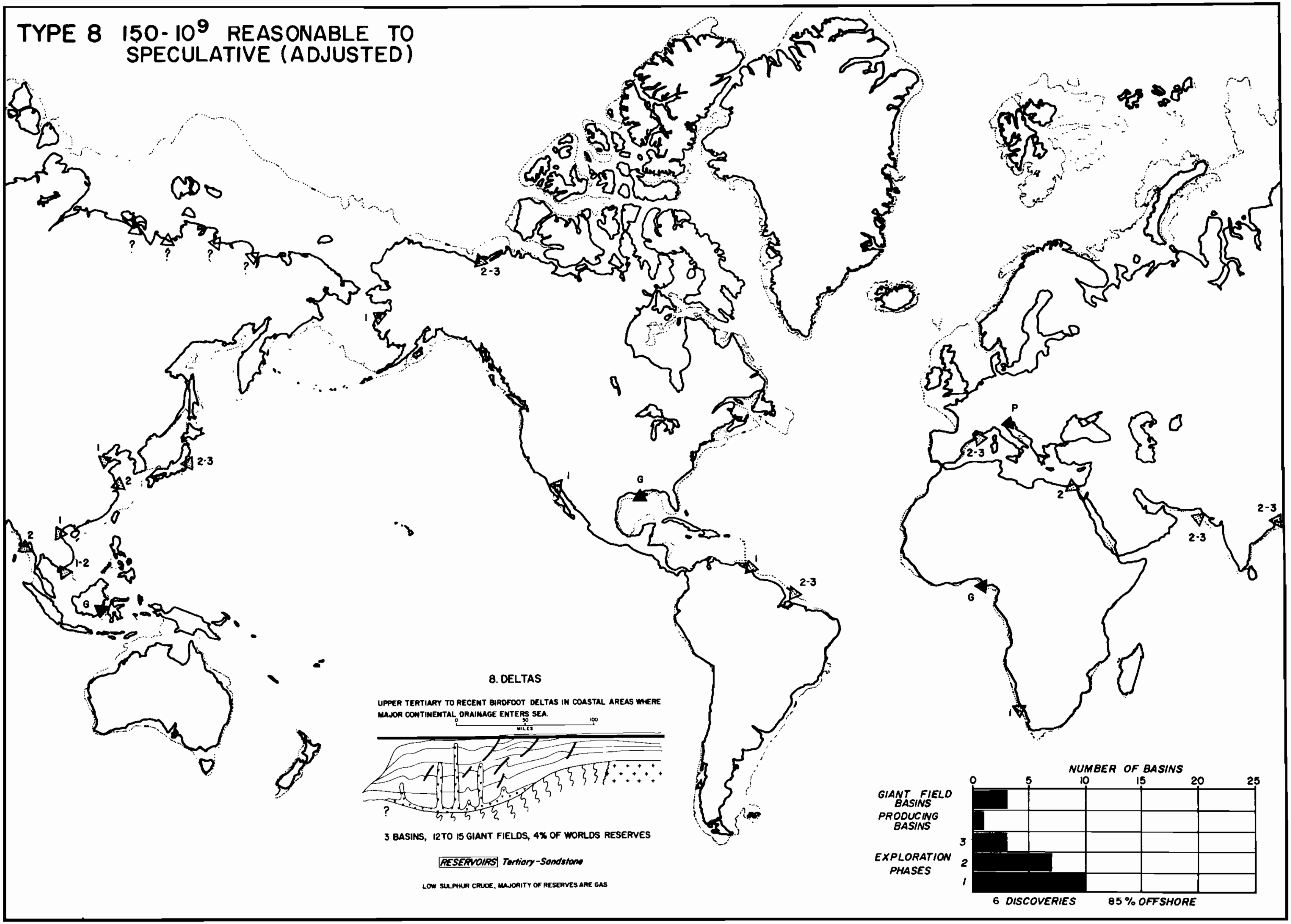


Figure 12-9.--Map of deltas

less than about 5 percent of the basin's total reserves, and they appear to have three times as much gas as normal. Roll-over structures and flowage structures act as traps.

About one out of two explored deltas has commercial production and all appear to have a few giants. The giants represent much less than 75 percent of the basin reserves.

OCEANIC BASINS

Oceanic basins of the continental rise and abyssal plains (Fig. 12-10) are estimated to contain half of the world's marine sediments (Emory 1974) and in many deep-water areas the sedimentary section reaches a substantial thickness, conducive to oil generation, with evidence of structural traps providing areas for accumulation. Deep-ocean basins are untested with regard to petroleum; however, organic-rich sediments have been recovered in some of the Joides deep-sea drilling project cores. The greatest unanswered concern is whether deep-ocean basins develop reservoir rocks.

There now is insufficient evidence to evaluate the resources of these basins and an estimate at this time would be unsatisfactory. When sufficient data are forthcoming and future drilling furnishes the industry with one or more analogs of these basin types, resource estimates may be attempted. A truly worldwide estimate of petroleum resources must remain incomplete until more data are available.

EVOLUTION OF BASIN TYPES

These, then, are the fundamental prototypes of basins. However, many present basins have characteristics of two or more of the fundamental prototypes (Fig. 12-11). Examples of combinations would include Type 8 deltas superimposed on Type 7 intermontane basins in East Kalimantan and Burma/Martaben; Type 8 deltas overlying a possible Type 4 marginal basin in the Mackenzie delta area; Type 5 pull-apart basins or Type 8 deltas underlain by Type 3 rift basins off east Canada, the Northwest Shield of Australia, western India, and possibly Norway north

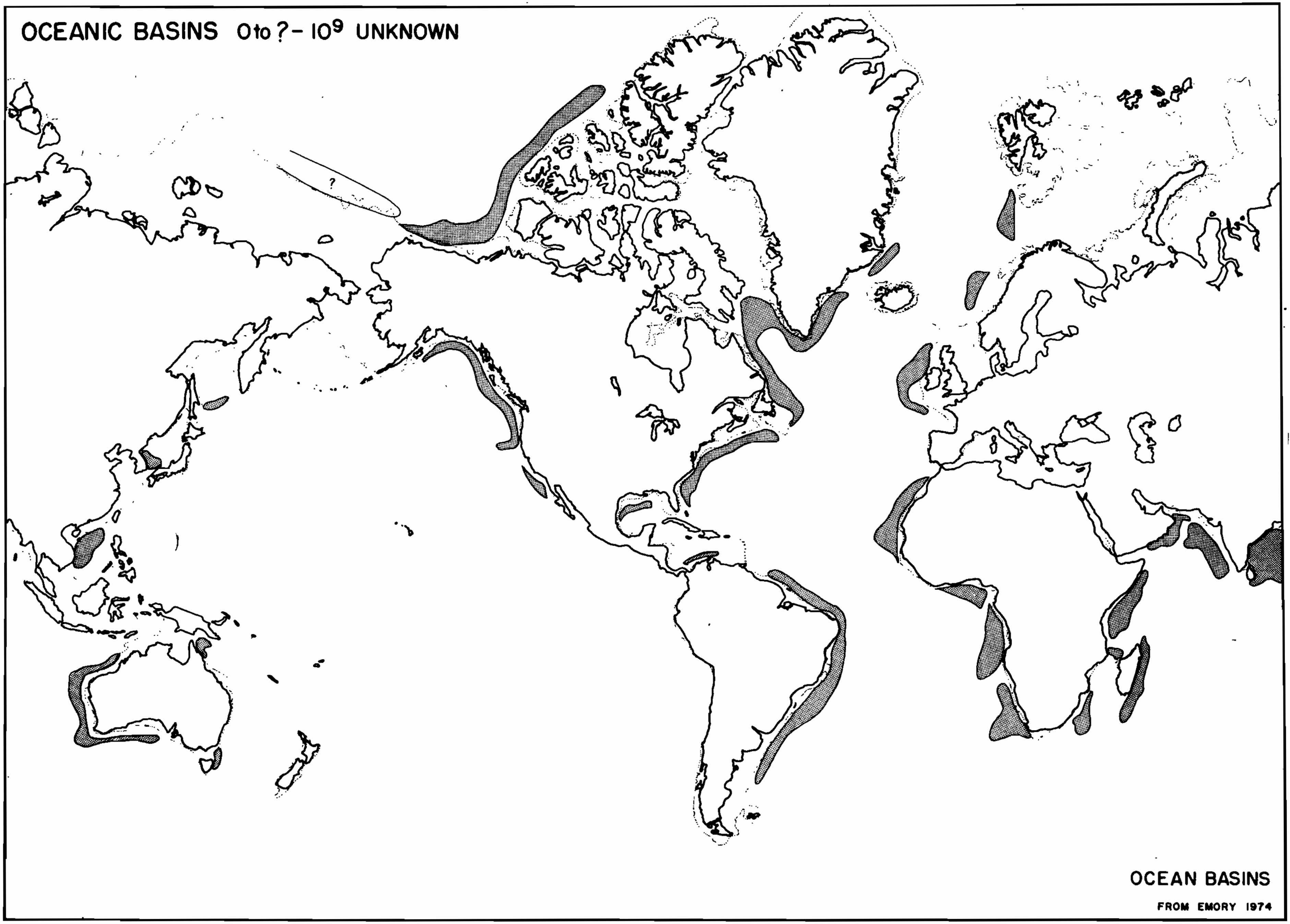


Figure 12-10.--Map of oceanic basins

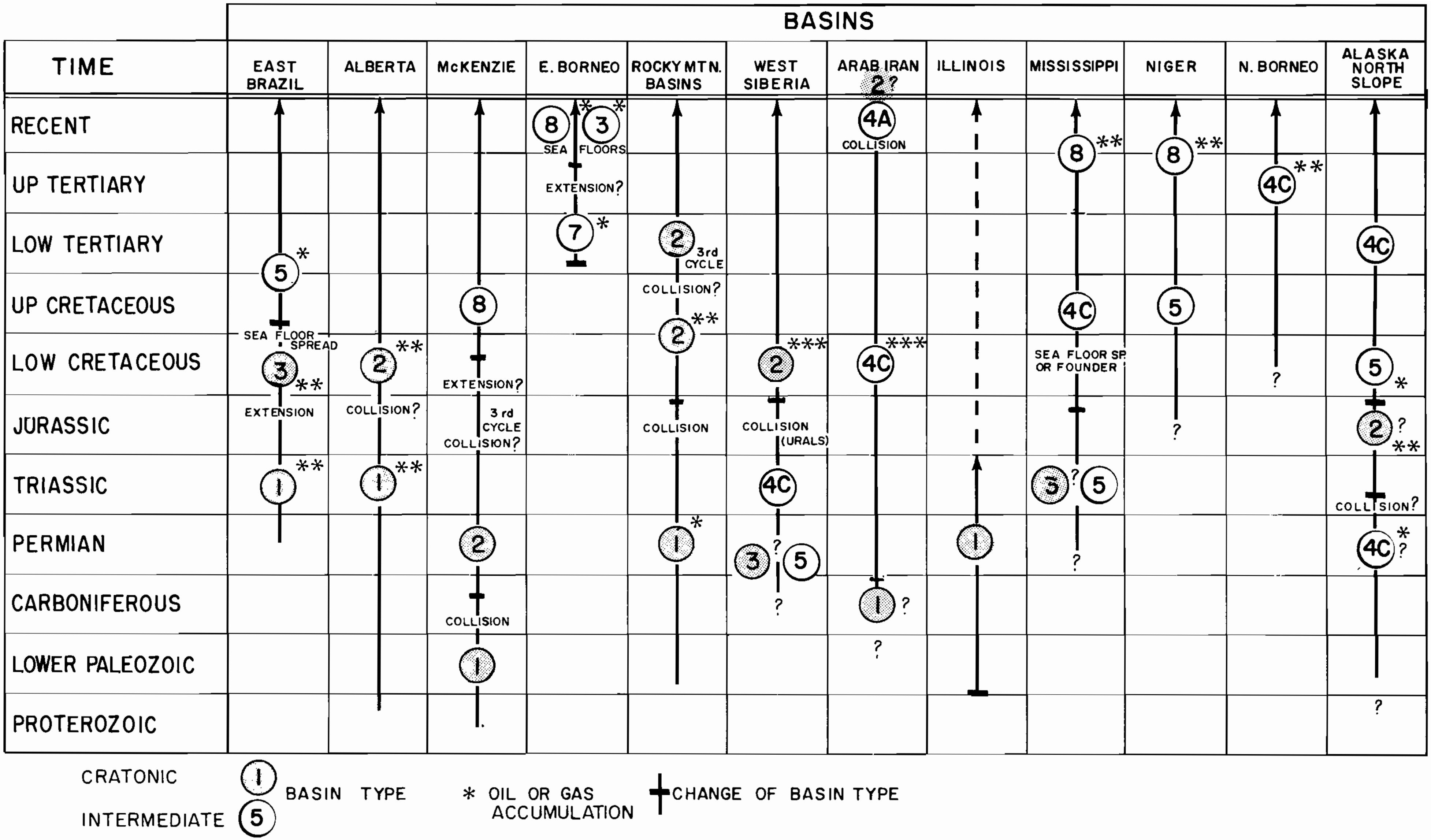


Figure 12-11.--Evolution of basin prototypes

of latitude 62°N; and Type 3 rifts superimposed on Type 2 cratonic basins, such as the central graben of the North Sea. Thus, a basin's development through time may change tectonically and combine one or more prototype basin forms. The Type 2 cratonic multicycle basins all seem to have started as Type 1 cratonic interior basins and ended with an orogenic pulse starting a second cycle of basin development. The basins located over oceanic crust at the margin of the intermediate and oceanic zones appear to be very complicated and many different types are expected.

What, then, are the fundamental statistics of hydrocarbon accumulation in relation to the reserves of giant fields and their basin types? The requisite factors include trap, reservoir rocks, source, cap rocks, and migration.

TRAPS

Trap types (Fig. 12-12) have been divided into structural, stratigraphic, and combinations of both. Worldwide reserves in giant fields are shown on the left, and it is apparent that about 95 percent of the reserves and more than 85 percent of the fields are located in visible structure-related traps, and three-quarters of these are some form of anticlinal uplift. Structurally-visible combination traps have been increasing the world's giant reserves in the North Sea, Libya, Middle East, West Siberia, and Australia in recent years (Klemme, 1974).

The various basins with giant fields reflect the typical tectonic stresses and trap types associated with the postulated stresses of sea-floor spreading (Fig. 12-13). Anticlines or structural combination traps dominate the compressional sides of continents (see basin Types 6-7, 4A-B, and Type 2 on left side of diagram), while subsidence-related anticlines, combination traps and stratigraphic traps dominate in the Type 4C, Type 3, Type 5, and Type 8 basins (on right).

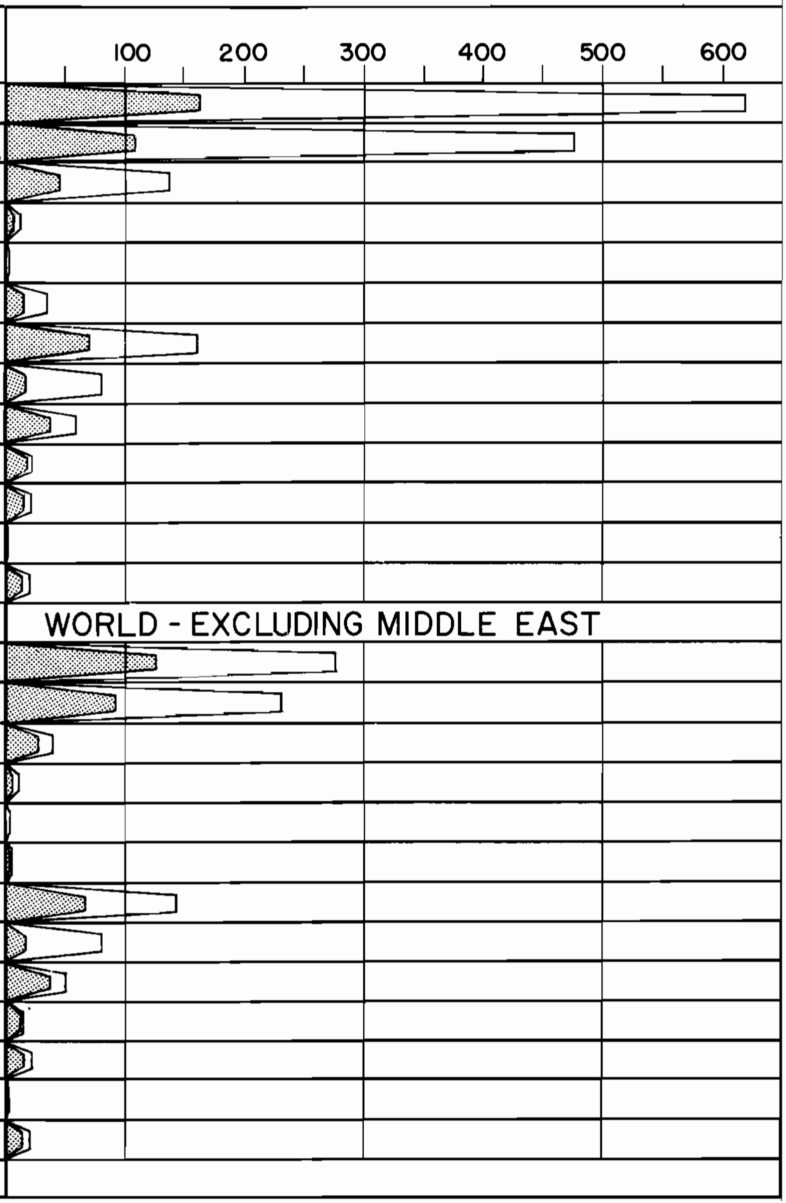
Although anticlinal traps predominate in continental and continental-margin basins, available data suggest that in continental margins and particularly their offshore areas a greater-than-average number of combination stratigraphic and structural

TOTAL WORLD

			BILLION BARRELS	NUMBER FIELDS
STRUCTURAL	I ANTICLINAL TRAPS	I (Total)	618/73.9%	163/61.0%
		I a	475/56.9%	109/40.8%
		I b	136/16.3%	44/16.4%
		I c	6/0.7%	10/3.8%
	II FAULT TRAPS	II (Total)	2/0.2%	2/0.7%
	III FLOWAGE TRAPS	III (Total)	34/4.0%	15/5.6%
COMBINATION	IV COMBINATION TRAPS	IV (Total)	161/19.2%	71/26.9%
		IV a	80/9.6%	16/5.9%
		IV b	59/7.0%	37/14.2%
		IV c	22/2.6%	18/6.8%
STRATI-GRAPHIC	V STRATIGRAPHIC TRAPS	V (Total)	21/2.5%	15/5.6%
		V a	2/0.2%	1/0.6%
		V b	19/2.3%	14/5.0%
		TOTAL	836	266

WORLD - EXCLUDING MIDDLE EAST

			BILLION BARRELS	NUMBER FIELDS
STRUCTURAL	I ANTICLINAL TRAPS	I (Total)	276/61.9%	126/59.4%
		I a	230/51.7%	90/42.4%
		I b	39/8.8%	26/12.3%
		I c	6/1.4%	10/4.7%
	II FAULT TRAPS	II (Total)	2/0.4%	2/0.9%
	III FLOWAGE TRAPS	III (Total)	4/1.0%	3/1.4%
COMBINATION	IV COMBINATION TRAPS	IV (Total)	142/31.9%	66/31.1%
		IV a	80/17.9%	16/7.4%
		IV b	49/10.9%	37/17.4%
		IV c	14/3.1%	13/6.3%
STRATI-GRAPHIC	V STRATIGRAPHIC TRAPS	V (Total)	21/4.8%	15/7.1%
		V a	2/0.4%	1/0.7%
		V b	19/4.4%	4/6.4%
		TOTAL	445	212



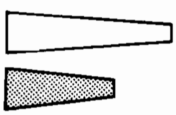


Figure 12-12.--Trap types

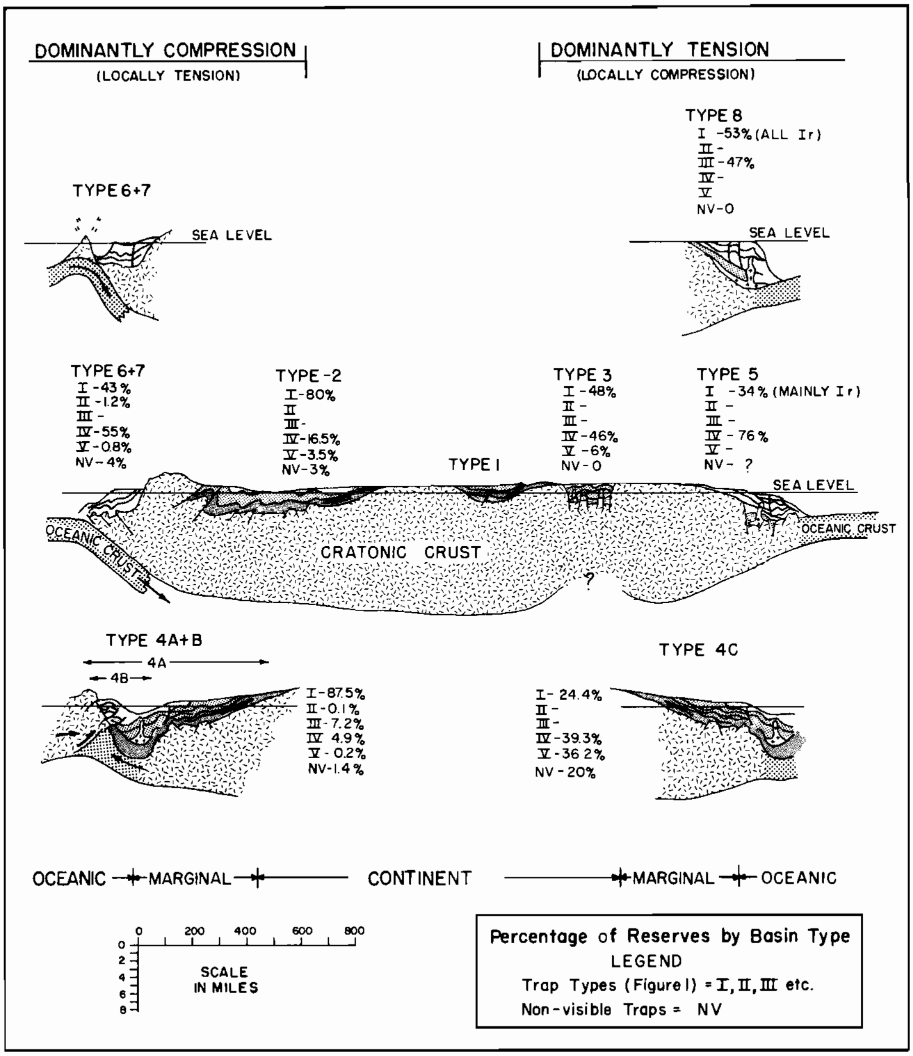


Figure 12-13.--Trap types related to basin types

traps, flowage traps, fault traps, and tensional anticlinal traps will be encountered (Klemme, 1974). These more unconventional traps may present the industry with more difficult exploration in the future. Figure 12-14 shows giant offshore traps in relation to the 18 percent of the world's total giant reserves found in offshore waters. The disproportionate trap types rise above the 18 percent line.

The "breakthrough" whereby elusive, purely stratigraphic traps may be predicted and thereby contribute a substantial share of the world's reserves has not occurred. This does not imply eventual predestination of large reserves from stratigraphic traps. On the other hand, the importance of stratigraphic factors in many of the world's giant combination stratigraphic/structural traps seems well established. These combination traps are more visible or detectable and are expected to contribute substantially to the world's future reserves.

RESERVOIRS

The reservoir rock of giant fields is about 61 percent sandstone worldwide, or about 80 percent excluding the Middle East. Carbonate reservoirs account for about 40 percent of giant reserves, mainly from the Middle East (Fig. 12-15). These carbonate reservoirs are about equally divided between the primary depositional clastic porosity of limestones and the secondary porosity of late-stage dolomitization and tectonic fracturing. Expressed another way, 80 percent of giant reservoirs are the result of primary deposition. Most of the reservoir rocks are Mesozoic in age. Cratonic basins and Type 4A and B intermediate crustal basins have mixed sandstone and carbonate reservoirs whereas Type 4C and all other intermediate basins are predominately sandstone reservoirs.

SOURCES

If one accepts that hydrocarbons are of organic origin, the available data for source-rock determination are much less reliable than for reservoir rocks. Only about one-third of the

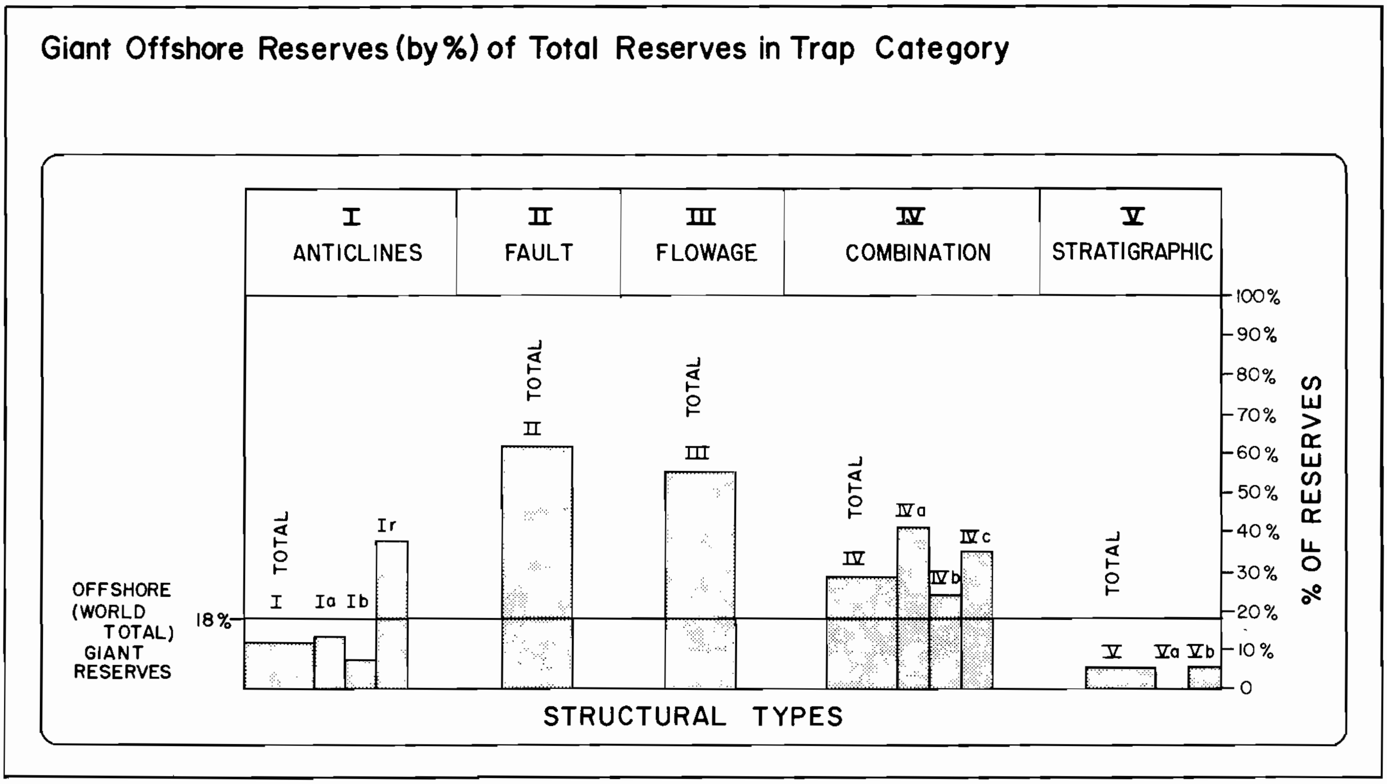
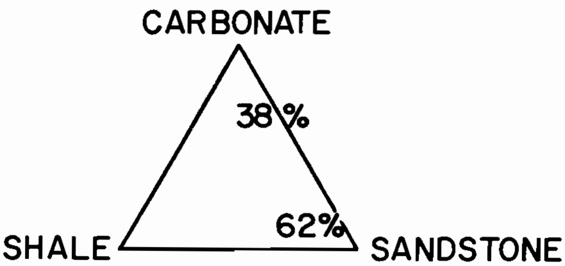


Figure 12-14.--Offshore trap types

RESERVOIR ROCK *



* OUTSIDE MIDDLE EAST
81% SANDSTONE
19% CARBONATE

* AGE TERTIARY 20%
MESOZOIC 68%
PALEOZOIC 12%

BASIN TYPE		RESERVOIR TYPE	
		CARBONATE	SANDSTONE
TYPE 2	CRATONIC (MULTICYCLE)	15%	85%
TYPE 3	CRATONIC (RIFT)	41%	59%
TYPE 4	INTERMEDIATE, EXTRACONTINENTAL		
	A (CLOSED)	62%	38%
	B (FOREDEEP)	99%	—
	C (OPEN)	28%	72%
TYPE 5	INTERMEDIATE, PULL-APART	—	100%
TYPE 6+7	INTERMEDIATE, INTERMONTANE	5%	95%
TYPE 8	INTERMEDIATE, DELTA	—	100%

Figure 12-15.--Reservoir rock statistics

reservoirs are based on reliable data with respect to source beds while in more than 50 percent of the fields assumptions must be made as to source (Fig. 12-16). Worldwide source rock appears to be chiefly shale.

CAP ROCKS

About 88 percent of the cap rock in giant fields outside the Middle East is shale. Evaporites predominate in the Type 4A Middle East basin and are associated with many of the carbonate reservoirs of the cratonic basins, while shale predominates in all other intermediate crustal basins.

REASONS FOR PRODUCTIVITY OF BASINS

Review of the giant and supergiant fields appears to confirm conventional oil-finding concepts:

1. Presence of traps that were growing during both the deposition of surrounding sediments and the generation and migration of hydrocarbons.

2. Good reservoirs, including their provenance, geometry, and hydrodynamics.

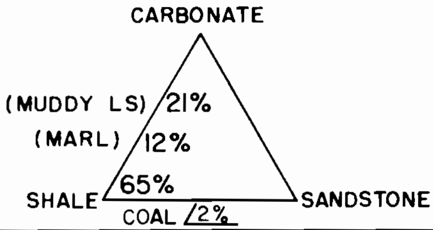
3. Abundant, rich source rock in contact with reservoirs.

4. Low to moderate intensity of deformation.

When all these factors are properly combined, quantities of hydrocarbons ranging from small to commercial seem assured. Where, in addition to these factors, special geologic factors are present in certain types of basins, giant or supergiant fields may be the result. These factors include:

1. Large traps. To illustrate this point, the 17 largest oil and gas supergiants (those above 10 x 10^9 barrels or gas equivalent) represent 60 percent of the world's reserves. These fields range in size from 200 to 4,000 mi^2, with a median field size of 500 mi^2 and an average of 900 mi^2 or 575,000 acres. This would be the same as a producing field covering nine UK blocks in the North Sea.

2. Basin Size. In some basin types the over-all basin sizes may be of importance. In Type 2 and 4 basins, except for



RELIABILITY

EVIDENT 31%
ASSUMED 50%
UNKNOWN TO ASSUMED .. 12%
NO DATA .. 7%

BASIN TYPES	SOURCE LITHOLOGY			
	LS(MUD)	MARL	SHALE	COAL
TYPE 1 CRATONIC INTERIOR	(1 FIELD ONLY)			
TYPE 2 CRATONIC MULTICYCLE	1.3%	0.7%	93%	5%
TYPE 3 CRATONIC RIFT	7.9%	5.7%	86.4%	—
EXTRA CONTINENTAL MARGIN				
TYPE 4A CLOSED	39%	22%	39%	—
4B FOREDEEP	?	?	100%±	—
4C OPEN	5.4%	1.7%	93%	—
TYPE 5 PULL-APART	?	?	100%±	—
TYPE 6+7 INTERMONTANE TRANSVERSE + STRIKE	—	—	99%	1%
TYPE 8 DELTA	—	—	100%	?

Figure 12-16.--Source rock statistics

the Appalachian basin, the 10 largest basins now producing (those with 200,000 mi^3 or more of sediments) recover from 70,000 to 600,000 barrels per mi^3 of sediment, or an average of 180,000 barrels. These large basins with low-intensity deformation appear to be super-rich and are estimated to account for 70 percent of produced reserves and present known reserves.

3. Extensive evaporite cover of a basin or a major portion of a basin (Iran, portions of Libya, several Type 2 basins).

4. Significant unconformities (Prudhoe Bay, Maracaibo, East Texas, Jurassic fields of North Sea Tertiary graben).

5. Unbreached regional arches, or the hinge zones on their flanks.

6. Higher-than-normal geothermal gradients (Types 6 and 7 and some Type 3 basins).

7. Secondary fractured reservoirs (Iran).

TEMPERATURE EFFECTS

The effect of temperature on giant oil accumulations has recently received considerable attention (Klemme, 1972; Pusey, 1973).

A basin's depth of hydrocarbon occurrence and its temperature history appear to be closely related to the heat-flow framework of the new global tectonics (Fig. 12-17). Most intermediate basins were, at some time in their histories, associated with significantly high heat-flow zones along various continental plate margins. In addition, Type 3 rift basins appear to be located in high heat-flow zones, which may be areas of incipient sea-floor spreading.

It appears with the data presently available, that many of these basins tend to yield more hydrocarbons per cubic mile of sediment than basins from low heat-flow areas. The most dramatic effect is in Type 6 and 7 basins. It also appears that more gas than oil will be found at depths below 12,000 feet. In fact, there are many indications that where extreme temperatures are present, hydrocarbons at depth have often been destroyed.

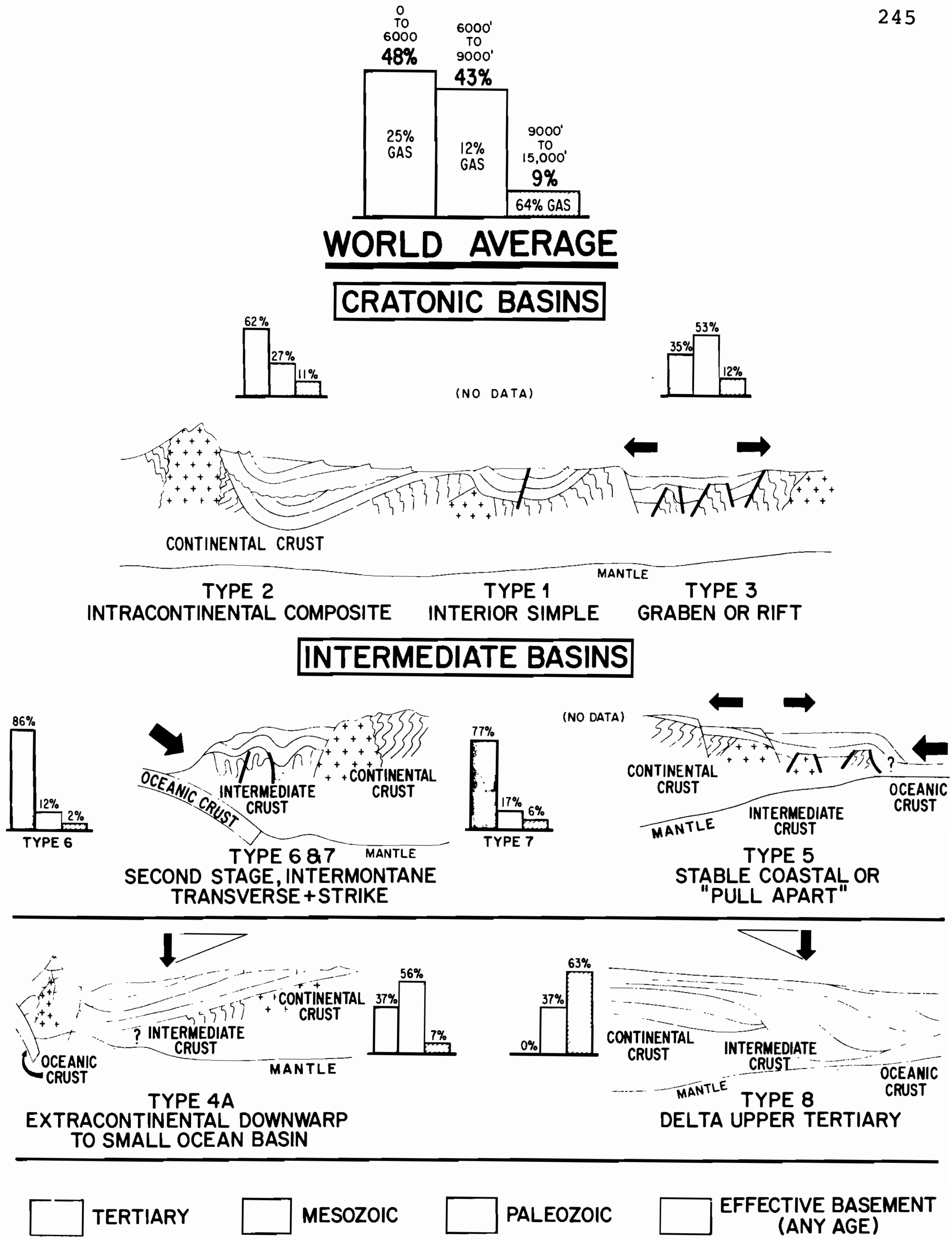


Figure 12-17.--Depth of production (reserves) related to generalized basin types

HISTORY OF THE PETROLEUM INDUSTRY IN RELATION TO BASIN DEVELOPMENT

Patterns over the last 100 years (Klemme, 1971) indicate certain success ratios when all producing basins are considered. Figure 12-18 is divided vertically into the pre-World War I period at the top, the period between World Wars I and II in the center, and the post-World War II period at the bottom. Numbers of basins are shown horizontally. It is noted that more basins are being explored, and more basins with production are being found now than earlier; however, the industry is experiencing a lower and lower success ratio. Early pre-World War I exploration was in basins with abundant surface seeps and other manifestations of petroleum. These basins were more obvious than most, and have had a higher success ratio than those explored subsequently.

Figure 12-19 shows, on the left, the effect of the age or time when a basin was explored, and on the right, the size of the basin being explored. The shorter development time in recent years may be related to the obvious improvement in industry techniques, some host government attitudes that spur development, and the competitive demand for hydrocarbons. On the right graph it is noted that in general the larger basins have required a longer development time. Certain small basins (such as Types 6 and 7 intermontane types) appear to develop and pay out very rapidly, and success in these basins requires early entry, whereas large (Type 4 extracontinental and the larger Type 2 intracratonic) basins develop more slowly, and late entry into them offers a chance for substantial discovery.

A tabulation of the fields in some of the various tectonic types of basins has been attempted. In arriving at the percentage of a basin's total reserves that the largest fields represent (Fig. 12-20), the critical judgment factor is the determination of a basin's ultimate reserves. Some basins with a long history of exploration are practically "worked out" and the ultimate can be calculated with some assurance; for other basins with much less development, the estimates are less satisfactory.

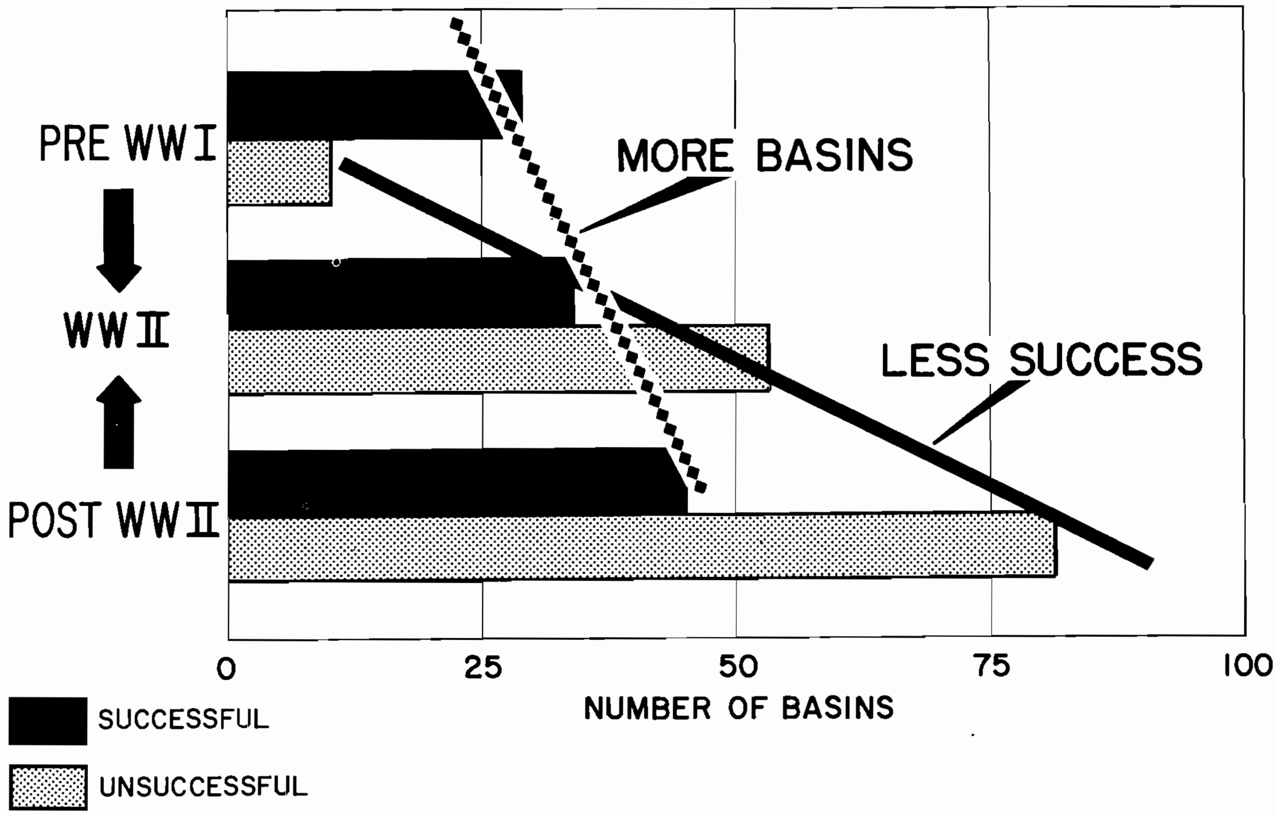


Figure 12-18.--Basin discovery success ratios

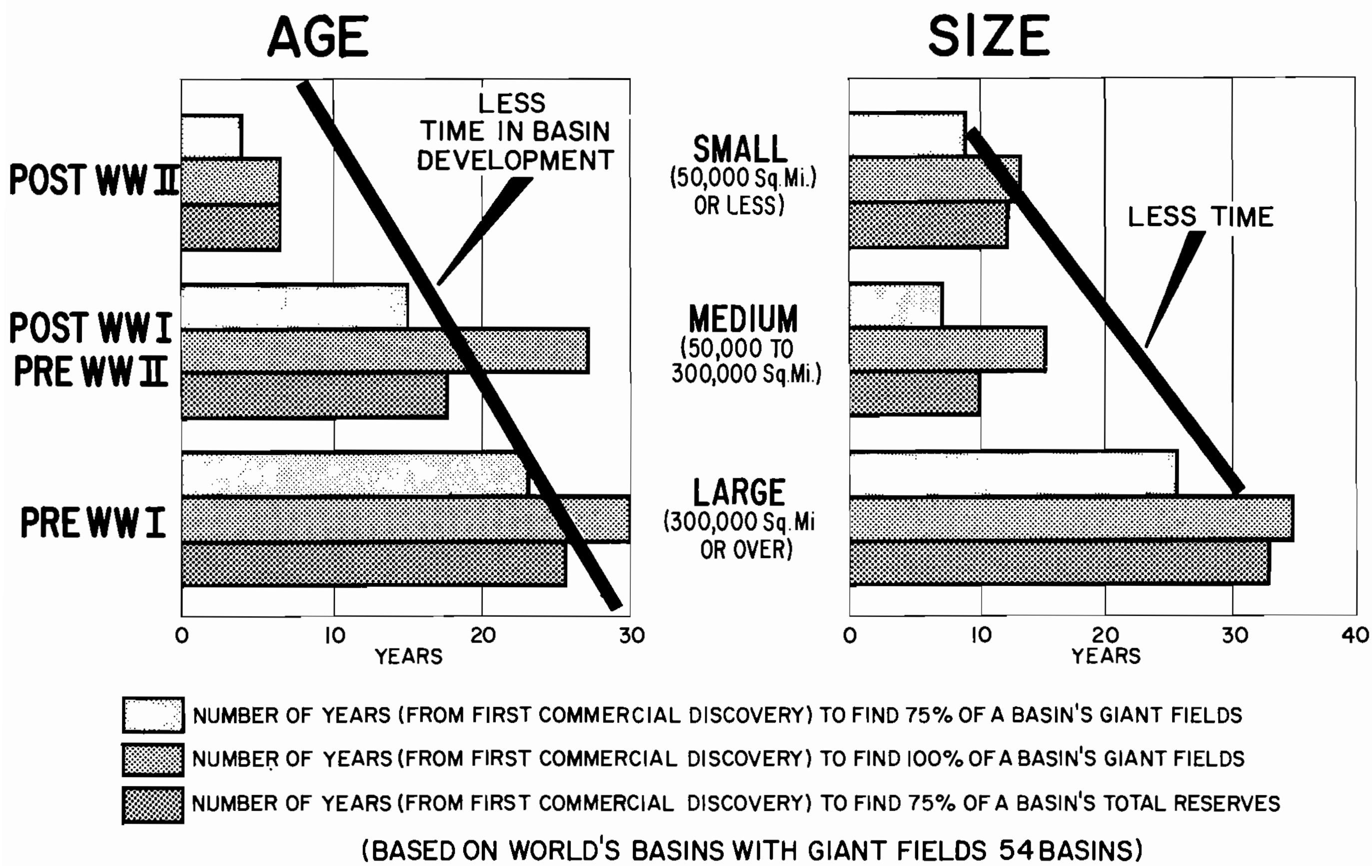


Figure 12-19.--Development timing in basins with giant fields

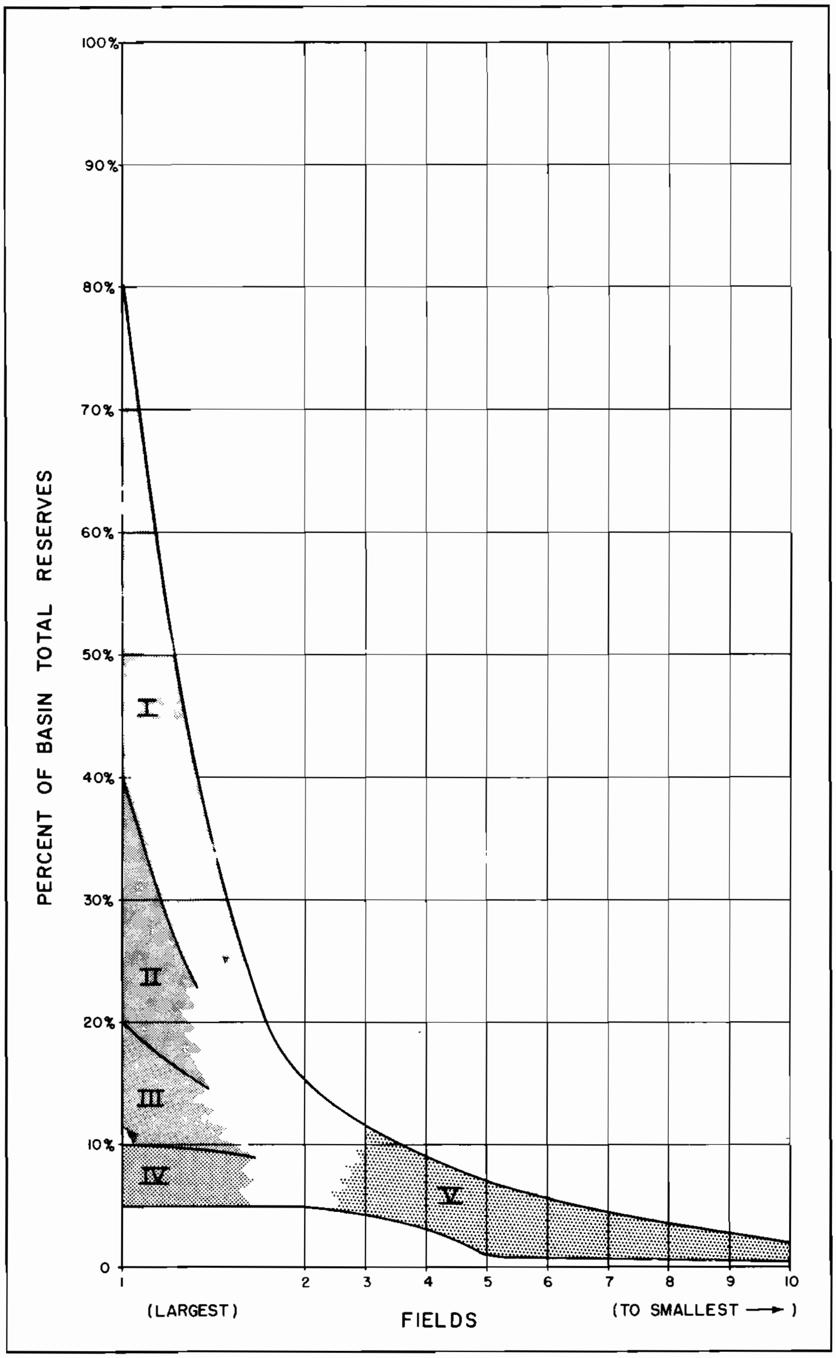


Figure 12-20.--Field-size spread of basins with giant fields

There appear to be five groupings of the largest or two largest fields in present basins (Fig. 12-20):

I Presence in any type of basin of a supergiant or one disproportionately large field. In cratonic basins this is often related to extensive regional arches that retain sufficient cover. In intermediate basins (mainly Types 6 and 7) the presence of supergiants appears relatively unpredictable.

II This grouping might be considered a more average or normal distribution.

III Represents large cratonic Type 2 and large intermediate Type 4A and 4B basins, due to absence of a single regional arch and abundance of individual traps. It is the pattern in extremely prolific basins.

IV Typical of deltas

V Generally from 1 to 5 percent of total reserves, this represents the average larger field size. One can predict reserves with more assurance from this curve. The risk for finding one of the three or four largest fields in any basin increases as the basin develops, because the largest fields are usually found early in development.

On the average, a large field contains 25 percent of a basin's reserves; fields from the 3rd to the 10th largest appear to contain from 1 to 3 percent of basin's reserves.

RELATIONSHIP OF BASIN CHARACTERISTICS TO FUTURE WORLD RESERVES AND ULTIMATE RESOURCES OF CONVENTIONAL RECOVERABLE OIL AND GAS

Past and present estimates of ultimate recoverable resources of oil and gas have a rather extensive range. If agreement is reached on what the world's cumulative production has been and present proven reserves reasonably recoverable from existing oil and gas fields, this figure may be compared with future undiscovered potential. Current figures (Moody, 1975; Adams and Kirkby, 1975) indicate this total (cumulative production plus proven and prospective) as of 1973-74, was equivalent to 1,500 x 10^9 barrels of oil equivalent. Of this, two-thirds was oil and one-third was gas. Estimates of future undiscovered oil and gas at the 9th World Petroleum Congress in Tokyo (Moody, 1975); Adams and Kirkby, 1975) indicated the world will ultimately find an equal amount of both oil and gas. This study would consider these and Weeks' (1959) estimates as reasonable. It would also consider the geographic breakdown of the 1975 estimates as reasonable.

In Fig. 12-1 the Mideast and West Siberia basins have been emphasized because they represent two-thirds of the giant reserves and well over 50 percent of the proven reserves. Because of the impact of these provinces on world oil and gas reserve estimates they were treated separately in this study and their values removed from many of the statistical calculations. With the exclusion of the Mideast and West Siberia, the world's basins (productive and nonproductive) were analyzed, first by a general classification and then related to the success ratio and recovery history of similar types of producing basins. This appears to be a combination of what Moody (1975) has termed the "geologic parameter analysis and analogue extension" and also his "analysis of production, reserve, discovery index and exploration success." Caution has been advised against too great a reliance on basin classification. Jones (1974) warns of "too vigorous application of basin classification and productivity." The use of the volumetric method of reserve estimation--that is, some ratio between the volume of sediments and reserves in a producing basin and a recovery factor when applied to volume of sediments in relatively unknown basins--has been questioned and often rejected (Hedberg, 1975; Nanz, 1975). Although the volumetric method was not directly used in this study, its consideration in estimation of potential reserves is essential, providing the proper risk factors are applied (Klemme, 1975). Some of those who object to the volumetric method and its analogue approach (Nanz, 1974; Bally, 1975) admit that its application might result in a smaller range of estimates if many (say more than 20) basins are considered.

When the world's basins as known at present are considered, a large sample is available. This sample resulted in the estimate presented in this study. The estimate is worldwide and the geographic breakdown of where these reserves will be found is not included; however, the location of the reserves may be expected to be in some ratio to the geographic and political location of the nonproductive basins.

These reserves total over 500 x 10^9 barrels (68 x 10^9 metric tons) of oil equivalent and when combined with the additions expected in the previously discussed prolific basins or provinces of the Mideast and West Siberia, indicate that a reasonable figure of around 1,000 x 10^9 barrels (136 x 10^9 metric tons) of undiscovered reserves in oil equivalent might be expected. This does not include an estimate of the deep oceanic basins or Antarctica and its environs. It is estimated that over 42 percent of these reserves would come from offshore.

This estimate is about two-thirds the magnitude of those presented at the 9th World Petroleum Congress in Tokyo in 1975 and those estimated by Weeks in 1959. It is slightly more than one-half the estimate of the worldwide undiscovered reserves made by the U.S. National Academy of Sciences in 1975.

In this study (Fig. 12-21), the remaining nonproducing basins of each type were plotted and the relative amount of exploration graphed (Fig. 12-3 through 12-9). All of the relatively unexplored basins together with half of the moderately explored basins were determined and compared to the risk for finding production and the risk for finding giants (Fig. 12-22) for each respective type. The number of basins that might ultimately develop were then related to the percentage of present proven world reserves that each basin type represents (see cross sections, Fig. 12-3 through 12-9). In some instances, the calculated figures were revised. In the case of Type 4 basins, the estimates were considerably downgraded because the presence of the Mideast high reserve basin in this category "skews" the input for calculations. In the case of Type 8 deltas, the estimates were upgraded due to the fact that giant fields in these basins represent less than 20 percent of their total

WORLD** BASINS POTENTIAL

BASIN TYPE	FUTURE RESERVES* NEW BASINS	% OFFSHORE	VALIDITY	ECONOMICS
1	15	10%	REASONABLE	DEPEND ON SIZE ACCUMULATIONS AND LOCATION
2	75	30%	REASONABLE	
3	75	35%	SPECULATIVE	
4	40	40%	REASONABLE	OFFSHORE ECONOMICS REQUIRE MORE CONCENTRATED ACCUMULATIONS WITH LARGE RESERVES AND HIGH PRODUCIBILITY
5	70	95%	RELATIVELY UNKNOWN	
6 & 7	105	65%	VARIABLE	
8	150	85%	REASONABLE TO SPECULATIVE	
OCEANIC	?	100%	UNTESTED	
MIDEAST***	320	20%	REASONABLE	
WEST SIBERIA***	150	?	?	
TOTAL	*1000 ± (REQUIRES REVISION WHEN OCEANIC BASINS TESTED)*			

* BILLIONS OF BBLS (OR GAS EQUIVILENT)
** EXCLUDING ANTARTICA
*** FROM 9th WORLD PET. CONG. ESTIMATES 1975

Figure 12-21.--Potential of world basins

"YARDSTICK" FOR BASIN EVALUATION

	BASIN TYPE	↓RECOVERY PER CUBIC MILE OF SEDIMENTS	CHANCE OF COMMERCIAL PRODUCTION	CHANCE OF PRESENCE OF GIANTS	FIELD SIZE * LARGEST FIELD (10th LARGEST FIELD)
CRATONIC BASINS	1. CRATONIC INTERIOR	35,000 HIGH 18,000 AVERAGE 3,500 LOW	30 %	20%	—
	2. CRATONIC MULTICYCLE (LARGE)	250,000 120,000 25,000	80 %	65 %	10% TO 50% (1.9% TO 0.6%)
	(SMALL)	75,000 40,000 7,500	50%	30%	30% ± (2% ±)
	3. CRATONIC RIFT	450,000 140,000 20,000	70 %	50%	30 % (1.7%)

↓ OR EQUIVALENT GAS

* BASED ON ULTIMATE RECOVERY OF TOTAL BASIN RESERVES

Figure 12-22a.--Yardstick for basin evaluation, cratonic basins

"YARDSTICK" FOR BASIN EVALUATION

	BASIN TYPE	RECOVERY PER CUBIC MILE OF SEDIMENTS	CHANCE OF COMMERCIAL PRODUCTION	CHANCE OF PRESENCE OF GIANTS	FIELD SIZE LARGEST FIELD (10th LARGEST FIELD)
INTERMEDIATE BASINS	4. INTEMEDIATE EXTRACONTINENTAL 4A. CLOSED	600,000 * 150,000 10,000	50%	50%	14 % (2 %)
	4B. FOREDEEP	60,000 25,000 1,000	40 %	10%	14 % (2 %)
	4C. OPEN	300,000 160,000 3,000	50%	65 %	30 % (0.6%)
	5. PULL-APART	? (PRESENTLY AVERAGE 40,000)	30%	20%	?
	6+7. INTERMONTANE	4,000,000 180,000 5,000	20%	40%	35 % (1.3%)
	8. DELTA	220,000 190,000 ?	50%	FEW GIANTS	6% (1.5%)
	AVERAGE ALL BASINS	50,000 TO 100,000	50 %	50%	25% (1.5%)

* MIDDLE EAST

Figure 12-22b.--Yardstick for basin evaluation, intermediate basins reserves. In Type 6 and 7 basins, a higher estimate was given than calculated because of both the size and the virgin nature of untested offshore basins of this type which would, in effect, lower the risk of discovery and volumetrically increase the reserves for an individual basin. Although the present rate of giant reserves to nongiant reserves is 75 percent and 25 percent respectively, a factor of 30 percent to 42 percent was used for nongiant reserves.

In the past, 2 or 3 times the present reserves have been predicted as the ultimate resources of oil and gas, while recently it has been suggested that future resources may only be one-fifth of present reserves (North, 1974). As to these variations, it appears that to establish high estimates, it will be necessary to discover another Mideast and another West Siberia (which represent two-thirds of the world's giant reserves). This does not appear likely, considering the remaining untested basins of the world. One would look for a large, gentle basin filled with Mesozoic and Tertiary sediments. Remaining untested basins either lack the size or the character and age of the sediments and one is inclined to conclude that the long sought corollary to the Mideast will not be found. Deep oceanic areas, where basins of the oceanic crust exist, may have a potential for accumulation of this size; however, since these areas are untested and relatively unknown, it would be unsatisfactory at present to predict basins like the Mideast and West Siberia in the continental rise and ocean deeps. On the other hand, minimal future reserves predictions do not take into account the ongoing potential in the incompletely developed Mideast and West Siberia basin.

With regard to the magnitude of undiscovered and ultimate oil and gas resources, it should be noted that the method of recovery in estimation of recoverable reserves of major gas deposits is not as important as it is for oil. In the case of oil, if one assumes that it is economically feasible to recover more than half of the nonprimary, in-place oil by enhanced recovery methods, the addition of enhanced recovery involves only about 20 percent of the ultimate oil-and-gas-equivalent resources. Thus, more substantial changes of magnitude, which would range from 50 percent to 100 percent of the ultimate oil and gas resources, are critical (Fig. 12-23). Starting with a base of an ultimate of 2,500 to 3,000 x 10^9 barrels (341 to 409 x 10^9 metric tons) of oil equivalent and an undiscovered estimate of 1,000 to 1,500 x 10^9 barrels (136 to 204 x 10^9 metric tons) of oil equivalent, what are the conditions which might involve appreciable changes in estimates? Some of the changes suggested in this study, and there may be more, follow.

SUMMARY

Higher estimates of oil and gas resources have been made in the past than in this paper. In order for these estimates to increase by 50 percent or more:

1. One more of each of the Mideast and West Siberia basins, with their prolific reserves, must be found, requiring large basins of Tertiary and Mesozoic sediments to be present. Basins of such size with similar tectonic and sedimentary histories and age do not appear to be present.

The importance of giant fields, in any analysis of oil and gas accumulations, has a corollary in the presence of supersize reserves in two of the world's basins (Mideast and West Siberia). These super-reserve basins represent one-half of the world's reserves, whereas the remaining 64 basins with giant fields make up most of the remaining one-half of the world's reserves. The reserves in the largest basin of the remaining 64 basins may approach one-tenth of the Mideast reserves. If it is assumed that there are no more Mideast and West Siberia basins to be found it would require 276 basins similar to the reserves in the 64 basins mentioned above to double present reserves or 8 basins one-third the reserve size of the Mideast. To date no basin with the exception of West Siberia has approached one-third the size of the Mideast and since the earth is finite, there do not appear to be sufficient basins which would allow 276 basins to pass through the historical risk barrier (Fig. 12-21).

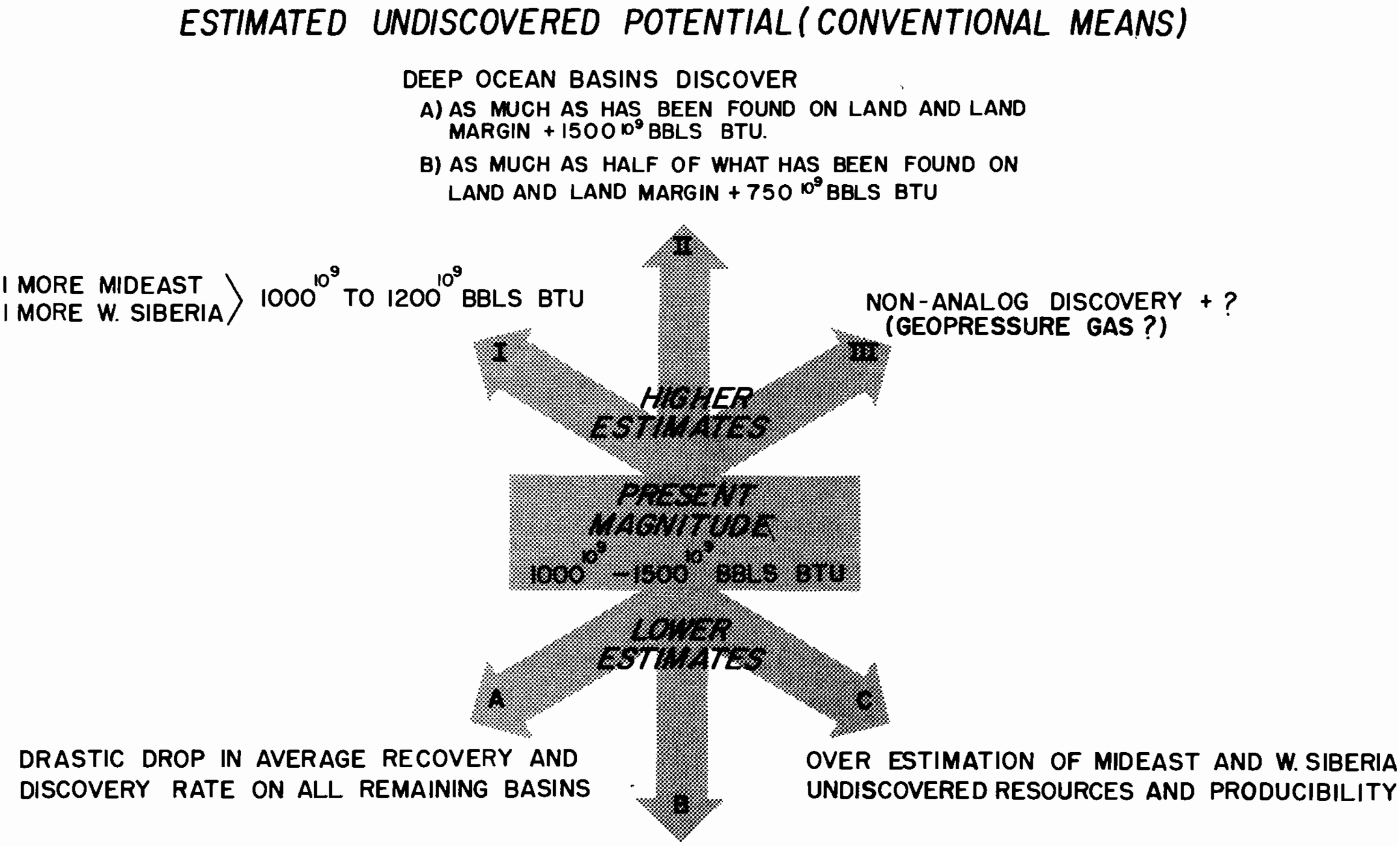


Figure 12-23.--World reserves--oil and gas

2. Deep ocean basins are untested and until more is known of them worldwide, ultimate reserve estimates are incomplete. Their reserve potential ranges from 0 to some unknown upper value.

3. If a nonanalogue type accumulation occurs (that is, a discovery of major oil or gas accumulation not similar to the geologic parameters of past accumulations) then a new trend of potential reserves might be established and a new dimension would be added to ultimate reserves. However, 95 percent of the giant fields and the great majority of the nongiant fields have been found on the basis of the anticlinal theory, which was formulated 90 years ago. Extensive drilling in the non-anticlinal portions of many North American and European basins or provinces has failed to establish any new trend which would significantly affect world reserves of conventional recoverable oil or gas. To date, the most significant nonanalogue type of accumulation appears to be the presence of large amounts of gas in geopressured formations. Whether these potential resources are recoverable by either conventional means or within economic limits is an unanswered question. In any event this nonanalogue type of accumulation and the prospect of deeper drilling might allow some upward revision of world ultimate gas resources, as has been noted in the last 10 years (Fig. 12-1).

Lower estimates are suggested by some recent studies (Mackay and North, 1974).

1. A drastic drop from the historically projected discovery and recovery rates on all remaining nonproductive and unexplored basins could alter the ultimate reserves. However, as many of these basins are relatively untested in offshore areas it is probably too early to downgrade their potential.

2. Present escalating exploration, development, and producing costs of oil and gas recovery in normal terrain, and the additional costs for more inaccessible areas on land and in the offshore and deep offshore appear to make the economics of recovery one of the most important factors on this chart. In the final analysis it is this factor, together with political

considerations, which will determine what percentage of ultimate reserves will be recovered.

3. An overestimation of future discoveries in the Mideast and West Siberia would affect the ultimate reserve figures. However, recent appraisals of the Mideast (Beydoun, 1975; Adams and Kirkby, 1975) suggest these estimates as reasonable.

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CHAPTER 13

GAS FROM CONVENTIONAL OIL FIELDS

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INTRODUCTION

Future petroleum reserves and productivity are dependent upon: (1) policies of the major petroleum producing countries; (2) cooperation between these countries and the petroleum industry; (3) present oil and gas reserves; (4) petroleum exploration; (5) exploration, drilling, and production research; and (6) technology development and application.

In the past, only those hydrocarbons occurring in the more porous and permeable formations were of commercial interest. However, following the energy crisis and with rapidly increasing petroleum prices, attention is being focused on all petroleum accumulations, and efforts are being made to apply, improve, and develop technology to permit economic recovery of these resources. This paper is directed to consideration of the future availability of natural gas from conventional oil fields.

PETROLEUM POLICY

On an international basis, there is a need for urgency and commitment by governments and industry to cooperate to remove restraints on petroleum exploration and exploitation. Simply stated, there is a need for fair market determination of resource allocation and investment decisions. Coupled with this, it is

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essential to have a stable, satisfactory economic and political climate. There is the need for positive incentives to expand exploration activities for which risk capital is sorely needed. This requires a fair return on total investment as well as anticipation of attractive earnings on current and future investments. Price incentives may partially provide the stimulus for such capital.

Complementing and supplementing these incentives, a consistent and stable policy directed to encourage accelerated development of petroleum reserves should be provided. Of particular importance are policy issues relating to leasing; environmental, conservation, and ecological impairment; production and product regulation; resource allocation, including import quotas; price regulation, including petroleum, materials, and labor; and taxation. The seriousness of the energy crisis necessitates practical trade-offs of such issues to achieve additional reserves and productivity. These trade-offs can be modified as the solution to the energy crisis evolves.

PETROLEUM RESERVOIRS

Oil and gas accumulations occur in underground traps formed by structural, stratigraphic, or a combination of structural and stratigraphic features. These hydrocarbons are contained in intergranular openings, joints, fractures, and solution cavities in sands, sandstones, limestones, and dolomites. That part of a trap in which oil or gas is contained in a hydraulically-connected system is called a reservoir. Another portion of the trap, called an aquifer, may contain water which is hydraulically connected to the reservoir. Since many reservoirs are located in large sedimentary basins they may have a common aquifer.

At initial reservoir conditions, the hydrocarbon fluid may be in either a single or two-phase state. If the fluid is a single-phase liquid all the gas present is dissolved in the oil. However, the single phase may be a vapor. If there are hydrocarbons in this gas phase which may be recovered as a liquid phase at surface conditions, the reservoir is called gas-condensate.

Due to the characteristics of petroleum and the pressures and temperatures prevailing during occurrence, migration, and accumulation, free gas, called a gas cap, may exist in the upper portion of the reservoir and be hydraulically connected to the oil, in an oil zone, located structurally lower.

Hence, due to the characteristics of the hydrocarbons and the reservoir pressure and temperature, a number of types of conventional oil and gas reservoirs may be identified. These are: (1) Oil reservoir: Undersaturated, Saturated; (2) Oil reservoir with associated gas cap; (3) Oil reservoir with associated aquifer: Undersaturated, Saturated; (4) Oil reservoir with associated gas cap and aquifer; (5) Gas-condensate reservoir: Nonretrograde, Retrograde; and (6) Gas reservoir.

Oil and gas move in the reservoir and to wells by fluid expansion, capillarity, natural or artificial fluid displacement, and gravitational segregation. In many reservoirs all of these mechanisms may be operating simultaneously. However, during any given period of the life of the reservoir one or more of these mechanisms may predominate naturally or due to artificial control. These mechanisms may be operative in all types of petroleum reservoirs identified previously. The objective of petroleum reservoir engineering is to utilize these mechanisms to achieve maximum economic recovery.

Four types of reserves initially could be estimated: (1) Free gas in the gas cap; (2) Recoverable liquid from the gas cap; (3) Gas dissolved in oil in the oil zone; (4) Oil in the oil zone.

However, at any time in the life of a reservoir, estimate of reserves could change not only due to acquisition of additional factual and production data, but also because of natural or artificial changes in the reservoir mechanism or engineering operation. This will be discussed below.

WORLD PETROLEUM RESERVES

From the foregoing, it is evident that the future availability of natural gas is dependent upon gas recovery from both natural gas and oil reservoirs. Table 13-1 has been prepared to show the World Natural Gas and Crude Oil Reserves as of January 1, 1975. At the present rate of consumption, these reserves represent a supply of gas and oil for 50 and 30 years, respectively. However, use of gas for pressure maintenance to increase oil recovery and the accelerated use of gas for manufacturing other products may seriously reduce the life of the natural gas reserves.

The total world reserves of natural gas of $2{,}147 \times 10^{12}$ ft^3 can be considered to be approximately 40 percent associated gas and 60 percent nonassociated gas. This is testimony to the fact that the future availability of natural gas from present reserves is dependent to a great extent upon future oil production and practices related to oil production.

Table 13-1 and supporting data used in its preparation permit the following observations:

1. Sixty-nine percent of the natural gas reserves are located in 5 countries; 82 percent are located in 10 countries.

2. Fifty-nine percent of the crude oil reserves are located in 5 countries; 80 percent in 10 countries.

3. Eighty-two percent of the natural gas and 80 percent of the crude oil reserves are located in 15 countries.

4. One hundred and nineteen natural gas fields, each with a reserve exceeding 1×10^{12} ft^3, contain 65 percent of the natrual gas reserves.

5. Eighty-three oil fields, each with reserves exceeding 1×10^9 barrels, contain 72 percent of the crude oil reserves.

6. Twenty-five oil fields, each with reserves exceeding 4×10^9 barrels, contain 52 percent of the crude oil reserves.

7. Seventy percent of the hydrocarbon reserves are located onshore or on the continental margins.

8. Over 85 percent of the hydrocarbon reserves are found in post-Permian sediments.

9. Of the hydrocarbon reserves, approximately 25 percent are found in sandstones, 25 percent in carbonates, and 50 percent in other types of rocks.

TABLE 13-1.--World petroleum reserves
(January 1, 1975)

	Natural gas ($10^{12}ft^3$)	Crude oil (10^9 barrels)		Natural gas ($10^{12}ft^3$)	Crude oil (10^9 barrels)
USSR	699.8	48.6	Libya	28.3	23.0
Iran	374.4	68.0	Iraq	27.5	35.1
USA	237.1	34.2	Abudhabi	24.9	26.4
Algeria	100.2	9.0	Norway	19.4	5.5
Netherlands	77.0	0.3	Burnei-Malaysia	18.2	4.7
Saudi Arabia	61.0	103.5	China	17.0	14.8
Canada	56.7	7.2	Pakistan	15.5	0.0
Neutral Zone	50.9	10.1	Indonesia	15.0	12.0
Nigeria	50.2	19.6	West Germany	12.5	0.5
Venezuela	42.9	14.6	Mexico	11.2	3.1
Kuwait	38.1	70.9	Others	139.1	33.1
United Kingdom	30.0	12.0	Total	2146.9	556.2

	Natural gas ($10^{12}ft^3$)	Crude oil (10^9 barrels)
North America, Total	305.0	44.5
Canada	56.7	7.2
Mexico	11.2	3.1
USA	237.1	34.2
South America, Total	42.9	14.6
Venezuela	42.9	14.6
Europe, Total	838.7	66.9
West Germany	12.5	0.5
Netherlands	77.0	0.3
Norway	19.4	5.5
United Kingdom	30.0	12.0
USSR	699.8	48.6
Africa, Total	178.7	51.6
Algeria	100.2	9.0
Libya	28.3	23.0
Nigeria	50.2	19.6
Asia, Middle East, Total	642.5	345.5
Abudhabi	24.9	26.4
Burnei-Malaysia	18.2	4.7
China	17.0	14.8
Indonesia	15.0	12.0
Iran	374.4	68.0
Iraq	27.5	35.1
Kuwait	38.1	70.9
Neutral Zone	50.9	10.1
Pakistan	15.5	0.0
Saudi Arabia	61.0	103.5

FUTURE PETROLEUM RESERVES

Much research has been done in the past in an effort to provide some basis for the prediction of the rate at which petroleum can be discovered and developed. Ordinarily, the historical rate of oil discovery is evaluated and it is concluded that the in-place volume of crude oil or natural gas discovered in the past may be related to drilling activity, through consideration of the number of exploratory wells and the total footage drilled per year. Past experience is based primarily on inland experience in a nonhostile environment. One immediately concedes that a relationship between future land and sea petroleum-resource potential is needed. Thus far, such a relationship has not been proposed for use on a worldwide basis. In limited areal studies, the conclusion has been that future reserve potential is equally divided between the inland and offshore areas. Certainly it is to be expected that drilling will proceed at a slower rate in offshore environments and implementation of resource development will be slower than inland.

It is very difficult to predict the future reserves and productivity of natural gas from conventional oil fields. Since the great portion of such gas is solution gas, a study of historical world crude oil reserves could serve as a basis for prediction. Analysis of these data indicate extremely rapid growth from 80 to 556 x 10^9 barrels during the period 1945 to 1975. However, during the period 1970 to 1975 crude oil reserves have varied only over a range of 520 to 560 x 10^9 barrels. This is evidence that under present international conditions, a crude oil, and hence an associated gas, reserve plateau has been reached. Associated gas increasingly is being used for pressure maintenance for the purpose of increasing oil recovery. This practice, together with the use of natural gas in product development, may result in decreasing associated gas reserves if new crude oil reserves are not found.

Associated gas reserve development is deterred by the rapidly increasing costs for drilling and completing wells. For inland wells the costs have nearly doubled ($13/foot to $25/foot in U.S.) during the past 10 years. Costs for offshore wells have increased from \$39/foot to over \$80/foot in the U.S. during the same period. These costs continue to rise at the same rate and there is no indication of leveling off.

Hydrocarbon price increases during the past 3 years have certainly offset some of the exploration and development cost trends. Crude oil price increases further encourage pressure maintenance and gas conservation. However, during the past 2 years, throughout the world, the value of natural gas is being recognized and in some areas has increased fourfold to \$2.00 per 10^3 ft^3 at the wellhead. This trend is expected to continue under present conditions. Experts believe that even in a free market with no restraints, the price will stablize at \$1.50 to \$1.65 per 10^3 ft^3.

Without question, any breakthrough in drilling technology could accelerate the rate of discovery of petroleum. Although drilling technology has steadily improved there have been no major innovations in the past 50 years. This is in spite of the expenditure of hundreds of millions of dollars in drilling research. Although many exotic drilling techniques have been proposed and are still being investigated, the rotary drilling technique still remains the most efficient and economic method for drilling in the earth's crust.

Assuming the most favorable economic and political climate, implementation of petroleum resource development requires at least a 5-year lead time. Geological and geophysical surveys must be conducted to identify favorable prospects; adequate funding and participation must be arranged; lands must be leased; drilling equipment must be acquired (or designed and built for special conditions); adequate manpower must be acquired and trained; well drilling and completion must be accomplished; production and transportation facilities installed; and product sales contracted.

Many consider that virtually all of the giant petroleum fields onshore have been discovered and that future inland discoveries will be confined to stratigraphic trap fields which are located most efficiently by drilling. Such field additions are expected to add ultimately to reserves and productivity.

However, what is needed are giant field discoveries which could complement immediately the needed petroleum reserves and productivity. The best prospects for such fields appear to lie in the offshore waters and remote inland areas. These areas remain relatively unexplored and should be the subject for accelerated geological and geophysical reconnaissance.

It is evident that urgent action is needed on a worldwide basis to formulate plans and initiate a program to provide a continuing reserve and production capacity for petroleum for use by society in the future. Such a program necessitates simultaneous action in the areas of expanded exploration for petroleum and application of the latest technology to increase petroleum recovery from present fields.

It appears that what should be done immediately is to commence exploratory drilling in all favorable areas simultaneously. However, this is not possible because of the limited number of drilling rigs and manpower which are presently available. Hence, it is necessary that undeveloped resource areas be evaluated and rated according to potential for success. There is also a great need for development drilling in fields already discovered. Decisions must be made as to assignment of drilling rigs to exploratory and/or development drilling. At this time virtually all drilling rigs are committed for the next few years. It is obvious that resource development can be accelerated by providing more drilling rigs and qualified manpower.

Assuming that expanded exploratory programs are developed, it is imperative that every effort be made to utilize our material and human resources to the fullest. In the sections that follow, the procedures, practices, and technology needed to maximize efficient use of these resources to increase petroleum reserves, productivity, and recovery are presented.

PETROLEUM EXPLORATION

Once a petroleum prospect has been drilled, the discovery well completed, and drilling of other wells commenced, it is standard practice to estimate the hydrocarbons in place, the expected hydrocarbon productivity, and the hydrocarbon recovery.

Increasing emphasis is being placed upon early estimates due to the increased costs experienced in deep drilling and in the more hostile environments, particularly offshore.

RESERVES ASSESSMENT

Hydrocarbons in-place are estimated first by the volumetric method. This necessitates use of surface and subsurface data to construct subsurface and isopachous maps. These maps are prepared using data from cores, downhole logs, and drill-stem and production tests. A subsurface contour map depicts the geologic structure by lines connecting points of equal elevation on the top of the marker bed. Isopachous maps show lines connecting points of equal net formation thickness (oil or gas). These two maps together are used to determine the bulk volume of the oil or gas reservoir. The accuracy of this estimate is primarily dependent upon the interpretation of net sand thickness and the identification of the reservoir boundary as defined by permeability barriers, fluid contacts, and faults.

For each well, little difficulty is experienced in estimating the gross oil or gas formation thickness of intergranular rocks from available data. However, such estimates for carbonate rocks, particularly those which are fractured and fissured, are extremely difficult. Assuming that the estimate of gross thickness is possible, the estimates of net formation thickness frequently vary over a wide range. This appears to be because fewer core analyses and drill-stem and production test data are being obtained today than in the past. Increasing reliance for fluid saturation estimates (oil, gas, and water) is being placed on downhole log interpretation. Often there are insufficient core-analysis data to permit calibration and/or correlation with downhole log determined results.

A high degree of sophistication in downhole log interpretation, through the use of fundamental rock and fluid property data utilizing high speed computers, has been developed. Techniques permit estimates of the gross formation thickness utilizing any desired porosity and/or permeability restriction (cut off). In turn, the net formation thickness (oil or gas) can then be calculated, assuming any desired value for oil or gas saturation as a cut off. The results of such calculations can be represented graphically in the strip log form utilizing computer data plotters and printing accessories.

The techniques for making such estimates are excellent. However, the input data for porosity, permeability, and saturation that are used in estimating the net formation thickness are ordinarily of insufficient quantity and quality to justify their use. Often such data are not available for a particular field and data from similar formations in other fields are used as the basis for the analysis. There is need for increased core analysis, drill-stem, and production data. Improved core analysis methods are needed particularly for fractured and fissured carbonate rocks. Research is needed to improve the accuracy of estimates made for rock and fluid properties using downhole logs, particularly at high pressures and temperatures.

The boundary of a reservoir may be determined by development drilling, which demonstrates permeability barriers, fluid contacts, and faults. However, it is preferable in the early life of a field to conduct constant-rate production tests or pressure build-up tests to detect the reservoir limits. In addition, pulse testing should be utilized as a means of evaluating reservoir heterogeneity. During the past 20 years a new technology in formation evaluation using well testing has evolved. New techniques continue to be developed permitting exploitation of the reservoir with fewer wells and at a lower cost.

Once the net formation thickness map has been prepared, porosity and hydrocarbon saturation maps are prepared. By superposition, pore volume and hydrocarbon volume maps are then prepared. The latter is planimetered and the oil in-place estimated. A preliminary estimate of the hydrocarbon reserves may be made using an oil recovery factor. However, in the early field development period there are insufficient data to justify confidence in the identification of the reservoir mechanism and, hence, the recovery factor. Early well testing could provide data to permit an approximation of well productivity.

Although early volumetric estimates provide an approximation of hydrocarbons in place and hydrocarbon reserves, confidence in such estimates is only achieved when complemented, supplemented, and verified by more detailed and sophisticated material balance, well productivity, and mathematical reservoir model studies. These methods are described below.

PETROLEUM EXPLOITATION

In conventional oil fields the natural gas of interest is that dissolved in the oil in the oil zone and occurring as free gas in the gas cap. In practice, the recovery of gas and its rate of recovery is dependent upon the characteristics of the oil (gas solubility and shrinkage), the reservoir rock properties (homogeneity, vertical and horizontal permeabilities, fluid saturations, relative permeabilities), well spacing, relative prices of oil and gas, and the reservoir drive mechanism. During the past 30 years increasing attention has been directed to laboratory and field research which would result in most efficient utilization of the reservoir drive mechanism to maximize petroleum recovery and productivity.

Results to date have led to identification of various types of reservoir mechanisms as follows: In an oil reservoir with no free gas cap, two initial reservoir conditions may be visualized, namely, a saturated reservoir and an undersaturated reservoir. In the latter, all gas is dissolved in the oil. Gas solubility in oil ranges from zero (a dead oil) to several thousand ft^3 per barrel.

Considering that the oil zone is initially filled with gas-saturated oil and connate water, upon fluid withdrawal from the reservoir, the reservoir mechanism may be one or a combination of different types. The most common mechanism in such a reservoir is a solution-gas drive. This type drive is characterized by a short period of high oil production at the initial solution-gas ratio, followed by a rapidly declining oil production rate and a rapidly increasing gas-oil ratio. Oil recovery by this mechanism is relatively low (20 to 40 percent of that originally present). Solution-gas production is rapid and gas recovery is relatively low. Free gas remaining in the oil zone and solution gas remaining in the residual oil is lost for all practical purposes. The magnitude of the loss is dependent primarily upon the oil recovery, since free gas must occupy the reservoir volume previously occupied by the produced oil, at the reservoir abandonment pressure. A potential source of additional gas reserves is from low-pressure crude oil and natural gas reservoirs. Research is needed to develop technology by which this resource may be recovered economically.

Another possible reservoir mechanism may develop when fluid withdrawal rates and reservoir rock and fluid properties are such as to permit segregation of the gas to form a secondary gas cap. Development of a secondary gas cap is accelerated by a high ratio of vertical to horizontal permeability and low fluid withdrawal rates. A secondary gas cap can also be developed artificially by injecting gas on the crest of the structure. The gas cap thus formed helps to maintain the reservoir pressure and prevents liberation of the dissolved gas from the oil. As a consequence, higher oil recovery (30 to 60 percent of oil originally present) and oil production rates are obtained than by solution gas drive. Although the gas recovery may be the same or greater than that obtained by solution gas drive, gas production rates are lower and gas production is delayed due to the accumulation of the segregated gas in the gas cap and the gas-invaded oil zone.

As mentioned earlier, oil zones filled with gas-saturated oil and connate water often have associated aquifers. Fluid withdrawal from the oil zone may induce water encroachment. The fluid withdrawal rates may be such that the rate of water encroachment may maintain the reservoir pressure. In such a case, high oil recovery (60 to 80 percent of oil originally present) is obtained at virtually a constant gas-oil ratio corresponding to the initial solution gas-oil ratio. The gas recovery and gas production rate is probably higher for this type of reservoir mechanism than for others.

However, in some water-drive reservoirs, fluid withdrawal rates, reservoir rock and fluid properties, and aquifer properties may be such that only a partial water drive develops and the reservoir pressure declines as fluids are withdrawn. Partial water-drive reservoirs yield oil and gas recoveries and productivities intermediate between solution-gas drive and water-drive, dependent upon the predominant mechanism. Obviously, a secondary gas cap could develop naturally in a partial water-drive reservoir and the recoveries and productivities would change accordingly.

Frequently, a petroleum reservoir containing gas-saturated oil in the oil zone has an associated free gas cap initially. In such a reservoir, fluids are withdrawn from the lower structural portion with a gas-cap drive mechanism prevailing. The gas cap helps to maintain the reservoir pressure, the larger the size of the gas cap relative to the oil zone, the greater the degree of pressure maintenance. The oil recovery and production rates and gas recovery and production rates correspond to those obtained in reservoirs which develop secondary gas caps.

Some petroleum reservoirs consist of a gas-saturated oil zone with an initial associated-gas cap and an aquifer. It is obvious that such a reservoir could be produced by a number of different reservoir mechanisms or a combination of mechanisms. In such a reservoir, production is generally regarded to be the result of a combination-drive mechanism. However, it will be recalled that oil and gas recoveries and productivities by water-drive are ordinarily the highest. Hence, efforts are made to control fluid withdrawals from the oil zone in such a manner that the water encroachment maintains a constant reservoir pressure and that the gas-oil contact remains at the same subsea datum. This is exceedingly difficult to achieve in practice. In an active water-drive reservoir with an associated-gas cap, the principal concern is to prevent displacing the oil from the oil zone into the gas cap. Withdrawal of gas from the gas cap would certainly encourage such migration. In the event that oil is displaced into the gas cap, the great majority of such oil is considered unrecoverable.

Undersaturated oil reservoirs with very active water drives (constant reservoir pressure) yield gas recovery approaching that of the initial solution gas. Hence, gas recovery is directly related to the residual oil saturation remaining after water encroachment. Laboratory research indicates that for any particular reservoir rock and fluid system there is an optimum reservoir pressure (and hence oil and gas saturation) at which oil and gas recovery is maximized. This implies that reservoir fluid withdrawals should be matched with fluid encroachment to achieve the desired pressure drawdown. In practice, this has been difficult to achieve due first to a lack of reservoir rock and fluid property data, and second to field operational problems.

From the foregoing, it is evident that a petroleum reservoir is a complex rock and fluid system in which natural and artificial energies must be controlled in order to achieve maximum economic hydrocarbon recovery and productivity. During the past two decades a high degree of sophistication in reservoir operations has been achieved. Mathematical simulation models have been developed for reservoirs which permit, when appropriate laboratory and field data are available, the identification of the natural reservoir drive mechanism, the estimation of the amount of initial hydrocarbons in place, and the prediction of the future performance of the reservoir utilizing the natural or an artificial reservoir drive mechanism. Early in the life of a reservoir, in the absence of sufficient data, assumed rock and fluid properties and reservoir drive mechanism, can be used for the simulation; the hydrocarbon recovery and the rate of recovery may then be predicted. These predictions can be compared with those obtained from the field, with time, and the simulator modified accordingly to match actual reservoir performance. Results obtained from this work may be used to plan the orderly development of a reservoir to achieve maximum hydrocarbon recovery and the greatest economic return on investment.

Reservoir simulation research is presently directed toward reducing simulation costs, particularly for heterogeneous (vertical and lateral) combination-drive reservoirs. However, there is still a great need for additional simpler, less expensive simulators for the more conventional types of reservoir-drive mechanisms. Practical utilization of the results from reservoir simulations is limited by the quantity and quality of the rock and fluid property and field data available. Due to the high costs of core and fluid analysis and downhole logging, increasing dependence is being placed upon the evaluation of such properties from production experience and build up or pulse tests.

SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

Natural gas reserves in conventional oil fields (associated gas) are derived from gas in solution in reservoir oil and from gas in associated-gas caps. These gas reserves are estimated to be 859 x 10^{12} ft^3 on January 1, 1975. Over 80 percent of these gas reserves are found in less than 100 oil fields, located in 15 countries.

Past experience inland leads one to believe that significant future gas reserves will be found offshore and in other unexplored areas of the world. Such exploration is hazardous, expensive, and risky and in addition largely dependent upon political and economic factors. There is an urgent need for expanded worldwide exploration and exploitation through provision for additional drilling equipment, materials, and qualified personnel. Increasing costs are impeding such efforts but petroleum price increases are partially offsetting these deterrents. Improved drilling and production technology is contributing greatly to increasing petroleum reserves. Field and laboratory research should be encouraged and financial assistance provided for these efforts on an expanded and continuing basis. The equipment and materiel shortages necessitate a comprehensive evaluation of petroleum potential, present and future, and the allocation of material and human resources to achieve the maximum rate of increase of petroleum reserves and productivity.

Future gas productivity and recovery is partly dependent upon policy decisions relating to leasing, protection of the environment from ecological impairment, conservation, personnel allocation, and capital and equipment availability. Further, it is dependent upon economic factors, including hydrocarbon production and product regulation; resource allocation, including its use in manufacturing valuable products, and as related to exports and imports; price regulation, including petroleum, materials, equipment, and labor; and taxation.

Associated gas production and recovery is directly related to increased oil recovery efficiency through pressure maintenance, using gas and water.

Since 80 percent of the associated gas reserves exist in less than 100 fields, every effort must be made to operate these fields in such a way as to optimize hydrocarbon recovery and achieve the desired economic realization. Petroleum reservoir engineering related to associated gas reservoirs is reasonably well established. Methods are developed already to estimate initial fluids in place, identify the natural reservoir drive mechanism, predict the future performance of the reservoir under natural and artificial drives, and estimate the petroleum reserves.

Certain restraints are imposed upon such estimates as follows: reservoir fluid sampling, core analysis methods, downhole well tests, production tests and interpretation, downhole logging methods, and log interpretation all need improvement; formation evaluation is reasonably sound for intergranular petroleum reservoirs but carbonate reservoir formation evaluation is inadequate; techniques are needed to identify and economically produce low pressure gas in reservoirs; and improved petroleum recovery from water-drive reservoirs is needed. It appears that these improvements can be achieved only through improved formation evaluation and production practices.

CHAPTER 14

GAS FROM CONVENTIONAL GAS FIELDS

Robert L. Whiting[1]

INTRODUCTION

The availability of natural gas from conventional oil fields is considered in Chapter 15. This chapter is directed to natural gas availability from conventional (nonassociated) gas fields, including gas-condensate reservoirs. Observations made in Chapter 15 relative to petroleum policy, petroleum reservoirs, world petroleum reserves, future petroleum reserves, and petroleum exploration are equally applicable to conventional gas fields; however, those observations are supplemented with information unique to conventional gas reservoirs.

WORLD PETROLEUM RESERVES

The world petroleum reserve of natural gas is estimated as $2{,}147 \times 10^{12}ft^3$ as of January 1, 1975. Of this total, $1{,}288 \times 10^{12}ft^3$, or 60 percent, is estimated to occur in conventional gas fields, and $859 \times 10^{12}ft^3$, or 40 percent, in associated gas fields.

Over the last 10 years, natural gas reserves have increased from approximately 868 to $2{,}147 \times 10^{12}ft^3$. An analysis of reserves information for this period shows that the major portion of the increase is attributable to the discovery of a limited number of large conventional gas fields in heretofore unexplored areas. The majority of these fields and reserves is located in

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the USSR, the remainder in the North Sea. From all evidence, the USSR, Middle East, China, and the offshore areas of the world appear to have the greatest potential for providing future gas reserves.

Ultimate crude oil recovery has been estimated, during the past 20 years, to be in the range of 1,500 to 3,000 x 10^9 barrels and natural gas recovery in the range of 5,000 to 10,000 x $10^{12}ft^3$. Irrespective of the magnitude of the estimate, most experts agree that approximately half of the recoverable crude oil has been discovered. The discovery of the remainder of this resource, and the rate of discovery, is largely dependent upon political and economic factors. Also, substantial quantities of oil now considered economically unrecoverable may be recovered through improved technology.

If estimated natural gas reserves are 2,147 x $10^{12}ft^3$, cumulative natural gas production is approximately 1,400 x $10^{12}ft^3$, and if these amounts represent about half of ultimately recoverable gas, then ultimately recoverable natural gas will approximate 7,000 x $10^{12}ft^3$.

If these estimates prove approximately correct, it may be expected that future reserve additions of associated gas will be about 1,500 x $10^{12}ft^3$ and of nonassociated gas, 1,900 x $10^{12}ft^3$. Further, about 30 percent of these natural gas reserves will be found offshore and 70 percent inland.

Based upon recent drilling and completion experience, average 1975 costs inland are approximately \$0.18 per 10^3ft^3 of natural gas reserve developed. Offshore costs are more than \$0.50 per 10^3ft^3. Peripheral acquisition and operation costs are not included. On this basis, the cost of development of an additional 3,500 x $10^{12}ft^3$ of natural gas reserves on land would exceed \$600 x 10^9. If 30 percent of the reserves are developed offshore, the cost would exceed \$1.00 x 10^{12}.

CLASSIFICATION OF CONVENTIONAL GAS RESERVOIRS

Conventional gas reservoirs have been characterized in many different ways but most commonly on the basis of the surface producing gas-oil ratio. Using this method, any well (or field) which produces at a gas-oil ratio in excess of 100,000 ft^3 per barrel of and is considered as a gas well; one producing with a gas-oil ratio of zero to several thousand, an oil well; and one producing at a gas-oil ratio of 5,000 to 100,000, a gas-condensate well. In practice, similar surface gas-oil ratios have been obtained for reservoirs containing a variety of hydrocarbon fluid compositions, existing over a wide range of reservoir pressures and temperatures, and producing with natural or artificial mechanisms. This has resulted in both technical and legal misunderstanding of the nature of conventional gas reservoirs. Therefore, the simplified classification described above is considered inadequate.

Conventional gas reservoirs should be defined upon the basis of the location of their initial reservoir pressure and temperature on the usual pressure-temperature (P-T) diagram, such as that shown in Fig. 14-1. The phase envelope is bounded by the dew point and bubble-point lines converging at the critical point. At all P-T conditions enclosed within these boundaries, two phases, vapor and liquid, coexist. Utilizing the P-T diagram, petroleum reservoirs may be instantly characterized as gas, gas-condensate, or oil. Considering an initial reservoir condition at A, the pressure history of such a reservoir by normal depletion would be along the path $A-A_1$. A single phase reservoir fluid (gas) would exist throughout the history of production. Also the composition of the fluid produced will remain constant. These conditions will persist for gas reservoirs having initial temperatures exceeding the cricondentherm. It is evident that the fluid produced at surface conditions may be single phase or two phase (shown by path $A-A_2$) depending upon the surface P-T conditions.

Consider next a reservoir fluid existing initially at P-T condition B. The fluid is single phase and is usually called gas since it exists at a temperature exceeding the critical point. Upon pressure reduction in the reservoir, along path $B-B_1-B_2-B_3$, the reservoir phase conditions would be successively single phase, two phase (vapor and liquid) and single phase (vapor). For such conditions to prevail, B must be located between the critical point and the cricondentherm. Within the

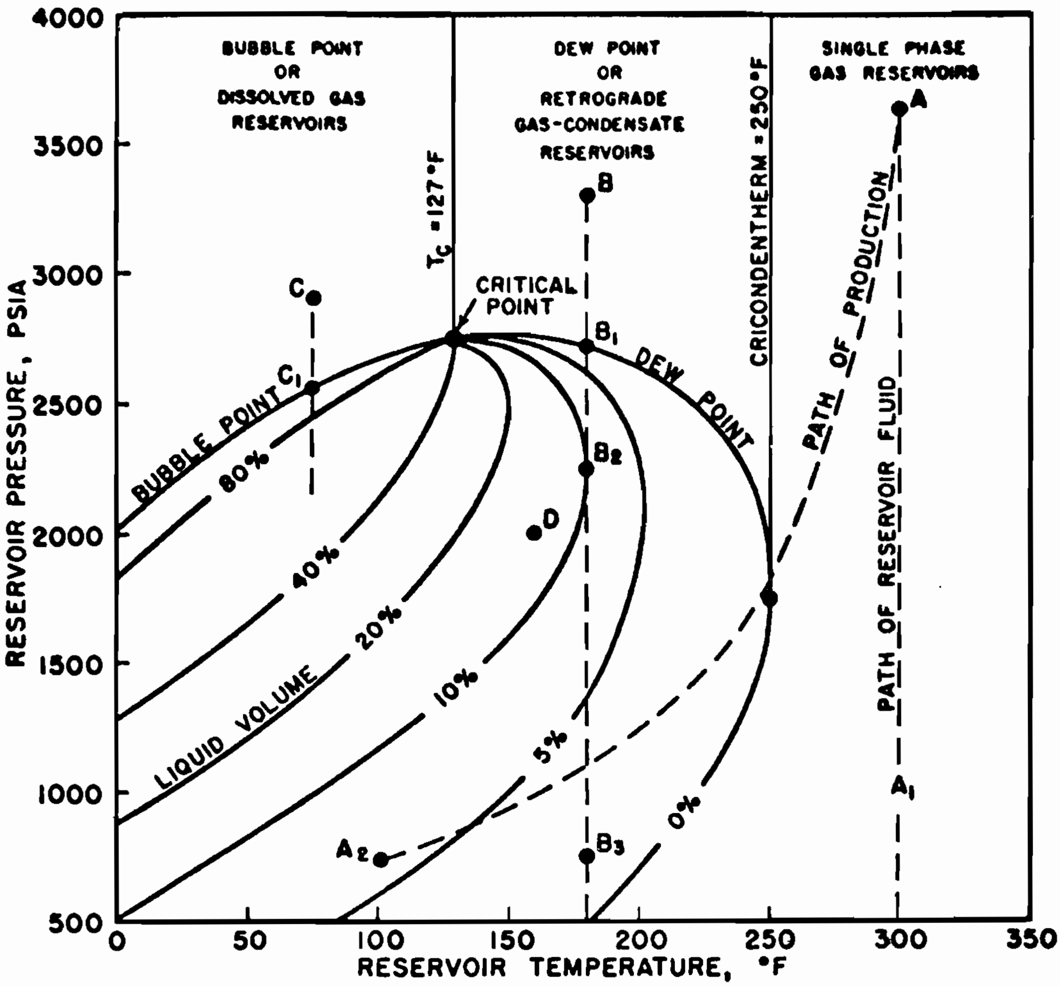

Figure 14-1.--Pressure-temperature phase diagram of a reservoir fluid

two phase region the maximum volume of liquid that will be condensed in the reservoir is dependent upon the initial reservoir fluid composition and the reservoir temperature. Along the path B-B_1 the composition of the produced fluid remains constant. However, as the reservoir pressure decreases due to fluid withdrawal, retrograde condensation occurs and liquid is condensed from the gas and accumulates in the reservoir. As a consequence, the composition of the produced fluid changes and is characterized by lower liquid content (higher gas-oil ratio). This retrograde condensation continues until a maximum volume of liquid is condensed. In some cases, a sufficient volume of liquid will be condensed in the reservoir to provide mobility of the liquid phase. In such cases the surface fluid composition is dependent upon the relative mobilities of the vapor and liquid in the reservoir. Unfortunately, as retrograde condensation occurs, the reservoir fluid composition changes, and the P-T envelope is shifted such that retrograde liquid condensation increases.

As reservoir pressure is reduced further along path B_2-B_3 revaporization of the retrograde liquid occurs and decreasing surface gas-oil ratios are observed. Generally for a particular initial hydrocarbon fluid, retrograde loss increases at lower reservoir temperature, higher abandonment pressure and for greater shifting of the phase envelope to the right.

Other possible reservoir fluid conditions are represented by initial conditions C and D, a single phase liquid (oil) reservoir and a two phase vapor-liquid (oil zone overlain by a gas cap) reservoir, respectively. The reservoir performance characteristics of these two type (associated gas) reservoirs have been discussed in the companion paper. However, attention is directed to the fact that in the gas cap type reservoir the gas cap may be either of the retrograde or nonretrograde type as illustrated in Fig. 14-2.

Hence, it is seen that conventional gas reservoirs exist initally in a single-state phase, ordinarily considered as gas. As fluid is produced from a reservoir, having an initial temperature above the cricondentherm, and reservoir pressure decreases,

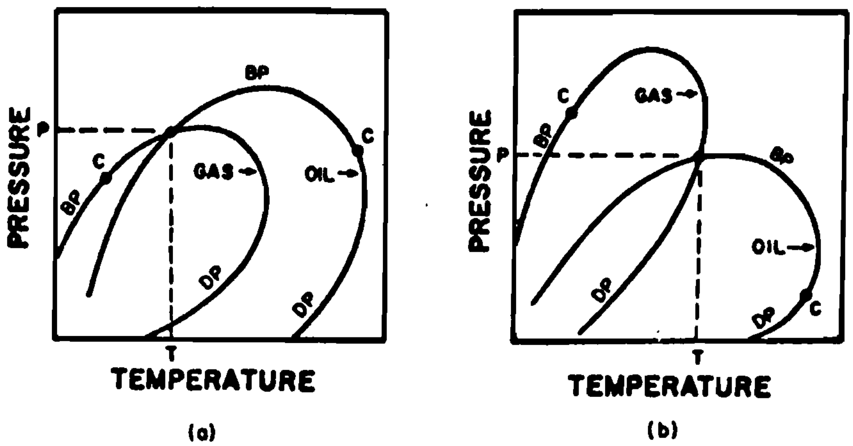

Figure 14-2.--Phase diagrams of a cap gas and oil zone fluid showing (a) retrograde cap gas, and (b) non-retrograde cap gas

the reservoir fluid remains single phase gas and the composition of the produced fluid remains constant. In a reservoir in which the initial reservoir temperature lies between the critical temperature and the cricondentherm, the reservoir fluid conditions will be successively single phase gas, two phase gas-liquid, and single phase gas upon adequate pressure reduction. The composition of the produced fluid will be dependent upon the relative mobilities of the gas and liquid in the reservoir.

VOLUMETRIC DEPLETION GAS AND GAS-CONDENSATE RESERVOIRS

The future availability of natural gas from gas reservoirs is dependent upon the initial volume of gas in place, the rate of production attainable, and the recovery efficiency. With respect to the estimate of the initial gas-in-place, the volumetric method is utilized in the early life of the field and is supplemented with more precise production test results and material balance estimates as additional laboratory and field data are obtained. The methods described in Chapter 15 for associated gas-in-place volumetric estimates are applicable to nonassociated gas reservoirs. However, in addition to the need for proper estimates of net formation thickness, areal extent, porosity, water saturation, and reservoir pressure and temperature, an accurate initial reservoir gas composition analysis is needed. Such analyses are used to estimate the gas deviation factor Z (compressibility factor). There has been limited research and very little data published on this gas property for gases containing such impurities as carbon dioxide, nitrogen, or hydrogen sulfide at elevated pressures and temperatures. Additional research is needed to establish the phase relationships for these impure hydrocarbon gases over a wide pressure-temperature-composition range. The need for such research is of greater urgency now than heretofore, because of need for some of these impurities for enhanced oil recovery operations as well as for other commercial value. Further, if these impure gases are to be exploited, research is needed to evaluate their effect upon equipment and the environment.

The estimate of initial gas-in-place using materials balance is perhaps the most accurate method available, provided accurate fluid property and fluid production data are available. In its simplest application, the ratio of pressure to the gas deviation factor (P/Z) is plotted against the cumulative wet-gas production (G_p). If the fluid production is composed of both hydrocarbon vapor and liquid, due to production controls, the vapor equivalent of the hydrocarbon liquid must be calculated and added to the dry-gas production to obtain G_p. To make this calculation, an analysis of the hydrocarbon liquid is required. Often water is produced with the hydrocarbons; if this is the case, a careful study is needed to ascertain if the water was initially in vapor or liquid form in the reservoir. Initial gas analyses assist in making this determination. Salinity tests of the produced water are also useful because saline water could indicate a liquid reservoir source. Sometimes it is necessary to make hydrocarbon-water phase studies in order to establish the amount of excess water vapor produced above the initial gas content. Any excess water should be treated as produced water and considered as liquid in the reservoir initially. If such data are not available, or their use inconclusive, the assumption is ordinarily made that the surface water is derived from reservoir water vapor. The vapor equivalent of the water liqud is calculated and added to the hydrocarbon wet gas volume to obtain G_p. If the resulting plot of P/Z versus G_p is linear it is ordinarily assumed that the relationship may be extrapolated to zero P/Z to obtain the estimate of the initial gas in place, G. Further, the reservoir mechanism is identified as volumetric depletion.

The reliability of the estimate of G is dependent upon the accuracy of the determination of reservoir pressure, gas deviation factor, and fluid production. Particular difficulty is experienced in obtaining representative reservoir pressure accurately in low permeability reservoirs, highly heterogeneous reservoir, highly fractured reservoirs, and reservoirs which are subjected to a wide range of rates of production, historically. In such cases, considerable time may be required to measure the reservoir pressure by performing various types of well tests, such as pressure build up. Often, production schedules do not permit time for such tests and considerable error may occur in the estimate of the reservoir pressure if based on limited build-up data.

Methods are well established for predicting gas productivity rates using periodic well testing. Initially, such tests may indicate formation damage and action is taken to alleviate this situation. Remedial workovers may be necessary during the life of the reservoir. However, in general, the rate of production for a reservoir is dependent upon the physical properties of the gas, heterogeneity of the reservoir, well spacing, reservoir pressure, and the practical pressure gradient that can be applied across the reservoir rock-fluid-well system.

Recovery efficiency for volumetric depletion reservoirs is relatively high, usually in the range of 80 to 95 percent. The recovery is dependent to a considerable extent upon the factors which affect production rate. Additionally, the price of gas and the abandonment P/Z ratio are controlling factors.

At the present time, there is much low-pressure, economically unrecoverable gas known in volumetric depletion reservoirs. Many such reservoirs are at shallow depths; are not located in close proximity to gas pipelines; and even in some cases where pipelines are favorably located the cost of gas compression equipment to boost the pressure to pipeline requirements is prohibitive.

WATER DRIVE GAS AND GAS-CONDENSATE RESERVOIRS

In many parts of the world, gas reservoirs are associated with aquifers as mentioned earlier. In some cases the aquifers contribute little or no energy to the gas reservoir and hence the reservoir mechanism can be considered as volumetric depletion. However, some of these aquifers are such that they contribute essentially all the reservoir energy for fluid production. Such gas reservoirs are commonly called water-drive reservoirs. In other cases the aquifer may provide only a portion of the energy necessary in fluid production and such reservoirs are classified as partial water drive.

Considering first the water-drive gas reservoirs, volumetric estimate of gas in place is made as discussed before. However, the water-oil contact must be established in addition to the other reservoir boundaries. This is done through the use of core, downhole log and well tests and analyses. In this type of reservoir mechanism it is impossible to estimate the fluids in place by material balance since the reservoir pressure remains constant and hence there is no change in the thermodynamic properties of the reservoir fluids.

Productivity is readily determined by production testing coupled with reservoir pressure surveys. In water-drive reservoirs, well spacing is critical in order to obtain the greatest influence of the water drive on total gas displacement. Further, close control of production operations, on an individual well basis, is necessary to trace the progress of the invading water and to plan remedial well workovers. Well testing to determine optimum production rates to achieve maximum macroscopic gas displacement and to minimize water coning should be made on a continuing basis. Under ideal conditions, production rates from this type reservoir are dependent upon the reservoir permeability to gas, the properties of the gas, and reservoir pressure gradients.

In gas reservoirs having active water drives, the recovery is dependent upon the initial connate water, the residual gas saturation in the invaded portion of the reservoir, and the portion of the reservoir pore volume invaded by water. Since the reservoir pressure remains constant, the abandonment pressure and the residual gas saturation exist at this pressure. Laboratory water flooding studies in homogeneous cores having a wide range of porosities, permeabilities, and initial gas saturations have yielded residual gas saturations from 10 to 75 percent. Heterogeneity, formation stratification, drainage pattern efficiency, and water coning or cusping will further reduce the gas recovery efficiency. Similarly, field experience with this type reservoir has produced disappointing recovery efficiencies in the range of 45 to 65 percent. Continuing efforts are being made to improve this recovery. For bottom-water drives, reservoir simulation research is being expanded in an effort to evaluate the factors affecting water coning and cusping. Similar research is directed to evaluation of the role of formation stratification in edge water drives on recovery efficiency. Remedial well research, including improved completion methods and formation shut off (use of plastics), is continuing and should contribute to increased recovery.

In many reservoirs having associated aquifers, the reservoir pressure declines initially upon fluid withdrawals and ultimately stablizes. At this time, the water encroachment is equal to the rate of fluid productions. Under these conditions the stabilized pressure is the abandonment pressure. In such a reservoir, the recovery is the sum of the recovery by essentially an active water drive to abandonment at the stabilization pressure. All other structure, rock, and fluid properties being equal, the recovery efficiency by partial water drive exceeds that of an active water drive simply because the residual gas trapped behind the invading water is at a lower pressure and hence represents a smaller volume at surface conditions. The productivity of partial water drive reservoirs exceeds that for volumetric depletion reservoirs but is less than that for active water drive reservoirs.

In summary, volumetric depletion reservoirs exhibit the highest gas recovery efficiency; active (ideal) water drives, the least; and partial water drives, intermediate. The magnitude of the latter is dependent upon the reservoir stabilization pressure relative to the initial reservoir pressure.

RETROGRADE GAS-CONDENSATE RESERVOIRS

The estimation of the gas in place by the volumetric method for retrograde gas-condensate reservoirs under volumetric depletion is identical to that used in such estimates for gas reservoirs. However, such an estimate by materials balance is considerably more complex and difficult since, during the life of the reservoir, two hydrocarbon fluid phases, gas and liquid, may be present in the reservoirs. To make the necessary calculations a laboratory pressure-volume-temperature analysis of the initial single phase reservoir fluid is needed. The reservoir conditions are simulated by placing the initial sample in a volumetric cell at the initial reservoir pressure and temperature and measuring the equilibrium volumes of vapor and liquid in the cell as the pressure is lowered successively by removing vapor from the cell. The volume and composition of each incremental amount of gas removed from the cell is measured. The liquid content of the produced gas may be measured directly in a scaled separator system or calculated from the composition for the appropriate field conditions using separators or a gasoline plant.

The volumetric depletion may also be calculated from the initial single phase reservoir fluid composition using equilibrium ratios. An equilibrium ratio for a hydrocarbon or hydrocarbon fraction expresses the relation between the mol fraction of that component in the vapor to its mol fraction in the liquid at a particular pressure and temperature for a particular hydrocarbon mixture. If appropriate equilibrium ratios are available, the relative volumes of liquid and vapor in the reservoir at any reservoir pressure and temperature may be calculated. Also, the composition of the produced liquid and vapor may be calculated. Equilibrium ratios for a wide variety of pressures, temperatures, and compositions are not readily available in the published literature. Additional equilibrium ratio data are sorely needed, especially for the heptanes plus hydrocarbons. However, techniques have been developed which permit approximation of equilibrium ratios for condensate systems from published equilibrium ratio data. Experience has proved that the calculated equilibrium ratios should be compared with laboratory data, even if of limited extent, to assure accuracy.

Using the laboratory P-V-T and the fluid productions under volumetric depletion, the gas recoveries and the liquid recovery at any reservoir pressure can be calculated. Hence, the initial gas in place and the recovery efficiency can be calculated. Experience has shown that such calculations are reasonably representative of field performance. In cases where there are differences, they have been ultimately traced to nonrepresentative initial reservoir fluid samples; difficulty in simulating laboratory cell and separation system to that of the field;

equilibrium ratios which are not applicable to the particular reservoir sample when this technique is used in estimations; reservoir heterogeneity and disproportionate fluid withdrawals from various parts of the reservoir.

Productivity from retrograde condensate volumetric depletion reservoirs is relatively high but not as great as that for gas-condensate reservoirs. Although, rarely does retrograde liquid flow in the reservoir because of its low liquid saturation, retrograde fluid saturation increases near the well bore due to the reservoir pressure gradient. Hence, there will be simultaneous flow of liquid and vapor, which may reduce the rate of gas-condensate production from the well.

Under proper operating conditions and usual abandonment pressures, the gas recovery ranges from 70 to 95 percent in retrograde gas reservoirs. However, due to the characteristics of the reservoir condensate and the difficulty of its revaporization, the liquid recovery ranges from 45 to 60 percent. Hence, the overall recovery seldom exceeds 80 percent and is often considerably less.

Like gas and gas-condensate reservoirs, retrograde condensate reservoirs may be produced under active or partial water drive. When such reservoirs are produced under an active water drive at constant initial pressure, retrograde condensation does not occur and the producing gas-oil ratios are constant. Recovery efficiency is dependent upon the same factors enumerated for active water drive gas reservoirs. Well spacing, reservoir heterogeneity, formation stratification, and water coning are major factors controlling recovery efficiency.

Partial water-drive gas-condensate reservoir productivity and recovery are quite similar to that of partial water drive gas reservoirs. However, at the stabilization reservoir pressure, not only is residual gas trapped in the water invaded zone, but also the retrograde liquid, which is ordinarily immobile at the low saturations.

In summary, the highest overall recovery for gas-condensate reservoirs is obtained by volumetric depletion and highest condensate recovery is obtained by active water drive. Intermediate overall efficiency is obtained by partial water drive which usually yields lower condensate recovery but higher gas recovery due to the lower reservoir stabilization pressure.

GAS CYCLING OF GAS-CONDENSATE RESERVOIRS

Since considerable quantity of condensate remains in retrograde-condensate volumetric depletion reservoirs at abandonment pressure, efforts are made to recover this valuable hydrocarbon. The most common practice is called gas cycling and consists of producing the gas-condensate liquid, stripping it of its liquid in a controlled series of separators or a gasoline plant, and returning the essentially dry gas to the reservoir. The reinjected dry gas, often supplemented with extraneous dry gas, assists in maintaining the reservoir pressure thereby reducing retrograde condensation. Further, through phase equilibrium, the dry gas may be enriched. Reinjection of the dry gas is continued until the dry gas reaches the producing wells and/or the operation becomes uneconomical. Thereafter, the reservoir is blown down to abandonment pressure to recover the hydrocarbon vapor and liquid remaining.

Production rates from cycling operations are highly predictable since it is normally equal to the rate of reinjection of dry gas. The productivities of the wet gas and dry gas, considered individually, are largely dependent upon the well spacing and the formation stratification. More specifically, microscopic displacement of wet gas by dry gas is ordinarily considered to be in the range of 65 to 95 percent. However, the areal and vertical sweep of the dry gas is dependent upon the well spacing, including skewed and irregular patterns, and also the dry gas injection and wet gas production rates of the individual wells. Modern practice is to model fields which are to be subject to cycling and establish optimum well spacings for injectors and producers and optimize rates of injection and production to maximize reservoir sweep efficiency. Under such circumstances, sweep efficiencies are in the range of 80 to 90 percent. Stratification is of serious consequence in many cycling operations and may jeopardize the success of the project if means are not taken to control its effect on the operation. As is evident, stratification factors may range from 0 to 100 percent. Ordinarily, if the stratification factor is less than 70 percent, the cycling operation is not considered practical.

In many cases, the combination of microscopic displacement efficiency, sweep efficiency, and stratification factor yields a condensate recovery of 45 to 65 percent. It is recalled that for volumetric depletion the condensate recovery is approximately in the same range. Further, cycling requires additional investment in wells, lease lines, liquid recovery plant, and compression equipment. Additional gas may need to be purchased and also the deferred income from the gas production may make the venture even less attractive.

In summary, it is evident that the decision to cycle gas-condensate reservoirs must be based upon detailed reservoir fluid and rock analyses; reservoir structural and boundary limits; reservoir simulation and performance studies; and economic considerations including accessory equipment necessary for the operation; the prices of gas and condensate and the deferred income from the gas.

SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

Natural gas reserves in conventional gas fields (nonassociated gas) are derived from dry gas, wet gas, and gas-condensate. These gas reserves are estimated to be $1,288 \times 10^{12} ft^3$ on Jan. 1, 1975, or 60 percent of the total gas reserves of $2,147 \times 10^{12} ft^3$. Sixty-five percent of these reserves are found in 119 fields, each with a reserve exceeding $10^{12} ft^3$.

Gas reserves increased by approximately 250 percent during the past 10 years, due primarily to the discovery of a limited number of large conventional gas fields in previously unexplored areas. During the past 5 years an apparent plateau in gas reserve additions has prevailed. From present evidence, the USSR, Middle East, China, and the offshore areas of the world appear to offer the greatest potential for providing future gas reserves.

The cumulative production of crude oil and natural gas to Jan. 1, 1975 is estimated as 350×10^9 barrels and 1,400 x

$10^{12} ft^3$, respectively. Upon the basis of these data, supplemented by geological and petroleum reservoir engineering studies, the writer estimates the ultimate crude oil and natural gas recovery to be 2,200 x 10^9 barrels and 7,000 x $10^{12} ft^3$, respectively. If these estimates prove correct it would be expected that future reserve additions of associated gas would approximate 1,500 x $10^{12} ft^3$ and nonassociated gas, 1,900 x $10^{12} ft^3$. Further, it is believed that 30 percent of these natural gas reserves will be found offshore and 70 percent inland. This implies that approximately half of the recoverable crude oil and natural gas has been discovered. Discovery of the remainder of this resource and the rate of discovery is primarily dependent upon political and economic factors. Hopefully, substantial quantities of known accumulations of petroleum, now considered uneconomic, may be recovered through accelerated and adequately funded technology research.

Based upon recent drilling and completion experience, average 1975 costs inland are approximately \$0.18 per $10^3 ft^3$ of natural gas reserve developed. Offshore costs are more than \$0.50 per $10^3 ft^3$. To this cost must be added peripheral acquisition, operation, and other costs which are highly variable, but for the sake of this illustration such costs will not be included. On this basis the cost of development of an additional 3,500 x $10^{12} ft^3$ of natural gas reserves on land would exceed \$600 x 10^9. Considering that 30 percent of the reserves would be developed offshore the cost would exceed \$1 x 10^{12}.

Petroleum reservoir engineering related to volumetric depletion nonassociated gas reservoirs is well established. Methods are developed to estimate initial fluids in place, identification of the natural reservoir mechanism, prediction of the future performance under natural and artificial drives, and estimation of petroleum reserves. Certain restraints are imposed upon such estimates and those restraints enumerated for associated gas reservoirs are applicable also to nonassociated gas reservoirs. Additionally, reservoir multiple fluid samples should be taken and analyses made for compressibility factors and phase relationships for hydrocarbon mixtures containing impurities over a wide pressure-volume-temperature-composition range. Routine whole-core analyses of carbonate reservoirs should be made until sufficient data are accumulated to characterize the section or to provide sufficient basis for calibrating down-hole well logs.

There is a need to develop techniques to identify and produce low porosity, low permeability, low pressure gas reservoirs.

There is an urgent need to develop petroleum reservoir engineering reservoir simulation techniques for carbonate reservoirs for the purpose of predicting hydrocarbons in place, productivity, and recovery. The state of this art is in its infancy and is deserving of expanded attention and research funding.

Retrograde gas-condensate reservoirs pose a problem since under present conditions cycling is usually uneconomic. Although gas processing and compression equipment is expensive the deferred income from the reinjected gas is frequently the critical factor. Replacement of hydrocarbon dry gas with a suitable substitute fluid appears to be a possible solution.

CHAPTER 15

THE POTENTIAL CONTRIBUTION OF SMALL OIL AND GAS DEPOSITS

Richard F. Meyer[1]

INTRODUCTION

At the end of 1975, world proved recoverable reserves of natural gas amounted to 2,232 x 10^{12} ft^3, of natural gas liquids, 45 to 70 x 10^9 barrels, and of crude oil, 659 x 10^9 barrels (Oil and Gas Journal, 1975). These are large amounts and do not include undiscovered conventional oil resources estimated by Moody (1975) at 600 to 1,400 x 10^9 barrels, or possible supplies from such sources as oil shale, synthetic liquids or gases from coal, or oil from tar sands. With respect to world demand, these supplies are physically sufficient for the balance of this century. This does not account, however, for the uneven world distribution of supply and demand. The United States, for example, has about 33 x 10^9 barrels of proved crude oil reserves, produces about 3 x 10^9 barrels per year, and must import about half of its annual requirements. For many other countries the supply inequalities are much larger; therefore, all possible supply sources require careful examination. One such source is the quantity of oil and gas found in small deposits which, in the past, may or may not have been economically producible. Such supplies, individually small though they may be, are, in the aggregate, significant. Their importance is great to those countries having small internal supply and presently small requirements.

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In the United States many factors tend to inhibit the search for oil and gas; prominent among them is the regulation of the average price of crude oil at about 70 percent of world price and, on the basis of heat value, natural gas at about 25 percent. As a result, the count of seismic crews has been declining at 13 percent annually for the past several years, and exploratory wells as a percent of all wells have declined at about 12 percent annually. Consequently, domestic U.S.-marketed natural-gas production and crude-oil-plus-condensate production are declining at annual rates of 8.5 and 6.5 percent, respectively.

Price controls may not be the sole controlling factor in the decline in new oil and gas supply. The inability to find large deposits leads companies to look elsewhere than exploration for investment opportunities. Additional uncertainties relate to environmental considerations, especially with regard to offshore leasing programs.

About 1,000 oil fields in the United States with production of at least 300,000 barrels per year account for about 85 percent of total domestic production at this time. This means that about 16,000 small deposits of oil contribute about 15 percent of the oil produced annually in the United States.

DEFINITIONS

The American Association of Petroleum Geologists defines a small deposit as one containing producible reserves at time of discovery of less than 1×10^6 barrels of oil, at an assumed rate of recovery of about 33 percent, or less than 6×10^9 ft^3 of gas, at an assumed recovery of about 80 percent. However, for present purposes, this definition is broadened to include deposits of less than 10×10^6 barrels of oil or 60×10^9 ft^3 of gas.

SIZE DISTRIBUTION OF DEPOSITS

Although this paper is directed principally at those deposits containing original recoverable reserves of 10×10^6

barrels or less, it would be remiss not to consider the potential of older fields of any size that are in an advanced state of decline. Generally, the wells in such fields are termed stripper wells because they are capable of producing a field average of no more than 10 barrels daily per well. In 1974, about 366,000 such wells in the United States produced an average of slightly more than 3 barrels per day, for a cumulative total of 412×10^6 barrels, or about 13 percent of United States production (IOCC, 1975). Such wells have a remaining reserve of about 4.9×10^9 barrels, and about 40 percent of these reserves are in fields under secondary recovery. These are significant data, the importance of which has been underscored by Pederson (1974). Increased price/cost ratios since 1973 have helped to arrest the decline of stripper-well production, which is particulary sensitive to such ratios. Pederson estimated that an average price/cost ratio of 5.02, as much as 412×10^6 barrels of additional domestic production would be available over the 1973 to 1980 period at a 10 percent-decline rate. With production at a 5 percent decline, the additional oil would amount to about 588×10^6 barrels during the same period.

The American Association of Petroleum Geologist reports the results of North American drilling activity annually (Johnston, 1976). An estimate is made of the size distribution of new-field wildcat discoveries, which is reviewed and updated after each 6-year interval of development and production experience. The 149,215 new-field wildcat wells drilled in the 25-year period 1945 to 1969 resulted in 1,442 oil discoveries with reserves in the 1 to 10×10^6 barrel range and 325 with reserves in excess of 10×10^6 barrels. Together these represent only 1.2 percent of new-field discoveries. Likewise, these wildcats resulted in the discovery of 1,013 gas fields in the 6 to 60×10^9 ft^3 category and 390 gas fields of larger size. The new-field finding rates are fairly consistent over this time and suggest that new-field exploratory wells will continue to result in the finding of an inventory of small but significant fields that may serve as future targets for enhanced recovery through applicable stimulation techniques.

The following perspective on United States oil and gas reservoirs is derived from the U.S. Geological Survey oil-and-gas field data bank. The data are based on cumulative production through 1973, because insufficient information is available on ultimate recovery; the general results obtained on a cumulative production basis, however, permit some valid conclusions.

Small oil fields (those with less than 10×10^6 barrels of reserves) have contributed about 17 percent of total United States crude oil production to date. The average such reservoir is at a depth of 5,400 feet, contains oil at 38° gravity API, and has average oil saturations of about 20 percent. In 1973, the average annual production from the small fields was about 39,000 barrels. The reservoirs are 31 percent carbonate rocks and the remainder clastic. About 34 percent of the production is obtained from depths of less than 4,000 ft, 48 percent between 4,000 and 8,000 ft. In age, the production is 31 percent Tertiary, 13 percent Mesozoic, and the balance Paleozoic, mostly Permian and Pennsylvanian.

It is less easy to categorize small gas deposits in this way because unknown amounts of gas were vented and flared in the past; however, over the past 20 years, very little gas has been so wasted. About 10 percent of past production is estimated to have come from small gas deposits. In 1973, the average small nonassociated gas deposit produced about 6×10^9 ft^3, and the associated gas deposits, somewhat more. This suggests the importance of small gas deposits as an adjunct to the associated oil fields. Small gas reservoirs are at an average depth of 6,300 ft and 90 percent are in sandstones, the rest in carbonates. Depth ranges differ from those of small oil deposits, 17 percent of production going from less than 4,000 ft, 41 percent, from 4,000 to 8,000 ft, and 38 percent, below 8,000 ft. Two-thirds of the production is from rocks of Tertiary age; the bulk of the balance is from Cretaceous and Pennsylvania strata. The preceding data express past and present experience with the size distributions of small deposits.

Kaufman et al. (1975) stated that future exploration activities will be the result of the discovery process (e.g., surface reconnaissance, magnetic, gravimetric, and seismic surveys) and acts (drilling of exploratory wells) that culminate in the discovery of petroleum deposits. These authors then described a probabilistic model of oil and gas discovery, an essential element of which is the predicted field-size distribution. They correctly pointed out that the smallest size field found must be large enough to include oil in reservoirs producible at prices greater than those pertaining at the time of estimation. These criteria will allow for future advances in price and technology. In any case, it seems certain that in virtually any place in the world, the discovery process will result in the finding of many more small than large deposits. It is the role of these small deposits that is of importance to this paper which attempts to define their potential resource contribution, once discovered.

ABANDONED RESERVOIRS

The oil and gas field data file yielded information on 12,310 abandoned oil reservoirs. Cumulative average production of about 195,000 barrels of oil was obtained from each of these reservoirs, but of the total, only 31 reservoirs produced as much as 10×10^6 barrels. The abandoned reservoirs that produced less than 10×10^6 barrels are not likely to be considered for redrilling on the basis of improved economics and advanced technology. Some might be considered for recompletion if the casing and tubing has not been pulled or, if it has, if the condition of the hole is still favorable. In addition, these reservoirs would have to be evaluated to determine remaining oil-in-place. If the reservoirs had been artificially fractured or had undergone enhanced recovery processes before the wells were abandoned, there is little likelihood that the wells could be commercially recompleted and produced.

DEVELOPMENT FACTORS

In general, a deliberate search for small deposits is not made. However, the search for large deposits generally leads to the finding of small ones; therefore judgments must be made as to the economic producibility of the small deposits. As a result, the potential resource contribution of small deposits relates to whether they will be found and, if so, whether they will be economically and technologically exploitable. Some of the exploitability factors follow.

Transportation Network

In an established producing province major transportation networks almost invariably exist, so that a small deposit requires only gathering of the oil, either by pipeline or truck. In remote areas, however, even a large number of small discoveries may not be sufficient to justify major trunklines; and it may not be feasible to gather the oil by other means, such as trucks. This was the case in northern Alaska until the discovery of the giant Prudhoe Bay field.

Sunk Costs

In many areas, small fields have been discovered that may not be more than marginally producible but that may be so located that the operator will complete a well in an effort to recover some costs and to enhance his crude oil or gas supply. Even more important are marginal wells in fields experiencing long decline, particularly when an increase in price enables continuation of production beyond the previous cut-off point (economic limit rate) on the decline curve.

Price of Oil and Gas

Oil and gas selling price is probably the most important factor in gauging whether or not to place a small deposit on production. The price/cost ratio is a factor in the search process itself, but discovery of a small deposit influences judgment on potential profitability and, therefore, whether or not to place the deposit on production. Such judgment is based on reservoir engineering, amount of oil in place, artificial stimulation, and enhanced recovery possibility.

Gas-Oil Ratios

Many small oil reservoirs contain dissolved gas which may be a factor in the economic viability of a field. Sly (1974) has described a compressor that operates off the oil pumping unit of a well and enables capture of the otherwise vented or flared gas. When the gas/oil ratio is high, the gas is an important increment to the energy supply and thus to the profit of the well.

Offshore Fields

In offshore areas, small fields are the least likely to make an important (if any) contribution to supply. According to Lewin & Associates (1976), a 10×10^6 barrel field may be producible in water depths of as much as 100 ft at current oil prices and with an 8 percent discounted-cash-flow (DCF) rate of return. At greater water depths and with higher DCF rates of return, small fields probably will not be economic because of the high front-end capital requirements. In any case, 10×10^6 barrels of recoverable reserves appears to be the offshore limiting factor, even at foreseeable higher oil prices; elimination of bonuses, royalties, and taxes might reduce this to 5×10^6 barrels.

Enhanced Oil Recovery

It is ordinarily most effective to begin enhanced oil recovery (EOR) concurrently with primary production. If a 10×10^6 barrel field represents 30×10^6 barrels of original oil in place (with 33 percent recovery), than an attractive amount of oil in place remains as a target for EOR methods. Geffen (1974) estimated that as much as 59×10^9 barrels of oil might be produced by EOR from the remaining oil in place in known U.S. deposits. How much of this oil may eventually be recoverable by known methods or what part actually resides in small fields is unknown. Because most EOR projects are aimed at large fields and because special reservoir characteristics are required for these methods to be successful, the net contribution from the smaller deposits has not been estimated. Perhaps 5 to 10 x 10^9 barrels is a reasonable guess. However, the fact is that most EOR methods, and particularly thermal recovery, could be applied to small deposits where proper reservoir conditions and economic incentives exist. Such incentives would have to be sufficiently large to outweigh the added EOR costs, e.g., compressors for steam drive; CO_2 gas for CO_2 drive; and chemicals for surfactant/polymer and polymer-waterflood drives. Lewin & Associates (1976) described the dimensions of production untis for five EOR methods as follows:

Method	Acres	Production Wells	Injection Wells
Steam drive	2.5	1	0.8
In situ combustion	20	1	.3
CO_2 miscible	40	1	.8
Surfactant/polymer	5	1	.8
Polymer	40	1	.5

SUMMARY

This paper is intended to outline some of the supply possibilities from small oil and gas deposits. Given that small deposits will continue to be found, the critical factor becomes one of economics and technology related to their recovery. As world prices of crude oil continue to rise, the exploitation of small deposits becomes more feasible. Small deposits certainly will become more attractive in those areas where demand is high and supply is limited. The smaller deposits can make a relatively more important contribution to demand where supply is limited than is the case in the more prolific producing countries where supply is abundant.

Although the examples used have related to the United States experience, the data may be applied anywhere in the world. As the search goes on elsewhere, field-size distributions and finding rates will not vary importantly from the United States model. For this reason, the chart prepared by Grossling (Chapter 2) is immensely significant. On the chart, the estimated 26.1 x 10^6 mi^2 of petroleum-prospective areas of the world are

depicted in areal proportion. Each solid circle on the chart represents 50,000 boreholes. Relative to the United States, every other area in the world is underdeveloped in terms of exploratory and development drilling. Should each of these other areas attain the petroleum maturity of the United States, they would show similar oil and gas distributions, including a preponderance of small deposits. Although those exploring for petroleum in any country prefer to find giant fields of 1,000 x 10^6 barrels of recoverable reserves, it may prove more rewarding to think in more realistic terms of petroleum systems based upon large numbers of small deposits.

Muslimov and Akhmedzvanon (1975) have described an example of the future role of small fields. In the Tataria area of the USSR, a mature petroleum area, production is declining so that of 77 oil fields not now in production, over half are small by present definition. To produce them efficiently the fields have been grouped according to structural position, geologic age, and proximity of the fields, and production programs devised based upon reservoir parameters that are averages for each group as a whole.

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CHAPTER 16

PETROLEUM POTENTIAL OF SEDIMENTARY BASINS IN THE DEVELOPING COUNTRIES

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INTRODUCTION

World petroleum production in 1975 totaled 2.7×10^9 tons of oil and 1.2×10^{12} m^3 of natural gas. Although these figures are slightly down from the 1973-1974 level, they are expected to rise as high as $6\text{-}6.5 \times 10^9$ tons of oil and $2.5\text{-}3 \times 10^{12}$ m^3 by the end of the century. The main oil producers are the developing countries of Latin America, Africa, the Middle East, and South-East Asia; at present they account for 60 percent of world crude oil production, and they apparently will keep that leading position in the future. The developing countries' share of world marketable gas production is 10 percent, and of gross natural gas production (gas losses included), about 20 percent. The share of developing countries in world gas production will undoubtedly increase simultaneously with expansion of worldwide trade of gas in liquefied form or by pipelines.

In this aspect, it is important to estimate the total petroleum resources of large sedimentary basins in the developing countries, and future prospects for oil and gas production.

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LATIN AMERICA

This vast region is situated between the North American platform on the north, a system of deep-water trenches of the Pacific Ocean on the west, and the Atlantic thalassocraton in the east. The largest part of it is occupied by Brazilian and Patagonian platforms, framed by folded structures of the Andean Cordillera, and Antilles-Caribbean geosyncline. Within that region more than 60 sedimentary petroleum-bearing basins are identified, which consist of depressions filled with marine, coastal marine, volcanic, and continental deposits of the Phanerozoic.

The basins are combined into four principal groups, according to structural type: interplatform, intermountain, transitional from platforms to folded areas, and transitional from continental to ocean structures.

By the beginning of 1976, commercial oil and gas fields had been discovered in 24 basins. The most prolific in terms of estimated proved reserves and annual production are Maracaibo, Orinoco, and Gulf of Mexico basins. About 1,250 oil and gas fields have been discovered, among them such large fields as Lagunillas, Tia Juana, and Bochaquero (Bolivar zone) in Venezuela. Each of these large fields contains more than 500 x 10^6 tons, and reserves of 20 fields surpass 100 x 10^6 tons of oil and 100 x 10^9 m^3 of gas.

Initial (original) potential geological (in-place) hydrocarbon resources of all the sedimentary basins of Latin America (including adjoining areas of Pacific and Atlantic Oceans and Caribbean Sea) are estimated to be 444 x 10^9 tons (in oil equivalent). The recoverable part of resources (with known methods of field development) accounts for 210 x 10^9 tons, including 84 x 10^9 tons of oil and natural gas liquids (NGL), and 116 x 10^{12} m^3 of gas. The resources are evenly distributed among prospective areas of land and continental shelf and slope (Table 16-1).

More than 60 percent of hydrocarbon resources (in oil equivalent) confined to sedimentary basins are located at the junction of continental and ocean structures. The significant

TABLE 16-1.--Initial potential recoverable petroleum resources of sedimentary basins in the developing countries (oil and NGL in 10^9 tons, gas in 10^{12} m^3)

Regions	Onshore		Shelf		Slope		Total	
	Oil and NGL	Gas	Oil and NGL	Gas	Oil and NGL	Gas	Oil and NGL	Gas
Latin America	32	43	32	37	30	36	94	116
Africa	45	24	25	20	30	21	100	65
Middle East	81	21	30	9	1	1	112	31
South and Southeast Asia	17	11	23	14	16	9	56	34
Total	175	99	110	80	77	67	362	246

part of the resources (about 19 percent) belongs to Subantilles-Subandes belt, i.e., the junction of ancient platform and folded structures. Intermountain basins of the Andes, Cordillera, and Antilles contain about 14 percent, and interplatform basins of Brazilian and Patagonian platforms, only 6 percent of hydrocarbon resources.

A very substantial quantity of oil and gas resources exists in offshore areas. The total prospective area of shelf covers more than 3×10^{12} km^2. The most prospective areas for petroleum exploration are located in submarine prolongation of sedimentary basins of the Atlantic and Caribbean coasts, which account for 90 percent of hydrocarbon resources of Latin America shelf zone.

By the beginning of 1976, proved recoverable reserves of 11.6×10^9 tons of oil and NGL and 4.4×10^{12} m^3 of gas had been discovered and 6.6×10^9 tons of oil and 1.9×10^{12} m^3 of gas had already been extracted. The remaining proved recoverable reserves amount to 5×10^9 tons of oil and 2.5×10^{12} m^3 of gas (Table 16-2).

Thus, to the present time, the exploration rate of initial potential recoverable resources (IPRR) of this region is 12 percent for oil and 4 percent for gas, and the extraction rate of IPRR is 7 percent and 2 percent respectively.[2] For oil resources on land, the exploration rate is 22 percent and rate for gas resources is 5 to 6 percent on land as well as on the shelf, and the extracted quantity is small. Deep water areas have not yet been touched by exploration.

AFRICA

The main part of the continent is occupied by the ancient African-Arabian platform. More recent folded structures are

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[2] $$\text{Exploration rate} = \frac{\text{Proved reserves + cumulative production}}{\text{Initial potential recoverable resources}}$$

$$\text{Extraction rate} = \frac{\text{Cumulative production}}{\text{Initial potential recoverable resources}}$$

TABLE 16-2.--Proved reserves, cumulative production, and undiscovered reserves of petroleum in the developing countries at 1.1.1976 (oil and NGL in 10^9 tons, gas in 10^{12} m^3)

Regions	Remaining proved reserves		Cumulative production		Undiscovered reserves	
	Oil and NGL	Gas	Oil and NGL	Gas	Oil and NGL	Gas
Latin America	5.0	2.5	6.6	1.9	82.4	111.6
Onshore	3.3	1.3	4.2	1.1	24.4	40.6
Shelf	1.7	1.2	2.4	0.8	28	35
Slope	-	-	-	-	30	36
Africa	8.7	5.9	2.7	0.4	88.6	58.7
Onshore	6.0	5.0	2.3	0.3	36.6	18.7
Shelf	2.7	0.9	0.4	0.1	22	19
Slope	-	-	-	-	30	21
Middle East	50.1	15.2	11.6	1.4	50.3	14.4
Onshore	41.1	13.2	10.4	1.4	29.3	6.4
Shelf	9.0	2.0	1.2	-	20	7
Slope	-	-	-	-	1	1
South and Southeast Asia	2.6	2.1	1.2	0.3	52.2	31.6
Onshore	2.2	1.1	1.1	0.3	14.2	9.6
Shelf	0.4	1.0	0.1	-	22	13
Slope	-	-	-	-	16	9
Total	66.4	25.7	22.1	4.0	273.5	216.3
Onshore	52.6	20.6	18.0	3.1	104.5	75.3
Shelf	13.8	5.1	4.1	0.9	92.0	74.0
Slope	-	-	-	-	77.0	67.0

Source: Table 16-1 plus "Oil and Gas Journ.," 1974, 1975, "Twentieth-century petroleum statistics," 1974, Dallas.

situated in the northwest and south parts of the region. There are broad depressions within the platforms, with relatively thin sedimentary cover (Taudeny, Maly-Niger, Okavango, Kalahary).

In the north part of the Sahara plate several large depressions and the Mediterranean pericratonal trough form the single Near-Mediterranean area of accumulation of sediments of great thickness. The Near-Indian and Near-Atlantic subsidence areas, along the east and west peripheral parts of the platform, are step-like, plunging toward the two oceans. Within three above-mentioned, near-ocean areas and interplatform depressions about 40 petroleum-bearing basins are defined. The largest of them in terms of estimated proved reserves and annual oil and gas production are the Sahara-Libyan, Gulf of Guinea, Quanza-Cameroons, and Gulf of Suez basins.

By the beginning of 1976 in Africa over 500 oil and gas fields had been discovered, including 20 fields with recoverable reserves more than 100 x 10^6 tons of oil and 100 x 10^9 m^3 of gas. The giant oil fields, Hassi-Messaoud (Algeria) and Sarir (Libya), contain 714 and 216 x 10^6 tons, respectively, and Hassi R'Mel gas-condensate field (Algeria) contains more than 1.9 x 10^{12} m^3 of gas. About 60 percent of all fields in Africa, including giants, have been discovered in Sahara-Libyan basin.

Estimates of initial potential hydrocarbon resources of all sedimentary basins of Africa, including adjacent parts of Atlantic and Indian Oceans and Mediterranean Sea, totaled 423 x 10^9 tons (in oil equivalent), and the recoverable part (with present methods of field development), 165 x 10^9 tons (100 x 10^9 tons of oil and NGL and 65 x 10^{12} m^3 of gas). About 42 percent of petroleum resources is confined to the prospective parts of land basins, and the other part is evenly distributed between the shelf and continental slope areas (Table 16-1).

Almost 99 percent of African petroleum resources is found in basins located at the junction of continental and ocean structures. The largest portion of the petroleum resources (more than 40 percent) is concentrated in sedimentary basins of the northern (Near-Mediterranean) subsidence area. The other part is distributed mainly between the basins of western and eastern near-ocean areas.

Vast internal synclines of African platform and narrow troughs of the East-African rift system contain only 1 percent of all the hydrocarbon resources of the continent.

By the beginning of 1976, 11.4 x 10^9 tons of oil and NGL and 6.3 x 10^{12} m^3 of proved gas reserves had been discovered; 2.7 x 10^9 tons of oil and 0.4 x 10^{12} m^3 of gas had been extracted; and the remaining proved reserves were equal to 8.7 x 10^9 tons of oil and 5.9 x 10^{12} m^3 of gas (Table 16-2). Consequently, the exploration rate of IRPP of oil and gas is 11 percent and 10 percent respectively, and the extraction rate, 3 percent and 0.6 percent. Petroleum resources of ocean areas (except Gulf of Suez and offshore Gulf of Guinea) are very sparsely explored and produced.

MIDDLE EAST

This most prolific petroleum-bearing region includes the countries of the Persian Gulf, Mesopotamian trough, and Arabian peninsula. At present the Middle East is the main oil-producing region in the world.

From the geological point of view this region is located within the northeast part of African-Arabian platform, Alpine-Himalayan fold system, and its junction with the platform. Sinai and the eastern coast of the Mediterranean are the northeast peripheral part of Sahara plate. The largest part of this region is occupied by Arabian plate, bounded by the rift systems of the Gulf of Aden, the Red Sea, and Arab-Jordan. Alpine-Himalayan fold structures occupy the northern and eastern parts of the region.

Within Middle East, 30 petroleum-bearing basins are identified, which are confined to the zones of junction of folded structures of the Arabian and Turanian plates, as well as to the internal depressions of the platform and folded structures. By the beginning of 1976, commercial oil and gas fields had been discovered in six basins.

Ninety-eight percent of the total of 200 discovered fields is located in the Persian Gulf basin. There are 72 fields with hydrocarbon reserves more than 100 x 10^6 tons of oil or 100 x 10^9 m^3 of gas and 27 fields with reserves more than 500 x 10^6 tons of oil or 500 x 10^9 m^3 of gas. Almost all of them are in the Persian Gulf basin.

Initial potential geological hydrocarbon resources of the Middle East, including sea areas of the Persian and Oman Gulfs and adjacent areas of the Mediterranean, Black, and Red Seas, are estimated to be 430 x 10^9 tons (in oil equivalent), and the recoverable part (with present methods of field development), 143 x 10^9 tons (112 x 10^9 tons of oil and NGL and 31 x 10^{12} m^3 of gas). About 70 percent of these resources is concentrated on land and about 27 percent offshore of the above-mentioned gulfs and seas. The petroleum resources of the continental slope are not important (Table 16-1).

Over 90 percent of petroleum resources of this region is connected with the basins of the Persian Gulf. About 80 percent of oil resources and 60 percent of gas resources of the region are concentrated within the Arabian plate and 18 percent and 26 percent, respectively, in the Mesopotamian trough. The basins of North Iran and the Red Sea water area are highly prospective, but the total volume of petroleum resources they contain is not comparable to those of Persian Gulf basin.

By the beginning of 1976, in the Middle East, proved reserves of 61.7 x 10^9 tons of oil and NGL and 16.6 x 10^{12} m^3 of gas had been discovered, of which 11.6 x 10^9 tons and 1.4 x 10^{12} m^3 had been extracted; the remaining proved reserves were 50.1 x 10^9 tons of oil and 15.2 x 10^{12} m^3 of gas, respectively (Table 16-2).

Consequently, the exploration rate of IPRR is now 55 percent for both oil and gas resources, and the extraction rate, 10 percent for oil and 5 percent for gas.

SOUTH AND SOUTHEAST ASIA

This region includes the group of developing countries which are situated on the Hindustan Peninsula--Afghanistan, Bangladesh, India, Pakistan, and Sri-Lanka. All these countries devote their efforts to developing their national petroleum industry.

South Asia is situated on the ancient Hindustan platform, framed by Alpine-Himalayan fold belt in the northwest, north, and northeast. There are six petroleum-bearing basins in the junction zone of the platform and the fold belt, two within the intermountain depressions, and six within internal parts of the platform and the parts of it which plunge into the ocean.

By the beginning of 1976, more than 50 oil and gas fields had been discovered, most of them in the Pakistan, Pendjab, Assam, Cambay (India), and Bengal (Bangladesh) basins. There are not many large fields: in only three gas fields do the proved reserves exceed 100 x 10^9 m^3. There are no oil fields of this category in South Asia for the present.

Southeast Asia is a vast region, spreading from the Gulf of Bengal in the northwest to Australia in the southeast. There are both the oil-producing countries (Burma, Brunei, Indonesia, Malaysia) and countries with only exploratory work (Cambodia, Laos, Thailand, Philippines) in this region.

Southeast Asia is situated in the junction zone of Mediterranean-Himalayan and Pacific mobile belts, between the South China platform on the north, the system of Alpine fold structures on the west, and deep-water trenches on the southwest, south, and east. More than 30 petroleum-bearing basins are situated within its boundaries, most of them concentrated within intermountain depressions of different ages. Commercial oil and gas fields have been discovered in 16 basins.

By the beginning of 1976, more than 220 fields, mostly oil, had been discovered in Southeast Asia. Most of them are located in South Sumatra, Central Sumatra, North Sawa, Sarawak, East Kalimantan (Indonesia), and Irrawady (Burma) basins. One of the new basins of great interest for conducting exploratory work is the Gulf of Siam, where oil and gas fields have already been discovered offshore Malaysia, Thailand, and Cambodia. The proved oil reserves in Minas (Indonesia) are more than 700 x 10^6 tons, and more than 300 x 10^6 tons in Seria and West-Ampa

(Brunei). Many oil fields have more than 50 x 10^6 tons of oil reserves.

Initial potential geological (in-place) hydrocarbon resources of all the sedimentary basins in Southeast Asia, including adjacent sea areas of the Indian and the Pacific Oceans, are estimated to be 205 x 10^9 tons (in oil equivalent), the recoverable part being 90 x 10^9 tons (56 x 10^9 tons of oil and NGL and 34 x 10^{12} m^3 of gas). About 30 percent of these resources are concentrated on land, 40 percent on shelf, and 30 percent on continental slope (Table 16-1).

The largest volumes of petroleum resources of South Asia are concentrated in the basins continuing to the junction zone of the ancient Hindustan platform and the Alpine-Himalayan fold belt. More than 70 percent of all the resources of this subcontinent are connected with these basins. In Southeast Asia more than 95 percent of all petroleum resources are confined to intermountain depressions of the Mesozoic and Cenozoic fold belts as well as to the junction of these areas. The basins of the ancient Indo-China massif do not play a significant role in these resources.

The oil and gas exploratory work in South and Southeast Asia began in the 19th century. By the beginning of 1976, 3.8 x 10^9 tons of oil and NGL and 2.4 x 10^{12} m^3 of gas had been discovered, of which 1.2 x 10^9 tons of oil and 0.3 x 10^{12} m^3 of gas had been extracted. The remaining recoverable proved reserves amount to 2.6 x 10^9 tons of oil and 2.1 x 10^{12} m^3 of gas (Table 16-2).

Consequently, at present the exploration rate of IPRR is 7 percent for oil and gas, and the extraction rate is only about 2 percent.

SUMMARY

The general characteristics of oil and gas recoverable resources in the developing countries are given in Tables 16-1 and 16-2. The total volume of these resources is estimated to be 362 x 10^9 tons of oil and NGL and 246 x 10^{12} m^3 of gas, of which

45 percent, 30 percent, and 25 percent are connected with land, shelf, and continental slope, respectively.

By the beginning of 1976, 88.5 x 10^9 tons of oil and NGL and 29.7 x 10^{12} m^3 of recoverable proved gas reserves (or 24 percent and 12 percent of recoverable part of IPRR) had been explored in the developing countries. During the whole period of oil and gas field development in these countries about 22.1 x 10^9 tons of oil and NGL and 4 x 10^{12} m^3 of gas, or 6 percent and 2 percent of IPRR, respectively, were extracted. The petroleum resources within the continental parts of the sedimentary basins are explored to the greatest degree (40 percent of oil and 24 percent of gas resources), but to a lesser degree on the shelf (16 percent and 8 percent). The petroleum resources of the deep water areas are practically untouched by exploration.

All these facts suggest that prospects for oil and gas discoveries are high enough in many developing countries of Latin America, Africa, and Asia, to expect an increase in petroleum production in these regions. According to the estimates, this production in the developing countries may reach as high as 2,000 to 2,100 x 10^6 tons of oil (including NGL) and 180 to 190 x 10^9 m^3 of gas by 1980, and 2,800 to 2,850 x 10^6 tons of oil and 400 to 450 x 10^9 m^3 of gas by the end of the century.

CHAPTER 17

UNITED NATIONS ECONOMIC COMMISSION FOR AFRICA (ECA): SUMMARY OF ITS ACTIVITIES IN THE FIELD OF PETROLEUM

T. Filimon[1]

Africa emerged as a petroleum producing continent after the Second World War and experienced a spectacular development of its hydrocarbon resources during the 1950's and 1960's.

In 1959 the United Nations Economic Commission for Africa was established and one of the many tasks of this forum was to assist African newly independent states in their economic development. As the number of independent countries has grown, the tasks of the Commission and assistance required in the field of natural resources development has become greater and greater.

During the 1960's there were eight petroleum producing countries in Africa, and at the end of that decade their proved reserves of crude oil were estimated to be about 9.5 percent of the world's proved reserves.

As a result of this new African position, ECA initiated in 1970 a systematic study of African hydrocarbon resources, in order to be able to assist at any time any member state of the Commission in the field of exploration, training of manpower, planning, and formulation of policies in this field.

All these efforts have been carried out within the ECA's Division of Natural Resources, Science and Technology and have been concentrated initially on the preparation of the First African Conference on Petroleum Industry and Manpower Requirements in the Field of Hydrocarbons.

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[1]UNECA, Addis Ababa, Ethiopia.

For the said Conference, studies have been elaborated on petroleum development in each African producing country, from the beginning of their petroleum activities until 1973, as the Conference took place in 1974 in Tripoli, Libya. In addition, activities carried out in the field of petroleum by African countries other than producers have been reviewed and their results analyzed. In this respect, African sedimentary basins have been studied, hydrocarbon prospects evaluated, and hydrocarbon resources estimated, for practically all African countries.

In the process of reserves estimation, the following classification has been adopted:

1. Proved reserves--the amount of hydrocarbons discovered by a sufficient number of drilled wells and on the basis of data obtained, considered as commercially recoverable by present day techniques at current costs and price level;

2. Probable reserves--those hydrocarbons supposed to exist in the discovered fields by extrapolation of a single well data or of data obtained from a reduced number of wells;

3. Possible reserves--undiscovered hydrocarbons but supposed to exist, given favorable geological conditions for their generation and accumulation.

It is not the intention of this note to analyze the results obtained. These results may not be as accurate as those calculated by specialized institutes or by other recognized authorities in this field, but they fall within generally recognized figures and give a clear picture of the African continent's reserves. Detailed figures are mentioned in the documents available with ECA in Addis Ababa. Informative data for crude oil proved reserves only are given in Fig. 17-5, together with African production of crude since 1960. The reserves have been estimated by groups of sedimentary basins; areas covered by these basins are given in a very condensed form in Fig. 17-1.

Offshore sedimentary areas in Africa up to 200 m water depth have been estimated as covering some 6.5×10^6 km^2. To this we have to add a considerable area covered by African interior continental basins, of which only the Congo Basin Gulf has more than 0.5×10^6 km^2. In estimations we did not include the oil which can be recovered from oil shales in Madagascar, Morocco, and Zaire (15×10^9 tons), or from tar sands already known to exist in Ivory Coast, Gabon, Ghana, Madagascar, and Nigeria; however, these should not be ignored.

As it seems that a significant number of participants at the present Conference are interested in data concerning petroleum exploration and development in Africa, three figures have been attached to this note (Figs. 17-2, 3, and 4) to illustrate these aspects of petroleum activities. All data are generalized but accurate, being based on existing documents prepared by ECA in Addis Ababa. It is essential to note that Africa has considerable area with petroleum prospects which need further exploration and many areas which have not yet been touched by exploration at all, considering the small number of exploratory wells (wildcats) drilled to date (Fig. 17-3).

The recent increase in crude oil and refined products prices has shown to those African countries which have no production of crude, and therefore are importers either of crude for their refineries or of petroleum products for their own markets, that the only solution, although a long-term one, to balance their energy demands and supplies, is to make efforts to explore, develop, and produce oil of their own, onshore or offshore. In addition these countries must look into the development of alternate sources of energy, such as hydropower, solar, geothermal, wind, and biogas.

Exploratory results already obtained during the present decade in Cameroon, Chad, Equatorial Guinea, Ethiopia, Ghana, Madagascar, Nigeria, Sudan, Tanzania, and Togo, place these countries among probable future African crude oil producers; in addition, Zaire started production in November 1975. (With Zaire the number of African crude producers increased to 10.) Therefore, exploration in African nonproducing countries should be intensified and at the present stage of our knowledge, it should be directed not only towards offshore areas but also towards the internal basins.

The present ECA's Energy Unit Work Programme is mainly aimed at the development of African energy resources, including hydrocarbons whether as crude oil, gas, oil from shales, or oil from tar sands. Efforts are being made to prepare an inventory of these resources, to prepare an Energy Resources Atlas of Africa, to establish an African Petroleum Institute with a Documentation Center in this field, and finally, to establish an African Petroleum Organization. Efforts are also being made to assist African states in their endeavor to explore and develop other sources of energy (hydropower and nonconventional), to assist them in planning, in training of nationals, and in formulation of their own energy resources development policies.

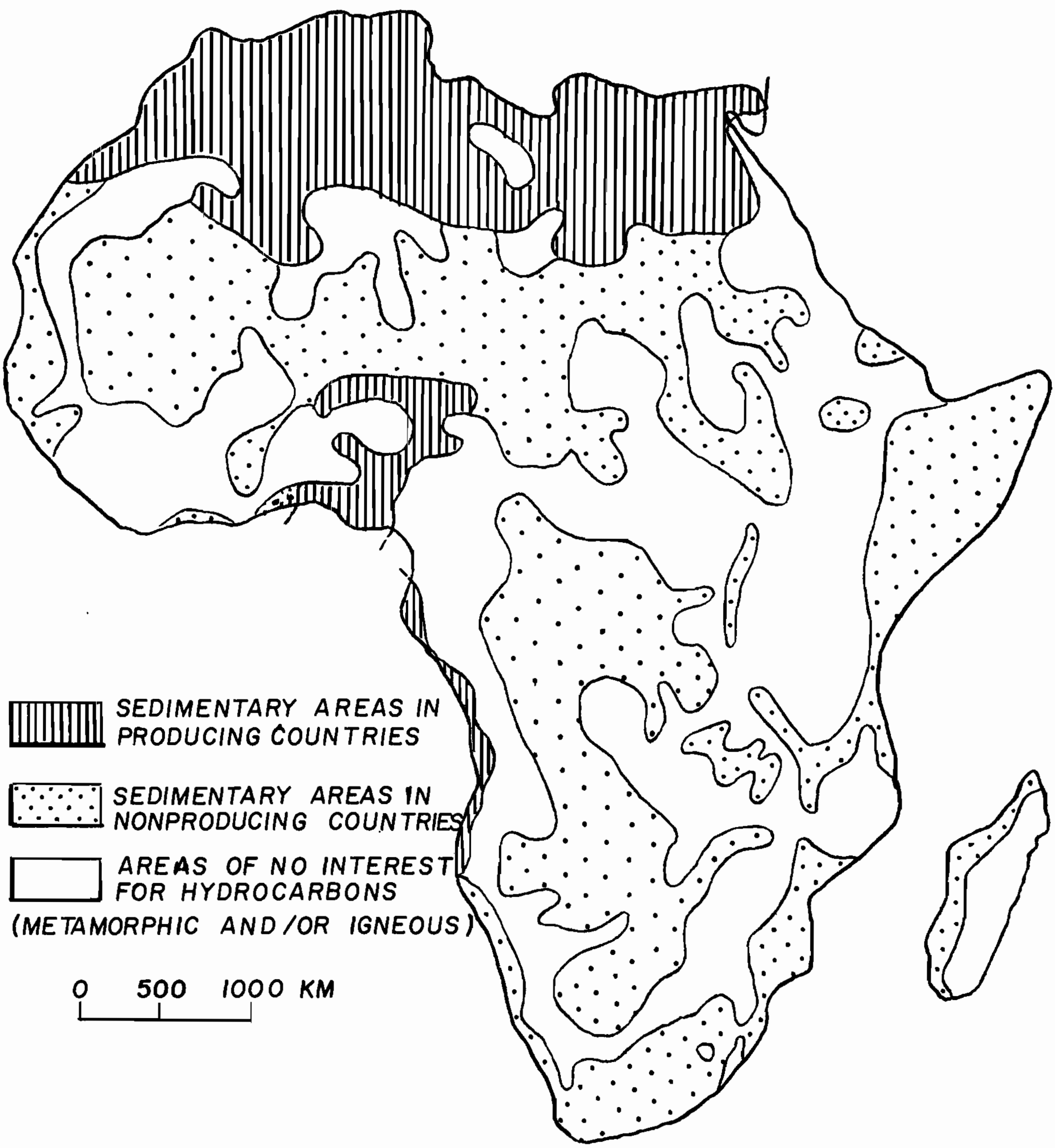


Figure 17-1.--The sedimentary areas of Africa (after Bull., American Assoc. Petroleum Geol.)

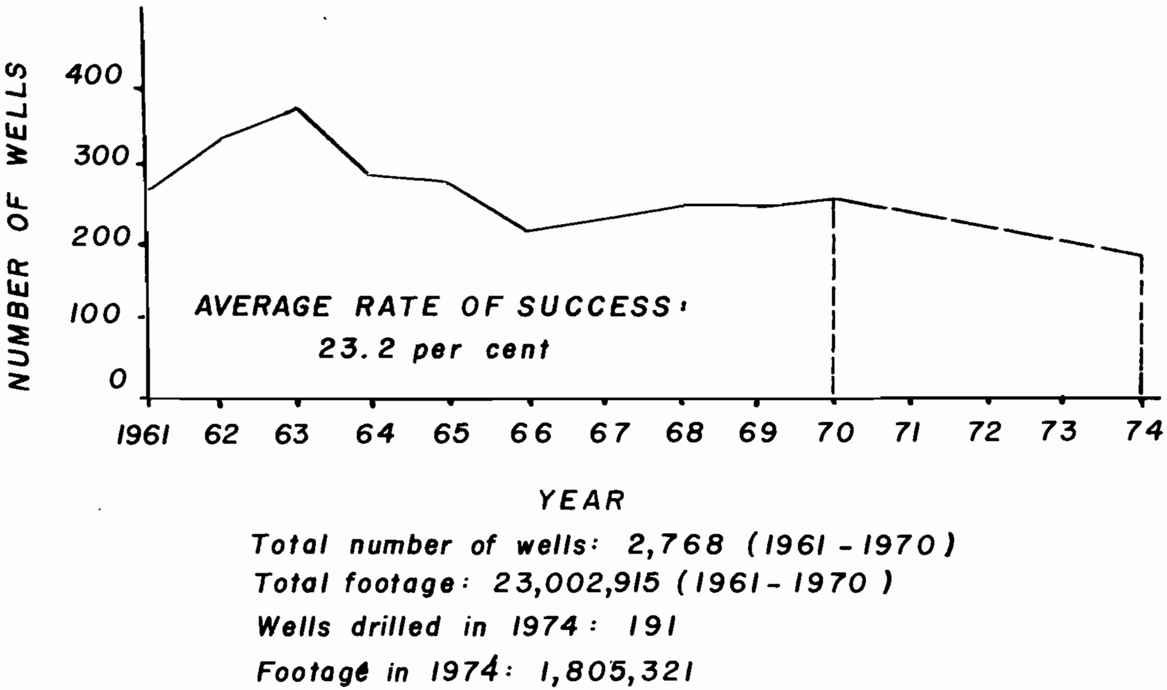


Figure 17-2.--New-field wildcat exploratory wells drilled in Africa, 1961-1970 and 1974 (data for 1971-1973 available from UNECA, Addis Ababa)

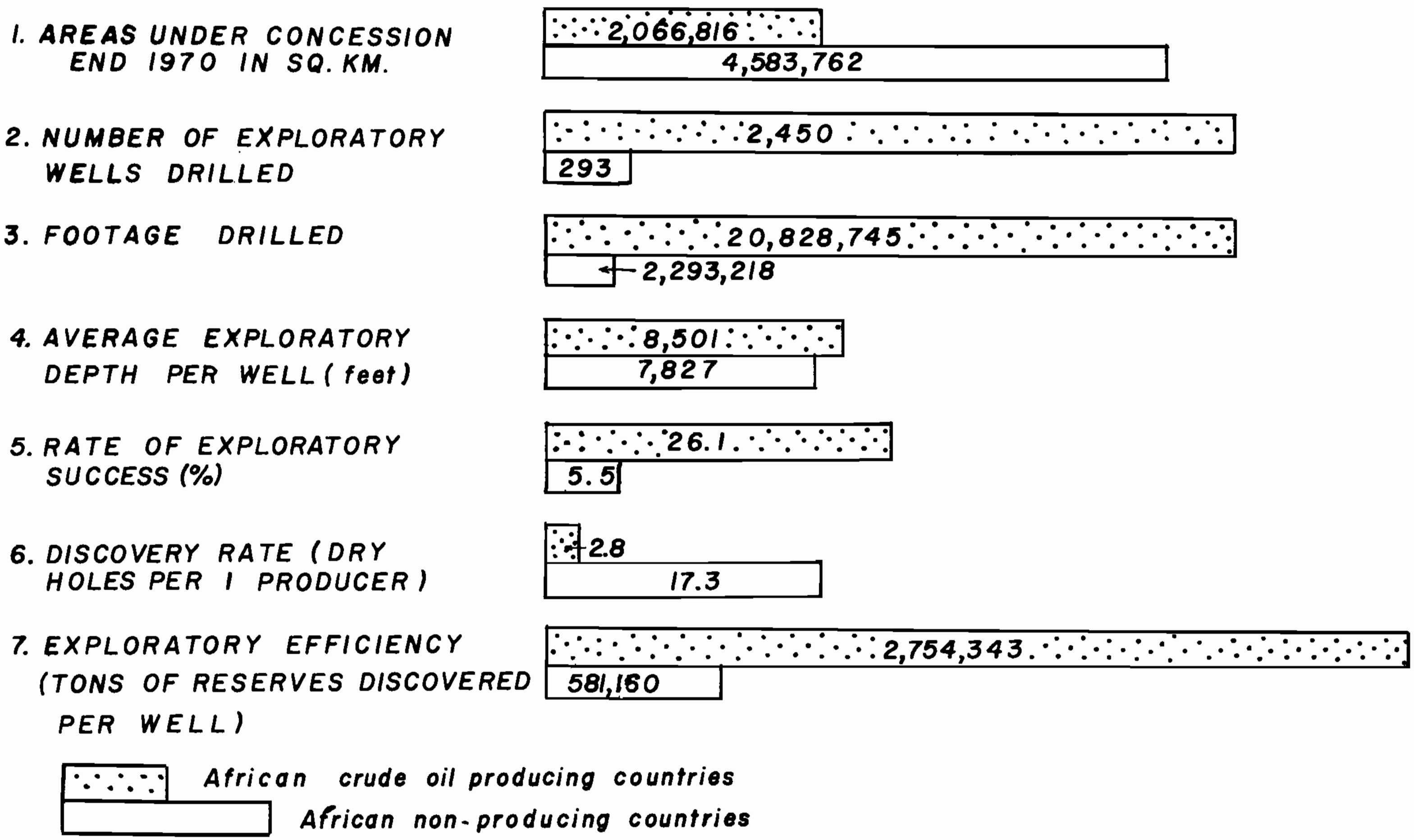
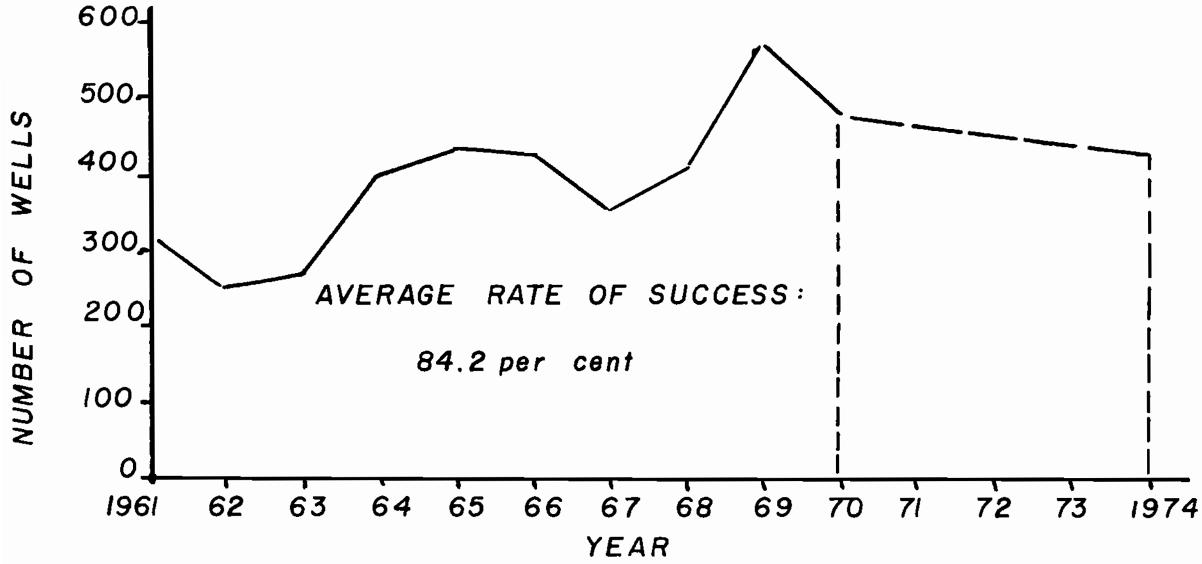


Figure 17-3.--Exploratory (new-field wildcat) drilling success in Africa



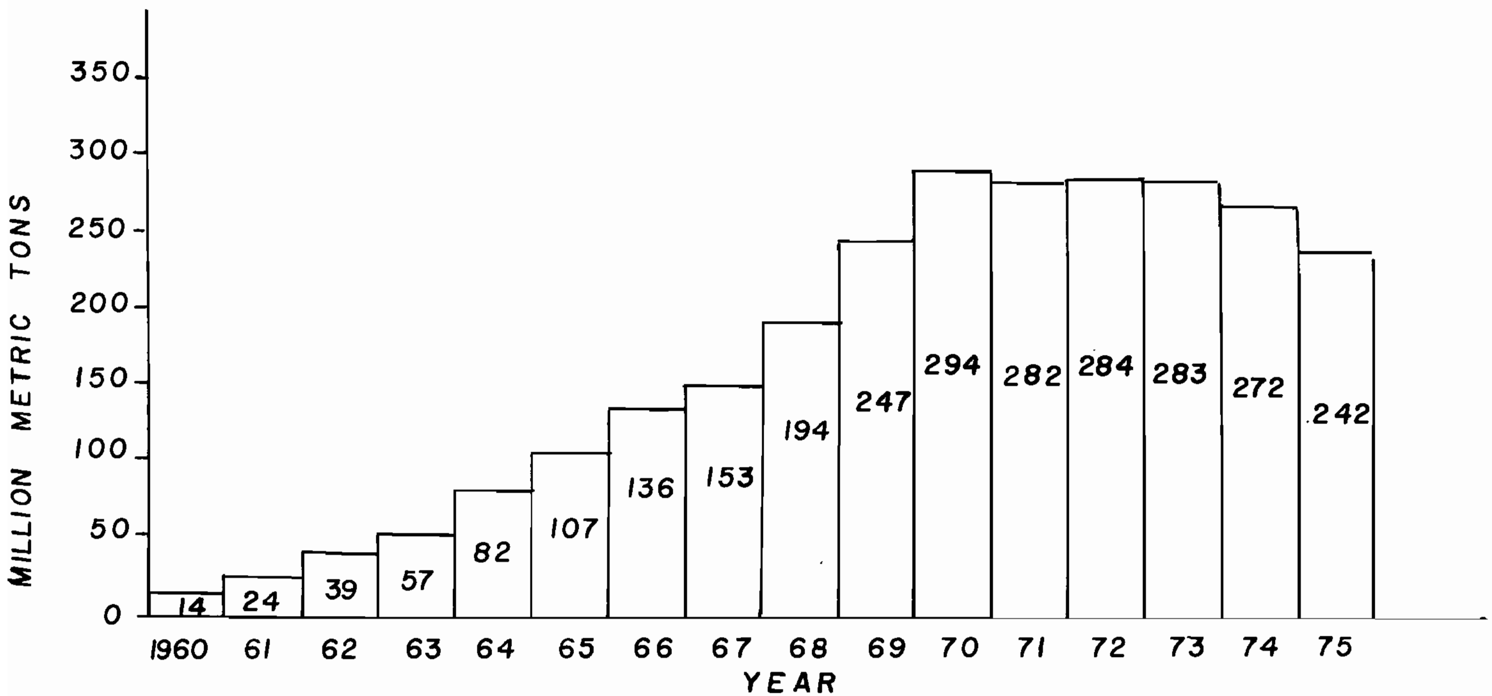
Total number of wells: 3,935 (1961-1970)

Total footage: 28,843,800 (1961-1970)

Wells drilled in 1974: 437

Footage in 1974: 3,706,200

Figure 17-4.--Development-well drilling in Africa, 1961-1970 and 1974 (data for 1971-1973 available from UNECA, Addis Ababa)



AFRICAN CRUDE OIL RESERVES (PROVED)

in 1960: 900 million metric tons
in 1970: 5600 million metric tons
in 1975: 9250 million metric tons

Figure 17-5.--Crude oil production in Africa, 1960-1975

CHAPTER 18

INVESTMENT STRATEGIES FOR MAXIMIZING OIL RESERVES' RECOVERY FROM MAJOR OFF-SHORE FIELDS[1]

K. E. Rosing, P. R. Odell, and Hester Vogelaar

Last year we here reported our work on a simulation model of the North Sea Oil Province [1]. Upon the publication of the full report there was considerable controversy and scepticism about our estimates, which were two to four times as great as the oil companies [2]. Discussions during 1975 revealed that a large portion of the difference was for definitional reasons. Our report assumed that all technically recoverable reserves in fields large enough to be economically developed would be recovered while the companies' estimates were based on reserves considered to be profitably recoverable. The present research deals with economic implications of this definitional difference.

At this moment the research is limited to British waters. A large number of fields with varying quantities of economically recoverable reserves (Fig. 18-1) have been discovered over the past 6 years. The declaration of recoverable reserves indicated for each of the various fields pertain, in each case, to a specific investment plan; that plan in each case is, however, only one of a series of possible alternative development systems. The recoverable reserves of a field are not a fixed quantity, as analysts of North Sea oil, for example Mackay and Mackay [3],

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[1] "This report is a preliminary extract from: Prof. Peter R. Odell, Dr. Kenneth E. Rosing with Ms. Hester Vogelaar, Optimal Development of the North Sea's Oil Fields: A Study of Divergent Government and Company Interests and their Reconciliation. (Kogan Page, London, 1976), which discusses and expands on the issues raised here."

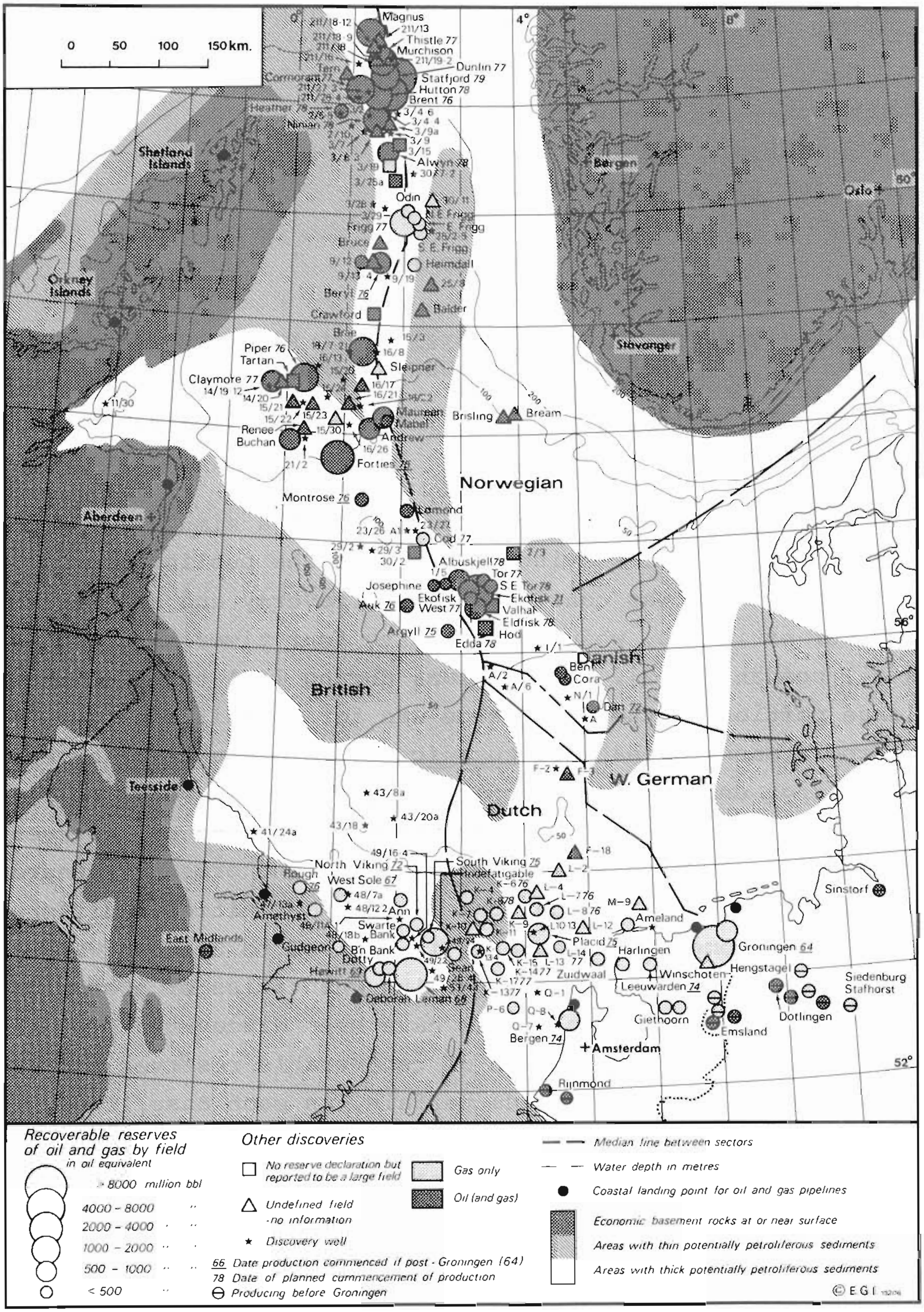

Figure 18-1.--The North Sea oil and gas fields and discoveries to the end of September 1976

have invariably assumed, but rather a variable quantity determined by the operating company's investment decision. Since the technically recoverable reserves of a field are a finite quantity there is an absolute upper limit on profitably recoverable reserves as well. Below this limit, however, additional increments of investment can be made to produce additional quantities of oil during the economically significant time period.

The geographic characteristics of the North Sea with its deep water, its severe storms with high waves, and fields located some 200 km from land, is unique in the experience of the oil companies [4]. The development of most of these fields will require multiple platform systems. Each platform will have a number of wells (a maximum of about 40) but the technical limitations of deviated drilling dictate a maximum area covered by wells from one platform of about 3 km radius (at about 2 km below the sea bed). Each well will then draw oil from a limited area during an economically significant time. Of course the dynamic characteristics of a reservoir will not limit the ultimate recovery from a well to such an area but the life-span of a platform and the rate of return on investment required by a company will limit the area which can be drained by each single well (Fig. 18-2).

In the selection of a system for the development of any particular oil field the operator is faced with a rising unit cost curve for his investment. Given an oil reservoir, such as that shown in cross-section in Fig. 18-2, a company making a decision to develop the field with one platform would place that platform on the thickest, most productive sands, thus giving the largest return of oil for each dollar of investment. Should they decide to install a two platform system then the area of most productive sands would be shared between the two with each platform in addition tapping areas of less productive sands. Therefore the average productivity of each platform will decline as one moves from the system with one platform through systems with 2,3,...,n platforms. The rising unit cost curve per platform system is illustrated in Fig. 18-3 which also shows clearly the "lumpiness" of the investment brought about by the necessity

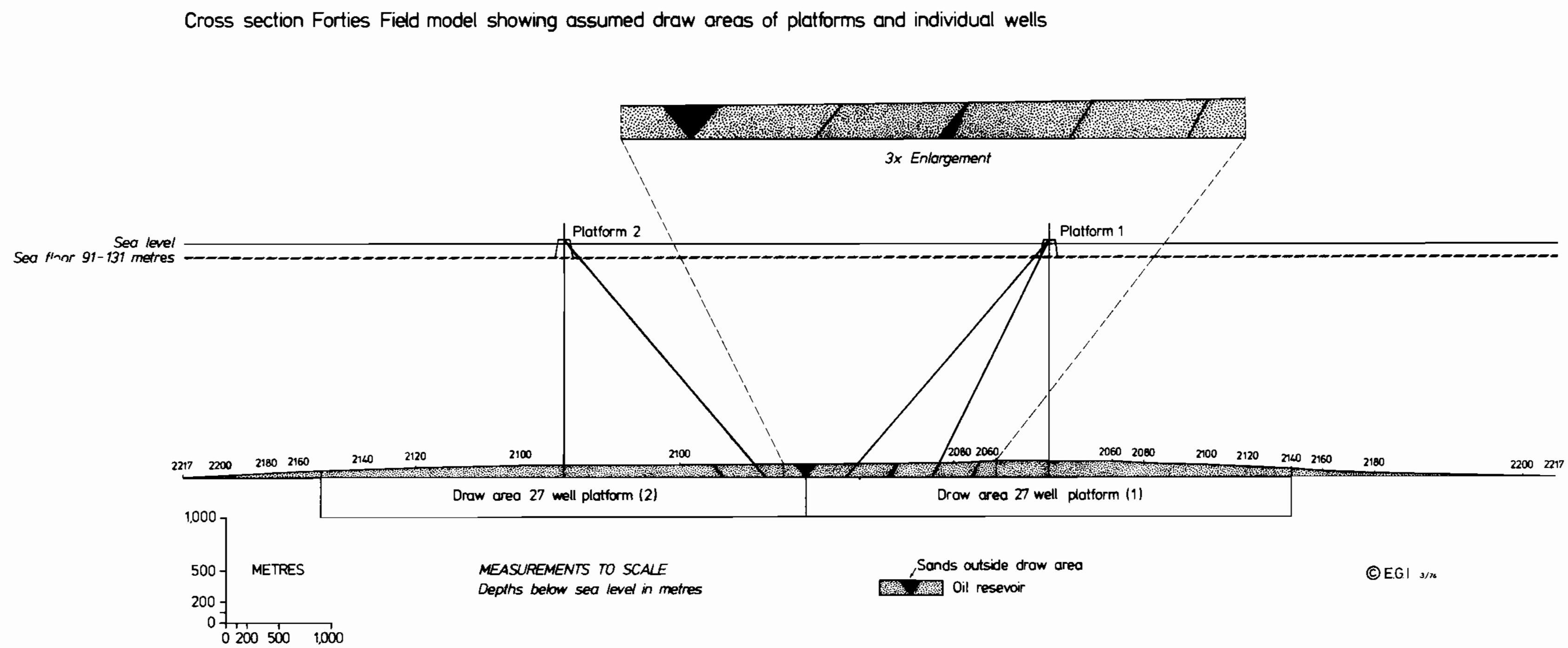

Figure 18-2.--A cross-section of the Forties Field. The horizontal and vertical scales are equal. A platform in any particular location can deviate wells to tap only a limited area. Each well can recover oil from only a limited area in an economically significant time.

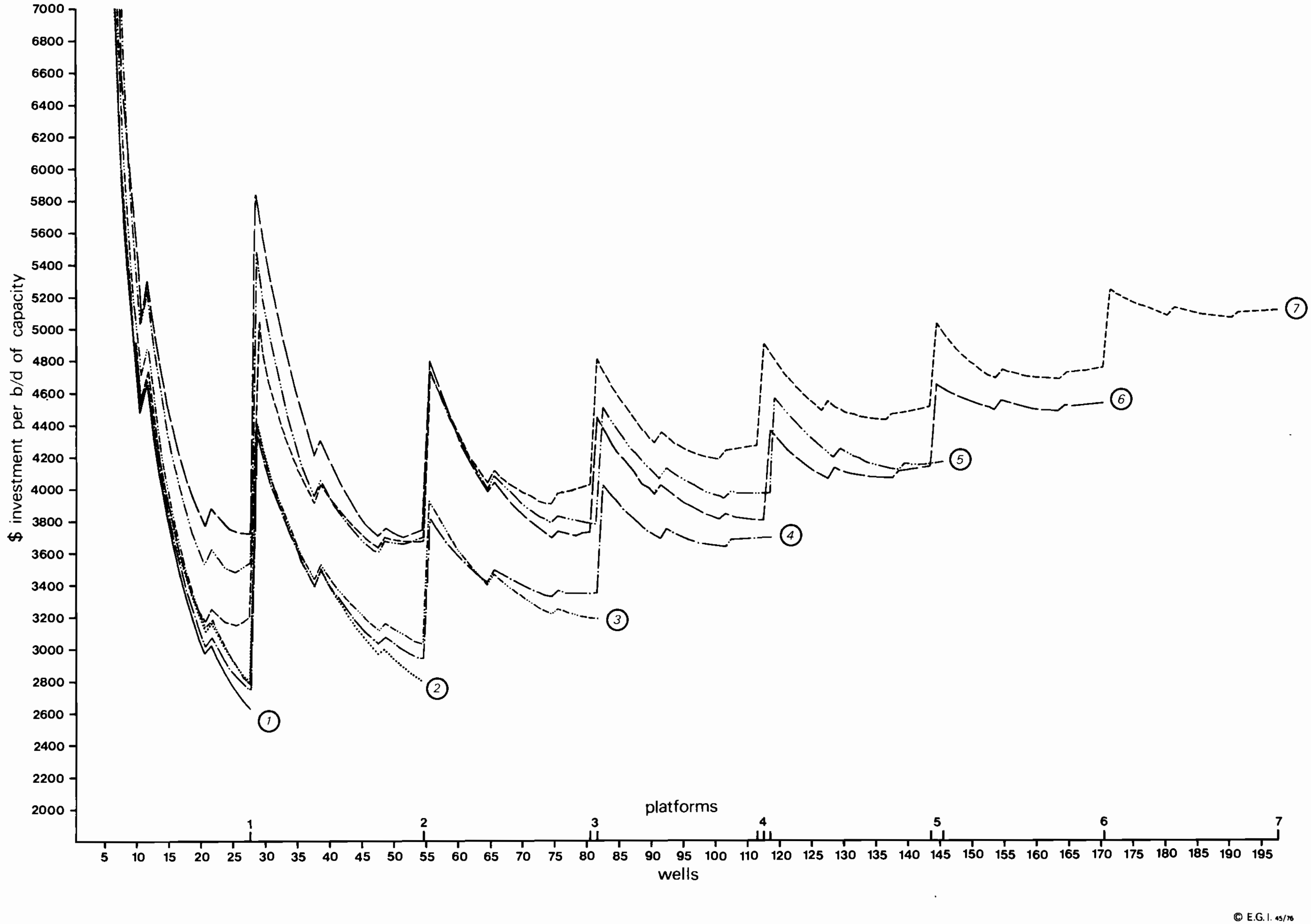

Figure 18-3.--Since each system is designed to utilize the most productive area of sand feasible the average unit cost of each successively larger system must be higher than the average cost in smaller systems. The figures in circles (marked 1, 2,......7) indicate the average unit

of platform by platform development. The lumpiness of the investment in the platform units, together with the rising average unit cost curve, create an environment in which company decisions on producing the field result in the development of a field which reflects the necessary minimization of risk and the achievement of high minimum expected rates of return on the investment. Such a pattern of development is logical for a company behaving commercially in this situation--but, in that the recovery of oil is limited, it may be less than an optimal development of the field from the state's point of view.

The choice of the number of platforms to install and the locations on the field for these platforms is a decision which must be made early in the history of the field. Unlike experience in shallower, calmer waters, or on land, a deep-water field cannot be developed by successive production decisions based on the process of "drilling it up" as production experience is gained. Additionally, the size of the reservoirs precludes the Gulf Coast experience of optimally locating one platform to produce several reservoirs [5]. The choice of system must therefore be made early and any attempt to add additional platforms later in the plan is likely to result in sub-optimal field development and a higher than necessary investment per unit of production. The calculation of the future recoverability of oil from a deep-water off-shore field can thus be related directly to the known geography of the field and to the system of development which is chosen given this knowledge and the calculations of optimum returns to investment.

We have chosen, as an example, the Forties Field of B.P. because at the time of commencing the study more information was available on the nature of this reservoir than was then available for any other large field in British waters. Data on individual fields may be found in Woodland [6]. A hexagonal grid was imposed upon the map of the reservoir sands (Fig. 18-4) with each of our hexagons having an area equal to the average well spacing as defined by B.P. This gives a series of hexagonal units, each considered a potential well draw area, of a size which B.P. considered desirable, on average, for the

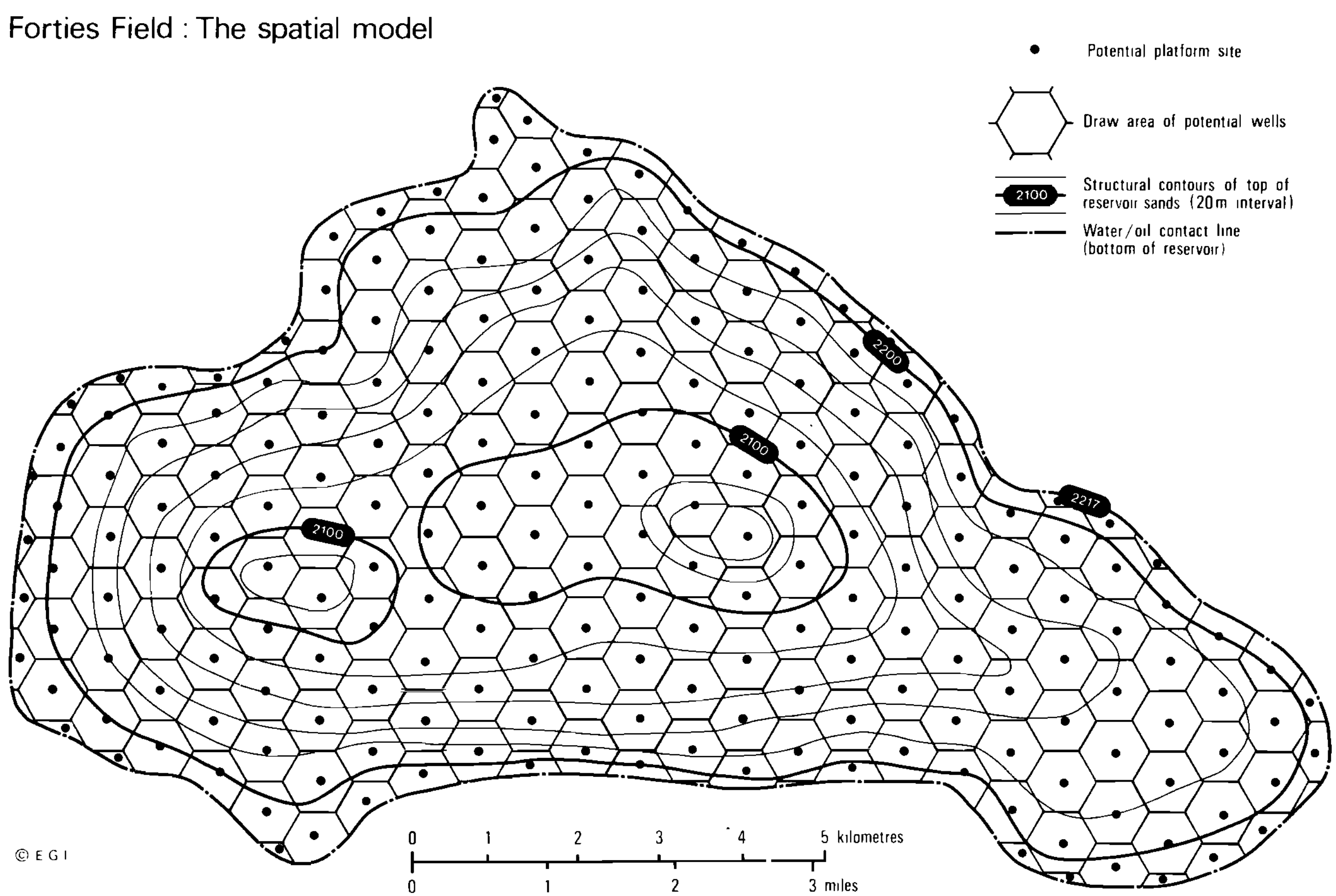

Figure 18-4.--The area of each hexagon of our hexagonal grid is equal to the well draw area as defined by B.P. By interpolating the structural contours within each hexagon its average thickness is found. From this the volume of oil it would produce if a well were drilled can be calculated. The spatial problem to be solved is to find which set of platform locations allow maximum production for each system. (See Figs. 18-5 and 18-6.)

maximum production of the oil present during an economically significant time period.

The potential recoverable oil from each hexagon was calculated by the volumetric method. This entailed, for each hexagon:

1. Interpolating the average depth of the top of the reservoir sands from the map (Fig. 18-4);

2. Subtracting the depth of the water/oil contact line to give the thickness of oil bearing sands;

3. Multiplying the thickness times the area to give the bulk volume of oil bearing sands;

4. Multiplying by the porosity to give the oil in place;

5. Multiplying by the expected recovery factor to give the amount of production;

6. Multiplying by 0.70 to correct for the water/oil separation and to convert from barrels of gaseous oil at reservoir pressure and temperature to barrels of separated oil at standard pressure and temperature.[2]

The model of the reservoir was then solved for each of the various systems, that is, a series of systems with successively 1,2,3,4,5,6, and 7 platforms. Solutions 4 and 6 (with the B.P. system for comparison) are illustrated in Figures 18-5 and 18-6.

The solution involved the simultaneous choice of the optimum location of each platform in one system and the selection of the optimum wells to be drilled (well draw areas to be produced) subject to the limitation on the number of wells per platform and the draw area of the platform. The per platform production was then summed and reduced by 10 percent to correct for the use of fully contiguous hexagons rather than tangential circles. The result was then reduced by a further 10 percent to correct for the planar net of hexagons in a situation which is in reality a set of diverging hexagonal columns (Fig. 18-2).

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[2]The various parameters were from Woodland [6], except for the water/oil separation and the expansion factor which are not publicaly available. A reasonable estimate of the two together was therefore used.

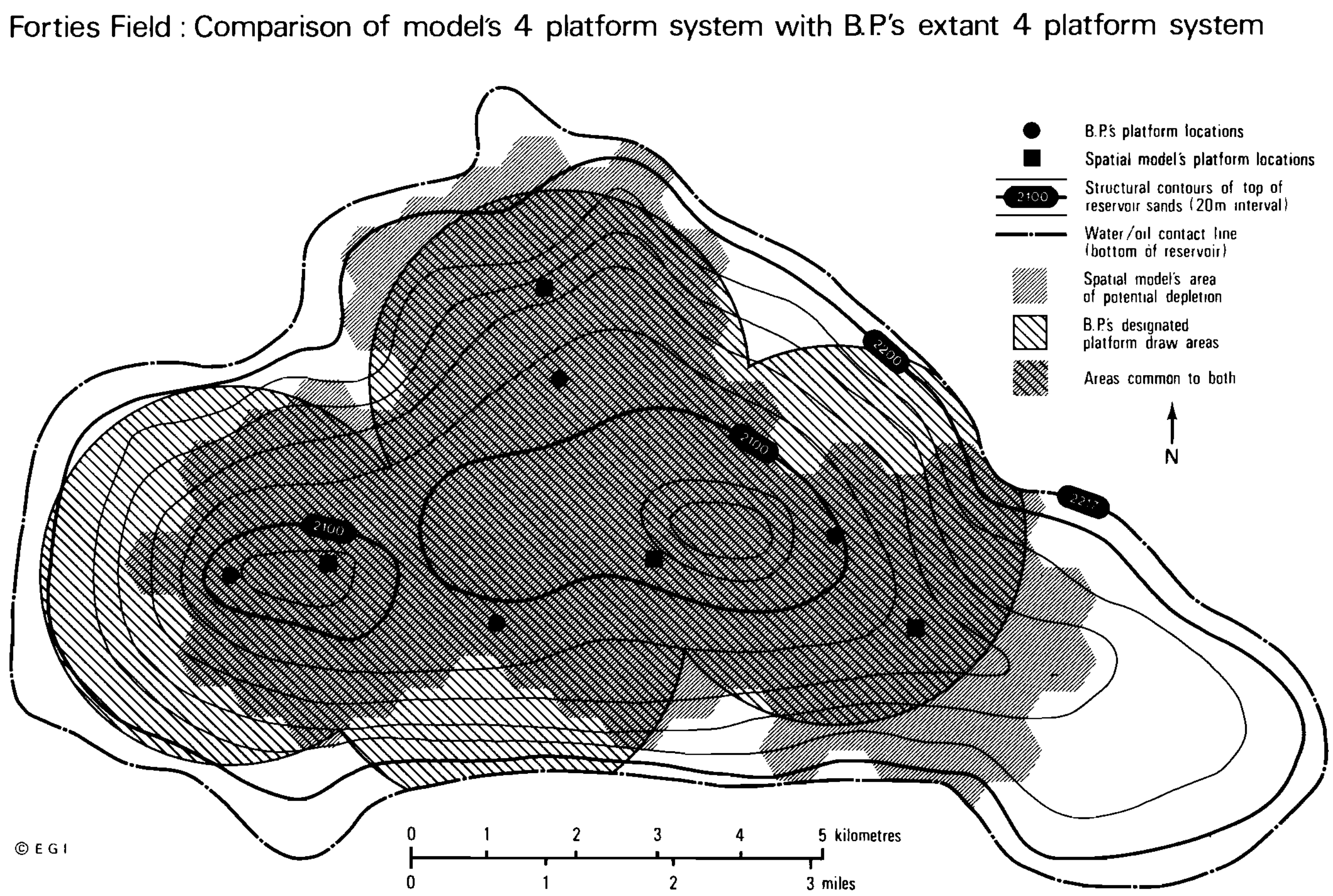

Figure 18-5.--The optimal location for each of the four platforms of the model's four-platform system is shown by a black square. The total area which will be depleted by wells drilled from these platforms is indicated. B.P.'s four-platform locations are shown by four black dots with their platform draw areas indicated for comparison.

Forties Field : Comparison of model's 6 platform system with B.P.'s extant 4 platform system

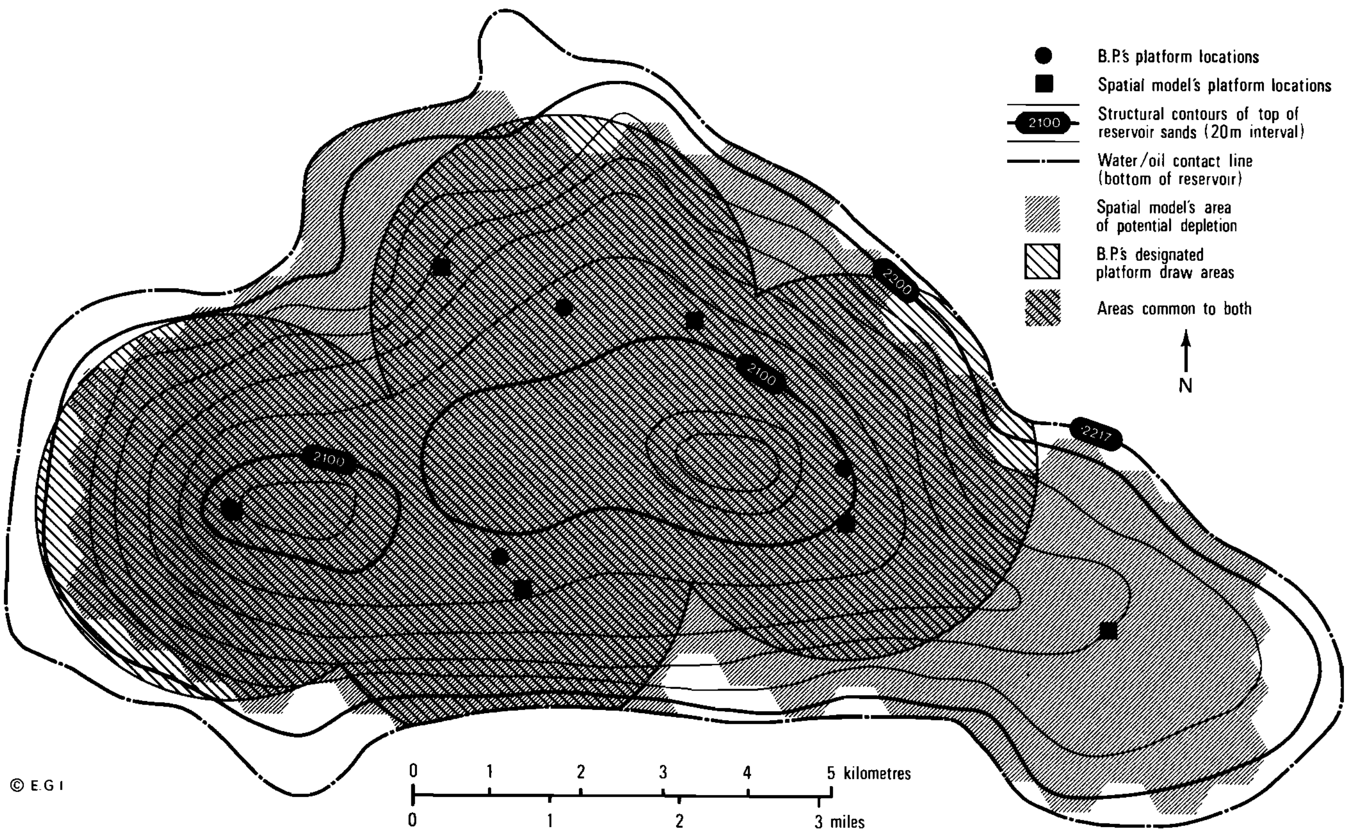

Figure 18-6.--The optimum location for each of the six platforms of the model's six-platform system is shown by a black square. The total area which will be depleted by wells drilled from these platforms is indicated. B.P.'s four-platform locations are shown by black dots with their platform draw areas indicated for comparison.

The volumes of oil produced by each of the seven solutions were then submitted to a financial analysis program. The principal inputs to this program consisted of:

1. The number of platforms and the amount of oil recoverable from each platform (derived from the work described above);

2. The total cost of each platform, including wells equipment, associated transport facilities, and inflating over time (derived from published data);

3. The timing of the investment over a period of years (derived from the timing of installation and assumed payment schedules);

4. The depletion curve for the oil recovered by each platform (derived from normal depletion curves as used by companies);

5. Annual running costs and their inflation (derived from total capital costs and varied according to whether a tanker or pipeline would be used);

6. The price of oil produced and the rate of price increase (derived from the current price and assumptions on future movements);

7. The taxes payable, Royalties, Petroleum Revenue Tax, Corporation Tax (derived from the various U.K. tax laws);

8. A Discount Rate for companies' costs and revenues, calculated as a function of a minimum 15 percent rate (to represent normal risks and opportunity costs) plus an additional percentage to represent the increasing risk to the companies' investment as it moves from a one platform to an n platform system.

9. A Discount Rate for the Government's Tax Take and the total value of oil, derived from their current borrowing rates.

A number of runs of the financial analysis program were then made to test the sensitivity of the various inputs. The D-1 series is shown in Fig. 18-7. Key variables in this example were: 5). 15 percent of total capital costs for the 1 and 2 platform systems (served by tanker), 8 percent of total capital costs for the 3,4,5,6, and 7 platform systems (pipeline) inflating each year by 10 percent of the previous years running cost; 6). $12.50 per barrel and increasing at $0.50 per year.

Figure 18-7 clearly shows a divergence of interest on the part of the company and the interest of the government and the national economy. The company will naturally choose to install a four platform system at which the NPV of its investment is maximized while the government would prefer to have a six platform system installed since that would result in higher tax return and greater benefit to the national economy. Figure 18-7 also illustrates the results of the E-1 series in which all inputs are identical to the D-1 series except that the cost of constructing and installing the 5th, 6th, and 7th platform is met by the government. A reconciliation of the divergence of interest is obtained with the company's most attractive plan now being the six platform system as well as the government's.

Because of the dynamic nature of the fluid flow in the reservoir the recovery of the four platform system would eventually approach that of the six platform system, but this additional oil would be recovered only in the later years of the fields' life. For this reason the program D-1 was rerun with enhanced recovery, that is, the four platform recovery increased to within 5 percent of the six platform recovery. The additional recovery began in the 13th year and the depletion curve extended over a total of 25 years rather than 20. As Fig. 18-7 shows, the enhanced recovery does not significantly alter the financial results for either government or company and does not approach the better results for both parties achieved through the use of a six platform system in part financed by the government. The results of these various runs are shown in Table 18-1.

Conclusion

The geography of an oil reservoir, the commercial considerations of the company involved in the development of the reserve, and the tax policy of the government all seem to contribute to a tendency to produce a smaller portion of the reserves of an oil reservoir than is technically possible and desirable from the point of view of maximizing the recovery of oil. Thus any government interested in the <u>full</u> exploitation of such a

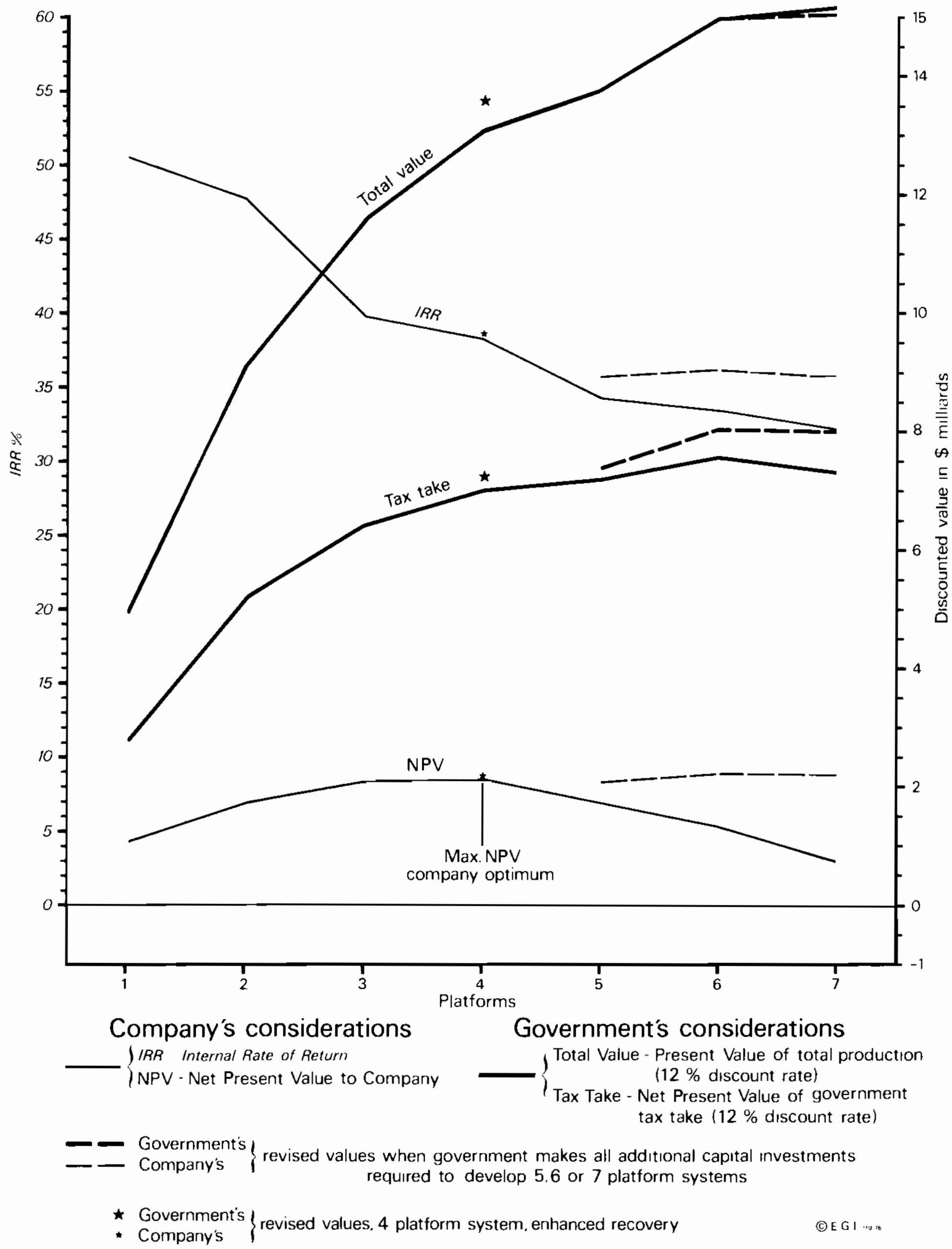

Figure 18-7.--The net present value of the company's oil production, the present value of the government's tax take on the oil produced, and the present value of the total oil produced are shown for each system. (See text.)

TABLE 18-1.--Comparison of the return on investment on 4-platform and 6-platform systems

	4-platform system		6-platform system	
	Normal recovery	Enhanced recovery	All company investment	Govt. investment for additional costs involved
Total production of oil (10^6 bbls)	1935	2225	2315	2315
Period of oil production (years)	18	22	18	18
N.P.V. of company investment ($\$ \times 10^9$)	2.09	2.14	1.32	2.22
Value of oil produced in P.V. terms ($\$ \times 10^9$)	13.1	13.64	15.01	15.01
N.P.V. of government revenues ($\$ \times 10^9$)	7.04	7.25	7.56	8.07
P.V. of government investment ($\$ \times 10^9$)	--	--	--	0.92
Rate of return on government investment	--	--	--	34.5%

resource has to find appropriate incentives to give the companies in order to pursuade them more fully to utilize the reserves.

We have in this paper suggested that the government, either by tax remissions or by direct subsidy, should, in its own interests, support the construction and placement of the incremental platforms required to develop a field more closely to its technical potential. The effect of such action is, in this example, to increase the Net Present Value of the investment in the development for both the oil companies and for the government.

The British Government has recognized, in the Petroleum Revenue Tax legislation, the problem of the development of small or marginal fields. The legislation makes possible tax regimes which help with their development. What has not been recognized in the legislation is the implication of a rising unit cost curve in the development of large reservoirs so that present legislation tends to inhibit their full development, so eliminating the production potential for part of the technically recoverable reserves of a field--to the detriment of policies which seek to optimize the production of the world's finite resources of oil. One way of eliminating this "waste" of resources has been illustrated in this paper. Though this may not be practical in itself it may serve to orient our thoughts towards alternative methods of achieving optimal oil recovery systems in regions similar to the North Sea.

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[3] See, for example, D. I. Mackay and G. A. Mackay, The Political Economy of North Sea Oil, (London: Martin Robertson, 1975), chapter 4; and/or the semi-published calculations of the profitability of North Sea Oil: Wood MacKenzie & Co., (Edinburgh: Wood MacKenzie & Co., 1975) or as summarized in: The Petroleum Economist, Vol. XLII, No. 12, (Dec. 1975), pp. 458-460.

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CHAPTER 19

AN R&D EFFORT FOR OIL PRODUCTION IN DEEP WATER

M. Comtet[1]

INTRODUCTION

The jump in petroleum prices by a factor of five during the last 3 years, and the sudden awareness of the danger for an economy to rely almost exclusively on a single form of energy, have led the principal industrial nations to orient their policy towards the conservation of energy and the development of alternative sources.

Taking into account, however, the time-scale implied for the substitution of one form of energy by another, the most recent studies forecast that by the end of this century, hydrocarbons will still remain the major source of energy supply, representing at that time more than 50 percent of the total world energy demand.

The increasing demand in hydrocarbons, and the desire to postpone the dateline for the lack of physical reserves, will lead to an intensification of exploration efforts, particularly toward offshore fields, due to the progressive saturation in onshore discoveries.

Today, offshore petroleum represents one-third of proven oil reserves and 20 percent of world oil production.

If we keep in mind that half of the sedimentary basins lie under the sea (Fig. 19-1), the ocean floor looks quite promising

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[1]ELF-Aquitaine, Paris, France.

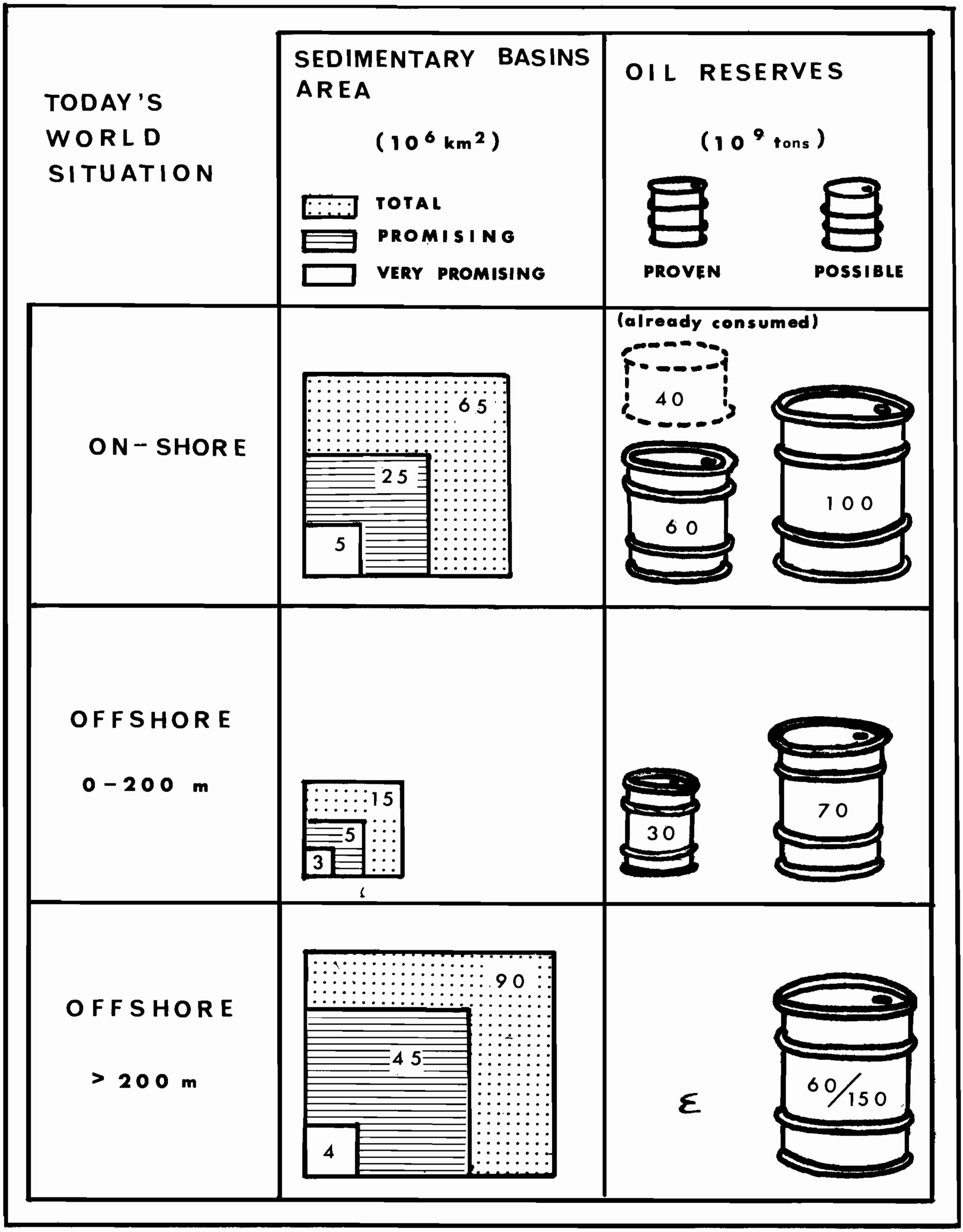

Figure 19-1.--Distribution of world oil reserves

for the future, providing that the tools necessary to conquer it can be developed.

HISTORICAL DEVELOPMENT OF OFFSHORE TECHNOLOGY

Initiated in the early 1930's and considered as a marginal activity, production equipment moved progressively into swamps, shallow waters, and deeper waters on increasingly longer stilts and legs (Lake of Maracaibo, Caspian Sea, Gulf of Mexico).

During the last decade, offshore oil production became a fast-growing activity, going into deeper and deeper waters and facing more hostile climates (e.g., North Sea), professionals continued to content themselves with adapting the same techniques to the ocean as those developed for onshore operations.

As a result, fixed platforms installed in the sea bed have progressively become technical and economical "monsters." Today current platforms are made of 20,000 to 50,000 tons of steel or 100,000 to 200,000 tons of concrete (the Eiffel tower is 7,000 tons!). Thus, close to 1×10^6 tons of materials and $\$5 \times 10^9$ will be necessary to put into production the Frigg field in the North Sea, from which 300,000 barrels of oil-equivalent of gas per day is expected. We are now reaching a turning point in the history of offshore technology. To progress farther and to produce oil at depths greater than 600 ft, a new technical approach to the problem is required.

AN APPROACH TOWARD PRODUCTION AT GREATER DEPTH

In the case of exploratory drillings, which are short term operations, satisfactory solutions have already been reached, including dynamic positioning and anchorage, and automatic drilling systems.

Oil production in deep water is a much more difficult problem to solve.

Among the different alternatives possible, the approach we have selected consists in locating all the production facilities at the surface on a floating structure, with only the well heads, the connecting systems, and manifolds located at the bottom.

The projected production system, for use in water as deep as 3,000 ft, and the actual system, limited to water depths of approximately 600 ft, are shown in Fig. 19-2.

In our project, submerged well heads can be either spread out on the sea floor or grouped together on a template as indicated.

The oil production is gathered through connecting lines and then brought to the surface by means of a riser. This riser connects the fixed bottom and the free floating production platform. This platform supports the separating and treatment units and the remote control apparatus. The automatic connection of the submerged collecting lines is one of the difficult problems to be solved. The riser, which is made of a bundle of several pipes, will permit the evacuation of the oil to the surface, the testing of the wells separately, the injection of water or gas in the field, and remote control of the well heads. In this project, the production platform, anchored by cable, limits the accessible depth of water to about 3,000 ft. To overcome this limitation and to go beyond this depth, a dynamic anchorage system will need to be developed. If the evacuation of oil by pipeline is not possible a floating vessel can be used (Fig. 19-3) which will perform three functions: treatment, storage, and loading. Some elements of this new technology are actually being tested in vivo under 200 ft of water at the Grondin field off the coast of Gabon.

These shallow testing conditions facilitate control operations and allow direct intervention of the divers during this experimental phase.

This project is part of the joint national venture on offshore petroleum technology, partially supported by the EEC.

We hope the important scientific and technical R&D effort we are undertaking in that field will contribute to the development of petroleum activity in deep ocean.

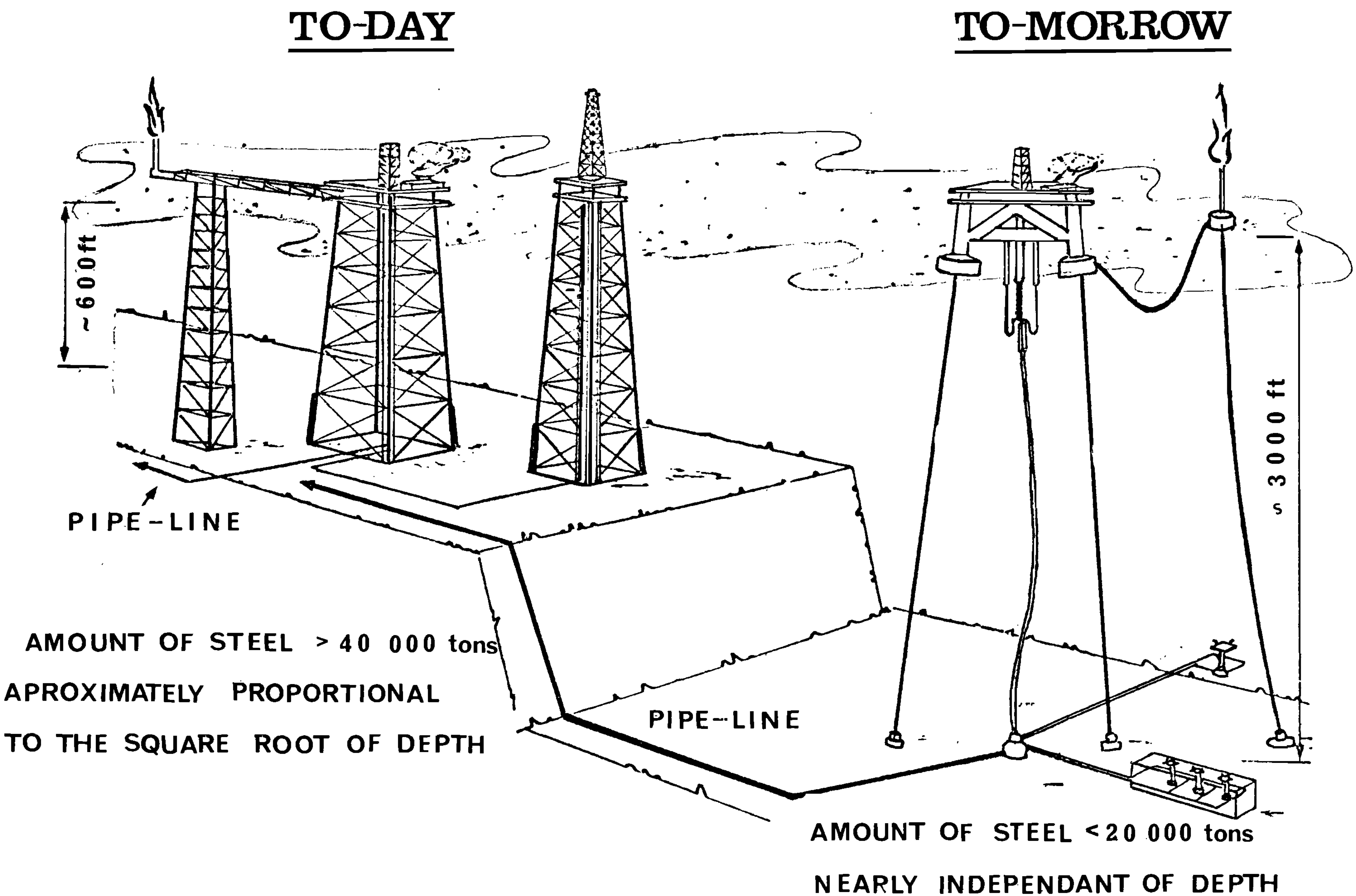

Figure 19-2.--Comparison between production systems with evacuation by pipeline

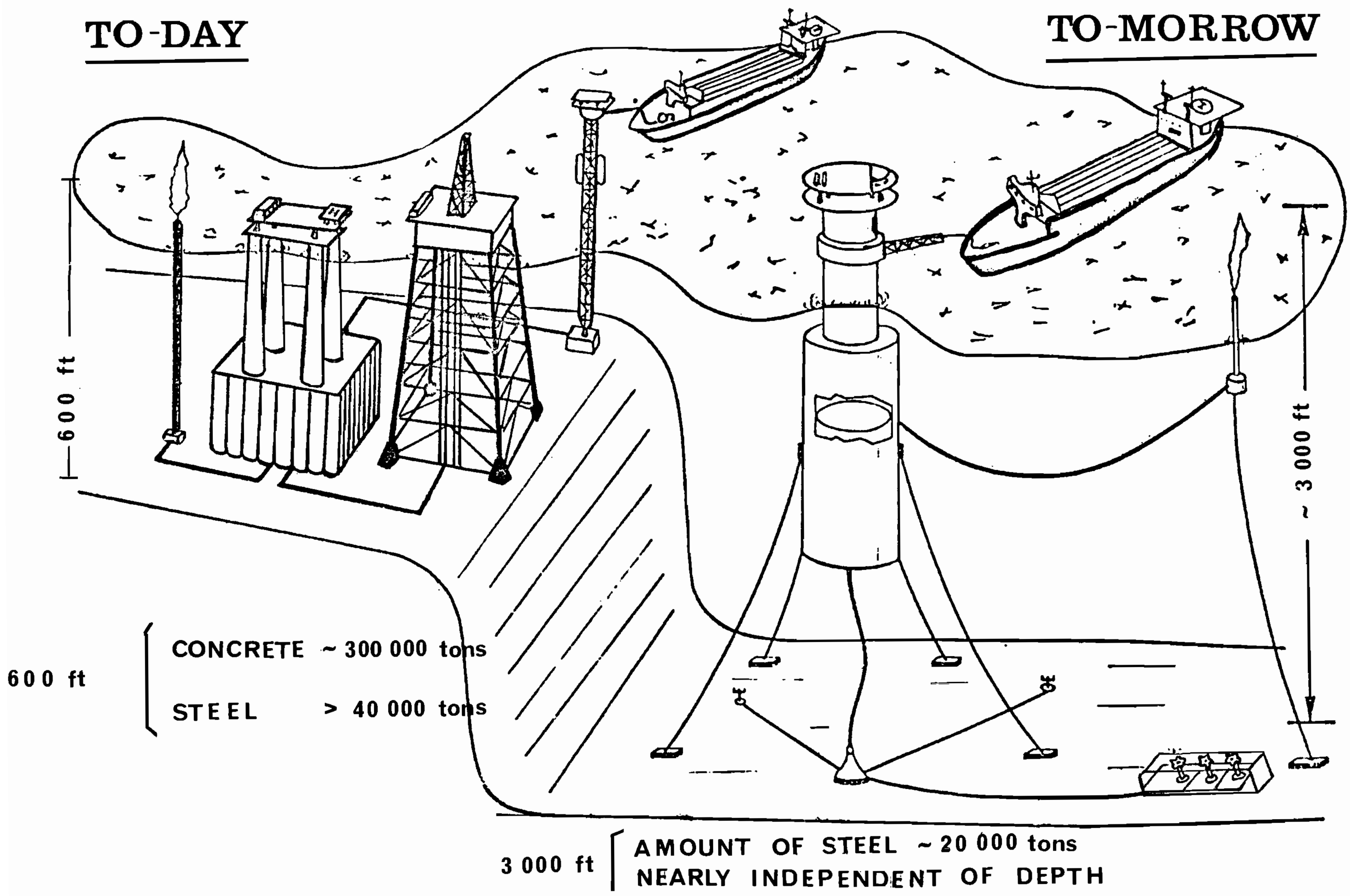

Figure 19-3.--Comparison between production systems with loading at sea

CHAPTER 20

STATUS OF THE USSR NATURAL GAS INDUSTRIAL POTENTIAL AND FUTURE PROSPECTS

I. P. Zhabrev, V. I. Yermakov, E. Y. London,
V. I. Staroselsky, and V. P. Stupakov[1]

Natural gas contribution to the USSR fuel-energy supply has increased to date to 21.5 percent and in the foreseeable future will apparently maintain a steady upward trend.

A total of 289.3 x 10^9 m^3 of natural gas was produced during 1975 and the increase to 1980 is estimated at 400 to 435 x 10^9 m^3. Such a high forecast of the country's natural gas producing capacity is in accord with the magnitude of available reserves of natural gas, which to date exceed 25 x 10^{12} m^3.

The rapid development of the gas industry in the past two decades was strongly influenced by the discovery of major gas-bearing provinces within the European and, especially, within the vast Asian areas of the country. Previous exploration for natural gas resulted for the most part in minor or moderate gas finds, which allowed little significant improvement in the country's available gas supply. Production coming from the established gas fields in North Daghestan, South Ukraine, Zavolzhye, and other regions, could not meet the country's needs of local industries. A total of 3,219 x 10^6 m^3 of natural gas, mostly associated, was produced over all the USSR in 1940.

Consideration of the factors affecting prewar development makes it immediately apparent that the flagging of the country's industrial gas supply was due mainly to limited exploration

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[1]USSR.

confined to primary oil-bearing areas, particularly in the Azerbaidjan SSR, Grozny, and Ural-Emba districts; West Turkmenia; the western part of the Timan-Pechora province; and the Krasnodar and Daghestan regions. As a result, mainly oil-discoveries were made and there seemed to be general agreement that the country had a poor overall gas potential.

The first major gas discoveries in the USSR were made in the early 1950's. The areas chiefly concerned were the North Stavropol, Shebelinsk, and Gazli dry-gas fields and a number of gas-condensate fields in North Krasnodar. During the same period, gas discoveries were made in West Siberia (Beryozovskoye) and Yakut (Ust-Vilyuiskoye) areas.

These events, first of all, created the necessity of organizing commercial gas production and, secondly, displayed evidence that there are adequate potential supplies of natural gas to be found in various environments all over the country--in Europe, West and East Siberia, and Middle Asia.

Subsequent intensive exploration and development work carried on in virgin territories, with emphasis on gas, led to the discovery of the most prolific fields and areas. This occasioned a large addition to proved reserves and strongly influenced the further growth of gas production. Past production of natural gas in 1950 was 5.8×10^9 m^3 and in 1955, 9×10^9 m^3, whereas in 1970 it averaged 197.9×10^9 m^3 and, at the end of 1975, 289.3×10^9 m^3. By 1976 cumulative gas production for the entire country approximated $2{,}500 \times 10^9$ m^3.

Estimates show that in the USSR there are somewhat more than 8.5×10^6 km^2 with established gas production or prospective for gas, including 1.8×10^6 km^2 of primary gas-bearing, 0.3×10^6 km^2 of predominantly oil-bearing, and 6.4×10^6 km^2 of oil and gas bearing area.

Worthy of note is the fact that to date there are 730 gas and gas-condensate producing areas; 75, or about 10 percent, have estimated available reserves above 30×10^9 m^3 and 80 percent of the total reserves are concentrated in these highly prolific gas fields.

Commercial gas comes from formations of the Cambrian to the Neogene, and noncommercial gas finds have been made in Upper Proterozoic sediments. Commercial gas finds in the Cambrian were made in East Siberia, particularly in the southern part of the platform. The most significant production zones are in the Lower Cambrian clastic-carbonate rocks in the Markovsk, Srednye-Botuobinsk, and several other minor gas fields. Showings of oil and gas were encountered in the Middle and Upper Cambrian rocks. The information available indicates that a major part of the area of the East Siberian platform has favorable prospects for Cambrian gas.

Little is known as yet of the Ordovician and Silurian formations and the gas prospects are subject to speculation. Commercial gas has been found in the Timan-Pechora oil and gas province. A well drilled in the kimberlite plug of Udachni (Yakutia) flowed gas. There are indications that gas might be found in certain areas of the East Siberian platform, particularly within the vast pre-Sayan depression, and elsewhere.

The Devonian formation is predominantly oil-bearing. Small gas fields have been discovered in the Timan-Pechora oil and gas province, the Nizhni-Povolzhye areas, and recently in the Chu-Sarisuisky synclinal depression (Kazakhsky ASSR). There are favorable prospects for gas in the Devonian in the Dneprovsk-Donetsk and pre-Caspian depressions, the pre-Ural foredeep, and the Tungusk synclinal depression. The evidence indicates that gas accumulations in the Devonian may be found at depths below 5,000 m, but the availability of this gas is strongly dependent on engineering techniques.

The major portion of the proved reserves of natural gas is in the Permian-Carboniferous rocks of the Paleozoic. The most attractive areas are in deeply submerged basins with sedimentary volumes of more than 5 km. The reservoirs rich in gas are overlain by practically impermeable salt rocks, that provide excellent capping for the accumulations. Such conditions have been identified in the Dneprovsk-Donetsk depression, the pre-Ural foredeep, and in the Vilyuisk syncline. The major established gas fields in the Permian-Carboniferous, e.g., Orenburg, Shebelinks, Zapadno-Krestischensk, and Vuktil are in the European areas of the USSR. Many more areas, believed to be favorable for gas in the Permo-Carboniferous sections, have been prospected in the marginal provinces of the pre-Caspian depression, within the pre-Verkhoyansk, Anabar-Lensk, and Khatanga foredeeps, and in several other areas of the Russian and East Siberian platforms.

The most significant proved and potential reserves of natural gas known to date are in the Mesozoic formations.

Gas fields, where production comes from the Triassic, have been found in the Dneprovsk-Donetsk basin, the Bolshezemelskaya Tundra, and the Vilyuisk depression. The Srednyevilyuisk gas field is producing from Triassic rocks and available evidence indicates that new gas finds in the Triassic might be made in the pre-Caspian depression, the pre-Verkhoyansk foredeep, and in other places.

Important gas accumulations have been found in the Jurassic. Numerous gas fields in the Jurassic were discovered in the pre-Caucasus, the pre-Carpathian, and Dneprovo-Donetsk basins, and in the Nizhni-Povolzhye area. Exploration for gas in the Jurassic began just recently. In the light of present knowledge it is believed that in the North Caucasus the prospects are favorable for deep gas finds in the Middle Jurassic beds which are overlain by thick salt and shale caps.

In the Amu-Dar'ya gas province, Middle Asia, there are several areas already producing gas in the Jurassic (Samantepe, Urtabulak, Ushkir, and others). Numerous gas and oil fields have been found in the Jurassic in South Mangishlak.

The Beryozuvsk, Ust-Vilyuisk, Vasyugan, and Vilyuisk gas fields, Siberia, produce essentially from Jurassic rocks. These sediments are believed prospective for gas in other areas of the USSR, particularly in the Far East and North East regions.

The most prolific fields and largest proved reserves of natural gas in the USSR, known to date, are in Cretaceous rocks. The Urengoy, Yamburg, Zapolyarnoye, Medvezhye, and others, in the northern part of West Siberia, are among the world's largest known gas fields. Major gas fields in East Turkmenia, West

Uzbekistan, and the pre-Caucasus produce principally from Lower Cretaceous rocks. Other areas of East Siberia, the Far East, and North East of the USSR have favorable prospects for gas in the Cretaceous.

Several fields in the pre-Caucasus (the Stavropol gas field), pre-Carpathian, West Turkmenian, and Azerbaidjan regions produce or have produced mainly from Cenozoic rocks. Some minor fields where production comes from Cenozoic rocks are in the Ferghana Valley, Tadjikistan, and Sakhalin Island. A discovery well completed in 1968 in the Neogene, in the Anadir basin, flowed commercial gas.

Analysis of the stratigraphic distribution of the proved reserves of natural gas makes it immediately apparent that the rich gas reserves are clearly associated with certain distinctive producing zones of the sedimentary sequence, which are remarkably uniform in character over wide areas. The evidence indicates that within areas of the ancient platforms the major gas reserves are associated with the Permo-Carboniferous and the Lower Paleozoic sections, which are the principal strata controlling gas accumulation throughout the Russian and East Siberian platforms. The primary gas-producing zones, which are highly prolific in the areas of West Siberia, Middle Asia, and the pre-Caucasus, are in the Mesozic Upper Jurassic-Cretaceous formation. The available gas reserves in these sedimentary sections approximate 20 x 10^{12} m^3, i.e., 80 percent of the proved reserves of natural gas in the USSR.

Geological interpretation of the data obtained from exploration and development drilling, carried on in the country to date, provided evidence of the conditions controlling oil and gas accumulation. Application of these concepts prompted the discovery of primary gas-bearing, as well as oil-bearing areas. As a result, by 1976 the estimated proved reserves of natural gas in the A+B+C_1 categories approximated 25.1 x 10^{12} m^3, 17 percent of which are within European areas, 66.6 percent in West Siberia, and 14.1 percent in Middle Asia and Kazakhstan.

The proved reserves of natural gas are essentially in primary gas-bearing areas with relatively low recoverable oil reserves. The areas chiefly concerned are in North Tyumen, Uzbekistan, East Turkmenia, and East Ukraine (Dneprovsk-Donetsk basin).

The major gas reserves are for the most part in highly prolific gas and gas-condensate fields. Free-gas caps in oil fields contain no more than 4 percent of the total available reserves. Most of the free-gas caps are in the established oil-producing areas of South Tyumen, West Turkmenia, and Krasnodar.

Of the country's available gas reserves, 81.5 percent are in Mesozoic rocks, 15.1 percent in Paleozoic, and only 3.2 percent in Cenozoic.

As mentioned above, the major portion of the proved reserves of natural gas are in Cretaceous rocks that are of wide areal extent and high gas potential throughout the West Siberian, Turkmenian, Kazakhstan, and North Caucasian regions.

Studies of the distribution of natural gas reserves in relation to depth evidence strongly that 9.5 percent of the discovered reserves are at depths above 1,000 m, 83 percent at depths ranging from 1,000 to 3,000 m, and 7.4 percent below 3,000 m. In view of recent discoveries in the areas of Ukraine SSR, Komi SSR, and Turkmen SSR, it becomes immediately apparent that essential gas and gas-condensate finds might be made at depth. Of the gas reserves within the European areas of the country, 15.3 percent are estimated at depths below 3,000 m. In the Ukrainian SSR, 48.9 percent of the recoverable gas reserves are in formations below 3,000 m. In Middle Asia, 37 percent of the available reserves have been explored in deep areas.

There are currently in the USSR over 730 gas-producing fields including dry-gas, free-gas caps in oil fields, and gas-condensate. The most prolific areas are within the Russian, East and West Siberian, and Middle Asian platforms. The most significant reserves of natural gas associated with intermountain depressions are in the South Caspian, including the western (Azerbaidjan SSR) and eastern (West Turkmenia) marginal provinces. Of the total gas fields discovered to date, 619 contain dry-gas or gas-condensate.

An outstanding feature of the established gas-producing areas is the concentration of major deposits of hydrocarbons within one or two highly prolific producing zones. In 333 (57.5 percent of the total) dry-gas and gas-condensate fields the productive section is in one or two uniform, highly prolific reservoirs. The Orenburg, Vuktil, Shatlik, Shebelinsk, and other fields are volumetric reservoirs with huge reserves of natural gas.

The USSR overall has 1,264 gas-pays in already-producing areas of dry-gas and gas-condensate. Of these, 713 are in European areas, 247 (19.5 percent) in the Ukraine, 129 (9.8 percent) in the gas-producing areas of Uzbekistan, and 104 (8.2 percent) in Turkmenia. The 333 gas-pays containing dry-gas, i.e., 38 percent of the total estimated for entire country, are in the already gas-producing areas of Middle Asia and Kazakhstan. Numerous gas fields with multiple gas-pays have been discovered.

Gas accumulation within the sedimentary section is profoundly influenced by the degree of continuity and controlling features of the confining beds. The fundamental control of gas accumulations by impermeable salt deposits is apparent in the Permian. Such impermeable sections of widespread regional extent create a situation where no gas of significant quantities can accumulate in the overlying sedimentary rocks. On the other hand, previous channels and limited continuity of the capping rocks furnish avenues for vertical migration, resulting in the redeposition of the hydrocarbons in the overlying beds. There is positive proof of the presence of such conditions in the established gas fields in the areas of the Ukraine, Nizhni-Povolzhye, West Uzbekistan, and others. The evidence indicates that similar conditions are common in clastic rocks.

Of the total gas accumulations known to date, 748, or 59 percent, are at depths between 1,000 and 3,000 m and 500 (40 percent) of these are in the Mesozoic section.

Although minor gas finds have been made in formations lying below 5,000 m, it is here suggested that the discouraging results in deeper prospecting are due mainly to sparse drilling in these zones and do not imply that the gas potential at depth is less attractive. The general opinion, supported by the observed results, is that the prospects for gas and gas-condensate increase with depth, whereas the discovery of oil deposits is subject to considerable conjecture. The major discovered gas reserves are in primary gas-bearing areas, where oil accumulations are practically unknown, or of minor significance.

Upon careful analysis of the many factors controlling gas accumulation, it becomes apparent that the specific conditions in primary gas-bearing areas are due to tectonic features. The evidence indicates that within ancient platforms the established gas-bearing areas are in deep depressions of Late Paleozoic development. Prolonged subsidence which occurred during the Lower and Upper Paleozoic allowed a great thickness of sediments, including widespread evaporites, to accumulate in the basins. These subsidiary structures are for the most part within the marginal areas of the platform and largely known as marginal or intracratonic depressions.

The primary gas-bearing areas in the Mesozoic are confined to depressions of maximum subsidence, which generally occur in the central parts of the platforms. In contrast, the subsidiary structures, located within marginal regions of the platforms adjacent to Alpine fold belts, as well as intermountain depressions of the fold belts, are essentially oil-bearing areas.

The major available reserves of natural gas, approximately 90 percent of the total estimated reserves of the Russian platform, are within the deep subsidiary structures of the pre-Ural foredeep and the Dneprovsk-Donetsk depression.

There is as yet meager knowledge of the tectonic features controlling gas accumulation within the East Siberian platform. However, the major gas discoveries are in the Vilyuisk synclinal depression of Paleozoic-Early Mesozoic age. There seems to be general agreement that adequate potential supplies of natural gas might be found within the deep subsidiary structures of the Tungusk syncline and the pre-Verkhoyansk foredeep.

The huge reserves of natural gas discovered in the North Tyumen areas, West Siberia, are in depressions of maximum subsidence of the platform. On the contrary, the primary oil-producing areas, established in the southern part of the platform, are in shallow depressions, where Mesozoic sedimentary rocks are not more than 2 to 3 km thick.

Similarly, in Middle Asia the major gas reserves are within the deeply submerged depressions. The Amu-Dar'ya synclinal depression which accumulated over 10 km of sedimentary rocks, is a primary gas-bearing area.

The rate at which the undiscovered gas supply has been made available in past years serves to prove that more intensive exploration should profoundly increase the available reserves of natural gas in the foreseeable future. In past years the addition in the country's overall gas supplies by far surpassed the gain in gas production. An immediate result of this was a steady ever-increasing gain in recoverable gas reserves. Estimates show a 28-fold increase to 1966, whereas by 1975 the increase in recoverable gas reserves as compared to gas production was 95.9 times. Cumulative production during the same period increased from 125.2 to 289.3 x 10^9 m^3.

Outstanding among the established gas-producing areas were those in West Siberia, Middle Asia, and Orenburg regions, where the recoverable reserves totaled 9 x 10^{12} m^3, or 92 percent of the country's total which to the end of 1975 amounted to an estimated 11 x 10^{12} m^3.

The exploration program for future gas prospects involves an increase in drilling operations in the more attractive areas which in recent years have shown encouraging results for major gas discoveries, and limited drilling in areas where the prospects believed to be favorable have offered little encouragement. In the gas-producing areas of North Tyumen, West Siberia, additional drilling of confirmation wells is of compelling importance in order to evaluate the available and remaining undiscovered supply of natural gas and gas-condensate in the Jurassic-Cretaceous formations. Late developments in the Urengoy gas field serve to prove that new discoveries can be made in the sedimentary sections underlying the rich Senomanian producing zone. Four gas-condensate finds have been made in the Valangian, five in the Hauterivian-Barremian, and two dry-gas finds in the

Aptian-Albian sections. Similar discoveries have been made in other areas (Zapolyarnoye and others) of the North Tyumen region and give indication of important gas reserves in the Neocomian-Jurassic sections.

Despite the brisk pace of exploration in these most prolific areas, records of drilling operations show that the most dense drilling averages one well per 5,500 km^2. There are as yet large untested targets at depth. Consequently, great emphasis should be made on future deep prospecting for the undiscovered supply of natural gas, both in the Senomanian and the Neocomian-Jurassic; on further development drilling in the highly prolific productive zones; and on the magnitude of new discoveries to be made in unknown prospective zones. Hence, in the foregoing outline it is apparent that the exploration program for future prospects in the North Tyumen areas involves intensive drilling particularly within the already-producing fields. The primary objectives are the Lower Cretaceous rocks, particularly the Senomanian, containing the reservoirs richest in gas, and the Jurassic, which has shown favorable prospects for gas. Besides, additional development drilling is of compelling importance to provide a higher overall production, required to meet the ever-increasing demand for gas and also to appraise the commercial value of oil deposits that underlie the gas. Consideration of the problems stated strongly indicates the necessity of a significant increase in drilling operations in the Urengoy, Zapolyarnoye, Zapadno-Tarkosalinsk, and Vostochno-Tarkosalinsk gas fields, which are the most susceptible to greater ultimate recoveries.

Besides, the exploration program in the North Tyumen region involves a large expansion into the virtually unknown areas of the Yamal Peninsula. Despite the meager drilling operations carried on in recent years in the northwestern parts of the Peninsula, important gas discoveries were made in the Senomanian, Albian, and Aptian. The gas fields are located on major brachyanticlinal structures, such as the Bovanenkovsk, Kharasaveysk, Yuzhni-Tambeysk, and others.

The past years witnessed important developments in East Siberia which indicate rather strongly that the area has adequate gas supplies to insure future efficient development of the gas industry. The proved reserves of natural gas in the Leno-Vilyuisk syncline approximate, to date, 615 x 10^9 m^3. This basin contains a sedimentary section 6 to 7 km thick and highly favorable gas prospects over an area of somewhat more than 850,000 km^2. Many more areas within the Vilyuisk synclinal depression, the central and northern parts of the Verkhoyansk foredeep, the Nepsk-Bouobinsk anticline, the junction of the anticline and the pre-Patom foredeep, the Tungusk depression, and the Anabar Uplift have favorable prospects for gas discoveries. The high estimation of the total undiscovered reserves of natural gas in these areas of Yakut SSR strongly suggests the necessity of intensive exploration drilling by which the potential supply of natural gas can be found and made available.

The primary objectives are:

- The Triassic and Jurassic sediments in the Vilyuisk depression;
- The Upper Jurassic and underlying sections of the Khapchagai meganticlinorium;
- The Lower Paleozoic and Precambrian (Vendian) sedimentary rocks within the Mirnen Uplift and the Vilyuchansk arch.

Besides, the exploration program involves additional development drilling in the Ust-Yeniseysk area and Krasnoyarsk, and more intensive work within the Tungusk synclinal depression, which has an area of more than 900 km^2. The chief objectives are the Precambrian-Triassic sections which have a thickness of more than 6 km. Recent gas finds, made in the Cambrian on local structures within the internal and marginal areas of the depression, strongly support the high forecast of the basin's gas potential. The most attractive areas are the Tarukhansk-Norilsk ridge, Podkamenno-Tungusk Uplift, and the Khatanga arch.

The Irkutsk area, where gas discoveries were made in the Cambrian, is regarded as highly favorable for new gas finds. The most attractive areas available for exploration are the

Nepsk Uplift, the Ust-Kut High, the Bratsk Uplift, and the Verkhnyeangarsk series of highs in the Irkutsk Amphitheater.

Many of the already-productive places in East Turkmenia offer good prospects for new gas discoveries in the sedimentary sections underlying the Upper Jurassic evaporites. The observed results encourage more dense drilling in the carbonate rocks, where discoveries of sour gas might be made, and in the clastic rocks for low-sulfur gas. The prospects are highly favorable and encourage further deep drilling in the Upper Jurassic in Shatlik, where gas production is established, and in the underlying Middle and Lower Jurassic in Kirpichlinsk and Zaungusk, where commercial gas finds might be made. The southwestern submerged section of the Gissar mountain range, Uzbek SSR, is an important area for gas prospecting.

In view of recent developments in Middle Asia, a major exploration question is the possible magnitude of gas discoveries to be made in the Paleozoic rocks within the Thuranian platform. The area chiefly concerned is the Chu-Sarisuisk depression, where gas accumulations have been found in Carboniferous and Devonian rocks.

Thus, there are many attractive areas with good prospects for gas and gas-condensate in Siberia and Middle Asia. In contrast, the European part of the country, especially Povolzhye, North Caucasus, and the Ukraine, in past years have shown a marked decline in available remaining reserves of natural gas and the magnitude of future discoveries is subject to considerable conjecture.

One of the primary objectives is the Denisovsk trough of the pre-Ural foredeep, Komi SSR, where additional available reserves might be found. Additional exploration in the Karataikhinsk and Kosyu-Rogovsk areas of the Timan-Pechora depression might offer encouraging results for further gas prospecting.

In the Orenburg region, the pre-Ural foredeep, the south flank of the Sol-Iletsk Uplift, and the South Orenburg area are considered most attractive for available reserves of natural gas. The future exploratory objectives are local structures in the northern and western provinces of the pre-Caspian depression, where, as in Nizhni-Povolzhye, accumulations of sweet gas might be found in the Devonian.

Future exploration in the Ukraine and North Caucasus will be along the lines of the foregoing program. Considering the results, an adequate addition to proved reserves might be obtained to maintain present gas production.

The rate at which the potential gas supply can be made available throughout the USSR and in particular areas strongly depends on the magnitude of future discoveries and necessitates significant improvement in prospecting methods being used.

The huge reserves of natural gas in the already-producing areas of North Tyumen, Yakutia, and Middle Asia offer great advantages for the foundation of production centers of high capacity and prompt the necessity of constructing powerful gathering and transmission systems for the transport of large volumes of gas to the main consuming centers in the west and east. Cumulative production to 1980 will increase to approximately 125 to 155 x 10^9 m^3 and will continue rapid growth in the foreseeable future. The predicted increase in available gas reserves in East Siberia, particularly in Yakut USSR, also creates a high productive capacity for these regions. Future prospects for gas production are associated with Asian USSR, where 84 percent of the estimated proved reserves and 88 percent of the remaining potential supply of natural gas is found.

CHAPTER 21

DISTRIBUTION OF POTENTIAL HYDROCARBON RESOURCES IN THE USSR AND ITS BEARING ON PROSPECT EVALUATION

S. P. Maximov, G. E. Dickenstein, and I. P. Lavrushko[1]

Distribution of potential petroleum resources is controlled by a set of geological and geochemical factors. Since the large territory of the Soviet Union is remarkable for the great variety of its geological structure, it appears evident that the problem of unveiling these regularities is the currently central problem and, therefore, it is tackled by groups of scientists in many research organizations of the country. To reveal the laws governing the occurrence of hydrocarbon accumulations, a series of investigations is being undertaken. They include analysis of the discovered oil and gas fields and their distribution by types and stratigraphic position, and study of productive units and caprocks. Great importance is attached to detailed study of tectonics and geological evolution of large regions. With this in view, the structure of various tectonic elements, their fracturing, local uplift, and time of formation, is analyzed.

During recent years extensive geochemical investigations also have been accomplished. They include study of organic matter, bitumens, oils, gases, and condensates as well as elaboration of their classification. This was done to enable geologists to forecast the phase state and quality of hydrocarbons to be found and also to evaluate the parameters which control the oil and gas generation and migration ability of rocks, considering the thermal and pressure conditions of the earth's interior.

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[1]USSR.

These investigations are necessary to acquire a general idea of the petroleum potential of the area.

Extensive work has been conducted also to develop techniques, both geological and geochemical, for evaluation of predicted (speculative) hydrocarbon reserves. The first of these includes the analogy and volumetric methods proper and the second, volumetric-statistical methods. Computer processing techniques are used in both groups of methods.

The following analytical techniques are used while conducting the whole series of investigations: modelling of oil and gas pool formation and exploration procedures; isotope study of different elements; gas chromatography; compositional analysis of rocks and study of their reservoir properties; and similar approaches.

A great significance is attached to the problem of oil and gas regioning[2] in the USSR. This is done by taking into consideration both the results of geological exploration and research carried out in the Soviet Union, and experience assimilated abroad.

The oil and gas is of great importance, firstly, for revealing geological conditions which determine the pattern of potential hydrocarbon resources distribution, and, secondly, for defining zones where conditions are most favorable for the concentration of large resources. Consequently, this important problem is solved by undertaking the whole series of investigations mentioned above.

In this paper the USSR is subdivided into oil and gas bearing provinces, regions, and areas (Fig. 21-1). This allows the finding of distinct regularities in distribution of maximum oil and gas concentrations within the limits of the largest tectonic elements and zones. Moreover, the application of this principle allows the differentiation of the whole prospective territory of the Soviet Union. It would have been a very complex task to solve the same problem if regioning was done according to the

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[2] Oil and gas "regioning" means subdivision of the territory into regions, taking into account similarity of regional geology and petroleum potential.

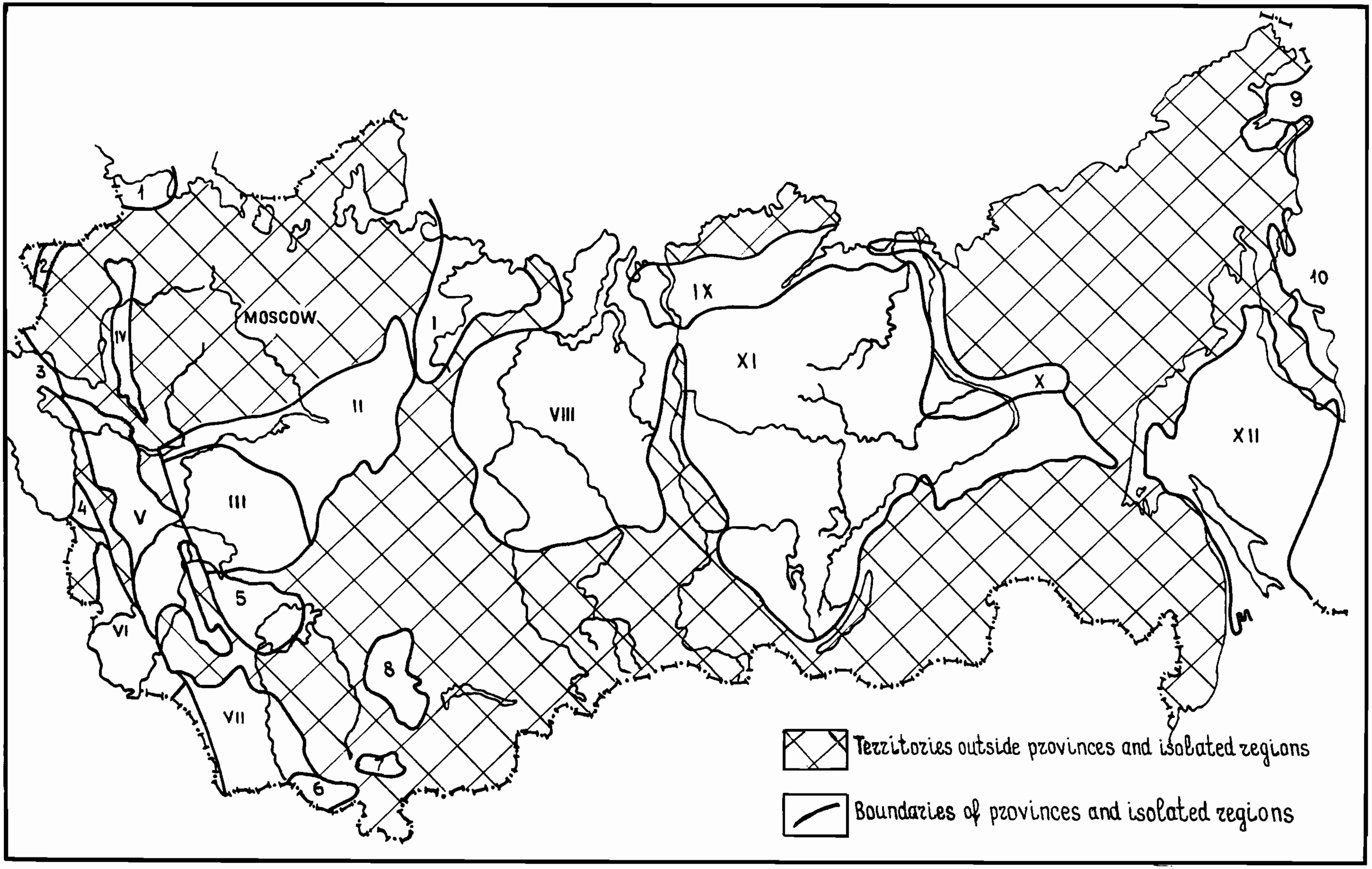

Figure 21-1.--Location of oil- and gas-bearing provinces and isolated areas in the USSR

"basin" principle. The Volga-Ural province, which can not be considered as a basin, may serve as an example to make the point clear. The North Caucasus-Mangyshlak, Lena-Tunguska, and other provinces are examples of the same kind.

The procedure of oil and gas regioning of the USSR implies detailed analysis of geotectonic, lithostratigraphic, paleogeographic, paleostructural, geochemical, hydrogeologic, geomorphological, and other peculiarities of each region. Finally these investigations make it possible to assess prospects and exploration rates of oil and gas bearing territories as a whole, as well as to determine the potential of certain individual rock stratigraphic units.

The following are the definitions of provinces, regions, and areas.

An oil and gas bearing province is a large isolated territory composed of sedimentary rocks developed within extensive areas. It is confined to one or a group of contiguous large tectonic elements (plate, syneclise, anticlise, foredeep) which have similar features of structure and geological evolution, a certain productive stratigraphic range, a set of geochemical, lithofacies, and hydrogeological conditions, as well as a high potential to generate and accumulate hydrocarbons. An oil and gas bearing province is limited by nonprospective and poorly prospective lands. In a number of cases one oil-gas bearing province can border another, being separated by main faults or a zone where an abrupt change in the ages of sedimentary rocks takes place.

If similar territories are estimated to have sufficient predicted reserves but oil and gas fields have not yet been found, they are denoted by a term "prospective oil-gas bearing provinces."

An oil-gas bearing region can be either a part of an oil-gas bearing province or an isolated area, mainly confined to one or several large structural elements (foredeep, arch, fault bench, large elongated swell, depression, zone of uplifts or sags). These elements should be characterized by similar structure, geological evolution, and regional distribution of main productive horizons. Their predicted and initial proved reserves of oil and gas should be considerable.

If similar territories seem to contain sufficient quantities of predicted reserves but do not have proved reserves they are named prospective oil-gas bearing regions. Isolated oil-gas bearing regions are generally limited by nonprospective or poorly prospective lands.

An oil-gas bearing area is a part of an oil-gas bearing region. This territory, with proved hydrocarbon reserves, is confined to the locality where oil and gas fields were discovered and it commonly occupies one or several structural elements of medium size (basement rise, linear swell, dome-like uplift, depression) or portions of them. These elements should include the same pay horizons, occurring approximately at the same depths. The types of oil and gas fields and phase state of hydrocarbons in pools, should also bear a resemblance.

Depending upon the ratio between proved oil and gas reserves one can distinguish oil-bearing (more than 90 percent oil), gas-bearing (more than 90 percent gas), oil-gas and gas-oil bearing (predominance of either fluid) provinces, regions, and areas.

The following largest, large, and medium sized structural elements in sedimentary rocks were used for the purpose of oil-gas regioning:

1. largest positive elements: anticlises, cresta-like uplifts; and negative elements: syneclises, graben-like troughs, foredeeps;

2. large positive structural elements: arches, linear megaswells, zones of uplifts; and negative elements: depressions, troughs;

3. medium-sized positive elements: linear swells, dome-like uplifts, basement rises, anticlinal zones; and negative elements: depressions, basins.

The boundaries of platforms, folded areas, foredeeps, and intermountain depressions, both inland and offshore, were defined by analyzing all recently-obtained geological and geophysical data. Tectonic regioning of the folded areas was done in compliance with the conventional scheme.

Principally, two types of the largest and large arch-like uplifts can be distinguished. These types, differing from one another by depth to the basement, are as follows.

The first type comprises uplifts where the basement lies at very shallow depths or even is exposed at the surface (Beloruss-Mazursk, Voronezh, and Anabar anticlises and, Tokmov and Kara-bagaz arches).

The second type includes those uplifts where the basement lies at depths of 1.5 or more km (Central Karakum, Tartar, and Nizhnevartov arches).

Most of the arch-like uplifts belonging to the first type are nonprospective, while the uplifts of the second type are considered to be prospective. Thus it is to be said that insufficient thickness of the sedimentary cover is the first sign negating the prospects of the territory. The boundary outlining the prospective and poorly prospective territories within the limits of Turan, West Siberian, Russian, and other plates approximately follows the 1.0 to 1.5 km contour line of the basement relief.

The 12 oil-gas and gas-oil bearing provinces and 10 isolated (oil-gas bearing and prospective) regions were delineated within the confines of the USSR, including its offshore area. They occupy an area of 10.4 x 10^6 km^2 (37 percent of the prospective land of the USSR). These provinces and regions, confined to the largest or large geotectonic elements, are shown on the map (Fig. 21-1) and listed below:

PROVINCES

Timan-Pechora oil-gas bearing - I
Volga-Ural oil-gas bearing - II
Pre-Caspian oil-gas bearing - III
Dnieper-Pripyat gas-oil bearing - IV
North Caucasus-Mangyshlak oil-gas bearing - V
South Caspian oil-gas bearing - VI
Amu-Darya gas-oil bearing - VII
West Siberian oil-gas bearing - VIII
Yenisei-Laptev gas-oil bearing - IX
Lena-Vilyui gas-oil bearing - X

Lena Tunguska oil-gas bearing - XI
Okhotsk oil-gas bearing - XII

ISOLATED REGIONS

Baltic oil-bearing - 1
Pre-Carpathian oil-gas bearing - 2
Pre-Black Sea-Crimea gas-oil bearing - 3
Black Sea oil-gas bearing - 4
Northern Ustyurt gas-oil bearing - 5
Surkhan-Vaksh oil-gas bearing - 6
Fergana oil-gas bearing - 7
Chu-Saryisu gas-oil bearing - 8
Anadyr prospective oil-gas bearing - 9
Eastern Kamchatka prospective oil-gas bearing - 10

Oil-gas bearing provinces of West Siberia (Lena-Tungus, Lena-Vilyui, and Enisei-Khatang) have common boundaries extending for rather great distance. This may be explained by the fact that the main stages of their evolution proceeded at different times, which in turn accounts for different ages of sedimentary strata.

Some of the largest and large tectonic elements (Mezensk, Turgai, and Syr-Darya syneclises, intermountain depressions, and troughs of the Tien Shan orogen, Kazakh shield, Primamur, and Primor areas of the Far East, and others) were not classified as oil-gas geological subdivisions since either their petroleum possibilities were measured only by qualitative parameters or they have been proved to have extremely low potential resources.

Most of the folded systems, shields, and basement outcrops on the platforms are attributed to the nonprospective lands. However, some anticlinoriums, synclinoriums, and periclines within folded systems (East Carpathian anticlinorium, Zalair and Magnitogorsk synclinoriums, north-western and south-eastern plunges of the Big Caucasus meganticlinorium) were evaluated in terms of their quantitative and qualitative possibilities.

It appears from the data on the USSR territories that commercial oil and gas stratigraphic accumulations cover a broad stratigraphic range, from Upper Proterozoic strata of Vendian age, developed within the ancient Siberian platform (Lena-Tungusk oil-gas bearing province), to Upper Pliocene formations of the South Caspian oil-gas bearing province. However, the maximum volumes of hydrocarbons are accumulated within a more limited stratigraphic interval which comprises Devonian, Carboniferous, and Permian strata of the Paleozoic sequence and Jurassic and Cretaceous units of Mesozoic sequence. The share of oil and gas reserves in Neogene rocks is small.

Following the discovery of the West Siberian oil-gas provinces the share of potential resources in Mesozoic rocks increased.

At present the proved hydrocarbon reserves in main stratigraphic sequences are distributed in the following way.

	Oil (Recoverable) (%)	Natural gas (%)
Paleozoic sequence	41.2	16.8
Mesozoic sequence	50.2	79.7
Cenozoic sequence	8.6	3.5
	100.0	100.0

Concentration of the main hydrocarbon reserves in Mesozoic rocks seems to be related to Late Paleozoic Hercynian folding followed by a period of very intense heating of the Earth's crust. It appears from investigations conducted during recent years that high temperatures further the process of hydrocarbon generation to a much greater extent than high pressures imposed in the subsurface rocks. These high temperatures increased the activity of hydrocarbon migration from source rocks, led to redistribution of hydrocarbons in previously existing pools, and formed large fields during the Mesozoic era. The absence of large oil and gas accumulations in Triassic rocks, the oldest in the Mesozoic sequence, suggests that in Triassic time the thermal regime resulting from hercynian folding processes was still characterized by too-high temperatures. Under these conditions large hydrocarbon accumulations could not exist.

The analysis of data on well, or relatively well-studied territories is of particular importance, for establishing regularities in distribution of potential hydrocarbon resources in the earth's crust. In these areas reliable observed relations between different factors relating to petroleum productivity allow definition of a number of the most important parameters necessary for revealing regularities in the oil and gas accumulation process, the formation of hydrocarbon pools, and the distribution of proved and speculative resources.

Regarding the problem of establishing regularities accounting for the process of oil and gas accumulation and distribution by phase state and reservoir volume, it may be said that this can be successfully solved only if a principle of oil-gas geological regioning is taken as a starting point. Application of this principle implies analysis of those tectonic elements of the Earth's crust that were notable for similar geologic evolution, geochemical environments, depositional conditions, and field formation processes. With this in view the provinces and isolated regions are outlined within the limits of ancient and young platforms (including adjacent foredeeps) and mobile zones.

The following provinces are distinguished on the ancient Eastern European platform:

1. Volga-Ural (including marginal Pre-Ural foredeep)
2. Timan-Pechora (including marginal Pre-Ural foredeep)
3. Dnieper-Prypyat
4. Pre-Caspian

The ancient Siberian platform comprised the Lena-Tungusk, Enisei-Laptev and Lena-Vilyui provinces.

The ancient platforms have great potential hydrocarbon resources. This is readily explained by the fact that provinces of these platforms occupy extensive areas and their sedimentary fills are of considerable volume. This is clearly seen on Table 21-1.

The total hydrocarbon potential resources of the ancient platforms (including foredeeps) make up 46 percent of the grand total resources of the Soviet Union.

The share of gaseous hydrocarbons found on ancient platforms is different. The most reliable data on this question are available for the well-studied Volga-Ural and Dnieper-Pripyat provinces. Oil dominates in the first province and gas in the second

TABLE 21-1.--Platforms of the USSR of Mesozoic and Paleozoic age

Name of the province and its maximum size along axes (km)	Areas (10^3 km2)	Maximum thickness of sedimentary cover (km)	Volume of sedimentary fill (10^6 km^3)	Stratigraphic range of oil and gas occurrence
Volga-Ural (900 x 1,300), including foredeep	700 100	6	1.4 0.4	Devonian-Permian
Timan-Pechora (650 x 1,000) including foredeep	350 (land) 110	12	1.4 0.6	Silurian-Triassic
Dnieper-Prypiatsky (150 x 1,000)	100	16	0.8	Devonian-Jurassic
Pre-Caspian (750 x 1,000)	500	20	5.3	Devonian-Cretaceous
Total for provinces of the Eastern European platforms, including foredeep	1,650 210	6-20	8.9 1.0	Silurian-Jurassic
Lena-Tungus	2,800	9	9.0	Precambrian-Permian
Enisei-Laptev (300 x 1,800) including foredeep	390 100	12	1.8 0.7	Permian-Cretaceous
Lena-Vilyui (400 x 1,300) including foredeep	280 100	12	2.0 0.5	Permian-Cretaceous
Total for provinces of the Siberian platform including foredeeps	3,470 200	9-12	12.8 1.2	Precambrian-Cretaceous
Total for ancient paltforms including foredeeps	5,120 410	6-20	21.7 2.2	Permian-Cretaceous

one. Such a proportion of fluid and gaseous hydrocarbons is accounted for mainly by the following factors.

The reserves discovered in the Dnieper-Prypyat province are concentrated in Lower Permian-Carboniferous rocks, composing the southeastern part of the depression (Shebelinka, Western Kresti-shensk, Efremovka, and other fields). The main gas source beds are represented by Middle Carboniferous coal-bearing formations, where organic matter is of humic composition. Coal fields of Donbas region are associated with this formation. The province in question is also remarkable for its peculiar geological evolution because it belongs to a graben-like troughs structure, where tectonic movements were active. A sedimentary cover 16 km thick testifies to active past movements.

In Volga-Ural oil-gas bearing province oil reserves are associated with Devonian and Carboniferous strata where organic matter is mostly of sapropel type. Maximum depths to the basement surface penetrated in zones of main concentration of oil reserves (central areas of the province) range between 2 and 4 kms.

In Timan-Pechora province oil fields also predominate.

The following provinces are distinguished on young platforms:

1. Northern Caucasus-Mangyshlak (including Kuban and Tersk-Caspian foredeep);
2. Amu-Darya (including Pre-Copetdag foredeep);
3. West Siberia.

Data on young platforms, comprising large potential hydrocarbon resources are given in Table 21-2.

Potential hydrocarbon resources of young platforms, including foredeeps, make up 49 percent of the grand total resources of the USSR.

The phase state of hydrocarbon occurrence discovered within the most studied areas of young platforms is described below.

In Northern Caucasus-Mangyshlak province the shares of gas and oil are almost equal. In platform areas of Central and Western Fore-Caucasus, gas makes up 97 percent. In the remaining

TABLE 21-2.--Platforms of the USSR of Mesozoic and later age

Name of the province and its maximum size along axes (km)	Areas (10^3 km^2)	Maximum thickness of sedimentary cover (km)	Volume of sedimentary fill (10^6 km^3)	Stratigraphic range of oil and gas occurrence
Northern Caucasus-Mangyshlak (500 x 1,900)	530	12	2.8	Triassic-Neogene
including foredeep	120		1.0	
Anu-Darya (500 x 1,000)	360	7	1.3	Jurassic-Cretaceous
including foredeep	30		0.2	
West Siberian (1,400 x 2,200)	1,900	9	8.0	Carboniferous-Cretaceous
Total for provinces of young platforms	2,790	7-12	12.1	
including foredeep	150		1.2	

provinces of young platforms, gaseous hydrocarbons occur in much larger quantities than oil.

In Northern Caucasus-Mangyshlak province (in its platform part) and in West Siberian province the main proved oil reserves are in Jurassic and Neocomian rocks which occur at depths of 3.5 to 4 km. It is suggested that in northern areas of West Siberia, large volumes of gas may also be discovered in these rocks, which occur there at greater depths. In younger sediments of Albian (Northern Caucasus) and Upper Cretaceous and Paleogene (Northern Caucasus) age, gas fields predominate. This regularity is accounted for by a number of factors. The most important of factors analyzed is the type of organic matter which generated hydrocarbons and also thermal and pressure conditions under which oil and gas source rocks existed.

While comparing the platforms by age of their formation it can be concluded that gaseous hydrocarbons predominate on young platforms. This seems to be related with duration of processes responsible for formation of oil and gas source rocks, and generation and accumulation of hydrocarbons. It seems that source rock strata of young platforms are not sufficiently mature in terms of transformation state of organic matter, and therefore, they produce gas rather than oil.

However, this regularity is not observed in some areas of young platforms, where the ratio of oil to gas is essentially different. For example, in Eastern Fore-Caucasus (platform part) and Southern Mangyshlak regions, the share of gaseous hydrocarbons makes up 21 and 8 percent respectively. This appears to be explained by the higher degree of transformation of source rock organic matter because the tectonic regime was more active and the sediments buried to greater depths.

Data on ancient and young platforms pertain to relatively well-studied provinces where initial proved geological reserves of oil and gas were estimated. From the analysis performed, it turns out that the established ratio of fluid to gaseous hydrocarbons would not change in principle if predicted reserves were also taken into account.

The territory of the Soviet Union includes South Caspian and Ikhotsk provinces, which are considered to belong to mobile belts. Some data on these provinces are given in Table 21-3.

The mode of distribution of potential hydrocarbon resources is the same in mobile belts as in platforms and foredeeps.

The South Caspian oil-gas province, being one of the oldest producing areas in the USSR, is the most studied. The main proved hydrocarbon reserves are concentrated here in productive strata of Middle Pliocene age, which are considered by some workers to be the source rocks. In the future, predominantly gas fields may be discovered in deeper horizons of the productive strata and in underlying rocks. Gas may also predominate in central parts of South Caspian depression.

From data presented above and obtained during analysis of potential hydrocarbon resources (which comprise predicted reserves, initial proved reserves of categories A + B + C, and prospective reserves of C_2 category), it becomes possible to define the main tendencies in resource distribution by main geotectonic elements of the USSR.

The principal hydrocarbon resources are confined to the platform territories (without foredeeps), which cover an area of 7.9×10^6 km^2 (including isolated oil-gas bearing regions of platforms); this accounts for 76 percent of the area occupied by all provinces and isolated regions of the USSR. Ancient platform areas make up $4{,}810 \times 10^3$ km^2, while young ones account for $3{,}110 \times 10^3$ km^2.

The volume of sedimentary fill expressed in cubic kilometers is an important index for determining the hydrocarbon potential of the area. As a whole, the volume of sedimentary fill of all USSR oil-gas provinces and isolated regions within platforms makes up 32.1×10^6 km^3 including 19.5×10^6 km^3 estimated for ancient platforms.

Mobile belts (foredeeps, epiplatformal orogens, and eugeosynclinal regions), whose geological evolution was characterized notably by active tectonic movements, cover an area of $2{,}470 \times 10^3$ km^2, including 580×10^3 km^2 in foredeeps. The volume of this sedimentary fill is 10.4×10^6 km^3 in foredeeps.

TABLE 21-3.--Mobile belts of the USSR

Name of the province and its maximum size along axes (km)	Areas (10^3 km^2)	Maximum thickness of sedimentary cover (km)	Volume of sedimentary fill (10^6 km^3)	Stratigraphic range of oil and gas occurrence
South Caspian (300 x 1,000)	200	20	2.6	Cretaceous Neogen
Okhotsk (1,200 x 2,000)	1,200	7	2.5	Neogene

The total area of oil-gas bearing provinces and regions in mobile zones (including foredeeps) makes up 23.8 percent of the whole area occupied by all provinces and regions of the USSR; the volume of sedimentary fill accounts for 24.4 percent.

The main initial proved hydrocarbon reserves of mobile belts are concentrated in South Caspian province and Sakhalin region of the Okhotsk province; Pre-Carpathian, Indola-Kuban and Tersk-Caspian foredeeps (Northern Caucasus-Mangyshlak province); and Pre-Ural foredeep (Volga-Ural and Timan-Pechora oil-gas bearing province). Potential hydrocarbon resources of the mobile zone are much less compared with those estimated for platform regions, making up 5.0 percent of the grand total reserves of the USSR.

The bulk of the potential hydrocarbon resources estimated for oil-gas bearing provinces and regions of the USSR are associated with large uplifts (arches and their flanks), which are bordered by extensive negative structures filled with sedimentary rocks of great volume.

Consequently, the largest hydrocarbon resources in the Soviet Union are associated with platform regions. There exists a usually direct relationship between potential hydrocarbon resources and area and volume of sedimentary cover developed in oil-gas provinces. This relationship is well-defined in such relatively well studied provinces as Volga-Ural and Dnieper-Pripyat (confined to the ancient platform), Northern-Caucasus-Mangyshlak, West Siberian, and Amu-Darya (confined to the young platform), and South Caspian (confined to the mobile tectonic belt).

Mesozoic sequence contains the largest quantities of potential hydrocarbon resources, with gas proved reserves being particularly high. The main hydrocarbon resources in these sediments were established in West Siberia, with lesser amounts in Amu-Darya, Northern Caucasus-Mangyshlak, Lena-Vilyui, and Enisei-Laptev provinces.

Large potential resources are concentrated in Paleozoic sequence (Devonian, Carboniferous, Permian rocks) in Eastern-European platform (Volga-Ural, Timan-Pechora, Dnieper-Pripyat and Pre-Caspian provinces). The extensive Lena-Tunguska province is not yet sufficiently studied, but its hydrocarbon possibilities are high. Several oil and gas fields already have been discovered here in Vendian and Lower Paleozoic rocks.

Offshore areas of internal and marginal seas of the USSR are also considered to be rather prospective, yet the rate of their study is insufficient, except for the southern part of the Caspian Sea.

CHAPTER 22

EVALUATION METHODS OF HYDROCARBON POTENTIAL RESERVES IN EAST SIBERIA

V. S. Surkov[1]

East Siberia occupies a vast territory of the Soviet Union, between the Enisei River on the West and the Lena River on the East. The ancient Siberian platform, which is associated with great prospects for oil and gas field discovery, covers part of the territory.

The platform includes the Aldansky and Anabarsky shields, where Archean and Lower Proterozoic folded complexes crop out. Its central part, the area of which is 3.4×10^6 km^2, forms the plate, the ancient crystalline basement of which is buried to considerable depth and overlapped by Paleozoic and Mesozoic sedimentary platform deposits.

In the Siberian platform the sedimentary formations of possible oil and gas content are insufficiently explored by geophysical methods and deep drilling, due to great complexity of geological structure of the area and difficulties in its exploitation. In spite of poor geologic data on the Siberian platform, however, regional exploration work is being carried out providing much data and allowing determination of the thickness of platform rocks, examination of facies composition and geochemical features of sedimentary formations, vertically and laterally, and evaluation of hydrocarbon potential reserves.

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In the Siberian platform the formations of possible oil and gas content differ in geologic history; stratigraphic range of oil and gas-bearing, and potentially oil and gas-bearing, complexes; dominant type of hydrocarbons in their accumulations; and tectonic and structural-lithologic features. This is why this region was divided into two provinces. Oil and gas-bearing province means the area of a large geotectonic structure of possible oil and gas content, or a major part (the area of which is not less than 0.5×10^6 km^2) characterized by the similarity of geologic structure and history, and the same level of oil and gas content (with accuracy to system rank). According to the differences mentioned above, two oil and gas-bearing provinces were distinguished within the Siberian platform: Leno-Tungusskaya and Khatangsko-Vilyuiskaya.

1. Leno-Tungusskaya oil and gas bearing province occupies 2.8×10^6 million km^2 and includes the largest structures of the Siberian platform: Tungusskaya and Prisayano-Eniseiskaya synclines, Anabarskaya, Aldanskaya and Nepsko-Botuobinskaya anticlines, and others. The level of oil and gas content involves Late Ripean and Paleozoic deposits of total thickness 1.5 to 6 km with volume of sedimentary filling being 8.613×10^6 km^3.

The geologic structure of the province involves clastic-carbonate deposits of Ripean and all Paleozoic systems as well as Triassic tuffaceous extrusive formation. The thickness of the latter ones reaches 3 km in the north of Tungusskaya syncline.

Sandstones, which vary in thickness over a wide range and have a mean porosity of 10 to 12 percent, are reservoirs in the Vendian-Lower Cambrian clastic complex. Argillaceous-carbonate deposits serve as their seal.

Fractured porous and cavernous dolomites and limestones are reservoirs in the Cambrian carbonate and carbonate-salt bearing complex. Middle to Upper Cambrian argillaceous-carbonate deposits serve as the regional, and salt beds as zone cap rocks.

In the north of the Tungusskaya syncline the following deposits with possible oil and gas content can be distinguished: Middle Paleozoic deposits composed of carbonate and argillaceous-carbonate rocks and Upper Paleozoic deposits represented by alternating thick beds of sandstones, shales, and coals.

The location of structures and their relationship in the different horizons of platform sediments of Leno-Tungusskaya oil and gas bearing province have been studied poorly. According to geologic and geophysical data on Lower Paleozoic formations, many large arches and uplifts, complicated with second and third order structures, which can serve as traps for hydrocarbon accumulations, can be distinguished.

Sills and discordant intrusions in traps developed in much of the Tungusskaya syncline are of special importance in the structure of Leno-Tungusskaya oil and gas-bearing province. Their influence on oil and gas content varies. When intruded they can destroy oil and gas accumulations. At the same time, the associated additional heating of the sedimentary rocks intensifies the oil and gas generation processes.

A set of sills and discordant intrusions appears to put additional obstacles in the path of migrating hydrocarbons, and in the north of Tungusskaya syncline tuffaceous extrusive formations overlap Paleozoic rocks, forming an additional thick regional cap rock. On the whole, trappean magmatism complicated the regularities of oil and gas distribution in sedimentary formations but perhaps it could not essentially decrease the total oil and gas possibilities of this province.

Over most of the area Paleozoic deposits are saturated with brines of sedimentary origin. For the reasons given we may consider that favorable hydrogeologic conditions for oil and gas accumulation and preservation exist in the section of Leno-Tungusskaya syncline. In the Vendian-Cambrian deposits of Leno-Tungusskaya syncline commercial oil and gas pools have been discovered and numerous bitumen accumulations (asphaltic deposits) are recorded in Recent truncated and eroded deposits.

It is implied that intensive hydrocarbon generation and oil and gas formation occurred in the rocks of that age. However, under conditions of long-term uplift and intensive denudation of overlapping rocks, part of the oil and gas was eroded and destroyed, partially or completely. Where these accumulations were subjected to long-term subsidence, and are presently overlapped by a thick series of relatively impermeable rocks isolated from post-genetic influences, they are in optimal condition for preservation. It is proved (despite relatively small volume of exploration drilling) by the oil and gas field discoveries within Tungusskaya syncline and Nepsko-Botuobinskaya anticline as well as by noncommercial and semicommercial oil and gas shows over some areas. Leno-Tungusskaya province is divided into nine oil and gas bearing regions, each confined to a geo-structural element of super-order or first-order structure group, and with an area of not less than 50,000 km^2, analogous geologic history, common oil geologic complexes, and similar types of hydrocarbon compounds.

2. Khatangsko-Vilyuiskaya oil and gas bearing province is considerably smaller than the Leno-Tungusskaya province. Its area is 670,000 km^2.

Tectonically the province is confined to Upper Paleozoic and Mesozoic marginal depressions of the Siberian platforms; to Enisei-Khatangsky, Leno-Anabarsky, and Priverkhoyansky regional troughs; and to the Vilyuiskaya syncline. Within the province the sedimentary cover is represented by Upper Ripean and Paleo-zoic-Mesozoic formations and reaches a thickness of 13 km. The greatest depth to the base of the sedimentary rocks is recorded within the Enisei-Khatangsky regional trough.

Upper Paleozoic-Mesozoic deposits, which are associated with the main oil and gas reserves, account for almost half of the sedimentary filling. However, it should be noted that Permian and Triassic oil and gas bearing strata occur as a rule at more than 4,000 m. These strata are best investigated in the Vilyuiskaya syncline.

Lower Middle Jurassic clastic formations occur at various depths from 1,000 to 7,000 m.

Lower Jurassic formations are prospective for gas and gas-condensate deposits, and Middle Jurassic for gas deposits.

Upper Jurassic-Lower Cretaceous clastic complexes occur at various depths (up to 4,000 m in troughs). Lower Cretaceous deposits are highly prospective for gas and gas-condensate exploration. The possibility of discovery of oil and gas deposits at their base would not be rejected.

In the north of Enisei-Khatangsky trough, Upper Cretaceous deposits may contain gas as well. These deposits are barren over the rest of the area.

In Upper Paleozoic-Lower Cretaceous deposits the hydrogeologic environment is mainly favorable for the formation and preservation of hydrocarbon accumulations.

Large-scale depressions and troughs, separated by uplifts of large amplitude and areal extent and complicated by minor structures, constitute the main tectonic elements of the province.

In the Khatangsko-Vilyuiskaya oil and gas bearing province, commercial gas present in Permian, Triassic, Jurassic and Cretaceous sediments has been found by exploration. Significant gas accumulations were discovered in the Enisei-Khatangsky regional trough and Vilyuiskaya syncline.

The oil and gas bearing complexes are poorly investigated and, therefore, evaluation methods of primary potential oil and gas reserves usually used in well-explored regions are inapplicable to the Siberian platform as yet.

Considering conditions described above, volumetric-statistical and volumetric-genetic methods were employed for evaluation of the hydrocarbon potential reserves. Along with these methods the analog method was used for platform Mesozoic deposits.

The essence of the volumetric-statistical method is that the potential hydrocarbon resources of sedimentary basins are proportional to the volume of their sedimentary filling. The volumetric density of the geological reserves for the studied region is assumed to be average, calculated on the basis of other regions well explored by deep drilling.

The potential reserve volumetric density is differentiated according to the nature of the geologic complex and the reservoir and cap rock quality.

When choosing parameters for the evaluation of the potential hydrocarbon resources within the Siberian platform, the hydrocarbon reserve volumetric density data in the main, well-explored oil and gas bearing provinces of the world were taken into consideration.

In the oil and gas bearing complexes, which occur at depths ranges of 1.5 to 2.0 and 3.5 to 4.0 km and have passed through the main phases of oil and gas generation (if the rocks are composed of marine sedimentary formations with sapropelic organic matter), gas dominates over the entire depth interval.

In particular, in Paleozoic sedimentary formations composed of carbonate and clastic-carbonate rocks, liquid hydrocarbons constitute 60 to 85 percent of total hydrocarbon reserves. Other conditions being equal, the hydrocarbon gas contribution is slightly higher in the presence of saline zones in a section. As a rule gas prevails in sedimentary sections filled by marine deposits to depths of 1,000 to 1,200 m and more than 5,000 to 6,000 m. The greater part of oil reserves is concentrated within the depth interval 1,200 to 2,400 m; oil reserves (percent of total reserves) decrease at depths of more than 3,000 m.

When differentiating hydrocarbon reserves into oil, condensate, and free and associated gas, a method based on the solution of a set of equations was developed: coefficient values were fitted by the analog method, based on facies appearance, initial type of organic matter, Series age, recent and paleotemperatures and pressures, and recent and paleo-depths of occurrence.

For Leno-Tungusskaya oil and gas bearing province the estimation of hydrocarbon potential reserves was obtained by the volumetric-genetic method worked out by A. E. Kontorovich, et al. (1975). It is based on differences in bitumen content and composition in the central part of oil and gas producing argillaceous series compared to the underlying and overlying strata.

The existence of such regularity has been evidenced by presence of primary migration processes in rocks and correlation between materials with high capability for migration (hydrocarbons) and with low capability for migration (resins and asphaltenes). This permits definition of the amount of hydrocarbon which has migrated from 1 km^2 of oil producing area by simple mathematical calculations.

The hydrocarbon amount which migrated from the source rocks and the amount in known deposits makes it possible to estimate the accumulation coefficient within the oil and gas gathering area.

For oil and gas bearing complexes in Leno-Tungusskaya oil and gas bearing province accumulation coefficients were assumed within the range of 0.02 to 0.05. Coefficients of preservation of liquid and gaseous hydrocarbon deposits were introduced for unfavorable geological factors described above. For liquid hydrocarbons they varied from 0.8 to 0.2 and for gaseous hydrocarbons from 0.4 to 0.1.

The results of potential hydrocarbon resource evaluation in East Siberia calculated by volumetric-genetic and volumetric-statistical methods turned out to be almost identical.

For Khatangsko-Vilyuiskaya oil and gas bearing province the method of comparison with a standard was also used. Cretaceous deposits which are well explored within the area of the Tanamsky arch were taken as a standard for Mesozoic and Upper Paleozoic deposits of Enisei-Khatangsky and Leno-Anabarsky oil and gas bearing regions.

In defining the density of Permian, Triassic, Jurassic, and Cretaceous deposits in other regions of the province, corrections were introduced into standard values of reserves for thickness and porosity of reservoirs, quality of cap rocks, and depth of deposit occurrence.

Thus, methods used for estimation of hydrocarbon potential reserves within East Siberia provided rather optimistic and reliable results on predicted oil and gas reserves in that area. This has led to exploration for oil and gas on a wide scale.

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SECTION IV. ENHANCED OIL RECOVERY

CHAPTER 23

ENHANCED OIL RECOVERY: WHAT OF THE FUTURE?

Claude R. Hocott[1]

INTRODUCTION

Since the early days of the development of the science of reservoir engineering, the petroleum industry has dreamed of a displacement process which would achieve 100 percent oil recovery. When researchers first began to experiment with the techniques which form the basis of most of the tertiary-recovery processes being tested today, the goal of complete displacement appeared attainable. However, not only has the dream eluded the researcher, but its realization does not appear to be much closer than it was a decade or so ago. Most tertiary recovery processes are looking at recoveries of only about one-half the residual oil remaining after water flooding. Although the quantity of oil reserves which may be realized by even this modest target is substantial, it still leaves an attractive and much needed volume of petroleum behind.

This assessment of the status of enhanced oil recovery points to the need to explore other avenues for the underlying causes for the lower than hoped for recoveries. Practically all of the research to date on improved recovery technology has been concerned with the fluid systems and their interaction within the rock pore. Although reservoir geologists and engineers have long realized the limitations to recovery resulting from formation

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heterogeneities, lenticularities, and lithologies, little research has been directed toward quantifying this influence. In fact, it is only recently that the tools and the methodologies have been developed to investigate reservoir formation and rock parameters more fully. Many geologists and engineers believe that it is in this realm that the next incremental improvements in oil recovery will be realized.

DISPLACEMENT EFFICIENCY

Naturally one of the most important aspects of an oil recovery process is the efficiency of the mechanism of oil displacement from the individual pores of the rock. When oil is displaced immiscibly from a porous rock, say by gas or water, a residual oil saturation is reached beyond which no more oil flows out of individual pores. Available data indicate that at this stage the oil no longer exists in the rock in a continuous phase, but is coalesced by capillary forces into isolated, discrete droplets which cannot be displaced under the viscous forces available in the reservoir. It is the break-up of the continuous filaments of the oil phase that improved oil-recovery processes seek to reverse, or to prevent if inaugurated soon enough.

The extent to which some of the exotic displacing agents accomplish this is attested by the fact that 100 percent recovery efficiency is attained in linear displacement experiments in the laboratory on uniform sand packs containing reservoir oil and water. The effectiveness of these particular recovery systems is further confirmed by instances in which cores are cut in wells drilled behind the advancing displacement front and reveal that the formation is flushed clean of residual oil. At least in such instances the reason for overall reduced recovery efficiency must be sought elsewhere.

RESERVOIR HETEROGENEITY

Improvements in oil recovery efficiency would be illusive enough if the operator could accurately map the various characteristics of the reservoir and continuously monitor the situation prevailing throughout the reservoir during the recovery operation. Because direct inspection is physically impossible, conditions prevailing within the reservoir must be determined by interpreting such data as can be collected. Although available observational tools have been expanded considerably in recent years, these have yet to be exploited to the maximum possible degree.

STRATIGRAPHIC CONTINUITY

The first and most direct observation on the characteristics of the reservoir is gained through core analysis, followed closely by, and interrelated with, various electric, sonic, and radioactivity logs. It is very difficult to infer the quantitative properties of the reservoir between wells, using only wellbore sampling. However, these two observational procedures must form the framework on which any stratigraphic or lithologic map is to be developed.

Today there are additional observational procedures to determine the extent to which stratigraphic lensing may interfere with the recovery process. Geophysics, while conventionally utilized as an exploration tool, can be of valuable assistance in some situations and its capabilities are expanding all the time. High-resolution seismic profiles, particularly at shallow depths, can provide a valuable stratigraphic description. When correlated with appropriate well logs, interpretation can be quite accurate. Engineers are now well versed in the use of pressure-transient techniques, such as interference tests between wells and pulse tests. Correlation of the data from all such tools can be tedious, painstaking work but application of the results to control recovery operations should be worth the effort. It is obvious that every oil-bearing segment of reservoir rock, with its complex lenticularity, must be accessible to both injection and production wells if maximum oil recovery is to be attained.

One of the better indicators of the complex character of a reservoir and the efficacy of its development plan is the performance of individual wells during primary or secondary recovery through careful analysis of production histories, time of arrival of displacement fronts, and the rate of increase of displacing fluid percentage. In effect, this is what is hoped to be accomplished by a pilot test of a selected small segment of a reservoir prior to design and installation of a field-wide tertiary operation. If the portion of the field selected for the pilot study is representative, data for design and development of full-scale operations can be quite adequate and also informative with respect to the economics of the process. In the small scale tests, tracers are frequently added to the displacing fluids injected into the input well to increase the diagnostic value of the performance history of the producing well or wells. In addition, in-fill wells may be drilled to provide further core analysis and logging information for confirmatory purposes after completion of the pilot project.

PETROFABRICS

Geologists and engineers involved in oil recovery technology have long recognized the influence of directional permeability in a reservoir on the flow of fluids incident to recovery. For instance, it is not uncommon for vertical permeability to be considerably less than that in either horizontal direction. Sometimes thin, impermeable laminae so effectively subdivide a formation that cross flow between horizontal layers is not possible. Complete knowledge of this fact and a clear understanding of its influence on flow behavior is essential to proper design, development, and control of a producing operation if oil recovery is to be optimized.

Equally important in many displacement regimes is the directional variation of horizontal permeability. Thus, studies show that anisotropy is equally as important in low interfacial-tension tertiary displacement systems as it is in normal waterflooding, where capillary forces tend to stabilize displacing fronts. Only when the anisotropic character of the reservoir is known, can prediction be made of channeling, fingering, and coning tendencies, and a pattern of injection-production wells be designed to overcome the influence of permeability variations.

Of course, determining the anisotropy of a formation by interpolating between observation points is tricky business.

However, a careful determination of depositional environments and statistical reservoir analysis can establish patterns of variation.

Sedimentary conditions of deposition, including stream bed or alluvial fan, barrier island, bay or beach, or reef, present characteristic formation properties which determine reservoir and recovery behavior. Efficient oil recovery is a haphazard operation when these parameters are not known and therefore not taken into account in planning the operation. Hence, the future looks more encouraging as better geologic tools become available.

Not only are the physical, chemical, and biological conditions of deposition important but also post-depositional alterations of the reservoir rock; these factors greatly influence the behavior and interaction of the fluids present. Such parameters as calcium-magnesium ratios in the rock may determine the properties of the fluid system selected for the displacement process. In some cases the organic content of the sediments has been shown to influence recovery efficiency.

DEVELOPMENT AND CONTROL

It is readily apparent from this discussion of enhanced oil recovery processes that successful application will be much more manpower-intensive than is the case with conventional primary and secondary recovery operations. Just as successful water flooding operations require more careful planning, design, and control than is commonly needed in the primary stage of flush field production, so tertiary recovery demands greater attention to field performance from a technological standpoint.

It seems obvious that not only must the design and development of such operations be based on careful analysis of reservoir characteristics and the capabilities of the oil displacing system, but continuing, thorough observation of the performance of the producing well must be carried out in order to correct for deviations from predictions caused by unaccounted for variations in the reservoir properties. In this way injection and production patterns may be controlled in such a manner as to maximize the sweep efficiency as well as the displacement effectiveness of the recovery operation.

Far too many pilot field tests have been given a black eye as the result of an ill-conceived, poorly planned, carelessly designed, and sloppily executed operation which resulted in a misinterpretation of the data observed. The future of efficient oil recovery depends on the extent to which the industry is prepared to give the professional attention to the high technology required. It has always been anomalous that so few professionals and so little scientific thought is given to a highly technical, capital intensive, and expensive operation as oil recovery which in comparable magnitude in a refinery or chemical plant would have a competent staff of technologists and professional supervision around the clock.

LIMITATIONS OF ENHANCED RECOVERY

Although it has been demonstrated that numerous enhanced recovery processes can be effective in displacing additional oil from certain fields depleted by either primary or combined primary and secondary operations, not one has yet proven commercial from an economic standpoint, except for certain terminal installations. Although the future oil supply-price relationship promises to alter this situation, it still behooves the engineer and the operator to consider methods for optimizing the application of the processes.

One control available for future fields is the time of inauguration of enhanced recovery operations. Even though a tertiary operation can be successful, a three-stage operation may be a poor alternative for a two-stage or even a single-stage recovery operation employing the most efficient recovery system from the beginning. Reservoirs frequently are produced in such a way that after primary and/or secondary operations, additional recovery by tertiary methods is not feasible either because of reservoir damage or too low a remaining residual oil saturation. If such is the prospect, many fields already in primary or secondary operation may be considered for early conversion to a more effective displacement system. Because economics play such a large role in the amount of ultimate recovery from reservoirs, any development plan which keeps total development expense and operating costs at a minimum must be given high priority.

NEW TECHNOLOGICAL HOPES

The hopes, aspirations, and ingenuity of creative minds know no bounds. Many ideas have been suggested and schemes tested to win the last ultimate drop of petroleum from the reservoir. In addition to heat and chemicals, ultra-sonics, imposed electromotive force, and laser have been proposed as techniques for alteration of rock properties or modification of streamlines and flow patterns in order to enhance the displacement of oil from the formation. To date no viable process or even demonstrated benefit has come from this type of experiment, but hope springs eternal.

One idea which has captured the attention of many recovery experts is the use of small nuclear explosives to fracture and secure a large drainage radius, particularly in tight formations, to enhance recovery. Current experience, based on trials for increasing recovery of natural gas by this technique, has not been encouraging. However, this idea has drawn attention to the tremendous resources which reside in rocks of such low permeability as to be uneconomic even at presently forecast prices.

One observation on the geology of these formations is being given serious consideration. Many of the formations are fractured. In fact, most sedimentary rocks have incipient fractures criss-crossing the strata at frequent intervals. One only has to look closely at an outcrop or escarpment to gain an impression of this condition. Past production histories of oil recovery from fractured or highly fissured zones indicate that when reservoir pressure is reduced the fissures close tightly and production behavior is altered. Oil recovery is usually impeded. This observation has led some geologists and engineers to postulate that maintaining a super-pressure in the formation may render the hydrocarbons accessible to economic recovery.

Recovery research has moved in one direction that is self-defeating insofar as water-based fluid displacement is concerned. This is to strive for extremely low interfacial tension between the oil and water phases, a process which eliminates capillary imbibition into water-wet, low-permeability rocks. If possible, interfacial tension should be increased in order to enhance water flooding of fractured or fissured, extremely tight reservoirs. Another deterrent is inherent in the agents used for mobility control; most of the solutions used for increasing viscosity are thixotropic and tend to enhance channeling, fingering, or coning. If one could build dilantancy into the displacing fluids, this tendency would be retarded.

Another observation from past production history may deserve consideration for additional recovery. This is the relative effectiveness of water or gas in the displacement of oil from the rock. It has been noted frequently in secondary recovery operations that when oil saturations are high and connate water saturations low, additional recovery by water drive is highly favorable. However, in those cases where the connate water saturations are high, higher ultimate recovery by gas drive is more likely. From this, one is led to the conclusion that insufficient attention has been given to gas-based tertiary recovery processes in watered-out reservoirs. Almost universally such tertiary systems are water-based, utilizing polymers, surfactants, and solubilizers. Perhaps if such reservoirs are dewatered with hydrocarbon-enriched gas or carbon dioxide-rich gas, oil recovery may be more readily enhanced.

In any event the future looks bright for enhanced oil recovery from a whole host of reservoir situations. The rewards are sufficient to encourage even the most skeptical to renewed efforts.

CHAPTER 24

SECONDARY RECOVERY OF OIL

Ben H. Caudle[1]

INTRODUCTION

In this paper, secondary recovery will be considered to be those fluid injection projects which are directed toward the displacement of oil into producing wells. The injection of fluid for the primary purpose of maintaining or increasing reservoir pressure will not be included, nor will the paper address directly the newer fluid-injection methods, often called tertiary recovery. Thus, secondary recovery will include waterflooding and some gas injection projects, with waterflood being the method most often used. It is estimated that nearly half of the oil produced daily in the United States comes from waterflood projects [1].

NOMENCLATURE (From SPE List)

1. B_o = Oil formation volume factor
2. B_w = Water formation factor
3. E_p = Displacement efficiency
4. E_s = Pattern sweep efficiency
5. k = Permeability
6. M = Mobility ratio
7. N_p = Cumulative oil recovery
8. S_{cw} = Connate water saturation

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9. S_{gr} = Residual gas saturation
10. S_{or} = Residual oil saturation
11. V_{id} = Dimensionless volumes injected: $\frac{\text{volume injects}}{\text{pore volume x } E_D}$
12. W_i = Cumulative water injected
13. μ = Viscosity

THE NEED FOR SECONDARY RECOVERY

When an oil well is completed and its bore emptied of fluid, reservoir pressure causes oil (and perhaps gas and water) to flow into the well, where it is then lifted to the surface. As oil production is continued, the reservoir pressure declines unless a fluid such as water enters the reservoir to replace the produced oil. Only a few oil reservoirs are fortunate enough to have a contiguous aquifer which is able to supply water as fast as the oil is normally produced. Thus, nearly all reservoirs experience decreasing reservoir pressure during primary production. Decreasing reservoir pressure adversely affects oil production in two ways. First, the force necessary to drive oil into the well bore is decreased. Second, and more important, decreasing reservoir pressure soon causes some of the gas held in solution to be released as discrete gas bubbles in the pore spaces of the reservoir rock (Fig. 24-1). At quite low gas saturations (2 to 5 percent of the pore space) these gas bubbles will combine to form continuous gas flow channels into the production wells (Fig. 24-2). These gas channels inhibit the flow of oil while allowing easy paths for gas flow. This results in rapidly rising gas-oil ratios when primary production is continued at pressures below the bubble point pressure.

Without either fluid injection or an active natural waterdrive, oil recovery is usually restricted to a range of 5 to 20 percent of the oil originally in place by the time the reservoir pressure--and consequently, the oil production--falls to the point at which further production is not economically feasible. The oil remaining in the reservoir at this time is generally well dispersed, but the reservoir contains a network of gas channels which have a high flow capacity even though their volume may be small.

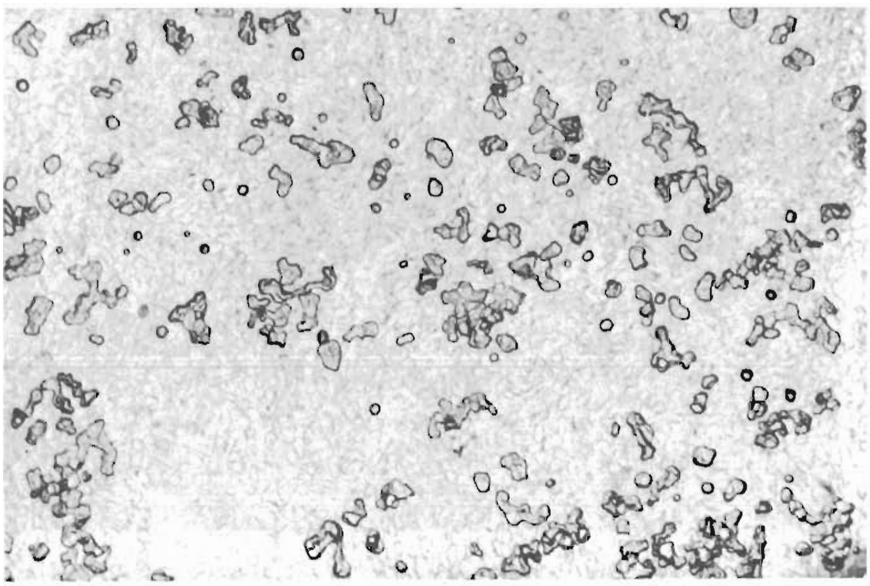

Figure 24-1.--Gas evolving from solution in porous medium

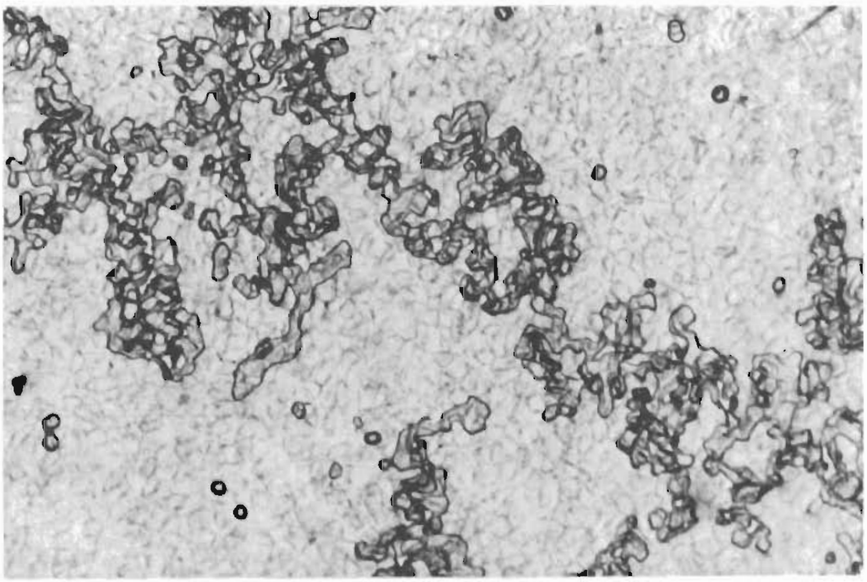

Figure 24-2.--Gas-flow channels in an oil-filled matrix

OIL DISPLACEMENT BY WATER OR GAS

Waterflooding has long been the major secondary-recovery method. As a consequence, the advantages and disadvantages are better known than those for other displacing fluids. Water (treated to remove possible plugging materials) is injected into the oil-bearing part of the reservoir to force oil toward the production wells. Water, because of its nearly incompressible nature, can raise the reservoir pressure quickly. As water invades the oil- and gas-bearing regions it typically displaces more than half of the oil it encounters. This oil, being pushed by the water, refills the gas channels either by causing gas flow or by dissolving the gas at the higher pressure. As soon as the gas channels have been refilled around a production well, the oil production rate will rise. Most waterfloods are designed so that increased oil production in older wells occurs within a period of 6 months to a year. As mentioned above, water is relatively efficient at displacing oil, typically leaving only about one-third of the reservoir pore space still containing oil that is widely dispersed as individual droplets (Fig. 24-3). If water could be made to invade all of the reservoir and if all of the oil displaced by the water could be produced, the residual oil after waterflood would be less than half of the oil originally in place.

The injection of gas as a secondary recovery fluid has not been used as often--or as successfully--as has water injection. In general, gas is not as efficient as water unless reservoir conditions are such that the gas and reservoir oil are completely miscible. Miscibility between gas and oil requires relatively high reservoir pressure and oil gravities, which makes the majority of oil reservoirs unsuitable for this type of displacement. In the absence of miscibility between the injected gas and the reservoir oil, the residual oil left in the invaded region is greater than that left by water. Of the oil being produced in the United States by secondary recovery, less than 10 percent comes from gas injection [1].

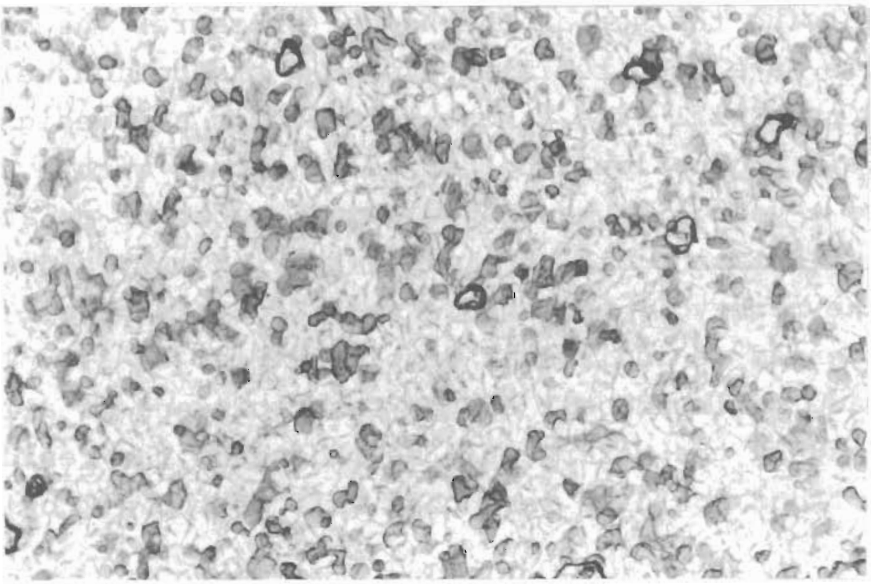

Figure 24-3.--Residual oil after a water flood

SECONDARY RECOVERY EFFICIENCIES

The ability of the injected fluid to displace oil from the invaded portion of the reservoir is called "displacement efficiency." It can be expressed as the fraction of the oil in place which is replaced by the injected fluid. This is most commonly expressed by the change in fluid saturations before and after the displacement. For example, in a waterflood:

$$\text{Displacement efficiency } (E_D) = 1 - S_{cw} - S_{or} - S_{gr}$$

In a miscible-type gas drive, where there is no residual oil left, the displacement efficiency would be:

$$E_D = 1 - S_{cw}$$

Because the injected fluid does not reach all parts of a reservoir, the total recovery efficiency will be the displacement efficiency multiplied by the fraction of the reservoir volume actually invaded by the water. This fractional invaded volume is called the reservoir conformance factor, and is affected by two major factors: the pattern sweep efficiency resulting from the geometric arrangement of the wells and the modifying effects of reservoir heterogeneities.

Pattern sweep efficiencies of less than one result from the unequal path lengths between injection and production wells. Figure 24-4 shows one element of a five-spot injection pattern in which each injection well is centered between four producers. The different flow paths are illustrated by the dashed lines. Because the longest flow paths are about 50 percent longer than the shortest ones, the leading edge of the injected fluid will reach a production well first along the shortest path. Thus, the injected fluid front at this time would be in the position shown by the solid line in Fig. 24-4. The pattern sweep efficiency shown would be given by the ratio of the area inside the solid line (the swept or invaded area) to the area of the entire pattern element. Two things should be noted. First, the sweep efficiency is not a constant quantity; it increases linearly with cumulative injected volumes, up to the time of breakthrough, and it continues to increase, but more slowly, while the oil production rates decrease. Second, the sweep efficiency for any pattern is affected by the ratio of the fluid permeabilities and

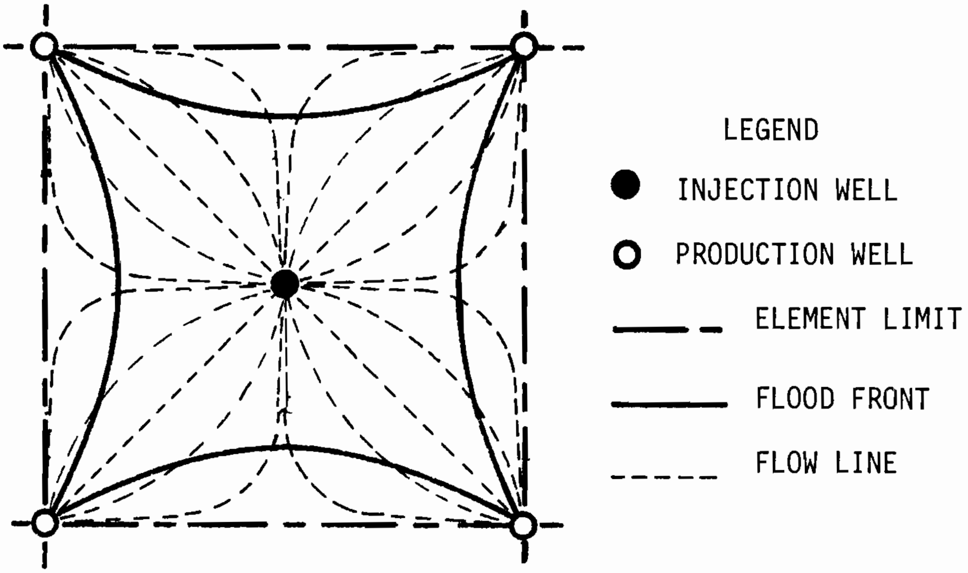

Figure 24-4.--Fluid movement in a five-spot element

viscosities. The specific parameter is the mobility ratio and it is defined as:

$$M = \frac{(k/\mu)_{\text{injected fluid}}}{(k/\mu)_{\text{reservoir fluid}}}$$

The dependence of pattern sweep efficiency on injected volumes and on mobility ratio is illustrated in Fig. 24-5.

If pattern sweep efficiencies were the only factor affecting reservoir conformance, the oil recovery at any time during the flood could be found by using:

$$N_p = E_s \times E_D \times \text{reservoir fluid volume}/B_o$$

The injected fluid volume necessary to reach this recovery would be (for a waterflood):

$$W_i = V_{id} \times E_D \times \text{reservoir fluid volume}/B_w$$

Since the oil production tapers off even though the injection rate is maintained as a constant, the flood project will end when the value of the oil production falls below the operational cost.

The second major factor in reservoir conformance is the adverse effect of permeability heterogeneity. Flow paths between injection and production wells which have different permeabilities will cause faster flow through the higher permeability path. The most common--and the most harmful--type of reservoir heterogeneity is horizontal layering or stratification of the reservoir rock. These horizontal layers often have quite different permeabilities even though they lie close together in the same producing formation. To understand their adverse effect on reservoir conformance, and thus on oil production, consider a reservoir consisting of only two layers having equal volumes and displacement efficiencies but having permeabilities that differ by a factor of two. Roughly two-thirds of the injected fluid would move into the higher permeability layer while one-third would invade the other layer. Thus, break-through in the higher permeability layer would occur with the other layer only halfway to this recovery. The high permeability layer would be cycling injected fluid while the other layer produces oil. For such a reservoir, having the pattern sweep efficiency shown by the M = 1 curve of Fig. 24-5, the oil recovery history of the

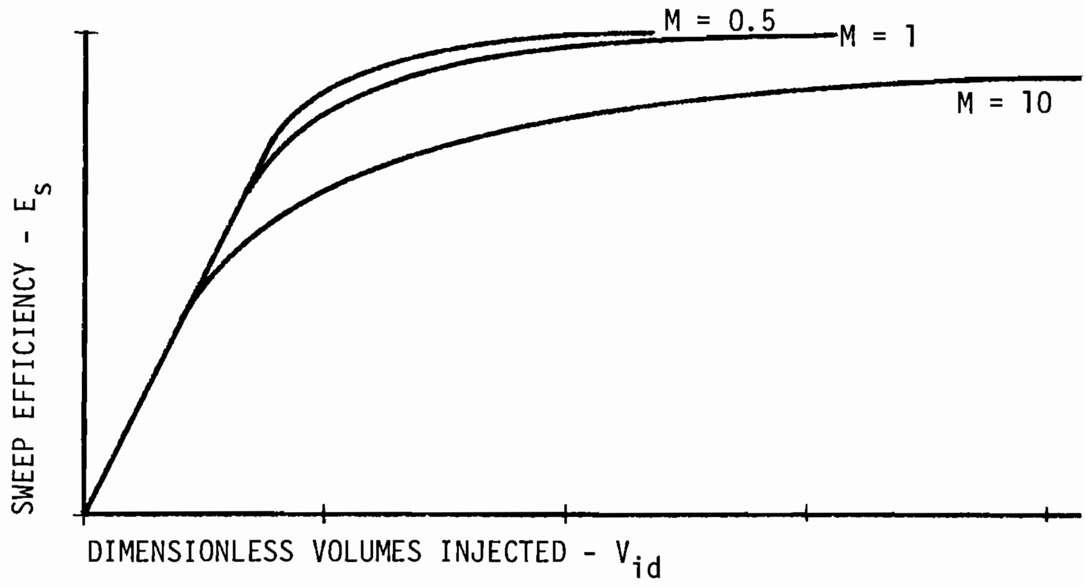

Figure 24-5.--Pattern sweep efficiencies in a five-spot pattern

two-layered reservoir compared to what it would have been if it were homogeneous is shown in Fig. 24-6. It is obvious that the two-layered systems will become uneconomic to continue in operation at a lower oil recovery.

A typical oil reservoir is composed of many such strata and their permeabilities often differ by orders of magnitude. Because it has been found impractical to isolate these strata from each other by selective well completion techniques, the heterogeneities are responsible for substantially lowered oil recoveries in many fluid injection projects.

As in pattern sweep efficiency, the effects of permeability heterogeneities are modified by the fluid mobility ratio. Mobility ratios greater than one increase the adverse effects of stratification while mobility ratios less than one decrease these effects. Therefore, a waterflood is usually less affected by stratification than is a gas drive, and the injection of viscous water can decrease these adverse effects even further.

There are several published methods for estimating the effect of stratification in secondary recovery projects [2, 3, 4]. All of these treat the total reservoir as if each layer were independent of the others, except for common completion at the well bores. Such estimates are reasonable for most secondary recovery projects and probably equally as precise as the knowledge of the degree of permeability stratification. Figure 24-7 shows an example of the effect of stratification on the expected oil recovery, as calculated by the method presented in reference 2.

CONCLUSIONS

Waterflooding has been and probably will remain the principal secondary recovery method, because of greater efficiency and better economics than gas injection. While the displacement efficiency of water is around 0.5, the actual recovery efficiency will be lower because of reservoir conformance effects. Although many feel that a waterflood will recover an additional amount of oil equal to that already produced by primary, a better figure is that successful waterfloods, plus the preceding primary

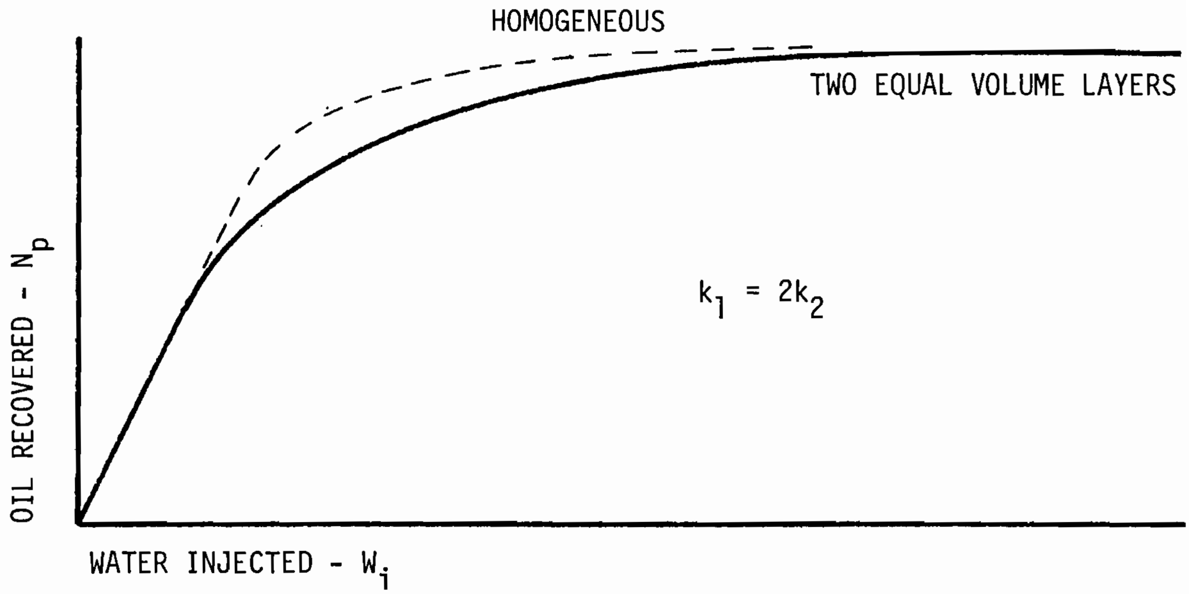

Figure 24-6.--Effect of two strata on oil recovery

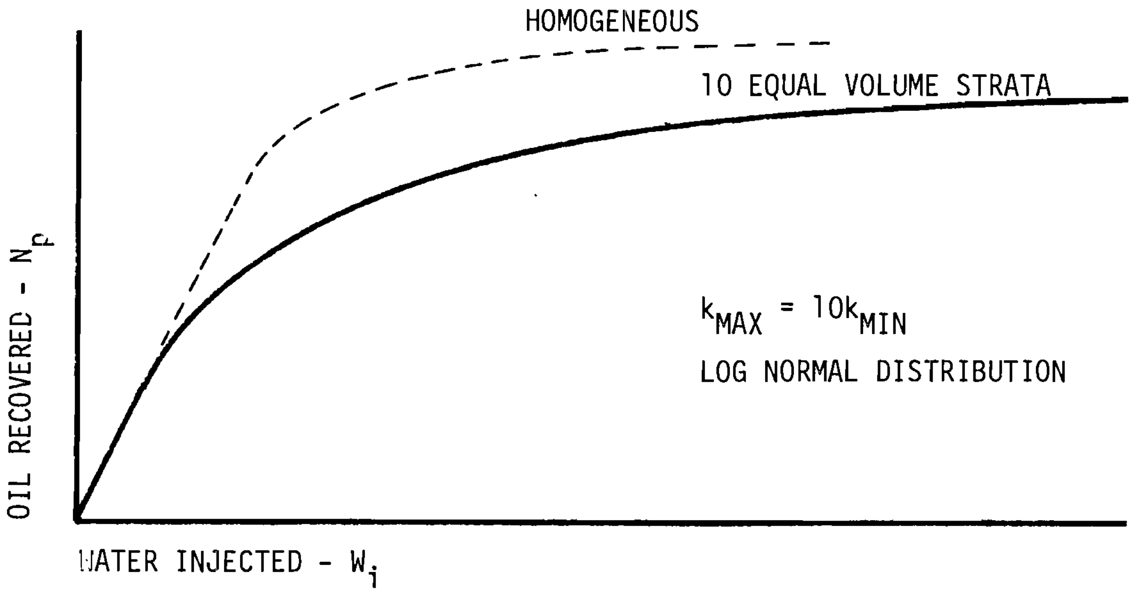

Figure 24-7.--Effect of multiple strata on oil recovery

production, will usually recover between 40 and 60 percent of the oil originally in place in the reservoir.

The oil left in the reservoir after waterflooding will be distributed in two groups. About half will be left as isolated residual oil droplets in the water-flushed portion of the reservoir. The remainder will be collected in those reservoir areas where the water does not go because of reservoir conformances.

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CHAPTER 25

SECONDARY RECOVERY OPERATIONS OF OeMV-AKTIENGESELLSCHAFT

A. G. Kaufmann[1]

INTRODUCTION

OeMV-Aktiengesellschaft is an integrated oil company. It shares belong to to the government of the Federal Republic of Austria. Eighty percent of the Austrian crude oil is produced from fields of our company. OeMV's domestic activity is concentrated in the inner alpine Vienna basin, where the first economic oil was found in 1913 in the neighborhood of the little village Egbell, today a part of Czechoslovakia. The second area of interest is the Molasse basin. The initial oil-in-place in all reservoirs amounts to approximately 250 x 10^6 tons (1.75 x 10^9 barrels) of which 90 x 10^6 tons (630 x 10^6 barrels) or 36 percent will be recoverable by today's standards of knowledge.

Secondary recovery was started to enhance recovery in the year 1946 by air injection in small sandstone reservoirs. Water injection followed immediately in the year 1953 in the Flysch reservoir near Neusiedl, in the Vienna basin.

Water was injected for flooding, pressure maintenance, or repressuring into approximately 20 pools. Three programs provide higher oil production rates and faster recovery, but additional recovery of oil is negligible. Such waterfloods are called discount oil projects.

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CRITERIA FOR THE SELECTION OF POOLS

Approximately 400 pools are oil-bearing in our concessions. Of these production units, 29 hold 75 percent of the total initial oil-in-place. These larger reservoirs are those of which the initial oil-in-place is larger than one million tons (7×10^6 barrels). In these reservoirs a recovery of 40 percent can be expected. To improve recovery, 11 pools of the 29 are waterflooded and two additional projects are in planning stage. In the remaining large pools either an active water drive is present or the geological and petrophysical conditions do not allow a waterflood project to be economical. Of the 17 water injection programs actually running, 13 show improvement of recovery efficiency. On average, the recovery of all secondary recovery programs amounts to 42 percent compared with approximately 34 percent under primary depletion conditions. If discount oil programs are not taken in consideration, the average recovery of the water injection programs was improved from primary, 15 percent, to primary plus secondary, 25 percent. On average the same recovery factor of 25 percent is reached by all the pools of our company where no water injection took place. During the 1950 decade, projects had been planned in which the primary depletion status more or less was reached. At this point the aim was to start water injection much earlier in the depletion status. In all cases the water injection pattern was planned in such a manner that the effect was like a natural water drive behavior. In some cases, reservoir pressure was increased by water injection. Based on reservoir behavior, it could be concluded that there exists an optimum reservoir pressure which ensures maximum recovery efficiency.

The early projects were installed as pattern floods. Pressure maintenance programs are operated more like contour floods. In these cases water is injected into the aquifier in the immediate neighborhood of the oil-water contact. This has the advantage that maximum injectivity is gained. These areas do not have any residual oil or gas saturation which extremely decrease injectivity. The idea of water injection in the so-called discount oil programs is to support the partial water drive and to reduce the influence of the expanding gas cap. In the next 25 years the three discount oil programs will reach a recovery factor of 60 percent as compared to 55 percent without injection. Today, 10 secondary recovery projects are in operation and the daily rate amounts to 30 percent of total production. Of the remaining reserves of our company, 77 percent are covered by these waterflood reservoirs. The initial reserves of our company by secondary recovery total 12 x 10^6 tons (84 x 10^6 barrels) of additional oil. The recovery factor will be increased from 30.6 percent for primary alone to 35.5 percent for primary plus secondary.

WATER TREATMENT AND INJECTORS

In the first projects, where pattern-flooding following primary depletion was used, only existing wells could be used for injection because of economic reasons. For the programs started after 1960, new wells were drilled for water injection. Analysis of compatibility between brines, oil field waters, and fresh water from rivers was undertaken to find for each project the economical injection water. In only a few cases could fresh water be used. In most of the projects the oil field brine had to be treated for injection because the formation contained swelling clay minerals; in those cases, fresh water caused permeability reduction. In all our programs, water is moved by low pressure pipe systems to the injection wells where according to the specific situation, high pressure pumps are installed with maximum pressure at well head conditions of 100 at (1400 psi). In 1960, in the first project in the Matzen oil field, high pressure pipelines from a central distribution point had been installed to supply the injection wells. This system was found to be inoperable. Special care is necessary at the beginning of a waterflood program concerning the absolute cleanliness of the pipe system for water distribution. Therefore, the individual pipes must be circulated long enough for input and output water to become identical in chemical composition. The same is true for the injection wells, which are swabbed until the chemical composition of the water is identical with the formation water of the pay. In some cases it is necessary to swab the wells for two weeks. In special cases, in which the workover job would last too long, gas lift is installed to produce water from the wells more economically.

METHOD OF PROPOSAL OF WATERFLOODING

Most projects, such as Stiles, Dykstra Parson, Buckly-Leverett, had been calculated by conventional waterflood prediction methods. The predictions of primary reservoir behavior were deduced by the Tarner method and decline analyses. During the actual behavior of the programs in the middle sixties, we found that the above mentioned methods give conservative answers according to the recovery factor. We found that higher values could be expected. In one of the programs, the 8th Torton of the Matzen oil field, primary recovery factor was expected to be 16 percent. Proposals of consulting companies and our own predictions by conventional methods showed that water injection--in this special case contour flooding--would give an ultimate recovery of approximately 20.5 percent or 900,000 tons (6.3×10^6 barrels) additional oil. After 3 years operating this program, a review showed that this value is too low. At the end of 1960 pool behavior showed that the recovery factor must be much higher, in the range of 27 percent at least. This was one of the reasons for our buying a black-oil model for reservoir simulation. With this digital computer program we found that in the next 25 years recovery will get up to 34 percent and the ultimate recovery will amount to 38 percent. In some other pools reservoir simulation lead to a better performance characteristic and therefore gave better knowledge of future reserves and ultimate recovery. Reservoir simulation showed in all cases that the results are closer to the actual behavior than the results from conventional methods.

A special study covering the 8th Torton of the Matzen oil field tried to find if there exists an optimum reservoir pressure at which the injection program should be started. This optimum needs to be understood from physical and economical standpoints. The study showed for this special case that a maximum exists. Initial reservoir pressure of 120 at (1700 psi) needed to be lowered to 40 at (600 psi) to have the optimum conditions for injection for maximum recovery.

SUMMARY

For 20 years OeMV-Aktiengesellschaft has been operating secondary water injection programs. By these waterflood and pressure maintenance programs it was possible to produce at higher rates and additional oil was made available to supply Austria. For our country, this is an essential contribution to political economics. In the middle of 1976, 5×10^6 tons (35×10^6 barrels) of additional oil has been produced. The total production by this method is expected to be 12×10^6 tons (84×10^6) barrels. Recovery factor could be increased from 30.6 for primary to 35.5 percent. All brines which are produced in the field of Matzen are reinjected in the reservoirs. This is a remarkable contribution toward preventing water pollution.

CHAPTER 26

TERTIARY OIL RECOVERY: HOW COME IT'S CALLED THAT?

Claude R. Hocott[1]

INTRODUCTION

It is always possible to look back on the practices of the past and point out how backward and inefficient were those people. Such is certainly the case in the petroleum industry. This type of exercise is not very profitable unless a careful analysis of those practices yields the knowledge and understanding which form a foundation for progress.

Although minor uses of petroleum have been commonplace since antiquity, the petroleum industry as we know it is only slightly more than a century old. Furthermore, reservoir engineering--the technology of oil recovery from geologic traps--is less than 50 years old and has grown into a science during this period. It is not surprising that some of the early production practices are considered most inefficient by present standards or that some of the terminology which emerged as the industry developed may be somewhat confused and confusing. The terms primary, secondary, and tertiary recovery are certainly no exception. It shall be the purpose of this paper to review some of the history, describe the main recovery practices, and clarify the meaning of the oil field terminology insofar as oil-recovery practices are concerned.

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EARLY HISTORY

The first commercial drilling for oil occurred around tar seeps or petroleum springs, where the natural gas usually present had escaped and most of the natural reservoir energy had dissipated. Oil flowed into these early wells by gravity or under a low-grade water drive (not recognized at the time). Consequently, as "wildcat" drilling moved out to search for oil, the early drillers were not equipped to cope with the tremendous energy resident in deeper, sealed geologic traps containing oil and gas. The resultant "gushers" had to blow themselves out, with great waste, in order to dissipate the natural reservoir pressure so that pipe could be set and pumping equipment installed to recover the oil that moved to the well bore, again largely by gravity flow. For years the presence of natural gas was considered a nuisance to be gotten rid of so that one could get on with the production of oil. A few pioneers early recognized the fallacy of this practice and cried out for conservation of natural reservoir energy. One such person was John Franklin Carll, who explained that the "beer barrel principle" should be applicable to a closed oil and gas reservoir. A number of people, including Orton, Hayes, and Kennedy, understood as early as 1900 the benefits to be derived from gas drive and advocated conservation, or return of gas to the reservoir, to assist the oil displacement process.

PRIMARY RECOVERY

The production of oil and gas has been such a seemingly simple, straightforward operation that the world is little prepared for the sophisticated technology involved in the current enhanced recovery process. In fact, the industry itself for many years did not recognize the intricacies of the displacement process involved. Actually, of course, oil does not have the inherent capacity to expel itself from the reservoir. Being only slightly compressible, the results would be very disappointing indeed if only the expansion of the oil were relied on for oil recovery. Continued flow in the reservoir depends on the presence of a displacing agent or agents to move the oil to the well bore and thence to the surface.

Dissolved-Gas Drive

Many of the fields discovered early in the history of the petroleum industry were produced by dissolved-gas drive. Even those reservoirs where other displacement mechanisms were available were produced at such rates that dissolved gas became the dominant displacing agent. Since the supply of gas in this process is limited to that stored in solution in the oil, it is soon exhausted and flow ceases, except for that oil which may drain to the well bore due to a gravity head. Although the amount of oil recovered by dissolved-gas drive varies depending on the characteristics of the reservoir rock and its contained fluids, the recovery efficiency by this process is of very low order, ranging from 10 to 30 percent of the original oil content. Because of this low recovery efficiency, such fields have been the chief candidates for secondary recovery operations or for later tertiary recovery processes.

Gas-Cap Drive

Frequently oil reservoirs originally have present a free-gas zone overlying the oil-saturated strata. This permits the reservoir to be produced so that this gas zone, or gas cap, grows concurrently with oil withdrawal, thus displacing the oil to a structurally lower position and thereby maintaining oil-saturated rock near the well bore. Depending on the relative size of the original gas cap, this process can be considerably more efficient than dissolved-gas drive, occasionally reaching 40 or 50 percent.

However, a gas-cap drive ceases when the original gas is depleted, even though production may continue under gravity forces. Through recognition that the high-pressure gas in the cap was an efficient recovery agent, many operators choose to augment the gas originally in the reservoir by the return to the cap of all produced gas or introduction of gas from other sources. Further, where no gas cap was originally present one can be artifically created by injection of produced or extraneous gas.

Gas injection results in an enhanced or assisted recovery process during the primary operation and it is seldom referred to as secondary recovery. On the other hand, if a field which has been depleted by either dissolved-gas or partial gas-cap drive is repressured by the injection of extraneous gas and a secondary cap is formed by driving the repressured oil to the structurally lower portions of the reservoir, then the recovery operation is considered to be secondary.

Water Drive

Water drive is generally recognized to be the most efficient natural displacement mechanism available to the operator. A water drive is similar to a gas-cap drive except that oil displacement occurs at an advancing water-oil front instead of at or behind a gas-oil interface. The greater efficiency of the water as a displacing agent is due largely to the greater viscosity of water in contrast to gas. Other benefits may be derived from the capillary forces effective during water drive in water-wet reservoir rock and from the fact that pressure maintenance is more frequently possible with natural water drive than with an expanding gas cap.

When the drive capacity of the advancing water is insufficient to maintain the reservoir pressure at or near original, the drive may be augmented by the injection of extraneous water, gas, or both. The result again is an assisted or enhanced primary recovery operation, by either augmented water or combination drive.

SECONDARY RECOVERY

Formerly, it was common practice to produce fields at rates which resulted in relatively inefficient recovery of oil. The most frequent cause of this low ultimate recovery was reliance on dissolved-gas drive as a displacement mechanism, even when other recovery mechanisms were naturally available. Consequently, these fields have been profitable candidates for secondary-recovery operations following depletion by the less efficient primary operations.

Since the development of modern reservoir engineering such uncontrolled operations have become much less common and today occur only when the economics of augmented or assisted primary recovery techniques do not justify the required additional investment.

Water Flooding

Water flooding is the most frequently practiced secondary recovery displacement mechanism. It is so well developed and understood that every field at all favorable to the technique will sooner or later be water flooded. The economics of water flooding is usually more attractive than any alternative technique, which increases its preferred position.

Where water flooding is carefully designed and controlled, the ultimate recovery at the end of the secondary operation may be equivalent to a well-managed and efficient primary water drive. However, there are numerous cases where primary operations were conducted in such a manner that water flooding is precluded as a secondary-recovery operation. For instance, if a gas cap is allowed or caused to shrink, and reservoir oil moves into the gas zone, much of that oil will be unrecoverable by water drive. Often, the majority of the oil that remains after primary operations is in portions of the reservoir rock not readily accessible to the encroaching water. The shrinkage and increase in viscosity of oil denuded of dissolved gas render the oil less susceptible to displacement by water flooding. It should be recognized that not every old reservoir is a candidate for secondary recovery. Many secondary water flooding attempts have failed because a paucity of data or inept assessment failed to disclose the true nature of the prospect.

Thermal

Thermal recovery ranks next to water flooding and gas-injection pressure-maintenance in popularity as a secondary oil recovery method. This is usually accomplished either by injecting steam as an external heating agent or by sustaining an in situ flame front through injection of air to generate the heat by burning a portion of the reservoir oil. This process is most effective for oils of high viscosity. Frequently the primary production from such a field is so low (under 5 percent) that the operation is for all practical purposes a primary recovery application. Occasionally, thermal processes are considered for true secondary operations where lower viscosity oils (30^{o} to 35^{o} API gravity) have been depleted by gas drive or even water drive; however, the quantity of heat required to heat both the residual oil and the total reservoir rock may require burning too much of the oil for this method to be economical.

TERTIARY RECOVERY

The common use of the term "Tertiary Recovery" to designate the more complex, highly technical recovery processes has resulted in much confusion. Insofar as the processes are applied in a one, two, three sequence, this nomenclature is accurate. Further, when used to describe techniques which are more sophisticated and demanding than conventional water flooding and gas-injection pressure-maintenance, the terminology may still have some justification. However, to apply this designation to enriched-gas pressure-maintenance, super-pressure gas drive, or hydrocarbon miscible or mobility-control polymer-solution drives, when they are clearly used as secondary (in time sequence) operations, is misleading and often results in confusion among regulatory bodies, economists, and other nontechnical entities. The use of such descriptors as enhanced, improved, or assisted-recovery techniques is more proper but still inadequate on occasion. To date, no simplified nomenclature has been accepted in the literature as a generalized designation for the broad field of supplemental recovery processes being developed to recover a substantial portion of the remaining, otherwise unrecoverable residual oil following conventional recovery practices.

Micellar/Surfactant Flooding

Micellar/surfactant recovery is a designation recently adopted by the Oil and Gas Journal for a process which, in its various modes, receives a wide range of compositions. Usually, a petroleum sulfonate is used as a surface-active agent, either alone or with a co-surfactant, to achieve exceedingly low interfacial tension between the residual oil and the displacing agent. This process is usually applied as a true tertiary operation to scrub out oil remaining in the reservoir following a secondary water flooding. Obviously, if the water-displacement front advances through the reservoir as a primary water drive, the analogous micellar/surfactant recovery process becomes a secondary operation insofar as the time sequence is concerned.

In any case, it is generally believed that micellar/surfactant recovery techniques offer the most promising mechanism for additional recovery from a watered-out reservoir.

Carbon Dioxide Flooding

In the quest for the ideal displacing agent, one having the property of complete miscibility with reservoir oil has long held a prominent position. In addition to the hydrocarbon-miscible processes, the use of CO_2 in slugs or small banks occupies a favorite spot. While CO_2 is not completely miscible with many reservoir crude oils, CO_2 flooding appears to offer many of the advantages and properties of miscible floods, when properly controlled. Its use has been receiving particular attention in the United States in those areas where natural deposits of highly concentrated CO_2 are available from high-pressure wells. Carbon dioxide likewise would seem to be more advantageous in secondary operations where residual oil saturations tend to be greater.

Many so-called tertiary operations may be more effectively applied than secondary methods to high oil saturations. In the past, low oil prices favored a recovery sequence whereby the less costly secondary recovery techniques were applied before the more expensive enhanced recovery techniques; this resulted in less time delay before realizing returns on the high early costs of such processes. If oil prices increase more rapidly than operating costs, there should be a tendency to move toward application of the more expensive yet more effective enhanced techniques in the secondary phase, or even during the primary phase.

Although sematics have little effect on the technology of oil recovery from the reservoir, nontechnical barriers arise from misunderstandings over nomenclature and inhibit ready application of desirable programs. Therefore, careful attention must be given to develop a precise, meaningful, and uniform designation for common operations in the realm of oil recovery technology.

CHAPTER 27

ENHANCED OIL RECOVERY IS AN IMPORTANT WAY TO INCREASE OIL RESOURCES

N. S. Erofeev,[1] M. L. Surguchev,[2] and E. M. Halimov[1]

INTRODUCTION

Oil is now the basic fuel among the energy sources included in the energy balance of all commercially developed countries, amounting to 47 to 75 percent, whereas its share in the world energy balance is 54 percent. In 1975 annual world oil production amounted to 2.8 x 10^9 tons.

The rate of increase in oil consumption in the world for the previous 15 years reached an average 5.5 percent per year, whereas in commercially developed countries it reached 8 to 15 percent per year.

Known and expected oil reserves do not suggest that such a rate of increase in oil consumption can be kept up for a long time in the future. In the 9th World Petroleum Congress (Tokyo, 1975) the total known and expected recoverable oil reserves in the world were estimated to be 273 x 10^9 tons. Of these, more than 45 x 10^9 tons already have been recovered and consumed. With a 5.5 percent annual rate of increase in oil consumption it would be required to bring the world oil production rate to 8 x 10^9 tons per year over the next two decades to recover an additional 130 x 10^9 tons of oil and actually to discover all

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expected oil reserves. Though the largest part of the land and shelf already have been studied well enough by seismic methods, the probability of discovering all expected reserves of oil before 1955 is not high.

Thus, the prediction made by M. King Hubbert, which supposes an increase in oil production up to a maximum of about 5.8×10^9 tons in 1995, a 3.5 percent annual rate of increase in oil consumption, and then a steady decrease in oil production, may be considered well-grounded. This means that for two decades in the future satisfaction of demand for oil will be poorer than in the past and that later, a sharp deficit in oil will be felt over the world.

In such a situation, oil-recovery enhancement is the most reasonable way to get additional resources of oil, which will facilitate transition to new alternative energy sources (atomic energy, pure hydrogen, synthetic fuel, geothermal and solar energy, and others). Reserves of these energy sources are large.

At present, in all oil-producing countries, methods applied for recovery of oil from the reservoirs are not entirely satisfactory. On the average, 55 to 65 percent of the known geological reserves of oil world-wide has not been recovered, using modern, commercially tested methods of oil field development. In many large oil fields, characterized by especially complex geological conditions (high viscosity of oil, nonuniform fracturing of reservoir rock, and similar factors), 80 to 90 percent of original geological reserves of oil (oil-in-place) remain unrecoverable while producing them with natural drive and waterflooding. In the Soviet Union, Russkoye, Usa, and other oil fields can be assigned to such a type.

The problem of increasing the rate of recovery of oil from the reservoirs is found to be an important and difficult problem in the whole world. Actually, all the oil-producing countries are anxious about the poor use of oil reserves and take measures for enhancement of reservoir oil recovery. However, extensive study of reservoir oil recovery problems has been carried out in only a fiew of them, including the USSR, USA, Canada, and Romania. In others, the technology developed in these countries has been applied.

In the Soviet Union various aspects of the problem of oil recovery enhancement have been studied, and since the forties, artificial waterflooding of oil deposits has been widely applied. At present, water injection rates reach 1 x 10^9 m^3 per year and more than 85 percent of the total quantity of oil has been produced in fields where waterflooding is applied.

In contrast to foreign practice, waterflooding in the oil fields of the USSR is applied not as a secondary method of oil production, as in the USA and the other countries, but actually from the very beginning of development of the fields. This peculiarity in application of waterflood, as investigation shows, has served as one of the basic reasons permitting the Soviet Union to ensure a relatively high share of recovery of oil from the reservoirs (on average, more than 45 percent) and high oil production rates with wide well-spacing patterns. The Soviet Union exceeded the USA in oil production rate in 1974, though the number of operating wells is seven to eight times less than in the USA. The cumulative total of wells drilled in the USSR is 15 to 18 times less than in the USA.

At the same time, the problem of improved reservoir oil recovery continues to be one of the basic problems in the Soviet Union with respect to increasing future oil resources.

Oil recovery enhancement methods investigated and tested in the oil fields of the country and the connection between them can be represented schematically (Fig. 27-1).

Future methods of oil field development under study are based on application of various new agents (chemicals, gas, heat, and solvents) together with waterflooding of reservoirs. With each new agent several methods actually are studied, differing either in the sort of agent or in the applied technology.

All the above-mentioned methods of reservoir oil recovery enhancement are now at different stages of study and application and can be placed into four groups by degree of readiness for commercial application in the Soviet Union:

1. Commercial methods, that is, methods which already have been widely applied. They include:

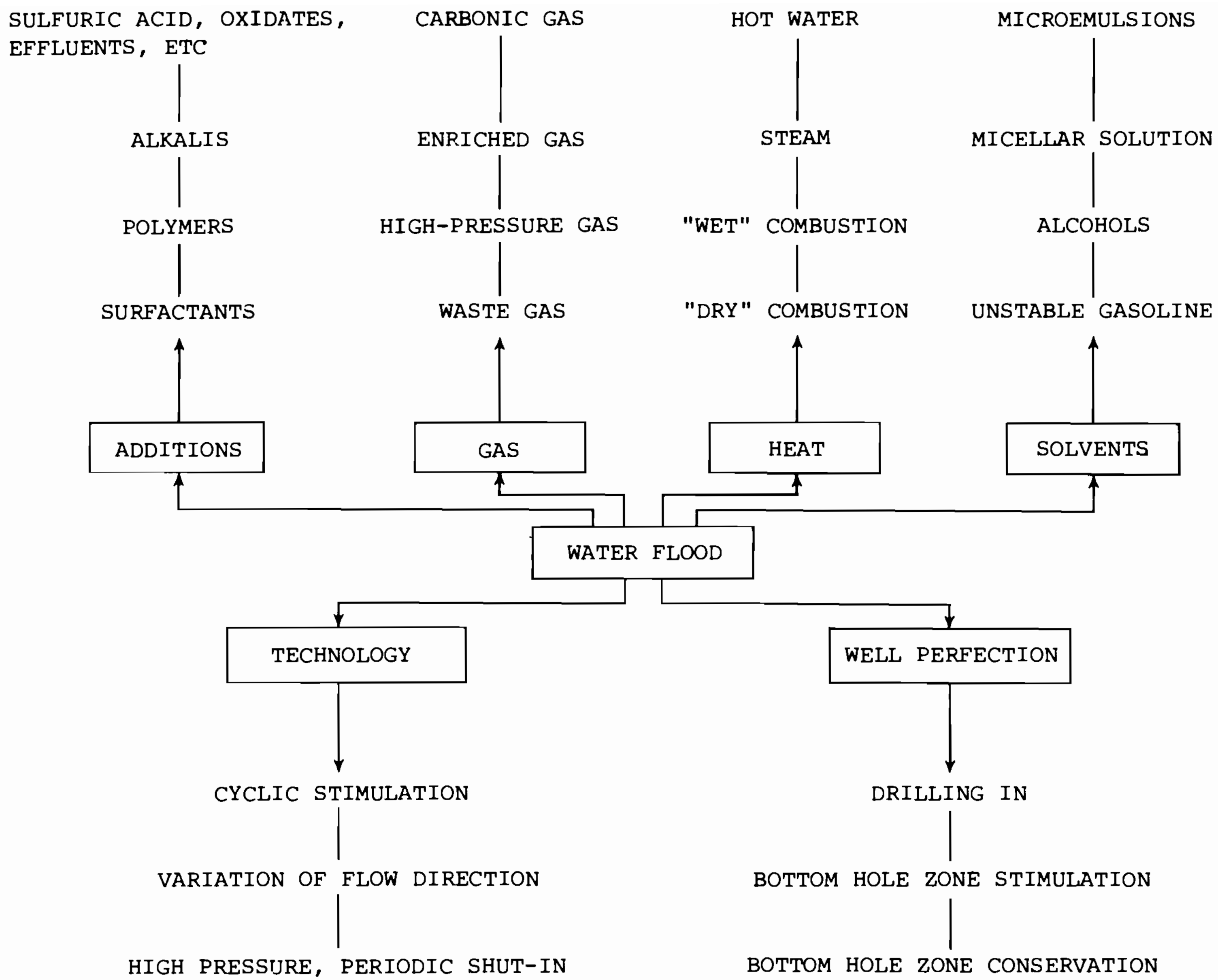

Figure 27-1.--Methods of oil recovery improvement

- water flood
- reservoir cyclic stimulation
- bottom-hole steam-cyclic stimulation.

2. Methods ready for commercial application, that is, methods which have undergone extensive commercial testing. They include:

- surfactant flood
- polymer flood
- displacement of oil by steam
- combined gas and water injection
- sulphuric acid reservoir stimulation.

3. Methods under trial-commercial testing, that is, methods which have been commercially tested in individual field-test areas. They include:

- CO_2 flood
- in situ combustion
- miscible displacement
- bottom-hole thermal-acoustic stimulation.

4. Methods prepared for commercial testing, that is, methods which have proven effective in laboratory tests. They include:

- micellar flood
- caustic flood
- oxydate flood
- injection of water and gas hydrates.

Results obtained during testing in the oil fields of certain of the methods listed above are described as follows.

RESERVOIR CYCLIC STIMULATION

This method is applied during waterflooding in many oil fields of West Siberia, Tataria, Bashkiria, Kuibishev, and other regions. The method can be applied at any stage of production and in any field produced with waterflooding. This method can be realized by change of the rate of the water injection. For example, the best results have been obtained by application from the initial stage of field development and in fields with highly nonuniform (heterogeneous) reservoirs. Reservoir cyclic stimulation allows increased oil recovery of about 3 to 5 percent over current oil production increases of about 10 to 25 percent, by decreasing the water injection rate as compared with ordinary waterflood.

On the basis of extensive theoretical study, analysis, and generalization of the results of commercial tests, methods for optimum programming of the process at various geological conditions have been developed.

SURFACTANT FLOOD

A prospective method calls for injection of water solutions of nonionic surfactants into reservoirs. The technology of the method is simple and it can be applied in new fields without substantial capital expense, as well as in old oil fields without reconstruction of operating waterflooding systems. A small quantity of surfactant is added in water to be used for injection. Being absorbed at oil-water and water-rock interface, the surfactant essentially decreases water surface tension at the boundary with oil, and improves wetting of rock by water; this facilitates displacement of oil from rock. A part of the surfactant is dissolved in oil and to a considerable extent this suppresses rheological properties of the oil. Due to the fact that the limiting shear stress is decreased, oil in pore space becomes more mobile.

Surfactant injection is most efficient if applied from the very start of production in the oil field. If surfactant is injected from the very beginning of production of a field, a 1.5 to 2-fold increase over water-free oil recovery is observed. Extensive tests have been carried out in the oil-bearing area where the productive formation is composed of Carboniferous sandstone. Twelve injection and 39 production wells are available in the test area. The increase in oil recovery during a 9-year period amounted to 8 percent. Estimates made for various fields show the possibility of increasing reservoir oil recovery by about 5 to 12 percent, depending on the stage of development. By using one ton of dry surfactant, 100 tons of additional oil are produced. The solution was tested in fields with oil viscosity from

2-30 cp, and higher. By using surfactants, low-productive formations, which are usually not produced successfully because of small water-intake capacity of wells, can be produced. This method can be combined successfully with cyclic reservoir stimulation, resulting in still higher efficiency.

Application of surfactants is impossible without solution of environmental protection problems, because most surfactants are characterized by a low rate of biochemical decay. Transition to application of soft surfactants has been planned. While using surfactants to improve oil recovery, their activity should be kept as long as possible under various thermodynamic conditions, that is under various temperatures in the reservoirs. In this way the agents may be characterized as to maximum decay stability. Thus, with application of such agents a number of measures for protection of the environment and carrying out of the closed technological cycle is provided.

In the USSR, it is planned to expand application of surfactants to improve oil recovery.

CO_2 FLOOD

Addition of carbonic acid to water to be injected into a formation or its application as a slug before water injection is an efficient method of oil recovery enhancement.

When oil contacts the carbonated water, the carbon dioxide, which is more soluble in hydrocarbon fluids than in water, passes from the water into the oil. As a result, oil viscosity is decreased whereas oil volume is increased. Water saturated with carbon dioxide becomes more viscous, pH and surface tension at the oil-water boundary decrease, wetting of rock by water improves, and separation and washing-off of oil film occur. This results in increased rate of wetting of saturated rock by water. In the filtration process, permeability of porous media increases due to decrease in swelling of clay and solution of calcium carbonates.

Addition of 4 to 5 percent carbonic acid to water injected into a formation or creation of carbonic acid slug allows increased oil recovery of about 10 to 15 percent as compared with ordinary waterflood.

Commercial tests were carried out in a reservoir composed of Lower Carboniferous clastic rock being produced by waterflood. Carbonic acid was injected in an area where one injection well and four production wells were available. The injection of the carbonated water resulted in a 6 percent increase in oil recovery compared with waterflood. From 10 to 15 tons of additional oil were obtained per ton of added carbonic acid.

Due to the high efficiency of carbonic acid in improving oil recovery, the demand for this acid has increased sharply. High-tonnage production of carbonic acid can be obtained by utilization of gaseous wastes from alcohol plants, oil refineries, and petrochemical, chemical, and other energy plants. Simultaneously, environmental protection problems require solution.

The most inexpensive source of CO_2 for application in the oil industry is naturally occurring deposits associated with oil fields. Other possible sources of carbonic acid are given in Table 27-1.

TABLE 27-1.--Sources of carbonic acid

Source	Annual output (10^3 tons)	Approximate cost per ton (roubles)	Price per ton (roubles)	
			Calculated	Needed to establish production
Petrochemical plant	300	4.7	6.2	8
Oil refinery	240	6.4	8.9	10
Soda-cement plant	380	40.2	44.1	45
Heat and power plant	1,530	40.9	44.9	50
Hydro-electric power station	1,530	40.9	44.9	50

Thus, resources of carbonic acid for use in improvement of oil recovery are rather high, but the most important source will be CO_2 produced with natural gas in oil and gas fields or as free (nonassociated) CO_2 gas.

POLYMER FLOOD

Polymer flood is one of the physico-chemical methods developed for commercial application. However, its area of efficient application is limited. Permeability of the reservoir must be higher than 100 md, and the viscosity higher than 10 to 20 cp.

Commercial testing of this method, carried out in a number of Soviet fields, shows that injection of 1 ton of polymer calculated for 100 percent concentration, may yield recovery of 300 to 800 tons of oil.

Cost of extra produced oil is 1.5 to 2 times less than prime cost (unit cost) of oil produced from the wells before injection of the polymer. It is expected that by injection of solution of not less than 25 to 30 percent of pore volume, the increase in oil recovery will exceed 10 percent of geological reserves (oil-in-place). This method is characterized by better results when combined with micellar flood and with cyclic waterflood at higher injection pressure. Application, however, is limited by shortage of the agent and by its high cost.

DISPLACEMENT OF OIL BY HIGH-PRESSURE GAS AND GAS-WATER MIXTURE

Massive, steeply dipping zones, deposits, and dense rock deposits with permeability of not less than 50 md, which contain oil of low viscosity and specific gravity, can be used as targets for injection of high-pressure gas, which provide miscible displacement of the oil by gas from reservoirs. Oil deposits near sources of available hydrocarbon gases can be used for injection of water-gas mixtures, which is more efficient than pressure maintenance by water or gas separately. Such conditions are observed in a number of new regions of the Soviet Union, where resources of both associated and nonassociated natural gas are available. Under certain conditions, oil recovery can be increased about 5 to 8 percent using the gas injection method.

High-pressure gas and water-gas mixtures require, for injection, gas-motor or gas-turbine compressors of high capacity. Such compressors, which are not yet commercially manufactured in the USSR, are found to be the most efficient for injection of gas into the reservoir.

DISPLACEMENT OF OIL BY STEAM COMBINED WITH WATERFLOOD

This method consists of injection of saturated or superheated steam into the reservoir, followed by transition to injection of nonheated water to move hot slug to production wells.

The effect of this method is to decrease oil viscosity, cause thermal fluid expansion, and improve wetting ability of displacing water. As a result, recovery rate and final oil recovery are increased. The areas for application of this method are deposits of oil of higher than 50 cp viscosity, at depths of 1,000 to 1,100 m with reservoir thickness of 10 to 15 m. This method is also recommended for production of bituminous deposits.

This method now is ready for commercial application.

RECOVERY OF OIL BY COMBINATION OF WATERFLOOD AND IN SITU COMBUSTION (WET COMBUSTION)

This method consists of injection of an oxidant into the reservoir and combustion of a small part of oil, as a result of which thermal energy is formed in the reservoir itself. The oxidant, together with air, results in the formation of an extensive zone of saturated steam ahead of the combustion front, as well as reduction of the quantity of burnt fuel and of air consumption.

As a result, recovery rate and final oil recovery are increased. The optimum area for application of this method is in an oil deposit with viscosity of 10 to 100 cp, at depths up to 1,500 m, and with permeability higher than 100 md.

After commercial tests are carried out, commercial application of the method is expected to start in 1980. This method may result in 4.5×10^6 tons of additional oil recovery.

HOT WATERFLOOD

Application of hot waterflood is reasonable under specific conditions, in fields where it is required to maintain original reservoir temperature. Injection of hot water into a reservoir with high paraffinic oil was initiated in accordance with the production project. Hot water injection rate is to be brought to 40 to 45 x 10^6 m^3 per year and oil recovery is expected to increase about 7 to 9 percent.

MICELLAR FLOOD

Micellar flood is considered as the method for improvement of oil recovery from already flooded and depleted reservoirs with higher than 50 md permeability and oil viscosity not higher than 10 to 15 cp. The technology of the method consists in displacing residual oil from the formation by a micellar-solution slug amounting to 5 to 7 percent of pore volume of the deposit. Then a buffer of water, thickened by polymers in the amount of 20 to 50 percent of pore volume is injected. Possible increase in the oil recovery factor is estimated to be 0.25 to 0.30, as compared with ordinary waterflood. However, for commercial application of this method a large quantity of one of the basic components of micellar solutions, that is, insoluble surfactants, is required. The possible extra quantity of produced oil is estimated at 4 to 6 tons per ton of micellar solution. Cost of 1 ton of micellar solution is 50 to 80 roubles. Extensive laboratory testing and the start of commercial testing of this method is expected before 1980.

SUMMARY AND CONCLUSIONS

In the period from 1970 till 1975, due to application of the above-mentioned methods, more than 10 x 10^6 tons of additional oil were produced; of this, 3 x 10^6 tons were produced in 1975. Wide commercial application of oil recovery enhancement methods will allow inclusion of additional hundreds of millions of tons of raw material in the active energy balance.

On the basis of theoretical study, practical application, and commercial testing of various production and improved recovery methods, the following optimum parameters and the factors which favor or do not favor their application (Table 27-2) can be stated.

TABLE 27-2.--Screening criteria for oil recovery methods

	Method	Optimum viscosity (cp)	Possible oil recovery (percent)	.Favorable factors	Unfavorable factors
1.	Waterflood	1.0-10	40-60	Reservoir uniformity	Fissuring, dismembering
2.	Cyclic stimulation	1.0-10	43-63	Hydrophylity, nonuniformity	Dismembering, hydrophobity
3.	Surfactant flood	1.0-10	45-65	Low water-cut, sand content	Clay content, fissuring
4.	Polymer flood	5-20	45-50	High permeability	Fissuring
5.	Gas-water injection	1-10	50-65	Low permeability, anisotropic	Isotropic, hydrophobity
6.	CO_2 flood	5-15	45-60	Steep dip, anisotropic	Salinity, fissuring
7.	Micellar flood	5-10	60-80	Low salinity	Fissuring
8.	Combustion	10-50	55-70	Thin reservoir	Fissuring
9.	Steam injection	50-5,000	50-60	Thick reservoir	Depth more than 1,000 m
10.	Caustic flood	1.0-10	50-65	Naphthenic acids, asphaltenes	Saline
11.	Oxidate flood	1-10	45-65	Carbonate content	Clay content low or high
12.	Steam cyclic simulation	10-1,000	35-45	Asphaltenes, paraffin	Hydrophobity, water saturation

The areas for optimum application of various oil recovery enhancement methods are different. Each individual method can be effectively applied to specific geologic and physical conditions, whereas, altogether, the methods cover the whole range of conditions found in the field. Thus, the problem of increasing oil resources in the discovered fields consists in wide application of one or another of practically all known reservoir oil recovery enhancement methods, as well as those under study.

The main factor to be considered for application of oil recovery enhancement methods is oil viscosity. But even within the range of optimum oil viscosity the unfavorable factors (Table 27-2), especially reservoir fissuring, can make the expediency of application of almost any method doubtful.

As a whole, the methods based on combinations of waterflood with chemical agents, gas, and solvent, cover reserves of oil of not lower than 10 to 20 cp viscosity. Because these reserves account for the largest share of the total (75 to 80 percent), the possibilities for application of these methods are widest. Increase in reservoir oil recovery due to application of all these methods, with the exception of micellar flood, is, however, relatively low (5 to 15 percent) compared with ordinary waterflood.

Thermal recovery methods can be efficiently applied for reserves of highly viscous oil (higher than 10 to 20 cp), which comprise 20 to 25 percent of the total. However, the increase in reservoir oil recovery with these methods is considerably higher than with waterflood alone, reaching 25 to 30 percent.

In the USSR for the next 20 to 25 years, wide application of all the methods for enhancement of reservoir oil recovery is planned, covering 70 to 80 percent of geological reserves of oil (oil-in-place).

Taking into consideration appropriate conditions and possible scale of application for these methods, an increase in oil recovery averaging about 13 to 18 percent of oil-in-place and increasing total oil recovery to an average of 58 to 63 percent may be expected. Recoverable oil resources at the same time are increased about 30 to 40 percent.

It is possible that from each 1×10^9 tons of oil-in-place (geological reserves) an average of 130 to 180×10^6 tons of oil can be recovered due to application of new production methods available at present, in addition to the 450 to 460×10^6 tons of oil recovered by waterflood. This is an important increase in oil resources.

However, to realize this reserve a large quantity of raw material and sufficient technical means are required. For instance, for polymer flooding of 1×10^6 tons of original oil-in-place about 250 to 300×10^3 tons of polymer of 100 percent concentration are required; an average of 70 to 80×10^6 tons of additional recoverable reserves will result.

With micellar flooding of 1×10^9 tons of original oil-in-place, recoverable reserves can be increased by 250 to 300×10^6 tons beyond reserves recovered by ordinary waterflooding. For this, 700 to 800×10^3 tons of surfactants soluble in oil (sulphonates), 200 to 300×10^3 tons of detergent (isopropl alcohol), 500×10^3 tons of liquid hydrocarbon (gasoline, light oil), and 100 to 200×10^3 tons of polymer (polyacrylamide) will be required.

Applying thermal methods to the same 1×10^9 tons of original oil-in-place will recover about 250 to 300×10^6 tons of additional oil during a 15-20 year period, as compared with waterflooding. But to realize this in such scope, 500 to 600×10^6 tons of steam (30 to 35×10^6 tons per year) or 250 to 300×10^9 m^3 of air (15 to 20×10^9 m^3 per year) need to be injected. These figures show the scope of production of the required raw material and of technology required over a period of 15 to 20 years to increase substantially the oil resources of the USSR by these means.

Economic analysis of the results of the experimental study and trial-commercial testing of all the above-mentioned reservoir oil recovery enhancement methods show that they are profitable under present oil prices and demand conditions; in the future they will be more and more profitable as the deficit in oil and its cost continue to grow.

CHAPTER 28

TERTIARY OIL RECOVERY PROCESSES: PHYSICAL PRINCIPLES AND POTENTIALITIES

A. H. Houpeurt[1]

INTRODUCTION

Several methods were proposed over the past 20 years for recovering a part of the 67 percent of the oil left in place after the primary and the secondary production periods corresponding to the natural depletion and to the injection of water or gas in their natural conditions respectively [1].

These methods are often grouped under the name of "Tertiary recovery processes," which is self-explanatory, but a new terminology has appeared in the literature recently, "enhanced oil recovery," and it covers in fact the same methods: surfactant processes, thermal processes, miscible drive, carbon dioxide processes, chemical floods, and improved waterfloods.

As a matter of fact, it is possible to use these new methods early in the active life of a field, chiefly when the efficiency of the conventional processes is questionable, and it is then meaningless to call them "tertiary methods."

It must be said too that the discovery of new fields is so costly that it is extremely attractive to look enviously at that tremendous amount of oil which was already discovered and which lies still in place. It is another reason for keeping the terminology which was chosen for the title of the present paper.

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RESIDUAL OIL AS TERTIARY TARGET

In order to imagine how the residual oil may be distributed in a reservoir after the primary and after the secondary production periods, it is of interest to come back first to the forces acting in a reservoir during these two periods of its exploitation.

Gravity is acting everywhere and at all times, but in an invariable direction, and any oil at the bottom of a well (cellar oil) cannot generally be recovered by gravity only.

Like gravity, expansion acts everywhere in a reservoir (if not with the same intensity everywhere at a given time), but the direction of the pressure forces depends on the will of the operator insofar as he is able to choose the location of the wells, their completion methods, and their flowing bottom hole pressures.

If no active aquifer is connected with the field, the oil flows toward the wells because of the pressure gradient and downdip because of the gravity, but capillary forces tend to keep a large amount of the oil-in-place disseminated in the reservoir and inhibit its collection in the lower parts of the reservoir where it could be possible to capture it.

When water is able to enter naturally into the reservoir during its depletion, it flows also from the part of the boundary which is really open toward the wells, according to the distribution of the permeabilities and pressure gradients. That water entry creates a new situation: because the water generally displaces more oil than does gas, and because the water cannot sweep all the reservoir, the residual oil is not equally distributed throughout the reservoir at the time of abandonment.

Moreover the radial character of the flow around the wells is responsible for coning of the water and it is very difficult to avoid the consequences of this feature.

The water (or the gas) which is injected in a reservoir during its secondary period of production is efficient insofar as it can stay in place. Any contrast between the properties of the reservoir rocks, as well as any contrast between the properties of the fluid in place and the injected fluid acts against the efficiency of the displacement of the oil by water and even more so by gas.

Any permeability variation in a layer will enable the injected fluid to bypass a more or less important part of the oil-in-place and make a breakthrough to the well bore earlier than the oil. Any difference between the permeabilities of a multi-layered reservoir will accelerate the flow in the more permeable layer, also causing an early breakthrough. Any difference between fluid densities will originate a water tongue or a gas umbrella, even in a very homogeneous medium, with the same result. As the water is generally less viscous than the oil, instabilities easily develop, leading also to an early breakthrough.

The target of the tertiary processes is that oil which has been left in place after the secondary period of production. The short analysis which was presented above shows that it will not be easy to know where such oil is really located in the reservoirs, and that among the various reasons which are responsible for the low efficiency of the secondary recovery, many may also act against the efficiency of at least some of the tertiary processes.

In order to understand how the new processes intend to improve the recovery, it may be good to remind why the oil displacement is not completely in the swept part of the reservoir.

Gravity is responsible for the entrapment of oil droplets in the cavities presented by the upper wall of the pores; capillarity blocks the thresholds with drops of oil when the pressure gradient is unable to overcome the difference of the capillary pressures imposed on the drops by the pore geometry in its front and rear parts. Molecular forces may be responsible for the direct contact of the oil with the solid phase at some points; the solid presents organic molecules which are preferential sites for the absorption of the oil.

Each of the new processes aims at improving the recovery by a specific action on the sweeping efficiency or on the capillary retention, but most of them actually act in various ways and it would be very arbitrary to classify them too strictly.

Polymer flooding and foam drive aim at increasing sweep efficiency; surfactant processes, like the other miscible processes, try to increase the amount of oil which is displaced from the swept volume. The thermal processes act on the two factors and, like the miscible methods, implicate diffusion effects, but they are indeed very different.

POLYMER FLOODING

Addition of polymers to flood water increases the viscosity of the displacing phase and decreases the mobility ratio of that phase relative to the mobility of the displaced phase, enabling a better vertical and areal sweeping efficiency.

The viscosity of the solution may be as high as 10 or even 100 cp when an amount of polymer varying from 100 to 1,000 ppm is added.

The polymers are chosen in the family of the polyacrylamides or in the one of the polysaccharides; it seems that other compounds were tested, like an ethylenic polyoxide, but field tests were performed with polymers of the first two kinds only.

As a matter of fact, polymer flooding is much more complex than displacement with an improved water, because the solution is not a Newtonian fluid; because, behind the polymer slug, the permeability of the porous medium is lower than before its flow; because the polymers are more or less absorbed by the porous medium; and finally, because the polymers, which are long chain, high molecular weight compounds, are fragile and break during their flow.

Their degradation depends on the temperature, which must be lower than 120° C, and on the salinity of the interstitial water; the fluid velocity is another factor of degradation when it is high as in the vicinity of the wells.

The efficiency of the injection of a polymer solution in a reservoir is better when the latter is heterogeneous and the water saturation is not too high; the viscosity of the oil must be lower than 150 cp. The reservoir permeability must be larger than 100 md; fractured reservoirs cannot be polymer-flooded.

The economy of the process is governed by the price of the polymer, which was recently $1.25/pound and it was estimated that this process was increasing the price of oil by $0.80/barrel With the new prices of the crude, it seems that the development of the process will continue; more than 50 tests have been performed in the field, giving good technical results, but the polymer slug must be large, from 10 to 30 percent of the pore volume of the reservoir.

Before starting any field test it is recommended to study the behavior of the polymer solution in the laboratory by experiments made in the actual medium at velocities corresponding to the ones which will be imposed in the field. These experiments will furnish data about actual mobility reduction and polymer retention during the flow of the solution and will enable the reservoir engineer to calculate the oil displacement in the field, using an adequate mathematical model.

FOAM DRIVE

The fundamental property of a foam is that its viscosity is much higher than that of its components. At the laboratory scale, the efficiency of the foam drive, as well as the stability of the foam when adequate surfactant is used, was easily demonstrated.

It seems that the use of foam drive in the field is meeting numerous obstacles and the stability of the foam in situ is not easily maintained. It has been observed that the foam breaks at the contact with the oil and it is now impossible to know how long a foam is able to keep its structure when flowing in a porous medium.

As a matter of fact, the technical literature does not include many papers devoted to foam drive, which was patented in 1960. In 1970 considerable research and field work was said to be needed in order to develop the process, but it seems that, in spite of the economic superiority of the method, it has been more or less abandoned. One may think that the foaming agent is easily absorbed on the porous medium and that the stability of the foam is poor because of that absorption.

SURFACTANT SOLUTIONS

The ability of surfactant solutions to improve the efficiency of injected water for displacing oil was investigated very early (in 1920), but the results were first discouraging, probably because the surfactants which were available at that time were unable to lower the interfacial tension between the oil and the solution to the very low level which is needed.

Recent research has shown that the interfacial tension must fall far below 1 dyne/cm in order to actually improve the displacement of oil. It also was demonstrated that sulfonates were able to lower the interfacial tension to the desired level, their molecular weight being in the range of 400; these chemicals are all the more efficient as a number of sulfonates groups is high in molecular weight.

Unfortunately, these chemicals are easily absorbed by the reservoir rocks, and moreover, it is necessary to use a mixture containing sulfonates of lower molecular weights as well for obtaining a sufficient solubility; that is why the resulting decrease of the interfacial tension is not as large as could be wished.

The surfactants which are available today are degradated by most of the interstitial waters (the salinity must be below .2 or .3 mole/litre) and are costly.

Surfactant flooding will become practical and efficient only when these technical and economical obstacles will be eliminated.

At the moderate concentration of 1 percent, surfactant flooding would charge every barrel of oil about $4.00 in the present status of the market.

MICELLAR SOLUTIONS (MICROEMULSIONS)

These solutions are in fact emulsions in which the droplets of the dispersed material are in the range of less than a micron--in fact from 1 micron to 1/100 of a micron.

Such a dispersion can be obtained by mixing a hydrocarbon, water, a surfactant, and a second chemical which is generally an alcohol: a typical composition, for instance, is 25 percent water, 57 percent oil, 15 percent surfactant, and 3 percent alcohol. Such a solution is acting like a miscible slug, able to mix with oil as well as with water.

When a slug of that type is pushed in a reservoir, the emulsion, which is a water-in-oil emulsion, mixes easily with the oil-in-place; there is no interface and the displacement is a miscible one. Behind the slug, the displacing water tends to invert the emulsion, which becomes an oil-in-water type emulsion. A continuity of fluids is so created with no interfaces between the injected water and the oil-in-place.

Obviously such a method of recovery is very attractive, but the problems which were listed about the surfactant solutions arise for the microemulsions too, and the limitations in the use of the process are the same. Salinity of the interstitial water is the major obstacle, but temperature also tends to break the microemulsions.

The volume of the slug which must be employed in order to get a good result may apparently vary from 3 to 15 percent of the pore volume to be swept. In the best conditions it seems that today the charge would be of about $6.00/barrel of oil.

Twelve field tests were reported in 1974, all in sandstones. Reservoir salinities ranged from 0.2 to 10 percent and the amount of sulfonates per barrel of recovered oil ranged from 7 to 15 pounds. The highest reservoir temperature was 60° C. The permeabilities were ranging from 50 to 250 md for all the tests but one. The oil viscosities were less than 10 cp and the densities less than 0.904 (25°API).

Many laboratories attempt to find new chemicals having a better behavior with regard to the temperature and to the salt, but it seems that it is difficult to synthetize molecules having better properties than the sulfonates.

MISCIBLE DRIVES

It is possible to group under that denomination at least four processes: three are improved gas drives, and the fourth, is, rather, an improved water-drive.

LPG slugs have the property to mix in every proportion with oil as well as with natural gas: the miscibility is controlled by the temperature and the pressure in the field. Normally it can be achieved at pressures of approximately 1,000 to 15,000 psi (70 to 105 kg/cm^2) depending on the reservoir temperature.

The process can be efficient for oils between 30^o and 50^{o}API. It seems that for very viscous oils, the miscibility between the LPG slug and the oil becomes very unstable in such a way that the miscible zone is dispersed and finally the miscibility disappears.

Gravity is also acting against the efficiency of the process because of the great difference between the density of the oil and that of the LPG. It is recommended to use LPG slugs downdip, and to moderate the velocity of the displacement in order to avoid any fingering.

When used in favorable conditions, the process can recover 90 percent of the oil in place. Nevertheless, the price of the LPG is high and the process is costly ($3.00 to $4.00/barrel).

High pressure miscible drive is a process enabling the operator to recover a very high proportion of the oil-in-place (90 percent in the swept area) if the temperature and pressure conditions are such that miscibility can occur between the natural gas which is injected and the oil-in-place. This requires deep reservoirs containing rather light oil (API gravity higher than 35^o). The crude must contain a fairly high content of intermediates in order to create the mixing zone. The process was applied to the giant field of Hassi-Messaoud, at a pressure which was extremely high (400 kg/cm^2) and temperature of about 120^o C. at a depth of 4,000 m.

Other gases than natural gas have demonstrated their ability to mix with the oils (nitrogen, carbon dioxide, flue gas) but the cost for preparing these gases will add to the injection costs, which can easily reach $3.00 to $4.00/barrel of oil. The process is very attractive if the oil contains naturally a high amount of dissolved gas which is produced with the oil.

High pressure gas drive implies a perfect control of the well injectivity and requires a thorough elimination of any product able to plug the formation by itself or indirectly. Some problems may also arise during the compression of the gas if liquid phases can appear. The number of high pressure gas drive exploitations is not known exactly; together with the enriched gas drive process described next, there were about 100 a few years ago.

Enriched gas drive is a process in which a gas containing a high percentage of intermediates is used for displacing the oil (from 20 to 40 percent propane and butane). Thermodynamical exchanges between the oil and the enriched gas enable the two phases to become continuous, as in the other processes described above.

Enriched gas drive can be efficient at pressures which are much lower than those required by the high pressure gas drive (from 1,500 to 3,000 psi). The process requires considerable quantities of intermediates, which are not always available. The oil which can be recovered by this process ranges between 30° and 50°API, and, like the other miscible processes, enriched gas drive will be most inefficient if the viscosity of the oil is greater than a few cp. Nevertheless the process is well adapted to the recovery of oils of higher molecular weight than those which are produced by high pressure gas drive.

Alcohol flood is the fourth process which will enter in the present class of processes. The alcohols containing 3, 4, or 5 carbons are soluble in water and in oils, obviously enabling a miscible drive. Isopropyl alcohol is the least expensive (about $10/barrel) and it is expected that it could be recovered by water flood after the oil [2].

The process offers two advantages:

- It works at any pressure, contrary to all the other miscible processes which were described above and which require definite pressures.
- The alcohol slug is pushed by water, which is a relatively inexpensive fluid with a better mobility ratio and more limited gravity effects than a gas-drive.

The oils which may be recovered by the process may have a fairly low API gravity (from 25° to 55°).

As far as the author knows, no field test results have been published.

CARBON DIOXIDE DRIVE

Carbon dioxide is a very interesting product:

- It is soluble in water and in oil, much more so in the latter.
- When dissolved in oil, it greatly reduces the viscosity of that phase, and, on the contrary, it increases water viscosity, improving substantially the viscosity ratio of the two fluids, that is, the mobility ratio of the displacement.
- The oil may swell considerably under the effect of the dissolved gas (from 10 to 20 percent), reducing its density; gravity effects are minimized.
- The interfacial tension between water and oil falls to low values: it is even possible to reach miscibility between supercritical carbon dioxide and the oils.
- Finally, in carbonate reservoirs, a positive effect is obtained on the rock--sometimes on argillaceous rocks as well.

These last effects are important for improving the injectivity of the wells in the carbonate reservoirs. The favorable effect reported on the argillaceous rocks is related to the low pH maintained by the carbon dioxide.

Seven large scale tests were performed in recent years using injection of supercritical carbon dioxide as a reagent. Temperatures ranged from 45^{o} to 20^{o}C, pressures from 105 to 350 kg/cm^2 (110 to 250^{o}F and 1,500 to 5,000 psi). The permeabilities ranged from 4 to 300 md and the oil gravities were higher than 25^{o}API.

Of these seven tests, five used gas only, one a water drive, and one a combination of both water drive and gas drive. The results of these tests are not known.

One of the important restrictions to the use of the process, which seems all the more attractive as carbon dioxide is unable to furnish any energy by itself, will be the supply of the tremendous amount of gas which may be necessary. Carbon dioxide is found in natural deposits, sometimes discovered when looking for natural gas; it is also a by-product of numerous plants, and is manufactured in some places in order to satisfy different needs.

The purity of the gas may vary from 80 to 100 percent and its price ranges from about \$0.30 to \$3.00/1,00 ft^3 [3].

Even if the gas were available free of charge, compressing and transporting it over a distance of a few hundred miles costs about \$1.00/1,000 ft^3. If one barrel of oil is recovered for every 6,000 ft^3 of injected carbon dioxide, the expense for circulating this amount of gas and for avoiding corrosion damage will reach about \$10/barrel [4].

THERMAL PROCESSES

The oil recovery in fields containing heavy oils is always very low because the viscosity of such oils is generally very high, and the mobility ratio is very poor. It may be said that such fields cannot produce an important part of their oil-in-place if conventional methods only are used.

Heat is an agent able to reduce greatly the viscosity of the oils; it also reduces the water viscosity, but to a lesser degree, in such a way that the mobility ratio is improved when the temperature increases. Several processes have been developed to benefit by the action of temperature on oil viscosity: hot water injection, steam injection, and in situ combustion, the last two offering several variants [5].

The greatest obstacle which is met in handling heat is presented by heat losses in the well, and then in the reservoir itself, in the part which is already swept by the hot fluid. The advantages of the in situ combustion on that account are obvious.

Hot water drive

When hot water is injected in a well, it pushes ahead the oil-in-place and, at the same time, it raises the temperature of the oil. The temperature feature of the injection of hot water is the reduction of the residual oil saturation observed in the hotter zone. The weakness of the process derives from heat losses.

Steam injection

There are two ways for displacing oil by steam. Steam can be injected in order to heat the oil in the vicinity of the well;

then the well is used as a producing well. This cyclic steam injection process has been used in many fields for 15 years: in California for instance, more than 12,000 barrels/day are now produced with this technology. Heat is generated for about 4 weeks, when production is resumed. Several cycles are applied to a well when the production falls below a fixed level.

Steam injection is also used continuously for pushing the oil-in-place towards the production wells. This process has some advantages over the injection of hot water, because steam contains more heat than water in the same mass, enabling the operator to get higher temperatures in the formation. A part of the lighter components of the oil are often vaporized and flow with the steam, condensing in the vicinity of the virgin oil, where the temperature is lower than close to the injection well. The oil is actually displaced by the condensed vapor, that is, by hot water as in the first case.

Steam drive in laboratory experiments recovers as much as 80 percent of the oil-in-place, but in the field, the recovery is much lower, because of the rather low areal sweeping efficiency. Nevertheless, the effect on the mobility ratio is not the same for hot fluids as for the conventional water drive: as a matter of fact, the instability of the displacement makes the diffusion of the heat easier if fingering occurs.

The injection of hot fluids is restricted to reservoirs having a permeability higher than 300 md, containing at least 16 percent of oil; the thickness of the bed must be at least 10 m, the depth must be less than 1,000 m. The viscosity of the oil may be high (5,000 cp).

Field tests have demonstrated the efficiency of cyclic steam injection. More than 1,000 wells are producing by that process in California and Venezuela.

In some cases, the steam is followed by cold water in order to recover at least a part of the heat which is disseminated in the vicinity of the injection well. The injected water becomes hot and can act efficiently in the field as driving agent.

In situ combustion

The basic idea of in situ combustion is to create heat in the reservoir itself. For that purpose oxidation of the oil is started in a well and a stream of atmospheric air is circulated in the reservoir in order to supply the oxygen needed for feeding the combustion. Different variants of the process exist, known as forward combustion (the air stream and the combustion flow in the same direction), reverse combustion (the combustion front and the air stream are going in opposite directions), and wet combustion (water is injected at the same time as air, in a forward combustion, in order to recover the heat which was developed by combustion in the reservoir areas already swept).

These processes may be used in reservoirs having a thickness of at least a few meters (if they were thinner, the heat losses would become too large), and permeability must range at least over a few hundred md. The oil must be of coke. The consumption of air ranges from 1,000 to 2,000 Std m^3/m^3 of oil when the process is applied in favorable conditions. The amount of oil-in-place (oil volume per unit volume of rock) must be higher than 100 l/m^3. A good porosity makes the process efficient because it will be easy to find the 30 or 40 kg of coke which are needed for the combustion if the amount of oil is large.

Forward combustion may be used for oils ranging from 10^o to 40^oAPI. The reverse one is very well suited for oil ranging from 5^o to 20^oAPI, because the oil will flow towards the well in a zone which was swept by the combustion front and in which the temperature is high.

Wet combustion is a variant of the forward combustion in which a part of the heat which was developed by the combustion is collected by cold water. The water flows across zones which are progressively hotter and therefore it vaporizes. The vapor crosses over the combustion front and brings ahead of the front a part of the heat which was collected upward.

More than 30 field tests have been conducted (as reported in 1975), but detailed technical results are not known.

CONCLUSION

Different methods are proposed in order to increase the recovery of the oil which cannot be recovered by the consumption of the internal energy of the fields and of their associated aquifers. Each one will have its own field of efficiency, and the result will certainly depend on the characteristics of the reservoir to which they will be applied. Each oil field is a separate case and it will be always hard to forecast what will be the efficiency of a given process when applied to it.

Efficiency will depend on the reservoir heterogeneity, which is not easily known and which governs the sweep efficiency for all the processes (even for the diffusional processes). On the other hand, one cannot change the direction of gravity and the diffusional processes are acting so slowly that it is questionable that they can be very powerful during the 20 or 30 years of an exploitation.

It is the opinion of some experts [4] that in the USA, for example, where the amount of discovered oil is about 400×10^9 barrels of oil, tertiary recovery will add some 365×10^6 barrels of oil per year in 1990, that is, less than .001 percent of the initial oil-in-place. One century would be needed for recovering 10 percent of that oil (assuming that the efficiency of the processes would not change during that time).

In other words, there is oil to recover using the methods which are today proposed and demonstrated, but it is not foreseeable that the average value of the recovery may exceed 45 or 50 percent of the discovered oil. Nevertheless, the 15 or 20 percent which is attainable is worth all our care.

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CHAPTER 29

TERTIARY RECOVERY OF CRUDE OIL

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INTRODUCTION

We will define tertiary recovery of crude oil to include all schemes for recovering crude oil which require the input of external energy into the reservoir with the exceptions of mere water or gas injection. Because of a dwindling discovery rate of new petroleum resources and a long history of exploitation of discovered resources, the industry in the United States of America is more involved in the development of tertiary recovery schemes than is the industry in the rest of the world.

The target for tertiary recovery in the United States is some fraction of the 300 x 10^9 barrels that will not be recovered by conventional technology. The geographical distribution of this 300 x 10^9 barrels is shown on Table 29-1. In actual fact, the 300 x 10^9 barrel figure may be on the high side since it is now believed that many original estimates of oil originally in place, particularly in reservoirs discovered prior to 1950, were on the high side. It is not likely that the residual oil would be less than 250 x 10^9 barrels.

Before entering into a discussion and analysis of tertiary recovery, it will be well to examine in some detail certain of the evidence which confirms the need for tertiary recovery, viz., the limits on discovering new resources in any geographical or political area, and the limits to increasing recovery efficiency with conventional waterflooding technology.

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TABLE 29-1.--Estimated unrecovered oil in the United States

	Original oil in place	Estimated ultimate recovery	Recovery (%)	Estimated residual	
	10^9 barrels			10^9 barrels	% U.S.
Louisiana-South	30.96	16.13	52.1%	14.83	--
Texas-East End Districts 2, 3, 5, & 6	35.17	19.32	54.9%	15.85	--
Subtotal-Gulf Coast	66.13	35.45	53.6%	30.68	10.4
Texas-South & West Districts 1, 4, 7's, 8's 9, 10					
Carbonates	67.96	21.06	31.0%	46.90	--
Sands	46.97	11.16	23.8%	35.81	--
California	83.24	21.66	26.0%	61.58	--
Oklahoma	37.65	12.44	33.0%	25.21	--
Subtotal Ex-Gulf Coast	235.82	66.32	28.1%	169.50	57.3%
Remaining U.S.	138.77	43.24	31.2%	95.53	32.3%
TOTAL U.S.	440.72	145.01	32.9%	295.71	100.0%

THE LIMITS ON DISCOVERING NEW CRUDE OIL RESOURCES

The limits on discovering new resources are not always adequately recognized by national leaders and political bodies, and sometimes are not well recognized by theoretical, geological analyses. However, historical oil production statistics are unique in being able to present a clear picture of the limits to finding petroleum resources in any given geographical area.

Oil was discovered in the West Texas-Southeast New Mexico district of the United States in 1921, the Westbrook Field. In subsequent years this district became the leading oil province of the country. Its ultimate production by conventional technology is now estimated at 23.4×10^9 barrels from already-discovered fields. This is about 16 percent of the nation's total estimated ultimate recovery from known fields.

The chronological history of discoveries in this district is shown in Fig. 29-1. The total estimated ultimate recovery from any reservoir is attributed to the year in which the reservoir was first discovered. From 1921 to 1950 the cumulative discoveries increased rapidly. Big increases occur when the super giant fields are discovered: Yates in 1926, Wasson in 1936, and Kelly-Snider in 1949. These three fields account for some 20 percent of the total in this district. Together with three more fields, Slaughter, Goldsmith, and the Spraberry Trend, they account for about a third of the total. However, following Spraberry, discovery rates began to slow down--to a snail's pace by the mid-sixties.

There is only a remote chance that any significant revisions will be made to the district's primary and secondary recovery potential. This is so because of the great expertise that has been acquired and developed by the professional staffs in the oil industry in delineating reservoir boundaries, implementing pressure maintenance and secondary recovery operations rapidly, and estimating ultimate recovery. These statistics on the West Texas-Southeast New Mexico district are typical of every other producing province. They unequivocally lead to the conclusion that the petroleum resources in any geographical area are indeed limited. The lack of discoveries in recent years is in no way due to the

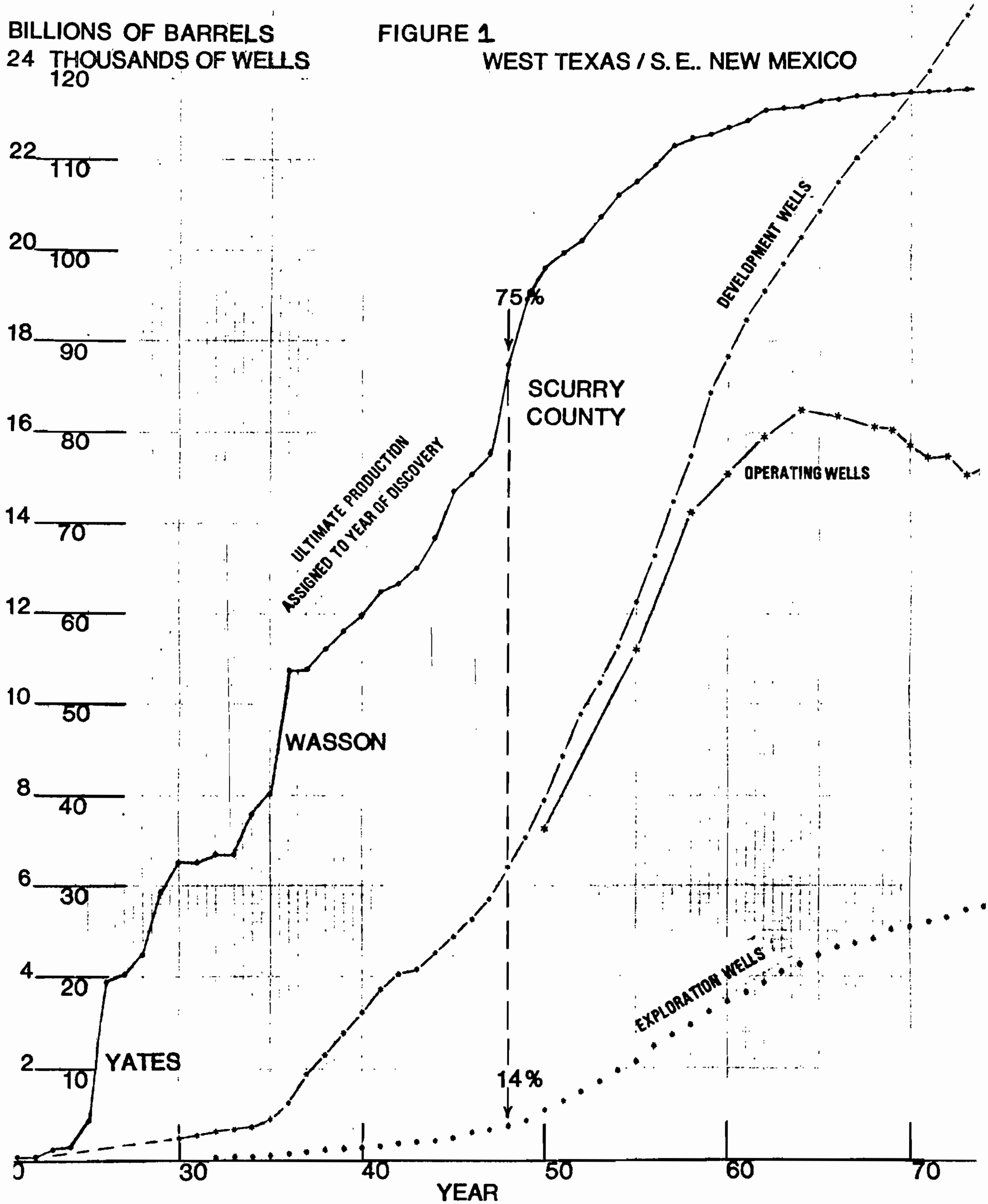

Figure 29-1.--Chronological history of discoveries in West Texas-Southeastern New Mexico

lack of effort in looking for new resources since, as shown in Fig. 29-1, a proportionately far greater number of exploratory wells were drilled in recent years than in earlier years, when significant discoveries were being made.

Given that the resources are limited, every effort must be made to secure the maximum recovery from each and every reservoir that is discovered. The industry in the United States had set about to achieve this many decades ago by introducing water flooding.

WATER FLOODING AND RECOVERY EFFICIENCY

Water flooding increases the recovery of crude oil by maintaining the reservoir pressure and by driving the pore saturation of crude oil down to a value characteristic of the lithology of the reservoir and the physico-chemical interaction of the crude and the displacing water. Unfortunately, the residual oil saturation to water flooding may vary from 5 to 40 percent, and, in addition, the injected water may sweep only a part of the reservoir when the mobility of the water is significantly greater than that of the oil or when the permeability distribution in the reservoir varies greatly. In Table 29-1 it can be seen that the natural water floods present in the reservoirs of East Texas and South Louisiana effect a recovery efficiency of over 50 percent, whereas with induced waterfloods in the rest of the country recovery efficiency is significantly less. The difference is primarily due to the higher porosity of the reservoirs and low viscosity of the crudes encountered in the East Texas-South Louisiana producing district.

The exact increase in recovery due to water flooding in the United States cannot be stated because of the absence of historical records of sufficient detail. However, data on revisions of estimated ultimate recoveries which have been accumulated by the American Petroleum Institute indicate that some 15 percent of the total ultimate recovery, about 22×10^9 barrels, will be produced by water flooding. Another statement of the same conclusion is that, of the overall recovery efficiency of 32.9 percent, 4.9

percent is attributable to water flooding. These statements of overall averages obscure the fact that in some reservoirs water flooding has increased the recovery by as much as 100 percent (the primary recovery was doubled).

It is apparent that even with the most modern and efficient primary development and secondary recovery operations, a large amount of crude oil will be left in the reservoirs at the economic conclusion of their implementation.

TARGETS FOR TERTIARY RECOVERY

The basic technical problem to be encountered in applying tertiary recovery schemes is to render crude oil mobile, so that it will flow through the reservoir and into a producing well. There are three basic types of reservoir situations for which tertiary processes are required.

1. The reservoirs have been subjected to secondary water flooding or gas injection and the recovery efficiency is still less than 50 percent. The residual oil saturations in the reservoirs are 25 percent or more. Reservoirs which have been reduced in saturation to less than 25 percent are not good candidates for tertiary operations, as will be discussed below, although the exact saturation at which tertiary recovery operations will be economically hopeless has not been defined yet. The majority of reservoirs in the United States will fall into this category of target for tertiary recovery.

2. The reservoir crude oil is so viscous that primary reservoir energy is insufficient to drive a significant amount of the original oil in place to the producing wells, and water flooding results in excessive bypassing. The recovery efficiency using conventional technology is very small and it is necessary to heat the reservoir to effect a marked drop in viscosity of the crude oil. In addition, reservoir energy is provided by the heat-carrying or heat-developing fluids. Steam injection and insitu combustion have already been successfully applied to many reservoirs of viscous oil in California, Canada, Venezuela, and the Netherlands. Recovery efficiency with steam injection methods has reached as much as 50 to 60 percent.

3. The permeability of the reservoir is so poor that neither primary nor secondary processes succeed in recovery of an economic quantity of petroleum in a reasonable time. Mechanical fracturing and well stimulation will be required on a scale not usually attained in conventional operations, in order to increase recovery from such reservoirs. The tight gas sands in the Piceance Basin of the Rocky Mountain states and the oil sands of the Spraberry formation of West Texas are examples of such reservoirs.

THE MECHANICS OF APPLYING TERTIARY RECOVERY TO CATEGORY 1 RESERVOIRS

In the terminal stages of water flooding or gas injection a pressure differential is still being exerted on the residual oil. The fact that the oil is no longer flowing through the reservoir and into a producing well is a clear statement of the fact that the mobility of the oil is zero. This absence of mobility in the residual oil is due to the fact that the oil has become disconnected and trapped in the porous media, as shown schematically in Fig. 29-2. The goal of any tertiary process will be to release the oil from this trap by either increasing the pressure differential, reducing the interfacial tension, or substituting a sacrificial, miscible fluid for the more valuable crude oil.

Two techniques have been generally suggested to achieve this goal. One is to use immiscible, aqueous solutions of surfactants to reduce the interfacial tension between the oil and the displacing water, and the second is to use miscible fluids which will displace the residual oil saturation. In the former case it is necessary to displace the surfactant slug with a less mobile polymer solution in order to avoid the need for using a whole pore volume of the surfactant solution, which would be excessively costly. In the second technique, the injected miscible fluid, if it is sufficiently inexpensive, may be left to fill the reservoir, or it may be displaced in turn by a second water flood, down to some selected residual saturation. The most recent attempts to use surfactants have involved systems which are so

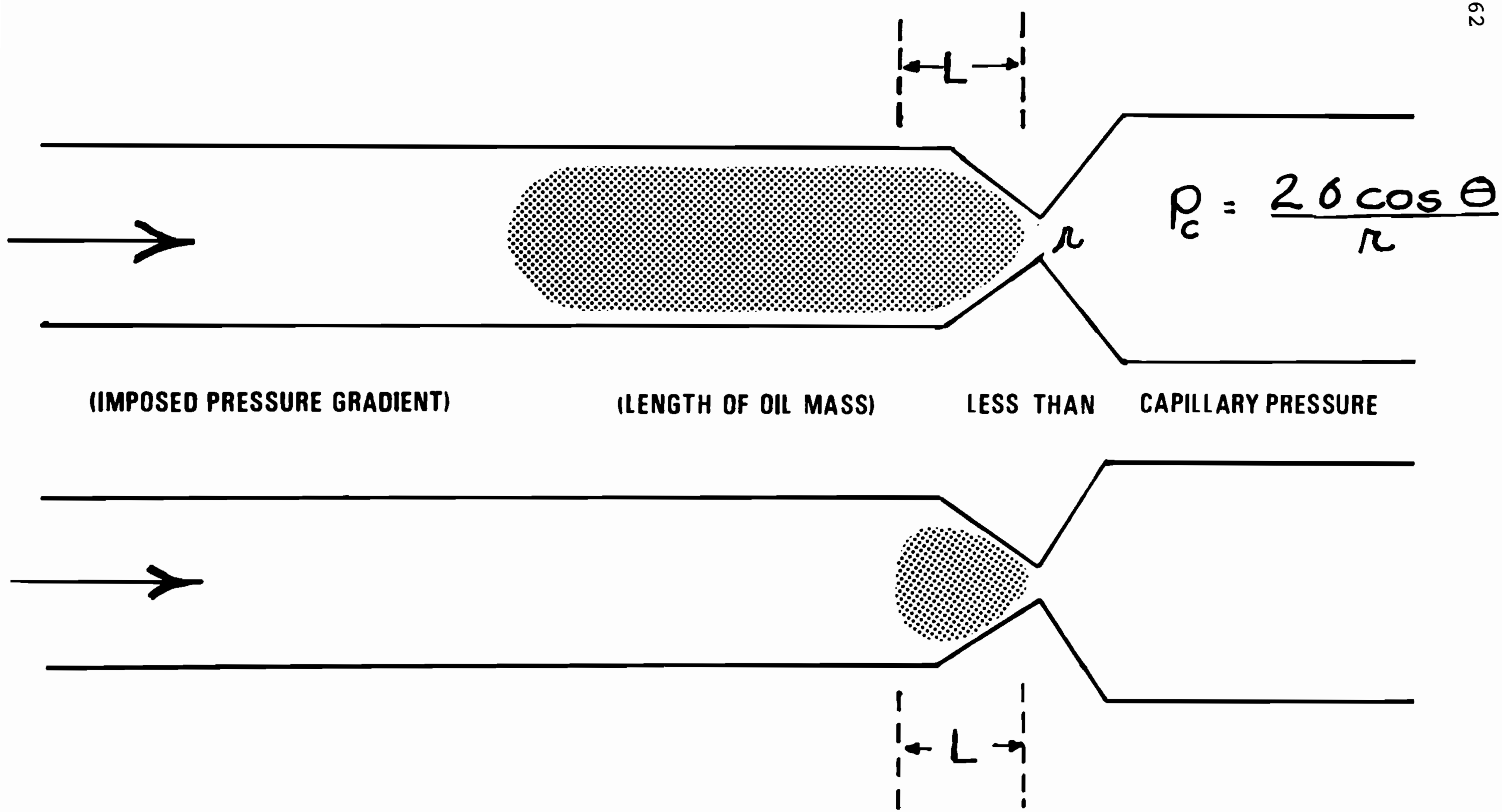

Figure 29-2.--Forces acting on trapped oil

concentrated in surfactant and co-surfactant that the injected fluid is initially miscible with the residual crude. Miscibility is eventually destroyed by adsorption and transfer of the surfactant to the oil phase; further oil displacement then occurs strictly as a function of any low interfacial tension that can be maintained.

It will be well to trace out the mechanics of displacement of residual crude oil by aqueous surfactant systems with the help of idealized representations of the porous media. The analysis may begin by reference to the simple case of water flooding.

Figure 29-3 shows two capillaries of different size filled with oil, although the walls themselves are coated with original, aqueous-phase salt water. We inject salt water into these capillaries and as expected the water displaces the oil in the larger one preferentially. In Fig. 29-3A, the viscosity of the oil equals that of the water and the resulting production performance is shown on the right. Much neat oil is produced and after water breakthrough in the large pore, a smaller amount is produced along with much larger quantities of water.

Figure 29-3C shows the case of the oil being less mobile than the water, and now we see that the relative rate of advance in the larger pore is even greater than before since, as water penetrates the large pore, the resistance to flow is auto-accelerated to lower and lower levels. Now, a much larger amount of water is produced before the last bit of oil. Thus, this model accounts for breakthrough of water prior to 100 percent oil depletion but does not account for any residual oil saturation.

In Fig. 29-4 we show a group of three subsidiary capillaries intersecting a fourth. Their relative size is not significant; what is significant is that at the intersection of the capillaries there are constrictions such as those which would exist at the contacts between grains in the actual porous media. The oil in the subsidiaries must enter the main-line capillary in order to be displaced out of this system. However, the oil in the main-line system in this sketch has moved past the intersection with the first two capillaries, and the flow in the latter two has stopped. It has stopped because the continuous oil thread has

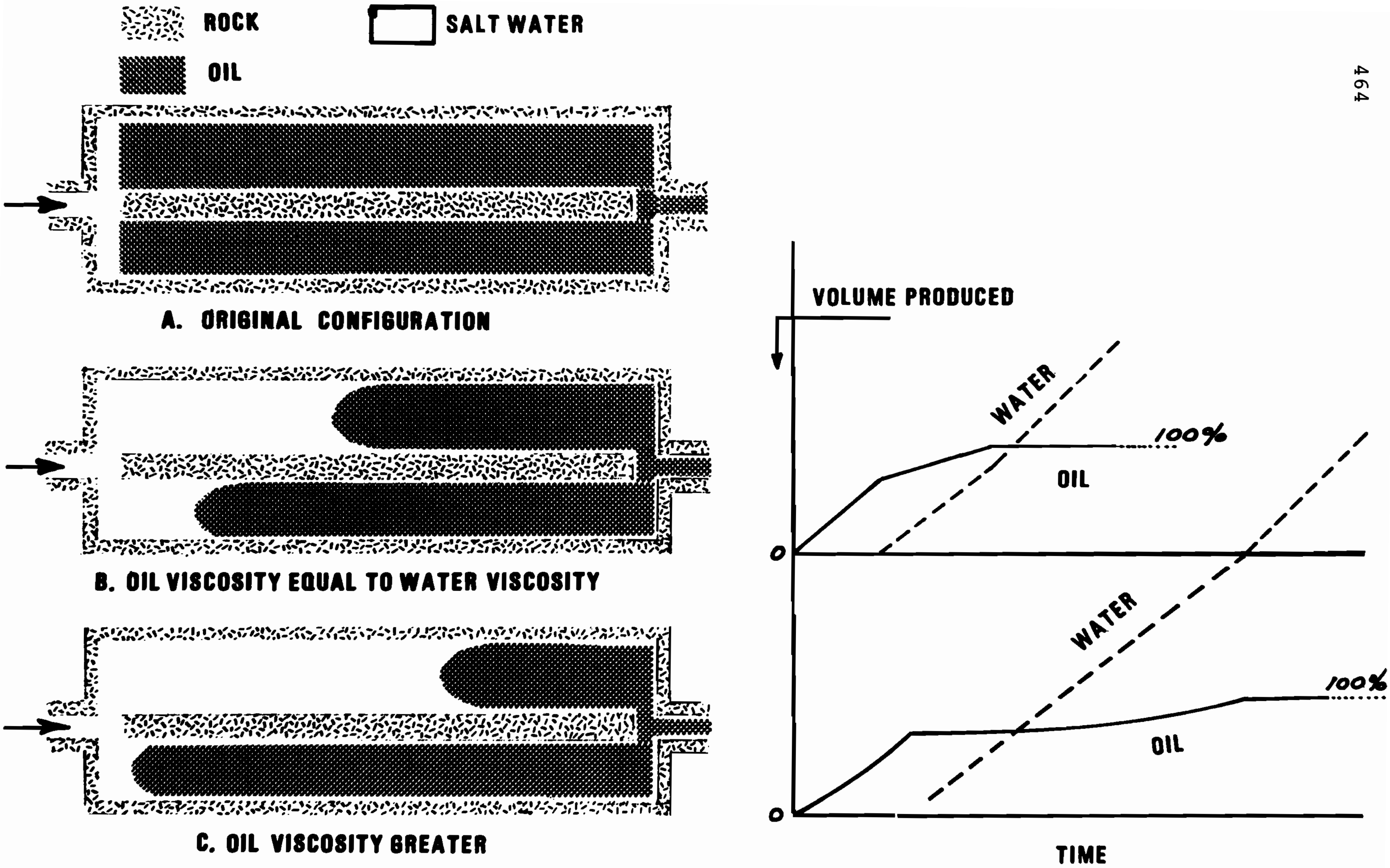

Figure 29-3.--Displacement of oil by water in parallel capillaries

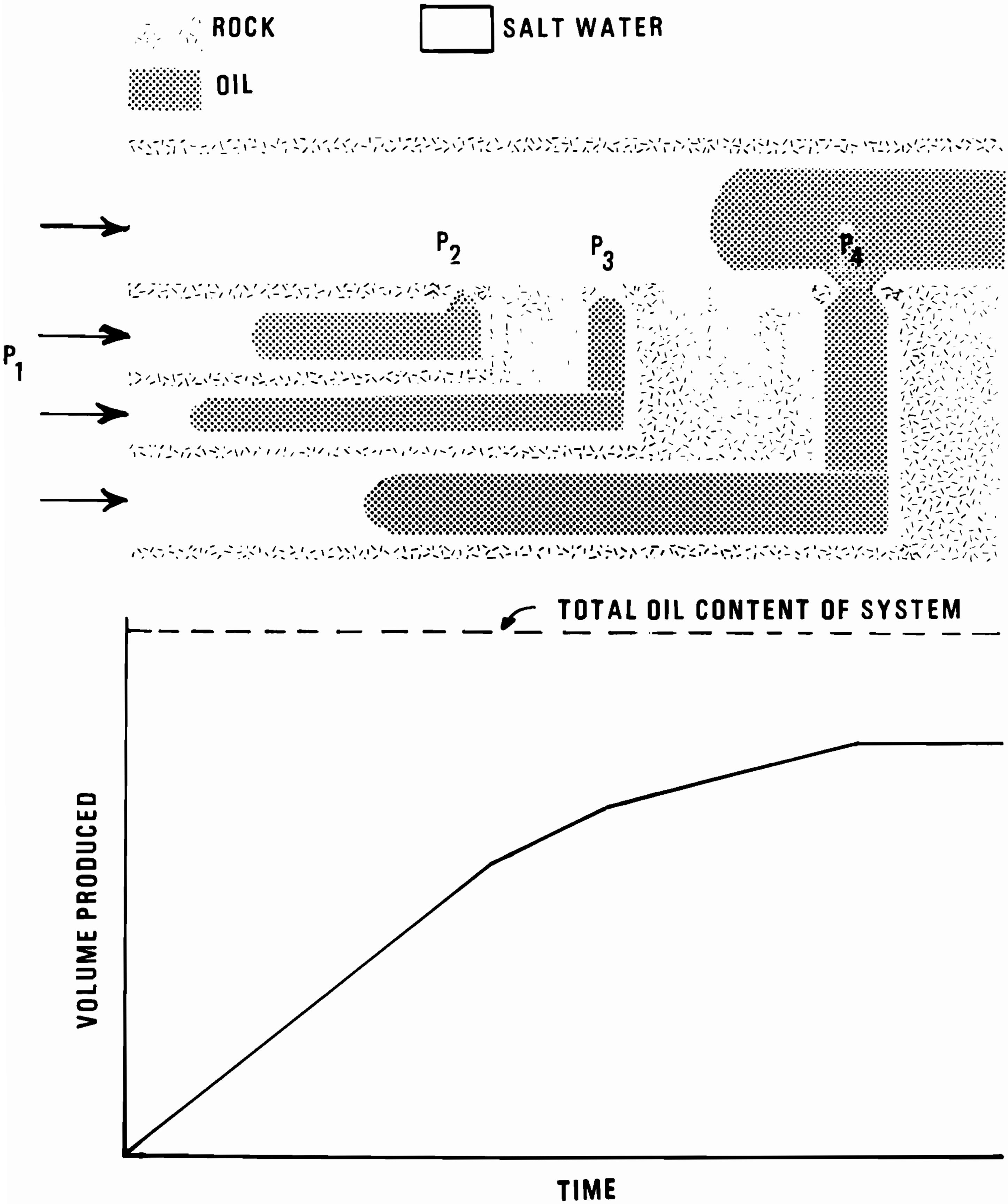

Figure 29-4.--Trapping of oil

been snapped off. The pressure required to force the nonwetting phase through the restriction--the Jamin force, illustrated in Fig. 29-2--is greater than the pressure gradient that is available. Pressure gradients in water floods are for the most part less than 1 psi/foot whereas the Jamin force can reach values of several pounds to several hundred pounds per foot depending upon the length of the oil slug that is snapped off, the interfacial tension between oil and water, and the dimension of the neck between the contacts. Therefore, when the last oil is produced from this microcosm, there is still some oil left behind, viz., the residual saturation. It is this residual oil which we want to mobilize and transport to the producing well when we introduce a surfactant system.

In Fig. 29-5 we do introduce the surfactant system. If the interfacial tension is sufficiently low--and it would have to be as low as 10^{-4} dynes/cm to release oil from the traps in most crude oil reservoirs--then the residual oil can be displaced through the constrictions under available field pressure-differentials. The displaced oil collects and forms a new oil bank at the leading edge of the surfactant slug. As the oil bank is displaced across the intersection of capillaries containing snapped-off oil globs, the oil bank itself (Fig. 29-6) serves as a collector for additional oil. The interfacial tension between oil in the bank and the residual oil is of course zero. Thus we see that a slug of oil will serve equally as well as the surfactant in triggering the formation of an oil bank, viz., the mobilization of the residual oil. The distinguishing feature of the surfactant is its ability to prevent breaking up of the oil bank and its dissipation into the same traps that accounted for the limited displacement-efficiency of the water flood. It is at the tail end of the new oil bank that the surfactant performs its main function.

Figure 29-6 also shows incipient subversion of the process. Not only is oil released from the bypassed capillaries, but the original connate saline water is also released into the surfactant slug. The slug must not lose its ability to maintain a low interfacial tension despite this invasion by salt water. This

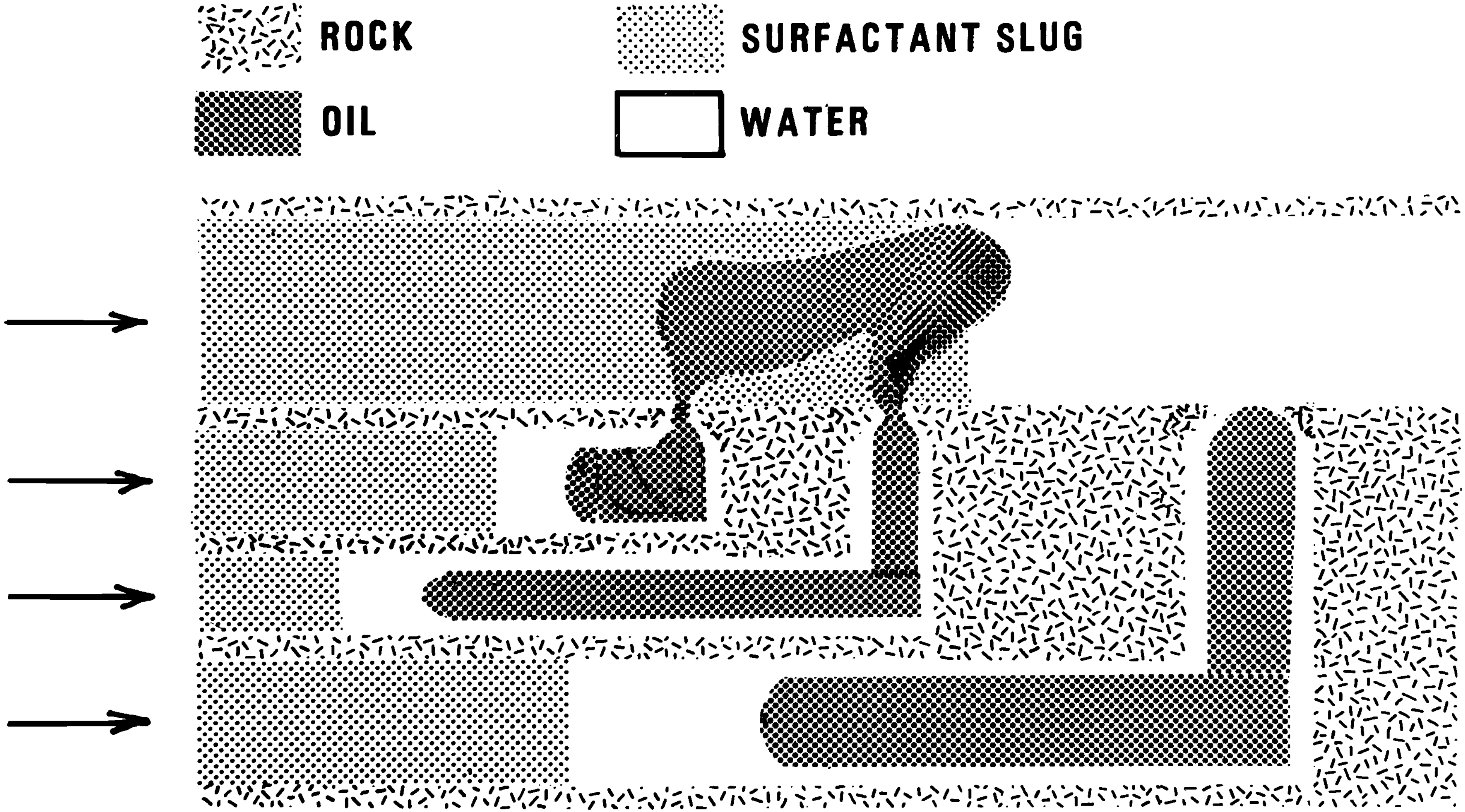

Figure 29-5.--Release of oil by surfactant system

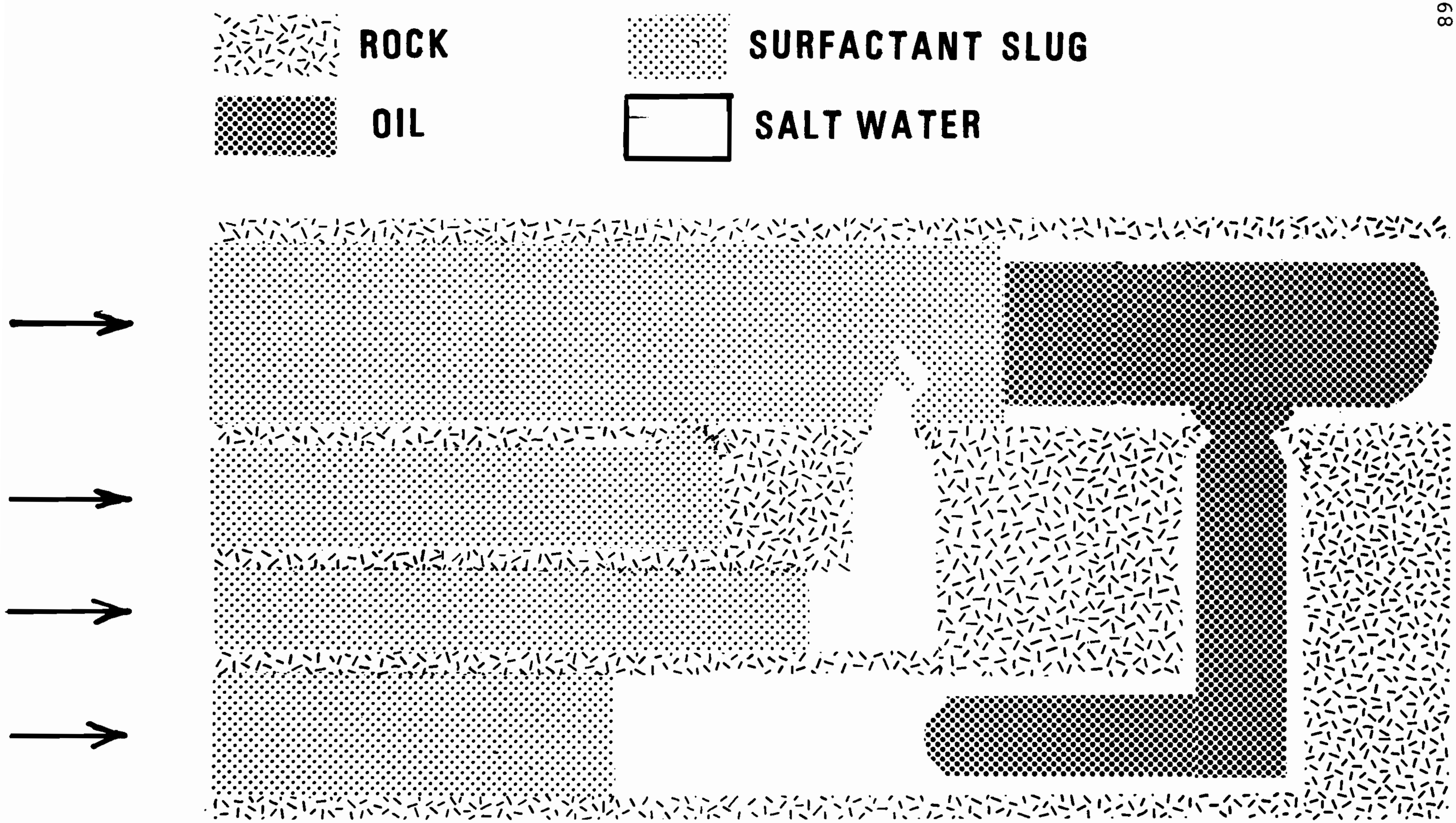

Figure 29-6.--Release of trapped oil by reformed oil bank

calls for significant saline resistance, which is not the easiest thing to achieve and, when achieved, is quite costly. This sketch, insofar as it may be a valid representation of the real world, also shows why a preflush of low-salinity water does not completely guarantee the avoidance of saline interference. The saline brines in the bypassed pores are not liberated until the oil in those pores is also released by the onset of the low interficial tension.

Let us suppose everything has gone well and the oil bank's tail end is being maintained intact by the surfactant slug. The oil bank moves downstream, where another configuration of capillaries is encountered (Fig. 29-7), a large capillary and a small one in parallel. The oil bank splits and is preferentially pushed down the larger, less resistive path. Because of the viscosity of the oil, the resistance to fluid flow rapidly builds up and more and more fluid begins to shift to the small capillary. If the surfactant slug, in turn, is less viscous than the oil and it encounters the junction of the two capillaries before the small capillary has been proportionately filled with oil, the surfactant will enter the small capillary and flow therein will be accelerated; the oil slug in the large capillary will be bypassed. Thus we see that the surfactant slug must be as viscous as the oil or be capable of developing viscosity if it is not to bypass the developing oil bank as a result of permeability heterogeneities and the unfavorable mobility ratio. In actual fact, the surfactant must be introduced as a slug and not continuously injected into the reservoir, because of its high unit cost. This fact requires that the surfactant slug be displaced through the reservoir by a cheaper aqueous polymer solution. It is obvious that the mobility of the polymer solution must at all times be somewhat less than that of the surfactant slug, in order to avoid the latter being bypassed by the polymer.

Unfortunately, velocity appears to be important, too, in these systems. This is probably related to the fact that in a low interfacial tension environment, any oil that does get caught in a capillary trap will tend to have been caught as rather small drops extending over but one or two pore spaces. The pressure

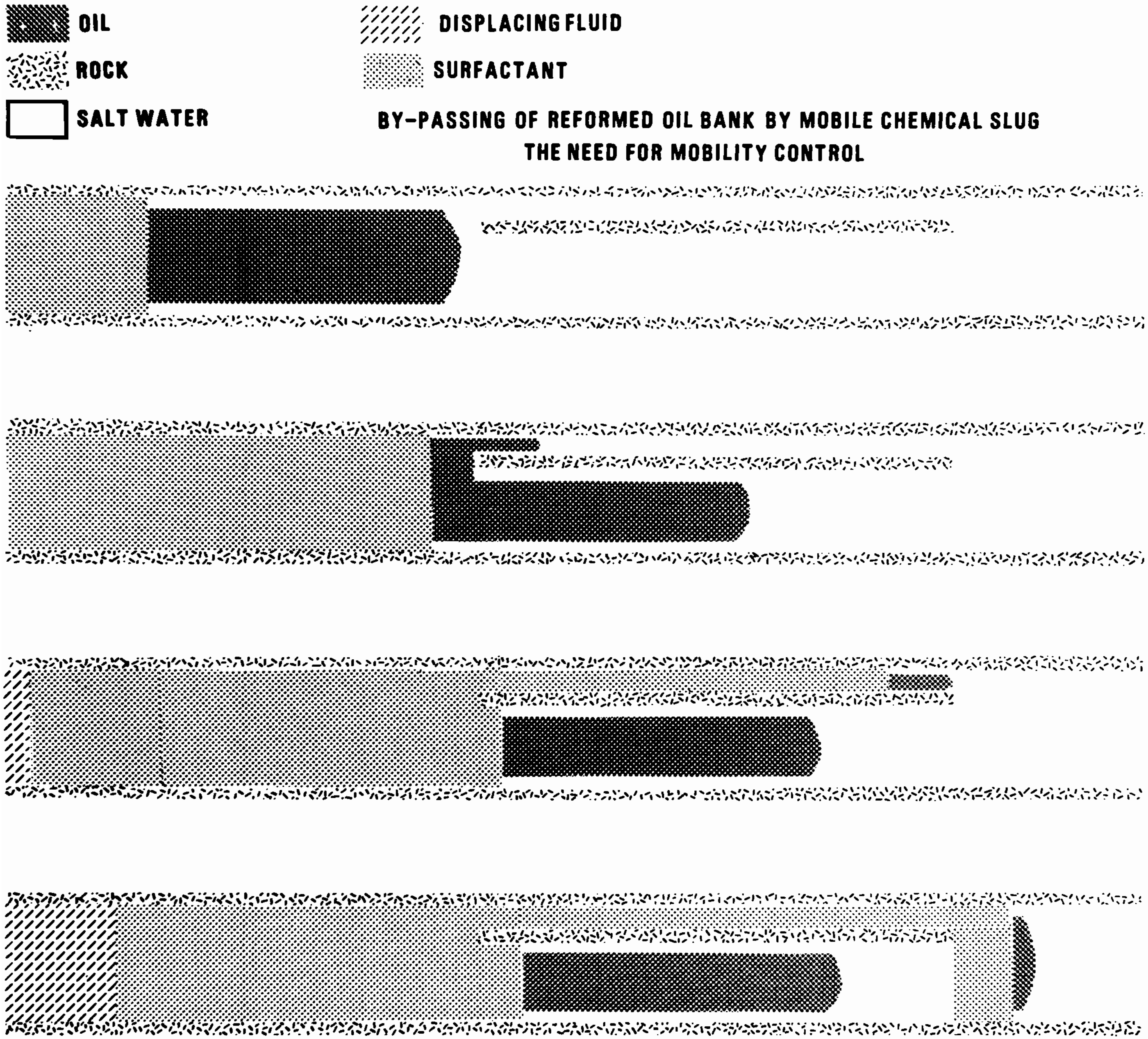

Figure 29-7.--By-passing of reformed oil bank by mobile chemical slug: The need for mobility control

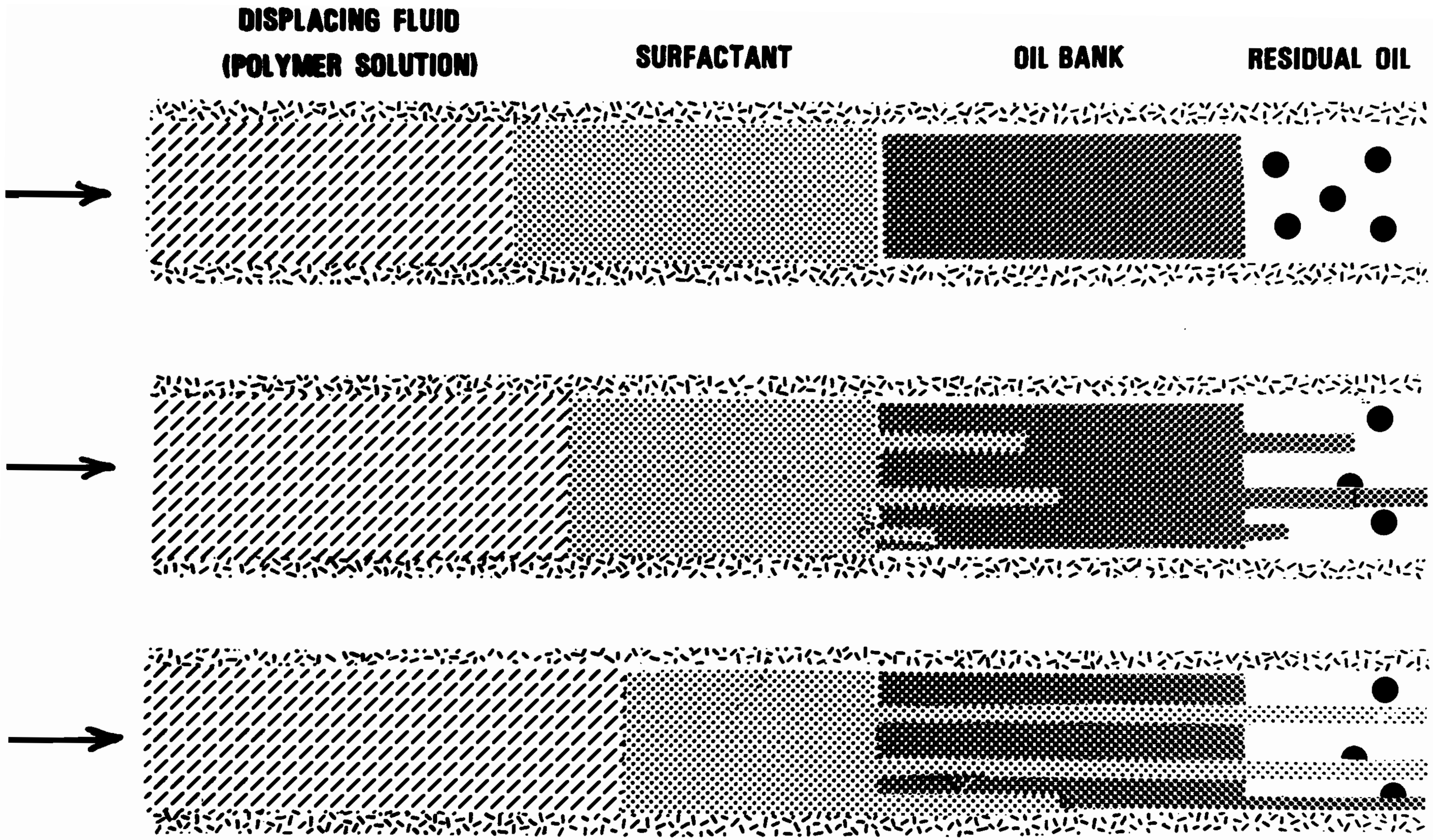

Figure 29-7A.--Instability of process due to loss of viscosity in surfactant slug (oil bank penetrated and by-passed)

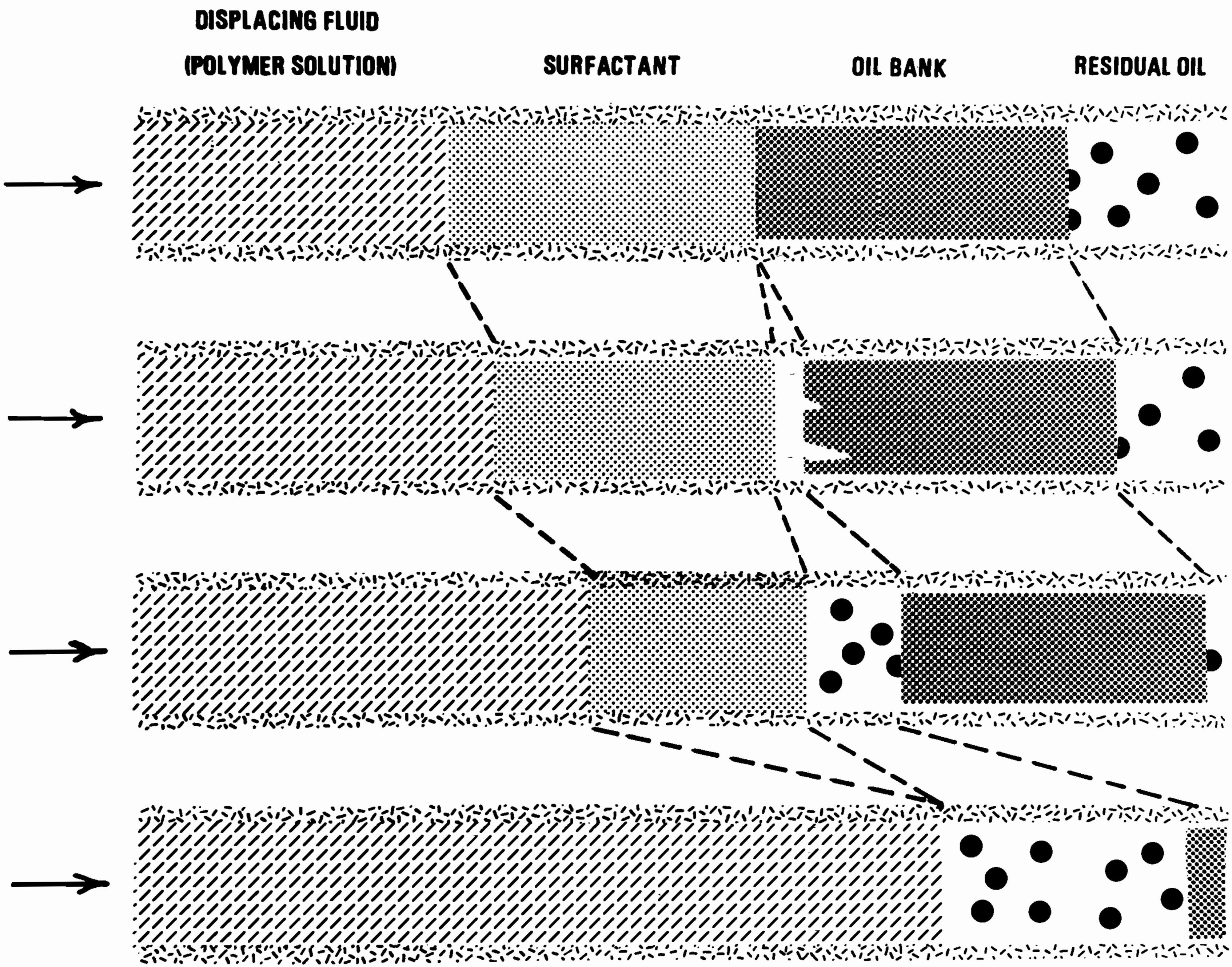

Figure 29-7B.--Loss of process stability by denudation
(adsorption of surfactant)

gradient required to release such a drop from a restriction is all the higher (see Fig. 29-2) because of the smaller value of the radius appearing in the denominator. The higher velocity is of course realized by imposing a higher pressure gradient in the reservoir. With viscous surfactant and polymer solutions, it is difficult to achieve the high velocities that apparently are required over large well spacings.

The efficiency of the system can be further destroyed by adsorption of the surfactant on mineral surfaces. If adsorption is significant enough to reduce the availability of the surfactant at the tail end of the developing oil bank, the oil bank will be destroyed by the invasion of high tension, surfactant-denuded water. Finally, interaction of polymers and surfactants as well as biological and thermal degradation contribute to mitigating the efficiency of the best designed recovery systems. Despite these adverse factors, it appears that available surfactant systems may work when used in relatively homogeneous reservoirs with short well-to-well spacings. The short well spacings make it possible to achieve higher velocities, and the smaller amount of rock surface the surfactant passes favors maintaining the integrity of these very sophisticated and complex systems.

A simpler way for achieving the goals set out for the surfactant processes is to use miscible fluids for displacing residual oil. Miscibility, of course, implies zero interfacial tension. The basic economic drawback to using miscible fluids is the relative cost of such materials when compared to that of crude oil. It should be recalled that a residual saturation of the displacing fluid, approximately equal to that of the residual oil saturation, will be left behind upon completion of the process. For the process to be economic it is apparent that the miscible displacing fluid must be significantly cheaper than the crude oil. This rules out practically all hydrocarbon fluids as the displacing fluids. The most important technological drawback is that almost all conceivable miscible fluids have a viscosity significantly less than that of crude oil. Viscous fingering and low sweep efficiency result, and again the process proves to be uneconomic.

Super-critical carbon dioxide is miscible with many reservoir crudes on first contact and will develop miscibility with many others after equilibration of the carbon dioxide with the residual crude oil. A carbon dioxide-rich phase develops. Carbon dioxide may be secured from natural accumulations, as a by-product of coal gasification, or even manufactured by specialty processes in various locations at acceptable costs if its subsequent efficiency in displacing crude oil is sufficiently high. However, the viscosity of carbon dioxide is but a fraction of that of most crudes. Bypassing of crude oil is endemic to miscible fluid displacing systems. In reservoirs with a low residual-oil saturation, the formation of an oil bank may not even be triggered, as a result of extensive bypassing of the residual oil by the injected carbon dioxide. This might be overcome by pre-injecting a slug of crude oil. The technical feasibility and economic penalty of such a scheme have not yet been developed.

It has been intimated that bypassing of any oil bank that is formed by the injection of carbon dioxide could be mitigated by the alternate injection of water slugs with the carbon dioxide. Although there is little doubt that the alternating sequence of wetting and nonwetting fluids, water and carbon dioxide, will result in a high Jamin resistance behind the oil bank and in watered-out channels, there is some question as to whether this can be achieved with impunity as far as the maintenance of an oil bank is concerned. A tertiary carbon dioxide flood, in mechanistic terms is a carbon dioxide flood of a water-filled reservoir, and much of what the carbon dioxide does is to displace the reservoir water. It is behind this displacement front that the carbon dioxide has access to the residual crude oil, dissolves in it, increases the volume of the nonwetting phase, connects the residual oil into an oil bank, and gets it moving again. It would appear superficially that the alternating slugs of water interspersed with the carbon dioxide would mitigate the efficiency of the latter. It is apparent that a great amount of research and development activity must be expended to improve the performance of miscible fluids in recovering tertiary oil. In this connection it is interesting to note that the reliable reports of successful carbon dioxide flooding in the field is in reservoirs which previously had not been water-flooded, viz., the oil saturation was probably well above 50 percent.

Carbon dioxide should prove to be a spectacular tool for tertiary recovery when it is used in up-dip injection in a dipping reservoir or at the top of a relatively thick reservoir. The density of carbon dioxide, if necessary, can be adjusted by the addition of relatively small amounts of methane to be less than that of most reservoir crude oils. At sufficiently low velocity a gravity-stabilized displacement could be achieved. Under such conditions a large slug of carbon dioxide could be displaced with air, a lighter gas, without interfacing with the process at the carbon dioxide-oil interface.

The apparent ability of carbon dioxide under sufficiently high pressure to displace oil down to very low residual saturations, when the initial saturation is high, suggests that in many cases carbon dioxide, if available, would be a superior fluid to water for use in secondary recovery operations. In fact, it would appear wise to inject the carbon dioxide at the onset of primary development. In an idealized situation, there would be every reason to expect a recovery efficiency approaching 100 percent. No technical or economic studies have been made of this suggestion and it is to be emphasized that two important conditions must be met to achieve such a use: the carbon dioxide must be available in adequate quantity at a cost compatible with the value of the recovered oil, and the reservoir lithology and the interaction of the crude with carbon dioxide must be such as to render the reservoir amenable to such a recovery scheme.

THE MECHANICS OF APPLYING TERTIARY RECOVERY TO CATEGORY 2 RESERVOIRS

Modern work on the use of steam to recover petroleum was begun almost two decades ago. The art and the science of steam soaking and steam flooding have been contributing an estimated 200,000 barrels a day to California's production total for most of the past 10 years. The added reserves are estimated to be 1 to 2 x 10^9 barrels and will undoubtedly be increased further in the coming years. Steam injection has been successful in other producing provinces, particularly in Venezuela, and the total world-wide production of oil by steam injection is probably between 750,000 and 1,000,000 barrels a day.

Steam injection works because of two factors. Steam is used to reduce the viscosity of the oil around the producing well. This reduction in viscosity results in a great increase in the flow rate of the crude oil under a much smaller pressure gradient. As a consequence, the pressure gradient available in the reservoir is increased and the steady-state influx of the crude is correspondingly increased. Secondly, steam injection reduces the residual saturation in the swept zone to very low values and the sweep efficiency itself is very high. Thus, a very large fraction of the original oil in place is maintained in the mobile oil bank.

The mechanics of crude oil displacement in an in situ combustion operation is basically the same as that which occurs in a steam drive. A steam drive is developed in the reservoir by the vaporization of reservoir water or water injected along with air supplied for maintaining the combustion. The temperature at the tail of the oil bank may indeed be higher than in a normal steam flood; therefore, the hydrocarbons which are available to the advancing air for combustion may be a high boiling point fraction of the crude or even a coke or pitch.

It is only at shallow depths that the cost of developing heat within the reservoir by an in situ combustion process is significantly less than the cost of heating the reservoir by steam injection. This, together with the severe operating problems encountered in many combustion operations and the need for steam to stimulate production response, has mitigated widespread application of in situ combustion.

The economic efficiency of a steam drive increases with injection rate, formation thickness, net to gross ratio, and bulk saturation of crude oil. The efficiency decreases with increasing pressure and increasing well spacing. The overall factor determining the economic success of a steam drive is the ultimate oil/steam ratio. This would have to be modified by local conditions, such as the cost of well completions, operating labor, suitable water for generating steam, royalties, and taxes. In current operations in California it appears that an oil/steam ratio as low as 0.15 will provide for an economically feasible operation. In past years a ratio of 0.20 to 0.25 was required because of depressed prices for the heavy crude oils.

With modern, efficient steam generators 1,000 barrels of water can be converted to steam by burning 65 barrels of crude oil. At the oil/steam ratio of 0.15, therefore, it can be estimated that it takes 0.57 barrels of crude to pay for the capital, operating costs (exclusive of fuel for steam generation), taxes, and royalties for every 1 barrel that is produced by steam injection at this time in California. The economic ratio could be reduced by using intrinsically cheaper fuels for generating steam than the crude itself. For example, in a producing province where coal, lignite, or refinery bottoms were available and used as fuel, a steam injection operation would be carried out even though the net energy gain in the operation was zero or negative. (It should be recalled that even in the most optimistically conceived coal liquefaction processes some one-third of the energy of the coal feedstock will be lost.)

In this connection, then, some attention should be drawn to the oil/steam ratios that might be obtained when using steam to recover high gravity crudes at water flood residual saturations. The results of calculations for a reservoir having a porosity of 20 percent and a recoverable oil saturation of 30 porosity-percent are presented in Table 29-2. Calculations were made for 5- and 10 acre spacing, injection rates of 500 and 1,000 barrels of steam per day, and pressure of 300 and 1,000 psi. It can be seen that by current standards the calculated ratios are on the whole less than that required for an economic venture. However, if cheaper fuels were used for generating steam, then it is quite probable that an economic, or, at least, a socially useful operation would be achieved.

In any steam-drive operation only some of the formation will be swept by steam and driven to a very low residual (less than 10 percent) whereas the remainder of the formation may be swept only

TABLE 29-2.--Calculated steam/oil ratio

1.0 PV water injected as 70 percent steam S = 0.30; Ø = 0.20 Gross thickness = 20 or 40 ft			
Pressure (psi)	Injection rate (band)	Steam/oil ratio	
		5-acre spacing	10-acre spacing
1,000	500	0.08/0.10	0.06/0.08
	1,000	0.10/0.13	0.08/0.10
300	500	0.13/0.16	0.10/0.13
	1,000	0.16/0.19	0.13/0.16

by hot water. This will be particularly true in thick formations where gravity segregation at the injection well and even in the formation may occur. It would appear that there is much work to be done in increasing the efficiency of steam drives despite the fact that their efficiency is already over 50 percent in many applications. Synergistic agents, which would increase the displacement efficiency of that part of the reservoir wet only by steam condensate, could be added to the wet steam injected into the formation. Already, research and development methods are under way on such schemes. A dual process is also conceivable in which steam is injected first to create a bank of residual oil, which then is driven into the producing wells by another type of process, such as chemical or polymer flood.

THE MECHANICS OF APPLYING TERTIARY RECOVERY TO CATEGORY 3 RESERVOIRS

A reservoir containing oil and/or gas but which has a low permeability will of course not produce at economic rates no matter what the size of the reservoir. The overall economics of tight reservoirs is made even more difficult by the fact that tight reservoirs will tend to be deeper reservoirs. There are many ways of stimulating tight reservoirs, but fracturing techniques have in general been superior to other methods. Given the parameters of a particular tight reservoir and the hypothesized effect of fracturing, then it is possible to calculate the production response upon stimulating the reservoir. Assuming wellbore damage is not involved, then a stimulated production response of more than a factor of 7 to 10 would not be expected. Thus, prior to any other considerations it is necessary to determine the base-line value of unstimulated production so that the economics of the stimulated production can be estimated. Alternately, an accurate measure of the in situ permeability of the reservoir should be determined and the unstimulated production rate calculated. Finally, even though the smell of hydrocarbon may be pervasive throughout a geological feature, that in itself may not indicate the presence of a truly large accumulation of oil or gas. It is the opinion of this writer that adequate resource estimations have not been made in the past of so-called great accumulations of oil and gas in tight reservoirs. Given a reservoir of some minimum permeability and some given content of oil and gas, it is easy to estimate what stimulated production rates will be reached. At that time, economic feasibility estimates can be made to determine whether an active development program is warranted.

CONCLUSIONS

In this brief review and critique of tertiary recovery of crude oil, an effort has been made to indicate the more important processes that have been proposed to achieve additional recovery. More importantly, an effort has been made to indicate the limitations and drawbacks of the proposed processes. This has been done because of the many disappointments that have been experienced in attempting to convert theoretical and laboratory studies to field practice. Much more research and development is called for and will be required to develop truly successful tertiary recovery operations in the real world and thereby exploit the resources of the earth to the fullest advantage of mankind. There is little doubt that the age of petroleum, if it has not yet passed its zenith, is shortly about to do so. No economically competitive nor physically available substitutes for petroleum are imminently available. It is necessary for the welfare of all the nations of the world that successful enhanced recovery techniques for petroleum be developed at the earliest possible time.

REFERENCES

The interested reader is referred to the Journal of the Society of Petroleum Engineers wherein practically all of the significant articles on tertiary recovery have appeared in recent years. In addition, the Society publishes a quarterly, Improved Oil Recovery Field Reports, in which are documented both experimental and development field operations on enhanced oil recovery.

CHAPTER 30

POTENTIAL AND ECONOMICS OF ENHANCED OIL RECOVERY[1]

V. A. Kuuskraa, J. M. Muller,
and O. T. Vipperman

The precipitous rises in oil prices between 1972 and 1975 dealt the final blow to the previously accepted notion of inexpensive, inexhaustible energy resources. As oil producing countries began to perceive the finiteness of their petroleum reserves and the inelasticity of the short term demand petroleum curve, a new era of energy economics was launched. The concepts of marginal barrel costs and competitive world oil market were replaced by the economics of pricing and allocation of depleting and increasingly expensive commodities.

Thus, the future availability of nature-made petroleum has become the subject of overwhelming concern to all nations and numerous efforts are being directed toward ensuring alternative and more assured sources of supply. This paper discusses one of these efforts--the introduction of advanced recovery technology, for increasing the recovery from the world's oil reservoirs.

After conventional (primary and secondary) production is depleted, substantial quantities of oil remain in existing developed oil fields. Until recently, most of this oil was regarded

[1]This paper represents the results of the combined work of the authors and their organizations on enhanced oil recovery (EOR) over the past several years. The material in this paper is derived from two previous analyses, The Potential and Economics of Enhanced Oil Recovery, Lewin and Associates, April 1976, and Review of Secondary and Tertiary Recovery of Crude Oil, Federal Energy Administration/Lewin and Associates, June 1975. Copies of the first report are available upon request.

as impossible or at least uneconomic to recover. This unrecovered oil (Fig. 30-1) amounts to almost 70 percent of the original oil-in-place. New developments in technology, coupled with the rise in world oil prices, however, give promise that substantial portions of this otherwise neglected oil can now be recovered. These new technical developments fall under the broad heading of enhanced oil recovery (EOR).

Summary of the Current Status of the Technology

The term enhanced oil recovery (EOR) or tertiary recovery[2] covers a range of advanced oil recovery methods that are grouped under three broad headings:

- Thermal
  - Steam drive
  - In situ combustion
  - Hot water flooding
- Chemical
  - Surfactant/polymer flooding
  - Polymer or caustic augmented waterflooding
- Miscible
  - Carbon dioxide miscible
  - Hydrocarbon miscible

Within the United States, enhanced oil recovery is far from a proven technology. Years of testing have yielded only one process--steam drive--that approaches being a conventional recovery technique. Even with the experience of at least 187

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[2]The terms "tertiary" and "enhanced" are used interchangeably in this text. They are used as shorthand for the newer "exotic" recovery methods and do not include the more conventional production enhancement methods of waterflooding, pressure maintenance, or cyclic steam. Thus, EOR includes steam drive, in situ combustion, carbon dioxide miscible flooding, surfactant/polymer flooding, and polymer-augmented waterflooding. Hydrocarbon miscible processes would be included in our definition of EOR but are not analyzed in this report because they are generally seen as uneconomic in the future. In terms of timing of usage, these techniques may be used either after primary recovery or after traditional enhanced recovery; thus being used either in a secondary or tertiary production time phase.

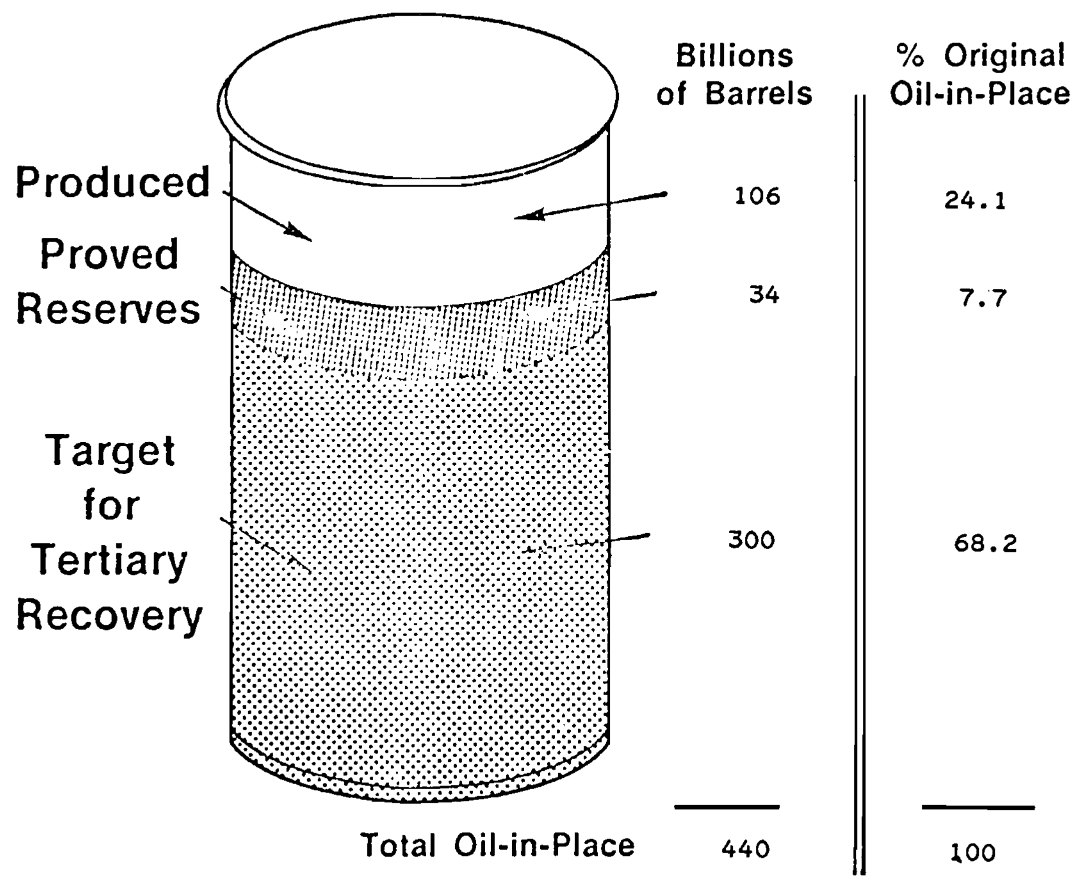

Figure 30-1.--Production, reserves, and residual oil-in-place--
U.S. onshore, except Alaska

projects and with over 130,000 acres under current development (shown by technique and type in Table 30-1), enhanced oil recovery has advanced slowly. The current status of the technology can be summarized thus:

- EOR currently accounts for over 240,000 barrels per day of production (including hydrocarbon miscible but not cyclic steam projects).
- Steam drive accounts for the largest portion of this production, 110,000 barrels per day; carbon dioxide miscible provides 70,000 barrels per day; hydrocarbon miscible contributes 40,000 barrels per day; in situ combustion, surfactant/polymer, polymer, carbon dioxide, and augmented waterflooding together provide the remaining 20,000 barrels per day.
- The process-related uncertainties vary substantially by technique:
  - -- Steam drive is approaching conventional application in the shallow, high saturation reservoirs to which it has typically been applied.
  - -- In situ combustion, while having experienced substantial testing, remains unproven and difficult to predict.
  - -- Carbon dioxide miscible flooding projects have not yet produced sufficient data to evaluate this technique's true potential. Some limits on its applicability have begun to appear.
  - -- Chemical processes have not fared well in the transition from laboratory to field pilot operation. Surfactant, polymer, and caustic applications are the least predictable and the farthest from conventional application.
- Major difficulties with many techniques have been encountered in extrapolating from laboratory results to field tests. Demonstrations of effectiveness in the lab have not been replicated in the field. This argues that substantial basic research, both in the lab and in the field, is required for the less proven techniques.

TABLE 30-1.--Field activity in enhanced oil recovery*

Technique	(Number of EOR projects) Technical pilots		Economic pilots		Field-wide development		Acreage under current development
	Total	Current	Total	Current	Total	Current	
Steam Drive	17	13	15	14	15	15	15,682
In Situ Combustion	17	3	6	5	19	10	4,548
CO_2 Miscible and Nonmiscible	5	4	6	6	2	2	38,618
Surfactant/ Polymer	12	10	7	7	2	2	1,418
Polymer-Augmented Waterflooding	3	0	14	9	14	11	14,624
Caustic Augmented Waterflooding	5	1	2	0	0	0	63
Hydrocarbon Miscible	9	7	6	5	10	8	56,782
TOTALS	68	44	57	47	62	48	131,735

*This is an update to the status report on EOR provided in The Potential and Economics of Enhanced Oil Recovery by Lewin & Associates, Inc., April 1976. While this file may not contain some current EOR projects, it contains all that have been reported in the literature and several that are described only in company reports submitted to the study.

Thus, it is not surprising that past estimates of the additional oil resources available through enhanced oil recovery have varied widely, ranging from less than 10 to over 100 x 10^9 barrels (Table 30-2).

It is essential, in the development of a national energy policy, to identify the potentially available resources. To the extent that EOR may add a significant increment to these resources, a decided effort should be made to quantify the potential. Variances as large as those previously noted are of limited use in constructing a long-range program. Further, it is insufficient to know only the reserve potential of EOR--one must also know its incremental costs. Under the market-based supply and demand operative in the United States economic system, the cost of the incremental barrel--the last unit or barrel produced and consumed--would establish the price of the commodity. Only after the added cost of EOR is reasonably determined, is it possible to measure alternative policy actions. For example, should EOR technology not materialize or prove too costly it may be in the national interest to pursue a nuclear, coal, or other energy-supply scenario rather than petroleum. The basic element is timing and cost--a nation's energy posture must necessarily recognize long-range requirements and usually will imply significant near-term investment, if its long-term goals are to materialize.

These concerns led to the commissioning of a new study of the potential of enhanced oil recovery designed to address these questions:

- By how much can EOR supplement domestic petroleum production? How much of this potential production can be brought on stream during the critical period of maximum vulnerability to interruptions in imports?
- What will be the cost of EOR? Will it be affordable in the near term?
- What portion of this total potential will industry develop under varying economic incentives? How much production could come during the critical period?

TABLE 30-2.--Recent estimates of EOR potential

	Potential EOR reserves (Billions of barrels)	Production by date (Millions of barrels)
1. Oil Companies[1]		
1	15	--
2	--	1.0 by 2005
3	25	0.5 by 1985
4	18	0.75 by 1985
5	110	1.0 by 1985
6	25	1.0-2.0 by 1990
2. Government Reports		
GURC[2] (1973)		
-- Almost Assured	18.5	1.1 by 1985
-- Reasonable	36.3	1.1 by 1985
FEA/PIR[3] (1974)		
-- Business as Usual ($11)	57	1.8 by 1985
EPA[4] (1975)	7-16	
FEA/Energy Outlook[5] (1976) ($12)		0.9 by 1985
FEA[1] (3 states) (1975) (11.28)		
-- Lower Bound	15.6	1.1 by 1985
-- Upper Bound	30.5	2.0 by 1985

[1]The Potential and Economics of Enhanced Oil Recovery, Lewin & Associates, Inc., for FEA, April 1976.

[2]Planning Criteria Relative to a National R&D Program Directed to the Enhanced Recovery of Crude Oil and Natural Gas, Gulf Universities Research Report No. 130, November 1973.

[3]Project Independence Report, Federal Energy Administration, November 1974.

[4]The Estimated Recovery Potential of Conventional Source Domestic Crude Oil, Mathmatica, Inc., for the U.S. Environmental Protection Agency, May 1975.

[5]1976 National Energy Outlook, Federal Energy Administration.

This study examined the potential of enhanced oil recovery under three price/research and development contingencies:

- Base Case: Using the "lower-tier" domestically controlled price of $5.25 per barrel, as of June 1975, and assuming the current pace of technological development.
- Lower Bound: Using the "upper-tier" domestically controlled price of $11.28 per barrel, as of June 1975, and assuming the current pace of technological development.
- Upper Bound: Combining the economic incentives of the higher, "upper-tier" price with an accelerated, successful program in research and development. This case assumes an aggressive R&D posture by both the government and industry toward EOR and requires that important technological breakthroughs be reached.

Beyond this, the study was requested to provide an IIASA case essentially using the economic and R&D assumption of the Upper Bound Case with no taxes or land ownership (royalty) payments.

The results of the study indicated the following:[3]

- Base Case: Under the Base Case economics of $5.25 per barrel, approximately 5×10^9 barrels would be produced through EOR. The bulk of this oil will be produced by thermal methods, steam drive, and in situ combustion, and 4×10^9 barrels of this amount is already booked in the proved or inferred reserves category.
- Lower Bound Case: Under the Lower Bound Case nearly 15×10^9 barrels of oil could be produced through EOR. The combination of improved economics and advances in technology improve the amount of recoverable oil;

[3]The EOR recovery and production potential is an estimate based on detailed reservoir studies in the states of Texas, California, and Louisiana. Although it is reasonable to suggest that other producing states will also materially contribute to EOR production, such an extrapolation cannot be made without subjecting the reservoirs in the other states to the combination of technical and economic constraints applied to the data in this report.

however, this case assumes that EOR remains a high risk technology requiring a high rate of return (20 percent) on successful projects.

- Upper Bound Case: Should the technology become conventionally applied, over 30×10^9 barrels of oil would become economically recoverable. The combination of an "upper-tier" price and an essentially risk free technology, when developed, promises substantial additions to the domestic energy reserves. However, considerable investment in R&D would be required to reach this case.
- IIASA Case: Under the improved economics of the IIASA Case, 38×10^9 barrels of oil would become economically recoverable.

These results are further summarized in Figures 30-2, 30-3, and 30-4.

Figure 30-2 shows the distribution of the remaining oil and EOR reserves. Column A represents the technically recoverable oil from EOR (under our and industry's best estimate of the state of that technology by the late 1980's). Column B shows the economically recoverable oil under "upper-tier" prices of $11.28 as of June 1975 (which is equivalent to about $13.00 per barrel[4] as of the end of 1976), with the result that the less attractive reservoirs would become uneconomic for EOR at the upper ranges of current world market prices. Column C shows the share of the economically recoverable oil for each of the recovery technologies.

Figure 30-3 displays the price-supply curve used for projected 37.9×10^9 barrels of economic reserves shown in Column B of the previous exhibit.

Figure 30-4 depicts the timing for proving the EOR reserves, according to the first three cases.

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[4]The study assumed a mid-1975 price of $11.28 which, under current domestic cost inflation, would translate into an end of 1976 price of about $13.00.

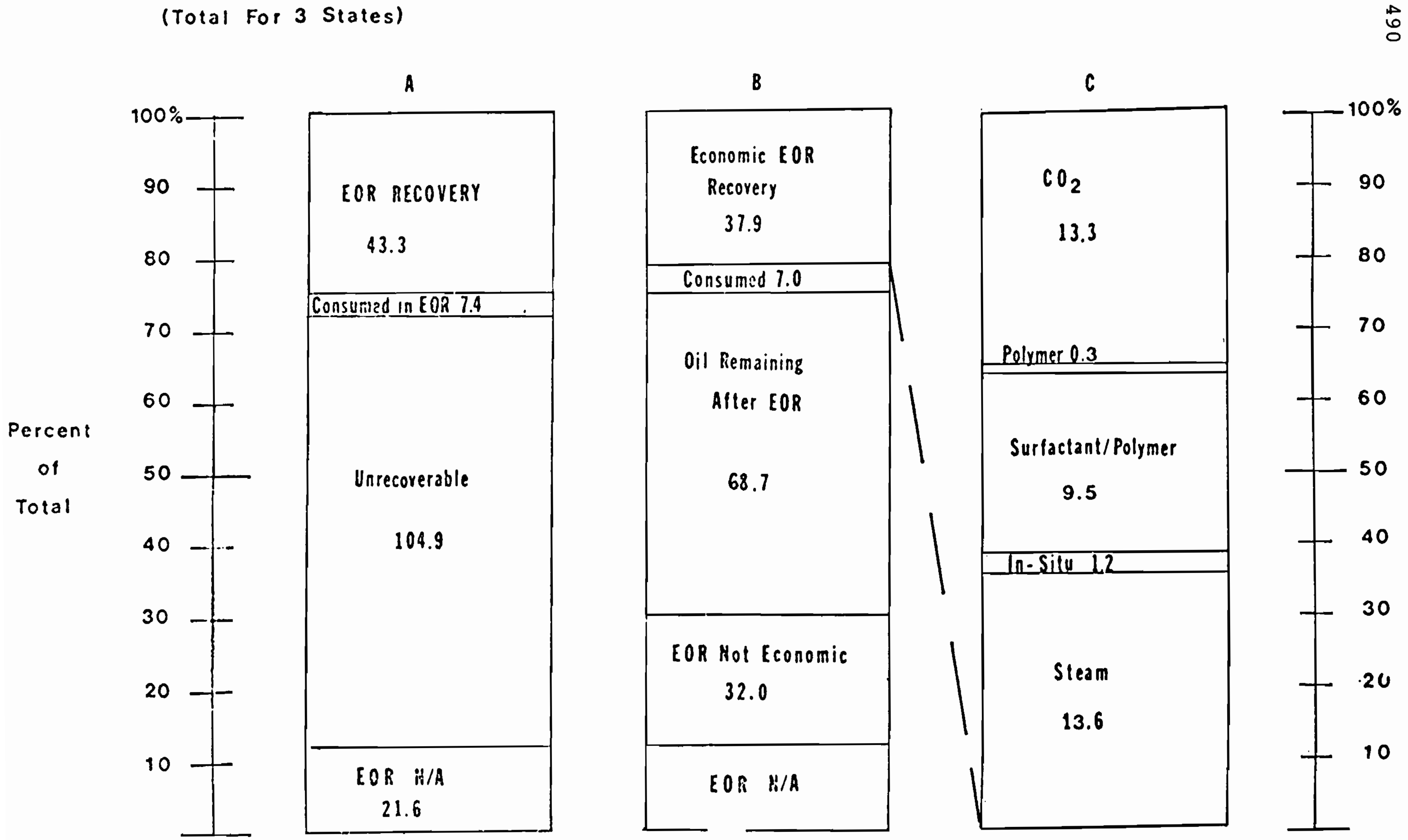


Figure 30-2.--Distribution of remaining oil and EOR reserves (10^9 barrels)

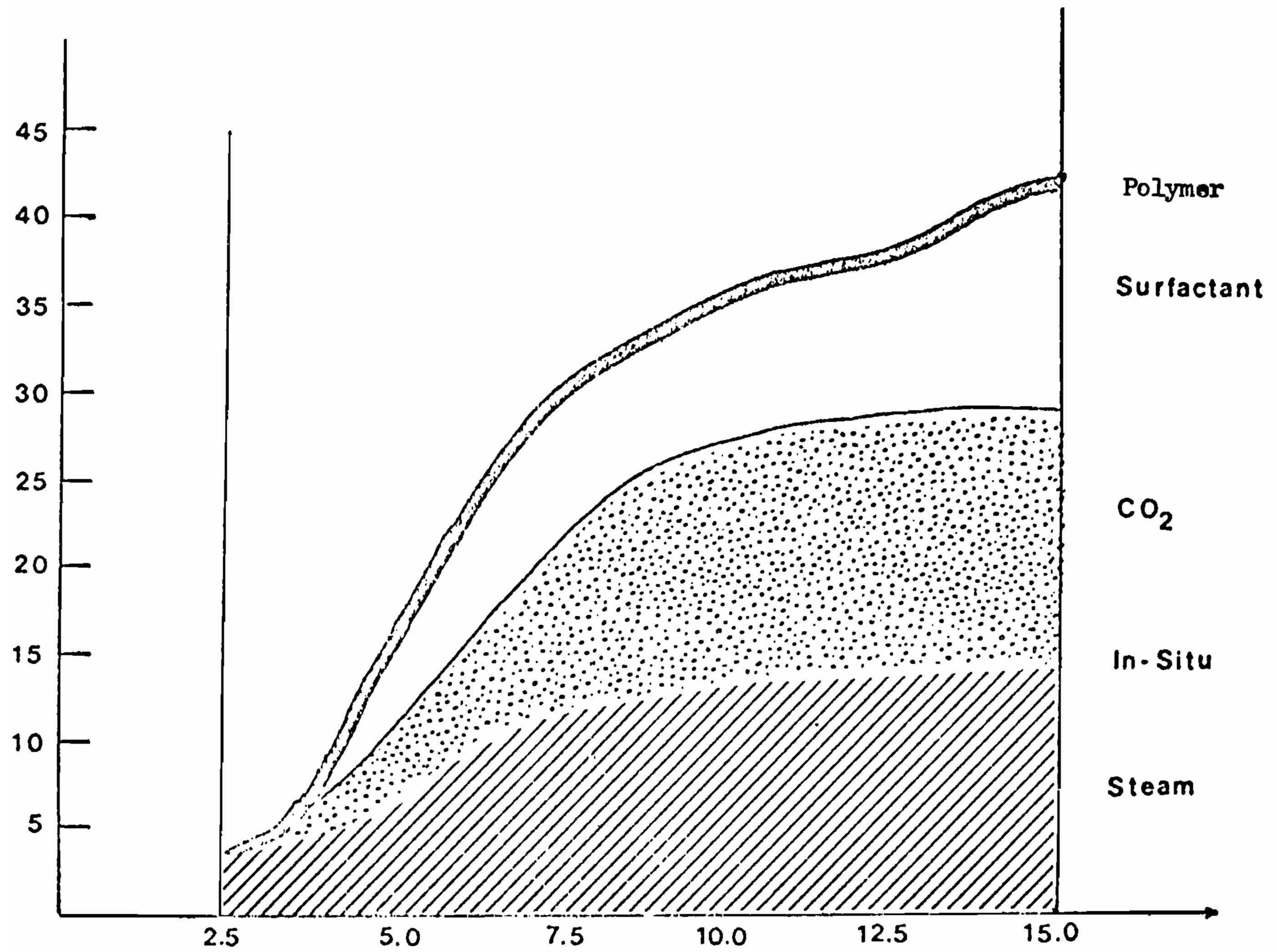


Figure 30-3.--Projected cumulative price-supply curve by technique (total for three states)

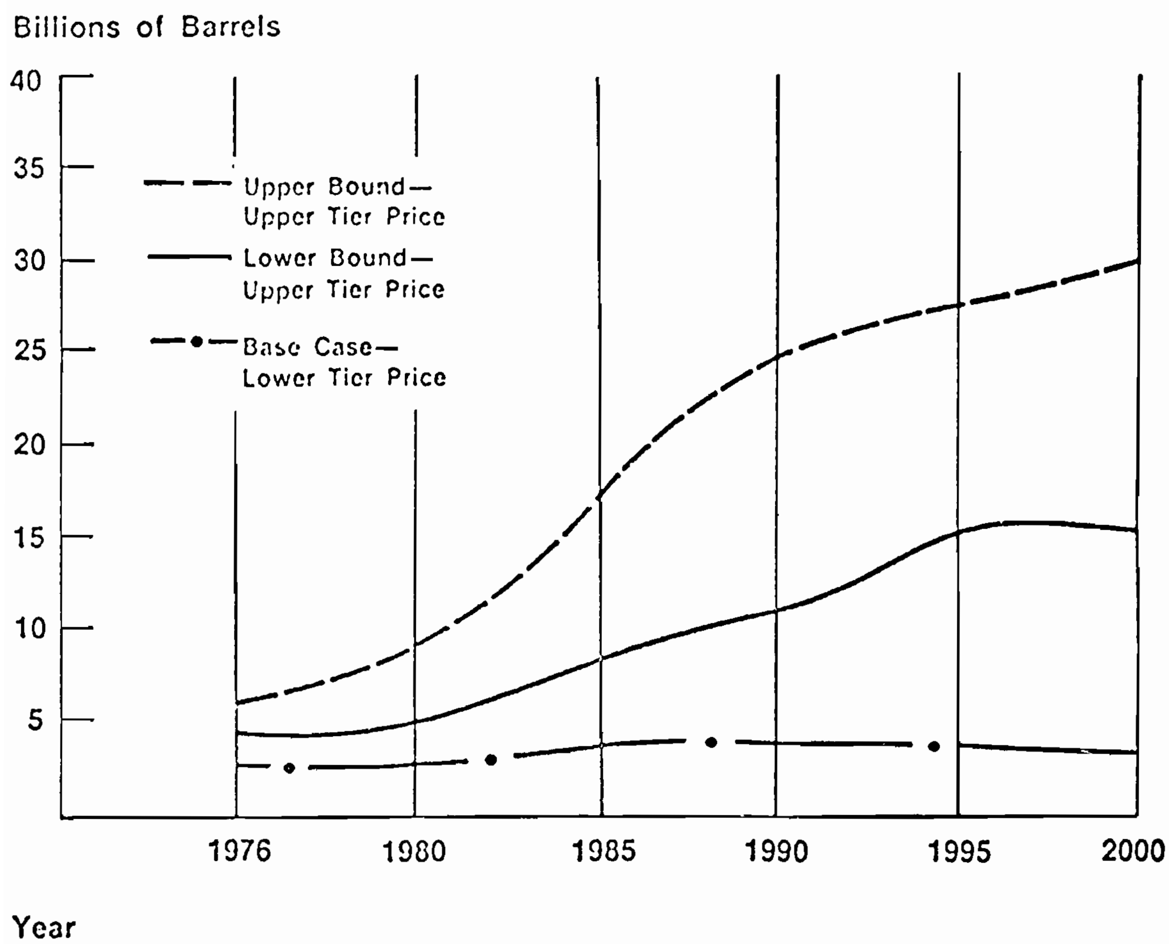


Figure 30-4.--Timing of proved tertiary reserves by case (total for three states)

STUDY METHODOLOGY

The portion of remaining oil that will be recovered through enhanced oil recovery (EOR) and the rate of EOR production are subjects of considerable controversy. Vast differences characterize previous projections of the quantity and rate of tertiary production. The study staff concluded that the differences resulted from a combination of: (1) the lack of precise, accepted terms for measuring tertiary oil recovery potential; (2) the variety of price assumptions for future crude oil prices; and (3) the divergent methodologies used for addressing the question. Thus, rather than add yet one more highly aggregated, national-level pronouncement of the potential of tertiary oil recovery, this study adopted a detailed, more explicit approach which employs precise economic terms and specific pricing assumptions.

In working toward such an approach, several major constraints had to be overcome, including:

1. The vast size of the population. The study restricted examination of the population to the major producing fields and reservoirs.
2. The absence of a detailed reservoir data base. Considerable effort was directed to building a reservoir data base from state records, field reports, and engineering/geological correlations.
3. The limited amount of volumetric data on reservoirs. Traditional state production reports, augmented with oil-in-place and reserves data from state hearings, trade publications, government-sponsored reserve studies, and data accumulated from company sources by the American Petroleum Institute, served as data sources.
4. The aggregate nature of general production costs. A careful set of unit costs for field development, well operations and maintenance, water injection, and other production costs were accumulated by region and depth.
5. The lack of cost information on tertiary oil recovery. The major field projects and practitioners were

surveyed to construct a series of building-block unit costs for each of the major tertiary recovery techniques.

In addressing these constraints, the study designed a methodology that follows an engineering and micro-economic approach and that emulates--on a slightly broader scale--the actual decision behavior of the companies that will bring tertiary recovery to fruition.

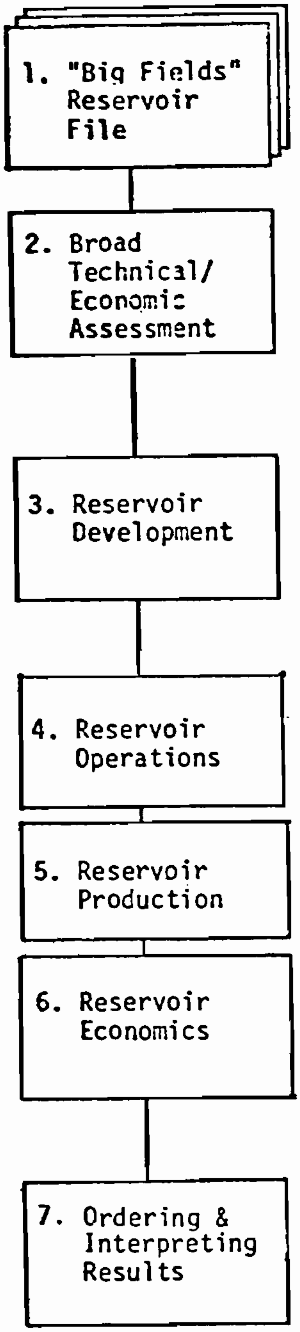
A summary of this seven part methodology used by the study is outlined in Figure 30-5. These seven basic steps are discussed briefly below:

Step 1. The "Big Fields" Reservoir File. The current analysis focuses on the three largest "lower-48" crude oil producing states--California, Louisiana (onshore), and Texas. Based on API data (Table 30-3), these states together contain 64 percent of the oil in the "lower-48" states remaining after primary and secondary recovery--the target for EOR/tertiary recovery.

TABLE 30-3.--Summary of oil volumes
(Billions of barrels)

	Original oil-in-place	Est. prim/sec recovery	% Recovery	Oil remaining after prim/sec
California	83.4	20.3	24	62.9
Louisiana (onshore)	25.4	11.7	46	13.7
Texas	150.1	49.5	33	100.6
Total 3 states	258.9	81.5	31	177.2
U.S. "lower-48"	401.5	123.3		278.2
3-states as % of U.S. "lower-48"				(64%)

In all, 245 reservoirs in 175 fields were analyzed. (The full report describes the construction of the "Big Fields" file and provides a list of the fields and reservoirs which comprise



RESERVOIR DESCRIBED BY:
- Reservoir characteristics
- Fluid characteristics
- Production history
- Original & remaining oil in place

RESERVOIR ASSIGNED TO:
- No EOR method applicable
- EOR development by
  - -- steam drive
  - -- in situ combustion
  - -- CO_2 miscible flood
  - -- surfactant/polymer flood
  - -- polymer waterflood

RESERVOIR DEVELOPED FOR EOR TECHNIQUE:
- Estimated start time & pace
- Phases of development
  - -- detailed study & planning
  - -- technical pilot
  - -- economic pilot
  - -- field-wide, phased expansion
- Costs of development

RESERVOIR OPERATING IN EOR TECHNIQUE:
- Costs of operation
- Costs of injected materials
- Timing of injection

RESERVOIR PRODUCES EOR OIL:
- Amount of production
- Rate of production for each development phase

RESERVOIR COSTS & PRODUCTION TOGETHER YIELD:
- Price necessary at required rate of return
- Rate of return at set prices
  - -- upper tier
  - -- lower tier

AGGREGATE PROJECTIONS OF:
- Total oil remaining in place where EOR techniques apply
- Potential EOR recovered resources
  - -- total, independent of price
  - -- price-supply curve in real price
  - -- price-supply curve with inflation
  - -- price-supply curve by technique & state
- Potential EOR reserves
  - -- total, independent of time
  - -- rate of "proved" reserves
- EOR recovery
  - -- total, independent of time
  - -- rate of recovery over time

Figure 30-5.--Structure of the analysis

the study's data base.) These reservoirs contain substantial portions of the remaining oil-in-place in the three states (Table 30-4).

TABLE 30-4.--"Big fields" data base used in the analysis

	Number of fields	Number of reservoirs	Percent of remaining oil
California	41	67	78
Louisiana (onshore)	24	34	48
Texas	110	144	51
Total in 3 states	175	245	60

These reservoirs were felt to be representative of the 3 states in the study, but not necessarily representative of the remaining 45 states. Thus, the study findings are projected to totals for the 3 states but not overall for the nation.

For these 245 reservoirs, detailed data were collected concerning formation and fluid characteristics, production histories, and original and remaining oil. Figure 30-6 is a copy of the data collection form used. Public documents were used as basic sources. Missing data were estimated, using engineering correlations. All data were edited for volumetric consistency, a requirement of later steps in the analysis.

Step 2. Broad Technical/Economic Assessment. The major tertiary recovery methods differ from one another substantially in their applicability to various crude oil and reservoir characteristics. In order to assess the applicability of specific methods to specific reservoirs, an explicit screening mechanism was required. Such a screening guide was developed for five major EOR methods (Fig. 30-7).

The guide was derived from three general sources:

- Consultation with acknowledged authorities in the EOR field from industry, government agencies, and universities.

Unit/Field Record

STATE ______

EOR METHOD	Applic. Yes	Applic. No	Reason
CO_2			
Hydrocarbon			
Micelle			
In Situ			
Steam Drive			
Polymer			

I. DESCRIPTION

Operator ______
County ______
Basin/Province ______
Geologic System (Age) ______
Reservoir Type ______
Unit Name ______

Report of (circle) Project Unit Field Formation Reserv. Basin
Field Name ______
Formation Name ______
Reservoir Name ______

II. RESERVOIR CHARACTERISTICS

Salinity - Conn - TDS ______ parts per million (ppm)
Salinity - Inj - TDS ______ ppm
Hardness - Calcium ______ ppm
Hardness - Magnesium ______ ppm
BH Temperature ______ °F
Permeability - Range ______ millidarcy (mD)
Permeability - Average ______ (mD)
Pay Thickness - Av Net ______ ft
Perm. x Thick/Visc. ______
Porosity ______ % V
Approximate Dip ______
Solution Gas-Oil Ratio (GOR) ______
Current GOR ______
Formation Volume Factor (Orig) ______
(Latest) ______

Reservoir Lithology ______
Primary Drive ______
Gas Cap (Orig) ______
(Latest) ______
Fractures ______
Conn. Water Saturation ______ %PV
Pres/Pre-EOR Oil Saturation ______ %PV
Pres/Pre-EOR Resid. Oil Satur. ______ B/AF
Gravity ______ °API
Viscosity ______ centipoise (cp)
Poros. x Resid. Oil Satur. ______
Depth (Subsurface) ______ ft
Satur. (Bubble Point) Pressure ______ pounds per sq. in. (psi)
Pressure (Orig.) ______ psi
(Latest) ______ psi

III. VOLUME/AREA/WELLS

	Unit/Project Total	Unit/Project Latest	Reservoir Total	Reservoir Latest	Field Total	Field Latest
Rock Volume - AF						
Rock Volume - BBL's						
Pore Volume - BBL's						
Producing Acres						
Producing Wells						
Injection Wells						
Well Spacing - Acres/ Producing Well						

IV. RECOVERABLE OIL & PRODUCTION TO DATE

API Recovery Factor (St/Dist/Lith) ______ %

ORIGINAL OIL	Drive Type	St. Year	Unit/Project BBL (000)	Unit/Project B/AF	Reservoir BBL (000)	Reservoir B/AF	Field BBL (000	Field B/AF
- Estimated Orig. Oil-in-Place (OOIP)-(1)								
- Estimated Orig. Oil-in-Place-(2)								
- Estimated Orig. Oil-in-Place-(3)								
TOTAL PRODUCTION (Yr.)								
- Primary								
- Secondary								
- Secondary								
- EOR								
- EOR								
CUMULATIVE PRODUCTION								
- % of OOIP-(1)			%	%	%	%	%	%
- % of OOIP-(2)			%	%	%	%	%	%
ESTIMATED ULT. RECOVERY								
- % of OOIP-(1)			%	%	%	%	%	%
- % of OOIP-(2)			%	%	%	%	%	%
ESTIMATED RESID. OIP at ABANDONMENT								
- % of OOIP-(1)			%	%	%	%	%	%
- % of OOIP-(2)			%	%	%	%	%	%

Figure 30-6.--Copy of data collection form

CRITERIA FOR THE APPLICATION OF SELECTED EOR METHODS

SCREENING PARAMETERS	STEAM DRIVE	IN SITU COMBUSTION	CO_2 MISCIBLE	MICELLAR/ POLYMER	IMPROVED WATERFLOOD
Viscosity – centipoise (cp) at reservoir conditions	NC[1]	NC	< 12 cp	< 20 cp	< 200 cp
Gravity – (Other than California Crudes)-°API (Calif. crudes)	>10° (>10°)	(10-45°) (10-45°)	>30° (>26°)	>28° (> 25°)	15 >18° (>16°)
Fraction of Oil Remaining in Area to be Flooded (before EOR) – %PV	50%[2]	50%[2]	25%	25%	50%
Oil Concentration – B/AF Porosity x Oil Saturation	<500 B/AF >0.065	>400 B/AF >.05	NC	NC	NC
Depth – feet	<5,000'[3]	>500'	>3,000'	NC - (8500')[3,5]	NC - (8500')[3,5]
Temperature – °F	NC	NC	NC	<200°F[5]	<200°F[5]
Original Bottom Hole Pressure – Pounds per square inch (psi)	NC	NC	>1,500 psi	NC	NC
Net Pay Thickness – feet	>20'	>10'	NC	NC	NC
Permeability – millidarcy (mD)	NC	NC	NC	>20 mD (with polymer drive)	>20 mD
Transmissibility (Permeability x Thickness/Visc.)	>100	>20	NC	NC	NC
Natural Water Drive[4]	none to weak	none to weak	none to weak	none to weak	none to weak
Gas Cap[4]	none to minor	none to minor	none to minor	none to minor	none to minor
Fractures	NC unless extreme	none to minor	none to minor	none to minor	none to minor
Lithology	NC	NC	NC	sandstone only[5]	NC
Salinity – parts per million (ppm) TDS	NC	NC	NC	<50,000 ppm[5]	NC
Hardness – ppm – calcium & magnesium	NC	NC	NC	<1,000 ppm[5]	NC
Comments	• Porosity x thickness (high) • 10-acre spacing • Economic freshwater available • Economic fuel available • High net to gross pay • Low clay content	• High dip preferred • Porosity x thickness high • 40-acre spacing • Low vertical permeability preferred • Preferred temperature >150 • High net to gross pay	• Thin pay preferred • High dip preferred • Homogeneous formation preferred • Porosity x thickness low • Natural CO_2 availability • Low vertical permeability in horizontal reservoirs	• Homogeneous formation preferred • Low clay content • Porosity x thickness (high) • Prefer water-flood sweep 50%	• Use with or prior to waterflood • Low calcium and clay content • Porosity x Thickness (high)

NOTES:

[1]NC = Not a critical factor (for all).

[2]In portion of field to be flooded. Assuming 80 percent of area of reservoir contains 95 percent of remaining oil, the oil saturation for the total field becomes 42 percent of pore volume.

[3]8500 ft. is approximately the depth at which the temperature constraint of 200°F will be reached.

[4]These criteria apply to reservoirs with substantial remaining primary recovery.

[5]Considered a constraint under current technology.

SOURCE: Lewin & Associates, Inc. (*Research and Development in Enhanced Oil Recovery*, Part 1, Page II-8, October 1976).

Figure 30-7.--Screening guide of criteria for the application of selected EOR methods

- Review of current literature and subsequent discussions with many of the authors.
- Analysis of field reports concerning actual EOR projects (Fig. 30-8).

Each reservoir in the "Big Fields" file was tested for its potential for tertiary recovery. The approach was first to screen out those reservoirs having low potential for tertiary recovery, and second to select the tertiary recovery technique most suitable for the remaining high potential reservoirs.

Step 3. Reservoir Development. Timing assumptions and reservoir development costs were assigned to each EOR project.

The timing for reservoir development considered the time required to study a reservoir, test a pilot, assess the economics, and develop across the entire reservoir.

Reservoir development costs accounted for the required well spacing pattern for the EOR technique, the condition of the wells, and the depth and geographic location of the field.

Step 4. Reservoir Operations. Reservoir operating costs were assigned to each EOR project. Individual well operating costs, calculated by depth and by region, were added to the costs of injection materials and injection operations, based on actual pore volumes.

Step 5. Reservoir Production. Detailed analysis of historic and ongoing EOR projects were used to develop the recovery models for each technique. In general, recovery projections were based on estimates of sweep and displacement efficiencies as applied to the reported oil viscosity and saturation (after primary and secondary recovery).

Step 6. Reservoir Economics. The costs and timing, calculated from above, were combined with individual production curves to: (a) compute the required price per barrel for the incremental enhanced/tertiary oil given a series of rates of return; and (b) compute rates of return given a series of prices. Special attention was given to current U.S. and world oil prices.

Step 7. Ordering and Interpreting the Results. The results of the recovery and economic analysis of each reservoir were translated into an aggregated sequence of estimates.

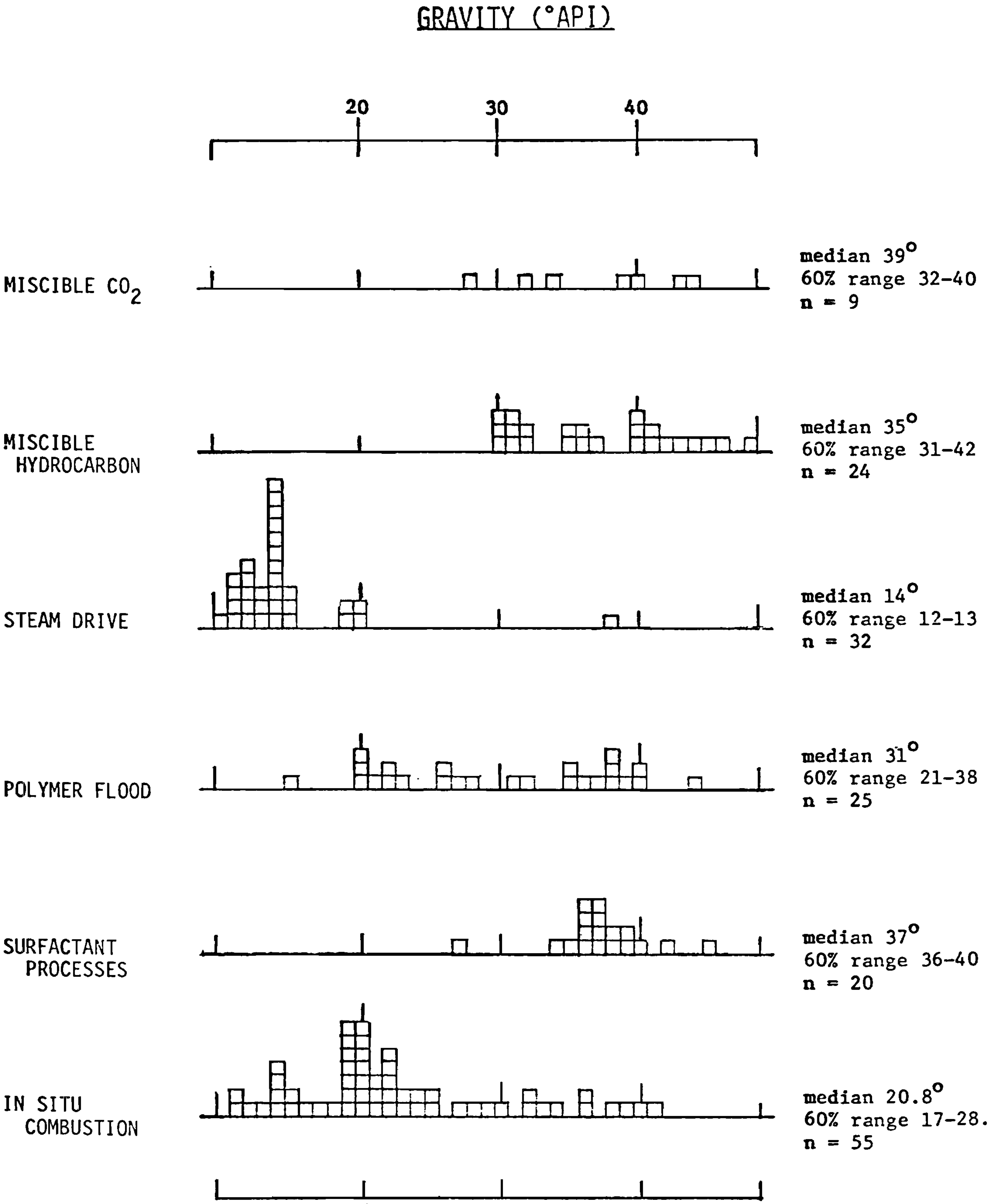


Figure 30-8.--Analysis of field reports of actual EOR projects

- Potential EOR Resources
  - -- Total, independent of price
  - -- Price-supply curves in real prices
  - -- Price-supply curves by technique and state

The following section sets forth the general economic model, as well as a detailed recovery cost model for one of the tertiary techniques, steam drive, and applies these models to a sample reservoir.

- Potential EOR Reserves
  - -- Total, independent of time or price
  - -- Rate of "proved" reserves over time
- EOR Production
  - -- Total, under various price assumptions
  - -- Production by technique and state

OIL RECOVERY AND ECONOMIC MODELS

The models have been designed to simulate the development and operation of actual EOR projects. Each reservoir found conducive to an EOR technique is processed through the models, which generate estimates of:

- The quantity of crude oil that will be produced from the project;
- A price sufficient to reimburse all costs of the project and to provide an adequate return on investment; and
- The timing at which reserves in the reservoir will be proved and produced.

Assumptions Common to All the Models

Several assumptions and procedures are common to all five economic models.

1. Size and Location of the Production Unit. The model establishes a uniform development pattern for each technique:

Dimensions of Assumed Production Units for Five EOR Methods

Method	Acres	Production wells	Injection wells
Steam Drive	2.5	1	0.8
In Situ Combustion	20	1	.3
CO_2 Miscible	40	1	.8
Surfactant/Polymer	5	1	.8
Polymer	40	1	.5

Field development proceeds in multiples of the above pattern, EOR confines itself to the richer, inner boundary of the field, and thermal development proceeds zone by zone within a reservoir.

2. Calculation of Residual Oil. Material balance equations were used to calculate the amount and the saturation of the residual oil.
3. Distribution of the Residual Oil. The recovery models assume that oil saturations are uniformly distributed throughout the reservoir, and that decreased spacing and cross-flooding would be used to place the injection fluid into the previously unswept zone.
4. Selection of EOR Technique. There are at least three competing goals that influence the specific selection of an EOR technique:
   - Maximum potential recovery;
   - Maximum return on investment; and
   - Timing of production.

   In general, the models are designed to focus on maximum recovery as constrained by reasonable cost assumptions. The models also seek to represent the most advanced, yet tested, approach for each recovery technique.
5. Risk Assumptions. The models provide for risk in four ways. First, the use of the technical and the economic screens are designed to eliminate the most

risky projects. Second, the model assigns a risk premium (in the rate of return calculation) to EOR. Third, the model assigns costs of failure to the project using an approach analogous to dry hole costs. Finally, EOR carries a large research and development cost allocation which helps compensate for risk.

6. Timing Assumptions. Two considerations for timing are included in the models. The first pertains to the pace at which a project will be conducted, and the second pertains to the time when a project will be commenced.

   To account for the pacing of a project, the models approximate the time span, by technique, for two paths of reservoir development--advanced and non-advanced. Both the advanced and nonadvanced paths entail a six-step process:

   - Study Reservoir. The reservoir and the formation fluids undergo a series of preliminary engineering and chemical tests. Based upon data collected in these tests, a company determines whether or not to continue the project.
   - Conduct Technical Pilot. A technical pilot test is conducted on a small portion of the reservoir acreage to see how effective the EOR technique will be in displacing oil.
   - Evaluate: Plan/Budget. The results are evaluated and if deemed favorable, an economic pilot is planned and budgeted.
   - Conduct Economic Pilot. An economic pilot is conducted on a large section of the reservoir to see whether the techniques will be profitable if expanded to the entire reservoir.
   - Evaluate: Plan/Budget. The results are evaluated and if favorable, plans are made to develop the entire reservoir.
   - Reservoir-Wide Phased Expansion. The remaining reservoir acreage is phased into development. Wells

are properly spaced and conditioned, and any additional equipment required for operations is installed.

Table 30-5 displays the schedule of development of both the advanced and nonadvanced path for each technique. The advanced tertiary development path imitates timing patterns used by tertiary-oriented companies and for more widely tested and used techniques. The nonadvanced development path follows the patterns of nontertiary-oriented companies and of the less proven or tested techniques.

TABLE 30-5.--Steps and timing for producing tertiary oil

(In years of elapsed time)

Step	Steam		In situ		CO_2		Micellar/ poly		Improved waterflood	
	Adv	Non-adv	Adv	Non-adv	Adv	Non-adv	Adv	Non-adv	Adv	Non-adv
1. Study Reservoir	1	1	1	1	1	1	1	1	1	1
2. Conduct Technical Pilot	0	2	0	2	0	2	0	2	0	0
3. Evaluate: Plan/Budget	0	1	0	1	0	1	0	1	0	0
4. Conduct Economic Pilot	3	3	2	2	2	4	3	4	2	5
5. Evaluate: Plan/Budget	1	1	1	2	2	1	1	1	1	1
6. Develop Reservoir	10	10	10*	10*	4	5	10	10	2	2
Total Elapsed Time	15	18	14	18	9	14	15	19	6	9

*In situ development proceeds in four separate segments introduced 3 years apart.

The models assume that the thermal techniques of steam flooding and in situ recovery will follow the advanced path, with the remaining techniques (i.e., CO_2 miscible, surfactant/polymer, and polymer-augmented waterflooding) following the nonadvanced path. Adoption of the advanced path by all companies could save from 3 to 5 years of project development time (Table 30-5).

The second timing assumption concerns the rate at which EOR projects are initiated. The model arrays the projects in a descending sequence of profitability. It then initiates the most profitable projects first. Considerable iteration is required to balance the pace of development with perceived capital and resource constraints.

Historically based timing and development assumptions are made for all reservoirs in which tertiary recovery has already been initiated. These reservoirs are placed on the development time-line according to the extent of their development in 1975.

Assumptions That Vary by Each Technique

Once the above common calculations are performed, the five models proceed through differing steps to produce estimates for:

- Total incremental tertiary production
- The schedule of tertiary production
- The schedule of injection
- Unit costs of the injection materials
- Surface equipment costs
- Detailed costs of development and operation expenditures
- Timing of all costs

A brief summary of key aspects of the steam drive model follows, exemplifying the assumptions that vary by technique.

ESTIMATING RECOVERY FOR STEAM DRIVE

Total Incremental Production. The recovery calculation for reservoirs with high oil viscosity--greater than 1,000 cp--is based on the following assumptions:

- The oil saturation, at project initiation, is uniformly distributed within the portion of the reservoir being developed.
- The effective sweep efficiency for steam is 35 percent of the reservoir pore volume and 35 percent for the hot water, thus leaving 30 percent unaffected.
- Residual oil saturation in the steam zone will be 0.08 and will be 0.30 in the hot water zone.
- Residual oil saturation in the unswept zone will stay the same as at initiation of project.

Thus:

$$\text{Incremental Tertiary Recovery} = \frac{(S_{OR2} - S_{ORDT})}{S_{OR2}} \text{ X ROIP}$$

Where:

S_{OR2} = Residual oil saturation after ultimate primary and secondary recovery

S_{ORDT} = Residual oil saturation after tertiary recovery

ROIP = Residual oil-in-place after ultimate primary and secondary recovery

$S_{ORDT} = 0.35(0.08) + 0.35(0.30) + 0.30\ (S_{OR2})$

(A different recovery equation is assigned to the lighter oils.)

1. <u>Timing of Recovery</u>. The initial response is realized from the injection of steam into the production well (Fig. 30-9). The analytic production unit is assumed to operate for 6 years, until the decreasing oil/steam ratio makes further operation uneconomic.
2. <u>Timing of Costs</u>. All field development and equipment outlays for the analytic unit are assumed to be made 1 year prior to the injection of steam. A small amount of steam is injected periodically into the production well during the first year, then 1.2 pore volumes of steam are injected into surrounding injection wells over a course of 6 years.

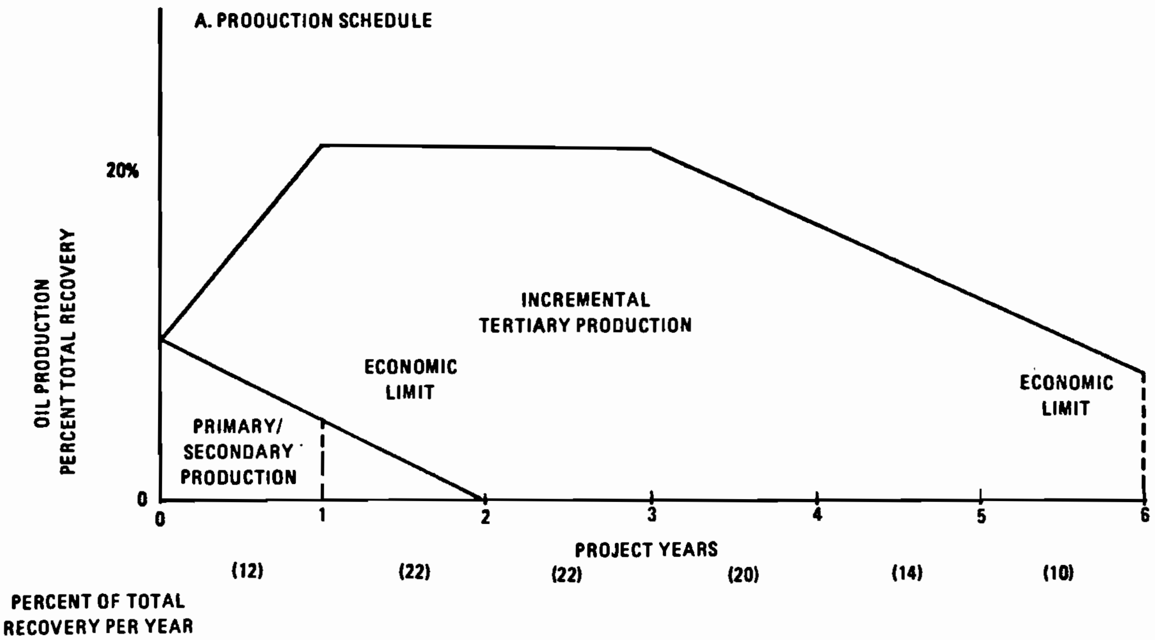


Figure 30-9.--Steam-drive production schedule

3. Unit Costs for Injected Fluids. The formula for unit costs of steam is: cost for one barrel of steam equals $0.08 plus to 0.0625 times the price of crude. The constant (0.08) represents the incremental operating cost for the steam generator and for water treatment. The coefficient (0.0625) is derived from the Btu requirements to generate 1 barrel of steam.
4. Generator Costs. The units and costs of installed generating equipment have been scaled from a 50 x 10^6 Btu/hour steam generator costing $270,000. A 1 x 10^6 Btu/hour unit is assumed to be able to generate 20,000 barrels of steam (water equivalent) per year.
5. Detailed Cost Data. The field development and operating costs for steam drive are estimated from detailed cost parameters reflecting region, depth, and condition of existing wells (Fig. 30-10 and Table 30-6). The results of applying this model to a particular reservoir are shown in Figure 30-11.

PRELIMINARY FINDINGS

In this portion of the report, certain preliminary findings will be described with emphasis on:

1. The projection of EOR/tertiary potential and price-supply by technique and geographic area (for the UNITAR/IIASA case without tax and ownership considerations).
2. The major constraints faced by oil producers contemplating enhanced oil recovery.
3. The kinds of risks and technological uncertainty surrounding EOR application responsible for the higher financial hurdles facing EOR (over conventional recovery technology).
4. The effect on the price-supply curve of the full economic costs borne by EOR producers, namely, taxes and land costs.

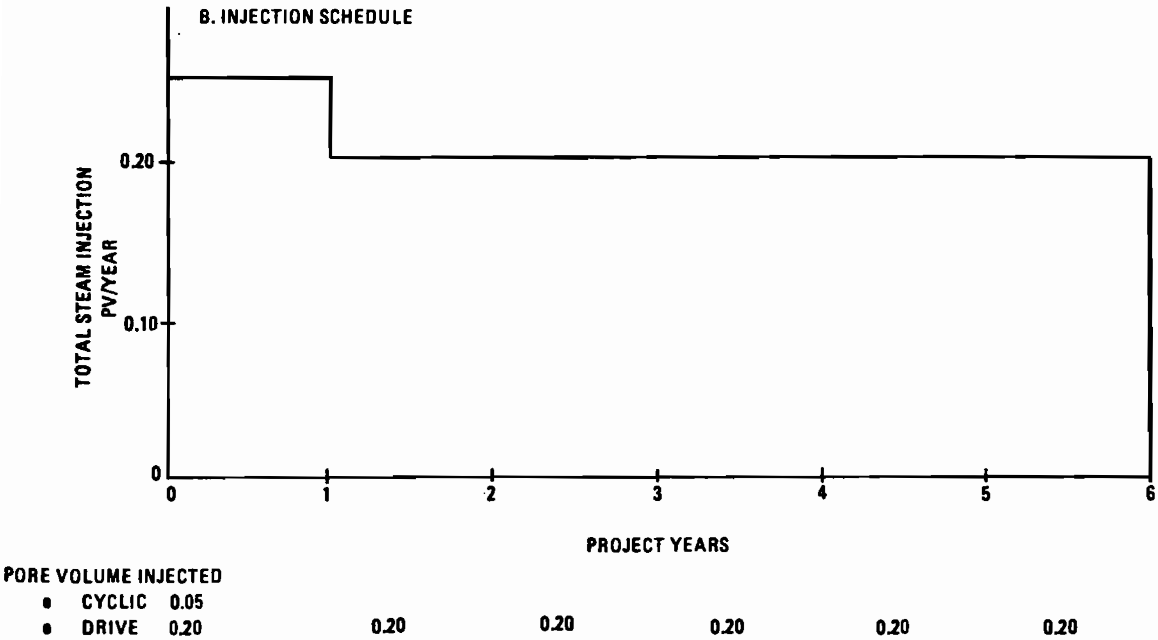


Figure 30-10.--Steam-drive injection schedule

FEA CRUDE OIL PRODUCTION ECONOMICS MODEL
Steam Drive

I. DATA ON FIELD

- Field/Reservoir ________
- Discovery Year: 1926
- Secondary Development Year: 1963
- Depth: 1388
- Total Acres: 3805
- Net Pay: 112
- Number of Zones: 4

II. A. ANALYTIC UNIT CHARACTERISTICS

- Unit Acres: 2.5
- Net Pay: 28
- Porosity: .35
- Pore Volume: 190,071 bbls
- API Gravity: 15 degrees
- Oil Saturation After Primary and Secondary: .58
- Decline Rate: 8.0%

B. OIL VOLUMES - ANALYTIC UNIT

- Original Oil-in-Place: 147,250
- Cum. Production to Date: 30,478
- Ult. Pri/Sec Production: 31,000
- Est. Tertiary Production: 54,718.
- Ult. Recovery From Unit: 85,718.

III. FIELD DEVELOPMENT/EQUIPMENT

	Production Wells		Injection Wells		Work-Overs Required
	Existing	Required	Existing	Required	
Units	0.50	0.50	0.0	0.80	0.10
Cost					$3,500
Well D&C		$17,246		$27,593	
Well Equipment		$21,250		$20,000	

- Generators/Compressors
  - -- 1.24 mm BTU/hr.
  - -- cost - $6671.
- Additional Zones
  - -- 3
  - -- cost - $63,000 per zone

Figure 30-11.--FEA crude oil production economics model for steam drive

IV. PRODUCTION AND INJECTION PROFILES PER ZONE (in Barrels)

Years	Old Production	New Production	Injection Volume
1	402	-	- 0 -
2	120	6,566	47,518
3		12,038	38,014
4		12,038	38,014
5		10,944	38,014
6		7,660	38,014
7		5,472	38,014
TOTAL	522	54,718	237,589

V. WELL OPERATING AND MAINTENANCE COSTS PER ZONE

Years	Well Up Costs	Increased O&M Costs	G&A on Operating Costs	Total Well O&M
1	-	-	-	-
2	15,112	3,003	3,623	21,738
3	15,300	3,040	3,668	22,008
4	15,300	3,040	3,668	22,008
5	15,300	3,040	3,668	22,008
6	15,300	3,040	3,668	22,008
7	15,300	3,040	3,668	22,008
TOTAL	91,612	18,203	21,963	131,778

VI. INVESTMENTS

Years	Tangible	Intangible	Other	Total Investments
1	80,689	15,572	4,234	100,495
8	-	63,000	2,520	65,520
15	-	63,000	2,520	65,520
22	-	63,000	2,520	65,520
TOTAL	80,689	204,572	11,794	297,055

VII. FULL RESERVOIR

- Scale Factor (reservoir/unit) = 1217.60
- Extrapolated Reservoir Tertiary: 266,496,960
- Crude Consumed as Fuel: 72,321,964
- Net Tertiary Production: 194,174,976

TABLE 30-6.--Sample of detailed cost data

Basic operating and maintenance costs
($/well/year for production and injection wells, including labor, fuel, artificial lift equipment operations, and routine maintenance costs)

State/ district	Geographic unit	Depth Range Avg. 0-2,500' (2,000)	2,500-5,000' (4,000)	5,000-10,000 (8,000)	10,000-15,000 (12,000)
California	1-4	$8,500	$11,150	$15,700	$21,200
Louisiana	5-7	5,350	7,700	9,150	14,100
Texas	8-19	4,475	5,250	7,250	10,575

Source: Bureau of Mines, IC-8561 (1970 costs), updated to 1975. See Exhibit 9 for the detailed cost elements used. See Appendix I of the full report for methods used in updating the 1970 BOM data to 1975 prices.

Cost elements as applied to an 8,000-foot well in Texas:

Item	Cost
Normal Daily Operation	
Field office overhead and supervisory	$860
Labor (pumper) including auto usage	1,100
Chemicals	275
Fuel, power, water	700
Operative supplies	65
Total Daily Operation	$3,000
Surface Repair and Maintenance	
Labor (roustabout)	315
Materials, supplies, services	475
Equipment usage	200
Other	360
Total Surface	1,350
Subsurface Repair, Maintenance, and Services	
Workover rig services	1,350
Remedial services	900
Equipment repair and/or replacement	600
Other	50
Total Subsurface	2,900
TOTAL DIRECT BASIC OPERATING EXPENSE	$7,250

DETAILED FINDINGS

The composition of the 37.9 x 10^9 barrels of incremental reserves (Fig. 30-12) must first be examined.

The column on the left has already been presented; by way of review, it is made up as follows:

- Of the 177.2 x 10^9 barrels remaining in place in the three states after primary and secondary:
  - -- 21.6 x 10^9 barrels is in fields not applicable to EOR
  - -- 32.0 x 10^9 barrels is in fields not currently economic even at upper tier domestic prices and assuming a "no risk" technology
- The remaining 113.6 x 10^9 barrels of oil-in-place is in fields technically and economically appropriate for EOR; of this:
  - -- 37.9 x 10^9 barrels would be recoverable
  - -- 7.0 x 10^9 barrels would be consumed producing the above reserves
  - -- 68.7 x 10^9 barrels would remain behind after the tertiary project (awaiting perhaps quaternary recovery)

The column on the right indicates how this enhanced oil is divided among the particular techniques involved.

- Steam Drive is responsible for the largest portion, approximately 13.6 x 10^9 barrels
- CO_2 Miscible accounts for 13.3 x 10^9 barrels
- Surfactant/Polymer account for most of the rest, 9.5 x 10^9 barrels
- In Situ Combustion contributes about 1.2 x 10^9 barrels
- Polymer-Augmented Waterflooding is responsible for 0.3 x 10^9 barrels.

While this is the case UNITAR/IIASA requested in their instructions, I should caution that these results are in no way assured--massive research and development expenditures would need to be made by industry and the federal government for these reserves to be realized. As such, and as stated in our report, it is an "upper bound" case that assumes enhanced oil recovery has progressed to the same level of technological sophistication

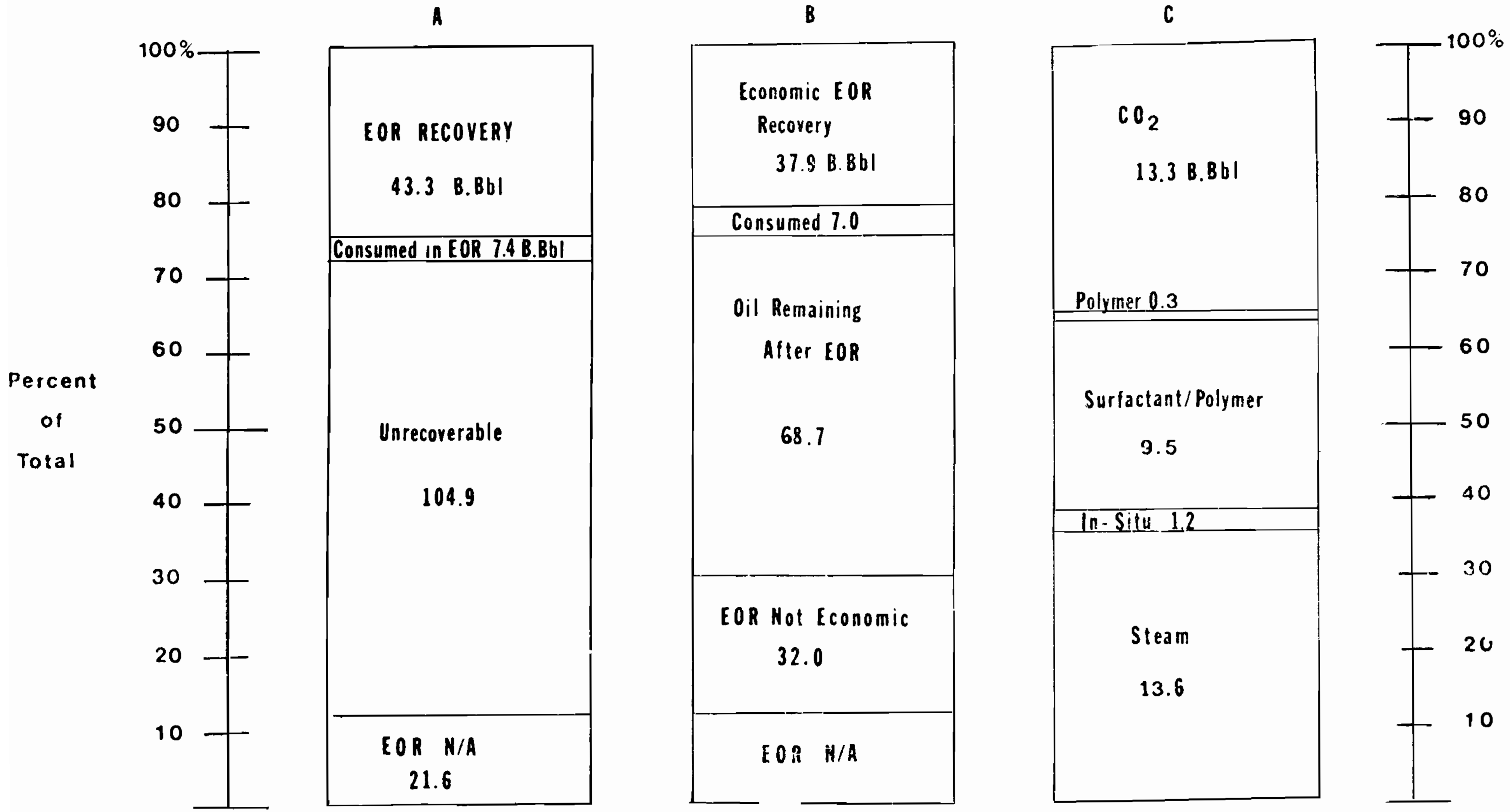


Figure 30-12.--Distribution of remaining oil and EOR reserves (10^9 barrels)

and predictability as conventional recovery and that it thus competes in the same capital/risk market place. I will return to this point again under the section on constraints.

The 37.9 x 10^9 barrels of potential reserves is realized across a broad range of prices as shown by the following price-supply curve (at an 8 percent rate of return) for enhanced recovery oil (Fig. 30-13).

Reading across from 37.9 and up from the upper tier price shows that:

- Steam drive and in situ combustion make up a major share of production realized at the lower prices; while
- CO_2 miscible and--to a greater extent, surfactant/ polymer--require high prices to bring on the bulk of the potential.

Beyond the variability introduced by recovery technique, an additional consideration, geography, enters the picture. As you may know, crude oil is produced from several distinct areas in the United States, each with differing characteristics in terms of the type of crude, reservoir characteristics, and many other factors.

Figure 30-14 is the same price-supply curve as before, broken down by state. This is in marked contrast to current and historical production rates which rank the states: Texas (1), Louisiana (2), and California (3). One of the explanations for this reversal is that success in tertiary recovery is closely related to residual oil left after primary and secondary recovery. Thus, in Louisiana, where recovery rates are high, there is proportionately less oil remaining for tertiary applications. The lower residual oil leads to both reduced technical performance and considerably less attractive economics.

Finally we have combined the technique and geographic variables in Figure 30-15 to show a price-supply curve for California. It is clear that the proportion of steam drive recovery is dramatically above the three state totals, while the share of carbon dioxide applications is greatly diminished. This distribution is directly related to the preponderance of heavy crudes in California which are recovered effectively by thermal methods.

Counterbalanced is the lack of naturally occurring CO_2, making CO_2 miscible recovery less attractive.

CONSTRAINTS

Numerous technical and economic constraints need to be considered in estimating the timing of proving and producing tertiary reserves. The technology needs to be proven, large amounts of capital will be required, and sufficient injection materials will need to be found or manufactured.

- Proving the technology. Rather than a single technology, tertiary recovery is composed of numerous recovery techniques, each at different stages of development. The thermal techniques are clearly most advanced, the CO_2 miscible methodology in its early stages of field application and the chemical floods (surfactants and polymers) barely out of the laboratory.
  Thus for some of the techniques, such as thermal, the challenge will be to make them work efficiently in less than ideal conditions; for others it will be to make them work, period. Considerable resources will need to be devoted to research and development before one can realize the reserve and production estimates potentially available from the UNITAR/IIASA "upper bound" case.
- Capital. Approximately $\$200 \times 10^9$ of expenditures (exclusive of well operating and overhead costs) would be required over the next 30 years to prove and produce the 37.9 billion barrels of tertiary oil projected for the upper bound case. Forty-five billion dollars would be required for field development and equipment and an additional billion for the injection chemicals and fluids (sulfonates, polymers, CO_2, steam). Thus, tertiary recovery, assuming an average of $\$7 \times 10^9$ per year of expenditures, would become a major competitor for the yearly $\$30 \times 10^9$ of U.S. oil and gas expenditures. A judicious sequencing of tertiary projects should provide sufficient cash flow in the later years. However, developments in

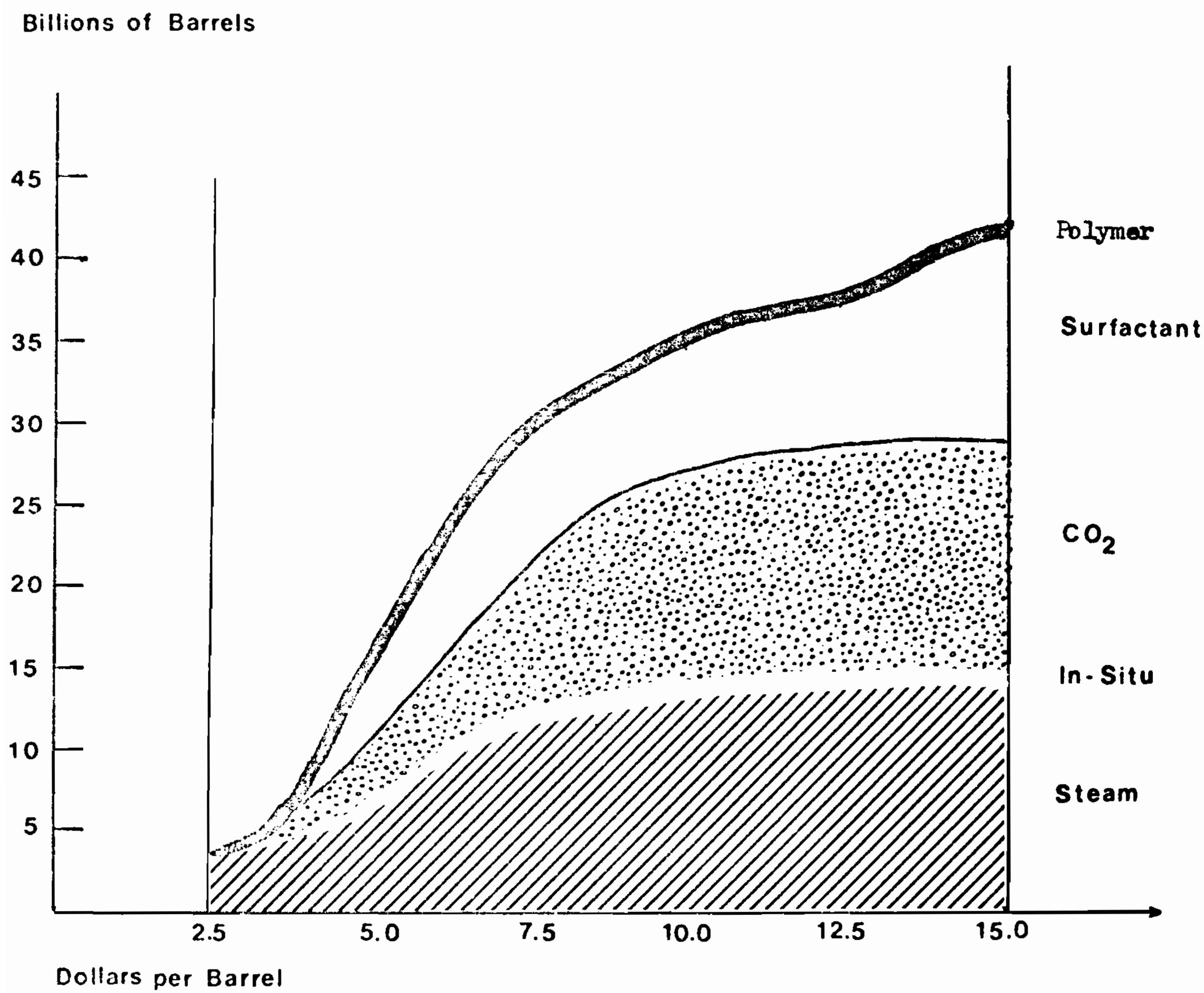


Figure 30-13.--Projected cumulative price-supply curve by technique (total for three states)

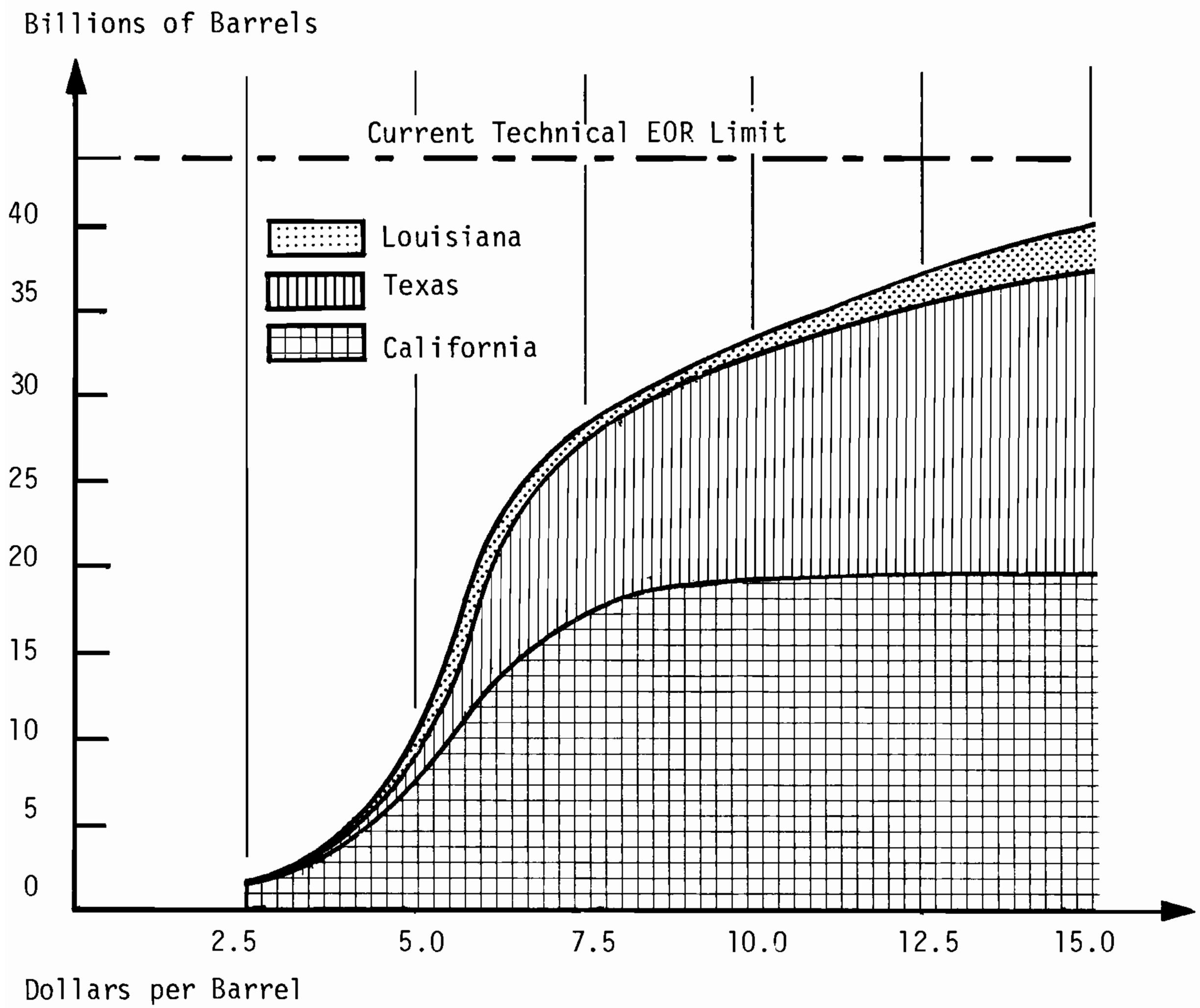


Figure 30-14.--Projected cumulative price-supply curve by state

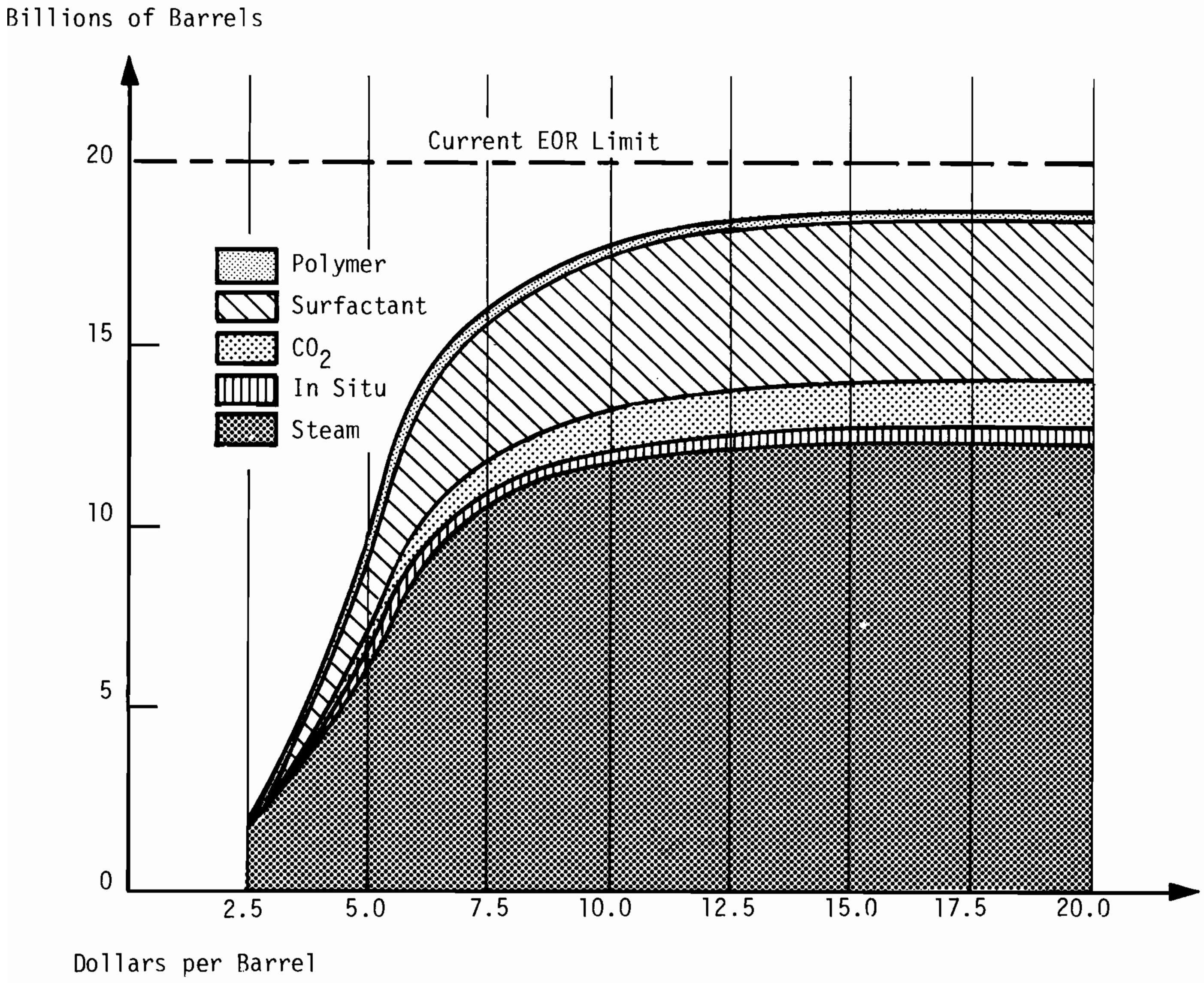


Figure 30-15.--California projected cumulative price-supply curve

the initial years (from 1976-1985) could be constrained by competing capital demands.

- Recovery materials. Tertiary oil recovery will need to spawn and nurture many new ventures in chemicals and CO_2 supply. Approximately 85 x 10^9 pounds of sulfonates, 9 x 10^9 pounds of polymers, and 12 x 10^9 pounds of alcohols would be required over the next 30 years to produce the nearly 10 x 10^9 barrels of tertiary oil attributable to surfactant/polymer recovery. However, sulfonate supply may not pose a near-term constraint. The domestic chemical industry already has the capacity to produce 500 x 10^6 pounds of sulfonate per year with additional major plants coming on stream. Moreover, new plant construction has a relatively short construction lead time (3 years) and the major demand for sulfonates will not come until after mid-1985. Polymer requirements could pose constraints, given that the current production of polyacrylamides and polysaccharides is estimated to be only about 300 x 10^6 pounds per year.[5]

  Approximately 60 x 10^{12} ft^3 of CO_2 will be required over the next 30 years to produce the 13 x 10^9 barrels of oil attributable to this technique. While recycled CO_2 can substitute for about a quarter, or 15 x 10^{12} ft^3 of the requirement, natural sources will still need to supply 30 x 10^{12} ft^3 and manufactured sources the remaining 15 x 10^{12} ft^3.

  Currently, CO_2 supply appears to provide a major constraint. While considerable quantities of naturally occurring CO_2 are produced with natural gas, and CO_2 is a by-product of many chemical and refining processes, its limited value has led to CO_2 being considered a waste material. Recent changes in the economic value of CO_2 have led to a renewed interest for discovering and

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[5] Chemicals for Microemulsion Flooding in EOR, March 1976, by Gulf Universities Research Consortium.

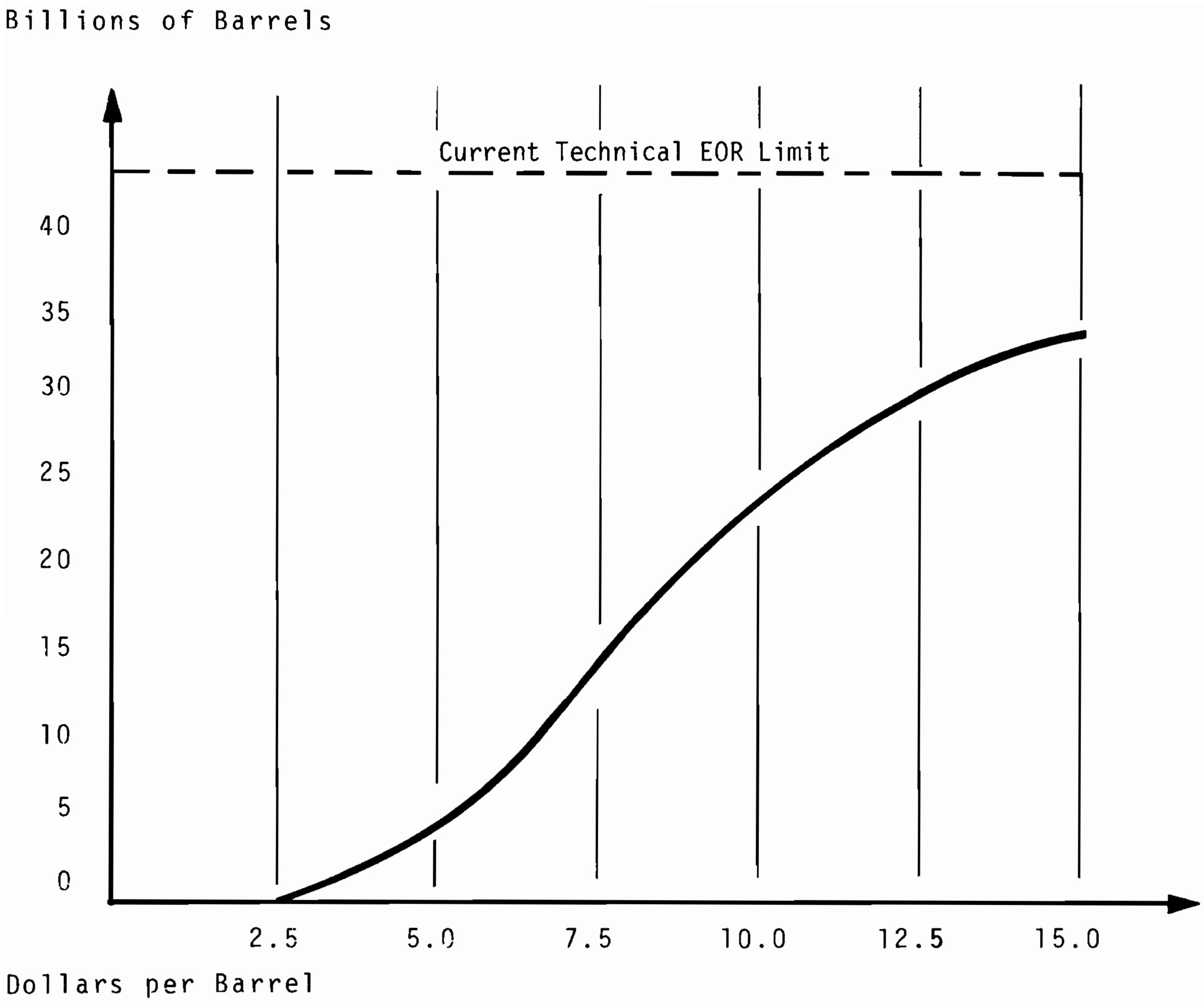
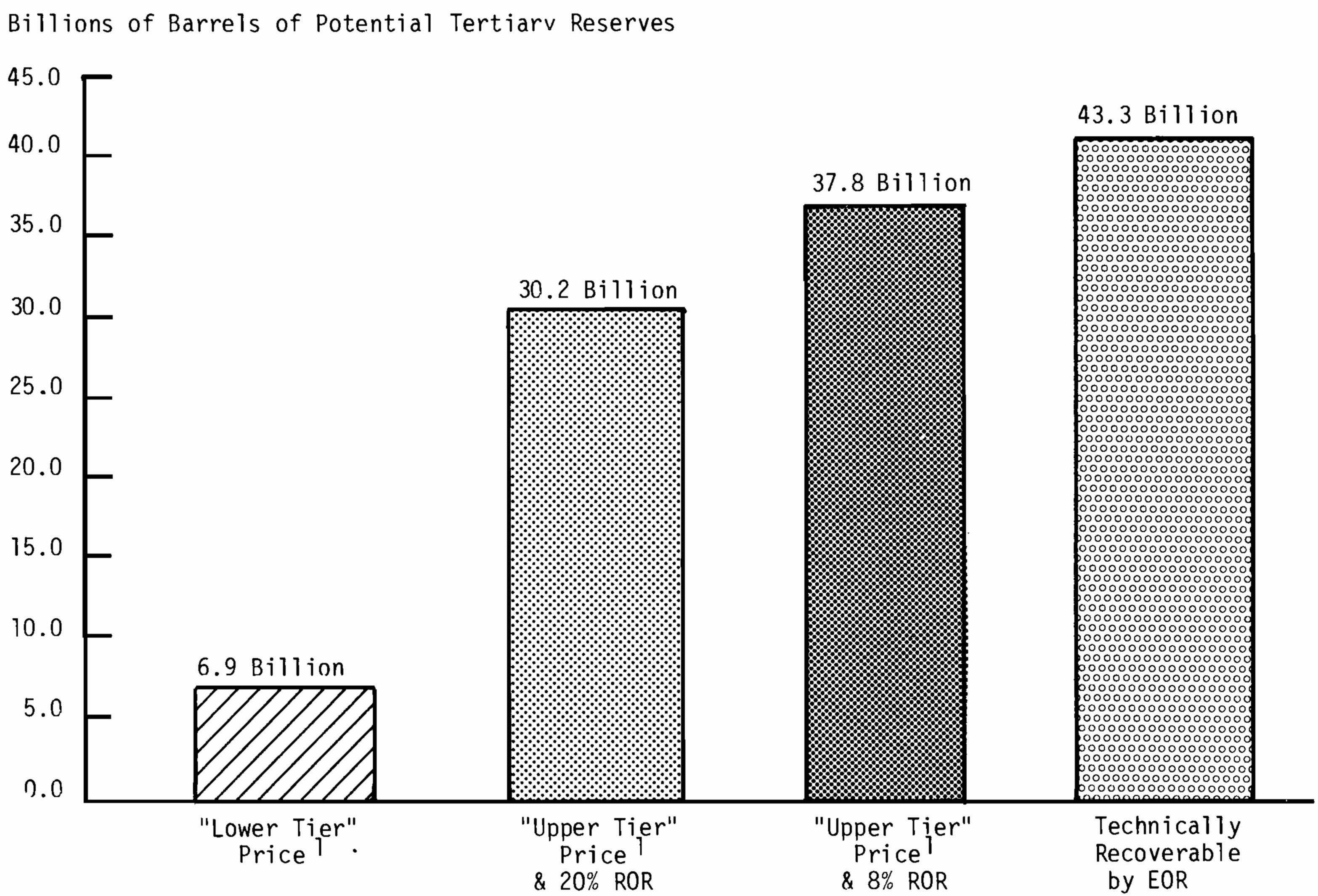


Figure 30-16.--Projected cumulative price-supply curve



[1]Price is Assumed To Be Maintained in "Real" Terms (i.e. Adjusted for Cost of Inflation Using Domestic GNP Cost Inflation Estimated at 7.5%.

Figure 30-17.--Sensitivity of tertiary reserves to price

capturing CO_2 supplies.[6] However, major improvements in transportation and recycling will need to be made before the full potential of this recovery technique can be realized.

ACCOUNTING FOR THE RISKY AND UNPROVEN NATURE OF THE TECHNOLOGY

One of the major concerns, at least in terms of private investments, is profitability. Enhanced oil recovery projects must compete for capital not only with other exploration and production prospects, but also with diverse investment opportunities. When one adds in the risks and uncertainty inherent in the new EOR processes, it may be more realistic to look toward a higher rate of return.

Figure 30-16 illustrates the price-supply curve for the three states at a 20 percent rate of return. The recovery is substantially reduced from the 8 percent case. The reduction is more or less across the board, except that steam drive, having become economic at lower prices, tends to hold its position.

For comparison purposes Figure 30-17 provides several scenarios utilizing different assumptions of prices and rates of return.

- On the right is the 43.3×10^9 barrels technically recoverable;
- Next is the 37.9×10^9 barrels recoverable at upper tier prices with an 8 percent ROR;
- Next is 30.2×10^9 barrels recoverable at the same price with a 20 percent ROR threshold;
- On the left is an 8 percent ROR case with lower tier prices--$\$6.9 \times 10^6$.

ACCOUNTING FOR OTHER ECONOMIC COSTS

Based on the specifications for papers to be presented to the Conference, tax and ownership costs were excluded from

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[6] L. W. Holm, "Status of CO_2 and Hydrocarbon Miscible Oil Recovery Methods," in Journal of Petroleum Technology, January 1976.

consideration. There are few instances in the world where this assumption will hold; certainly not in the United States.

Figure 30-18 illustrates the difference dramatically. These figures were developed using the tax and ownership structures currently in effect in the United States. The economically recoverable reserves drop dramatically, particularly for the 20 percent rate of return case.

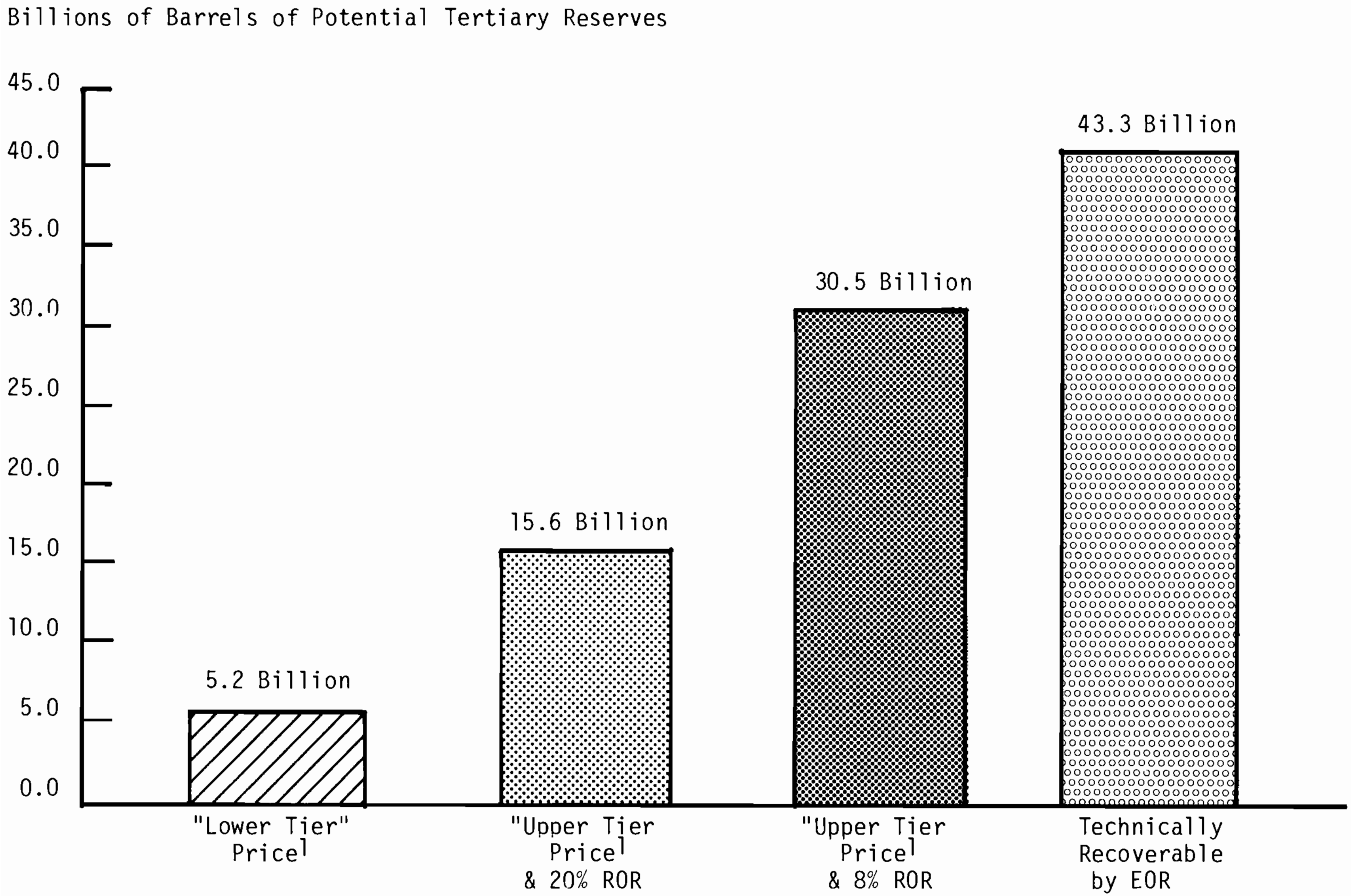
1. Reserve Additions. Figure 30-19 displays timing of the reserve addition of the three cases shown previously.

   The base case, in which prices are held at $5.25, is essentially flat, with little new activity. The two other cases show reserve additions representing projects which are or have been pilot tested awaiting improved economics or are totally dependent on technology development.

   The present state of the art of EOR in the United States is such that the lower bound case--the case providing 15.6×10^9 barrels of reserves--is a more probable course, at least until such time as governmental incentives and/or additional field experience have improved the technical and economic outlook and further quantified the risks involved.

   On Figure 30-20 the reserve additions for the lower bound case are broken down by technique. The surfactant/polymer technique is shown here as somewhat marginal, not coming on until after the more favorable CO_2 and steam drive projects have been initiated.

2. Tertiary Production. Finally, we have come to the most critical measure--production, or oil in the tank. The three cases examined (Table 7) provide widely different expectations. For example, in 1990, the base case provides 300,000 barrels per day, the lower bound 1.2×10^6 barrels per day, with the upper bound providing up to 3×10^6 barrels per day.



[1]Price is Assumed To Be Maintained in "Real" Terms (i.e. Adjusted for Cost of Inflation)

Figure 30-18.--Sensitivity of tertiary reserves to price

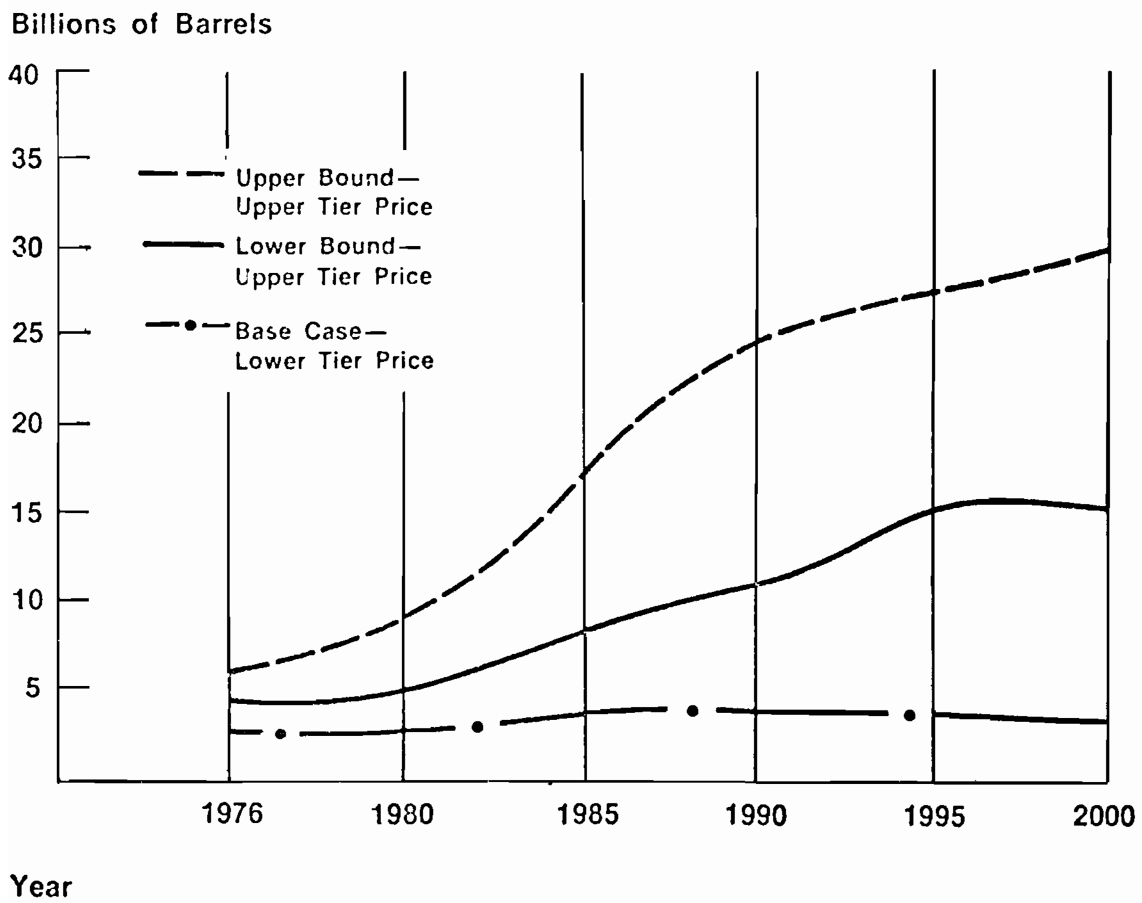


Figure 30-19.--Timing of proved tertiary reserves by case

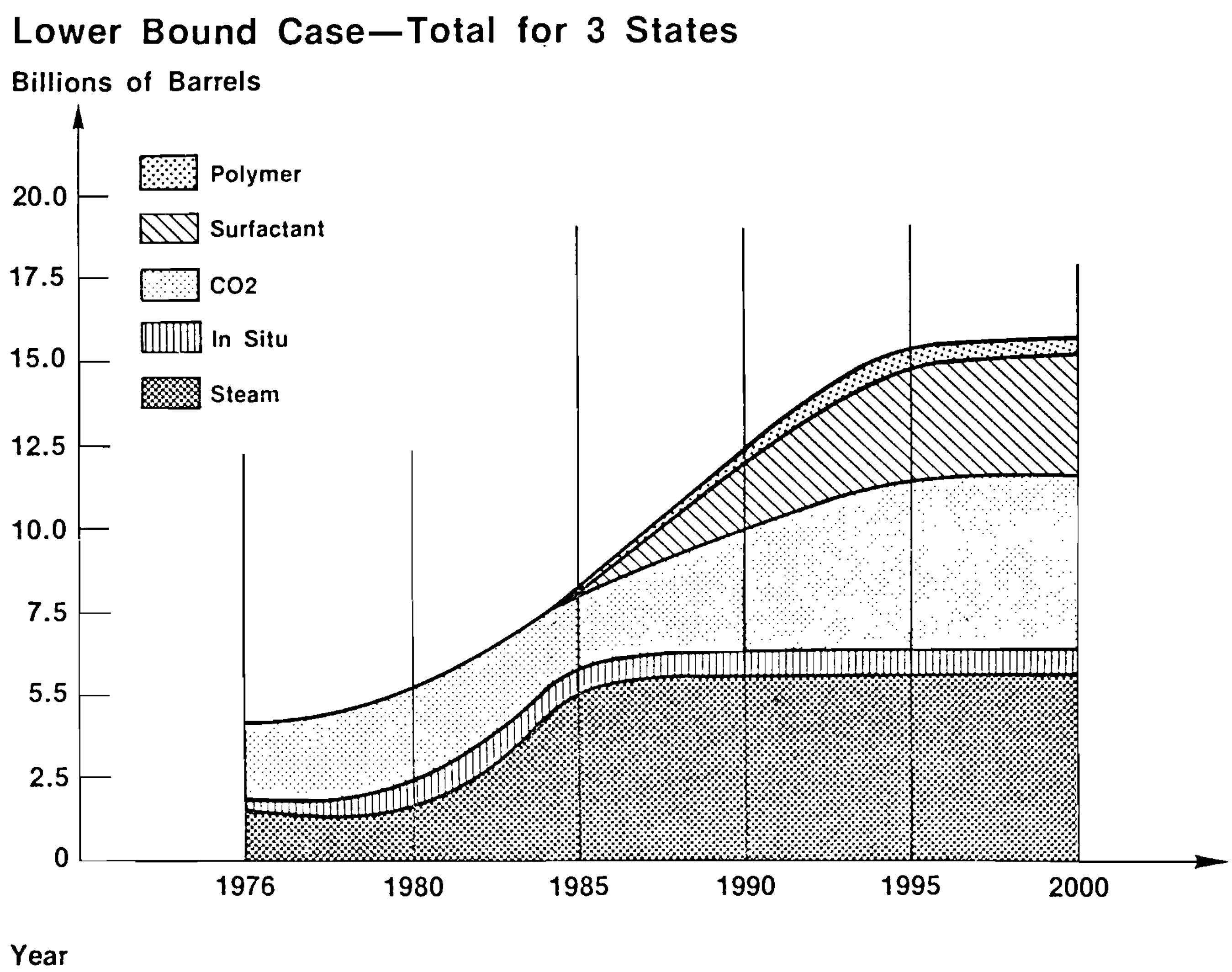


Figure 30-20.--Distribution of cumulative additions to proved reserves by tertiary recovery technique

TABLE 30-7.--Annual tertiary crude oil production

(Net production, 10^6 barrels/day)

	1976	1980	1985	1990	1995	2000
Base Case	0.2	0.4	0.4	0.3	0.3	0.2
Lower Bound	0.2	0.5	1.1	1.2	1.0	2.1
Upper Bound	0.2	0.7	2.0	3.0	3.8	3.6

Again, assuming no major shifts in R&D emphasis, for the most likely case, the lower bound, the timing and contribution of each tertiary technique is displayed in Table 30-8.

TABLE 30-8.--Annual tertiary crude oil production--lower bound case

(Net production, 10^6 barrels/day)

	1976	1980	1985	1990	1995	2000
1. Steam Drive	0.1	0.2	0.5	0.7	0.5	0.3
2. In Situ Combustion	*	0.1	0.1	0.1	*	*
3. CO_2 Miscible and Hydrocarbon Miscible[1]	0.1	0.2	0.4	0.3	0.2	0.7
4. Surfactant/Polymer	*	*	*	0.1	0.2	1.0
5. Polymer-Augmented Waterflooding	*	*	*	*	*	*
TOTAL	0.2	0.5	1.1	1.2	1.0	2.1

[1]Assumes that current hydrocarbon miscible projects will be converted to CO_2 miscible projects in the future.

*Less than 0.1; totals may not add due to rounding.

In 1990, of the 1.2×10^6 barrels per day attributable to EOR:

- Steam drive provides the bulk of the production, 700,000 barrels per day.
- CO_2 miscible remains relatively flat at 300,000 barrels per day.
- Surfactant/polymer only begins to make a contribution, at 100,000 barrels per day.

SUMMARY

In summary, we have three possible paths for the future:

- The bleak, or the base case, which represents a return to the economics of the 1960's, precluding much contribution from enhanced oil recovery.
- The reasonably attainable, or the lower bound case, which requires certain technological breakthroughs, and economics such as currently prevailing on the world market, but which will not be sufficient to replace declining production, and
- The upper bound case, which requires not only favorable economics, but also a high degree of cooperation between consumers and industry and government, as well as strong resource commitment to the emerging technology of EOR.

CHAPTER 31

TERTIARY RECOVERY OF CRUDE OIL

Chapman Cronquist[1]

INTRODUCTION

In the last 5 years, or so, as United States oil production capacity gradually peaked out and large waterfloods installed in west Texas in the 1950's approached economic limit, there has been accelerating activity towards developing "enhanced oil recovery" techniques to improve the recovery efficiency of oil from already developed reservoirs. The terms "enhanced oil recovery" (EOR) or "improved oil recovery" (IOR) refer to fluid injection processes for oil recovery other than conventional water or gas injection. The potential additional recovery from these processes is quite large, having been estimated at 18 to 36 x 10^9 barrels [21,22].

EOR activities have received unprecedented attention from all segments of the industry [10, 11, 14, 15, 21, 22, 32]. The Oil and Gas Journal has made the reported surveys of EOR activity every few years, with results of the first such survey being published in 1970 [1, 2, 38]. In its most recent survey, the Journal reported EOR activities in the United States increased from 132 projects in 1970 to 156 projects in 1975.

Most of this activity has involved teritiary recovery, i.e., processes capable of recovering additional oil from watered out reservoirs.

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TERMINOLOGY

The terminology of fluid injection processes for oil recovery is ambiguous and confusing. One regularly encounters terms like "assisted recovery," "supplemental recovery," "improved oil recovery," "enhanced recovery," "secondary recovery," or "tertiary recovery." In addition, there are terms used to describe processes, like surfactant flooding, microemulsion flooding, soluble oil flooding, micellar flooding, or trade names like MARAFLOOD [40] or UNIFLOOD [26].

Appendix A is a classification of fluid injection processes [22]. The terms "assisted" or "supplemental" oil recovery often are used interchangeably to describe any process in which additional energy or fluid is injected to augment natural reservoir energy. The terms "improved" or "enhanced" oil recovery often are used interchangeably and exclude conventional waterflooding or gas injection, as reflected by Appendix A.

Usage of the terms "secondary" and "tertiary" as applied to oil recovery methods is not consistent. As reflected by the discussion in Appendix B, the term "tertiary recovery" is here used for any process capable of recovering waterflood residual oil, whether or not it is the second or third fluid injection stage. The word "stage" will be used to identify process sequence where needed for clarity. Tertiary processes are identified with an asterisk in Appendix A and will be the subject of this paper.

CHARACTERISTICS

Most tertiary recovery processes currently are employed rather late in the secondary, i.e., waterflood stage and, thus, must operate at relatively high water-saturation and low oil-saturation. Both the reservoir mechanics and the economic consequences of this practice merit examination.

Reservoir

In areas already swept by water, additional oil, to be recovered, must be contacted, reconnected, mobilized, banked up, and displaced to wells where it must be produced at economic water/oil ratios (WOR). The need to contact significant volumes of residual oil means significant volumes of water must first be swept from the reservoir by the tertiary agent. The need for sweep efficiency can be met by adding polymers for mobility control in aqueous processes. The need has yet to be met in gaseous processes like carbon dioxide flooding.

Reconnecting and mobilizing residual oil requires greatly reducing or eliminating the capillary forces that trap oil during immiscible displacement [46]. Capillary forces, however, are beneficial to water encroachment in water wet rocks by causing inhibition of water into tighter parts of the reservoir. Capillary forces, which contribute to volumetric sweep during immiscible displacement, are greatly reduced or eliminated in tertiary processes. Because of this, volumetric sweep generally will be less efficient during tertiary than secondary (waterflood) recovery. As oil is banked up from a tertiary sweep, a certain amount of it is displaced toward producing wells. Some banked up oil, however, is displaced into reservoir volumes previously swept by water, that is, parts of the reservoir are resaturated with tertiary oil.

Economics

Certain economic aspects of tertiary recovery are a direct consequence of the reservoir mechanics of these processes. After the expense of installing or modifying existing facilities, the tertiary process must be started by injecting a slug of expensive material to reconnect and mobilize residual oil. This large initial expense is followed by a period of high WOR production with little, if any, income during a phase in which wells must be operated and water lifted and disposed. Tertiary oil, when produced, generally is produced along with substantial amounts of water, and artificial lift costs must be borne throughout project life. In addition, the technology of tertiary oil recovery is embryonic and not well understood. Performance predictions, therefore, carry a high degree of uncertainty. Risk of failure is high.

One might reasonably ask: "Why wait until the secondary stage is so far advanced before applying a tertiary process?"

"Why wait at all?" In part, the answer lies in the time-rate of recovery of incremental oil realized by applying more expensive tertiary processes. In soundly engineered waterfloods, reservoirs are operated at close to maximum efficient rate. Injection of an expensive fluid capable of tertiary recovery, instead of an inexpensive fluid like water, may increase ultimate recovery, but it will not generally result in an increase in current production rate. Thus, the large incremental expense required for tertiary recovery will not begin to be returned until effects of the increased ultimate recovery are manifested on the reservoir's productive capacity.

Aside from the economic point of view, related to the time value of expense and income, is the reservoir point of view, related to uncertainty about interwell fluid transmissibilities. With current interpretive procedures we are unable to quantify a reservoir's three dimensional characteristics with enough accuracy to predict reliably the reservoir's response to fluid injection. By observing reservoir response to injection of an inexpensive, but effective, displacing fluid like water we hope to learn enough about the reservoir's characteristics to better predict its response to more expensive tertiary fluids.

The ultimate goal in tertiary recovery, then, is to make a tradeoff between (a) the additional expense of learning more about a reservoir by prolonging secondary operation, and (b) the incremental present value by utilizing a more expensive, but more efficient, process.

PROCESSES

Tertiary processes, to have the capability of recovering additional oil from watered-out reservoirs, must have the capability of greatly reducing or eliminating the forces that cause oil to be trapped and retained in the reservoir. The problem, which has been discussed by numerous authors [46], basically is one of reducing or eliminating the oil-water interfacial tension forces which lead to capillary trapping during immiscible displacement, e.g., during water encroachment.

As noted in Appendix A, all the miscible processes are potential tertiary processes, as are in situ combustion and steam drive. The reservoir mechanics of these processes have been discussed extensively in the literature [20, 29, 30, 32, 37, 44].

Under current, and probable future economic conditions in the United States miscible slug and gas drive processes utilizing hydrocarbon fluids are not economically viable. Recent efforts for tertiary recovery of light oils have involved carbon-dioxide miscible flooding and surfactant flooding. Both of these processes enjoy a reasonably favorable net energy yield [3]. There have been a number of tests reported on steam displacement [23, 47] and in situ combustion for tertiary recovery [5, 35, 39], but results have been mixed, and a clear picture has not emerged.

Carbon Dioxide

The efficacy of carbon dioxide as an oil-recovery agent has been known for a long time. Recently it has become apparent that, under proper conditions, carbon dioxide would, when injected into an oil-bearing porous medium, develop miscibility with light oil (above 30° API) by successively vaporizing the lighter fractions of the reservoir oil, in a manner analogous to the high-pressure gas-drive process [29, 43]. There is disagreement, however, as to range of the lower fractions involved and as to effects of materials like methane and nitrogen on the miscibility process [29].

Nevertheless, several large projects have begun in the United States involving carbon dioxide injection [9, 30]. In some of these projects the carbon dioxide is being injected in the secondary stage; in others it is being used in the tertiary stage. Sufficient data, both laboratory and field, have been reported to indicate clearly that carbon dioxide will recover additional oil from waterflooded reservoirs [31].

Surfactants

Literature and patents on the use of surfactants to improve oil recovery efficiency from waterflooding go back over 50 years.

One of the major problems which has precluded widespread field usage is adsorption of surfactant within the reservoir. One modern approach to this problem involves use of various combinations of salts and surfactants to minimize adsorption within the reservoir, while at the same time minimizing interfacial tension between oil and water.

Numerous methods have been investigated to utilize surfactant in oil recovery [12, 19, 25, 26]. Two general methods have emerged. One method involves use of fairly high concentrations of surfactant, generally greater than 4 percent, in a small pore-volume slug, generally 0.04 to 0.07 reservoir pore-volume. The other method uses a fairly low concentration of surfactant, generally less than 4 percent, in a large pore-volume slug, generally greater than 0.25 pore-volume. In the former category are processes developed by Marathon (MARAFLOOD) and by Union Oil of California (UNIFLOOD). In the latter category are processes developed by Conoco, Exxon, Mobil, and Shell. Table 31-1 is a summary of the characteristics of the reservoirs in which company tests of surfactant processes have been carried out. This table is by no means all inclusive but includes surfactant projects for which there have been reasonably detailed articles published, which give geologic, engineering, and performance data.

In addition to those processes where surfactants are injected into the reservoir are those where surfactant-like materials are generated in situ. The latter are based on the observation that certain crude oils which contain naturally-occurring organic acids react with alkaline waters to generate soaps or surfactant-like materials at the interface. These processes, called alkaline or caustic flooding, have been discussed in the literature [4, 33], and a number of field tests have been reported. Overall activity, however, is at a fairly low level compared to other processes.

FIELD EXPERIENCE

A great deal of money and effort has been expended by the industry on laboratory research and field testing of EOR processes, a great deal of which has been on tertiary processes.

TABLE 31-1.--Surfactant flooding field tests--summary of reservoir characterics

Operator	Reservoir or formation[1]	Age	Depth (ft)	Temp (^{o}F)	Salinity (ppm chloride)	Porosity (fraction)	Permeability (md)	Ref
Conoco	Second Wall Creek	Cretaceous	3,050	120	3,000	.19	50	[16]
Exxon	Frio	Oligocene	5,100	165	20,000	.21	430	[41]
	Weiler	Mississippian	1,460	75	64,000	.21	100	[42]
Marathon	Robinson	Pennsylvanian	1,000	65	10,000	.20	200	[20]
Texaco/ Mobil	Benoist	Mississippian	1,750	80	39,000	.15	90	[48]
Pennzoil	Bradford	Devonian	1,860	68	4,500	.18	80	[8]
Shell	Tar Springs	Mississippian	2,100	95	75,000[2]	.17	70	[13]
Union	Bluff Creek	Permian	1,870	95	54,000	.23	500	[34]

[1] All tests in sandstones.

[2] Total dissolved solids.

Projects

There are tertiary projects currently operational in the United States which are larger than those described here. Projects reported here, however, are those in which waterflood residual oil clearly has been reconnected, mobilized, banked up, displaced, and produced in significant volumes. As carbon dioxide flooding and surfactant flooding are receiving a great deal of attention, a significant field test of each is discussed briefly.

Little Creek*

In late 1973 Shell Oil Company began a tertiary miscible carbon dioxide pilot program in the Little Creek Field [45]. This field is located in a deep Cretaceous sandstone trend of the Mississippi salt dome basin in southeastern United States.

The Denkman sand, at a depth of 10,700 feet, is the only reservoir in this low relief field [6]. This reservoir, a stratigraphic trap, consists of alluvial point bar deposits with an average net thickness of 30 feet. Average porosity and permeability are 0.234 and 65 millidarcies, respectively.

This reservoir, which originally contained 102×10^6 stock tank barrels of 39^o API oil, had been successfully waterflooded prior to the initiation of tertiary operations. Oil remaining in the reservoir at the conclusion of waterflood operations was estimated to be 55×10^6 stock tank barrels, with an average saturation of 0.21.

The tertiary miscible pilot is utilizing the existing 40-acre spaced wells. Initially, the test involved three production wells and one injection well in a quarter of an inverted 9-spot pattern. The pilot area is confined by a shale-out on two sides and by water injection on the other sides.

Carbon dioxide has been injected at about 3×10^6 ft^3 per day at a well-head injection pressure of about 2,500 psi. This

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*Shell Oil Company has made no public disclosure on this project other than in the references cited. In addition to these sources, information was compiled by the author from records of the Mississippi Oil and Gas Board and other reliable sources.

has provided a reservoir pressure of over 5,000 psi in the pilot area which is required to develop miscibility with the waterflood residual oil.

Initially, production from the pilot was 100 percent water [36], as expected. Teriary oil production first was observed in the west offset from the injector well about 3 months after carbon dioxide injection began. About 3 months later the other two production wells began producing tertiary oil.

Gas-oil ratio and oil production response has varied significantly among the three producing wells, probably due to the directional permeability effects. By the end of 1975 total oil production from the three pilot producers had increased to about 200 barrels per day, and producing water-oil ratios had decreased gradually to about 6:1. By year-end 1975, producing carbon dioxide-oil ratios in the pilot area had reached an average of 20,000 cubic feet per barrel [36].

Operational problems have been relatively minor, except for sporadic paraffin and asphaltine plugging of tubulars, wellhead, and flowlines. This was not observed during waterflood operations, and it seems apparent that selective fractionation of the produced oil by carbon dioxide may be the cause. Sand production, noted during the waterflood also, has caused some production difficulties. Except for minor start-up problems and supply logistics, carbon dioxide injection has proceeded with no major difficulty.

It is too early to make a reliable estimate of the response of a full-scale expansion of this project. Total tertiary oil recovery through the first quarter of 1976 was 80,000 barrels. The operator reports the project as ". . .promising. . ." [38]. From a technical point of view, one cannot help but be encouraged by the ability of the tertiary miscible carbon dioxide process to mobilize waterflood-trapped residual oil and generate a producible oil bank.

Robinson Area

Beginning in 1962, Marathon Oil Company, one of the pioneers in microemulsion flooding, has conducted a series of field tests of their MARAFLOOD process in the shallow (1,000 ft) Pennsylvanian fluvial sandstones in the Illinois basin of north-central United States [18, 40]. In addition, tests more recently have been run jointly with Pennzoil in the somewhat deeper (1,800 ft) Devonian sandstones in the Bradford Field in the Appalachian basin of eastern United States [8]. Discussion here will center on results of Marathon's activities in the Robinson sands, which have been extensively reported in the literature [20].

The Robinson sandstones appear to be alluvial point bar deposits which often are as much as 50 feet thick [24]. Although the Robinson sandstones are fairly widespread, individual sandstone bodies seldom are continuous laterally for more than a mile or two and from numerous separate reservoirs. Porosity of these sands ranges from about 0.16 to 0.22 and averages 0.20. Permeabilities range from about 10 to 600 millidarcies and average 300 millidarcies in the better areas. Diagenetic effects are minimal, and reservoir properties are controlled essentially by depositional conditions.

Original oil in place in these sands was about 1,150 barrels per acre/foot. The area has been extensively waterflooded, generally on 10 acre spacing. Waterflood recoveries are about 180, and primary recoveries about 300 barrels per acre/foot [40].

As described previously, the MARAFLOOD process utilizes a high surfactant concentration to make a microemulsion slug [19]. About 4 to 7 percent reservoir pore volume of slug is injected for tertiary recovery. The microemulsion slug is followed by about 0.5 to 1.0 pore volume of graded-viscosity mobility-buffer [17], which is displaced by 0.5 to 1.0 pore volume of water.

Continued improvements have been made in the process, and some 20 field tests have been conducted. Initially, the microemulsions were low water-content systems, but more recent tests utilize higher water-content slugs.

For their process in the Robinson sandstones Marathon estimates tertiary recoveries at about 45 percent of the oil remaining in place after waterflood, or about 290 barrels per acre/foot [40]. It is estimated that a full-scale (6,000 acre) MARAFLOOD on 2.5 acre spacing in the Robinson area would require an investment in wells, facilities, and chemicals of $\$260 \times 10^6$ (1975 costs). Operating expenses over a project life about 14 years are estimated at $\$50 \times 10^6$. Such a project would be expected to develop about 30×10^6 barrels of tertiary oil reserves [20]. From these figures it is apparent that the wellhead price of oil must be in the range of $15 per barrel or more for this to be an acceptable venture and return the operator a reasonable rate of return.

In arriving at its published cost and production estimates, Marathon has had the benefit of years of extensive testing of its process in the Robinson sands. One cannot reasonably expect that every operator will have this wealth of experience on each process taken to the field for testing.

As noted previously, however, economics of tertiary projects are quite sensitive to both project length and recovery volume. Plotted on Fig. 31-1 are several curves computed by assuming several perturbations on Marathon's published "base case" for its MARAFLOOD in the Robinson area [7]. Assumptions used to calculate each curve are summarized in Table 31-2.

The range of recoveries and production periods in Table 31-2 is within those commonly observed in field testing. As reflected by Fig. 31-1 the impact of these variations on discounted cost per discounted net barrel is quite severe.

Results

Certainly not all EOR experience is embodied in field tests like those described above, although ultimately that is where the technology and economics must be made to work. It is apparent from both field and laboratory experience to date, despite the expenditure of many millions of dollars, that tertiary recovery technology is embryonic compared to problems yet to be solved. For example, the target of tertiary processes is residual oil. Yet, we have only imprecise methods to quantify its saturation and its three-dimensional distribution in a reservoir. The aggregate reservoir rock-fluid system must be processed by relatively small volumes of complex and expensive fluids. Yet, we are only beginning to understand the relationships between

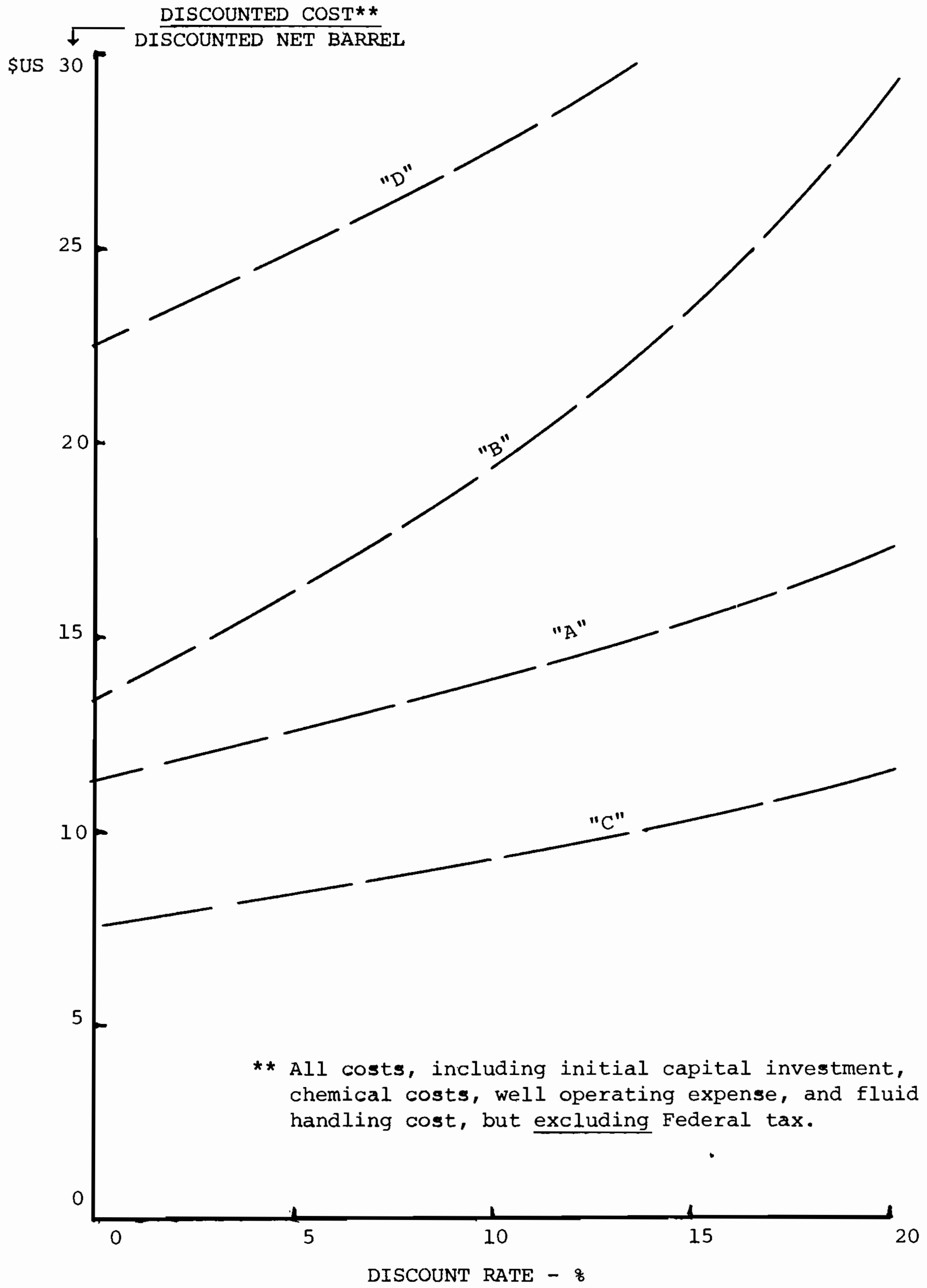

Figure 31-1.--Hypothetical "Maraflood" in Robinson area, Illinois (refer to Table 31-2 and text)

TABLE 31-2.--"MARAFLOOD" in Illinois--base case and perturbations

Curve	Recovery (bbls/AF)	Production period (years)	Comments
"A"	242	4	Based on data published by W. B. Gogarty in the January 1976 Journal of Petroleum Technology, pages 93 through 102, [20].*
"B"	242	8	Oil recovery assumed to take twice as long as "A," i.e., transmissibility one half that of "A." Field and unit costs the same as "A," but wells operated twice as long.
"C"	363	4	Oil recovery assumed to be 50 percent more than "A." No change in field and unit costs.
"D"	121	4	Oil recovery assumed to be 50 percent less than "A." No change in field and unit costs.

*Please refer to Table 31-1--Summary of reservoir characteristics.

reservoir sedimentology, diagenesis, petrofabrics, and rock chemistry. We need to understand these relationships so we can understand the physical and chemical response of tertiary fluids to this environment and to forces imposed on these fluids as we attempt to process the reservoir rock-fluid system.

ANALYSIS METHODOLOGY

Over the last 40 years or so, as waterflooding has become the principal method of secondary recovery, a comprehensive body of theoretical and practical knowledge has been accumulated and put to work in predicting probable response of specific reservoirs to water injection [32, 44]. Tertiary recovery, however, is still new and is much more complex than waterflooding. A comparable body of knowledge has yet to be accumulated.

Field tests of tertiary processes tend to be reservoir specific [20, 27]. It would be desirable, however, if results of a field test of a tertiary process in a specific reservoir could be extrapolated to other reservoirs. A relatively simple methodology to account for "first order" performance parameters could be useful. As reservoir performance data from field tests are related to rock-fluid properties, this methodology can be updated and refined.

As discussed previously, the performance of fluid displacement processes in porous media can be described by a plot of cumulative pore volumes recovered versus cumulative pore volumes injected. This type of plot is used widely in petroleum reservoir engineering literature. The shape of this kind of plot for a specific process in a specific reservoir is controlled by the factors which govern recovery efficiency for that process in that reservoir. There has been enough experience with this kind of plot, however, that given results from one test, one might be able to make qualitative judgments about relative effects of recovery of mobility ratio, reservoir heterogeneity, volumetric sweep, and displacement efficiency. A methodology incorporating this kind of plot with five spot injectivity relations is developed in Appendix C.

CONCLUSIONS

It is apparent that tertiary recovery technology still is in an early developmental stage. The physical chemistry, the fluid dynamics, and the operating problems associated with these processes are an order of magnitude more complex than those of conventional supplemental recovery processes. Scaling laws for extrapolation of pilot results to full scale projects have not yet been developed. Field test results of these processes are highly reservoir specific, and extrapolation of results to other reservoirs is extremely speculative. There is not yet an established technology for tertiary processes. Economic projections, therefore, must be considered accordingly and viewed with extreme caution.

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APPENDIX A#

CLASSIFICATION OF FLUID INJECTION PROCESSES FOR OIL RECOVERY

A. IMMISCIBLE PROCESSES
   1. Waterflood (injection of water)
   2. Gas Injection (injection of natural gas)

SECONDARY RECOVERY

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   3. Polymer Flood (injected with waterflood for mobility control)
   4. Foam Injection (injected with gas for mobility control)

*B. MISCIBLE PROCESSES (water driven or gas driven)
   1. Miscible Slug (liquid solvent--first contact miscibility processes)
   2. Miscible Gas Drive (with or without alternating gas-water injection for mobility control--multiple contact miscibility processes)
      a. Vaporizing (high-pressure natural gas, carbon dioxide, flue gas, nitrogen, etc.)
      b. Condensing (natural gas enriched with propane or butane, etc.)
   3. Surfactant Flooding (may not be truly "miscible" in scientific sense)
      a. High Surfactant Concentration (micellar, microemulsion, or miscible water flooding)
         .. Oil external (soluble oil flooding)
         .. Water external
      b. Low Surfactant Concentration (low tension waterflooding)
   4. Alkaline Waterflooding (not truly "miscible"--generates surfactants in situ by reacting with acidic crudes)

C. THERMAL PROCESSES
  *1. In Situ Combustion
      a. Forward Combustion
         .. Dry combustion
         .. Quenched combustion
      b. Reverse Combustion
   2. Heat Injection
      a. Downhole Heating
      b. Hot Fluid Injection
         .. Hot water drive
         .. Steam drive
      c. Cyclic Steam Stimulation (huff-and-puff)

ENHANCED RECOVERY

#Revised from GURC Report 148 (1976), Table 4 [22].
*Potential "tertiary" process (please see text).

APPENDIX B

As shown by Fig. 31-2, two stages can be identified in injection-recovery processes, "secondary" and "tertiary." For the purpose of this discussion we consider the secondary stage to include fluid injection processes designed to supplement natural reservoir energy. To be semantically consistent, one would consider the tertiary stage to include fluid injection processes designed to supplement the secondary stage. Industry use of the term "tertiary," however, includes fluid injection processes designed to recover oil potentially remaining after waterflood, whether or not the waterflood was "primary" or "secondary." The term "tertiary" is used here in this sense. Because most of the current interest in EOR technology is directed towards tertiary processes that part of the curve is examined in more detail.

As shown by Fig. 31-3, the axes of the graph may be shifted so the "tertiary" part of the curve passes through the origin. Cumulative volumes injected and recovered, then, become those volumes injected and recovered during the "tertiary" stage.

As tertiary processes generally are started fairly late in the "secondary" stage, a curve of pore volumes recovered for the tertiary stage typically is "S" shaped, or sigmoid.

In a waterflooded reservoir close to residual oil saturation, typically the case, the interval between the sigmoid curve and the material balance line represents water production.

As identified in Fig. 31-3, three production periods can be identified for tertiary processes started under post-waterflood saturation conditions:

(a) a period prior to arrival of the tertiary oil bank which is characterized by high producing water-oil-ratios (WOR), typically greater than 20:1.

(b) a period during which the tertiary oil "bank" arrives at the producing wells and is produced at lower WOR, typically no lower than about 3:1.

(c) a period after production of the oil "bank" during which the WOR gradually increases to the economic limit.

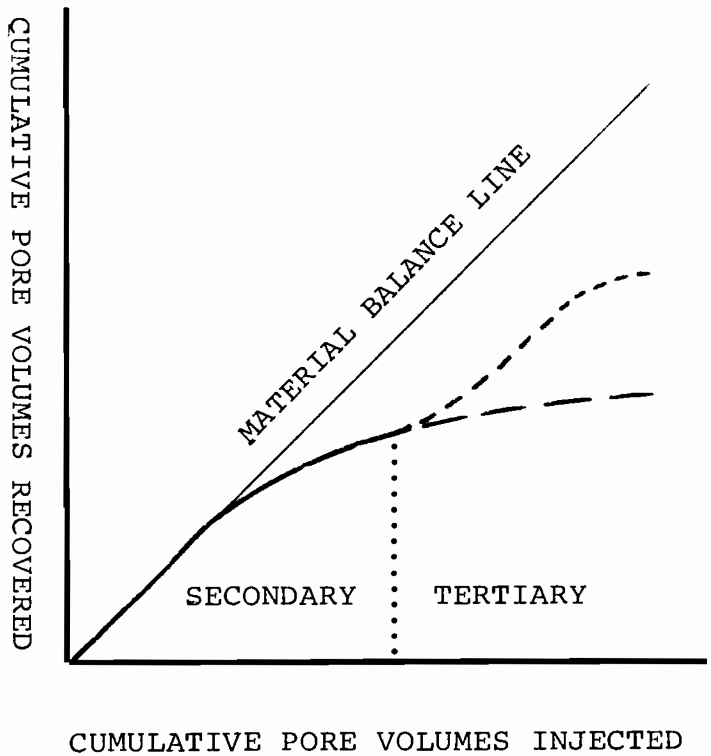

Figure 31-2.--Secondary and tertiary fluid injection stages

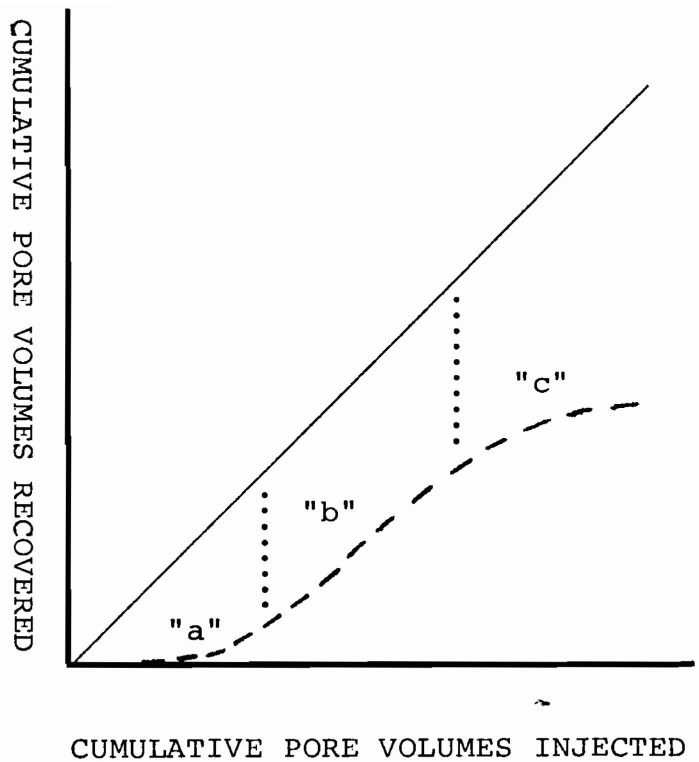

Figure 31-3.--Tertiary fluid injection stage

APPENDIX C

ANALYSIS METHODOLOGY

It is useful to characterize EOR process performance with cumulative pore volume curves as discussed in Appendix B. Economic viability of these processes, however, is governed by the time-rate of recovery of oil versus the time-rate of expense required to recover this oil. A procedure is needed to convert pore volumes to barrels and to relate these barrels to time.

Referring to the first quadrant of Fig. 31-4, reservoir barrels of pore space in a rock volume of area, A thickness, h, and porosity, Ø, are numerically equal to 7,758 Ø Ah, where 7,758 converts from acre-feet to 42 gallon barrels. Stock tank barrels of oil and water in this pore volume are:

$$\text{oil} = N_r = 7758 \emptyset Ah\ S_{or}/B_{or} \qquad \text{C-1a}$$

$$\text{water} = W = 7758 \emptyset Ah\ S_w/B_w \qquad \text{C-1b}$$

where S_{or} and S_w are the fractions of the pore space filled with oil and water, respectively. The terms B_{or} and B_w are the ratio of reservoir volume to stock tank volume for oil and water, respectively. Assuming a liquid filled (gas free) system, $S_{or} + S_w = 1$, and stock tank barrels of total liquids (oil plus water) is:

$$N_r + W = 7758 \emptyset Ah \left\{ \frac{S_{or}}{B_{or}} + \frac{1 - S_{or}}{B_w} \right\} \qquad \text{C-2}$$

In many cases of interest the formation volume factors (B_{or} and B_w) are approximately 1.0, and in a gas free system Equation C-2 reduces to:

$$N_r + W = 7758 \emptyset Ah \qquad \text{C-3}$$

The usual convention in oil recovery technology is to express oil recovery efficiency of a fluid injection process in

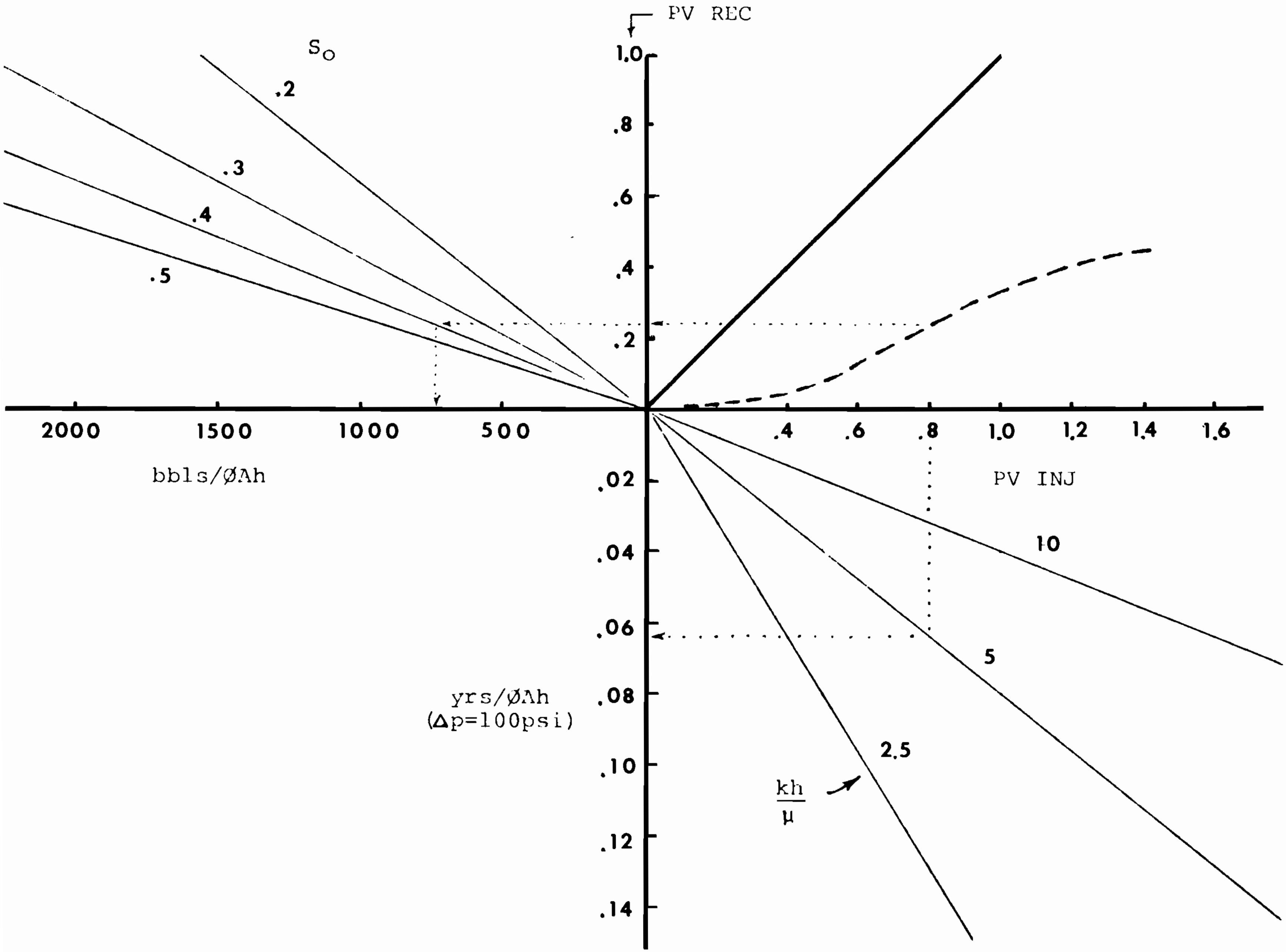

Figure 31-4.--Time-rate oil-recovery nomograph

terms of the volumes of oil in place at process initiation N_r. As noted previously, the fraction of the total pore volume saturated with oil at process initiation is S_{or}. Fractional pore volume oil recovery is, thus:

$$\frac{N_P}{N_r} = \frac{N_P/S_{or}}{7758\phi Ah} \qquad \text{C-4}$$

The oil saturation factor is introduced in the fourth quadrant of Fig. 31-4.

Cumulative pore volumes injected into a reservoir pattern element can be time related by use of the five-spot injectivity relation [44]:

$$q = \frac{Kh}{\mu} \left[\frac{3.54}{\ln\left(\frac{d}{r_w}\right) - .619}\right] \Delta P \qquad (B/D) \qquad \text{C-5}$$

where the units are B/D, darcies, feet, centipoise, and psi. As there are 7,758 barrels in a acre-foot, by introducing appropriate constants and inverting, Equation C-5 can be rearranged to solve for years to inject an acre-foot of pore space:

$$1/q = \frac{6\mu\ (\ln \frac{d}{r_w} - .619)}{kh\Delta p} \qquad (yrs/AF) \qquad \text{C-6}$$

Over commonly used well spacing, variation of the term in $\frac{d}{r_w}$ is negligible compared to variation in the other terms. The term in parentheses is approximately 6.6, and Equation C-6 simplifies to:

$$1/q = \frac{.40\mu}{kh\Delta p} \qquad \text{C-7}$$

which is the time in years required to inject an acre-foot (7,758 reservoir barrels) of liquid of 1 centipoise into a 1 darcy-foot reservoir with 100 psi pressure differential between injection and production wells.

The dotted line in Fig. 31-4 illustrates usage of this nomograph. With a 100 psi pressure differential, the time to inject 0.8 pore volume using a process in a reservoir with an effective transmissibility of 5.0 darcy-feet per centipoise is 0.064 years per acre-foot of porosity. If the reservoir is processed on 5-acre patterns and has an average of 20 net feet of pay and porosity of 0.25, this would require 1.6 years (0.064 x 5 x 20 x 0.25). At the end of this time cumulative oil recovery would be 0.24 pore volumes. If the reservoir had a residual oil saturation of 0.40 at process initiation, recovery would be 745 barrels of oil per acre-foot of pore volume in the pattern, or 18,625 barrels.

CHAPTER 32

A SYSTEMATIC APPROACH TO THE ASSESSMENT OF A NATION'S OIL SUPPLY ADDITIONS THROUGH ENHANCED RECOVERY METHODS

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INTRODUCTION

More efficient extraction of petroleum from the reservoirs of the world is of considerable importance and the problem has been addressed by research organizations for several decades. Several processes have the potential to produce oil and the literature is replete with reports pertaining to the technology of these enhanced recovery processes [1, 2, 3, 4]. (The cited references provide excellent reviews.) From the standpoint of a national oil supply, however, the primary concern is the contribution that enhanced recovery can make to the nation's oil reserves. Unfortunately, a high risk is involved in any a priori predictions of future reserves owing to the uncertainty in the success of the application of these recovery methods. Nevertheless, estimates of the potential enhanced oil reserves are necessary for national planning with regard to future oil supply and demand.

The problem can be illustrated by referring to the estimates of the potential contribution of enhanced recovery to the oil supply of the United States. The remaining oil in United States reservoirs after conventional primary and secondary recovery will be almost 300 billion barrels--a large target. The

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several estimates of potential contributions that have been made range from 5 to 100 x 10^9 barrels [5, 6, 7, 8, 9, 10, 11] or from less than 2 percent to about one-third of the remaining oil. These differences no doubt reflect differing opinions with regard to the uncertainties of the technical applicability and success of the enhanced recovery processes as well as differing views on cost constraints and the anticipated economic environment.

Several factors contribute to the uncertainties. There are uncertainties in the process technology, per se, and there are uncertainties in the application to specific reservoirs. There are questions about the displacement efficiency and volumetric conformance, oil saturation, reservoir characterization, and corrosion and well completion problems. In measuring success, however, the significant factors are the oil-in-place, the fraction of it that is produced, and the cost to produce it.

The uncertainties and the risks involved in applying these processes suggest that their application should be viewed in much the same way that exploration is viewed by exploration economists. In this way, enhanced oil reserves and costs could be estimated probabilistically, utilizing probability concepts that are commonly used in exploration economics [12, 13]. The purpose of this paper is to demonstrate how these concepts can be used to estimate enhanced oil reserves resulting from the application of enhanced recovery techniques. To do this we view the development of enhanced oil reserves as occurring in four sequential steps, each of which results in a reduction in the uncertainty but at a cost in both time and money. These steps are prospect screening, pre-pilot evaluation, the field pilot test, and the commercial venture decision. This development of reserves is illustrated by using one reservoir from a hypothetical national group of reservoirs as an example and subjecting it to analysis in each of these phases.

Prospect screening results in the initial decision as to whether to pursue enhanced recovery in a particular reservoir. The objective is to determine if the reservoir is suitable for any available technology and to make preliminary selections of appropriate recovery processes. For the most part the decisions are made on the basis of available information and, as a result, this phase is relatively cheap in dollars. The pre-pilot evaluation is a reservoir study to determine whether to continue to the field pilot test or to terminate further consideration. This is a more costly process than prospect screening, but it results in additional information and a better judgment regarding both the selection of the appropriate recovery process and the likelihood of its successful application. Ultimately, the decision to proceed with a commercial venture is based on information obtained from the field pilot test. During this test the actual performance of the process can be observed and estimates of oil recovery and costs can be made. With the exception of the commercial project, this is the most costly step in the development of enhanced oil reserves, but it also generates the most critical information.

In our hypothetical situation, we have used costs that are intended for example only, and we have ignored the influence of taxes, the time value of money, and DCF considerations, for these may vary depending upon local circumstances. As a result, the costs will not reflect actual costs for the specific application of these recovery processes and no extrapolation of these costs to specific situations should be made.

The analysis we present involves screening each oil reservoir in a nation's inventory. In countries such as the United States, where large numbers of reservoirs exist, this would be a considerable task that may be more amenable to treatment on a geographical or corporate basis. In smaller countries, or those with relatively few reservoirs, the job is more tractable.

PHASE 1 - PROSPECT SCREENING

The enhanced oil recovery gross base of a nation is a summation of the gross base of the individual reservoirs, each of which has different characteristics. This gross base is the oil remaining after conventional primary and secondary recovery techniques have been utilized. As a result of the different characteristics of the reservoirs, the gross base will represent varying fractions of the original oil-in-place for each reservoir.

For illustrative purposes consider the inventory of reservoirs listed in Table 32-1 and assume that these represent the total reservoirs of a nation. The apparent recovery by conventional techniques varies from zero to 65 percent and reflects differences in the character of the oil and rock and differences in the producing mechanisms. The remaining oil per reservoir varies from 76 to 640 x 10^6 stock tank barrels and the sum of these, which is the enhanced recovery gross resource base, is 1.274 x 10^9 stock tank barrels. These data are shown graphically in Fig. 32-1.

The first phase of the process of reducing the gross resources to enhanced oil reserves is prospect screening. During this phase all available information about each specific reservoir is analyzed. The data examined will include production and injection histories, well records, geology, reservoir and fluid properties, material, equipment and fuel requirements, and logistics. Particular questions of interest are:

1. What were the primary and secondary producing mechanisms? How effective was each at recovering oil? What evidence is there of directional permeability or preferential flow patterns? Is there a gas cap or bottom water?

2. What is the condition of the wells? Are there multiple completions? What workovers might be required? Are new wells needed?

3. What does the geology tell us? Are the reservoirs channel sands? Faulted? Is there much structure?

4. What are the reservoir properties? Is it sandstone or dolomite? Much clay? What types? What are the porosity and permeability? How heterogeneous is the reservoir? What is the depth, thickness, pressure, temperature?

5. What are the fluid properties? What is the specific gravity and viscosity of the oil? Any H_2S? What is the salinity and hardness of the interstitial water?

6. Is fuel or electricity readily available for compressors, pumps? What is the availability of needed chemicals?

On the basis of this survey, preliminary judgments are made regarding the possible enhanced recovery processes that might be

TABLE 32-1.--National oil reservoir inventory

(10^6 barrels)

Reservoir	Original oil-in-place	Ultimate conventional recovery	Remaining oil-in-place	Oil gravity (°API)
A	117	41	76	35
B	500	200	300	37
C	188	28	160	13
D	640	0	640	5
E	280	182	98	42
	Σ 1,725	451	1,274	

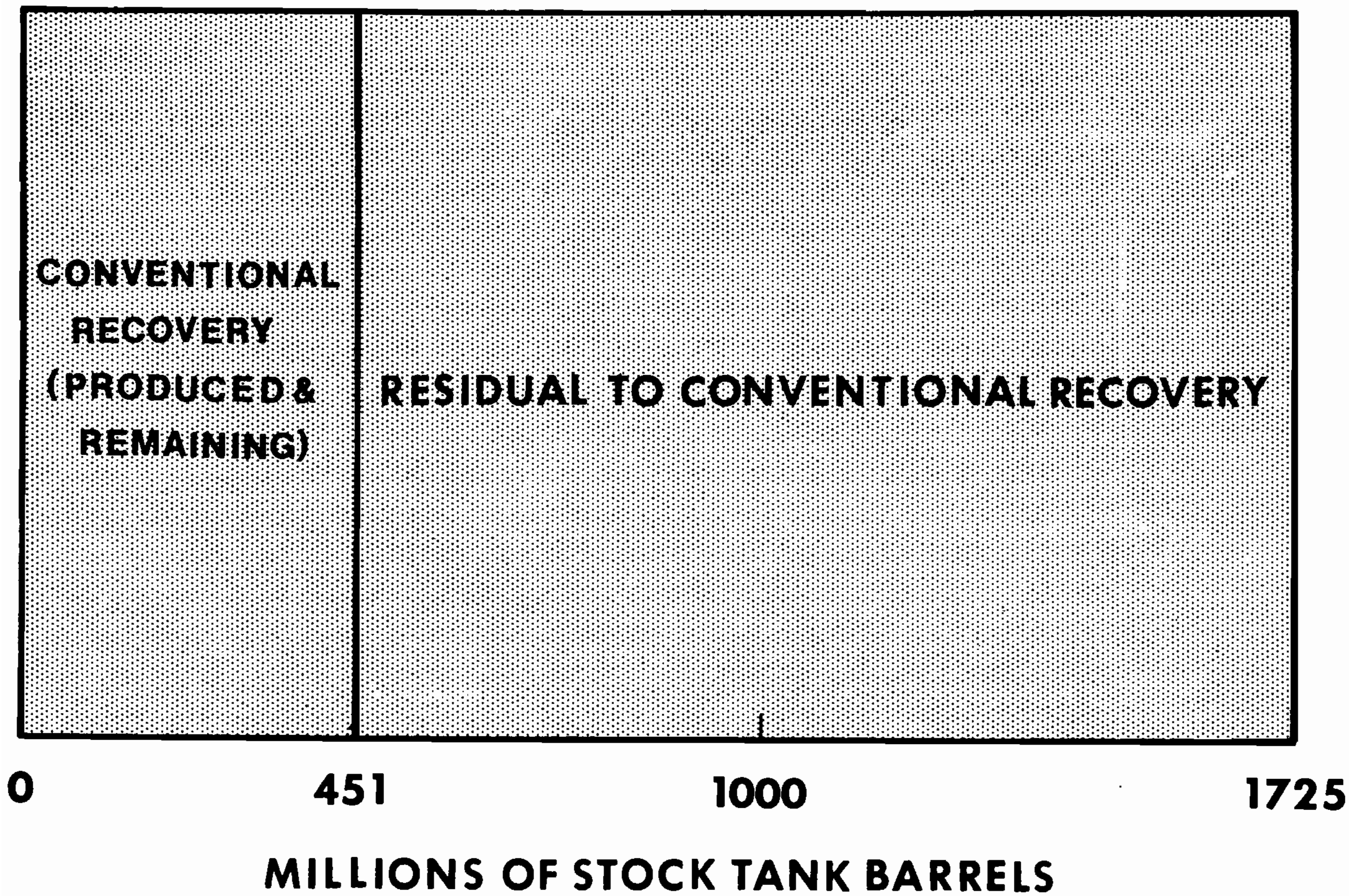


Figure 32-1.--National enhanced recovery gross resource base

used and the effectiveness of each. Finally, some laboratory work is done involving displacement tests in cores and mathematical model studies. From these results, the most likely process is selected and estimates are made of its recovery efficiency.

At this point the two major uncertainties to enhanced oil recovery are the oil-in-place and the recovery factor for the enhanced recovery process. Accordingly, these two factors are treated probabilistically. A low, a most likely, and a high value for the oil-in-place are developed and probabilities for each are assigned. These are judgments based on the prospect screening results. Similarly, the most likely and two additional estimates are developed for the recovery factor and probabilities are assigned. From these the first estimate of the frequency distribution of enhanced oil reserves can be made.

The frequency distribution of the enhanced oil reserves is obtained as follows. Using reservoir A as an example and referring to Table 32-1, note that the most likely oil-in-place value is 76×10^6 barrels. Based on information obtained during prospect screening, it was estimated that there is a one in four chance that the oil-in-place might be as low as 67×10^6 barrels and a one in seven chance that is as high as 86×10^6 barrels. Similarly, the recovery factor for the selected recovery process, a micellar flood, has been assigned a most likely value of 0.50 with a probability of 40 percent, and high and low values of 0.62 and 0.40, with probabilities of their occurrence of 30 percent each. These data are summarized in Table 32-2.

Note that our judgment, based on the prospect screening, results in a frequency distribution, namely, the most likely, high and low values, and their assigned probabilities [12]. This frequency distributuion converts into the triangular probability distribution shown in Table 32-2, where the 3 values, shown as circles, no longer represent the lowest or highest possible values. For example, we assigned probabilities to oil-in-place values of 67, 76, and 86×10^6 barrels. When these three points are placed in triangular distribution, the minimum point becomes 60×10^6 barrels and the maximum point 88×10^6 barrels. These points on the X-axis are absolute and represent minimum and maximum possible

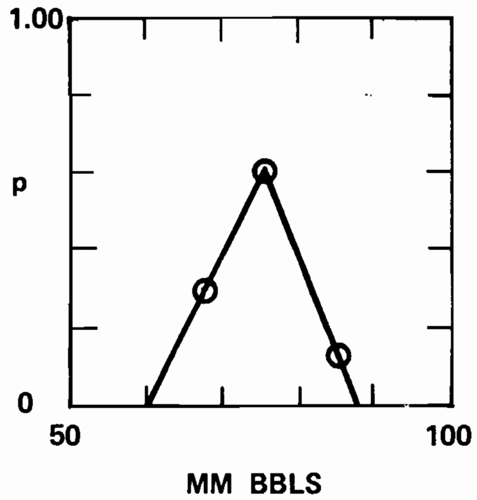
TABLE 32-2.--Reservoir A--Frequency and probability distributions for oil-in-place and recovery factor after phase 1

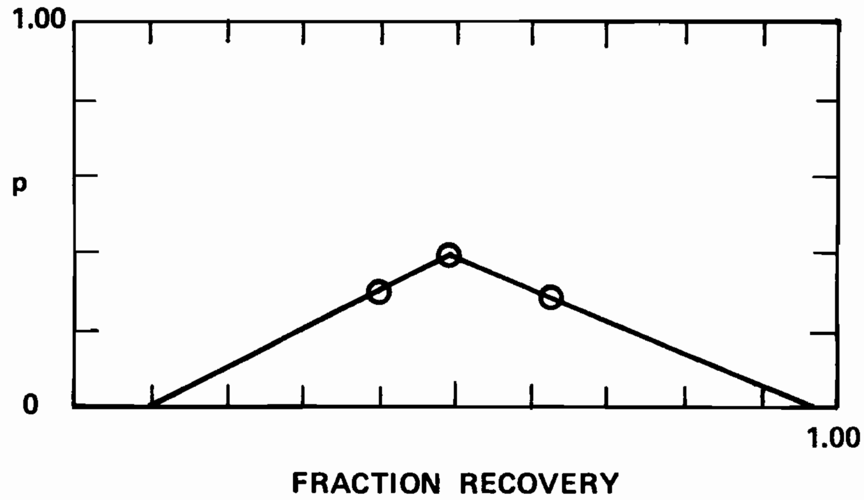
OIL-IN-PLACE

STOCK TANK BARRELS	p ( )
67×10^6	0.25
76×10^6	0.60
86×10^6	0.15

ENHANCED OIL RECOVERY FACTOR

FRACTION OF OIL-IN-PLACE	p ( )
0.40	0.3
0.50	0.4
0.62	0.3





values. Similarly, the possible values for the recovery factor range between a minimum of 0.10 and a maximum of 0.98.

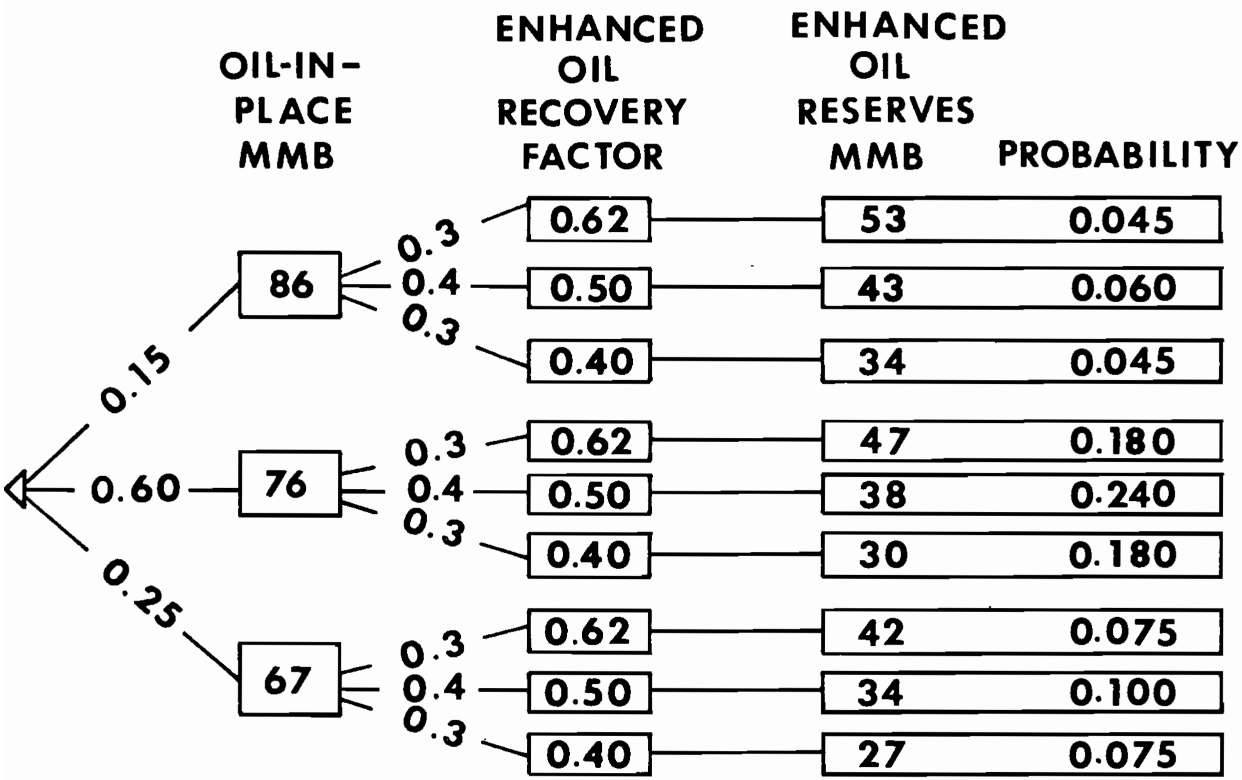
These two frequency distributions are now worked into a probability-tree diagram to determine the cumulative frequency distribution for the enhanced oil reserves. This is shown for reservoir A in Fig. 32-2.

Note that after the prospect screening phase for reservoir A, the expected value for the enhanced oil reserves is 38 x 10^6 barrels, with a variance of 56 x 10^6 barrels and a standard deviation of 7.5 x 10^6 barrels. The corresponding frequency distribution from Fig. 32-2 is plotted as a solid line in Fig. 32-3 and represents our first estimate for reservoir A.

The other reservoirs from our initial inventory are treated in a similar manner. The triangular probability distributions for all the oil-in-place and recovery factor data that were obtained from the prospect screening results are shown in Fig. 32-4. From the respective probability-tree diagrams, enhanced oil reserves frequency distributions are developed and expected values, variances, and standard deviations are calculated. These are listed in Table 32-3, together with the suggested enhanced recovery process for each reservoir.

Note that no reserves are indicated for reservoir D. On the basis of the screening process the decision has been made that suitable technology is not available and this reservoir must be eliminated from further consideration at this time. After prospect screening, the expected value for the national enhanced oil reserves is 383 x 10^6 barrels, with a standard deviation of 49 x 10^6 barrels. The cumulative frequency distribution for the national enhanced oil reserves after Phase 1 is shown by the solid line in Fig. 32-5. In Fig. 32-5 the enhanced oil reserves are added to the conventional oil (451 x 10^6 barrels) ultimate recovery reserves to show the relative contribution of enhanced recovery.

The remaining reservoirs can now be ranked according to local considerations of priority. These considerations include the size of the reservoir, the type of oil (there may be a demand for a certain oil, such as one with low sulfur content), the maturity of the field (there may be a need to start abandoning



ENHANCED OIL RESERVES MMB	CUMULATIVE PROBABILITY
27	1.000
30	0.925
34	0.745
38	0.600
42	0.360
43	0.285
47	0.225
53	0.045

$$\mu = 38 \text{ MMB}$$
$$\sigma^2 = 56 \text{ MMB}^2$$
$$\sigma = 7.5 \text{ MMB}$$

Figure 32-2.--Reservoir A--Probability tree diagram after phase 1

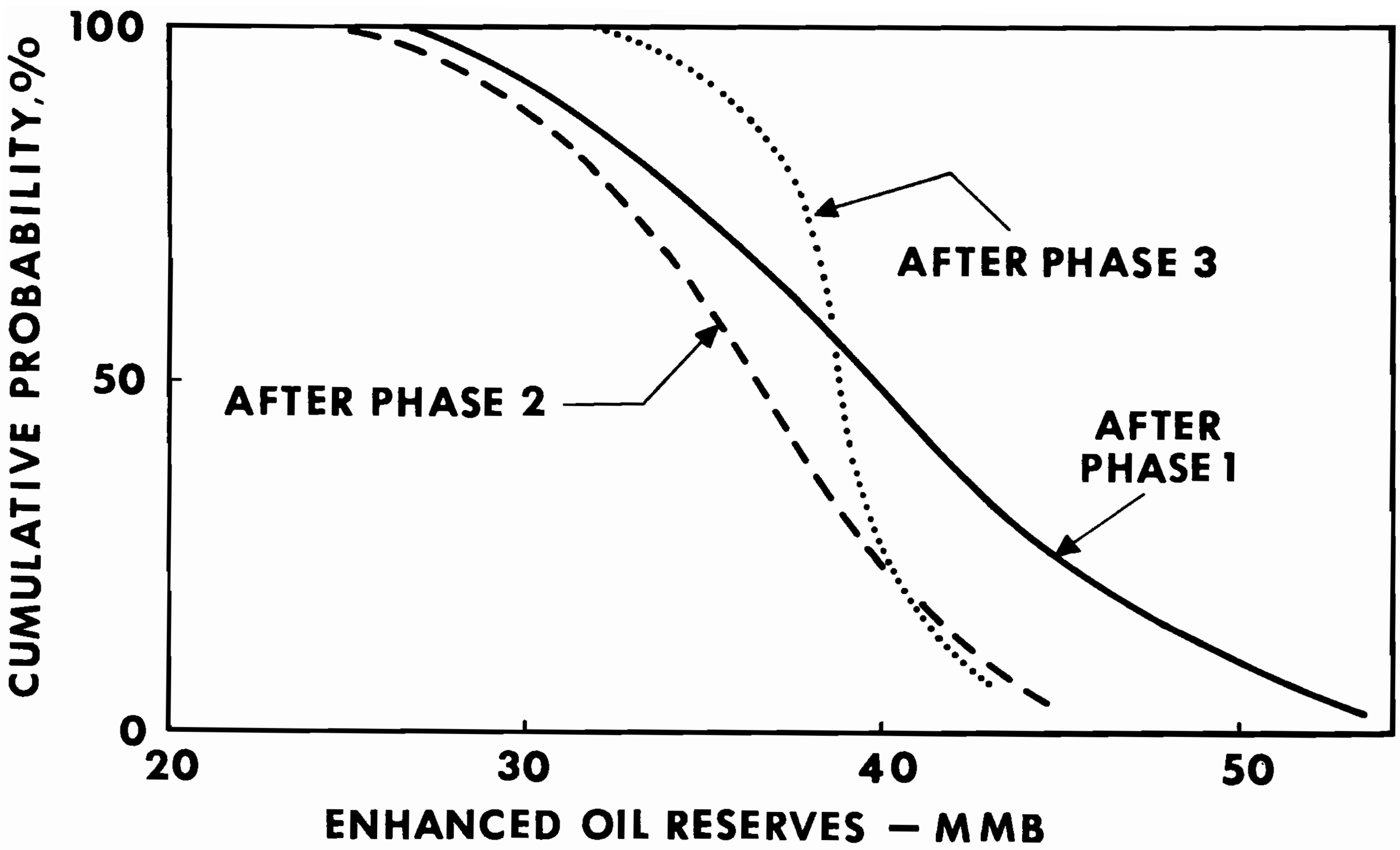


Figure 32-3.--Reservoir A--Cumulative frequency distribution (enhanced oil reserves)

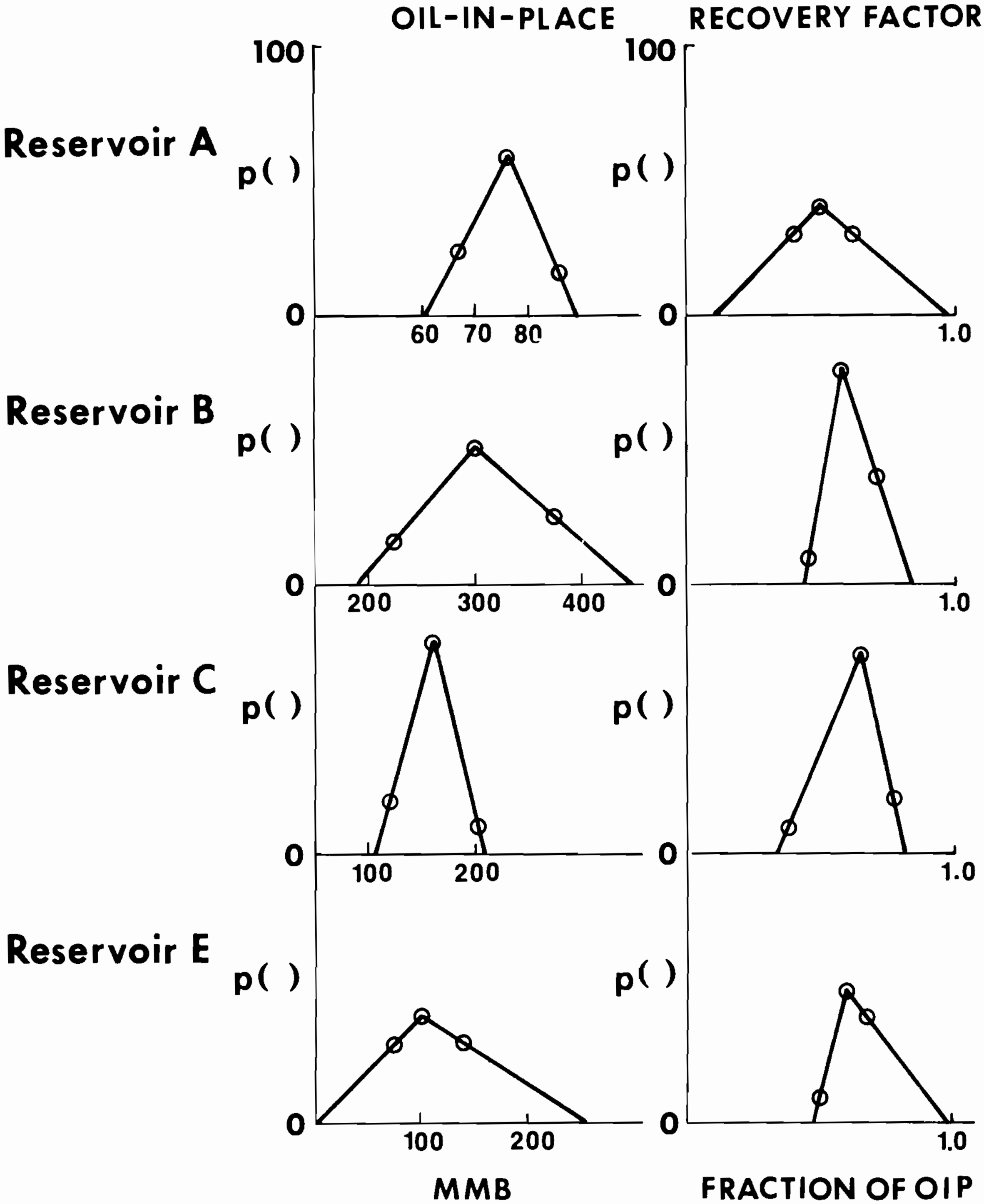


Figure 32-4.--Reservoirs A, B, C, E--Frequency and probability distributions for oil-in-place and recovery factor after phase 1

TABLE 32-3.--List of national enhanced oil reserves after phase 1

RESERVOIR	ENHANCED OIL RESERVES MILLIONS STOCK TANK BBLS μ	σ	OIL GRAVITY ° API	ENHANCED RECOVERY PROCESS
A	38	7.5	35	MICELLAR
B	179	39	37	MICELLAR
C	101	21	13	FIREFLOOD
D	0	–	5	NONE
E	65	18	36	MICELLAR

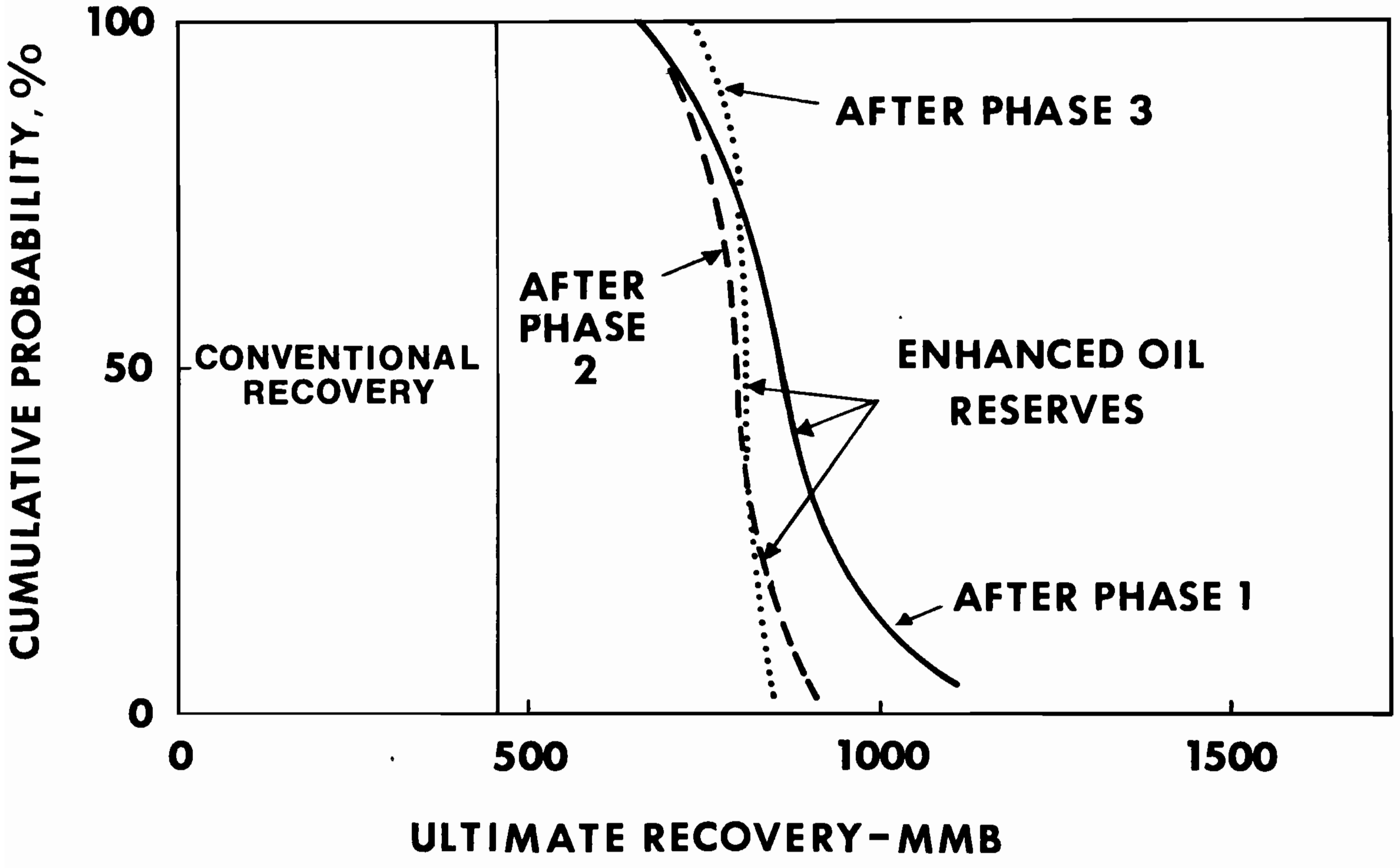


Figure 32-5.--Cumulative frequency distribution of national oil reserves

wells if further recovery action is not planned), and the geographic location. There could be others. We have chosen to rank the reservoirs according to size. The ranked list is shown in Table 32-4 together with tentative action plans for the next phase.

The aim of each phase of this analysis is to reduce uncertainty and refine the estimates of enhanced oil reserves. One reservoir has now been eliminated as a result of the prospect screening. All those remaining are considered to be potential contributors to the reserves and each should now be examined in more detail to determine if a field pilot is justified.

PHASE 2 - PRE-PILOT EVALUATION

The pre-pilot phase involves certain actions that are designed to tell us more about the particular reservoir and the process application. The work required here might include pressure surveys, injectivity tests, pressure fall-off tests, interference tests, pulse tests, new logs including log-inject-log programs, new wells with coring and core analyses, tracer studies, and detailed reservoir simulation. Pursley et al [14] and Harris [15] discuss the specific application of some of these techniques for pre-pilot evaluation. These studies can be relatively costly in both time and money. It could take anywhere from several months to a couple of years to complete the work and may cost several hundred thousand dollars. We aim to reduce the existing uncertainties in the oil-in-place and recovery factor estimates at the expense of time and money.

In Table 32-4 the action plans for the pre-pilot evaluation phase for each of the reservoirs were shown. Each reservoir will require somewhat different treatment, depending upon the amount of information available and its integrity. The coring and logging programs are aimed primarily at refining the values for oil-in-place, while the tracer surveys, pressure tests, pulse tests, and interference tests are aimed at a better understanding of where the injected fluids will go and what kind of recovery can be expected. The reservoir simulation will provide help for estimating both oil-in-place and recovery factor.

TABLE 32-4.--Ranked list of national enhanced oil reserves and action plans for phase 2 ranked by order of size

RESERVOIR	ENHANCED OIL RESERVES MM STB	ENHANCED RECOVERY PROCESS	ACTION PLAN ACTION	 COST $	 TIME YRS.
B	179	MICELLAR	DRILL, CORE & LOG 2 WELLS, PULSE TEST, LOG–INJECT–LOG, SIMULATION	400000	1.5
C	101	FIREFLOOD	DRILL, CORE & LOG 1 WELL, INJECTIVITY TESTS, INTERFERENCE TESTS	300000	0.75
E	65	MICELLAR	DRILL, CORE & LOG 1 WELL, LOG–INJECT–LOG, SIMULATION	500000	1
A	37	MICELLAR	DRILL, CORE & LOG 3 WELLS, PULSE TEST, INJECTIVITY & FALL–OFF TESTS, TRACER SURVEY	250000	1.25

At the conclusion of the pre-pilot evaluation, new estimates of oil-in-place and enhanced oil recovery factor are made, together with revised probability assignments. Referring again to the example, reservoir A, Table 32-5 shows the revised estimates and the triangular distributions. Data from Phase 1 are shown by the dashed lines for comparison. This second estimate results in a range for the oil-in-place from about 67 to 84 x 10^6 barrels and a recovery factor ranging from 28 to 70 percent. The range for the oil-in-place after Phase 2 is only about 60 percent of that of the first estimate. Similarly, the range for the recovery factor has been reduced to about one-half of that of the first estimate. These data are now incorporated into a probability tree as before with the result that the expected value for the enhanced oil reserves for reservoir A is now 35 x 10^6 barrels with a variance of 31 x 10^6 barrels^2 and a standard deviation of 5.5 x 10^6 barrels. The cumulative frequency distribution after Phase 2 is shown in Fig. 32-3 as a dashed curve. The other reservoirs are treated in a similar manner.

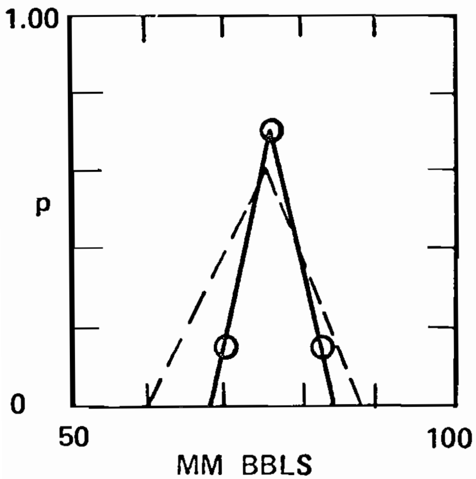
Field pilot tests are expensive and time consuming. Thus, prior to proceeding with Phase 3, the field pilot program, we develop rough cost estimates for field-wide ("commercial") enhanced recovery applications. These single value cost estimates for the specific projects are combined with the frequency distributions of the Phase 2 enhanced oil reserves to produce cumulative frequency distributions of the cost per barrel of enhanced oil recovery for each reservoir. In real life the time value of money as well as royalties and taxes need to be taken into consideration to generate project economics in terms of discounted cost per barrel per discounted barrel produced. For simplicity, we shall assume that capital as well as operating costs are all incurred at one given point in time, at which point all the enhanced-recovery oil will also be produced and that there are no taxes, royalties, or other indirect cost factors.

Again using reservoir A as an example, a total cost estimate of \$320 x 10^6 was developed for the "commercial" project. Using this number and the Phase 2 estimate for the enhanced oil distribution, an expected value of \$9.41 for the cost of the oil is derived with a variance of 2.42 \$^{2} and a standard deviation of

TABLE 32-5.--Reservoir A--Frequency and probability distributions for oil-in-place and recovery factor after phase 2

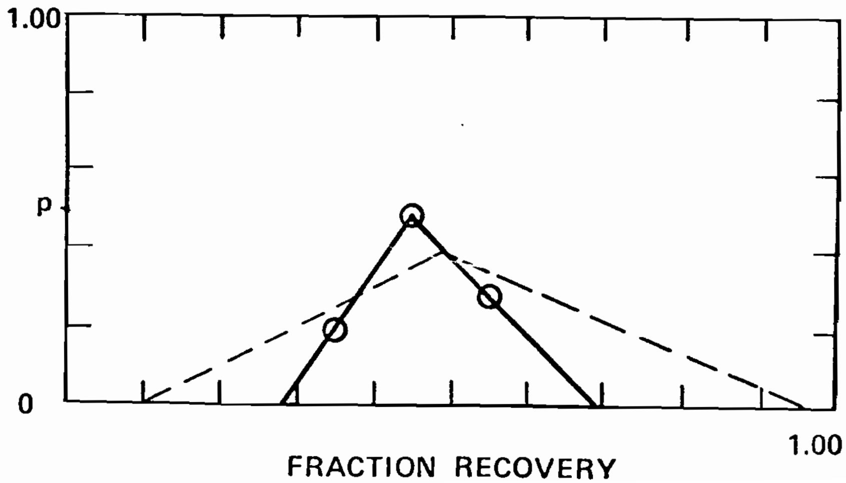
OIL-IN-PLACE

STOCK TANK BARRELS	p ( )
69×10^6	0.15
76×10^6	0.70
82×10^6	0.15



ENHANCED OIL RECOVERY FACTOR

FRACTION OF OIL-IN-PLACE	p ( )
0.35	0.2
0.45	0.5
0.55	0.3



\$1.56. The resulting cumulative frequency distribution of cost per barrel is shown in Table 32-6 and Fig. 32-6. From Fig. 32-6 we note that there is a 10 percent probability that the cost will be less than \$7 per barrel and an 88 percent probability that it would be less than \$11 per barrel.

We now introduce one further simplification regarding project economics. Since we neglect discount factors and therefore rate of return considerations, we will define an economically viable venture as one which generates a better than break-even proposition at a given oil price. In these terms the probability of project success can now be read off the cumulative frequency distribution curve in Fig. 32-6.

If we treat the other three reservoirs in a similar fashion, we arrive at the data shown in Table 32-7. We now have the Phase 2 reserve and cost data as well as probabilities of project success at three oil price levels, namely, \$7, \$9, and \$11, for each reservoir, which were derived from cumulative frequency curves such as the one shown in Fig. 32-6. Note that the expected cost value for reservoir E is \$22 per barrel and there is zero probability of producing oil at less than \$11 per barrel. On this basis (and low ranking from Table 32-4) this reservoir can be eliminated from further consideration at this time. The remaining enhanced oil reserves are 332 x 10^6 barrels (expected value) with a standard deviation of 34 x 10^6 barrels. The cumulative enhanced oil reserves for all reservoirs are shown as a dashed line in Fig. 32-5, again added to the recovery by conventional methods to give ultimate recovery.

The cost distributions for each field, such as shown in Fig. 32-6 for field A, can be used to derive the cumulative frequency distribution of the national enhanced oil reserves at different price levels. These data are plotted in Fig. 32-7 as a dashed line (minimum p (success) = 55 percent).

PHASE 3 - FIELD PILOT TEST

The next phase in the process of reducing enhanced recovery resources to enhanced oil reserves is the field pilot test. With data that have been accumulated so far, a decision can be made

TABLE 32-6.--Reservoir A--Cumulative frequency distribution for enhanced oil reserves and cost per barrel after phase 2

ENHANCED OIL RESERVES MM BBLS	Σ p ( )	COST $/BBL
24	1.000	13.33
27	0.970	11.85
29	0.830	11.03
31	0.800	10.32
34	0.725	9.41
37	0.375	8.65
38	0.300	8.42
42	0.255	7.62
45	0.045	7.11
μ = 35		μ = 9.41
σ^2 = 31		σ^2 = 2.42
σ = 5.5		σ = 1.56

TABLE 32-7.--National enhanced oil reserves--phase 2 reserves, cost per barrel and probability of commercial success

RESERVOIR	ENHANCED OIL RESERVES MM STB μ	ENHANCED OIL RESERVES MM STB σ	COMMERCIAL PROJECT COST MM $	COST $/BBL μ	COST $/BBL σ	PROBABILITY OF PROJECT SUCCESS AT OIL PRICE $ 7	$ 9	$ 11
B	155	30	1500	10.02	1.86	4	28	86
C	142	19	650	4.67	0.69	99	100	100
E	48	10	1025	22.00	3.75	0	0	0
A	35	5.5	320	9.41	2.42	10	56	88
	Σ 380							
	− 48		ELIMINATE RESERVOIR E					
	332							

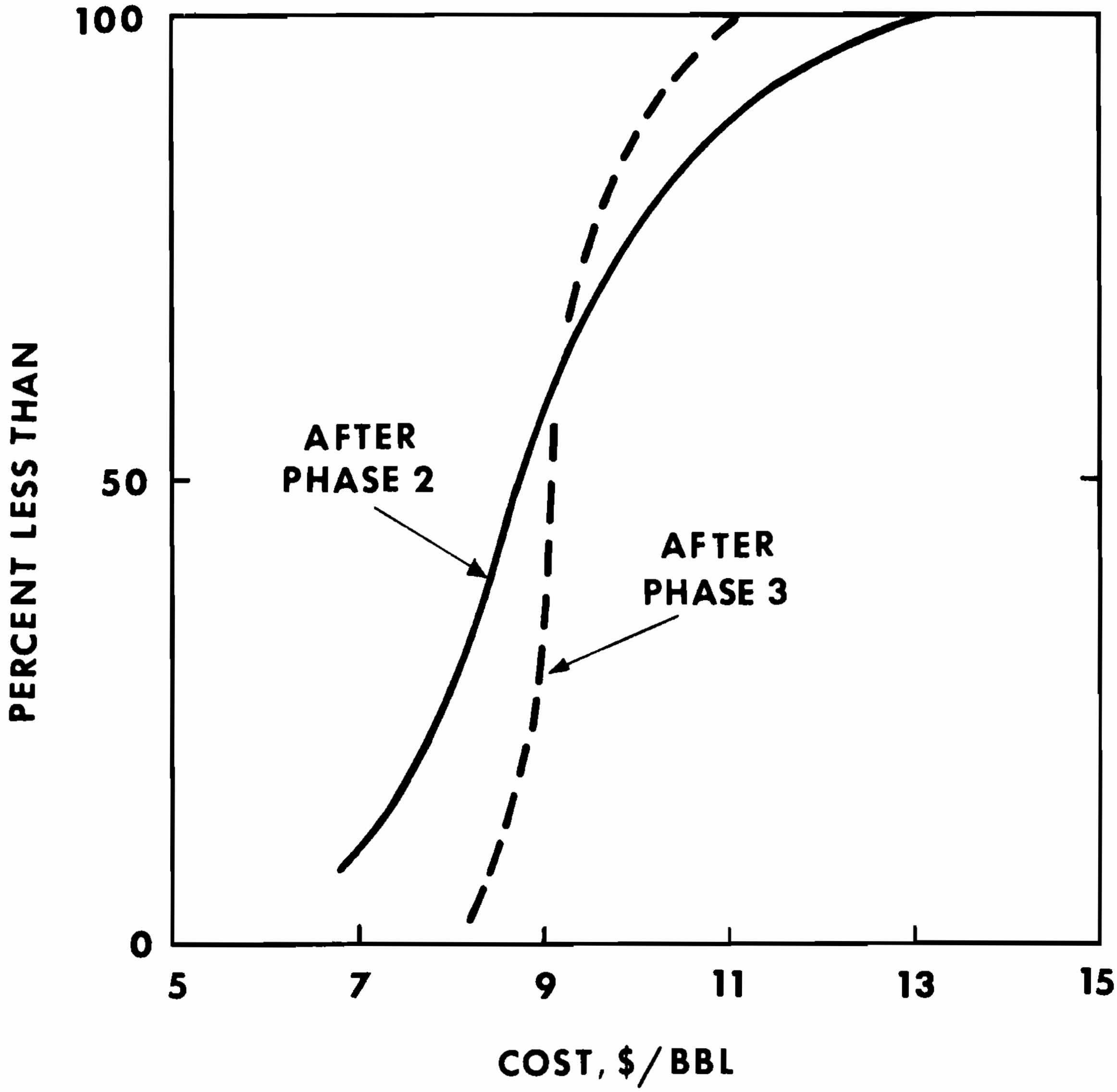


Figure 32-6.--Reservoir A--Cumulative frequency distribution for cost per barrel

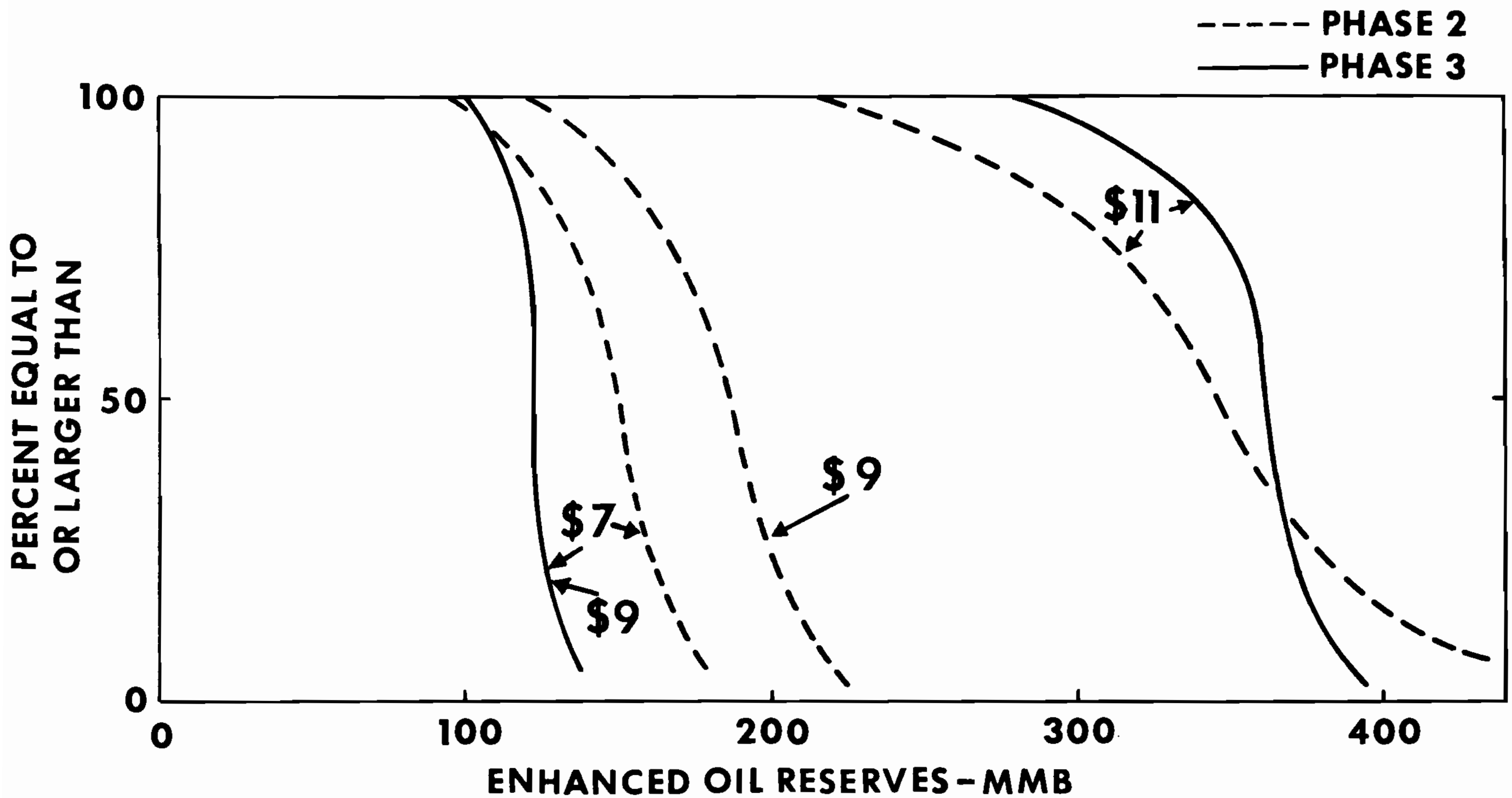


Figure 32-7.--Cumulative frequency distribution of national enhanced oil reserves at different price levels

whether to continue to the field pilot stage for any reservoir. The principal criterion for decision is a comparison of the cost of the pilot with the probability of producing oil at an acceptable cost.

From the initial example reservoir inventory, three reservoirs remain for consideration--reservoirs A, B, and C. Using a criterion of a 75 percent chance or higher that the oil will be produced at less than \$11 per barrel, all three reservoirs would be subjected to a field pilot test. This involves a relatively small portion of the reservoir in which a test and evaluation of the process are conducted. Field pilot testing is costly and time-consuming. A test may take 3 or 4 years to complete and cost several million dollars, all of which adds to the total cost of commercialization. Nevertheless, a successful test will result in refined estimates of oil-in-place and enhanced oil recovery factor and perhaps prevent large financial losses stemming from a premature field-wide expansion.

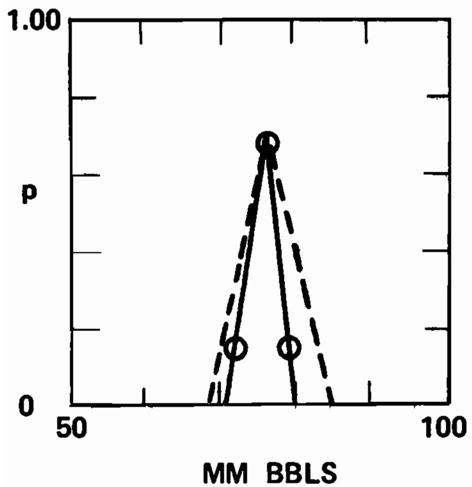
Referring again to the example reservoir, assume the field pilot test has been completed. As a result of this work new estimates of oil-in-place and enhanced oil recovery factor are made. These are shown in Table 32-8. Data from Phase 2 are shown by dashed lines for comparison.

As a result of the field pilot test the most likely value for the oil-in-place is now 76×10^6 barrels and the range has been reduced to about 9×10^6 barrels from 17×10^6 barrels after Phase 2 and 29×10^6 barrels after Phase 1. Similarly, the estimated recovery factor has a most likely value of 0.50, with a range reduced to about 0.14 from 0.42 after Phase 2 and 0.88 after Phase 1. In addition, the estimated total cost for the commercial project has increased to $\$360 \times 10^6$. The new probability-tree diagram calculations result in an expected value for enhanced oil reserves of 38×10^6 barrels with a variance of 6.5×10^6 barrels^2 and a standard deviation of 2.5×10^6 barrels. The frequency distribution is shown in Fig. 32-3 as a dotted curve. The cost-per-barrel frequency-distribution derived with the new total cost estimate of $\$360 \times 10^6$ is shown as a dotted line in Fig. 32-6.

In Table 32-9 are shown the Phase 3 (and final) estimates of enhanced oil reserves, cost per barrel, and probabilities of

TABLE 32-8.--Reservoir A--Frequency and probability distribution for oil-in-place and recovery factor after phase 3

OIL-IN-PLACE		ENHANCED OIL RECOVERY FACTOR	
STOCK TANK BARRELS	p ( )	FRACTION OF OIL-IN-PLACE	p ( )
72×10^6	0.15	0.45	0.15
76×10^6	0.70	0.50	0.65
79×10^6	0.15	0.55	0.20



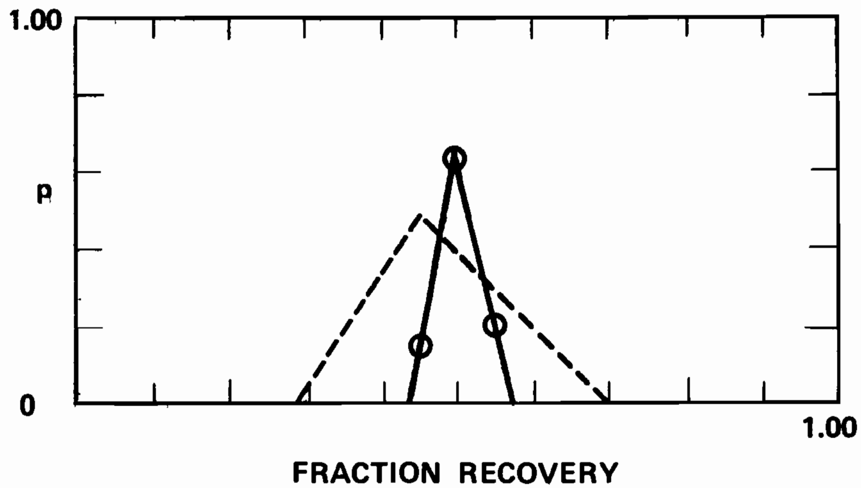


TABLE 32-9.--National enhanced oil reserves--phase 3 reserves, cost per barrel and probability of commercial success

RESERVOIR	ENHANCED OIL RESERVES MM STB μ	σ	COMMERCIAL PROJECT COST MM $	COST $/BBL μ	σ	PROBABILITY OF COMMERCIAL SUCCESS AT OIL PRICE $ 7	$ 9	$ 11
C	120	7	800	6.69	0.39	86	100	100
A	38	2.5	360	9.47	0.64	0	35	99
B	192	16	2200	11.01	0.94	0	4	78
	Σ 350							

commercial success at three price levels for the three remaining reservoirs from the initial inventory. The dotted line in Fig. 32-5 is the final cumulative frequency distribution of total enhanced oil reserves and the solid lines in Fig. 32-7 are the final cumulative frequency distributions of the national enhanced oil reserves at three oil price levels (minimum p (success) = 75 percent).

COMMERCIAL VENTURE DECISION

The above information can now be used for decisions regarding commercialization. The decision making criteria will vary with local circumstances. The data can be used to estimate the probability of economic success at any price level. For example, assume we are willing to take one chance in four that a project will be a commercial failure at an oil price of $7 per barrel. In other words, we require a 75 percent probability or better of commercial success before proceeding with a reservoirwide enhanced recovery project. From Table 32-9 we can see that only reservoir C fulfills the criterion (p = 86 percent). This, in our example, also holds for an oil price of $9 per barrel, where reservoir C has a probability of success of 100 percent, while reservoirs A and B rate at 35 percent and 4 percent, respectively. If, on the other hand, we would be willing to take one chance in four to fail at an oil price of $11 per barrel, we would implement commercial size ventures in all three reservoirs since probabilities of success are 100 percent, 99 percent, and 78 percent for reservoirs C, A, and B, respectively.

One additional consideration in real life is the estimate of daily production rates for the commercial projects. At the upper price level all these reservoirs would be commercialized. The production rates obtained during the field pilot test can be scaled up, based on injected fluid-produced fluid ratios and the rate of expansion. Fig. 32-8 shows both the enhanced oil production rate as a function of time for the three individual reservoirs and the total enhanced oil production rate for the nation represented by the example. We choose to start the project in reservoir C first since it has the highest probability of

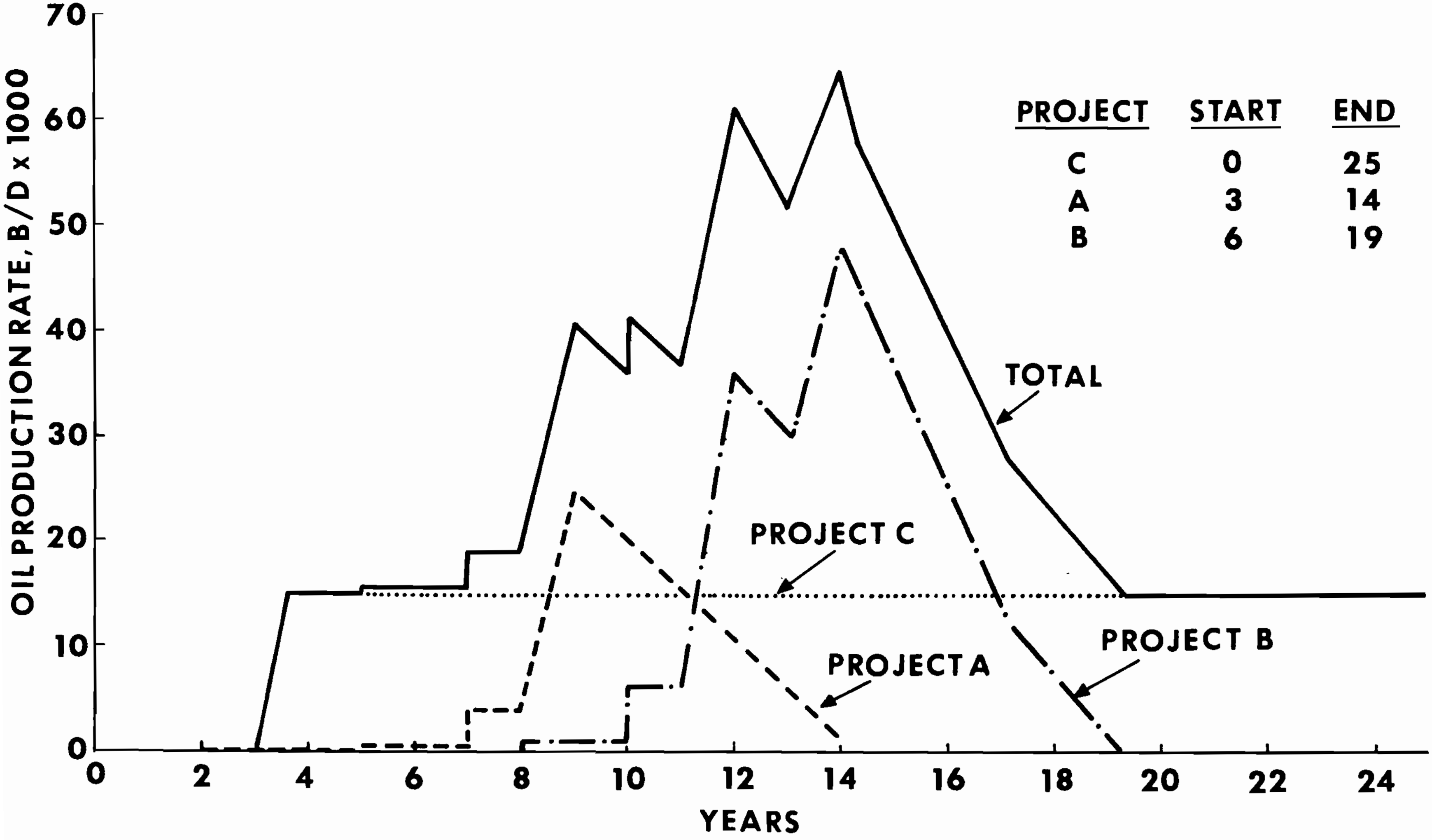


Figure 32-8.--Total national and project enhanced recovery production schedules

commercial success. After 3 years the project in reservoir A is started. Finally, after an additional 3 years the project in reservoir B would be started. The project life of projects A, B, and C is 14, 19, and 25 years, respectively. Peak production from the national commercial program reaches 65,000 barrels per day in year 14.

RESULTS AND CONCLUSIONS

In review, refer to Fig. 32-9 which shows the "decision path" for the three reservoirs at three price levels. At the end of Phase 1, prospect screening, an estimate of the oil-in-place and enhanced oil recovery factor was made and a cumulative frequency distribution for the enhanced oil reserves was derived. One reservoir was eliminated because of a lack of technology at this point. The remaining reservoirs were subjected to pre-pilot evaluation, Phase 2, at the end of which the oil-in-place and enhanced oil recovery-factor estimates were refined. This resulted in improved cumulative frequency distributions for enhanced oil reserves which were combined with an estimated cost for commercialization to yield a cumulative frequency distribution of enhanced oil cost per barrel. At this point a second reservoir was eliminated because of extremely high cost estimates. Of the remaining reservoirs, all three would go to the field pilot stage, Phase 3, at a price level of $11 per barrel, but only reservoirs A and C would go to the field pilot stage at $9 per barrel, and only reservoir C could be recommended for field pilot test at $7 per barrel if we adopt a Phase 2 probability of commercial success equal to or higher than 55 percent as the decision criterion to proceed with a pilot. At the conclusion of the field pilot test, Phase 3, only reservoir C would be recommended for commercialization at $7 and $9 per barrel. All three reservoirs would be commercialized at $11 per barrel. An initial enhanced recovery gross resource base of 1.274×10^9 barrels has been refined to an enhanced oil reserve of 350×10^6 barrels, with probabilities of commercial success close to 100 percent for the first 120×10^6 barrels (reservoir C), 99 percent for another 38×10^6 barrels (reservoir A), and 78 percent for

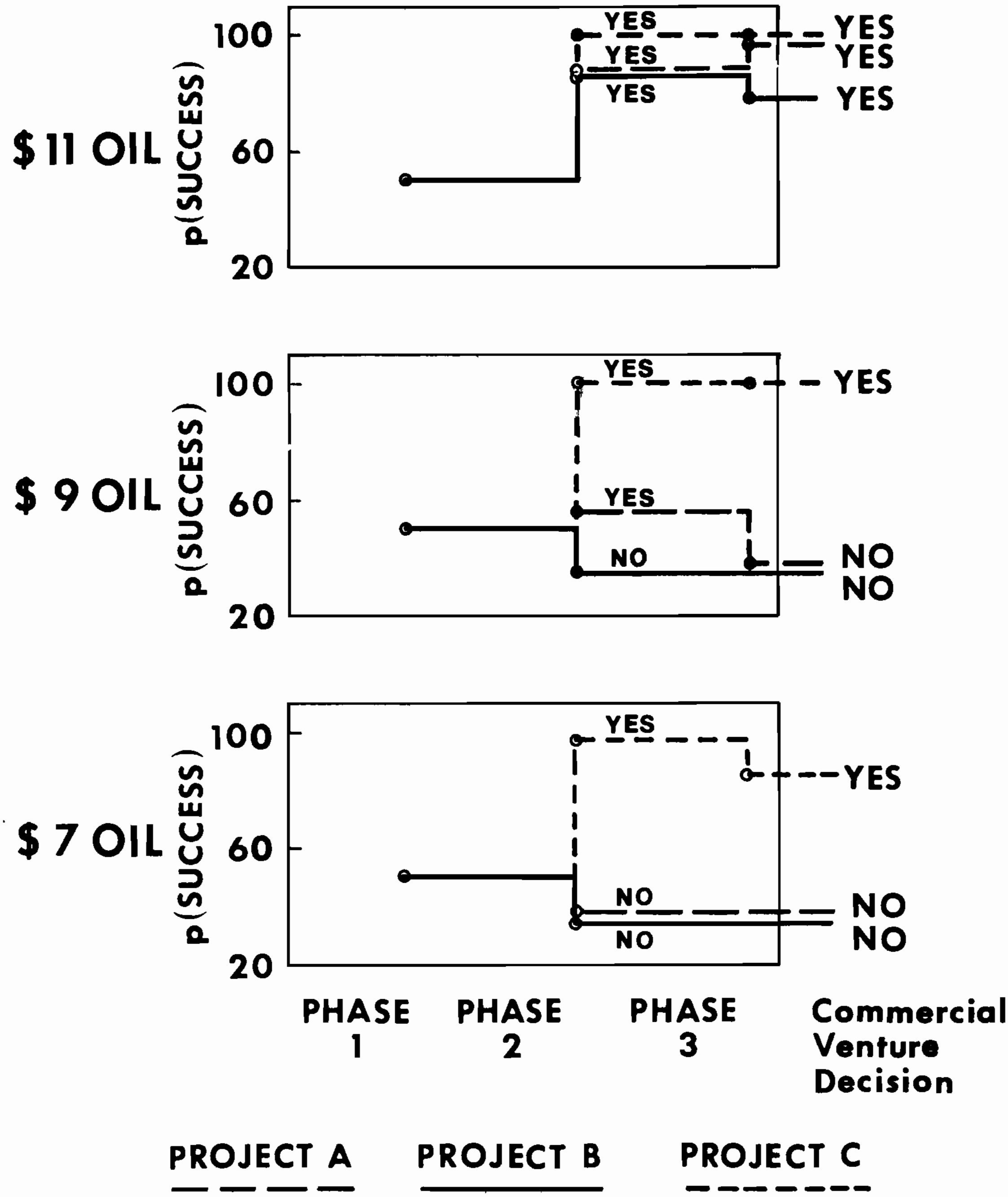


Figure 32-9.--Decision diagram from phase 1 to commercialization

the remaining 192 x 10^6 barrels (reservoir B) at an oil price of $11 per barrel.

The costs used in this analysis are simplified examples only. Actual costs can vary greatly depending upon the local situation. We recall that there has been no attempt to consider the time value of money, royalties, or taxes. The data and results presented here have been hand-calculated, which is possible with the simplifying assumptions that were made, in order to highlight the effect of probability and risk concepts as clearly as possible. In real life and with the aid of computers, one would include discounted cash flow methods or more sophisticated techniques such as investment efficiencies [16]. Also, the simple triangular probabilities chosen for this paper could be replaced by other distributions and/or converted to cumulative probability distributions via Monte Carlo simulation [12, 13] which would greatly facilitate the introduction and handling of additional variables if deemed necessary.

In conclusion, a methodology has been presented which provides for the systematic assessment of a nation's enhanced oil reserves. The introduction of risk analysis tools, such as triangular probability distributions for key variables, probability-tree diagrams, cumulative frequency distributions for enhanced oil reserves, enhanced oil costs per barrel, and probabilities of commercial venture success, all familiar to the exploration economist, are key components of this methodology. While real-life situations will require the introduction of DCF methods, the inclusion of taxes, royalties, and possibly Monte Carlo simulation, all easily amenable to computer treatment, we believe that a probabilistic framework has been established, which will facilitate the tractability of the complex question of the prediction and verification of national enhanced oil reserves.

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CHAPTER 33

A REVIEW OF THERMAL RECOVERY APPLICATIONS IN THE UNITED STATES

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ABSTRACT

Although there is definite proof of intentional use of hot fluid injection (both water and steam) dating to the 1920's and 30's, modern interest in thermal recovery of oil seems to date to the early 1950's with the discovery of the in situ combustion process. By the end of the 1950's, the first commercial in situ combustions were installed; these are still operating today. However, there are only a handful of commercial operations, most of which are in California, USA.

In the early 1960's the main interest in thermal recovery shifted to cyclic steam injection and production of oil. Where applicable, the cyclic process has been very successful, and most California operators have fully developed their cyclic steam injection potential. Currently, interest is shifting toward operations involving continuous injection coupled with cyclic steam stimulation of producing wells. Cyclic steam injection has been an important factor in delaying the decline in oil production rate in California.

Economically successful thermal oil recovery operations of all three major types: in situ combustion, continuous steam injection, and cyclic steam injection have been conducted in many

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parts of the world. Often these processes are combined to improve their effectiveness.

INTRODUCTION

Although there is clear evidence of intentional hot water and steam injection in the 1920's and 30's in the United States [1], and intentional in situ combustion in the early 1930's in Russia [2], modern interest in thermal recovery of oil dates from publications in the early 1950's [3, 4] concerning in situ combustion.

It was evident from the beginning that there was a large variety of ways to introduce heat into an oil reservoir. Many publications and patents concerning hot fluid injection and variations on in situ combustion appeared thoroughout the 1950's. By the end of the decade, the important features of continuous-drive thermal methods, such as combustion, steam, and hot water injection, were thoroughly documented in the literature. With regard to field operations, a number of pilot tests of in situ combustion had been conducted and described, but very little was known regarding field results of hot fluid injection. It was evident that in situ combustion was not economically feasible in all heavy oil reservoirs, and thus interest grew in hot fluid injection.

In 1961 and 1962, rumors began to circulate throughout the oil industry that Shell Oil Company was having considerable success with a new thermal recovery method for individual wells in the Yorba Linda field, California, involving a cyclic injection of steam and a following production period.[2] Other operators began to experiment with the method. Although results were not always good, results were extraordinary in enough cases to spur rapid development of the process. Today, some 23,000 wells of a state total of 41,000 active, have been steamed at least once in California [5] and some wells have been reported to have had as many as 16 cycles of steaming and production [5, 6]. Most operators feel that almost all wells in California suitable for cyclic

[2] D. N. Dietz has reported the method was discovered in 1959 almost simultaneously in California and Venezuela fields.

steam stimulation are now being steamed, even though the process has led to the drilling of many new wells.

Currently many operators in California feel that cyclic steam injection is principally a stimulation process. It will be necessary to use some continuous injection method in conjunction with cyclic steaming to achieve the high oil recoveries potentially available from thermal methods. It is often necessary, however, to perform several steam stimulation cycles before a continuous injection method will perform properly. The following presents a current inspection of thermal recovery operations.

IN SITU COMBUSTION

There have been over 100 field trials of in situ combustion oil recovery since description of the first successful field pilots in the early 1950's. Currently, there are only about 30 field tests in operation in the world. Perhaps the most significant statistic concerns the duration of the current field operations. Only two current operations have been underway for over 15 years: the Mobil Oil project on its Moco lease, Midway-Sunset Field, California; and the Kadane and Sons project in the West Newport Field, California. Both have been described as large-scale commercial operations [7, 8, 9].

The Kadane and Sons project is located on their Banning lease, near Huntington Beach, California. The project pilot was started in March, 1958 and commercial application began in 1960 with addition of an adjoining pattern. Another pattern was ignited in 1961, and three more in 1964. Currently, 30 injection wells in two separate projects are operating under combustion drive. Operations cover most of the 575-acre lease. There are three productive sands; the A sand is about 100 ft thick with the sand top ranging from 650 to 1,750 ft below surface. Most of the combustion patterns are completed in the B sand. It is about 250 ft thick and lies from 800 to 2,100 ft below surface. The C sand is about 150 ft thick and lies at depths from 1,700 to 2,350 ft. Air injection capacity is reported about 9×10^6 ft^3 per day. Ratio of cumulative air injected to cumulative oil produced was 10.7×10^3 ft^3 per barrel in 1965. Producing wells are stimulated by cyclic steam injection. The cumulative incremental oil production was reported as 4.7×10^6 barrels in 1972.

The Mobil Moco Zone operation began in January 1960. This zone was discovered in 1957, but was essentially shutin until 1959. This unique combustion operation has been termed a "primary" recovery process [9]. The structure is an anticline with dips of 20° on one side and 45° on the other. Six sands are involved in an interval from 2,100 to 2,700 ft depth. Total area is 150 acres. Initial oil content was 38×10^6 barrels of 14° API oil. Combustion was started spontaneously at the top of the structure in all six sands. Five injectors are now used with various combinations of sands open. The oil rate peaked at 3,300 barrels per day and was 1,600 barrels per day in 1970, at which time oil recovery was 9×10^6 barrels or 24 percent initial oil. Thirty producing wells were involved. Air injection rate ranged from 5 to 10×10^6 ft^3 per day and cumulative injection in 1970 was 26×10^9 ft^3, sufficient to burn 7.5 percent reservoir volume. The cumulative air-oil ratio of 2.9×10^3 ft^3 per day is likely the lowest that has been experienced. It was 4.5×10^3 ft^3 per barrel in 1970 and reported increasing slowly. Gates and Sklar [9] reported it was necessary to have close attention by experienced personnel to minimize risks.

In addition to the two oldest combustion operations, at least four large in situ combustion operations have been underway for at least 10 years. These include operations in the following California fields: San Ardo, South Belridge, and Lost Hills.

In addition to the preceding operations in California, there have been successful operations described in Rocky Mountain and Mid-continent states, Canada, Venezuela, and Europe [10-18a]. Some pilot tests described as successful have not been expanded into full-scale commercial operations.

In view of the apparent success of in situ combustion oil recovery at least in selected locations, a significant question is why there aren't more large-scale operations in progress. A number of important reasons exist. First, installation of in situ combustion requires a large investment [19]. Although the process was initially heralded as a tertiary or scavenging process, all currently successful operations have been installed in heavy oil reservoirs producing under primary drive and essentially fully developed. Thus there was initial oil mobility, and it was not necessary to drill many wells. Furthermore, the operator controlled the entire reservoir, or a large block of the reservoir, in every case. Even under these favorable circumstances, a large investment is required for air compression equipment for even a pilot operation.

It appears that two successive factors compounded this picture. In the early 1960's, many pilot in situ combustion tests reported serious operational problems. The problems included early breakthrough of the burning front and attendant mechanical problems with producing wells, formation of difficult emulsions, high air injection costs, and problems with injection wells. The low price for heavy crude oils did not help this picture. A second important factor was successful exploration in new oil provinces throughout the world. This forced oil producers to assign lower priorities to recovery of known domestic oil. A third factor was development of the cyclic steam injection process in the early 1960's. This will be discussed more completely later.

In regard to the operational problems, it was evident early that results from in situ combustion often varied widely and a great deal of engineering attention was required to solve new problems. Limitation of engineering manpower has further impeded large-scale combustion developments. Although all of the operational problems previously described can be handed in a properly-selected reservoir, there simply has not been sufficient engineering manpower available to undertake many such operations.

Nevertheless, interest continues in the process, and publications and patents regularly appear in the literature concerning refinements to make the process more efficient, and more widely applicable. One of the most recent involves continuous or cyclic injection of water with the injected air [21-25]. The purpose of this operation is to limit fuel consumption and to move heat ahead of the combustion zone by condensation of steam moving through the burning front. Studies indicate this process may reduce air requirements by a factor of three for some operations.

There are several reasons for continuing interest. Sufficient experience has been gained with cyclic steam injection to indicate that some form of continuous drive is required to obtain high percentage recoveries of inplace oil. Another reason for continuing interest is the perennial problem of recovery of oil from tar sands and oil shales. There appears to be a consensus that in situ combustion coupled with some form of fracturing in-place offers a solution for recovery of oil from shales, and that either combustion or steam injection is suitable for deep tar sands. Finally, the world-wide energy crisis and large increase in crude oil price has forced great current emphasis on all improved recovery methods, including combustion. There are many potential variations on the in situ combustion process which have not been tested; this process must still be considered in early development stages. When the business climate is ready, this process should find ready application throughout the world--in properly selected locations.

CONTINUOUS STEAM INJECTION

Interest in hot fluid injection processes predates in situ combustion. Field testing began about the same time as that for the combustion process, but field test results first became available in 1969 [26, 27]. Ramey [1] provides a history of hot fluid injection studies. By the early 1960's, it appears that hot water or steam injection dominated consideration. Laboratory studies indicated a distinct advantage in steam injection over hot water injection, and subsequent field trials of hot water injection have since given way to steam injection.

The term "steam injection" is misleading. The equipment currently being used in steam generation is usually single pass boilers which produce steam of about 80 percent quality, that is, 80 percent by weight steam and 20 percent water. This two-phase mixture of steam and liquid has been the injection fluid in both cyclic steam injection and continuous injection in most operations.

Sufficient technical information concerning steam injection became available during the latter 1950's that many operators began serious consideration of this process in the early 1960's. This interest was quickened by recognition of the operational problems involved in in situ combustion. Although a few continuous steam injection projects were underway, or had been completed, limited information on field results had been presented. Two significant operations were underway: first, Shell began steam injection at Yorba Linda in California, and Getty Oil Company (then Tidewater) began hot water injection at Kern River, California [28]. The Shell operation led to the development of the cyclic steam injection process (to be discussed later) which had a tremendous impact upon operations in California, and the Getty operation led to both continuous and cyclic steam injection and is now the largest thermal recovery operation in the world.

The cyclic steam injection process discovered by Shell was such an apparent success in California that many operators followed suit. This effectively stopped planned continuous steam injection operations for a time and several were suspended when it was discovered that the injection well would produce large oil rates. Nevertheless, a significant number of continuous steam injection projects were begun in the early 1960's. Table 33-1 lists the number of wells which have received steam injection for both continuous injection and cyclic injection projects for the years 1966-75, in California.

Most of the continuous drive injection wells are located in the South Belridge and Kern River fields in California. About 820 flood injection wells were on continuous duty in Kern River and 190 in the South Belridge field by 1974. It is interesting that the number of injection wells has shown a steady increase during the last 10 years, from 140 in 1966 to 1,630 in 1975 and significant that many of the continuous injection projects are actually large scale operations with many injection wells involved. These are not the usual single pattern pilot. Furthermore, several of these continuous drives have been in operation over 10 years.

TABLE 33-1.--Steam injection summary for California, USA

Year	Number of injection wells: Cyclic	Number of injection wells: Continuous drive	Total wells	Steam inj. 10^6 barrels*
1966	6,620	140	9,400	111
1967	8,280	200	12,500	118
1968	8,900	290	14,350	129
1969	8,920	410	15,820	127
1970	9,200	610	17,580	154
1971	8,960	770	18,960	184
1972	8,690	1,080	20,020	226
1973	8,040	1,140	20,980	244
1974	8,300	1,230	21,970	256
1975	8,790	1,630	??	305

*Measured as feedwater volume.

Source: [5]

In regard to the technical features of these operations, considerable channeling of steam toward producers has been described. One operator indicates that it has been possible to control channeling by interrupting steam injection from time to time. Other solutions have appeared in the literature as well. Another serious problem with steam injection of both types has been well failures. Table 33-2 lists drilling notices filed in California for the Kern River field during the years 1965-75. Notices for both new wells and reworks are tabulated. Two

TABLE 33-2.--Kern River field, California, drilling notices

Year	New wells	Reworks
1965	110	130
1966	370	200
1967	760	190
1968	480	360
1969	230	450
1970	450	540
1971	490	310
1972	50	150
1973	120	190
1974	520	550
1975	740	450

Source: [5]

facts are apparent. Steam injection has led to a large increase in drilling of new wells, and to a large increase in the number of reworked wells. Continuous steam injection operations appear to be used mainly with fairly new wells. Operators have found that use of high-temperature cements and proper provision for thermal expansion or cooling of pipe has minimized well failures [29]. Although detailed information on oil recovery is not yet available, recoveries in the range of 30 to 40 percent of oil inplace at the start of the operation have been reported a number of times [30], and there seems to be a consensus now that ultimate recovery will be above 50 to 60 percent in many cases.

The most interesting recent event in continuous steam injection involves the Getty Oil Company operations in Kern River, California [31]. Six 50 x 10^6 Btu per hour generators were being installed in mid-1969, for continuous steam injection duty. These generators were twice the size of the steam generators in common use. Furthermore, a 240 x 10^6 Btu per hour unit has also been installed for continuous injection duty. Getty has installed sophisticated computer facilities to monitor performance of 2,300 wells involved in both continuous and cyclic steam injection.

Recently, many papers concerning field tests of continuous steam drives have been presented [32-35]. An interesting account of mathematical modelling of steam injection has been presented by Weinstein et al [36].

CYCLIC STEAM INJECTION

As has been described briefly in the preceding, the cyclic steam injection process has undoubtedly been the most exciting development in thermal recovery in this decade. Table 33-1 shows that some 22,000 wells in California had received steam injection by the end of 1974. Most of these wells were on cyclic steam injection, and had been subjected to repeated cycles since the mid-1960's. Some wells have had as many as 16 cycles of steam injection. The cumulative steam injected through 1974 was 1.7 x 10^9 barrels of steam expressed as liquid feedwater volumes. Since generation of steam in California costs at least $0.25/barrel of feedwater, this figure represents over $400 x 10^6 for operating costs alone. To generate steam, it is estimated that there are over 400 steam generators operating in the state of California. This resulted in an estimated production of about 70 x 10^6 barrels of incremental oil production in 1974. Oil production by cyclic steam injection is one of two factors credited with reducing oil production decline in the state of California (Table 33-3). As can be seen, oil production declined steadily through 1963.

TABLE 33-3.--California annual oil production

Year	10^6 barrels
1959	309
1960	305
1961	300
1962	297
1963	301
1964	300
1965	316
1966	344
1967	360
1968	373
1969	365
1970	347
1971	327
1972	324
1973	317
1974	306
1975	307

Source: [5]

In 1964 a minimum was reached, and by October of 1967 state oil production reached the 1×10^6 barrels per day, and continued to climb before natural decline and the offshore drilling moratorium overcame the increases due to steam. It has been estimated that about 200,000 barrels per day may be attributed to thermal oil recovery--principally cyclic steam injection.

Cyclic steam injection has had a wide-ranging impact upon the oil industry and has spawned a variety of peripheral service industries in California. Some indication of this fact was apparent in the listing of drilling and rework notices filed (Table 33-2). Table 33-4 lists the state wide development drilling notices and the number of wells completed in the Kern River and Midway-Sunset Fields in California for the years 1960-75.

TABLE 33-4.--Selected California drilling data

Year	Development drilling notices	Development wells completed Kern River & Midway-Sunset
1960	1,390	320
1961	1,860	380
1962	2,260	540
1963	2,260	520
1964	2,150	390
1965	1,880	380
1966	2,010	590
1967	2,280	1,070
1968	2,110	980
1969	1,510	510
1970	1,500	510
1971	1,520	550
1972	1,080	370
1973	1,270	360
1974	1,970	670
1975	2,380	750

Source: [5]

Most of the wells completed in both fields in recent years have been attributed to cyclic steam injection operations. As can be seen, the total number of drilling notices filed in the state has been fairly static since 1962, but there has been an increase in the wells completed in the Kern River and Midway-Sunset Fields.

Another peripheral industry benefiting from the rapid growth of cyclic steam injection is that devoted to the manufacture of steam generation and water treating equipment. Since there are over 400 generators operating in California, the total investment in this category must be roughly $\$50 \times 10^6$.

In regard to water treating, several significant events are worth mentioning. Cyclic steam injection caused a severe injection water shortage for a time in the San Joaquin Valley in California. Injection water must be essentially potable for most of the generators working in the state. This led the West Kern County Water District to a $2.25 x 10^6 expansion project underwritten by interested oil companies in 1967 [6]. The water district increased its deliverability capacity from 4,000 to almost 10,000 gallons per minute. Another significant development in this area was installation of a water reclamation plant by Getty Oil in the Kern River Field. This plant went on stream in July, 1968, and is capable of cleaning and softening 200,000 barrels per day of produced water from oil sands (5,830 gallons per minute) [31].

Finally, cyclic steam injection has greatly accelerated installation of LACT and computer monitoring of production of heavy oil producers once believed not suitable candidates for such sophisticated instrumentation. There are a number of reasons for this development. The logistics of scheduling thousands of wells for cyclic injection, and more frequent workover operations resulting from increased oil, water, and sand production are staggering.

The technical development of this process has been novel. This is one of the old-school oil production methods in which operations mostly preceded research. A large number of field case histories were available before papers began to appear to explain how operators had been profiting from the operation. Although a number of mathematical models for cyclic steam injection are now available [36-39], it appears that a large variety of physical factors have contributed to the success of cyclic steam injection to varying degrees in various reservoirs. In California, a great deal of credit for increased oil rate has been attributed to well clean-up and increased gravity drainage in thick, unconsolidated sand reservoirs. In some studies, main credit is given to reduced oil viscosity due to heating. More recently, field operations in Venezuela have been described in which formation compaction due to subsidence appears to play a major role [40], and finally, several studies have appeared which indicate that relative permeability to oil may be improved at higher temperatures [40a].

Cyclic steam injection has been referred to by a variety of terms, including "push-pull," "huff-and-puff," and "steam soaking." The first two terms obviously refer to the general nature of the process. A batch of steam in the order of 5,000 to 15,000 barrels (as feedwater volume) is injected into a producing well, and then the well is produced for a period of time ranging from a few months to a year. The term "steam soaking" refers to a practice by a number of operators of shutting-in the well for a period of time (presumably heat "soaking" sand around the well) before placing it back on production. There has been controversy among California operators as to the need for the soaking period. Some operators have indicated that the well should be placed on production immediately following injection, while others indicate that a specific soaking period is necessary. Recently, a field study has been published which indicates that a certain minimum soaking time was beneficial in a specific reservoir [39], although results were not particularly sensitive to longer soaking periods than the recommended minimum. In general, experimentation with the total quantity of steam injected per foot of sand, the length of the soaking period, and well completion and operating practices continues in California. It appears that the response varies from field to field (and even from well to well within a given field). This sort of experimentation with careful engineering analysis has turned unsuccessful operations terminated by some operators into successful operations for others. This is only one of many signs that engineering and technology have finally come of age in the oil industry, and more importantly, are finding a good business climate for proper exploitation. Just a decade ago, it was necessary for thorough research evaluation prior to field application. Currently, operations personnel are ready and willing to generate new ideas, and management is willing to act upon them.

Concerning the future of the cyclic steam injection process, there is evidence that application in California is nearing the saturation point. Many operators in California feel that almost all possible candidate wells for steam stimulation have been scheduled for injection. It is clear from Table 33-1 that cyclic steaming is not finished; however, steam flooding is growing rapidly. Important work on the effect of well spacing and the re-steaming period is being done [41, 42] and significant discoveries on ways to avoid well heat-losses have been made recently [43]. This process will continue to be very important.

Some comment on the effect of social, economic, and political factors is in order here. Often these constraints dictate the engineering solution to a problem in such a subtle way that it isn't realized they exist. In the Wilmington-Long Beach area of California, subsidence of the surface had been a serious problem. Surface rights are very expensive and thus water injection for pressure maintenance with steam soaking for improved oil rate was the answer. On the other hand, subsidence in the Bolivar Coast of Venezuela was not an important matter, and compaction drive, aided by steam soaking to obtain improved oil rates and recovery, was selected. Interestingly, the estimated percentage oil recovery in both operations is nearly the same. It is likely that both oil provinces will ultimately use some additional drive, such as continuous steam injection.

Political action can develop information through federally supported research. The current energy crisis has stimulated federal support of research on alternate energy sources, as, for example, at the Geysers Steam Field, California [5]. Federal support of research on geothermal steam has been extensive. A significant program on geothermal reservoir engineering has been underway in the Petroleum Engineering Department, Stanford University, for over 8 years. The Energy Research and Development Administration (ERDA) recently has actively supported thermal recovery projects both in the laboratory and in the field. Through ERDA's support, a new laboratory facility at Stanford is being built; the main thrust of this new facility will be research on thermal recovery methods.

CONCLUDING REMARKS

Economically successful thermal oil recovery operations of all three major types--in situ combustion, continuous steam injection, and cyclic steam injection--are being conducted currently in many portions of the world. Probably the most significant application of these processes occurs currently in California, Canada, Venezuela, and the USSR. Nevertheless, the total world oil production attributed to thermal oil recovery is small. Due to the increasing demand for oil, thermal oil production should expand greatly in the near future [44].

It is likely that cyclic steam injection will continue to play an important role in conjunction with other drives. In regard to ultimate recovery of oil, in situ combustion and continuous steam injection have distinctive advantages which will dictate selection as the continuous drive mechanism for recovery of heavy oil, depending upon the particular reservoir and existing local conditions. Currently available equipment fired with lease crude may be used for either steam injection or air injection. Steam injection will require a supply of water not necessary for combustion operations. On the other hand, air pollution and the nature of the crude oil place limitations upon combustion operations. Overall, it seems that continuous steam injection will be used more than in situ combustion [44].

At the present time, thermal recovery methods offer the greatest possibility of high percentage recoveries of heavy oils, while other new methods appear best suited for recovery of intermediate to high-gravity oils. It is likely that the next decade will see important improvements in the continuous-drive thermal recovery processes. This should lead to expanded application of all thermal oil recovery processes in the future.

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CHAPTER 34

IN SITU COMBUSTION METHOD FOR OIL RECOVERY
STATE OF THE ART AND POTENTIAL

J. J. Stosur[1]

INTRODUCTION

The philosophy of the in situ combustion technique of oil recovery is simple. It is the use of energy derived from burning part of the oil in a reservoir to assist in the recovery of the remaining unburned oil. The process is relatively new and, not unusually, there has been a tendency in the industry to either magnify its possibilities or to belittle them. Like most other advanced recovery techniques, in situ combustion has its assets and liabilities. There are conditions under which its application may be technically and economically feasible and conditions under which it is neither practical nor economic.

There have been well over 100 field trials of the in situ combustion method since the description of the first successful field pilot tests in the early 1950's. The most recently published survey of the active enhanced recovery projects in the United States [1] showed that there were 21 active in situ combustion projects in 1975, an increase from 19 in 1973, and a decrease from 38 active projects in 1970. The results of early projects were generally discouraging; recent efforts show improved results but the method continues to be a high-risk technique.

[1]Energy Research and Development Administration, Washington, D. C., USA.

THE BASIC PROCESSES

There are two fundamentally different processes involving the in situ combustion method of oil recovery: (1) forward combustion and (2) reverse combustion. In the first, the combustion zone advances in the general direction of air flow; whereas in reverse combustion, the combustion zone moves in a direction opposite to that of the air flow.

Forward Combustion

In a forward combustion process, once oil is ignited spontaneously or with aid of a downhole heater, a combustion zone is established around the air-injection well. A temperature and fluid-saturation profile develops similar to that shown schematically in Fig. 34-1. Generally, the peak temperature varies between 600 and 1,200° F. In the combustion zone, crude oil is vaporized and cracked or carbonized to produce a residuum or coke deposit on the sand face. This deposit serves as fuel in the combustion zone. Heat is then carried forward by convection by the water resulting from combustion, vaporized interstitial water, and the hot gaseous byproducts of the combustion.

Any oil that is not swept from the path of the advancing combustion front serves as fuel for the process. As a result, if combustion is complete, the burned-out region behind the fire-front contains no liquid, only a clean, gray-colored, dry sand. Near the injection well, the air that has been injected most recently is cooled to a nearly ambient temperature. In the zone immediately ahead of the combustion zone, the temperature reaches a plateau of about 300-500° F, depending upon the maintained pressure. This plateau represents the temperature of condensing water vapor. Preceding the steam plateau (Fig. 34-1) is a bank of warm fluids and the long region of the practically undisturbed reservoir except for increased fuel-gas saturation. The overall displacement mechanism is a highly complex sequence of gas drive, water displacement, hot-water drive, and solvent-assisted steam drive [2].

The process is fuel dominated; that is, the combustion front can travel only as fast as the deposited fuel is consumed by the

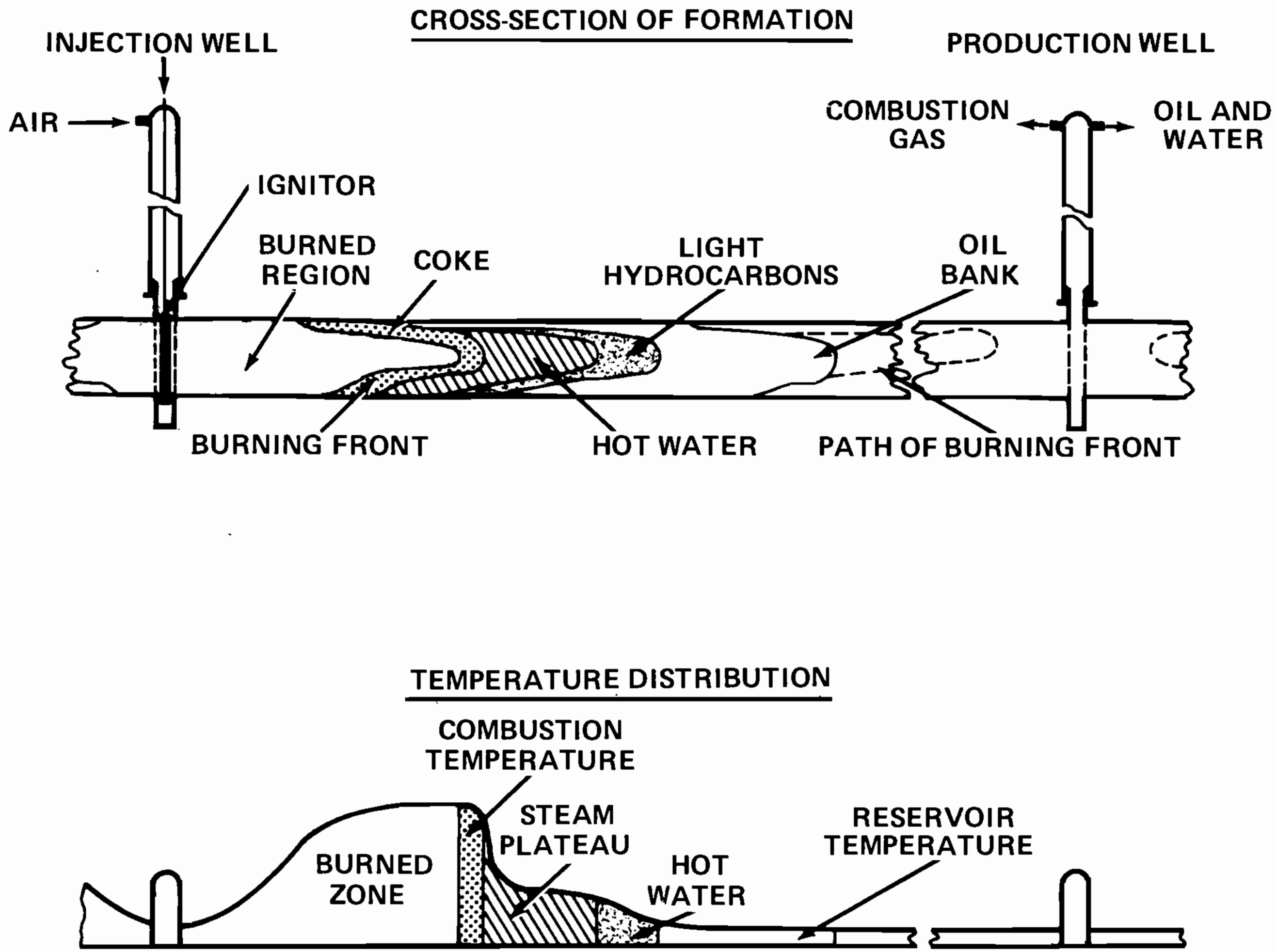

Figure 34-1.--Schematic diagram of in situ combustion process

oxygen in the injected air. It follows then, that the amount of fuel burned is a very important consideration since it is tied directly to air consumption--the most expensive item of the process. Also, fuel concentration along with air flux determine, to a large extent, if sufficient heat can be generated in the reservoir rock to support the combustion process or even whether or not the combustion can be conducted at all. Certain oils may leave very high deposits, such that the process would be prohibitively expensive with respect to economics, because of the excessive fuel consumption leading to high air-oil ratios [2]. Fuel availability at the combustion front is a function of oil gravity, porosity, oil saturation, oil viscosity, and atomic hydrogen-carbon ratio [3]. It is possible for free oxygen to pass through the combustion front or to bypass it due to air-channeling effects and, if this occurs, very severe downhole well corrosion problems can be anticipated.

Reverse Combustion

Reverse combustion has not progressed much beyond laboratory tests and a few small-spacing field pilot tests. It was developed as a method for recovery of very heavy oils which are so viscous that they cannot be produced by any conventional methods. Since the burning front moves in the reverse direction to air, the oil must flow through rock heated up to about 1,000^{o} F which reduces the viscosity of the oil by several orders of magnitude and permits it to flow freely into a well. The process is difficult to apply to commercial projects because spontaneous ignition around air-injection wells cuts off oxygen supply. Very heavy oils at very low reservoir temperature may be amenable to reverse combustion, because then spontaneous ignition may take several years to occur, while it may take anywhere from a few hours to a few weeks to spontaneously ignite other crude oils [4].

Wet Combustion

One of the recently developed refinements to forward dry combustion involves continuous or cyclic injection of water--a technique for improving the heat transport efficiency in the oil-bearing formation. The water, having a specific heat approximately four times that of air, absorbs heat left behind the fire front by evaporation and, as steam, carries the heat downstream beyond the combustion zone.

The direct result of water and air injection is the extension of the steam plateau to a greater distance, permitting more effective heat utilization for viscosity reduction of cold oil. The air requirement--a major expense of the in situ combustion process--can be decreased by partially quenching the combustion reaction. Increasing the water-air injection ratio can eventually reduce the temperature level in the combustion zone to that of saturated steam (Fig. 34-2). The temperature level of the saturated steam, usually from 300-500° F, is all that is necessary to reduce the viscosity of cold oil; any higher temperature generated in situ is essentially wasted on heating formation rock and the under- and overburden formations. At very high water-air ratios, the injected water can flow through the combustion zone without being converted to steam.

Despite some disappointing results from field pilot tests, a high level of interest in the technology is apparent from the regular appearance of publications and patents. There are many potential variations of the in situ combustion process and some may eventually be used to help solve the perennial problem of recovery of oil from tar sands and oil shales, if coupled with some form of fracturing or in situ retorting of a rubblized oil-shale rock. The consensus is that wet combustion offers significantly higher potential as a recovery method than does simple dry combustion.

PROCESS LIMITATIONS AND CAPABILITIES

Of the several enhanced-oil-recovery methods, in situ combustion is possibly the most complex technique. It is difficult to control in the field and even harder to simulate the process with a computer because of the variety of interacting physical and chemical phenomena.

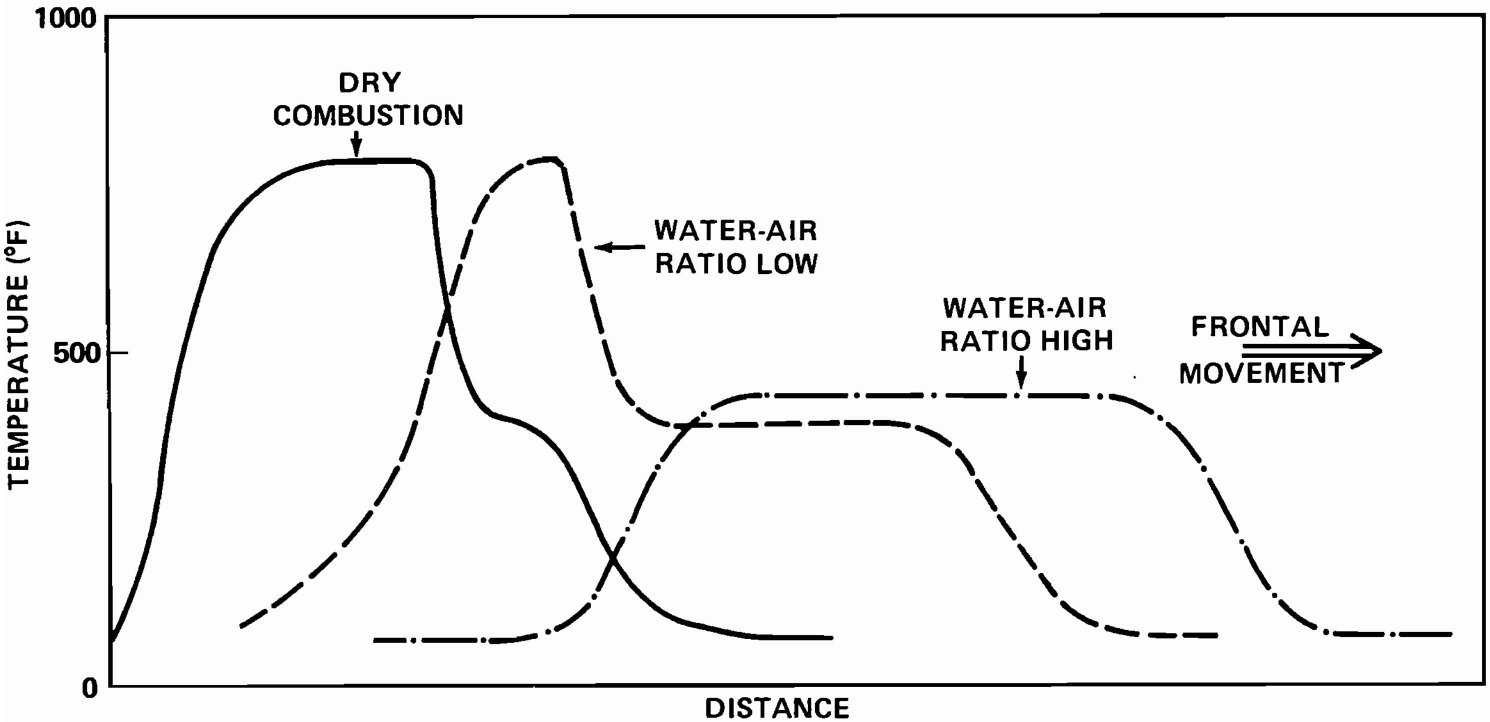

Figure 34-2.--Wet-combustion effect of water/air injection ratio on temperature profiles

Most of the problems occur at the producing end of the system and derive from three sources: elevated downhole temperatures, corrosion, and emulsions. The problem of hot production wells occurs when the temperature of fluids entering the production well is significantly above the reservoir temperature. High temperature combined with carbon dioxide and especially the presence of even a trace of unused oxygen create an environment conducive to severe corrosion problems. Hot wells may be cooled by injecting cold water into the annulus together with an emulsion-breaking agent, if necessary. Oxygen breakthrough can only be controlled by choking back the production well or severe damage of downhole equipment follows.

A normal in situ combustion project produces large volumes of exhaust gases. Under stabilized conditions, these gases are over 90 percent nitrogen, carbon dioxide, and steam. The net heat of combustion of such gases is so low that they will not burn under normal conditions. To reduce air pollution, in some cases, it has sometimes been necessary to incinerate the produced gases with supplemental fuels. It has been shown, however, that gas-combustion turbines can be used to recover the energy of compression, the sensible heat, and the heat of combustion in exhaust gases [5]. Pollution problems can then be solved while the exhaust gases are used to supplement the liquid fuel normally used to operate the turbine.

At the injection end there is corrosion hazard of simultaneous air and water injection and hazard of explosion of the well, if not completely clean of oil. Synthetic lubricants may be necessary for compressing air to high pressure.

Well ignition, initially of much concern to operators, can be achieved with a downhole burner, or spontaneously, with even a mild preheating by hot water or steam [6].

Plastic-coated tubing is frequently used in the injection and production wells to control corrosion and to control scale problems in the producers, particularly if strontium and barium are present.

One of the often neglected aspects in designing an in situ combustion project is the mobility of the cold oil in the reservoir, which must be moved if the firefront is to propagate. If the oil viscosity at reservoir temperature is too high, it may be difficult or impossible to get a project going at a satisfactory rate. Oil mobility ahead of the combustion front can actually be reduced by virtue of a three-phase flow regime, even though carbon dioxide, a combustion byproduct, has the effect of reducing oil viscosity. The practical significance of this is that there is an upper limit to the viscosity of oils that can be economically recovered by the forward in situ combustion process. It is not possible, however, to state the limiting oil viscosity for the process, since it depends so much upon such factors as the specific permeability of a formation, relative-permeability characteristics, well spacing, and the minimum economical production rate, among others.

On the other end of the oil-gravity scale, very light oils may not leave behind enough coke to support the combustion process. Asphaltic oils have better combustion characteristics than paraffinic oils; favorable burns were reported for oils ranging in gravity from 9 to over 40^{o} API, a broader range of application than possible with any other enhanced-recovery method.

One significant fact in the current picture regarding potential application of in situ combustion is an apparent consensus that this method offers the highest percentage of oil recovery in heavy oil prospects of any thermal recovery methods conceived so far [7]. One study on the potential contribution of enhanced-recovery technology to domestic crude-oil reserves [8] attributes higher compound recovery efficiency to the in situ combustion method than to any other known technique (Table 34-1). The advantages are that the heat can be generated in the oil reservoir itself, that fuel used in doing so is only a small portion of the reservoir oil, and the fuel consists of the least desirable heavy ends, most of which could not likely be recovered by any fluid-displacement method.

FUTURE POTENTIAL

Enhanced oil recovery with the in situ combustion method has not proved as promising as had earlier been hoped. According to a survey by the Oil and Gas Journal (Table 34-2) there were 38

TABLE 34-1.--Comparison of recovery efficiency in in situ combustion to other enhanced oil recovery processes

(Percent)

Process	(A) Process displacement efficiency	(B) Areal sweep efficiency	(C) Vertical sweep efficiency	(D) Compound recovery efficiency
In Situ Combustion	95	70	85	56
Steamflood	65	70	85	39
Cyclic Steam	--	--	--	20
Micro-Emulsion Flood	90	70	80	50
CO_2-Waterflood	80	50	80	32
NaOH-Waterflood	35	70	80	20

NOTE.--(D) = (A) (B) (C), where (B) x (C) yields the volumetric sweep efficiency (percent pore volume).

Source: After Hasiba and Wilson [8].

TABLE 34-2.--Active U.S. enhanced oil recovery projects

Method	1970	1973	1975
In Situ Combustion	38	19	21
Steamflood	22	22	31
Cyclic Steam	31	42	54
Polymer and Caustic	14/0	9/2	14/1
Micellar-Surfactant	5	7	13
Miscible Hydrocarbon	21	12	13
Carbon Dioxide	1	6	9
Total Active Projects	132	119	156

Source: Oil and Gas Journal Survey, April 5, 1976.

active projects in the 1970 survey, but only 21 active projects were reported for 1975. Another interesting statistic is that about 270,000 barrels of oil per day are now produced in the United States by enhanced-oil-recovery schemes and as much as 240,000 barrels per day of the total are being produced by thermal methods (cyclic steam, steam drive, and in situ combustion). Unfortunately, the contribution made by in situ combustion is relatively small.

In view of the apparent success of the method, at least in selected locations where project lifetime exceeds 10 years, it is fair to ask why there are not more large-scale operations and why there is an apparent decline in new project starts. There are a number of reasons. First, the method is very expensive; it requires a high initial investment for air compressors and special equipment. Furthermore, operating costs remain high throughout the project lifetime, particularly if corrosion problems are severe. All currently successful operations have been installed in heavy-oil reservoirs still producing under primary drive and essentially fully developed [7]. Thus, it was not necessary to drill many wells. Even under these favorable circumstances, a large investment still is required for air-compression equipment and well recompletions, for even a pilot operation.

Early results from in situ combustion often varied widely and a great deal of attention was required to solve the arising problems. Serious operational problems remain to be solved but they are not insurmountable. The principal problem can be traced directly to economic aspects; operators sought less expensive and more predictable modes of operations such as cyclic steam injection or steam drive.

It is almost certain that continued technological improvements will be made; there are so many potential variations of the in situ combustion process which have not been tested that this process must still be considered in early developmental states. When the business climate is ready, the process should find much wider application in properly selected reservoirs.

CONCLUDING REMARKS

In situ combustion is a highly complex process. While the performance of most other enhanced-oil-recovery processes can now be simulated, the simulation of the in situ recovery process remains "a task beyond man and computer" [9]. The process is beset with difficult-to-solve and expensive-to-correct operational problems. For example, after heat breakthrough, corrosion in producing wells may be so severe that it is impractical to keep the wells on stream (addition of cooling water can sometimes help for a while) [10].

Compared to other methods, in situ combustion is very expensive, partly because essentially the entire investment must be made before any oil is produced; the early investment of delayed income hurts profitability.

On the positive side, next to waterflooding, in situ combustion is perhaps the most widely applicable enhanced-recovery method. It is suitable for oils with gravities ranging from about 10^{o} to 40^{o} API and has the advantage in its use of omnipresent fluids. All secondary- and tertiary-recovery methods involve the injection of fluids, and it is unlikely that anyone will ever encounter cheaper and more readily available fluids than air and water.

The process definitely can produce additional oil where waterflooding cannot; in fact, it can be used in waterflooded reservoirs as a tertiary-recovery method. Unlike other thermal recovery processes, in situ combustion generates heat in the reservoir itself, which gives it a significant advantage. The amount of fuel consumed is a small fraction of the oil produced and it comprises the least desirable residuum, left behind as coke.

It is likely that the next decade will see important improvements made in the process of in situ combustion.

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CHAPTER 35

LOGISTIC RESTRAINTS FOR THE FUTURE PRODUCTION OF PETROLEUM BY TERTIARY RECOVERY

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Petroleum production by tertiary recovery processes, although conceptually not new, is far from being a mature technology insofar as general application is concerned. The technical difficulties and risks involved are described in other chapters in this section. As long as substantial technical uncertainties remain, meaningful economic analyses are all but impossible, except in terms of very broad ranges and qualitative principles. We can, nonetheless, identify those principles; establish first approximations for costs, production profiles, and other quantitative factors; and hence lead into a reasonable set of conjectures regarding future production.

As recently as 1975, a relatively optimistic viewpoint regarding tertiary production prevailed in many quarters. The present outlook is distinctly more cautious, as a result of a better perception of the technical, economic, and political uncertainties.

This paper examines the general logistic problems which will arise if tertiary recovery processes proceed on a broad scale and offers certain conclusions and guiding principles which will influence decisions regarding such applications.

The number of proposed methods is far too large to permit any detailed coverage. The use of surfactants has received a good

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bit of quantitative study; and surfactant methods will be given greatest attention as a means of illustration.

In no way is the primitive stage of development more apparent than in the fact that the definitions of secondary and tertiary recovery are a source of some contention. This paper will assume that the important tertiary processes are microemulsion flooding, surfactant flooding or "low-tension waterflood," carbon dioxide flooding, and thermal drives.

SURFACTANT METHODS

Surfactant recovery methods include both microemulsion flooding and "low-tension waterflooding"--the latter frequently not being considered a tertiary process. Since it influences the logistics of microemulsion technology, however, it is discussed below, together with predictions of demand and discussion of supply problems, costs, and general economic factors.

Background Conditions

The following conditions are stipulated in developing the forecasts of demand-supply:

- Response time is 4 years.
- Requirements for one barrel of oil produced are 10 pounds of sulfonates (100 percent active basis), 3 pounds of alcohols, and 1 pound of polymers.
- The average cost of domestic U. S. oil is about $7.50 per barrel. The overall average for the U. S., including imports, is about $10.30 per barrel.

No drastic political or economic upsets, other than those which have already occurred, and no miraculous technical breakthroughs are contemplated.

Forecast of Production by Microemulsion Flooding

Forecasts of production are presented in Fig. 35-1. It is improbable that general, large-scale use of microemulsion flooding can commence before 1979, leading to a significant level of production in 1983. Curve A is a reasonable but probably

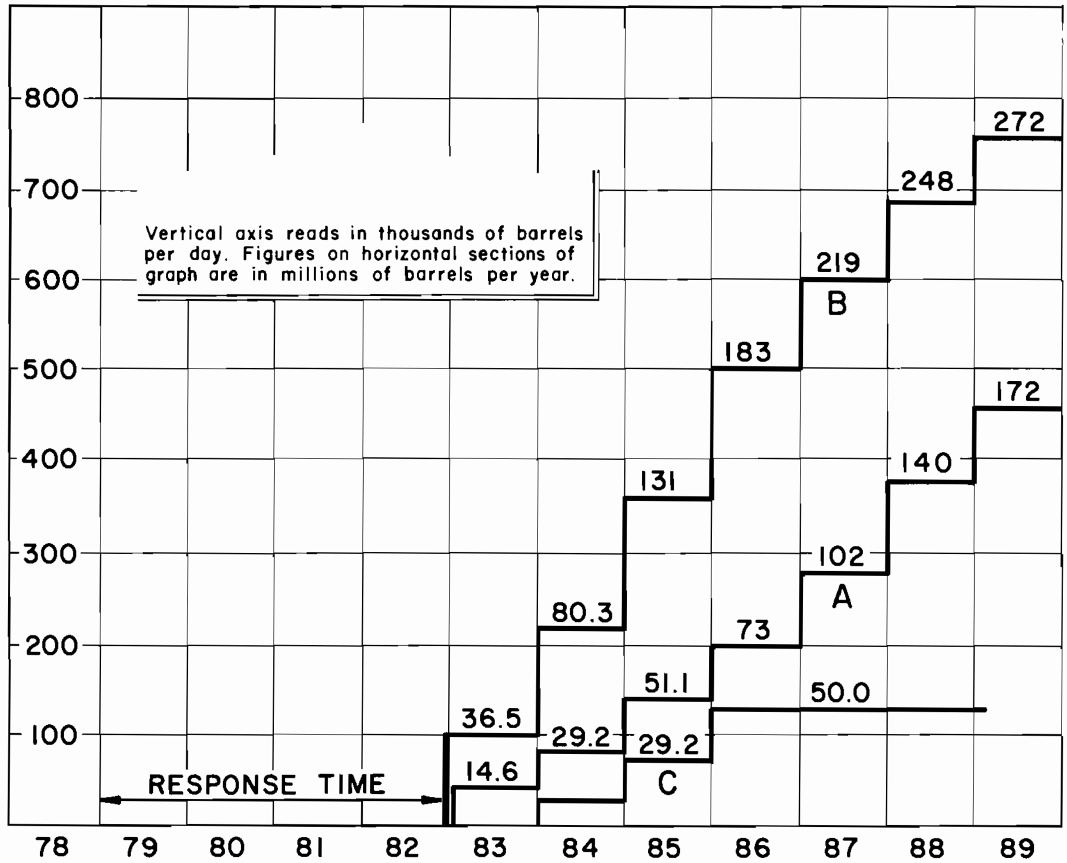

Figure 35-1.--Oil production by microemulsion flooding

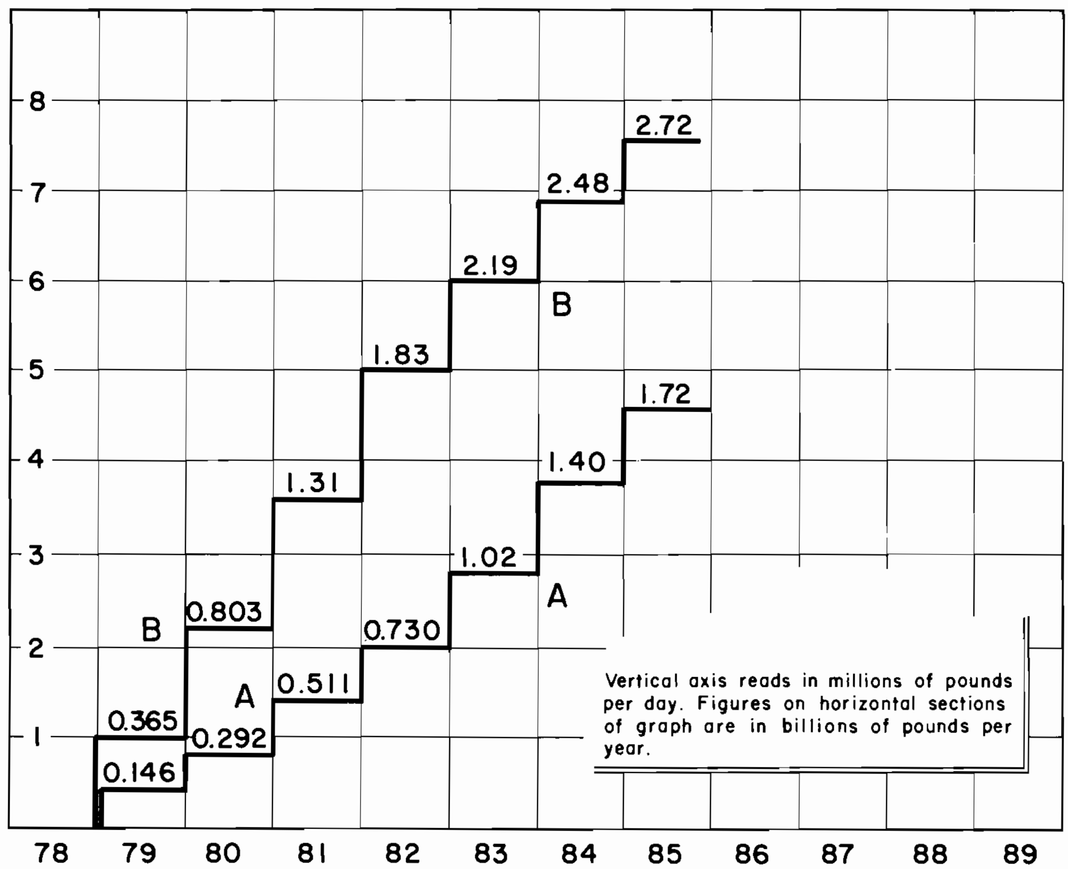

Figure 35-2.--Sulfonates demand for EOR

optimistic case. (It should be noted that industry confidence in early use of this technology has diminished in recent months.) Curve B is considered to be an upper limit, even with assumption of a "crash program"; and, hence, sets an upper limit on demands. Curve C is a minimal case based on application only to highly favorable situations.

Demand for Sulfonates

Demand for sulfonates by year is given in Fig. 35-2. An estimate of 10 pounds of sulfonate (100 percent active basis) per barrel of oil produced is widely accepted. The variation in estimates is about +5, -3. Estimates are influenced primarily by the following two factors: choice of broad spectrum or "tailored synthetics"; and, judgment regarding application to less favorable situations, as the technology is proved to be successful.

The figure of 10 pounds per barrel is not expected to decrease with time. About 70 to 80 percent is expected to be broad spectrum with a gradual move towards increased use of tailored synthetics when and if the technology is proved. The cost of broad-spectrum sulfonates is estimated to be 12 to 21¢/lb on a 60 percent active basis (20.0 to 35.0¢/lb on a 100 percent active basis). "Tailored synthetics" are estimated at 24 to 60¢/lb. The wide ranges in price result from the fact that some of these materials are much more expensive to synthesize. But, the use of the higher priced materials must be justified on an increased efficiency of recovery (i.e., a lower requirement in pounds per barrel of oil). Hence, for cost calculations, the figures given earlier for quantities required (10 pounds of sulfonates per barrel of crude) should be combined with the lower price ranges.

Demand for Alcohols

Alcohol demand appears in Figure 35-3. As estimate of 3 pounds of alcohol per barrel of oil produced appears to be valid, though with fairly wide variation. The variation seems to be based primarily on the choice of isopropyl alcohol (IPA) as

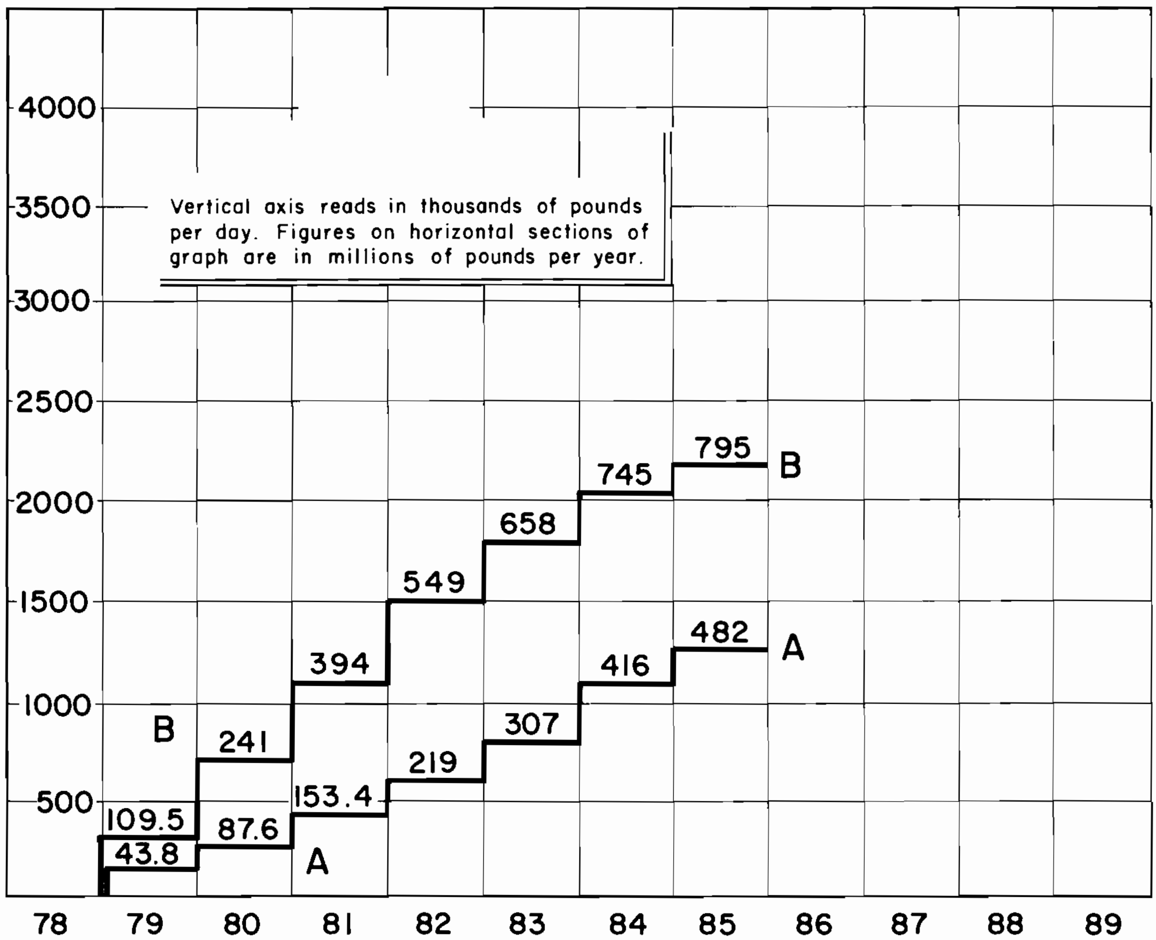

Figure 35-3.--Alcohols demand for EOR

against higher (C_4, C_5, C_6) alcohols. Use of higher alcohols (more "effective" per pound) tends to reduce the ratio, and of IPA to increase it. Cost estimates for IPA are 13 to 15¢/lb; for C_4 alcohols, 20¢/lb; and for higher alcohols, 30 to 40¢/lb. (Hence, alcohol cost per barrel of oil is at least partially balanced by counteracting factors of higher unit cost vs. lower volume required.) Usage of 50 percent IPA and 50 percent higher alcohols is predicted.

Demand for Polymers

Demand for polymers is shown in Fig. 35-4. A ratio of 1 pound of polymer per barrel of oil, with a range of ± 1/4 pound, is widely accepted, with a warning that saline reservoirs may require more. No decrease below this range is predicted. Industrial opinions indicate considerable dissatisfaction with the current generation of polymers and a need for extensive R & D on this topic. In some cases, the polymer is injected concurrently with the sulfonate, and in other cases is injected as a separate plug perhaps 2 years later. In developing the data for Fig. 35-4, the assumption was made that 50 percent of polymer use was concurrent and 50 percent 2 years subsequent to the sulfonate injection. Cost estimates are 1.00 to 0.60$/lb for polyacrylamides and 2.00 to 2.50/$/lb for polysaccharides. There is strong evidence that the cost of polysaccharides can be sharply reduced for the volume required for EOR.

Supply of Sulfonates

Current U.S. production of sulfonates (all types) is about 400×10^6 pounds per year. This amount provides very little material for microemulsion flooding applications, without infringing on current uses. Capacity appears to be about 600×10^6 pounds per year if quasi-obsolete detergent plants are included. (In addition, both Stepan Chemical and Marathon Oil expect to have plants on stream in July, 1976, both in the 70 to 90×10^6 pounds per year range.)

Several companies have indicated that they either have definite plans to expand production or have stand-by plans for

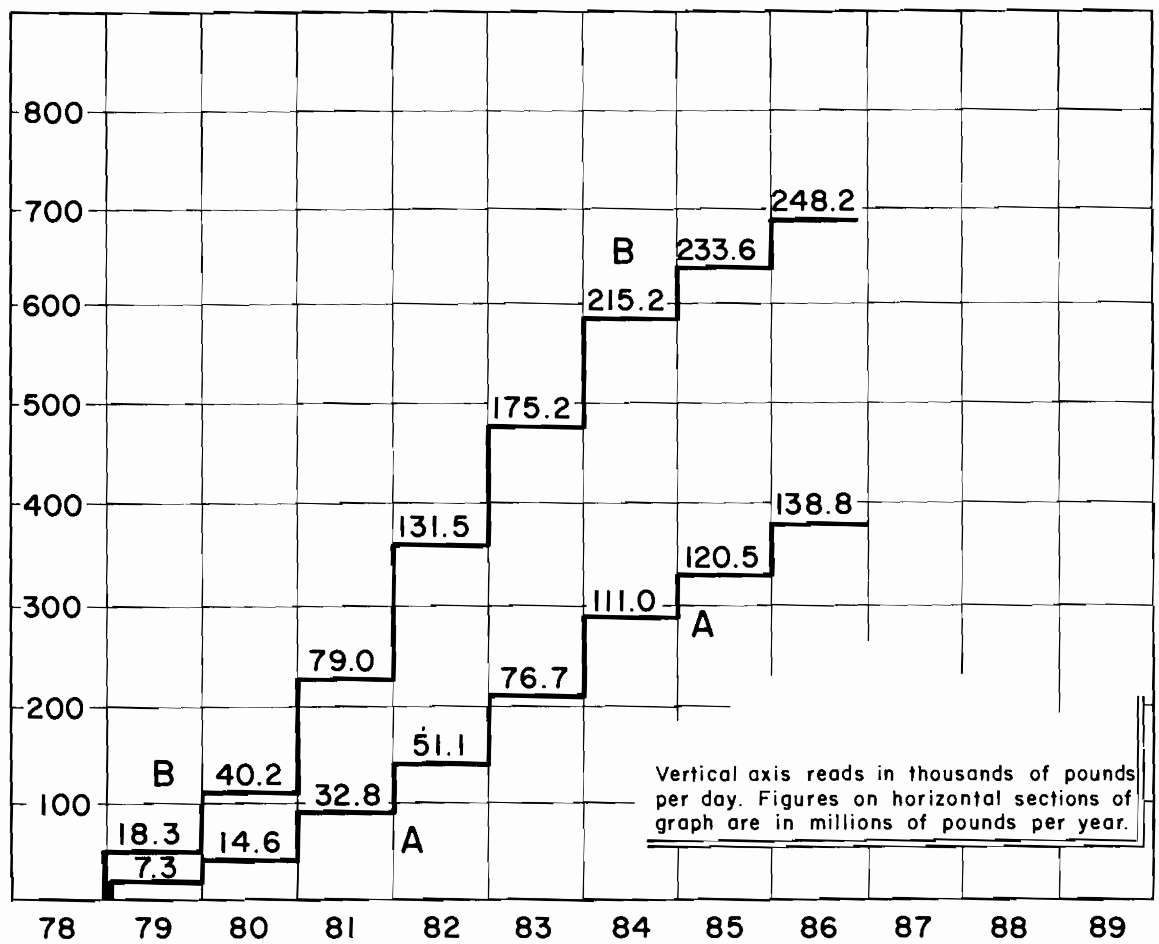

Figure 35-4.--Polymers demand for microemulsion EOR

plant construction, pending firm decisions on microemulsion applications. In the latter category are some of the largest oil companies. It appears quite logical and quite probable that a large producer, having decided on a major microemulsion program, will proceed to develop its own production capability. Thirty months must be allowed from a firm corporate decision to build, until the plant shall be on stream.

Capacity thus appears to be available to support a rapid escalation of field tests, but not full field production; and a building program must be visualized to accommodate the demand of Fig. 35-2. In general, such a building program will focus on plants located in or near large manufacturing complexes, rather than in producing fields.

Prices of 16¢/lb (± 4) for broad spectrum sulfonates (60 percent active basis on and 40¢/lb (± 15) for tailored synthetics would bring out an adequate supply. With this price structure, feedstock shortages or equipment availability are not viewed as serious future barriers.

Capital costs for the sulfonate plants are estimated at $0.15 to $0.30 per annual pound ($/an lb) for broad-spectrum materials, depending on purity; and 0.30 to 0.55 $/an lb for tailored synthetics. A weighted average for all production of 0.32 $/an lb appears to be reasonable. This leads to capital requirements (based on Fig. 35-2) of $\$234 \times 10^6$ (Case A) to $\$586 \times 10^6$ (Case B) to be expended in the period 1976 through 1980. This figure does <u>not</u> include cost of increasing national SO_3 capacity.

<u>Supply of Alcohols</u>

The question of alcohols supply is complicated by the unresolved question: will isopropyl alcohol be used, or will higher (C_4, C_5, C_6) alcohols be used. In this analysis, a usage of 50 percent IPA and 50 percent higher alcohols will be assumed.

Current <u>production</u> is about 2×10^9 lb/year of IPA, 800×10^6 lb/year of butyl alcohols, and about 100×10^6 lb/year of higher alcohols. The production of the latter is often tied to production of other "oxo-compounds," often seriously complicated the problem of expansion. Capacity is probably about 20 percent higher than these figures, for propyl and butyl alcohols; about 100 x 10^6 lb/year for pentanol; and 40 x 10^6 lb/year for hexanol. A few large oil companies have indicated their intention to go into production for their own requirements. This tendency is certainly not as common as in the case of sulfonates.

As with sulfonates, supply capacity is available for gradual escalation of a test program; but capacity to meet demand, as described in Fig. 35-3, may largely be new construction. Field plants are not contemplated.

Prices of 14¢/lb ($\pm$ 1) for IPA and 35¢/lb ($\pm$ 5) for higher alcohols will bring out required supplies. (One company reports available supplies of 500 x 10^6 lb/yr of TBA at 9¢/lb.) No serious feedstock or equipment barriers are foreseen in these price ranges.

Capital costs of 0.70 $/an lb for IPA and 0.95 $/an lb for higher alcohols are predicted. A weighted average of 0.83 $/an lb leads to capital requirements, based on Fig. 35-3, of $182 x 10^6 (Case A) and $455 x 10^6 (Case B), to be expended in the period 1976 through 1980.

Supply of Polymers

Demand and supply projections for polymers for EOR are made especially difficult by the general dissatisfaction with the current generation of materials. Polyacrylamides are substantially cheaper than polysaccharides, but are somewhat shear-sensitive and salt-sensitive. The industry feels that a great deal of research is required in this area. Hence, any polymers which are in large-scale use in the mid-1980's may be distinctly more effective than those immediately available. (As a first approximation, a usage of 50 percent polyacrylamides and 50 percent polysaccharides will be assumed.) Since the production of these polymers is a rather sophisticated process, no field plants are presently planned. In general, the large oil producers are not expected to undertake production for their own use.

Current production of polyacrylamides and polyaccharides is estimated to be about 35 x 10^6 pounds per year, of which perhaps

10×10^6 pounds per year might be available for EOR. This figure is subject to considerable question, since there are many compounds involved and the classification of these compounds is far from uniform. The percentage expansion of polymer production for microemulsion EOR will be far greater than the percentage expansion on sulfonate or alcohol production.

Prices are projected to be 1.45 \$/lb ($\pm$ 0.30) for polyacrylamides and 2.25 \$/lb ($\pm$ 0.25) for polysaccharides, under large-scale production conditions. Very large-scale production of polysaccharides might reduce the prices by one-third, or more.

Capital costs of 1.10 \$/an lb for polyacrylamides and 3.25 \$/an lb for polysaccharides are predicted. A weighted average of 2.38 \$/an lb leads to capital required (based on Fig. 35-4) of $\$192 \times 10^6$ (Case A) and $\$390 \times 10^6$ (Case B), to be expended in the period 1977 through 1981.

Surfactant Flooding or Low-tension Waterflooding

Increased application of surfactant flooding could significantly alter the supply requirements which are presented in Fig. 35-2. Although the concentration of surfactants which are typically used are distinctly lower than in microemulsion flooding, the total quantities may be quite large. It is most doubtful that demand, in any combination of events, will rise as high as Curve B. If, as an illustration, we conjecture a parallel development of both applications, so that a demand is created lying midway between A and B, temporary shortages of sulfonates could occur. Some real problems of supply would be encountered for several years. Here again the urgent need for a long-term stable climate for development is obvious.

Worldwide Applications

The same principles of demand and supply and of resulting logistic problems probably will apply worldwide, but with different production profiles, time schedules, and potentially serious transportation barriers. In regions which are quite far from major industrial centers, the economics of selecting the best technology will be distinctly different.

The generalization suggested earlier, however, will probably obtain: with the industry alert to the problem and a reasonably stable climate for development, a number of problems can be foreseen, but no serious and continuing restraints, other than manpower, as discussed below. In the remote chance of a "crash program," serious restraints on the chemicals themselves, plant construction, equipment, tubular goods, and transportation facilities may occur.

CARBON DIOXIDE FLOODING

Forecasts of CO_2 demand and supply are quite premature, at this point, except as part of an effort to foresee what restraints might occur. Tertiary production tests of this type have met with some degree of success, but the technology is far from being "proven," in general. It is improbable that general application can commence before 1981. The production profiles might then approximate those shown in Fig. 35-1, with earliest commencement deferred to 1981, and response time cut to 2 years. In this figure, Curve B must be considered a highly optimistic forecast, and Curve A, a more realistic one, assuming that development of the technology and the economic framework are favorable during the next 2 years.

Estimates of requirements for CO_2 range from 3 to 8 x 10^3 standard ft^3 per stock tank barrel of oil injected. Assuming that one-third of the CO_2 fingers through the formation, and is then recompressed and reinjected, the CO_2 supplied will be in a range of 2.25 to 6 x 10^3 ft^3 per barrel, at an 80 percent confidence level.

Assuming, as a rough approximation, that Curve A in Fig. 35-1 represents the production profile of oil, the demand for CO_2 in the U. S. will be in a range of 32.8 to 87.5 x 10^9 ft^3 per year in 1981, rising to a range of 167 to 445 in 1986.

The supply problem is largely one of "logistics" in the earlier, military definition of that word: how is the CO_2 to be supplied to the well in which it is needed. The amount of CO_2 generally "available" is enormous, but diffuse. As a practical matter, the sources are gas wells which are high in CO_2 or very large process plants, such as the proposed large coal-fired electric power plants. The probability that large CO_2 sources will be located very near those oil-fields in which the CO_2 is needed is quite remote. The U.S., CO_2 well sources are from 200 to 600 miles away from the locations in which the CO_2 might best be used. The problem, then, becomes one of pipelining rather than of production.

The cost of moving CO_2 by pipeline is in a range of \$2.00 to \$3.00 per 10^6 ft^3 per mile. The feasibility of constructing a pipeline to carry large volumes will vary greatly, of course, depending on the pressures required, the nature of the terrain to be crossed, the life of the project, and a number of other factors. At present, CO_2 may be regarded as a nuisance, in many cases, so that the value as produced might be almost zero. When and if it becomes apparent that it has value as a commodity, however, that viewpoint will change. As a first approximation then, we might assume a price range of 40 to 80¢ per 10^3 ft^3 at the point of production.

Now, as an illustration, let us assume a situation in which the requirement is 4 x 10^3 ft^3 per barrel, a production cost of 50¢ per 10^3 ft^3, and a transportation distance of 300 miles. We arrive at an incremental cost of \$5.00 per barrel for the CO_2. This figure does not, of course, include equipment and field operating costs.

A detailed analysis of equipment capital charges and operating costs would be far beyond the limits of this paper. A reasonable range of estimates indicates that from \$3.00 to \$5.00 per barrel will be added to the price of the oil. The equipment required is quite routine in nature, although some materials problems may appear, because of corrosion. Supply of the equipment should not be a significant problem, since it is not specialized, and since no crash program is anticipated.

Two points become immediately apparent. First, it is clear that the logistic analysis is highly specific to the case under consideration. Second, it is clear that, if the case is not favorable, the price of oil required in order to justify production by this technology quickly goes beyond reasonable bounds. Simplifying generalizations are quite dangerous, and we can do little more at this point than to list and examine the pertinent factors for specific cases.

Another approach which is now being made to this problem is to estimate the price of oil which is required in order to bring about significant incremental production by CO_2 flooding. The data are incomplete, as of this moment. A preliminary estimate indicates that \$15.00 to \$20.00 per barrel will be required in order to increase the U. S. reserves by 2 to 3 x 10^9 barrels. Only under the most favorable conditions will the price fall below this range.

The discussion of CO_2 flooding, to this point, has been based on U. S. conditions. No data have been assembled so far on other nations, but the principles set forth above will generally pertain. The basic requirement is the existence of a supply of CO_2 within reasonable pipeline transportation distance. Given these conditions, the future use of this technology depends primarily on reservoir and systems characteristics, large and local supply of CO_2, and a generally favorable economic structure.

THERMAL DRIVE

The classification of thermal drive as a tertiary process is open to question. The subject matter has been discussed earlier. In many cases, thermal drives are already a secondary process, or even, for very heavy oils, primary.

In contrast to other methods, no chemicals (such as CO_2 or surfactants) are introduced into the reservoir other than water and air. Aside from reservoir characteristics and production history, the selection of method and economic analysis depends very heavily on fuel costs and cost of compression.

As the prices of oil and gas rise, the economics of thermal drives improve rather slowly, because of the dependence on fuel costs. The equipment required consists mainly of compressors, boilers, and in some cases, water purification plants. Where choices exist between higher capital costs (for equipment) and fuel consumption, higher oil prices will naturally tend to favor the direction of higher capital investment.

Thermal drives of several types are in widespread use. Supply of equipment should not present any serious difficulties, unless an unexpectedly rapid development occurs.

The absence of any requirement for chemicals may make thermal drives relatively more favorable outside of the U. S. than inside the U. S. If such is the case, then the demand for the equipment required will increase substantially. Again, however, the relatively unspecialized nature of the equipment and the gradual buildup which can be expected would indicate that no serious industrial logistic problems will occur.

MOBILITY CONTROL AGENTS AND OTHER CHEMICALS

It should be noted that polyacrylamides and polysaccharides are used in secondary methods of recovery, notably in waterfloods, and that the demand may be very large if these applications do move ahead rapidly. There is no way to produce a valid forecast. It is difficult, however, to visualize a demand which would go beyond Curve B in Fig. 35-4. Such a situation would result in serious shortages until plant construction could close the gap.

Sodium hydroxide and "conditioning agents" (notably inorganic phosphates) for dealing with high-salinity problems, will be used in both secondary and tertiary applications. Industrial capacity for these chemicals is, in general, very large and the incremental demand for oil production should present no difficulty.

In surfactant methods, and to a much lesser degree in some other methods, a problem of emulsion-breaking exists. Large-scale application will create a demand for emulsion-breaking and antifouling agents.

EQUIPMENT SUPPLY AND PLANT CONSTRUCTION

Pumps, compressors, boilers, heaters, and water purification plants are the general categories of equipment required for injection operations. The design of separation equipment required may be conditioned by emulsion-breaking problems of a special nature. Since a good bit of "in-fill drilling" will be required, a demand for the customary drilling equipment and for tubular goods will be created. A number of specific corrosion problems have been encountered already which, once identified, can be resolved.

These supply problems can be identified even though they cannot be quantified, except as conjecture. It should be noted that the development of demand for such equipment for tertiary processes will almost certainly be paralleled by similar demands for secondary processes.

The manufacture of equipment, and of materials as well, calls for plant expansion and new construction, initiating the typical long chain of supply problems, reaching back to the level of raw material sources. This chain of events has been taken into account in making the judgment that all major problems of supply can be successfully resolved by an alert and orderly development. These observations serve to emphasize, however, the unavoidable risks and early capital investment, together with the urgent need for a stable political and economic climate.

The magnitude of the demands within the U. S. for chemicals and equipment can be met for practically any realistic prediction for the next 10 years, without severe dislocations. Much larger expansion of demand is most unlikely to occur earlier than the late 1980's, giving adequate time for industry to meet further increased demands. If, however, both secondary and tertiary methods advance rapidly, on a broad front, equipment supply will become a severe restraint. If, for instance, concurrent development of surfactant methods and CO_2 flooding and thermal drives occurs, severe bottlenecks in equipment supply will occur. The probability of this actually happening is remote.

MANPOWER

Manpower requirements appear at every step of our analysis as a critical and continuing problem. Assuming the eventual development of a reasonably favorable political climate, the supply of trained manpower may emerge as the only insurmountable restraint in applications of tertiary recovery. Such shortages exist throughout the field of energy supply.

In tertiary recovery applications, however, as with any undeveloped technology, there is a particularly unfavorable sort of circular logic at work: we foresee manpower shortages, when and as tertiary applications develop; but the progress of development itself is already constrained by the lack of trained manpower (for instance, in government funding agencies). In this case, we may need a "crash program" if rapid progress is to be made within the next decade.

THE IMPACT OF CRUDE OIL PRICES

One of the most difficult aspects to deal with is the effect of changes in the price of crude on chemicals, on equipment, and indeed, on all parts of our economic structure. It is completely obvious that the cost of sulfonates is a function of crude oil prices, since the oil provides the feedstock for sulfonation. It is, perhaps, less immediately obvious but not less true that the cost of equipment, plant construction, and plant operation are affected also. In particular, with such drastic changes as have occurred in recent years, the impact on the economy in general can invalidate any sort of "routine" forecasting.

In Fig. 35-5, an effort is made to illustrate this effect on fuels, chemicals for tertiary recovery, equipment, and construction. These figures are to be regarded as roughly quantitative only, for purpose of illustration.

The first figure, for gasoline and diesel fuel, is quite simple and may, in fact be numerically accurate. The in-plant cost of manufacturing diesel fuel is about one-third lower than the cost of manufacturing gasoline. As the price of crude rises, the cost of manufacturing rises, but much less than the crude itself; and the spread between the two, though increasing with the crude price, becomes much smaller on a percentage basis.

The cost of microemulsion chemicals is a bit more complicated. As a first approximation, we may consider that 20 percent of the cost of these chemicals is directly proportional to feedstock costs. If we then assume that 15 to 20 percent of the

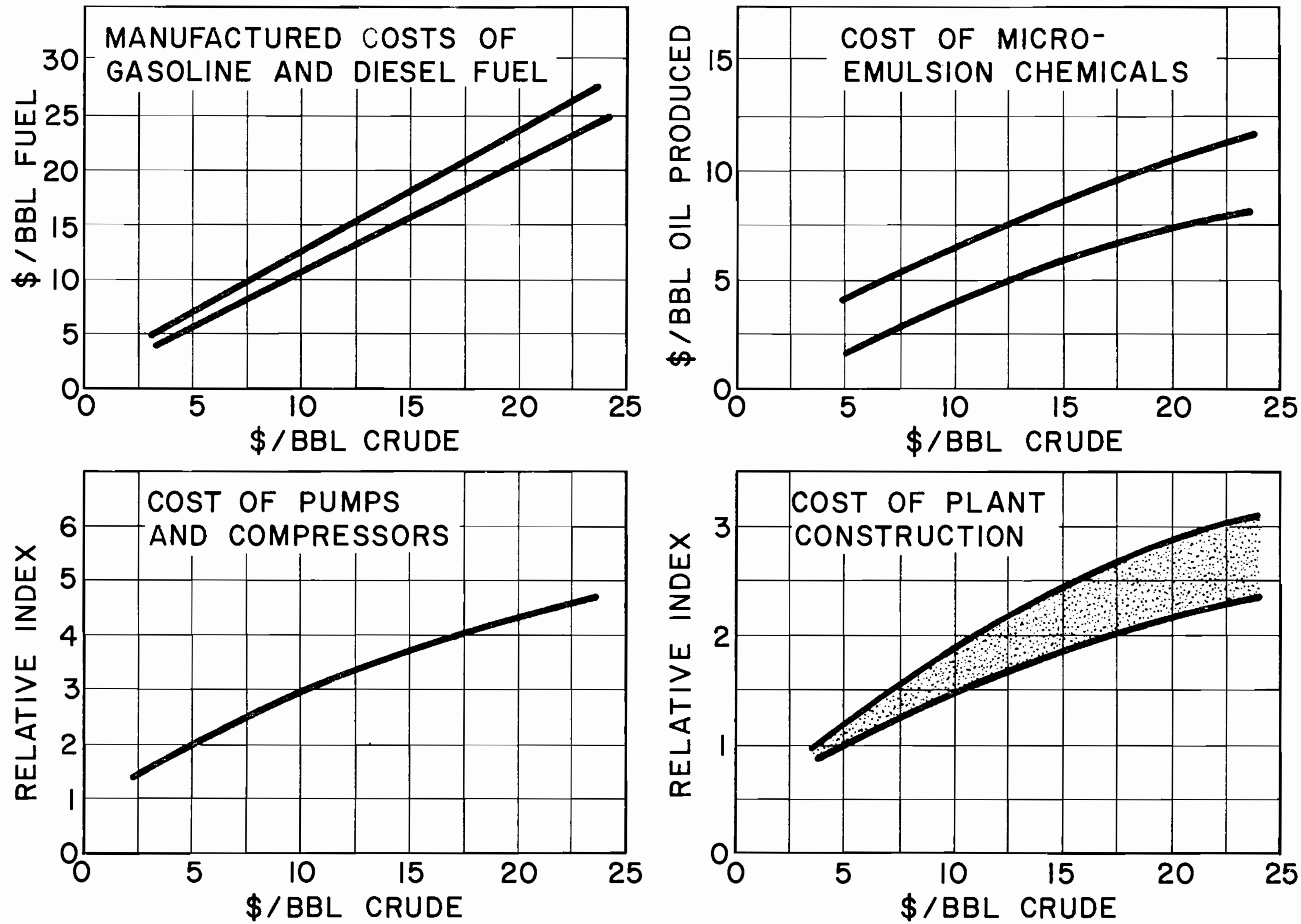

Figure 35-5.--Estimates of impact of crude oil price

chemicals' cost is established by crude prices as a result of more general inflationary impact, then a doubling of crude price should cause a rise of 35 to 40 percent in the cost of the chemicals. The injected cost should be larger, of course, and should show a somewhat steeper rise.

The figures for pumps and compressors and for plant construction are offered as examples only, since the investigations, on a direct, industrial data basis, are as yet incomplete.

This very simplistic discussion ignores a number of variables. Most important, perhaps, is the profitability required. The DCF rate of return has been assumed to be "typical" of the enterprise; for instance, 10 to 25 percent for fuels, but 15 to 20 percent for a more risky EOR venture.

It is astonishing to see how frequently this relationship has been ignored. Even though a precise analysis probably is impossible, the general effect must be included in all predictive work.

CONCLUSIONS

The various technologies of tertiary recovery are complex and not well understood. The financial risks involved are, in general, severe. Technically, each case depends heavily on the nature of the reservoir, the location, the previous production history, and a number of other factors. For instance, the economics are strongly dependent upon residual oil saturation; but the means for determining this factor are generally of poor reliability. Energy requirements are a major factor. Consequently, as the price of oil goes up, the cost of producing oil goes up. Many analyses have been in error, in the past, as a result of ignoring this point. Tertiary processes, being at the end of the line, are especially sensitive to this relationship. In general, the equipment and materials required are routine or, at least, not exotic, although, hopefully, significant improvement will be made. The applications of tertiary recovery processes as systems, however, are not to be regarded as a mature technology.

As a consequence of the statements above, generalizations regarding the overall system, predictions regarding aggregate production or equipment and material, or estimates of cost are extremely uncertain. Such cost analyses as are available today indicate a price range of $15.00 to $20.00 per barrel for U. S. production. The nature of the processes and the length of the development period indicate that there should not be any continuing logistic problems which cannot be prevented by adequate advance information to the manufacturing sector. This is not to say that there are no problems, but rather that there need not be serious delays and disruptions of supply. Trained manpower continues to appear as the most serious shortage in the development and application of tertiary processes.

In areas which are quite remote from large industrial centers, economics of tertiary processes may be much less favorable than they are in the current production areas of the United States.

The elements of high risk, of heavy capital investment, and of long delays demand a long term, stable economic and political climate if tertiary recovery is to move forward on a major scale. Such a climate is mandatory, if the technical problems are to be solved successfully for large-scale applications.

ACKNOWLEDGMENTS

The information on which this paper is based has been provided by about 50 corporations, on a strictly confidential basis. Even though they are not named, I wish to express my deep appreciation for their continuing efforts. Without the help of the Gulf Universities Research Consortium industrial affiliates and a substantial number of other industrial colleagues, this study would not have been possible.

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SECTION V. GAS IN TIGHT FORMATIONS

CHAPTER 36

THE RESOURCE POTENTIAL OF GAS IN TIGHT FORMATIONS

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INTRODUCTION

At year end 1974, world gas reserves are estimated to amount to about 2,160 x 10^{12} ft^3, of which the U.S. share is about 237 x 10^{12} ft^3, about 11 percent of the world total. U.S. production in 1974 was 21.3 x 10^{12} ft^3, resulting in a ratio of reserves to production of about 11:1. This is not a comfortable ratio, considering that natural gas provides more than 28 percent of total energy used. The U.S., therefore, must examine very carefully all potential sources of supply, including the natural gas known to exist in tight formations, both sandstones and organic black shales. This review is confined to possible future supplies of gas from tight sandstone formations; the tight shales are considered in Chapter 38.

DEFINITIONS

For present purposes, tight gas formations refer (Elkins, 1976) to certain sandstone deposits most commonly found in the western United States. The prospective reservoirs generally have porosities of 5 to 15 percent, immobile water saturations of 50 to 70 percent, and gas permeabilities of .001 to 1 millidarcies (md). At higher gas permeabilities, the formations are

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generally amenable to conventional fracturing and completion methods.

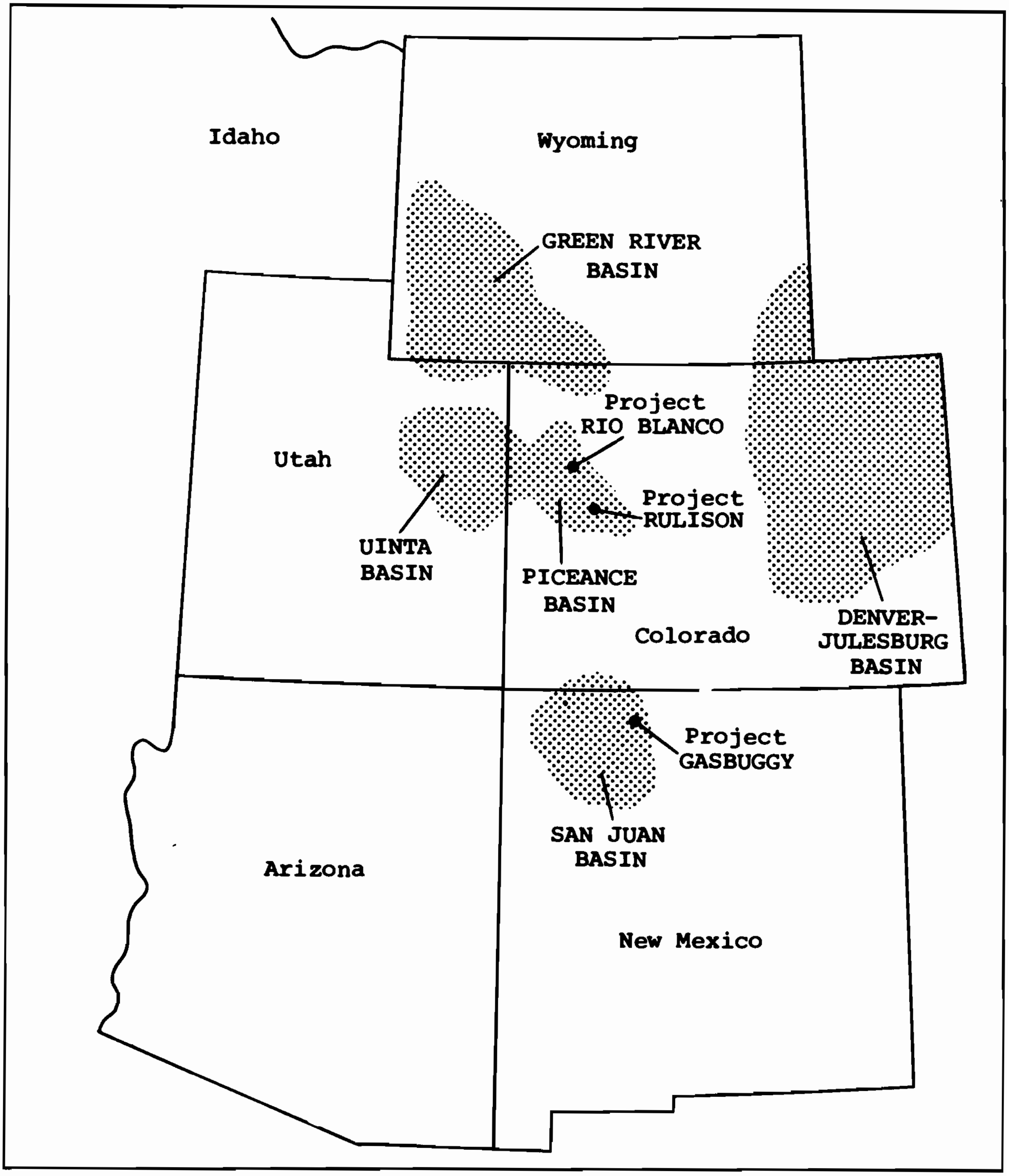
The formations themselves are of two general types with numerous gradations between. One type consists of massive, more or less homogeneous sand bodies of uniform thickness and considerable areal extent. The other type consists of shales and clays containing sandy zones or lenticular sandstone members. In either case, the basin containing the tight formations should measure in the thousands of square miles, in order to provide suitable targets. In some places, aquifers included in the stratigraphic section may strongly influence hydraulic-fracturing possibilities.

RESOURCES

Within the U.S. many areas contain formations that meet the definition of tight gas sand. The most important of these with respect to resource potential is the Rocky Mountain area (Fig. 36-1). The natural gas potential here was studied in detail for the 1973 National Gas Survey (U.S. Federal Power Commission, 1973), with particular emphasis on the Piceance, Green River, and Uinta basins. In this study, the following criteria were used to identify tight sandstone formations:

1. Low-permeability reservoirs not amenable to recovery with conventional completion techniques.
2. At least 100 ft of net pay, 65 percent or less water saturation, and 5 to 15 percent porosity.
3. At least 15 percent net sand in the gross prospective productive interval.
4. Reservoir depth between 5,000 and 15,000 ft.
5. Prospective areal extent of reservoir at least 12 mi^2.
6. Reservoirs in remote areas. This requirement is only applicable when nuclear fracturing is involved, but is not desirable when hydraulic fracturing is used.
7. Pay zones not interbedded with highly permeable aquifers.

The Frontier and Mesaverde Formations, which contain the tight sandstones in the three basins, consist of thick sequences



Source: Luetkehans et al. (1976)

Figure 36-1.--Tight gas-sand basins in the Rocky Mountains of Lower and Upper Cretaceous fluvial sandstones. The low permeability and discontinuous nature of the reservoirs explain the lack of conventional gas production in these formations.

Rich oil-shale deposits of the Green River Formation overlie the prospective tight gas strata in all three of the basins. Oil resources in high-grade shale alone, yielding 30 gallons or more of oil per ton, in zones more than 100 ft thick, total 418 x 10^9 barrels; of this amount, 355 x 10^9 barrels is in the Piceance basin, 50 x 10^9 barrels in the Uinta, and 13 x 10^9 barrels in the Green River basin (Culbertson and Pitman, 1973). The gas resources in the tight sandstones in the basins were determined volumetrically, on the basis of total pay interval and net pay thickness. The estimates also were assigned levels of confidence, defined as follows: Category 1, good well control; Category 2, inferred from geological interpretation but having sparse well control; and Category 3, speculative because of lack of testing. The estimates are summarized in Table 36-1.

Large quantities of gas are, without question, in place in the formations. Production tests following various fracturing experiments have proved this. However, the gas-resource estimates for the basins as a whole are imprecise, as are the data on basic reservoir parameters. Nevertheless, the gas resource figure of 600 x 10^{12} ft^3 tends to be quoted without qualification. Certainly for planning purposes relative to future gas supply, it would be wise to use only the total amount of 242 x 10^{12} ft^3 assigned to Category 1 in the three basins.

Tight formations exist in many other parts of the U.S. and, presumably, elsewhere in the world. The National Gas Survey study cited some specific examples: deep Mississippian and Pennsylvanian sandstones in Oklahoma, Cretaceous and Eocene sands in the Gulf basin of Texas, and Devonian sandstones in the Appalachian basin in the eastern U.S. Noran (1975) described an increase in productivity of a gas well in the Cotton Valley Formation (Upper Jurassic) of East Texas from 210 x 10^3 ft^3 per day to more than 1.6 x 10^6 ft^3 per day after massive hydraulic fracturing. In the Denver-Julesburg basin in eastern Colorado, the Cretaceous so-called "Muddy 'J' Formation" likewise is yielding as much as 1.5 x 10^6 ft^3 of gas daily, after fracturing, from test wells that may produce only 100 x 10^3 ft^3 per day naturally (Fast et al., 1975). The Denver-Julesburg basin contains an estimated 1.2 x 10^{12} ft^3 of gas in tight formations. These examples all do not indicate resource levels, but they show very clearly that the new fracturing techniques being perfected today for very low permeability gas sands demonstrate the possibility of increasing recoverable U.S. gas reserves manyfold, by enabling subeconomic resources to be moved into the prove-reserve category.

Table 36-1.--Estimate of gas resources in tight sandstones

	Depth interval (ft)	Area (mi^2)	Gas in place (10^{12} ft^3)
Piceance basin			
Category 1	5,600-8,750	550	103.2
Category 2	5,600-8,750	650	103.9
Total		1,200	207.1
Green River basin			
Category 1	8,000-12,000	140	37.1
Category 2	9,500-15,800	500	108.4
Category 3	9,000-12,000	500	94.5
Total		1,140	240.0
Uinta basin			
Category 1	8,000-11,000	300	101.6
Category 2	8,000-11,000	200	47.5
Total		500	149.1
TOTAL		2,840	596.2

NUCLEAR FRACTURING

The purpose of artificially fracturing tight formations is to increase the area of rock surface in direct communication with the well bore, thereby creating a pressure sink into which the gas in the low-permeability sands may move. Three techniques have been used to accomplish this fracturing, or enhancement of fracturing--with varying degrees of success. The first of these techniques to arrive on the scene under a major effort was nuclear fracturing.

The conceptual design of the nuclear technique is simple: to drill a well into the gas formation and to explode in the formation one, two, or more nuclear devices, either concurrently or sequentially, in order to create a rubble chimney and associated fractures through which the gas may enter the well. Thus a borehole of several hundred feet rather than a few inches is created. For the United States, the program for nuclear stimulation was initiated under the U.S. Atomic Energy Commission's Plowshare program for peaceful applications of nuclear explosives. During the period 1964-1973, the AEC spent about \$33.7 x 10^6 to develop and test nuclear-stimulation technology (U.S. General Accounting Office, 1974). The AEC participated in three nuclear-stimulation projects, Gasbuggy, Rulison, and Rio Blanco, the locations of which are shown in Fig. 36-1.

Gasbuggy

Project Gasbuggy was conducted in the San Juan basin, an area of low-permeability sands, but one where conventional techniques permit production. It was intended only to be experimental. In 1967, a single 29-kiloton device was detonated at 4,240 ft in the Lewis Shale with the objective of obtaining 900 x 10^6 ft^3 of gas over a 20-year period. Over a 6-year period the shale has yielded one-third that amount.

Rulison

Project Rulison (1969) was conducted in the Piceance basin in the Mesaverde Formation, a target tight gas sand for massive artificial stimulation. The single device was 43 kilotons, emplaced at 8,426 ft, or about twice the depth of Gasbuggy. It was later estimated that the experiment achieved about a fivefold increase in production over nearby conventional wells.

Rio Blanco

This project, also conducted in the Piceance basin, in 1973, involved the simultaneous explosion of three 30-kiloton devices emplaced at depths of 5,840, 6,230, and 6,690 ft. The objective was to create a continuous chimney to stimulate a 1,300-ft interval. Although all three devices exploded, communication between the three chimneys was not achieved. Before being shut in, in 1974, the well produced about 1.5×10^6 ft^3 per day.

Status

At present, there are no plans to continue the nuclear-stimulation program. The reasons for this are based on the environmental effects, availability of nuclear devices, and feasibility questions.

The total program envisioned for the three basins would have involved nearly 5,700 wells and 30,000 nuclear explosions of 100 kilotons yield each. This would have been a very heavy requirement for enriched uranium, posing a serious supply conflict with resources for electrical-power generation. Such a massive program might have been conducted safely, but, as pointed out by the Natural Gas Task Force (U.S. Federal Energy Administration, 1974), although evaluations of nuclear blasts on case-by-case basis may show relatively low environmental effect, the ramifications of the total system might well be different. In particular, there is serious concern that the explosives might adversely affect underground mining of the overlying rich oil-shale deposits. Adverse structural effects on nearby buildings and pipelines lead to serious disruptions of day-to-day living because of necessary evacuations of people. In addition, there are the inevitable releases of radioactive material to the atmosphere, some residual radioactivity in the produced gas, and the need to dispose of the produced tritiated water. Before the explosion of the Rio Blanco device, the strong public protest against the program led the State of Colorado to take legislative action against its continuation there.

A final problem with nuclear fracturing--a mechanical one--is that the combined chimney-fracture radius is not large. The total is about 400 ft, the chimneys having radii of 75 to 80 ft. This is a relatively small drainage area and is made worse by the fact that the fractures contain no propping agent. At depth, under lithostatic pressure, they tend to heal, thus curtailing ultimate production. This is a severely limiting factor to the nuclear-stimulation technology.

CHEMICAL EXPLOSIVE FRACTURING

The U.S. Bureau of Mines has for some years conducted experiments with chemical explosive fracturing. This technique is not only dangerous for the operator but has not proved successful. The technology appears to be most useful in areas of natural fractures, which are lacking in most tight gas sands. Additionally, such fracturing does not include a propping agent. The U.S. Energy Research and Development Administration has not achieved success with experiments on tight formations in north Texas and in the Appalachian region.

MASSIVE HYDRAULIC FRACTURING (MHF)

The artificial hydraulic fracturing of reservoir rocks has been a useful technique for more than 25 years. When introduced, it had a spectacular effect on well productivity and oil and gas supply. Now the technique is being utilized on a massive scale to release gas bound up in rocks of very low permeability. Most such strata contain few if any natural fractures to provide avenues for migration of the gas to the well bore. The induced fractures are vertical, or nearly so, cutting across bedding planes. The procedure is to pump into the well bore under very high pressure and for many hours, a fracturing fluid to induce the fracture, followed by a fluid containing a propping agent, such as sand or glass beads. When pumping stops, the fluids are forced back into the well bore, leaving the proppant behind to hold the fracture apart, thus providing communication over a large area to the well bore--the point of lowest pressure. In practice, of course, the procedure is complex.

Most desirable for a tight gas formation is the single propped fracture, vertical or nearly so, extending 1,000 to 2,000 ft on either side of the boreholes, and having a height of 100 to as many as 500 ft (Elkins, 1976). The in-place gas permeability and the thickness of the gas-bearing zone provide major controls on productivity; with lenticularity of the gas sands reduces gas permeability or drainage area. Further, if the fracture intersects an aquifer, water entering the fracture will reduce the gas flow.

The efficacy of MHF has been demonstrated in many places. However, it is not likely to be widely used in the U.S. until well-head gas prices rise to as much as $2 per 1,000 ft^3. This condition now obtains for gas produced for intrastate markets. Two other significant problems remain in the area of the Green River, Piceance, and Uinta basins, where the most prospective formations occur. The first problem may be availability of water for the process. The water requirement for each well is estimated to be 250 x 10^3 to as much as 2 x 10^6 gallons; however, most fluid from MHF projects is recovered, and little make-up water is needed. The second problem is one of insufficient knowledge of the exact amount of the target gas resource and lack of detailed data on the critical reservoir engineering factors pertinent to successful exploration and exploitation. In particular, reliable determinations of in-place gas permeability and of net pay thickness must be obtained. These data provide a permeability-times-thickness factor, given as millidarcy-feet, and, combined with pressure, define the volume of gas in place.

SUMMARY

Clearly, large but very imperfectly defined resources of natural gas are present in tight sandstone formations. The only presently known technology applicable to the recovery of such gas resources in the United States is massive hydraulic fracturing. The important point to be made is that a successful technology does in fact exist for adding significantly to world natural-gas reserves.

A definitive estimate of world resources of natural gas in tight sandstone formations cannot be made at present. This is an exceedingly important area for research. However, certain generalizations may be drawn from the U.S. example and experience. The Piceance-Uinta-Green River basins total, in prospective tight-gas-sand area, about 2,840 mi^2. This is only 1 percent of the Rocky Mountain sedimentary area of 461,500 mi^2 and is a tiny fraction of the 1.7×10^6 mi^2 of sedimentary area of the 48 contiguous States. However, the 242×10^{12} ft^3 of gas in place in Category 1 areas (Table 36-1) compares with an estimated 32×10^{12} ft^3 of gas-in-place in conventional gas deposits in the same three basins, 69×10^{12} ft^3 in the Rocky Mountain area as a whole, and 741×10^{12} ft^3 in the 48 contiguous States. The contiguous States also contain an estimated 580×10^{12} ft^3 of undiscovered gas-in-place, for a total of gas-in-place of $1,321 \times 10^{12}$ ft^3. This amount does not include gas in tight formations. Therefore, the gas in tight sands would represent, conservatively, 15 percent of U.S. in-place resources in the contiguous States onshore, and 24 percent of gas-in-place in tight sands and in proved deposits only.

World proved reserves of natural gas are $2,232 \times 10^{12}$ ft^3. On the basis of the conservative gas estimates for the U.S., world resources of gas in tight sandstones might be in the range of 393 to 744×10^{12} ft^3.

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CHAPTER 37

GAS IN TIGHT FORMATIONS

Philip L. Randolph

INTRODUCTION

In the United States, large quantities of natural gas are believed to exist in reservoirs having permeability too low for the gas to be classified as "reserves" producible under existing economic conditions and with proven technologies. The first portion of this paper briefly summarizes the history of efforts to define producing characteristics of this tight-reservoir resource base.

Economics provides the motivation to pursue large-scale stimulation of tight-sandstone natural gas reservoirs. Two hypothetical cases will be considered in detail to illustrate the dependence of justifiable well cost upon permeability and to illustrate the economic motivation for pursuing very large and expensive stimulation procedures.

HISTORICAL SUMMARY

Almost two decades ago, scientists seeking peaceful applications of nuclear explosive energy attracted national attention to an enormous United States natural gas resource base in thick, low permeability lower Tertiary and upper Cretaceous sandstone reservoirs in basins in the Rocky Mountain region of the western United States. At that time, only a few percent of the potential reservoir area had been explored by drilling. Production was so low that few, if any, wells were tested sufficiently to provide definition of reservoir characteristics adequate for calculating economics of production following large-scale reservoir stimulation. With recognition of the severe limitations of existing knowledge, the tight Rocky Mountain natural gas resource was estimated in 1966 to be 8.98×10^{12} m^3 (317×10^{12} ft^3) [1].

Nuclear Stimulation

Three nuclear stimulation experiments, Projects Gasbuggy [2,3], Rulison [4,5], and Rio Blanco [6], have been performed in the United States. These experiments have demonstrated that this stimulation technology can be safely employed, that the region of enhancement or permeability can be predicted with considerable accuracy, and that consumption of natural gas produced would result in acceptably small radiation exposures [7]. However, they also demonstrated that permeability, thickness of productive sand, and limited lateral extent of productive sandstones combined to make production rates less than previously anticipated.

It is emphasized that the discouraging economic implications of the nuclear stimulation experiments are due to poor reservoir characteristics and are applicable to any technology for producing tight reservoirs. The required advances in reservoir assessment technologies are being pursued.

Natural Gas Survey

In 1972, task forces of experts with the National Gas Survey of the Federal Power Commission [8] evaluated various aspects of future natural gas supply for the United States. One of these, the Natural Gas Technology Task Force, concentrated upon potential for production from tight sandstone reservoirs.

The Task Force report [8] reflects the combination of quantitative data with judgment to conclude that creating tremendous fractures in tight reservoirs may ultimately double U.S. natural gas reserves at a cost competitive with synthetic natural gas. These fractures could be created by either nuclear stimulation, or by hydraulic fracturing with much larger quantities of fluid and proppant sand than previously used (massive hydraulic fracturing).

Although the Task Force conclusions regarding gas-in-place, production rates, and economics were of necessity highly qualified, the conclusion that massive hydraulic fracturing may be economically competitive with nuclear stimulation provided a major turning point in United States research emphasis relative to tight sandstone reservoirs. This conclusion, plus the increasing public opposition to nuclear detonations, has resulted in the conduct of numerous massive hydraulic fracturing experiments, but only one nuclear stimulation experiment, since the Task Force deliberations.

Massive Hydraulic Fracturing

Since the National Gas Survey, the emphasis upon massive hydraulic fracturing research and upon field experiments with this technology has increased rapidly. Hydraulic fracturing of natural gas wells with roughly 1×10^6 liters (250,000 gallons) of gelled fluid and more than 200,000 kg (500,000 pounds) of proppant sand has become commonplace in the Rocky Mountain Cretaceous reservoirs. In addition, such hydraulic fracturing treatments are being employed in tight sandstone reservoirs at locations remote from the Rocky Mountain basins [9].

The outstanding demonstration of success in improving economics of production from tight sandstones is provided by development of the Wattenberg field north of Denver, Colorado. This field has an area of 2,500 km^2 (980 mi^2). Gas production is from the tight Muddy "J" formation which is approximately 15 m (50 ft) thick and is at a depth of about 2,450 m (8,000 ft). In situ permeability lies between 0.05 and 0.005 md.

Since 1973, large volumes of polymer-emulsion fluid carrying high concentrations of proppant sand have been employed in a series of experiments. Treatments with up to 1.95×10^6 liters (560,000 gallons) of fluid and 455,316 kg (1,003,800 pounds) of sand have been conducted. These experiments have revealed that the largest treatments are economically justified in the more permeable portions of the field and that the resultant high permeability fractures have a length of roughly 915 m (3,000 ft). At the present time, several wells are being completed each month by hydraulic fracturing with about 1.18 x 10^6 liters (311,000 gallons) of fluid and 272,000 kg (600,000 pounds) of proppant sand per well [10].

ECONOMICS OF PRODUCTION FOR VARIOUS PERMEABILITIES

The analysis that follows draws upon reservoir characteristics and production predictions that have been previously published [11]. These are shown in Table 37-1.

TABLE 37-1.--Assumed reservoir characteristics

Depth	2,800 m (9,200 ft)
Thickness	30 m (98.4 ft)
Natural gas pressure	281 kg/cm^2 (4,000 psi)
Porosity	10 percent
Water saturation of pores	50 percent
Permeability	.001, .01 and 0.1 md
Gas-in-place	3.34 x 10^6 m^3/hectare (30.5 x 10^9 ft^3/mi^2)

Assumed Production Geometry

Figure 37-1 illustrates the vertical fracture and drainage area configuration assumed for projecting production, in order to examine the relationship between production and permeability. Note that if drainage is to be as efficient as calculated for this geometry, the reservoir must be homogeneous and means must be developed to adjust well spacing on the basis of length and azimuthal direction of the hydraulic fractures.

Natural Gas Production Rates

Natural gas production, predicted with computer simulation for the properties and geometry described in Table 37-1 and Fig. 37-1, is shown in Fig. 37-2.

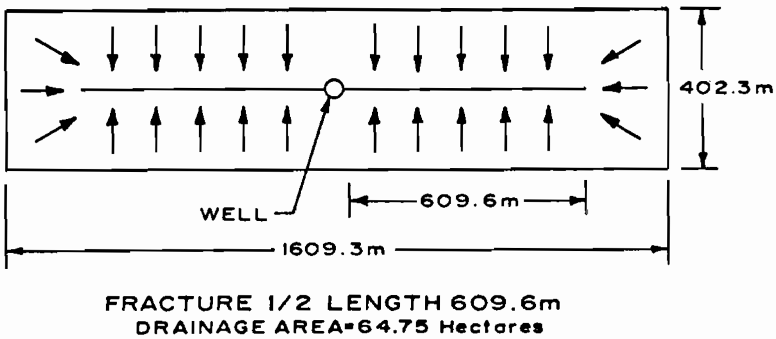

Figure 37-1.--Plan view of hydraulic fracture and drainage area

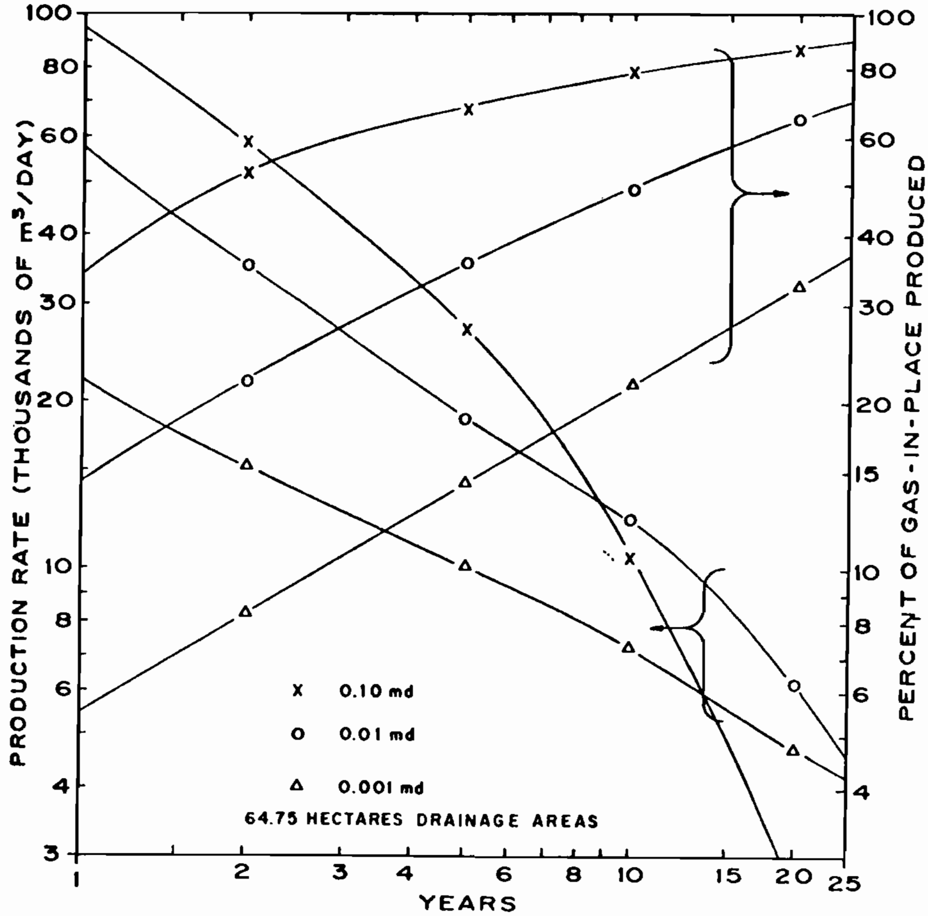

Figure 37-2.--Effect of permeability on production from reservoirs described in Table 37-1 and Figure 37-1

It is apparent from this figure that a drainage area of greater than 64.75 hectares (160 acres) is warranted for the relatively large permeability of 0.10 md. Production declines sharply after about 6 years and the production of about 70 percent of gas-in-place. This well spacing is close to optimal for permeability of 0.01 md because accelerated decline in production rate due to production of the majority of gas-in-place only occurs after about 15 years. An even narrower drainage area is desirable for a very tight (0.001 md) formation because only 32.4 percent of gas-in-place is projected to be produced in 20 years.

Discounted Production

Economic considerations are approximated by discounting future production to determine a present value for a well in terms of volume of natural gas. Results of this calculation for discount rates of 15 percent per year and 20 percent per year are set forth in Table 37-2. Figure 37-3 shows the amount that could be spent on a well, as a function of permeability, for the assumed reservoir conditions, stimulation geometry, and a natural gas price of \$0.02(U.S.)/m^3 or \$0.596(U.S.)/10^3 ft^3.

TABLE 37-2.--Discounted future production (10^6 m^3)

	Permeability		
	.001	.010	0.10
Gas-in-place in 64.75 hectares (160 ac)	216.3	216.3	216.3
Production in 20 years	70.0	139.1	190.1
20-year future production discounted at 15% per year			
Discounted volume	29.8	66.1	145.6
Percent of 20-year production	42.6%	47.5%	76.6%
20-year future production discounted at 20% per year			
Discounted volume	23.9	54.5	99.4
Percent of 20-year production	34.2%	39.2%	52.3%

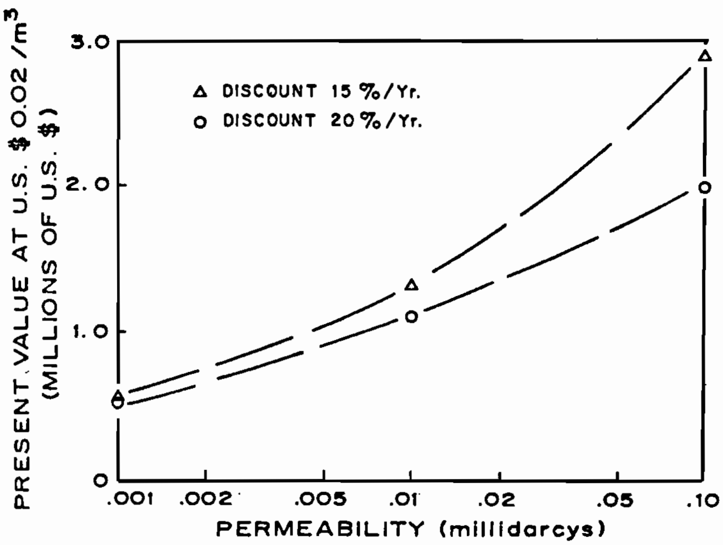

Figure 37-3.--Discounted production dependence upon permeability

The maximum warranted expenditure for drilling the well and completing it with hydraulic fractures propped to 610 m (2,000 ft),

- Increases linearly with selling price of natural gas,
- Varies linearly with the product of porosity x (1 minus water saturation of pores),
- Varies linearly with pay sandstone thickness, and
- Varies exponentially with pressure because as pressure increases both gas-in-place and the driving force increase.

Note that extrapolation of these results to any particular reservoir requires sensitivity to the strong dependence of the permeability of tight reservoirs upon both confining pressure and water saturation [12].

ECONOMICS OF PRODUCTION FOR VARIOUS SIZES OF STIMULATION TREATMENT

Reservoir characteristics assumed for examining the economic implication of the size of a hydraulic fracturing treatment, as well as nuclear stimulation, differ from those previously assumed. Although assumed pay sand thickness is the same, the characteristics set forth in Table 37-3 differ from those previously discussed in that (1) assumed depth is greater, (2) assumed natural gas pressure is greater and is above hydrostatic for the depth, (3) assumed porosity is smaller, and (4) assumed water saturation is higher. The assumed permeability of 0.0034 md is near the lower limit for tight reservoirs now being studied in the United States.

Stimulation Configurations

For examining the effect of hydraulic fracture length upon production, it has been assumed that each well is assigned an area of 129.5 hectares (320 acres). Hydraulic fractures are again assumed to be vertical and to extend equal distances in opposite directions from the wellbore. The production calculations again assume that the reservoir is homogeneous and that means will be developed for maximizing production by adjusting

TABLE 37-3.--Reservoir characteristics assumed for evaluating stimulation treatment size

Depth interval	2,700-3,350 m (9,000-11,000 ft)
Total pay thickness	30 m (98.4 ft)
Natural gas pressure	445 kg/cm^2 (6,334 psi)
Porosity	9.32 percent
Water saturation	55 percent
Permeability	0.0034 md
Gas-in-place	3.89 x 10^6 m^3/hectare (35.6 x 10^9 ft^3/mi^2)

well placement on the basis of the length and azimuthal direction of the hydraulic fractures. The 80-meter radius shown for nuclear stimulation corresponds to the outer radius of greatly increased permeability and is three times the radius of the cavity produced at the time of the nuclear detonation.

Projected Production for Various Stimulation Treatments

Results of computer simulation of production for the reservoir characteristics set forth in Table 37-3 and each of the stimulation geometries illustrated in Fig. 37-4 are set forth in Fig. 37-5. Computations to project production following hydraulic fracturing differ from those presented in examining the economic impact of permeability in that gas production from computer simulation was discounted by multiplying by a fracture effectiveness factor. That factor had a value of 0.8 from the first year and was chosen due to the assumption that the 30 meters of pay thickness was distributed over multiple sandstones and that the average fraction of total pay sand fractured would be 0.8. The value of this factor was reduced with time to represent a decrease in well productivity due to effects such as fracture healing, scale deposition, or water production. The first year factor of 0.8 was reduced by 0.025 each year so that by the twentieth year the factor was 0.325.

For the assumed 129.5 hectare (320 acre) drainage area for each well, none of the treatments produced a fraction of

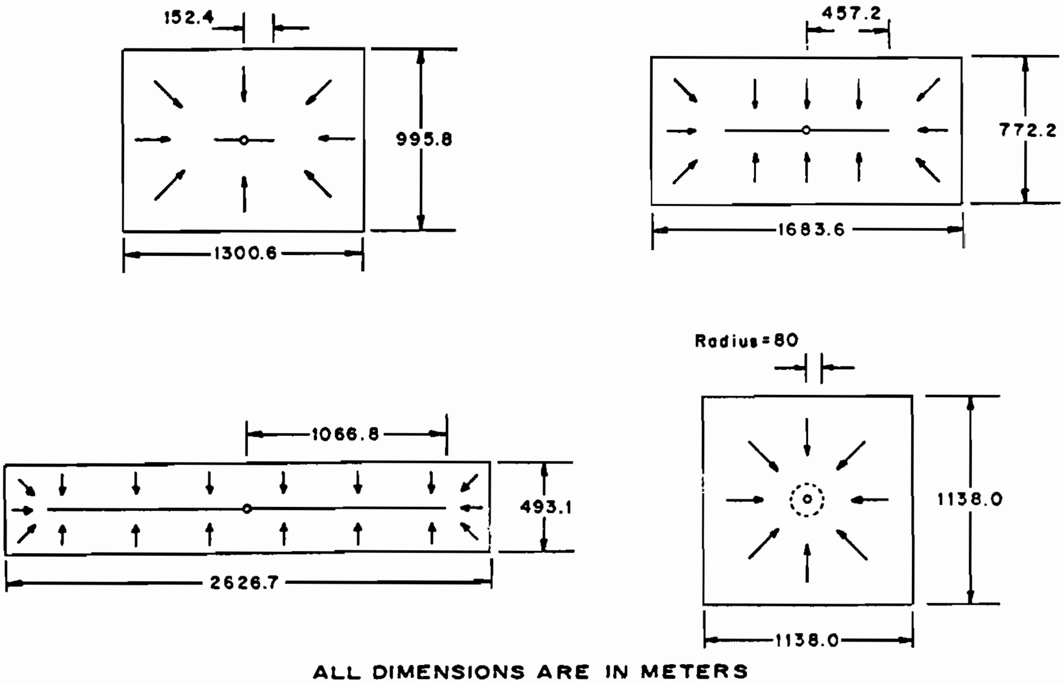

Figure 37-4.--Shapes of 129.5 hectare drainage areas for production calculations

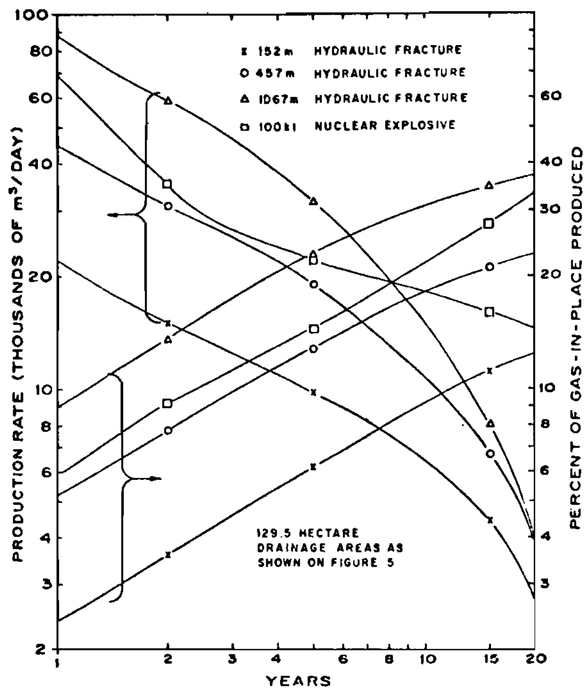

Figure 37-5.--Effect of stimulation geometry upon production from the reservoir defined in Table 37-4

gas-in-place large enough for production rate to experience rapid decline due to reservoir depletion. The portion of gas-in-place produced in 20 years varies between 12.4 percent and 37.3 percent.

In addition to geometry, factors contributing to differences in production decline with time between nuclear stimulation and hydraulic fracturing include:

1. Production after nuclear stimulation declines rapidly in the second year due to drainage of natural gas from reservoir rock whose permeability is dramatically increased by the detonation, and

2. It was not necessary to apply the fracture effectiveness factor because the stimulation mechanism is creation of a large volume of broken rock rather than providing a single narrow channel whose permeability depends upon proppant sand emplaced with the hydraulic fracturing fluid.

Discounted Production

The calculated production was discounted at rates of 15 percent per year and 20 percent per year in the same manner as for evaluation of the effect of permeability upon production. Results are presented in Table 37-4. Figure 37-6 shows these

TABLE 37-4.--Discounted future production
(10^6 m^3)

	Fracture length (meters)			Nuclear stimulation
	152	457	1,067	
Gas-in-place in 129.5 hectares	503.8	503.8	503.8	503.8
Production in 20 years	62.4	116.8	187.8	168.9
20-year production discounted at 15% per year				
Discounted volume	27.6	55.9	96.6	70.8
Percent of 20-year production	44.3%	47.9%	51.4%	41.9%
20-year production discounted at 20% per year				
Discounted volume	22.6	46.5	81.1	57.9
Percent of 20-year production	36.3%	39.8%	43.2%	34.3%

results for an assumed natural gas wellhead price of $0.02(U.S.)/m^3.

Present value (i.e., the expenditure economically justifiable for drilling and completing a well with large-scale stimulation) varies from about $0.5 x 10^6(U.S.) for 152 m (500 ft) fractures to about $1.75 x 10^6(U.S.) for fractures extending 1,067 m in opposite directions from the wellbore. The present value of a well completed by nuclear stimulation with 100-kiloton explosives is about $1.3 x 10^6(U.S.) and is equal to that for hydraulic fracturing with permeable propped fractures extending about 620 m in opposite directions from the wellbore.

Cost of Stimulation

The length of a massive hydraulic fracture of specified height increases as volume pumped to the 0.73 power. Near onshore producing areas in the United States, a minimal cost for completing an existing cased 3,000 m (10,000 ft) well with massive hydraulic fracturing is about $0.26(U.S.) per liter ($1.00 per gallon) of gelled fluid and proppant pumped. This rough estimate includes all costs to the operator and is not limited to the service company charges.

If achieving adequate fracture conductivity requires adjusting fluid viscosity such that a bed of proppant is formed to about 80 percent of fracture height, the cost per foot of propped fracture length may be three times as much or about $0.79(U.S.) per liter ($3.00 per gallon) of fluid and proppant pumped. This range of cost for creating permeable fractures with a height slightly greater than the assumed pay sand thickness of 30 m is shown on Fig. 37-7 as cost for hydraulic fracturing of a single sandstone.

On the other hand, the 30 m of assumed pay sandstone thickness may actually consist of small intervals in numerous sandstones distributed over a depth interval as large as 610 m (2,000 ft). Further, each of the multiple sandstones may fracture to a height much greater than the pay thicknesses. These possibilities are reflected in Fig. 37-7 by assuming that the cost of creating multiple fractures permeable to the desired

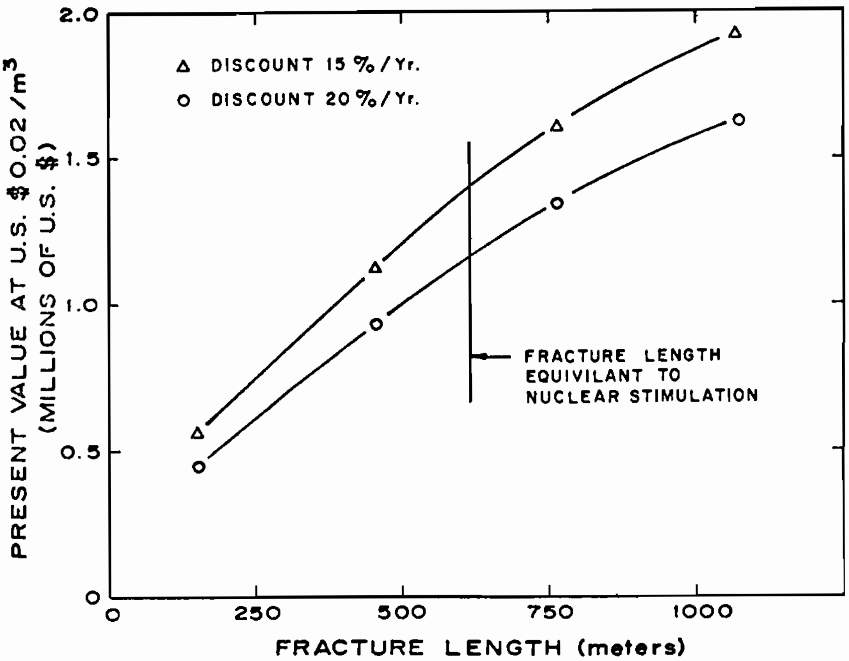

Figure 37-6.--Discounted production dependence upon hydraulic fracture length

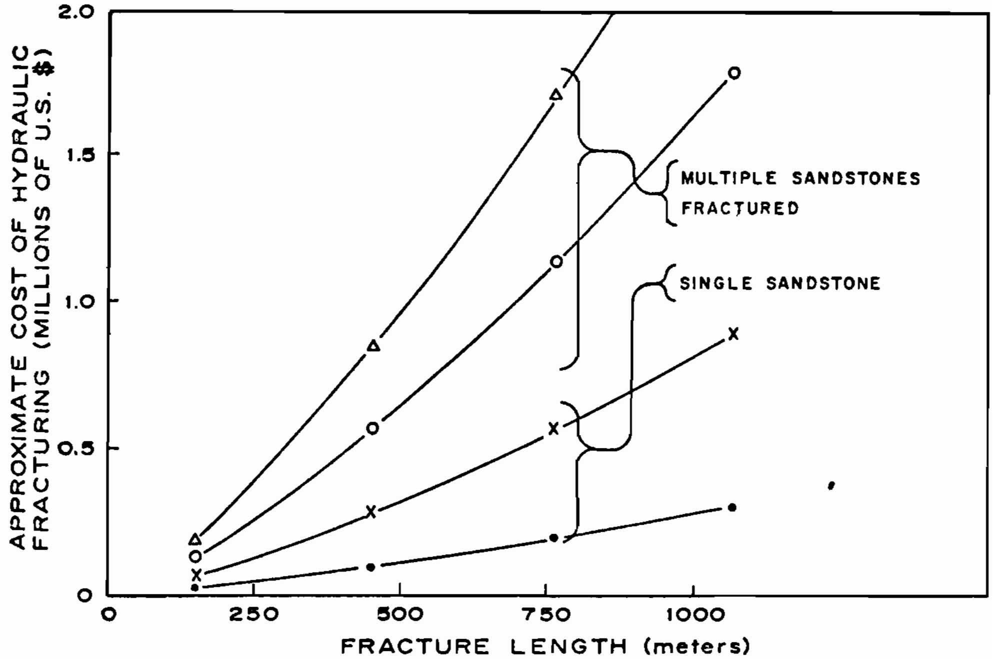

Figure 37-7.--Cost of hydraulic fracturing

length may be as much as two to three times the maximum cost for a fracture whose height is only slightly greater than the thickness of a single sandstone having 30 m of continuous pay thickness.

Since the discounted production following nuclear stimulation is about the same as for hydraulic fractures extending 620 m in opposite directions from the wellbore, Fig. 37-7 suggests that a cost of less than $450,000(U.S.) per explosive would be essential for an economic advantage relative to massive hydraulic fracturing.

Economic Motivation for Large-Scale Stimulation

The economic motivation for large-scale stimulation becomes apparent when one compares the present value of a well deduced from production predictions with cost of drilling the well and creating the permeable fracture length assumed in the production calculations. Two such comparisons are provided in Figs. 37-8 and 37-9.

In Fig. 37-8, a well cost of $390,000 is assumed. This is added to the fracturing cost from Fig. 37-7 and compared with the economically justifiable expenditure for a well from Fig. 37-6. Figure 37-8 reveals that very long fracture lengths are desirable if the assumed 30 m of pay is in a single sandstone. For 500 m long fractures, discounted production revenue exceeds cost by about $\$0.5 \times 10^6$(U.S.). For a 1,000 m fracture length, discounted production revenue exceeds cost by roughly $\$0.8 \times 10^6$ (U.S.). On the other hand, if the assumed 30 m pay thickness is distributed in multiple sandstones over a depth interval of hundreds of meters, a propped hydraulic fracture length of 250 to 500 m provides the best possibility of recovering well expenditures from production.

Figure 37-9 differs from Fig. 37-8 only by assuming that the cost of drilling, casing, and perforating the well is $\$1.11 \times 10^6$(U.S.). In this case, the cost of drilling and stimulating the well can be recovered only if the assumed 30 m of permeable height is in a single sandstone bounded by rock strata which preclude appreciable vertical fracture growth.

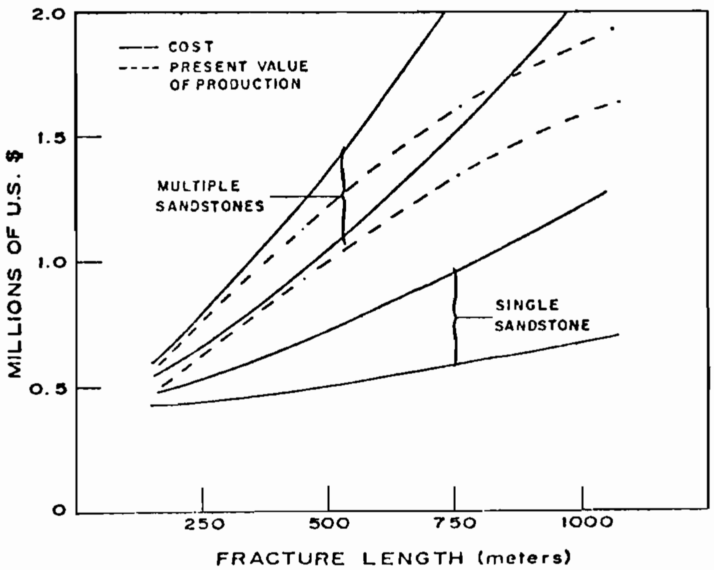

Figure 37-8.--Superposition of Figures 37-7 and 37-8 for a cased hole cost of U.S. $300,000

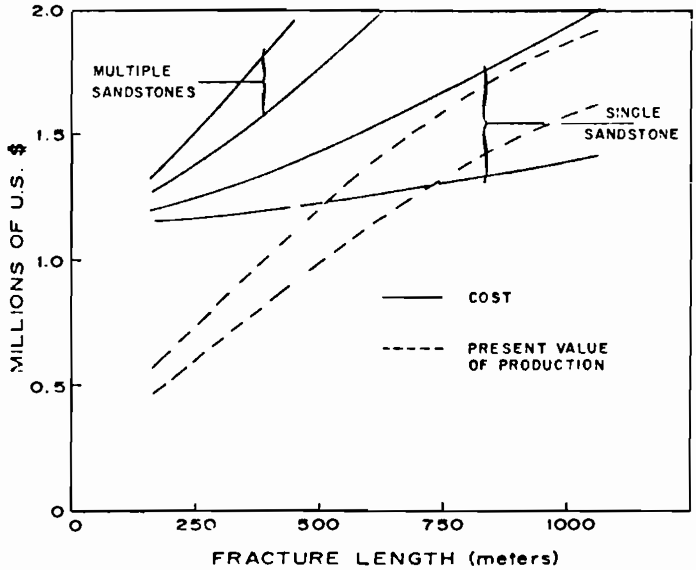

Figure 37-9.--Superposition of Figures 37-7 and 37-8 for a cased hole cost of U.S. $1,110,000

With this limited possibility, and minimal fracturing cost, a propped fracture length of 750 to 1,000 m appears essential for the well to be economically justified. Wellhead price of natural gas would have to be doubled before fracturing of nultiple sandstones could be economically justified.

CONCLUDING REMARKS

This paper has illustrated conditions under which large and expensive stimulation treatments appear economically desirable for very low permeability natural gas reservoirs. However, in applying these results to any particular reservoir, the following points should be carefully considered:

1. The production data presented does not represent actual field case histories. It is based upon computer simulation, assuming homogenous reservoirs.

2. Full-scale experiments have generally revealed prior estimates of reservoir characteristics to be overly optimistic. The technical problems are that water saturation of pores is near the value of 60 percent where permeability to natural gas is very low and where permeability is a strong function of water saturation. The combination of permeability reduction due to confining pressure and due to water saturation result in in situ permeability to natural gas being at most a few percent of the value measured in the laboratory on dried core with pressures of a few bars.

3. Technologies for defining the height, direction, and length of propped hydraulic fractures are still in the research stage. Dimensions of the region stimulated by nuclear detonations are known to much greater accuracy.

4. Logistics costs at remote locations may be much higher than reflected in this paper.

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CHAPTER 38

DEVONIAN SHALE PRODUCTION EASTERN KENTUCKY FIELD

Edward O. Ray

INTRODUCTION

The present availability of natural gas in the United States has caused much interest in low porosity and low permeability formations. The Appalachian Basin has long produced from such formations. It is estimated that more than 600,000 wells have been drilled in the Appalachian Basin, possibly as many as 750,000 wells [1]. Much of the production is marginal from an economic point of view; however, the Appalachian production is near the eastern markets, which lends additional value to it.

This paper will deal with Devonian Shale production in the Eastern Kentucky Field, which is the southernmost major component of Post-Ordovician oil and gas fields of the Appalachian Basin. The Eastern Kentucky Field is estimated to produce at least 85 percent of the annual natural gas production of the Commonwealth of Kentucky. It appears also that the Upper Devonian Shale, termed locally the Brown Shale, has yielded at least 60 percent of the cumulative production from the field and is the most important producing formation [2].

GEOLOGIC SETTING

The Eastern Kentucky Field is located within the Appalachian Plateau, between the Cincinnati Arch to the west and the Appalachian Front to the east. The Upper Devonian Brown

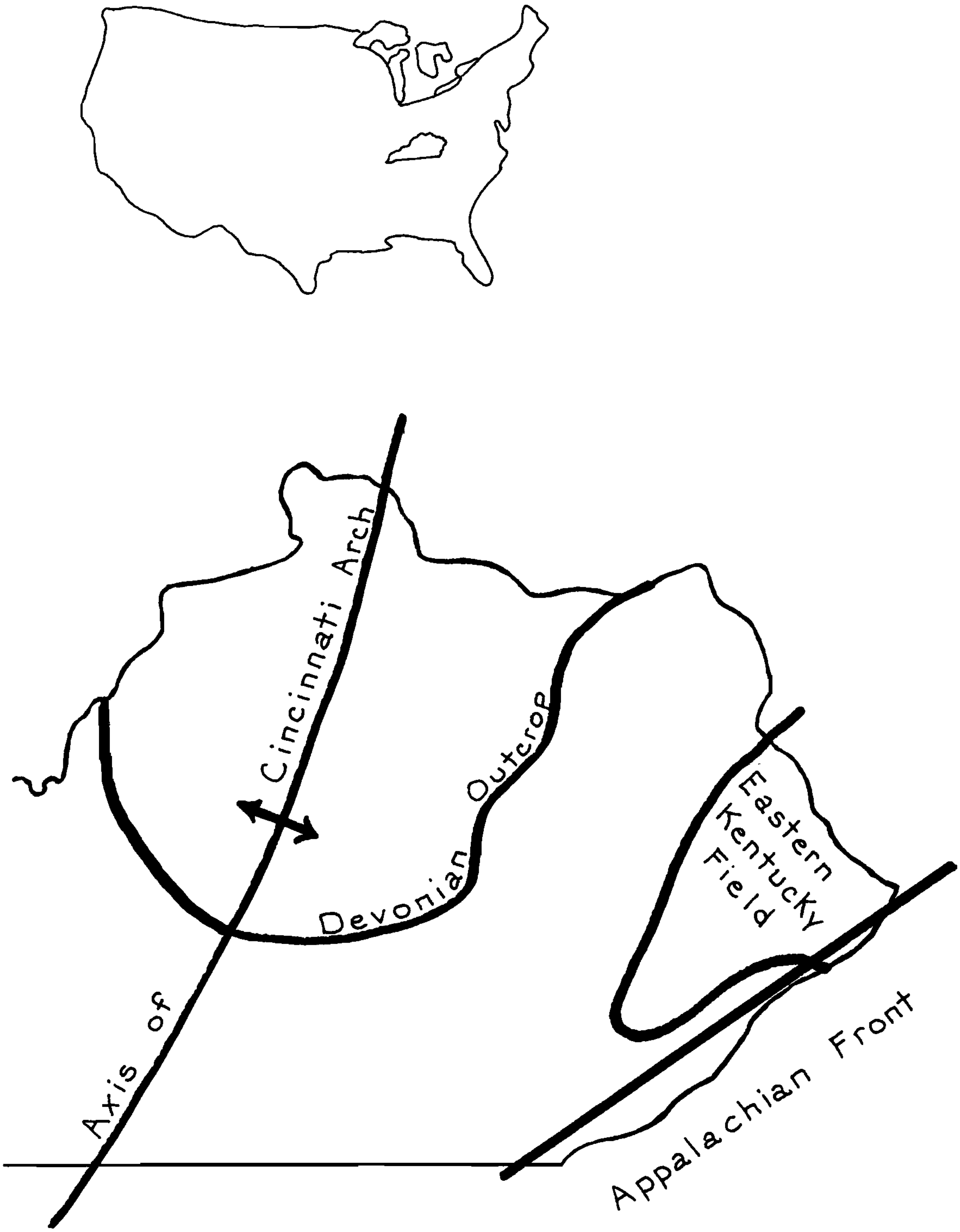

Figure 38-1.--Geographic and structural relation of Eastern Kentucky

Shale lies between the Lower Mississippian Berea Sand and the Onondaga Formation of Middle Devonian Age.

Post-Ordovician strata in the field generally strike northeast and dip regionally to the southeast. The Devonian Shales have a monoclinal dip of approximately 30 to 50 ft per mi and in producing areas their thickness varies from 200 to 900 ft. The Shales thin to the west, onto the eastern flank of the Cincinnati Arch [3]. Figure 38-1 shows the geographic location of the area under discussion.

LITHOLOGY

The Devonian Shales meet the definition of organic-rich shale because they contain 5 to 65 percent indigenous organic matter [4]. The most prevalent constituent of the shale is quartz and other components are kaolinite, pyrite, and accessory minerals such as fieldspar, calcite, gypsum, apatite, zircon, titanite, and muscovite [5]. The shale in general is fissile, finely laminated, and varicolored, but predominately black, brown, or greenish-grey.

MODE OF GAS OCCURRENCE

The outstanding feature of the Eastern Kentucky shales is the long and slow declining productive life of the gas produced from them. Many wells have produced significant amounts of gas for more than 50 years.

Core analysis has determined that the Shale itself may have up to 12 percent porosity; however, permeability values are commonly less than 1 md. Sand lenses or wedges are not discernible in the area under discussion. It is thought, therefore, that the majority of production is controlled by naturally-occurring fractures and further influenced by bedding planes and jointing. Billingsley et al. [6] give several indications to substantiate this belief. If natural porosity and permeability controlled the producing characteristics, the behavior of most wells would be rather similar with regard to reservoir pressure, yield of gas, and life index. It is demonstrated that wells relatively close together do not have common characteristics and the inverse is true also.

Both Avila [7] and Brown [8] have pointed out the relative importance of the natural fracturing itself, which tends to emulate the effect of an underground pipeline network, the connected pore space in the shale itself, and the gas adsorbed in the shale matrix, which is largely unrecoverable under present stimulation techniques. Due to adsorbed matrix gas, those authors demonstrate that of the total original gas in place, something less than 10 percent is presently recoverable.

DEVELOPMENT--EASTERN KENTUCKY FIELD

As of December 31, 1974, approximately 8,312 producing wells have been drilled in the Eastern Kentucky Field, as well as an estimated 1,146 dry holes, yielding a 14 percent dry-hole experience. A total of 4,616 of the productive wells have been classified as Devonian Shale producers, representing 56 percent of the productive completions.

Cumulative production for the entire Commonwealth of Kentucky, as of December 31, 1974, is estimated to be 3.1 x 10^{12} ft^3 [9]. The Eastern Kentucky Field is estimated to have produced 2.8 x 10^{12} ft^3 of the total, of which 1.7 x 10^{12} ft^3 or 60 percent is estimated to be from the Devonian Shale.

The 4,616 wells classified as Devonian Shale producers had an average final daily open flow of 331 x 10^3 ft^3 per day and are estimated to have an individual ultimate recovery per well of 430 x 10^6 ft^3.

STIMULATION PRACTICE

Conventional

Only 5 percent of the Shale completions have had natural flows in commercial quantities. Approximately 40 percent of the wells have had no measurable gas flow prior to stimulation. For many years the Shales have been routinely stimulated by open-hole (chemical explosive) shooting. Many variations in types and amounts of explosives have been experimentally tried. Standard practice evolved to the shooting of the entire section in one shot, the formation being exposed to approximately 10 pounds of 80 percent gelatinated nitroglycerin per foot of section.

Induced Hydraulic Fracturing

During 1965, Kentucky West Virginia Gas Company decided to attempt to experimentally fracture the Shale section hydraulically. This was to be a departure from conventional open-hole stimulation of shooting in that casing would be cemented through the unstable Shales and stimulation controlled through a limited-entry technique. Routine logging of wells had not been a field practice, and it was not known definitely which part or parts of the section contributed most to production. A review was made of the limited number of available radioactive gamma-density logs, and future wells were logged as standard practice. The suite of logs run was standardized to the radioactive gamma-density, temperature log, and sufficient induction logs to confirm water saturation.

Megascopically, the Shale appears quite similar from top to bottom, except for color variation, and further microscopic examination of drill samples revealed no tangible evidence of anything but fairly consistent characteristics for the entire section. Geochemical study may suggest whether, in fact, the Shales have either a mineralogical or chemical feature directly related to gas productivity [10]. The gamma logs show a very consistent series of radioactive units within the Shale that can be correlated throughout the field.

Temperature logs generally confirm that the interval of higher radioactivity in the lower section was the most consistent gas-bearing zone. A typical Shale section is depicted in Fig. 38-2.

That the Shale is incompatible with oil is a long established fact from the operation of gas wells. When small amounts of oil from formations up the hole are allowed to drain into the Shale section, the Shales tend to sluff, absorbing the

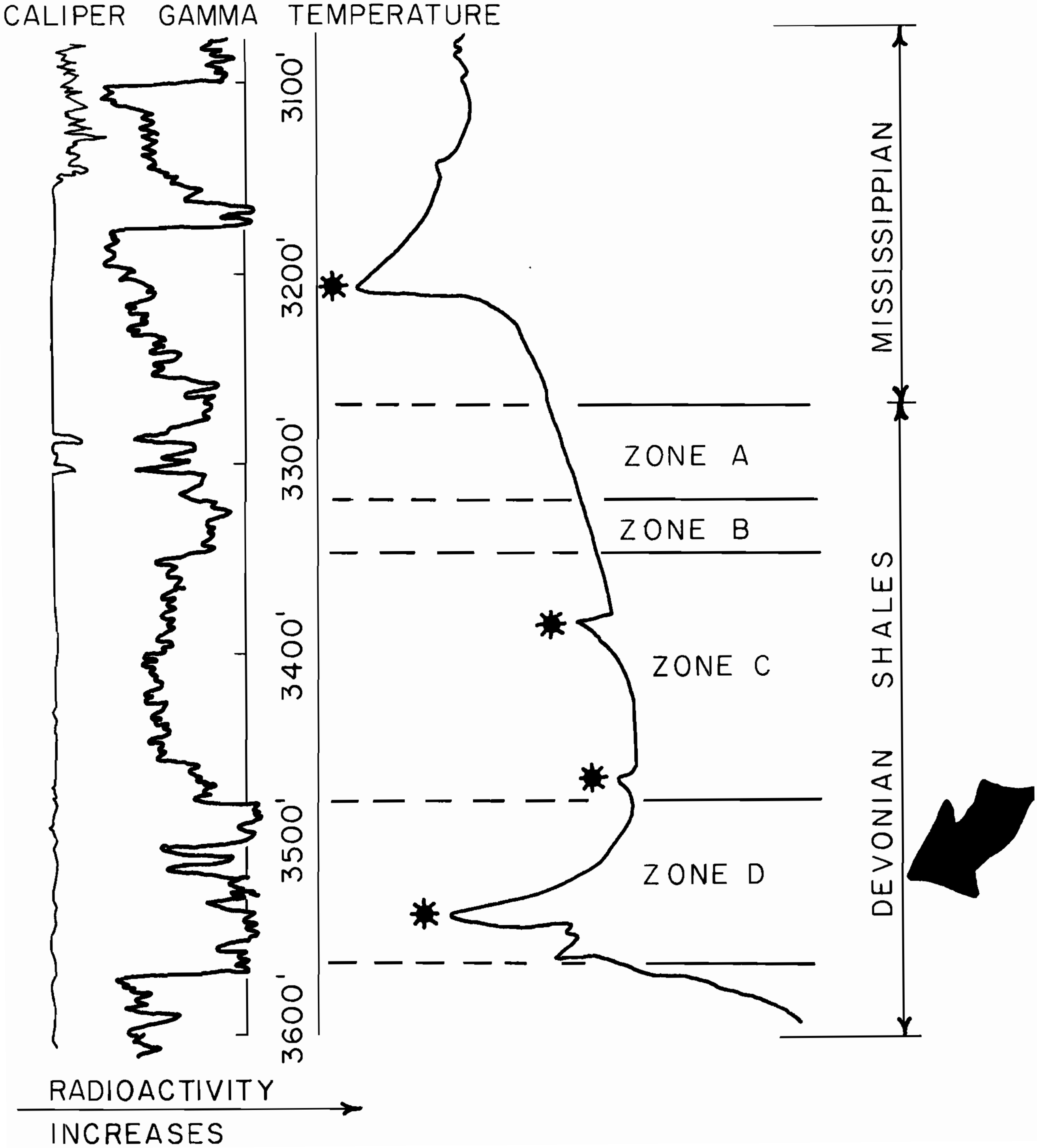

Figure 38-2.--Typical Devonian shale section

oil and forming a gummy residue that requires remedial work-over in gas wells. Before experimenting, it was thought that fracturing with water would produce the same results, the injected water largely being unrecoverable at best. It also was reasoned that the Shale was too unstable to support the sand-propping agent after fracturing and thus the fractures would heal after fracture pressure had dissipated.

These thoughts were soon dispelled by actual experience. During the initial stages of the fracture program, great care was taken to accurately measure fluid recovery after treatment. It was found that up to 80 percent of the injected fluid was recovered within 48 to 60 hours of clean out. The Shale was found to be stable enough to sustain induced fractures with the sand proppant.

The present standard hydraulic fracturing treatment on Devonian Shale wells is as follows:

Evaluate with Gamma-Density and Temperature Logs.

Set 4-1/2-inch casing through Devonian Shale and cement.

Run cement evaluation log.

Perforate 4-1/2-inch casing in pay zone intervals with mud-acid in hole.

Hydraulic fracture (Dowell Water Frac 20).

During the hydraulic fracturing process the following material and parameters have been used:

Average Injection Rate--48 barrels per minute

Average Treating Pressure--1,400 psig

Maximum Sand Rate--2 lbs per gal.

Sand size and amount:

20/40 Mesh--25,000 pounds

10/20 Mesh--25,000 pounds

Perforation--Average 18 shots, .41" size

Treatment Interval--Average 320 ft

Sand Laden Fluid--1,000 barrels

Single-Stage Treatment--Inject perforation ball-sealers during treatment to break out all zones.

DELIVERY PERFORMANCE HYDRAULIC FRACTURED SHALE WELLS

It was discovered that open flows in fractured Shale were comparable to conventionally-shot Shale wells. Since open flow results were similar from both fracturing and shooting, the next step was to put the fractured Shale wells on line and evaluate their production characteristics.

For comparative purposes, any number of shot-well deliverability records were available. The fractured Shale wells were categorized by open flow range to make the production comparison with shot wells having similar open flows.

The most critical comparison is the actual delivery performance of fractured Shale wells versus shot Shale wells. Table 38-1 illustrates that fractured Shale wells out-perform the shot Shale wells in all open flow ranges with regard to actual gas delivery. This is expressed graphically in Figs. 38-3 to 38-6.

It is interesting to compare the length of time a fractured Shale well will require to produce the ultimate recovery projected for a shot Shale well of comparable open flow (Table 38-2).

It is apparent that delivery performance is remarkably increased by induced fracturing in wells having final open flow ranges of 0 to 200 x 10^3 ft^3 per day. Historical experience has demonstrated that wells having a natural open flow of 500 x 10^3 ft^3 per day or greater do not respond to shooting, and, in fact, their initial open flows were actually decreased by shooting. It appears that the wells with a greater natural flow that are stimulated by hydraulic fracturing are supported by greater and/or more numerous natural fractures. With induced-fracture stimulation this presents mechanical problems; these include fluid loss, even to the point of a sand screen-out in the induced fracture system created, thus reducing the effectiveness of introducing more potential pay section to the bore hole.

TABLE 38-1.--Kentucky West Virginia Gas Company comparison of annual shale deliveries fractured shale wells - shot shale wells (12-31-75)

	Year 1	Year 2	Year 3	Year 4	Year 5
			0-100 MCF Range		
Frac	10,673*	10,314	9,160	9,340	
Shot	6,921	5,365	5,083	5,035	
Frac Increase:					
MCF	3,752	4,949	4,077	4,305	
Percentage	54%	92%	80%	86%	
			101-200 MCF Range		
Frac	15,667	14,680	17,311	14,675	15,586
Shot	13,727	11,270	10,040	9,078	9,218
Frac Increase:					
MCF	1,940	3,410	7,271	5,597	6,458
Percentage	14%	30%	72%	62%	71%
			201-300 MCF Range		
Frac	26,344	22,200	23,833	18,425	19,250
Shot	24,681	20,688	18,433	16,750	14,215
Frac Increase:					
MCF	1,663	1,512	5,400	1,674	5,035
Percentage	7%	7%	29%	10%	35%
			301-1,000 MCF Range		
Frac	40,333	33,133	33,480	28,700	30,850
Shot	43,562	33,450	29,743	24,117	--
Frac Increase:					
MCF	(3,229)	(317)	3,737	4,538	
Percentage	(7%)	(1%)	13%	19%	

*Units - MCF.

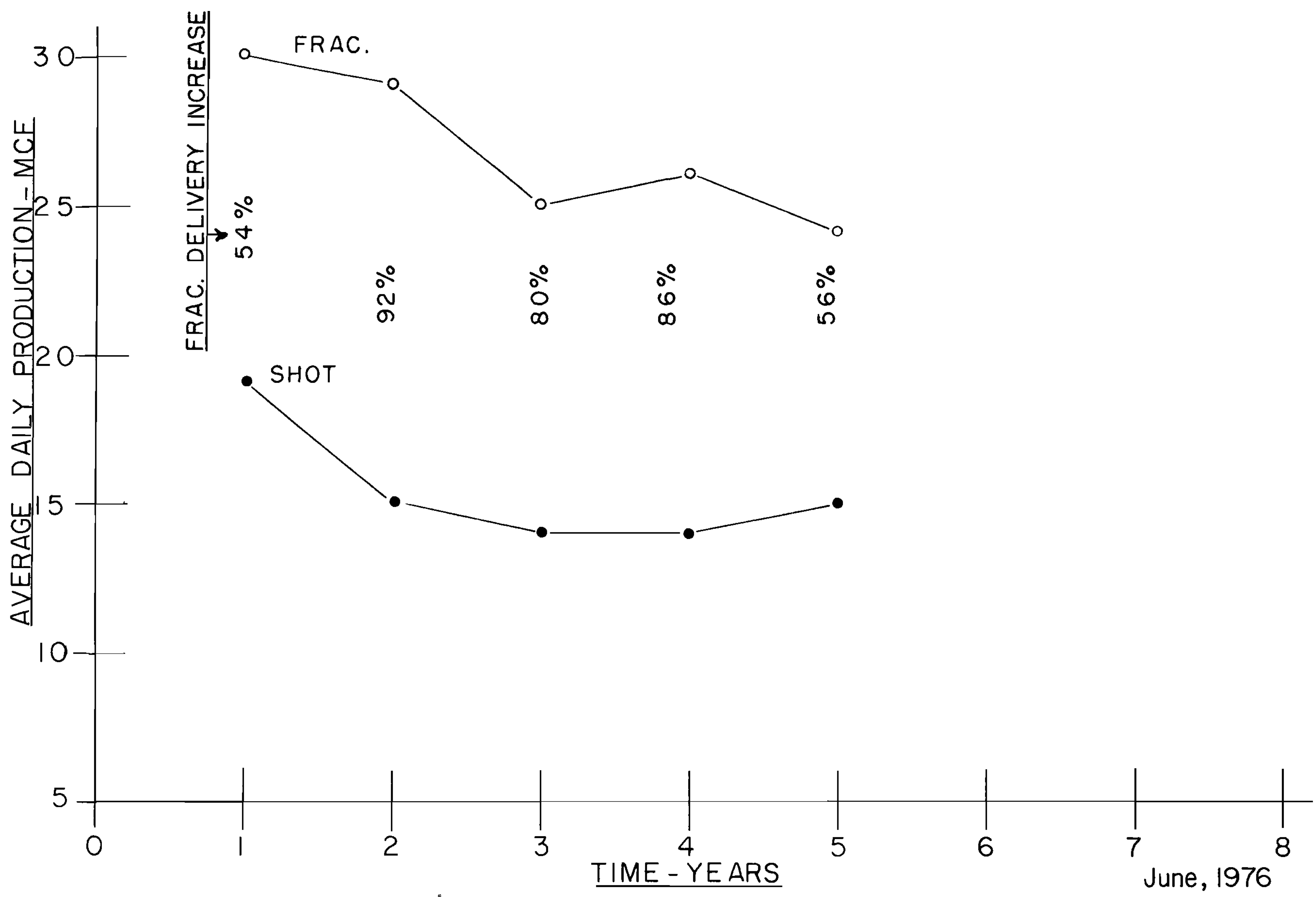

Figure 38-3.--Daily delivery comparison, fractured shale well to shot shale well, open flow range 0-100 x 10^3 ft^3

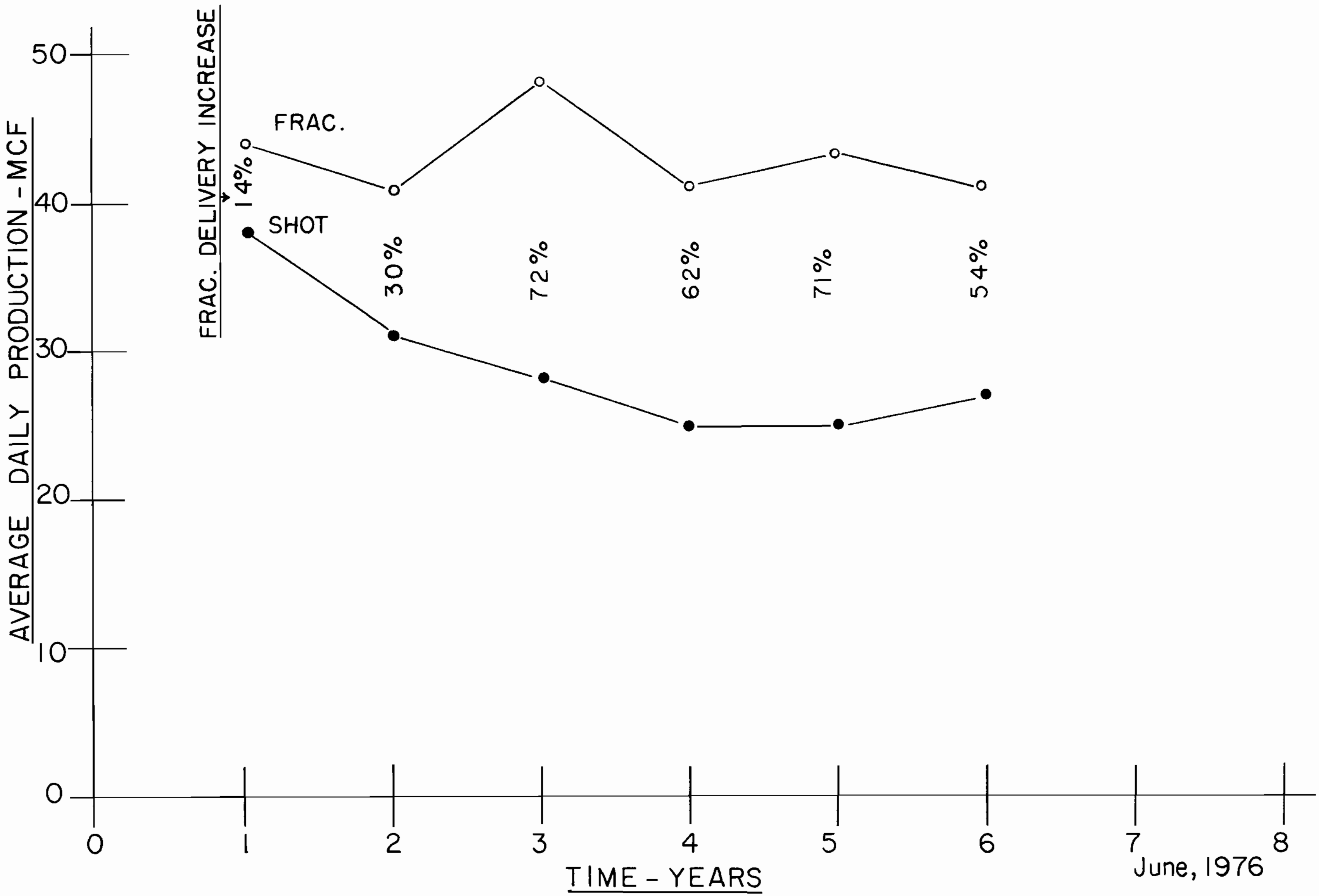

Figure 38-4.--Daily delivery comparison, fractured shale well to shot shale well, open flow range 101-200 x 10^3 ft^3

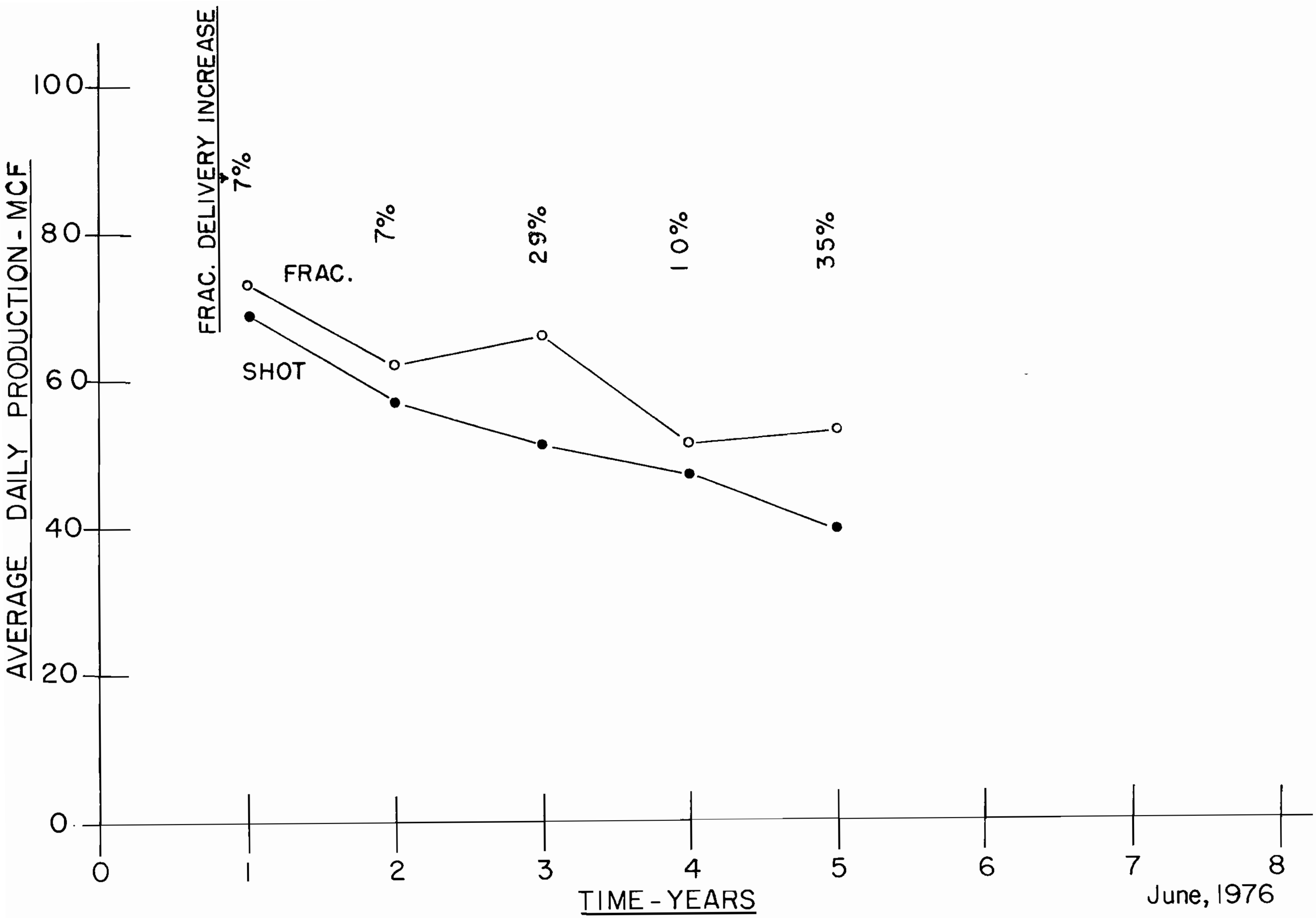

Figure 38-5.--Daily delivery comparison, fractured shale well to shot shale well, open flow range 201-300 x 10^3 ft^3

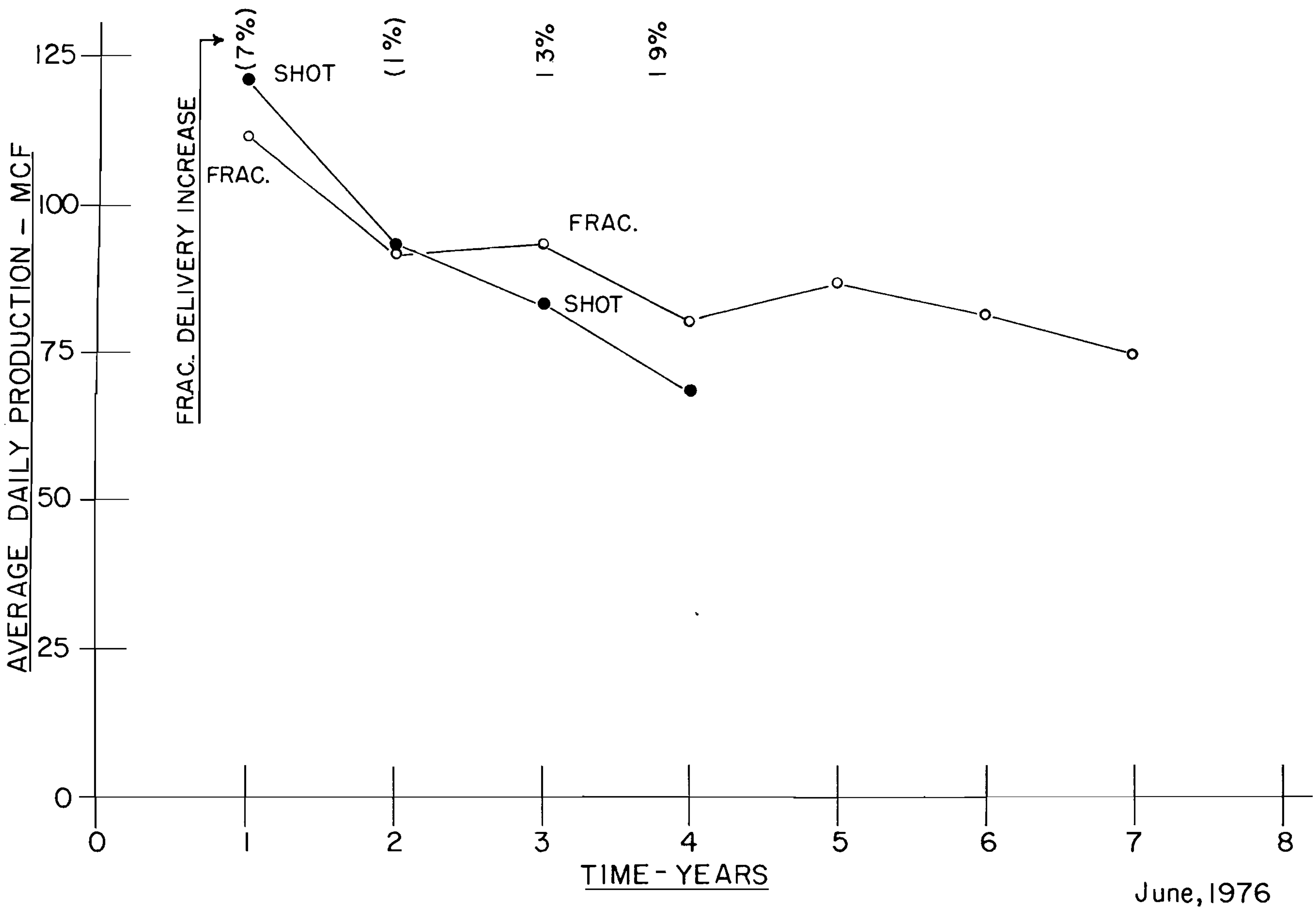

Figure 38-6.--Daily delivery comparison, fractured shale well to shot shale well, open flow range 301-1,000 x 10^3 ft^3

TABLE 38-2.--Rate of recovery

Open flow range (10^3 ft^3 per day)	Years to produce assigned reserves	
	Frac	Shot
0-100	16	32
101-200	16	30
201-300	23	28
301-1,000	Not estimated	

COMPLETION COSTS

For the year 1974, the national average cost for the U.S. for a single-completion gas well in the depth range of 2,500 to 3,749 feet was $59,387 [11]. The average cost of a well of similar depth during 1974 cost the Kentucky West Virginia Gas Company approximately $75,230. This 27 percent increase is due to several factors, including: mountainous Appalachian terrain, additional casing requirements for the protection of coal, and fluid conditions and geographical location in relation to location of well service companies.

The cost to drill and complete a gas well has dramatically increased since the year 1970, as evidenced by Fig. 38-7.

CONCLUSIONS

United States gas production peaked in 1972 and has been in a downward trend since. Artificially low prices for gas at the wellhead have created a greater demand for gas, but have also decreased the incentive to drill and develop new reserves. The price for interstate gas has been controlled since 1954, and the stimulus for new exploration and development would come by allowing natural gas to seek a competitive price level with other energy sources. With demand out-running supply, much attention is now being given to marginal economic areas in order to enhance supply. The energy consumption of the United States is staggering. Much research will be required in all energy

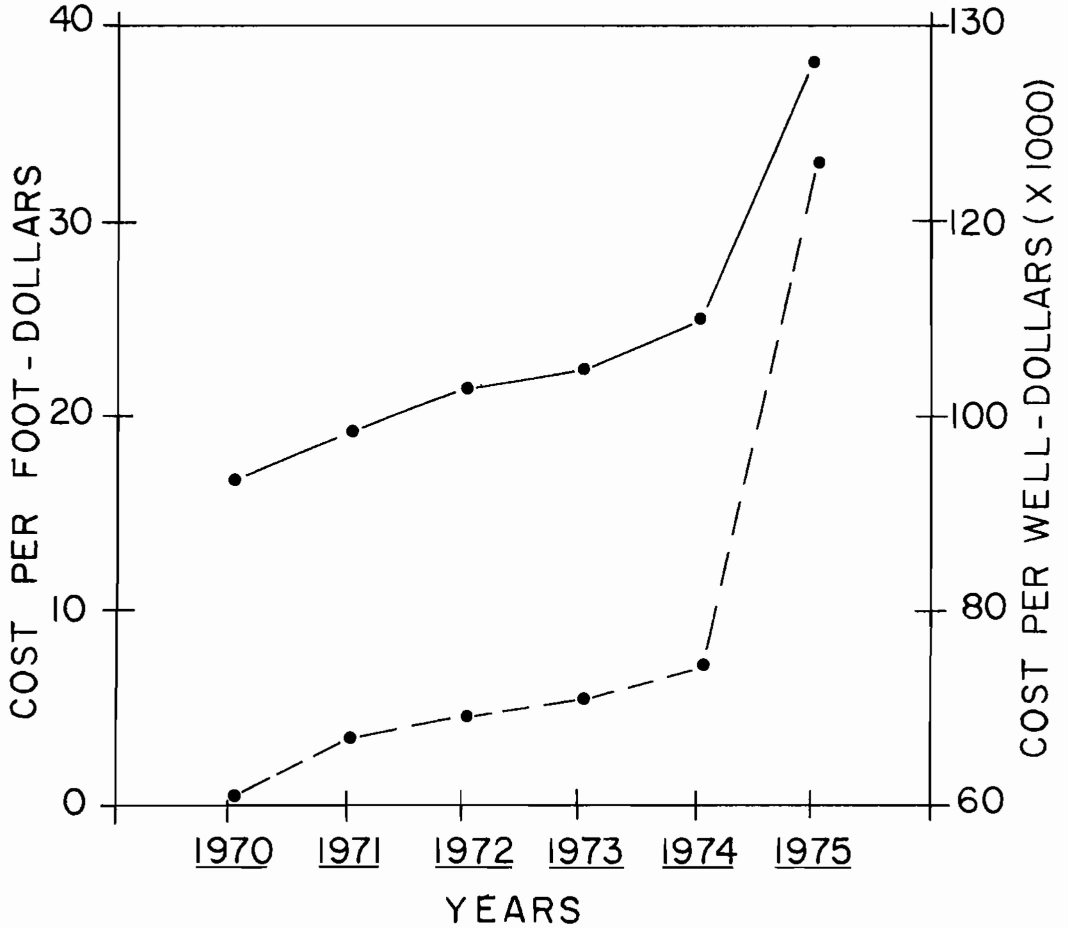

Figure 38-7.--Drilling costs--Eastern Kentucky

sources, both conventional and unconventional, to help offset the dollar deficit of energy imports which are annually increasing.

It is estimated that approximately 20 x 10^6 mi^2 of the world are underlain by sedimentary rocks [4]. It has been estimated also that over 5 percent of the sedimentary rocks in the United States are shales. Projected worldwide, organic shales could have considerable influence on future energy requirements through both conventional drilling and destructive distillation methods.

Much research is currently underway in the United States to test the economic effectiveness of various stimulation techniques in Shales. Among the more promising are chemical-explosive fracturing and massive hydraulic fracturing. Chemical-explosive fracturing is a process for injecting explosive into a formation and detonating it chemically. Massive hydraulic fracturing entails injecting enormous amounts of fluid and sand, of the magnitude of perhaps 350,000 gallons of fluid and 1 x 10^6 pounds of sand, into a formation in order to artificially fracture it and prop the fractures open. This permits the passage of fluids to the well bore from the area of the formation fractured.

In areas where natural fractures are believed to control production, directional deviated holes are being planned to intercept the greatest number of fractures, thus exposing more drainage to the bore hole.

The Devonian Shales have been a significant resource base for the Commonwealth of Kentucky. The estimated 1975 production for the entire state was 59,762 x 10^6 ft^3, of which 50,798 x 10^6 ft^3 or 85 percent is estimated to be from the Eastern Kentucky Field. Production from the Devonian Shale in the Eastern Kentucky Field for the year 1975 is estimated to be 40,638 x 10^6 ft^3 or 68 percent of all gas production from the Commonwealth.

The most important black Shale producing areas in the Eastern United States are in the states of Kentucky, Ohio, Virginia, and West Virginia. Of these, eastern Kentucky and western West Virginia are considered the most important.

Approximately 71,000 wells [12] in these states have been classified as gas producers, of which approximately 9,600 or 14 percent are estimated to be Shale producers.

Estimated 1975 production from all sources within the four states is 299,465 x 10^6 ft^3. The Devonian Shale of the Eastern Kentucky Field accounts for 14 percent of this production.

The significance of the Shale production is the ability to produce for many years at a predictable, stable rate. These production characteristics provide a reliable energy source which can be, and has been augmented by shallower production with a much faster depletion rate. A most important facet of the eastern Kentucky Shale gas is the high Btu value, as great as 1,250 Btu's per ft^3. The petrochemical potential of this gas adds to its resource value.

The Illinois and Michigan Basins are underlain by Devonian Shales. Perhaps their real potential has been overlooked by the scant evidence the Shale yields when drilled. The Shale-gas explorer must rely on very subtle anomalies, which are easy to overlook in areas having more dynamic production targets.

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CHAPTER 39

CURRENT STATUS OF PROJECTS GASBUGGY, RULISON, AND RIO BLANCO AND AN APPRAISAL OF NUCLEAR-EXPLOSIVE FRACTURING POTENTIAL FOR THE NEAR FUTURE

J. J. Stosur[1]

INTRODUCTION

A recent study by the Natural Gas Technology Task Force of the Federal Power Commission estimated that, in the deeply buried basins of the Rocky Mountain area, there is an estimated 600 x 10^{12} ft^3 of natural gas. For comparison, it is estimated [1] that about 500 x 10^{12} ft^3 of gas has been produced from all wells. The Rocky Mountain gas is held in very tight sandstones which must be fractured to provide adequate production rates. Since the conventional approaches to fracturing these tight formations do not normally result in commercial production, fracturing with nuclear explosives and with massive amounts of fluids and sand (massive hydraulic fracturing) were proposed and implemented. This paper concerns itself with the outcome of three nuclear-explosive fracturing experiments conducted in the tight gas-bearing formations of the Rocky Mountain Area (Fig. 39-1).

Ten years ago, nuclear-explosive well fracturing appeared to be an exciting and promising if not proven technology for unlocking natural gas from very tight formations which otherwise could not be exploited commercially. Now that the three tests have been completed and a proposed fourth test cancelled, it

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[1]U.S. Energy Research and Development Administration, Washington, D.C., USA.

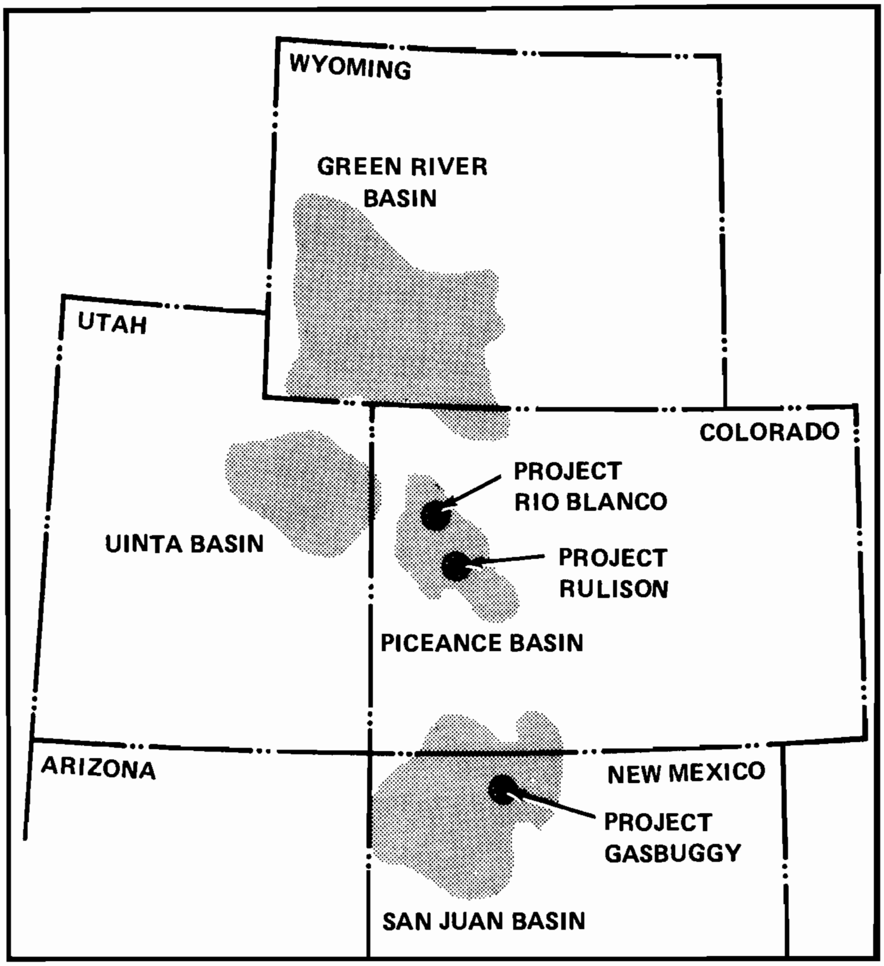

Figure 39-1.--Locations of nuclear-stimulated wells and major tight-gas reservoirs in the Rocky Mountains

generally is agreed that the three tests did not come up to expectations in either the postulated stimulation effects or the attendant hopes for economic benefits. However, the technical feasibility of using nuclear explosives to stimulate gas production from tight reservoirs has been demonstrated in terms of a two- to four-fold increase in gas-production rates relative to a hydraulically stimulated well.

Analysis of stimulation effects and the attendant costs leads to the conclusion that nuclear-explosive well fracturing at its present stage is not commercially attractive and that it might compete with the more conventional stimulation methods only if the total cost of nuclear stimulation is of the order of \$1.0 x 10^6. Currently, costs of nuclear-explosive fracturing are about one order of magnitude higher than those for massive-hydraulic-fracturing treatments.

Public acceptance of the technology is equally important; it has never been favorable and is downright hostile at this time with no prospect for near-term improvement. The problems are exemplified by voluminous environmental statements.

EVENTS OF AN UNDERGROUND NUCLEAR EXPLOSION

At detonation, the total energy of a nuclear-explosive reaction is released in less than one millisecond (msec). Initial pressures and temperatures are of the order of 15 x 10^9 pounds per square inch (psi) and 20 x 10^6 degrees Fahrenheit (°F), respectively. A supersonic shock wave moves out radially, vaporizing, melting, crushing, cracking, and displacing the rock. After this discharge of energy, the shock wave becomes elastic and the vaporized rock expands to form a spherical cavity.

Maximum cavity volume is achieved in about 100 msec. Subsequent heat losses, gas leak-off through the fracture system, and vapor condensation reduce the pressure until the fractured rock above the cavity can no longer be supported.

The cavity generally collapses within seconds to hours after detonation. Rock collapse into the cavity forms a complex chimney-rubble zone. Most of the molten material and radioactive fission products collect in the bottom of the chimney in the form of glassy slag. Collapse continues until an arch forms with sufficient strength to withstand the load of the overlying rock, or until the rubble zone in the chimney can support it.

The porosity in the rubble zone (void space between the fallen blocks) ranges from 20 to 30 percent and the permeability is assumed to be infinite. The various features of the postshot geometry can be readily calculated as a function of yield, depth of burial, and physical properties of rock, using a scaling equation developed from data on underground tests in various rock formations. Figure 39-2 is a graphic solution to some of these questions and shows how to quickly determine chimney radius and height as a function of depth of burial and nuclear yield for a sandstone formation.

EFFECTS ON RESERVOIR STIMULATION

The dominating importance of the unaltered formation is revealed by an objective appraisal of the combined chimney-fractured zone in relation to the drainage area. Therefore, a few brief but important points are first made on the significance of the radial dimensions of the combined chimney-fracture zone and the expected productivity improvement.

Reservoir response to nuclear-explosive fracturing in terms of producing rate and ultimate recovery depends upon contributions from three elements: the chimney, the fractured zone surrounding the chimney, and the unaltered formation beyond the fractured zone. The significance of the radial dimensions can best be illustrated using one of the tests, such as the most recent project, Rio Blanco, and the attendant reservoir characteristics. Project Rio Blanco consisted of the simultaneous detonation of three 30-kiloton (kt) nuclear explosives. The upper cavity had a radius of 66 feet and the fractured zone extended to a distance of about three cavity radii from the wellbore, according to the results from pressure-buildup and draw-down data.

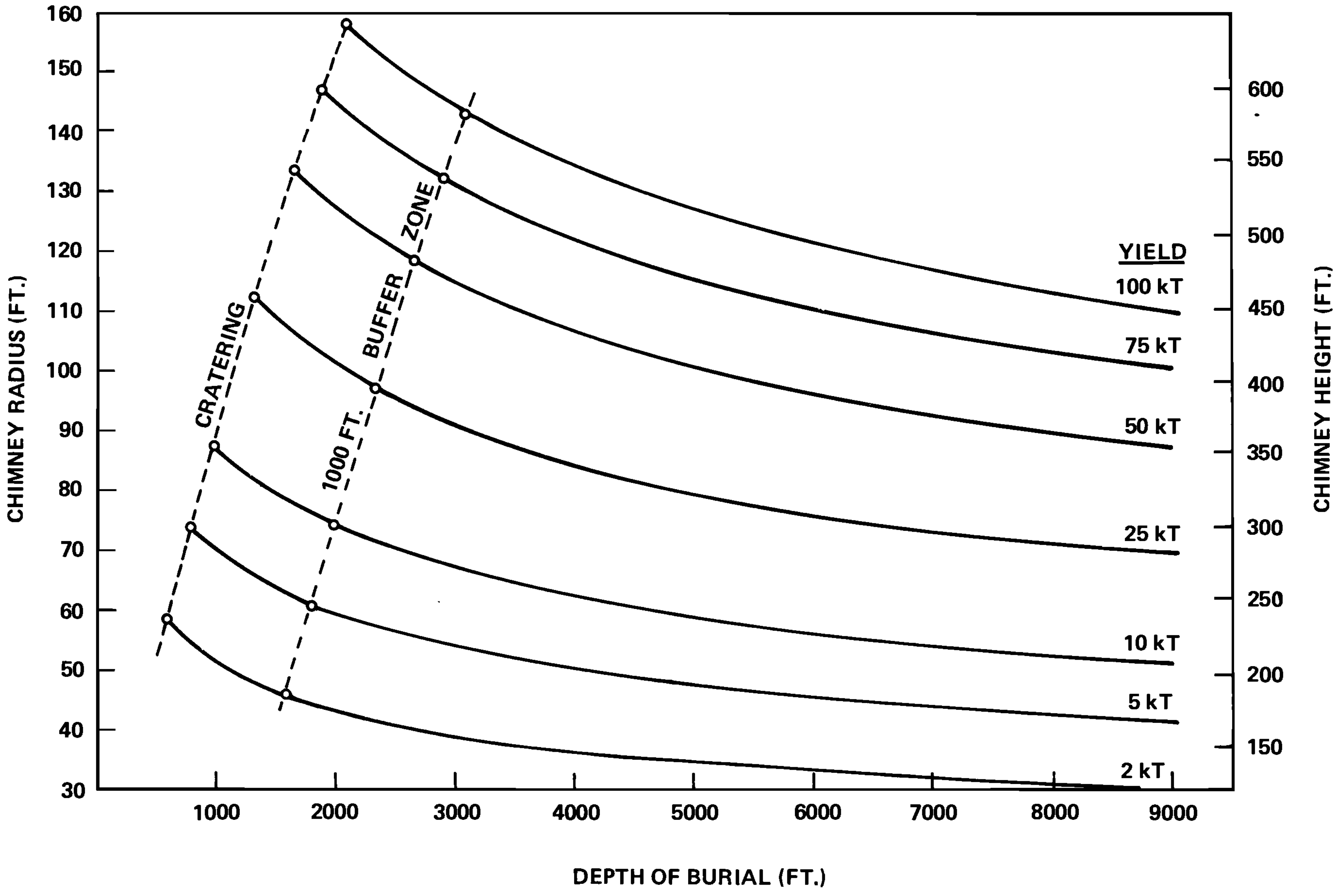

Figure 39-2.--Chimney dimensions for an underground nuclear explosion

Assuming that the gas-drainage area in the Fort Union and Mesaverde formations is 320 acres per well, the combined chimney-fractured zone (or the area physically altered by the blast), is only 2.8 acres or less than 1 percent of the drained area (Fig. 39-3). Even if the relatively small gas-drainage area of 160 acres per well is assumed, the stimulation area as a fraction of the well-chimney spacing is only 1.7 percent.

The volume of gas contained in the stimulated space is insignificant in relation to some 99 percent of the gas volume which is still locked outside the fractured zone and subject to the laws governing fluid flow in the unaltered porous medium. Furthermore, because of the logarithm of

$$\frac{r_e}{r_w}$$

term in the productivity-ratio equation (Appendix 1), once the wellbore is enlarged to a few feet, relatively small increases in productivity result from further increases in the wellbore radius. This is best illustrated in Fig. 39-4, which is a graphic solution to the productivity-ratio equation. The chimney and the surrounding fractures can be thought of as a rather very large wellbore. It is readily apparent that, irrespective of the size of the chimney and the surrounding fractures, gas must eventually flow into the chimney from the outer reaches in the drainage volume, which in turn overshadows the volume of the stimulated region of the reservoir. Practical considerations as well as current technology for commercial application of nuclear explosives preclude using larger charges than 100 kt. Massive hydraulic fracturing (MHF) suffers from precisely the same limitations,drainage geometry, even though the extent of a hydraulic fracture may easily exceed the radial extent of the nuclear-explosive-made fracture system. Recent experience with MHF shows that the results were, in general, considerably below expectations.

EXPECTED PRODUCTIVITY IMPROVEMENT

In evaluating well performance, the standard usually referred to is the productivity index of an open hole in which no

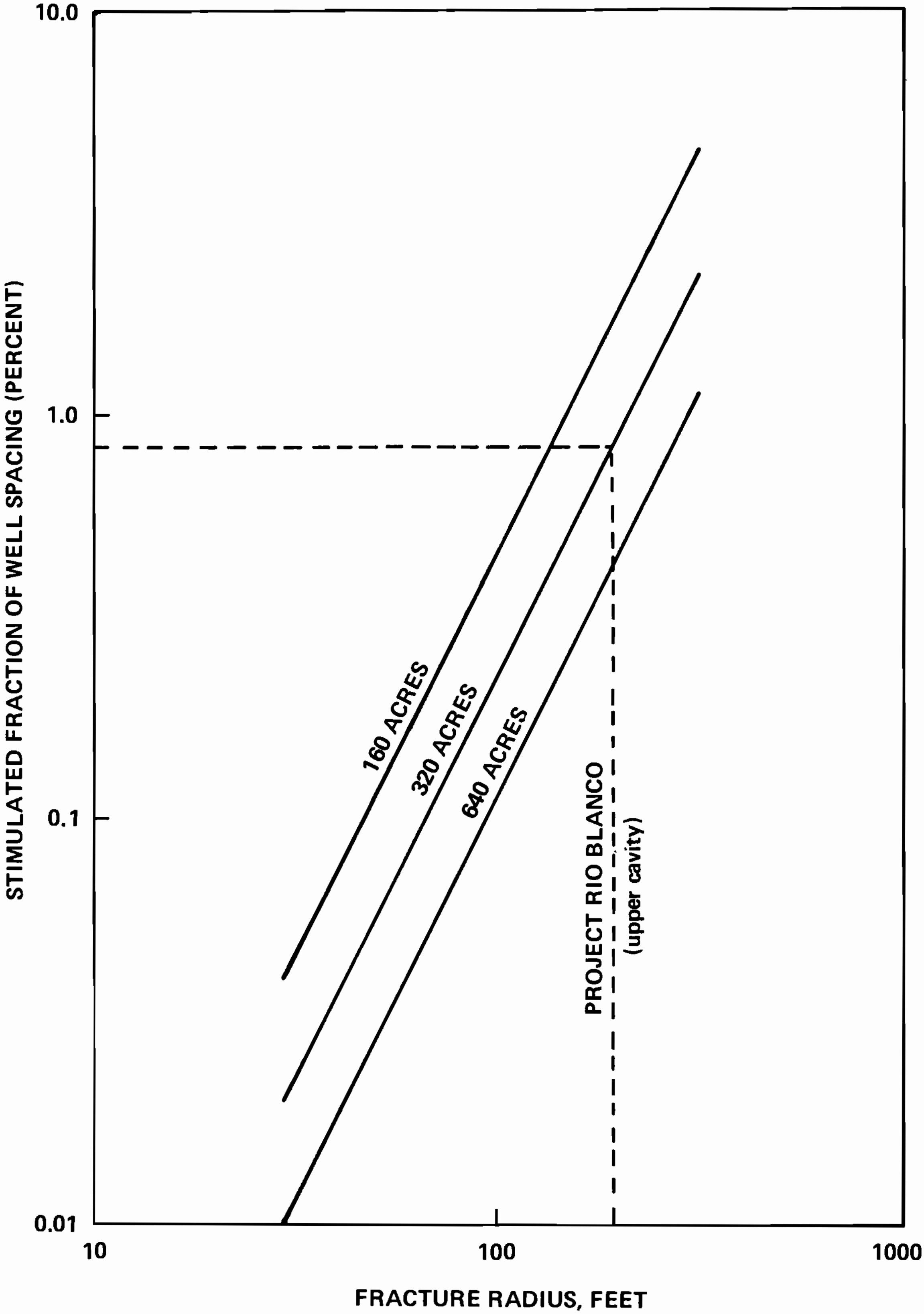

Figure 39-3.--Stimulated area as a fraction of well spacing

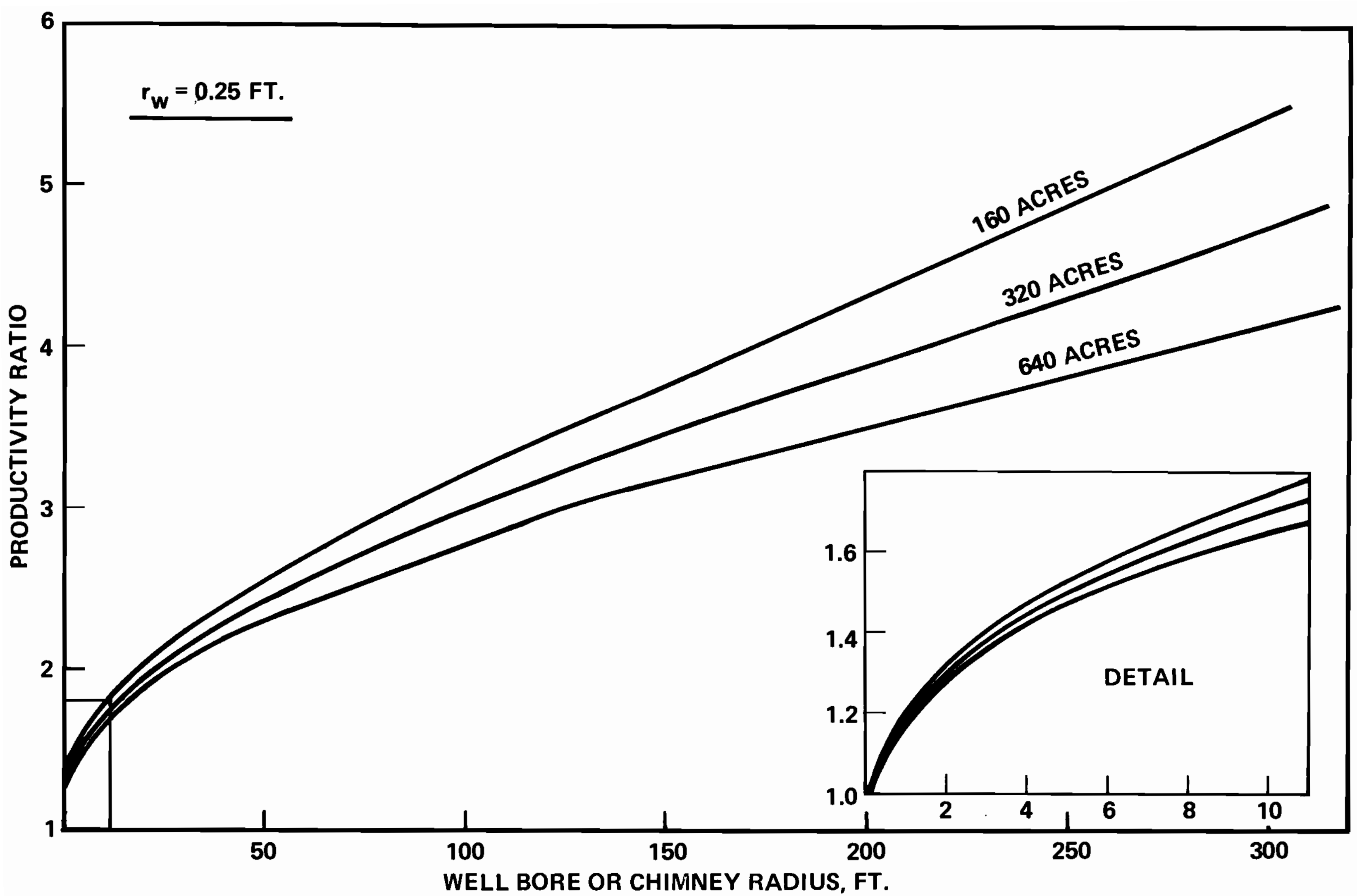

Figure 39-4.--Productivity ratio as a function of chimney radius and well spacing

alteration in permeability has occurred in the vicinity of the wellbore. Then the ratio of the productivity index of a well in any condition to the productivity index of a standard well is referred to as a productivity ratio or a stimulation ratio.

The productivity ratio is affected by large changes in wellbore radius and a large permeability improvement around it. To start with, the theoretical productivity ratio of a well, the radius of which is doubled by reaming from 0.25 to 0.5 feet (again 320-acre spacing is assumed) is computed to be 1.08, or a productivity-index improvement of approximately 8 percent. Enlarging the wellbore radius to 66 feet results in a 260-percent improvement in the productivity index. If the fractured zone were considered to have infinite permeability and the wellbore radius were 198 feet (project Rio Blanco), the productivity index for this limiting case would amount to 390 percent. It follows that the contribution of the fractured zone surrounding a nuclear chimney is relatively small, even for very large increase in permeability of the fractured zone. Figure 39-5 makes it possible to establish limits of the productivity ratio for the combined chimney-fractured zone area and fractured-zone permeability ranging from no improvement to an infinite improvement in permeability. The development of the concept is presented in Appendix 1.

The crux of the matter is that in well stimulation by enlargement, once a radius of a few feet is created, relatively small increases in productivity may be expected from further increases in wellbore dimensions (chimney, fractured zone). It seems plausible to assume that even somewhat more extensive fracturing than that predicted by the scaling equations will not likely result in more than a five- to six-fold increase in productivity. Clearly, the flow characteristics of an unaltered formation are no less important to nuclear stimulation than to any other stimulation method.

The distinct advantage of nuclear-explosive well fracturing lies in its capability to fracture very large intervals. This capability is particularly useful in areas where productive formations are numerous and separated by impermeable shales

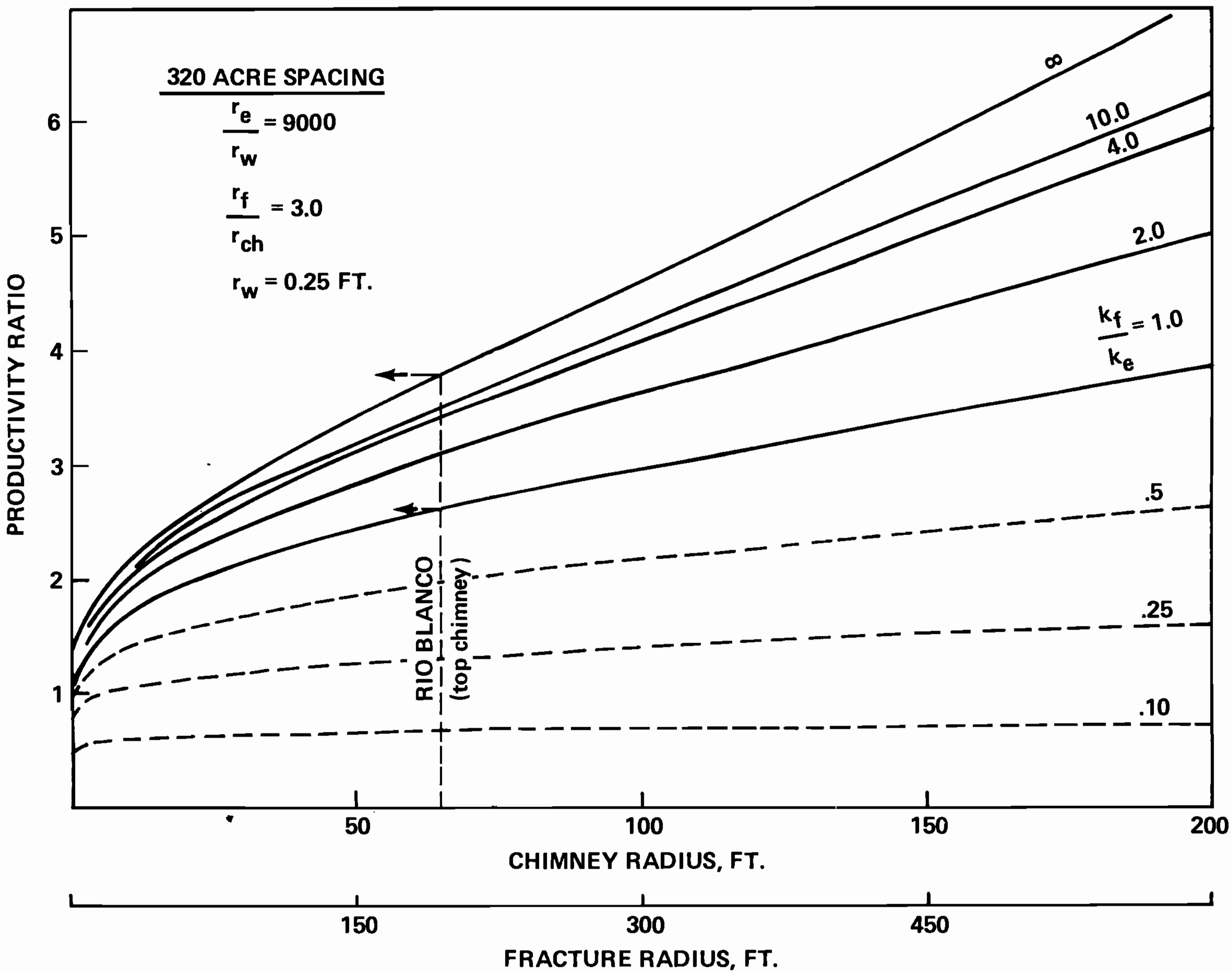

Figure 39-5.--Productivity ratio as a function of permeability alteration in fractured zone surrounding nuclear chimney

with thicknesses of several tens of feet. This advantage may, however, be a liability under less than ideal conditions, such as proximity to an aquifer, because of the necessity of the disposal of large volumes of contaminated water with radioactive elements.

IMPROVED DESIGN OF NUCLEAR DEVICES

A new, so-called Diamond series of nuclear devices was designed by the Energy Research and Development Administration (formerly Atomic Energy Commission), specifically for application in the Plowshare program. The design of the device is different from the standard one; it is only 7.8 inches in diameter, including the refrigerating canister, and produces much less residual tritium than the devices used for projects Gasbuggy and Rulison. For example, the total residual tritium for the Gasbuggy, Rulison, and each Rio Blanco explosive was estimated at 40,000, 10,000, and <1,000 curies (Ci), respectively. Only about 5 percent of the total tritium is contained in the gaseous phase; it is estimated that about 40 percent would be trapped in the melted rock and about 55 percent in water.

The small diameter of the explosive used in the last test helped cut drilling and well completion costs since standard, off-the-shelf bits and casing could be used. Comparison of these and other relevant data for the three nuclear-explosive fracturing experiments is shown in Table 39-1.

The cost of the Diamond device has not yet been revealed, but it is expected that it would not be lower than the charges for nuclear explosives projected by the Atomic Energy Commission some 14 years ago, which range from $350,000 for a 10 kt yield to $600,000 for a one-megaton explosive.

CURRENT STATUS OF NUCLEAR STIMULATION PROJECTS

If generalizations on the three nuclear-explosive fracturing tests were possible, then it would have to be said that: (1) predictions with respect to physical effects and cavity size were within, or close to the predetonation predictions; (2) the amount of residual tritium from the Gasbuggy to Rio Blanco

Table 39-1.--Comparison of relevant data for projects Gasbuggy, Rulison, and Rio Blanco

	Gasbuggy	Rulison	Rio Blanco
Date	Dec. 10, 1967	Sept. 10, 1969	May 17, 1973
Industrial sponsor	El Paso Nat. Gas Co.	Austral Oil Co.	CER Geonuclear Corp.
Location	San Juan Basin, New Mexico	Piceance Basin, W. Colorado	Piceance Basin, W. Colorado
Device size (kt)	29±3	43±8	(Simultaneous detonation of three 30-kt explosives)
Diameter of device (in)	18	9	7.8
T.D. of emplacement hole (ft)	4,400	8,700	7,869
Total tritium produced (Ci)	40,000	10,000	1,000
Depth of explosion (ft)	4,240	8,246	5,840, 6,230, and 6,690
Wt. of device and canister (lbs)	20,000	1,500	-
Length of device (ft)	30	15	-
Device run on	string of 7" casing	3/4" wire line	string of 7" casing
Size of hole drilled (in)	28 (special bit)	15 (stock bit)	15 (stock bit)
Size of casing set (in)	20 (special item)	10-3/4 (stock item)	10-3/4 (stock item)
Sealing material used	cement	sand and gravel	cement and gelled water
Cavity size, dia. x height (ft)	180 x 400	148 x 270	132 x (sphere)
Reentry after detonation	30 days	6 months	4 months

events was dramatically reduced, largely due to the new Diamond device; and perhaps most important, (3) in all three cases there was an apparently large discrepancy between the predetonation evaluation of the reservoir and reservoir characteristics as determined after the events. The first two generalizations are largely positive and will not be elaborated upon; however, the large discrepancy between the preshot and postshot formation evaluation deserves closer scrutiny.

In the case of Gasbuggy, a feasibility study estimated an average daily production (over 20 years) of about 500 x 10^3 standard ft^3 per day (MSCFD) against a 500 psi gathering-system pressure [2]. These estimates were based on a formation flow capacity of 25 millidarcy-feet (md-ft), a "conservative" fracture system and a smaller nuclear explosive than actually was used. Four months after production was initiated on a sustained basis, the rate was less than the predicted 20-year average and the bottom-hole pressure (BHP) was below 600 psi and still dropping. The best estimate of gas influx from the formation to the chimney was approximately 65 MSCFD at a chimney pressure of 500 psi. It now appears that the permeability of the rock matrix was grossly overestimated. Laboratory core-analysis data showed average permeability to be about 0.1 md, while pressure build-up data and production data from the chimney indicated matrix permeability of the order of 0.001 md or even lower.

A similar trend could be observed at project Rulison. In this case preshot formation permeability was estimated first at 0.5 md [3] and then at 0.01 md [4], while postshot production data and reservoir simulation studies indicated that actual matrix permeability was approximately 0.001 to 0.04 md [5]. Equally interesting is the degree of uncertainty in estimated net effective open pay, which was assumed 200 ft in one case [4] and only 75 ft in another [5], both studies being made after the preliminary production test data became available. Indeed, formation evaluation of very low permeability reservoirs has always been difficult, but when permeabilities are in the range of microdarcys, the current state-of-the-art of formation evaluation stretches to the limits of the available technology.

Project Rio Blanco confirmed the tendency to overestimate reservoir properties prior to the test. According to the feasibility study [6], the stimulated well (with three 30-kt, simultaneously-fired, explosives) could produce natural gas at a rate of 8 x 10^6 SCFD for 1.2 years, declining to 2 x 10^6 SCFD after 25 years; the expected recovery over the 25-year period was estimated at 26 x 10^9 SCF. The most recent estimate of the 25-year cumulative gas production from the upper chimney of project Rio Blanco was 1.1 x 10^9 SCF (Fig. 39-6). This corresponds to average daily production of 120 x 10^3 ft^3 per day.

One of the unexpected results obtained from Rio Blanco was that upon reentry of the region fractured by the top explosive, and after production testing, it was found that no communication existed with the regions fractured by the two lower explosives. Several independent evaluations were made before the detonation, based on cores, logs, and flow tests in a nearby test well. Within the interval stimulated by the upper explosion, the reservoir capacity was found to range from 4.1 to 7.6 md-ft. Actual performance tests, pressure fall-off, and build-up tests indicate formation capacity of only 0.73 md-ft, which is 6 to 10 times lower than expected. Formation capacity in the region stimulated by the bottom explosive appears to be in much better agreement with the predetonation estimates; all of the reservoir analysts judged it to be about 1 md-ft, compared to 0.5 md-ft determined from the production data. In terms of permeability, the regions stimulated by the upper and the bottom explosives had reservoir permeabilities of about 20 and 1.9 microdarcys, respectively, an ultra-low permeability by any standards.

Estimates of potential gas-production rates and ultimate cumulative recoveries varied widely, reflecting the large uncertainties in reservoir properties and gas in place. For example, a 1970 study [4] of the stimulation effects at the Rulison site predicted cumulative gas recovery over a 25-year period to be 4.6 to 8.0 x 10^9 ft^3 which corresponds to an average daily production rate of 500 to 900 x 10^3 ft^3 per day. Five

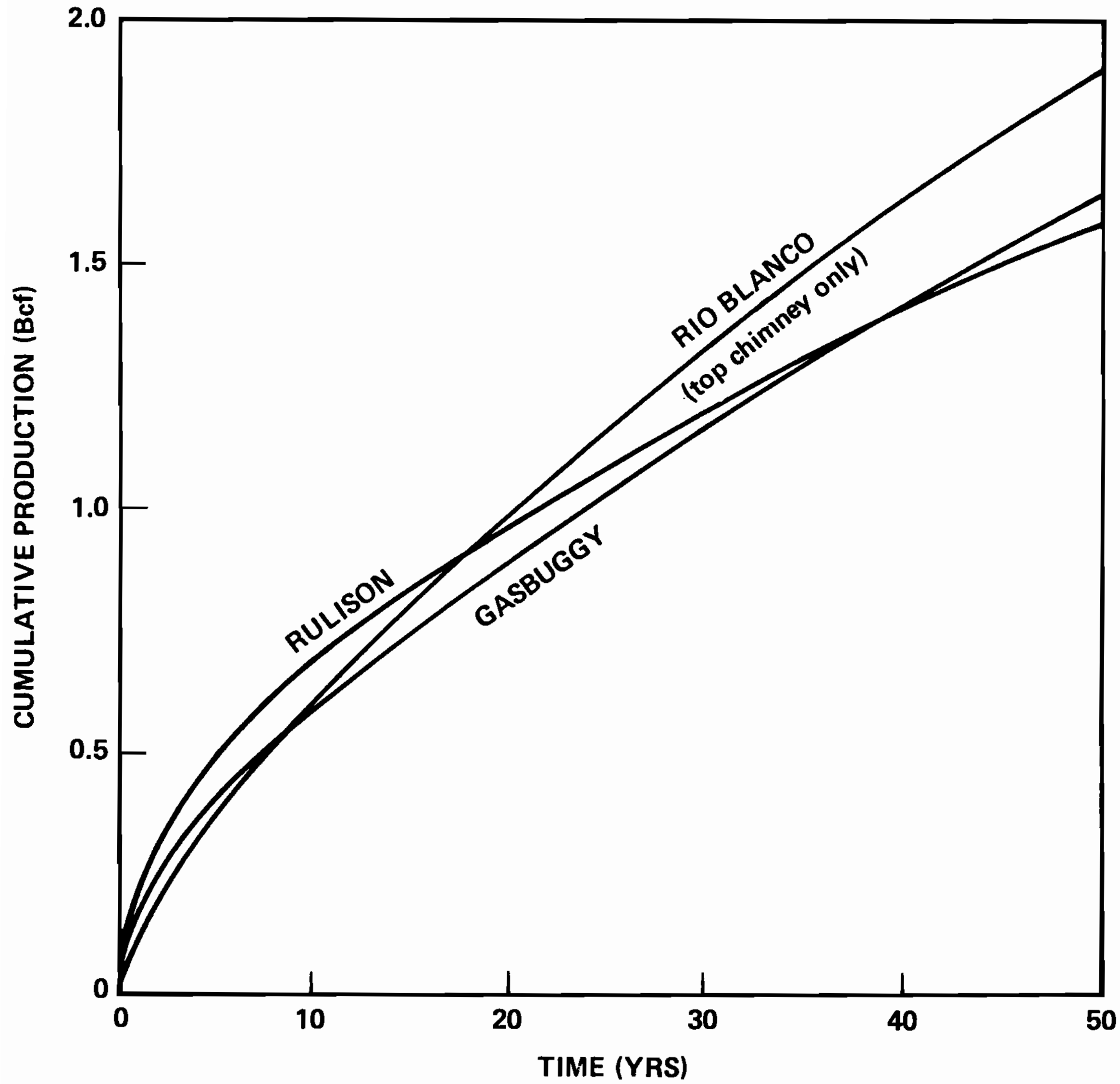

Figure 39-6.--Comparison of gas production from Gasbuggy, Rulison, and upper chimney of Rio Blanco

years later, another study compared the effects of the three nuclear stimulations [7] and concluded that a 50-year cumulative production from Gasbuggy, Rulison, or the Rio Blanco top chimney would amount to 1.5 to 20 x 10^9 ft^3, or about 80 to 110 x 10^3 ft^3 per day (Fig. 39-6).

The production tests in the Rulison and Rio Blanco wells are completed and the two wells will now be abandoned. The Gasbuggy well remains shut in.

The reasons for the lower than expected production performance of the three nuclear well fracturing tests are not yet clearly established, but several hypotheses are mentioned:

1. Overestimated formation permeability prior to the detonations appears to be by far the most important reason behind the lower than expected stimulation effects. In some cases formation porosity and net sand count were also overestimated. After the initial test data became available it was apparent that matrix permeability of the unfractured formation was very much lower.

It appears that the overestimate ranged from about 2 to 3 order of magnitude for project Gasbuggy, about 1 to 2 orders of magnitude for project Rulison, and a factor of 6 to 10 for the upper chimney region of project Rio Blanco. The bulk of reservoir rock beyond the unfractured region (99 percent of 320 acres) is still dominated by the ultra-low matrix permeability which results in lower than expected gas influx into the chimney from regions immediately adjacent to fractures emanating from the chimney. Lower deliverability and lower ultimate recovery than predicted then would be expected.

2. Closing of newly created, unsupported fractures. Increasing water influx into the cavity would decrease relative permeability to gas.

3. Glazing of initial cavity walls by the melted rock, most of which collects in the bottom of the cavity in form of a glassy slug, but some may solidify on cavity walls and create a "skin effect." This would apply mainly to a cavity which did not collapse or a partially collapsed chimney.

LIMITATIONS OF CURRENT TECHNOLOGY

Most of the effects of nuclear-explosive well fracturing have been within the range of the predetonation predictions, with two notable exceptions: (1) there was a large apparent discrepancy between the preshot reservoir evaluation and the reservoir characteristics determined from actual production testing for all of the three nuclear-explosive well fracturing experiments, and (2) the lack of communication between the chimneys at the Rio Blanco site was unexpected.

The lack of communication between the Rio Blanco chimneys may be characteristic of simultaneous detonations and, as such, it does not present much of a problem, even if sequential detonations will not result in inter-chimney communication. Of much larger concern is the fact that production testing in all three experiments resulted in considerable reevaluation of reservoir basic properties.

The so-called very tight gas formations differ greatly from conventional gas reservoirs. They may vary, at one extreme, from discrete gas-bearing zones of generally uniform thickness and extending over wide distances, to massive sections with numerous gas-bearing zones lensing in and out throughout the section [8]. These geological sequences will, in most cases, be made up predominantly of clays and shales with some sandy zones, so that it becomes difficult to recognize a "pay" zone. Furthermore, these pay zones may have porosity ranging from less than 5 percent to a high of 15 percent and have connate or immobile water saturation in the range of 50 to 70 percent. The in situ gas permeability of such formations may range from as low as 1 microdarcy to a few millidarcys, which may be 1 to 3 orders of magnitude lower than that of a common oil or gas reservoir. A number of fundamental questions relating to characterization of such reservoirs still have to be answered. Unfortunately, the nature of most such formations makes conventional logging less discriminating than desired.

The major problem areas are in the accurate determination of gas saturation, estimation of net pay, and in situ formation permeability. The accuracy of reservoir temperature, pressure, and porosity measurements appears reasonably adequate.

Another major problem area is in the calibration of log-derived information to laboratory measurements on cores and finally, to formation testing, such as pressure fall-off and pressure build-up. Log and core analyses remain the cornerstone upon which formation evaluation rests. Many of the basic principles used in core analyses today are the same as those originally established by the pioneers in the field and did not change materially since then. Some of these techniques are subject to severe limitations. It has been shown by a number of laboratory investigations that, for very low permeability sandstones, permeability depends upon both confining stress [10, 11,12,13] and water saturation [11] as shown in Fig. 39-7. This characteristic is now well known to individuals engaged in research on tight formations, but technology transfer has not yet been adequate for either service-company personnel who measure permeability in laboratories or many users of their services.

The reduction in permeability is greater for low-permeability rocks. Under the reservoir conditions representative of a tight formation at the beginning of gas production, the effective permeability is about 1/20 of what had been measured by the gas industry's standard method involving low-pressure measurements on a dried core. For example, conventional analysis of about 200 Gasbuggy cores gave an initial gas permeability of 0.16 md on dry cores and an average water saturation of 48 percent. If correction is made for the in situ overburden pressure of 3,000 psi (Fig. 39-7), the reduction factor resulting from overburden pressure and water saturation is 0.25 and 0.2, respectively. The overall permeability reduction factor is then 0.05, so that the in situ permeability would not be 0.16 but 0.008 md. The latter value, incidentally, compares more favorably with reservoir permeability obtained from production testing, which was approximately 0.01 md [7].

Other fundamental questions still need to be answered, such as whether water produced with gas (usually at much higher

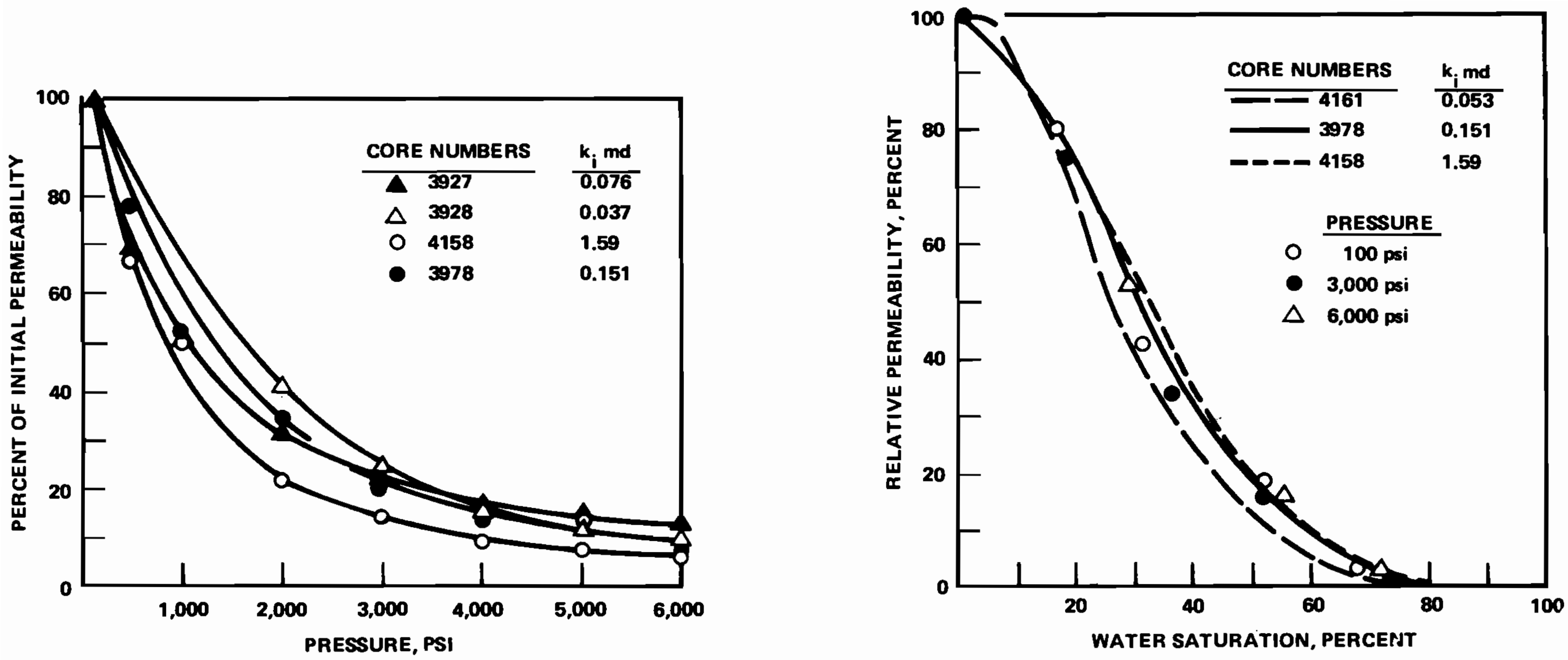

Figure 39-7.--Reservoir permeability as a function of confining pressure and water saturation

rates than anticipated) is coming out of the same pores which are occupied by gas, whether it comes mainly from sand stringers with gas essentially absent or below critical gas saturation, or whether the produced water is largely from shales.

PUBLIC ACCEPTANCE

Aside from the technical and economic aspects of nuclear-explosive fracturing, public acceptance of the technology is equally important. It has never been favorable and, in fact, recent publicity seems to have created new apprehensions. Project Rulison, for example, experienced numerous delays caused by protests from various ecological and environmental-protection groups.

Whether these actions stem from the inability of the public to discern the difference between nuclear weaponry and nuclear-explosive fracturing gas wells is immaterial; any company contemplating nuclear-explosive fracturing at this time must face almost incredible opposition from various groups and the public in general. The currently unfavorable economic picture of nuclear-explosive fracturing notwithstanding, fear of public resentment is probably another reason why no major oil company has engaged in nuclear-explosive well fracturing technology. Some smaller company perhaps may have counted on being in the forefront of modern technology, and on the favorable publicity fall-out.

The magnitude of the problems that the projects' sponsors must contend with is exemplified by environmental statements prepared for project Wagon Wheel [15] which was designed as an ultimate test involving five nuclear explosives to be set off sequentially. The project was finally terminated.

CONCLUDING REMARKS

The state of affairs of nuclear-explosive fracturing technology appears to be in the unenviable position of having technical, economic, and political problems.

The technical problems, while fundamental, are not insurmountable. Definite progress has been made since the first application of nuclear-explosive well fracturing and more is to come, particularly with respect to the better definition and understanding of the ultra-tight formations. The major problem areas appear to be in the accuracy of the determination of in situ permeability gas saturation, and the estimation of net pay. Even though no nuclear-explosive fracturing projects are planned in the foreseeable future, these aspects are given much attention in conjunction with the application of massive hydraulic fracturing.

Economic aspects are closely tied to the successful solution of technical problems. Many economic feasibility studies were performed and, even though there are sharp disagreements, the consensus is that nuclear-explosive fracturing can be economically viable. Studies performed by the people directly involved in the promulgation of the technology tended to be decidedly more optimistic than those performed by independent appraisers.

Political climate seems to pose the single largest obstacle at this time and it appears that no improvement can be expected in the foreseeable future. Public acceptance of the technology is at the lowest ebb and declining; until it is reversed, there seems little hope for the future of the technology. It also is apparent that the use of nuclear explosives in the future would require legal and political changes. Political expediency dictates that the current efforts in the development of very tight gas reservoirs be placed in the more conventional technology, such as massive hydraulic fracturing.

APPENDIX

Gas deliverability from a nuclear chimney depends heavily upon the formation's natural ability to conduct gas to the chimney.

Mathematical description of gas flow to the chimney has already received exhaustive treatment, ranging from very complex solutions to the comparatively simple radial form of Darcy's law. Even a basic assumption of radial flow has been strongly contested. It is felt that there is little point in making the model any more complex than necessary at this time. Therefore, radial Darcy flow is assumed.

The stimulation effect of a nuclear blast is most easily assessed on the basis of the improvement in well productivity relative to a standard unstimulated well. The term productivity ratio, or stimulation ratio, is commonly applied to such a comparison. With the assumption of radial flow, productivity ratio can be calculated in the usual manner.

Since the chimney is basically an enlarged wellbore, then its contribution alone may be expressed as follows:

$$PR = \frac{\ln \frac{r_e}{r_w}}{\ln \frac{r_e}{r_{ch}}} \qquad (1)$$

PR = productivity ratio

r_w = standard wellbore radius (ft)

r_{ch} = chimney radius (ft)

r_c = external drainage radius (ft)

Solutions of this equation for several well spacings are shown on Fig. 39-4.

The contribution of the fractured zone may be considered in terms of increased formation permeability or further enlargement of the wellbore to an "effective radius" which combines the chimney and fracture radii. Accurate prediction of the effect of the fractured zone on well productivity is nearly impossible because the distribution of fractures, their flow characteristics, and the influence of closing and/or sealing of unsupported fractures are not known quantitatively. However, without being too specific, it is possible to account for the productivity improvement of the fractured zone in terms of its permeability, relative to that of the unaltered formation. Modification of expression (1) to include the fractured zone and its average permeability improvement results in:

$$PR = \frac{\ln \frac{r_e}{r_w}}{\ln \frac{r_e}{r_f} + \frac{k_e}{k_f} \ln \frac{r_f}{r_{ch}}} \tag{2}$$

r_f = radius of fractured zone (ft)
k_e = natural formation permeability (md)
k_f = permeability of the fractured zone (md)

The contribution of the fractured zone surrounding the nuclear chimney is illustrated in Fig. 39-5.

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CHAPTER 40

ADVANCED STIMULATION SYSTEMS APPLIED TO MASSIVE HYDRAULIC FRACTURING--TECHNIQUES AND RESULTS

J. A. Hochhalter[1]

Massive hydraulic fracturing (MHF) is a term which has captured the interest and imagination of an industry.

Just what is MHF? Is it an 800 gallon ($3m^3$) treatment of 1945-50? Or one of the massive 1,600 gallon ($6m^3$) treatments of a year later? In the mid-50's it might have been a 10,000 gallon ($38m^3$) job. Only a few years later it might have been a 300 barrels/minute ($48m^3$/minute), 150,000 gallon ($570m^3$) treatment with 200,000 pounds of sand (90 tons). This treatment, the deepest, at 22,000 ft, ever performed (6,700m), might have been called massive. The trend in total sand placed and in treatment volume has been increasing at an accelerating rate in recent years. The required hydraulic horsepower has increased dramatically over the years, with higher pressures and higher rates. It is significant to note the decrease in average pumping rate in recent years. This is the direct result of recent developments in the technology of high viscosity fluid systems. There has been a strong trend toward water-based fracturing fluids. This is clearly a trend away from hydrocarbon fluids.

There are several reasons for this situation. As we routinely, hydraulically fracture deeper formations we are treating a greater proportion of gas reservoirs, and the addition of a third phase (liquid hydrocarbon) to a water-wet gas

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[1]Halliburton Co. Germany GMBH, The Hague, Netherlands.

formation invites production difficulties. Developments in the high viscosity, water-based fluids and the hybrid polymer-emulsion systems is also responsible for this trend.

Massive Hydraulic Fracturing--Really, what is it?

Maybe it can be defined by the volume of fluid pumped = 100,000 gallons (380m^3); or sand places--200,000 pounds (90 tons); or the gross formation thickness--400 ft (120m); or the fracture length--500 ft (150m).

These definitions are all misleading!

1.5 x 10^6 gallons (5,700m^3) have been pumped in one stage; 1.0 x 10^6 pounds (454 tons) of sand have been placed. Some formations are over 1,000 ft (300m) thick. Fractures one mile (1.6km) long have been created.

Massive Hydraulic Fracturing, from an historical standpoint then, is any real departure from the norm--usually a significant increase in fluid volume, sand volume, fracture length, and/or formation thickness.

The objective of any stimulation treatment is to increase the productivity of the treated well. The primary purpose of a hydraulic fracturing treating is to create a conductive fracture in the permeable reservoir. Darcy's Law for radial liquid flow indicates the parameters which we can influence.

$$Q = \frac{C\ Kh\ (Pe-Pw)}{u\ \ln\ (re/rw)}$$

where C = Constant of Proportionality

Q = Production Rate

K = Permeability

h = Height of the productive zone

Pe = Reservoir Pressure

Pw = Wellbore Pressure

u = Reservoir Fluid Viscosity

re = Drainage Radius

rw = Wellbore Radius

ln = Natural Log

There is relatively little that can be done to influence the formation permeability, and any shallow alteration will have extremely short term effects until steady state production returns to a pretreatment level.

The height of the productive zone can be altered to a certain extent by perforating techniques, but again, assuming vertical and horizontal permeability, additional perforating of the entire interval seldom significantly alters a well's productivity.

The reservoir pressure can be influenced by pressure maintenance projects such as water or gas injection; these techniques are not actually stimulation, but are designed to sustain an acceptable production rate. The wellbore pressure can easily be lowered to increase the productivity, but generally there is an economic limit to drawdown pressures as transmission pipelines must operate at moderate pressures to assure adequate deliverability over great distances. Compressors can change the economic picture here.

Reservoir viscosity has been a factor in tar sands and other heavy liquid hydrocarbon reservoirs, but has not been relevant to gas well stimulation.

The factor ln (re/rw) holds the key to hydraulic fracturing success. The productivity of a field may be increased by drilling more wells and decreasing the drainage radius. The smaller the re, the larger the Q, all else remaining the same. This is not, however, a practical solution in many cases and if we can increase the wellbore radius, we can decrease the rate controlling factor ln (re/rw). For example, if we increase the wellbore radius from 0.1m to 30m, the productivity will increase 3.5 times.

The hydraulic fracturing treatment does not physically enlarge the wellbore, but since a fracture is initiated at the wellbore and extends from the wellbore outward, the result is an increase in the effective wellbore radius. Work by Prats indicates that the effective wellbore radius may be approximated as one-quarter the total fracture length generated by the treatment, if the fracture is vertical and has infinite conductivity. This indicates that stimulation treatments should be designed for long, highly conductive fractures.

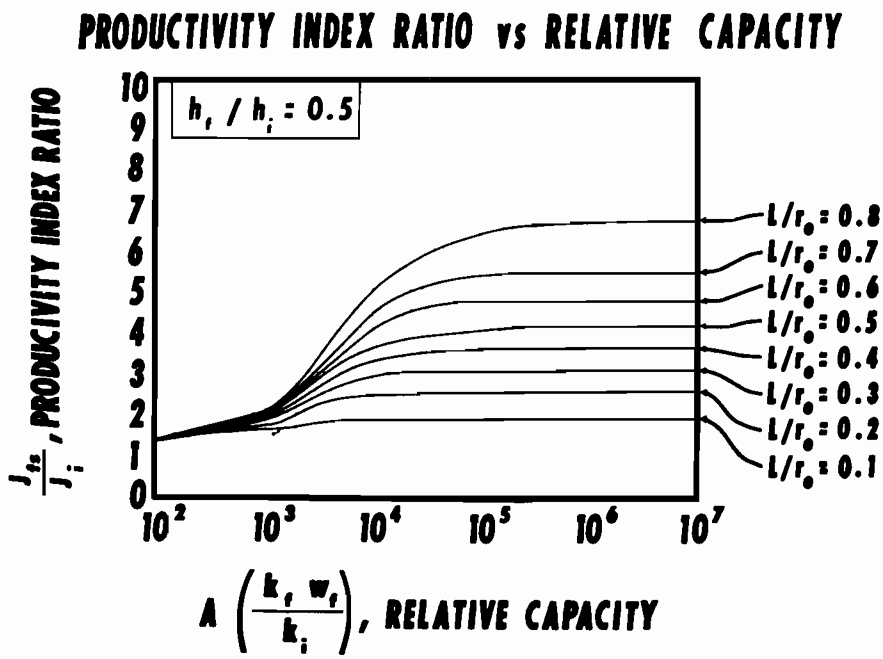

Figure 40-1.--Productivity index ratio vs. relative capacity

The understanding of the relationship among the factors of fracture height, fracture length, and fracture conductivity is essential to the task of designing effective fracture stimulation treatments.

A family of curves exists that is dependent upon the ratio of created fracture height and permeable formation height. An example (Fig. 40-1) of a situation where the Hf/Hi = 0.5, or the fracture height is one-half the reservoir height, shows the dependence of productivity upon fracture length and fracture conductivity. The relative fracture flow capacity is the ratio of the transmission capacity of the propped fracture compared to the formation deliverability to the fracture. This implies a definite relationship between the formation permeability and the proppant-bed permeability. The purpose of this discussion has been to emphasize the importance of fracture length to stimulation, especially in tight reservoirs where the relative fracture flow capacity is high.

Three areas of the Wattenburg field in Colorado were chosen as test areas for treatments of different geological developments. The area designated A, the area of best development, showed a remarkable dependence upon treatment size, or created fracture length. Area B demonstrated the same trend but to a lesser degree. Area C responded least of all, but still confirmed that stimulation of tight reservoir is volume dependent.

Besides the theoretical and mathematical aspects of MHF it is necessary to consider formation factors. The formation permeability will determine the extent of fluid lost to the formation during the treatment. Fluid loss additives may be required to lessen this quantity and shorten clean-up time in higher permeability tight zones (0.5 md or more). In reservoirs usually considered for MHF (0.1 md or less), the concern is to minimize the fluid retention of the formation caused by the high capillary forces developed.

The fluid considerations become:

1. Availability
2. Fluid retention tendencies

3. Clay swelling or migrating possibilities
4. Will iron problems be evidenced
5. What types of fluids will be used
6. What viscosity of fluid should be used
7. What will it cost.

Permeability recovery studies indicate that alcoholic fluids shorten the cleanup time for some formations, and that advancements in surface-tension agents can also assist in this recovery time factor.

There is no consensus of opinion as to the one best fluid, and very probably never will be. Each particular fluid has its own advantages and disadvantages, benefits and detrimental aspects. The fluids chosen thus far have been conventional guar gums, gelled fluids, derivitized low-residue guar gum fluids, crosslinked extremely high viscosity versions of the above, synthetic polymer gelled fluids, with and without alcoholic additives, and crosslinked synthetic polymer fluids. One of the highly popular fluids is a hybrid poly-emulsion system whereby a gelled water forms the external phase of a water/hydrocarbon emulsion. This polymeremulsion exhibits good fluid loss properties, good proppant carrying ability and breaks consistently. The low concentration of water, 30 to 50 percent, reduces the amount of imbibed water and seems to lessen damage in water-sensitive formations. One disadvantage of this system is a relatively high pumping friction.

In addition to the selection of treating fluids there is a required decision as to treating techniques. The injection rate affects the fracture width, length, sand transport distance, and fracture height. The relationship of fracture width governed by injection rate and viscosity has been established. The higher the viscosity for a given rate, the wider the fracture. The higher the rate at a given viscosity, the wider the fracture. The wider the fracture, the more proppant will be placed, and the higher the fracture flow capacity will be.

Should the interval be treated as a single zone, or multiple zones? Perhaps limited entry is a viable technique? Should an inert gas be incorporated to shorten cleanup time?

The feeling is that the more rapidly the well is opened and treating fluids recovered, the less time there is for formation damage to occur; however, another major company has data indicating that it requires a period of days for a tight formation to close on the proppant and hold it in place. Studies are still in progress on all of these questions.

One of the major problems associated with MHF is logistics. Large quantities of fluids, sand, additives, equipment, and men must be assembled and coordinated.

There have been successes and failures with MHF. The economics of the treatments performed to date are "tight hole" information and not generally open to the public.

The technique has been proven: the productivity of tight gas reservoirs can be improved. The mechanical equipment required to perform such treatments has been developed at great cost and is proven and available. The fluid technology is advancing daily. The technique selection and procedure are being refined.

The formation parameters are the key to success or failure. Mathematically, the greatest improvement which can be expected, assuming no wellbore damage, is about 14-fold. One may get lucky and connect with a natural fracture network, but proven reserves in a porous formation are not alone an indication of success. There must be permeability and MHF cannot create this permeability. The lower limits of this permeability have not been defined.

The dimensions of hydraulic fracturing have permanently escalated. Its mechanical limitations are still not in sight. The only existing limitations at the present time are economics. MHF is another step towards the challenging task of securing the consistently increasing energy demand of civilized mankind.

SECTION VI. TAR SAND, HEAVY OIL, AND OIL SHALE DEPOSITS

CHAPTER 41

DEVELOPMENT STATUS OF ALBERTA OIL SANDS--1976

Alberta Oil Sands Technology and Research Authority
Great Canadian Oil Sands Limited
A Canadian Oil Industry Task Force

INTRODUCTION

The Alberta oil sands, as one of the largest deposits of bituminous sands in the world, have undergone extensive testing for over three-quarters of a century, but commercialization of these vast reserves has only recently commenced. The deposits vary in depth from surface outcrops to beds overlain with more than 750 m of overburden. No single technology will be adequate to recover bitumen from all parts of the deposit, and the search for new technologies has received an impetus with the recent establishment of the Alberta Oil Sands Technology and Research Authority, an Alberta Government agency funded to the level of $\$100 \times 10^6$.

For those deposits close enough to the surface for surface mining, the Hot-Water Process has been selected for the first two commercial projects. One of these projects, Great Canadian Oil Sands, has been in operation for almost 7 years, and is currently at a production level of 50,000 barrels per day. Syncrude Canada Limited is building a 100,000 barrels per day plant and expects to be in full operation in 1979.

Extensive laboratory and field research has been carried out on methods of recovering the deeply buried bitumen using in situ techniques. Upwards of 20 pilot projects have been completed, are underway, or will start up during the next few years, using the most advanced in situ recovery concepts available. It is probable that some of these in situ tests will lead to commercial projects during the latter part of the 1980's.

In this paper, the past and future development of oil sands is considered in four parts. These deal with world reserves, research in technology, Canada's first surface-mining extraction plant, and the outlook for future oil-sands development.

PART A--WORLD-WIDE OIL SAND RESERVES

C.W. Bowman[1]
M.A. Carrigy[1]

GLOBAL RESERVES

Table 41-1 summarizes the major world oil sand reserves.

Large oil sand (tar sand) deposits are found on every continent except Australia. These deposits occur either at the surface or were found accidently during exploration for conventional petroleum. Until recently there was very little interest in developing these deposits, and few oil-producing nations have reliable estimates of the amount of their petroleum resources that occur in the form of heavy oil. Carrigy (1974) estimated from published and unpublished reference sources that 2.3 x 10^{12} barrels of heavy oil occur in oil sand deposits throughout the world. Of this amount 1 x 10^{12} barrels is found in Canada and at least 0.7 x 10^{12} barrels in Venezuela. Sparse information from the USSR suggests that a deposit, similar in size to the Athabasca deposit of Alberta, has been found in Siberia. These estimates of heavy oil are likely to be too low, and more heavy oil will probably be found in the future. It is probable that all the major deposits suitable for surface mining have already been discovered, but as less than 5 percent of the world's heavy

[1]Alberta Oil Sands Technology and Research Authority

TABLE 41-1.--In-place reserves in major oil-sand deposits in the world

Giant deposits (10^{12} barrels)		Large deposits (10^{9} barrels)		Medium deposits (10^{6} barrels)	
Location	Size	Location	Size	Location	Size
Orinoco (Venezuela)	0.7	Wabasca (Canada)	85	Selenizza (Albania)	371
Athabasca (Canada)	0.6	Peace River (Canada)	75	Guanoco (Venezuela)	62
Olenek (USSR)	0.6	Tar Sand Triangle (USA)	18	Asphalt Lake (Trinidad)	60
Cold Lake (Canada)	0.16	P.R. Spring (USA)	4	Santa Rosa (USA)	57
		Sunnyside (USA)	3	Sisquoc (USA)	50
		Bemolanga (Malagasy)	1.75	Asphalt (USA)	48
		Circle Cliffs (USA)	1.3	Tataros (Romania)	25
		Asphalt Ridge (USA)	1.2	Cheildag (USSR)	24
				Edna (USA)	166

Sources: Walters (1973)
Carrigy (Personal Communication)
Alberta Energy Resources Conservation Board (1963, 1973, 1974, 1976)

oil reserves is located in these near-surface deposits, attention must be focused on the deposits which lie beyond the reach of the open-pit mining techniques.

In searching for new oil sand deposits it is possible to identify some common features in their geological setting. They are found mostly near the edges of large sedimentary basins in poorly-defined traps in relatively thin, fresh-water sandstone reservoirs. These have a very large areal extent and are highly porous and permeable. The bitumen or heavy oil they contain is very viscous and is high in asphaltenes, sulphur, heavy metals, and such other impurities as oxygen and nitrogen.

Because of these undesirable properties, heavy oil accumulations are usually differentiated from conventional crude oil for administrative purposes. In Alberta, the Energy Resources Conservation Board defines oil sand deposits as those petroleum reservoirs containing bitumen of such viscosity that it cannot be produced through a well by normal production methods. Other definitions could be used, such as those petroleum reservoirs containing bitumen whose density is less than some specific level on the A.P.I. gravity scale, for example, 10 or 15. However, because any definition of heavy oil or bitumen involves the selection of an arbitrary point on a continuous scale of petroleum properties, it is probable that no universally acceptable division point will be found between bitumen and conventional petroleum.

ALBERTA RESERVES

The Alberta oil sands are found in at least four major deposits, the geographical location of which is shown in Fig. 41-1. The estimated oil-in-place reserves are shown in Fig. 41-2. As a result of the drilling which has occurred in the past decades, an estimate has been prepared of the extent of the deposit available for surface mining (150 feet or less of overburden) and in situ techniques (greater than 500 feet) (Fig. 41-3). The portion of the deposit between 150 and 500 feet has been classified as "uncertain." Underground mining has

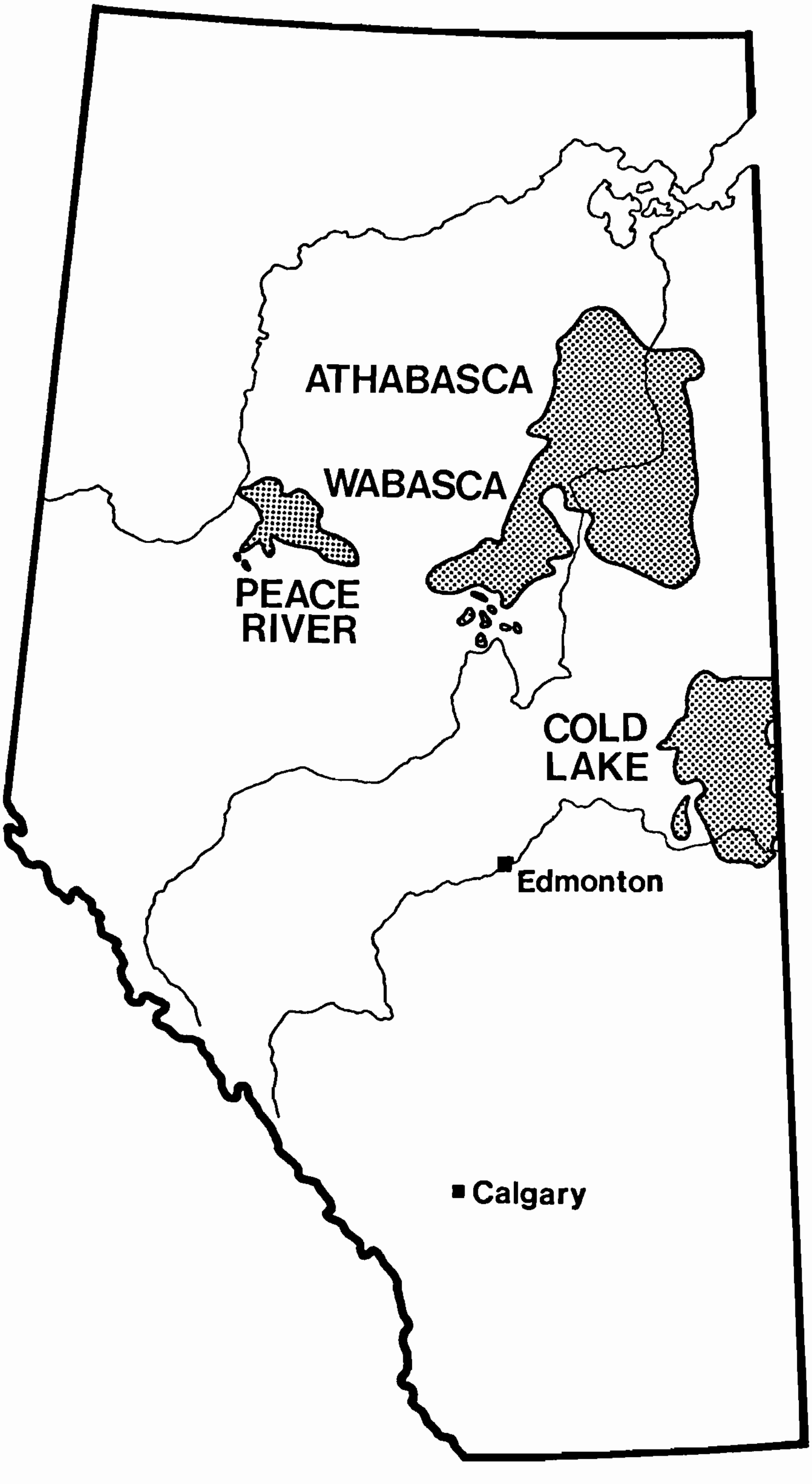

Figure 41-1.--Location of major Alberta oil sands deposits

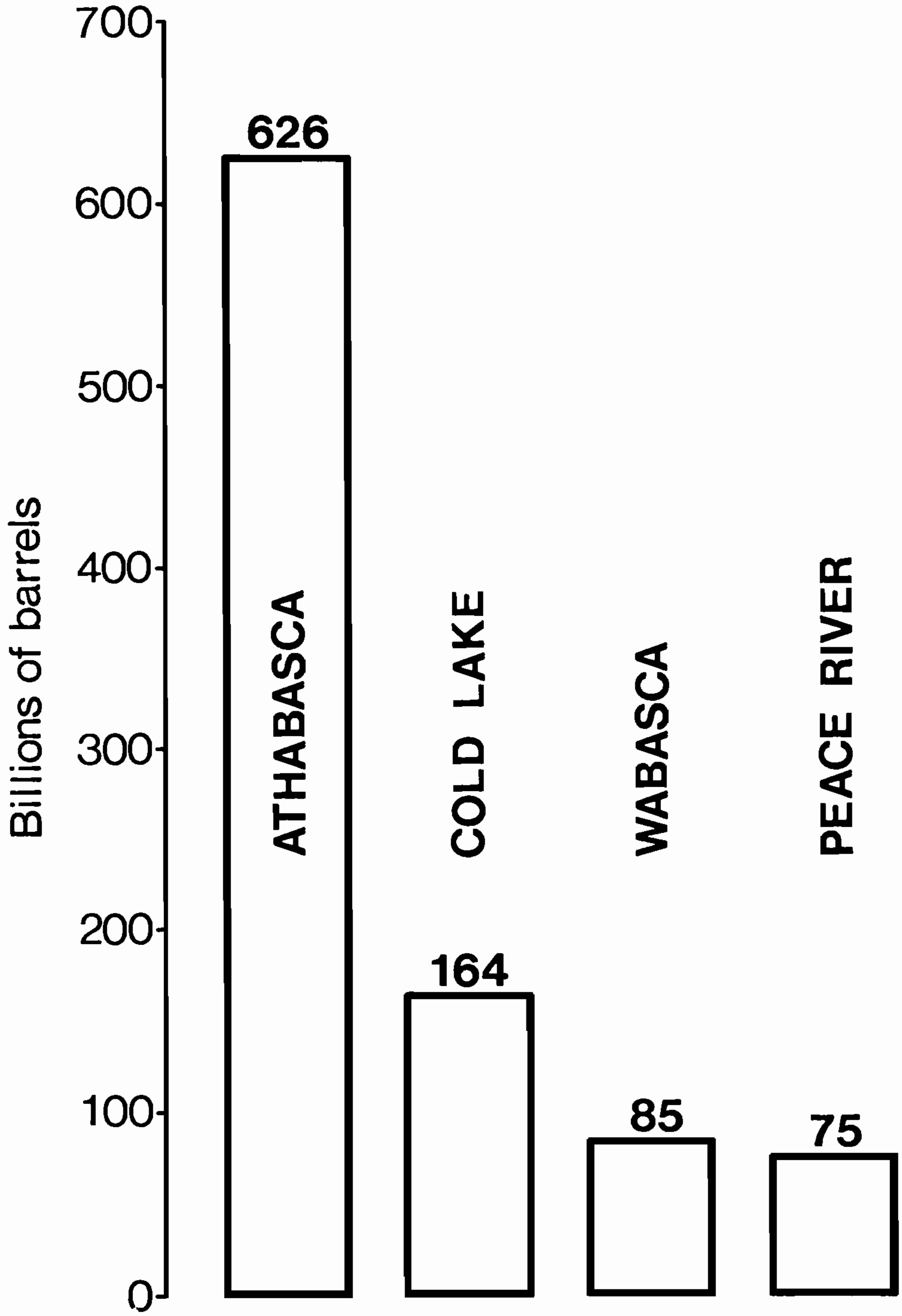

Figure 41-2.--Reserves of crude bitumen-in-place in the Athabasca, Cold Lake, Wabasca, and Peace River oil sands deposits

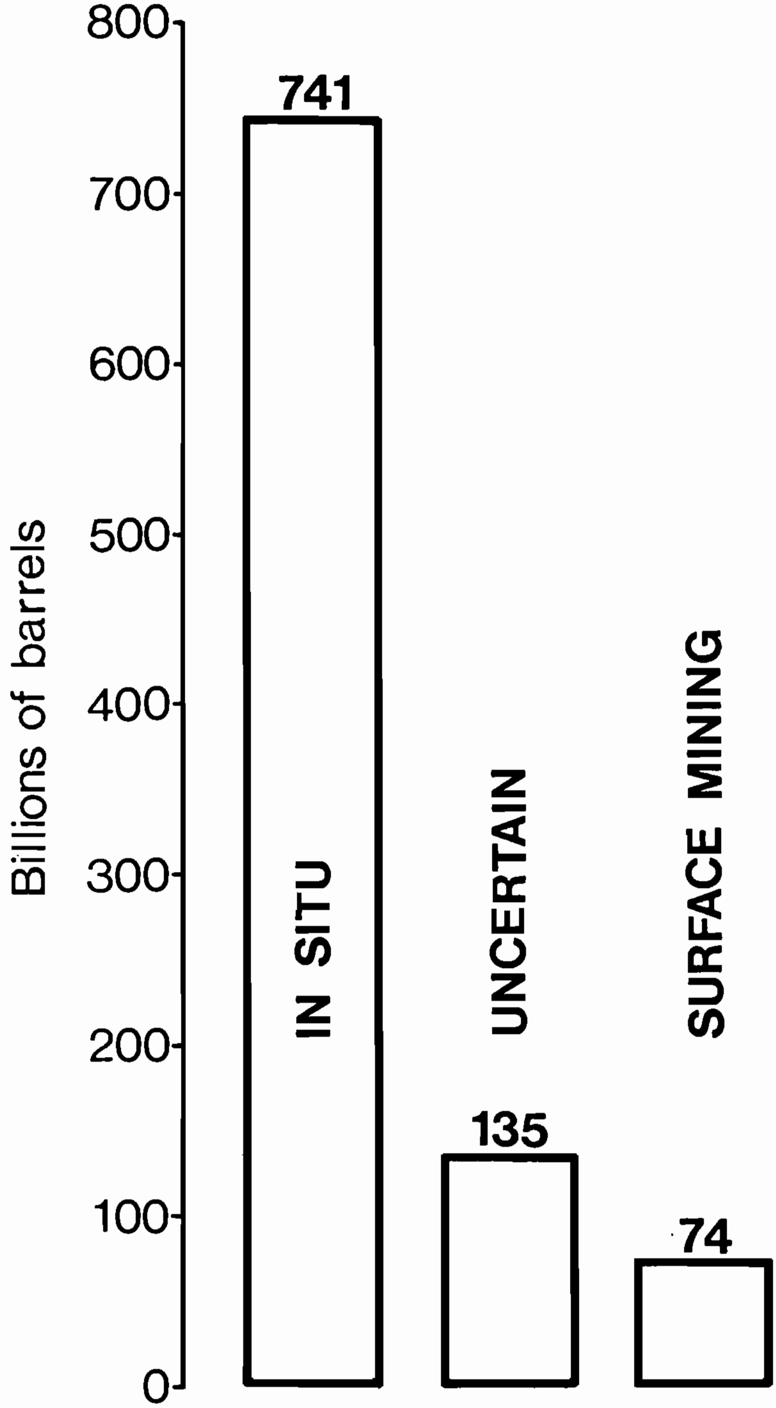

Figure 41-3.--Crude bitumen reserves in-place attributable to surface mining, uncertain, and in situ extraction methods

been considered for these intermediate reserves, but new concepts for in situ recovery may also prove to be feasible.

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PART B--THE ALBERTA SEARCH FOR NEW TECHNOLOGY

C.W. Bowman[2]

M.A. Carrigy[2]

A HISTORICAL PERSPECTIVE

At a conference such as this, which is devoted to training and research, it is appropriate to examine the state-of-the-art in Canadian oil sands research to see if some principles emerge from the Canadian experience that could serve as guidelines for those countries planning to embark on the development of their nonconventional petroleum resources.

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[2]Alberta Oil Sands Technology and Research Authority

Surface Mining

Canada has large deposits of oil sands accessible from the surface by open pit mining methods. It is this outcrop portion of the Athabasca deposit for which Canada is famous.

These outcrops along the Athabasca River in Northern Alberta have been known to exist for almost 200 years. The development of the current processes of mining and hot-water extraction took 50 years to progress from concept to commercialization. This has cost in the order of $\$50 \times 10^6$, and has involved continuous laboratory research, one field pilot (Clearwater), and two large 500 barrels/day demonstration plants (at Bitumount, by the Alberta Government and at Mildred Lake by Cities Service Athabasca Limited). A list of 13 of these activities is given in Bowman (1971). It is interesting to note that many of those programs were financed from government sources.

In Situ Recovery

In parallel with this development of surface mining and hot-water extraction a second research effort designed to exploit the more deeply buried (in situ) petroleum resources was started in the late 1950's and to date has cost upwards of $\$100 \times 10^6$. Most of this money has been spent on field experimental pilots in the Athabasca and Cold Lake deposits, the larger pilots costing on the average about $\$20 \times 10^6$ in 1976 dollars. To date, this research has been financed largely by the petroleum industry without government assistance. It is estimated that another $\$600 \times 10^6$ will need to be spent before commercial in situ processes are available for production from all four Alberta deposits and that this money will be spent over the next 10 to 15 year period.

Uses of Bitumen

The first use foreseen for the heavy oil or bitumen extracted from the Athabasca deposit was in its raw or slightly upgraded state as a paving material for roads, or for asphaltic cements. More recent interest has focused on the upgrading of the bitumen for use as a crude oil substitute for refinery feed stock. This upgrading step requires viscosity reduction (via cracking) and hydrogen enrichment (via carbon rejection or direct hydrogen addition). The latter will depend on advances in hydrogenation technology that will cost considerable time and money to perfect.

FUTURE FINANCIAL COMMITMENT

To assist other governments in budgeting R & D expenditures for the extraction of bitumen from oil sand deposits, the Canadian experience suggests that the necessary research expenditure may be in the order of $\$1.00/10^3$ barrels of bitumen in-place. On this basis the nearly 10^{12} barrels of bitumen in the Alberta deposits will require the expenditure of $\$1 \times 10^9$ on R & D over perhaps a 20 year period. A deposit of 10^9 barrels would thus justify only an expenditure of $\$1 \times 10^6$.

In Alberta, it is generally accepted that the minimum economic size for an oil-sands plant is one that produces at least 50,000 barrels of synthetic oil per day. Such a plant requires an in-place reserve of almost 1×10^9 barrels to give it a 30 year life. It is probable that any deposits with less than 1×10^9 barrels could not be economically developed as an alternate source of refinery feedstock. Smaller deposits may, however, be economically developed if there is a market for the bitumen in its raw or slightly upgraded state.

It should not be assumed that the technology developed in Canada can be transferred to other areas without modification. Before any extensive development or exploration of a new deposit is contemplated it would be wise to have preliminary extraction tests performed, as it is well known that differences in mineralogy of the sands and the state of bitumen-grain contact, ranging from hydrophyllic (water-wet) to hydrophobic (oil-wet), has a great effect on the choice of the primary extraction method.

THE CURRENT ALBERTA R & D PROGRAM

To coordinate the development of new oil sand technologies, the Alberta Government has established the Alberta Oil Sands Technology and Research Authority. The main programs of the Authority are as follows:

1. Definition of Priorities and Technological Barriers
   - Government, industry, university consensus of key barriers, and opportunity areas
   - Workshops on "Critical Path" barriers
   - State-of-the-art analyses of key technology segments
2. Grants and Loans
   - In situ laboratory and mathematical studies
   - New extraction techniques
   - Improved bitumen clean-up methods
   - More efficient bitumen upgrading methods
   - More extensive bitumen upgrading
   - Reduced environmental impact
   - Development of new equipment
   - Basic research
   - Support of academic activities
3. Partnerships with Industry or Governments
   - In situ field recovery tests
   - Bitumen upgrading pilot plants
   - Evaluation of new processing and materials handling equipment

Initial AOSTRA Activities

During its initial year of operation, the Authority has launched the following specific programs.

1. The publishing of guidelines for in situ field programs, to be carried out in 50/50 partnership with industry. Twenty applications were accepted under these guidelines on November 1, 1975, and five of these have now been accepted for joint funding. A key aspect will be that ownership of technology arising from the programs will reside with the Authority, with future licensing income being shared equitably between the Authority

and its industry partner. The Authority will be participating in three phases of the field projects, initial field testing (1 well), single pattern testing (5 to 10 wells), and prototype testing (up to 50 wells). The scope and schedule for typical projects are shown in Table 41-2 and Fig. 41-4.

TABLE 41-2

TABLE 41-2.--In situ recovery scale-up

	Single pattern	Prototype	Commercial
Bitumen production level barrels/day	300	3,000	130,000
Total number of wells	5 to 10	50	1,500
Cost $ millions	10	50	2,000 +
Staff numbers on site	15	35	2,000

2. The Authority has awarded a $\$2.8 \times 10^6$ contract to the Alberta Research Council to construct and operate two formation test beds for the evaluation of new in situ recovery processes. The largest of these beds will be capable of taking 4,000 pounds of oil sands and will allow the testing of oil displacement concepts at much lower cost than would be necessary in the field. These facilities will be made available to support the larger field experimental programs referred to above.

3. The Government of Canada's Hydrocracking Process has the potential for providing a higher liquid yield than obtainable from currently-practiced technologies for upgrading the bitumen. To assess the merits of this process, the Authority has awarded contracts to consultants to quantify the advantages of Hydrocracking over competitive technology, and to determine the appropriate size of unit for the next scale-up. These studies will assist the Authority in making a decision whether to participate in the further development of Hydrocracking.

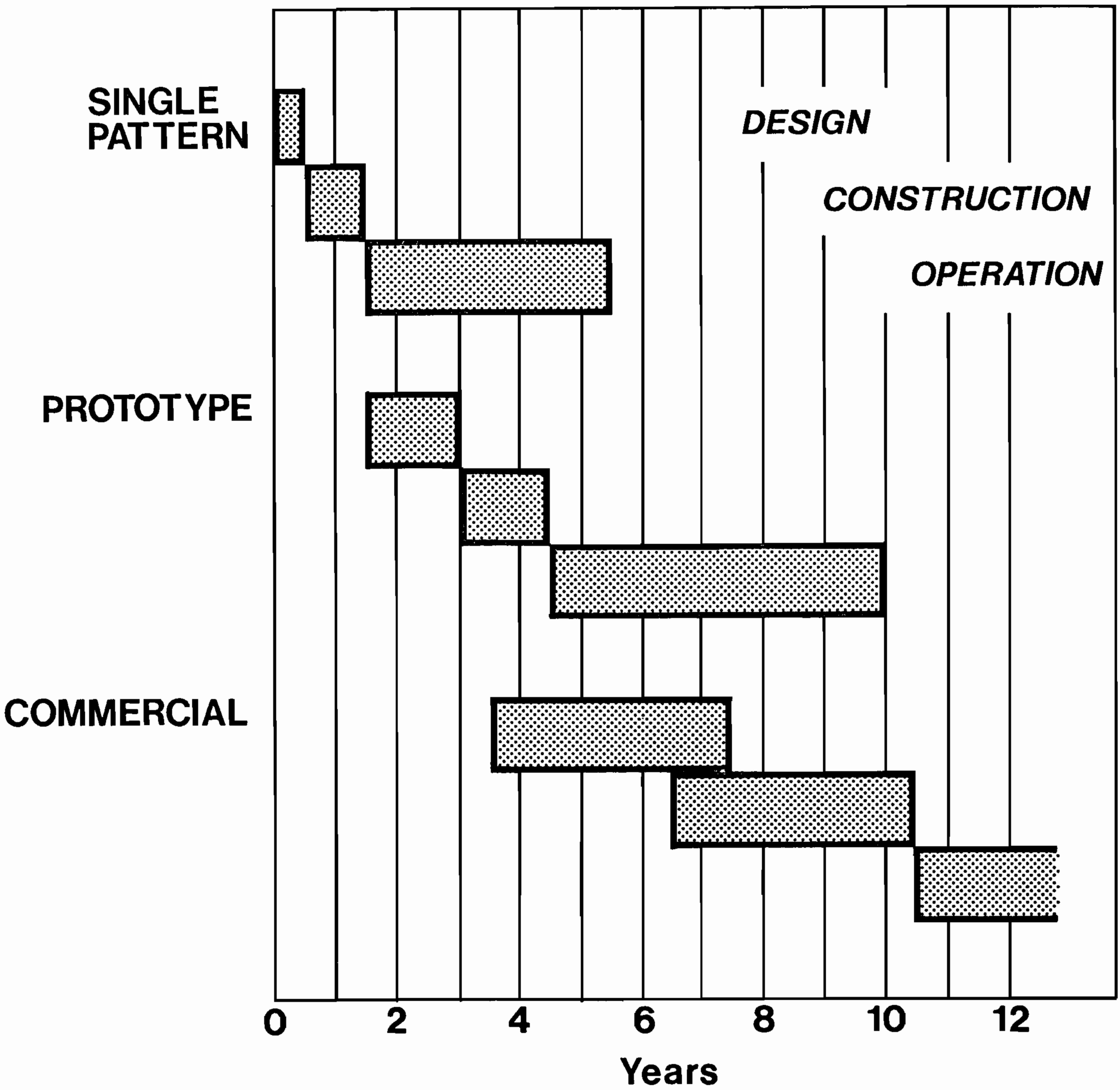

Figure 41-4.--In situ recovery development minimum schedule

4. Improved coking technology has also been identified as an area for Authority support. As an initial project in this area, the Authority purchased 15,000 barrels of bitumen from Great Canadian Oil Sands Ltd., for testing its suitability as feedstock for the Flexicoking Upgrading Process developed by Exxon Research and Engineering Company. This action took advantage of the opportunity to run Alberta bitumen through Exxon's 1,000 barrels/day Flexicoking demonstration unit, in Baytown, Texas, prior to this unit being taken out of service. The facility was originally constructed at a cost of $\$7 \times 10^6$ to test heavy petroleum stocks. The process reduces substantially the amount of high-sulphur coke which needs to be burned or stockpiled. If the process is used by the oil industry in Alberta, the Authority will be paid $100,000 for each Flexicoking unit built in the oil sands area. The total cost of the demonstration was approximately $800,000. The expenditures for the purchase and delivery of the bitumen, assumed by the Authority, was $362,000. The cost of running the pilot unit itself was paid by interested petroleum companies.

5. The Authority has signed an agreement with the Alberta Research Council to establish and operate an OIL SAND INFORMATION CENTRE for a 5 year period. Information for the Centre will be provided in an index, or abstract, form and will be available to individual researchers and libraries on a subscription basis.

6. The Authority held a multi-university seminar in the fall of 1975 to review research work presently underway at a number of Canadian universities. This was the first in a series of seminars to bring Canada's academic community fully into the search for improved oil sands technology.

7. Twenty-five scholarships and eight fellowships have been made available over the next 6 year period for oil sand research at three Alberta universities. The scholarships will be held by graduate students for a 2 year period and the research carried out will normally lead to either a Masters or Doctoral Degree. The fellowships are intended to assist post-doctoral level scientists in furthering their research training.

It is expected that many of these individuals will eventually enter the industrial research sphere.

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PART C--AN OVERVIEW OF CANADA'S FIRST COMMERCIAL SURFACE MINING EXTRACTION PLANT

W.L. Oliver[3]

INTRODUCTION

Many companies have experimented with the oil sands but only one--Great Canadian Oil Sands, a subsidiary of Sun Oil Company--has managed to develop a full scale plant capable of producing commercial volumes of product.

As the pioneer in developing this new project, it was necessary to combine three entirely new major operations, any of which could be, and was, beset with staggering problems. The three operations are:

1. A <u>mining operation</u> handling up to 200,000 tons per day of a material which has some very unique properties.

2. An <u>extraction process</u> which had never before been attempted on a commercial scale.

3. A <u>refining or upgrading plant</u> which would process a feedstock different enough from conventional oil feedstock to require a whole new set of operating standards.

Great Canadian has been successful at putting together such a project and operating it at higher than design rates but only after several years of concerted effort and the solution of many problems and the upgrading of much of the original equipment.

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[3]Great Canadian Oil Sands Limited

MINING OF OIL SAND

The mining operation involves clearing of the low grade spruce and tamarack trees in a swampy terrain, then draining the muskeg and overburden cover which requires a period of from 2 to 3 years. This is followed by muskeg removal, which can only be carried out during January and February when the low temperatures, which regularly reach -30°C, freeze it, simplifying handling. At this point the 40 to 50 feet of overburden which cover the entire ore body can be removed. This is accomplished by using a fleet of 150 ton-capacity trucks and front-end loaders. On average, 40 to 50,000 tons per day of overburden are handled. The tar sand is then mined by two giant bucket-wheel excavators, each working on a separate bench and together capable of handling up to 200,000 tons per day. On average 120,000 to 130,000 tons of tar sand per day are mined and carried to the extraction plant by a system of conveyors with a total length of over 6 miles.

EXTRACTION OF BITUMEN FROM TAR SAND

Bitumen extraction is accomplished by the hot-water process--a very simple process but one which is sometimes extremely difficult to control (Fig. 41-5). The fundamental steps in processing are feed conditioning, separation of the bitumen, waste disposal, and cleaning of the bitumen concentrate. The plant has four parallel processing lines each capable of handling about 2,300 tons of tar sand per hour.

Conditioning is done in a very short period of time by mixing feed with water and caustic soda at 82°C. The vessel used is a slowly rotating drum into which live steam is sparged below the slurry surface. In this process, the oil sand disintegrates, liberating bitumen from sand and clay particles. The slurry leaving the conditioning drum is passed over a vibrating screen to remove clay lumps and rocks and then into a separation cell.

In the separation process, the sand particles settle quickly to the bottom and the bitumen floats to the surface of

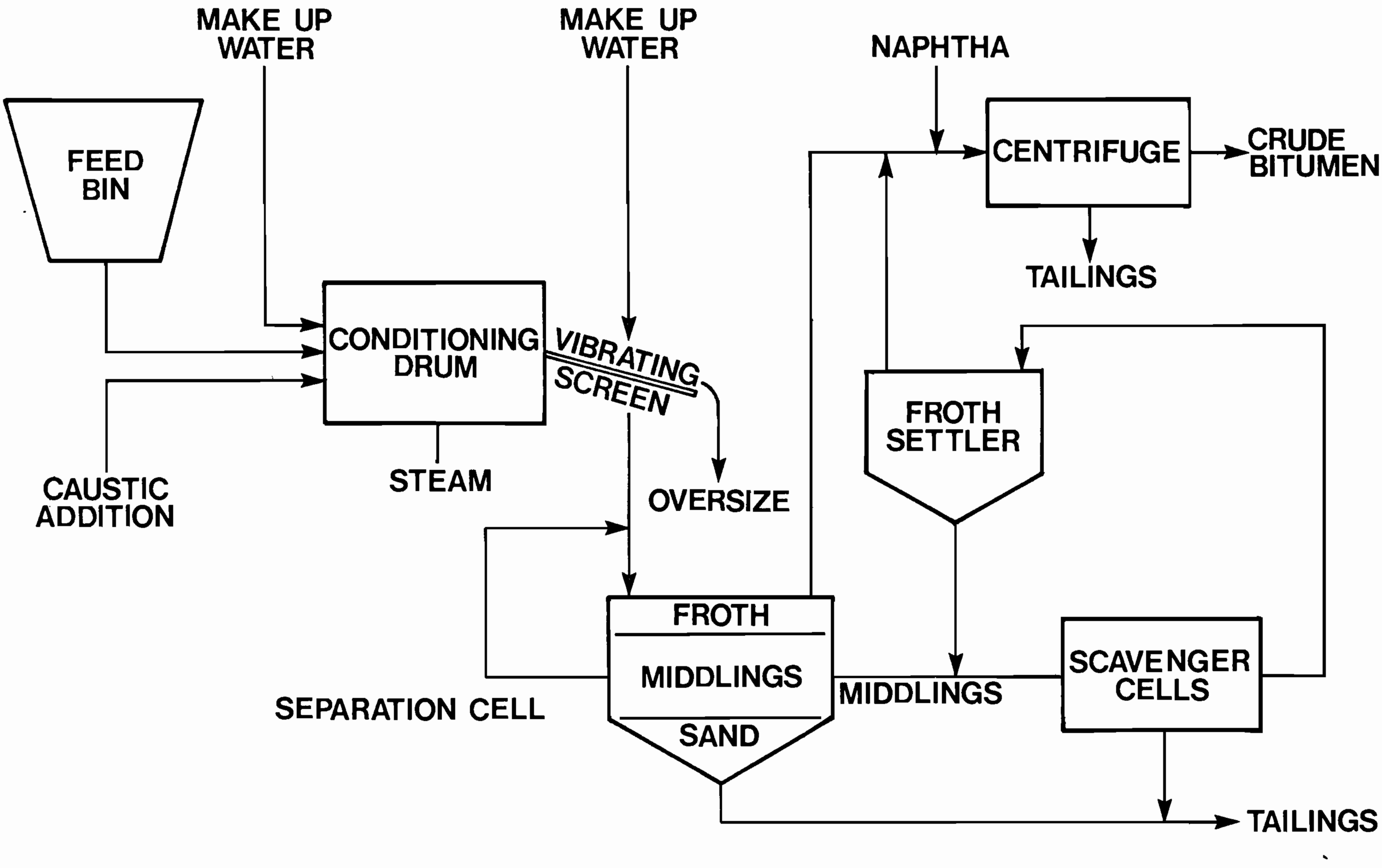

Figure 41-5.--GCOS extraction process

the cell. The bitumen froth flows from the top of the cell from whence it is pumped into final extraction for removing the bulk of its residual water and mineral particles. The aqueous layer in the center of the cell is withdrawn from the side of the cell and this sidestream is delivered to banks of standard Sub 'A' flotation cells where ordinary air flotation is used to scavenge the minute portions of bitumen.

The primary bitumen froth from the separation cell, along with the concentrate from the scavenger cells, after heating with steam and dilution with naphtha, is fed into the centrifuge plant to remove contaminants. The diluted bitumen product contains approximately 4 percent by weight water and mineral. The centrifuge process uses standard commercially available machines in parallel. The centrifuge plant is designed for recovery of over 97 percent of the bitumen. The solid material recovered is sent to the tailings pond.

UPGRADING

The bitumen as produced in the extraction plant is not suitable for market and must be upgraded before it can be shipped to customers for further use. Bitumen is a highly viscous, tarry, black material having a gravity of about 9° API, and containing about 5 percent sulphur, plus trace amounts of such heavy metals as nickel, vanadium, and iron (Table 41-3). Following secondary extraction, the bitumen is stored in diluted form to prevent it setting up like asphalt. This diluted bitumen storage is one of the few surge capacities that Great Canadian Oil Sands (GCOS) has in the three component system of mining, extraction, and upgrading.

Figure 41-6 is a line diagram of the first steps in the upgrading operations at GCOS. The diluent is recovered by heating the mixture to about 315°C and distilling it overhead in the diluent recovery unit. It is then returned to the extraction plant for reuse. After the diluent is removed, the bitumen is heated to about 480°C and introduced into a coking drum. This is a standard delayed coking operation in which the bitumen is physically broken into lighter materials and the heavy coke

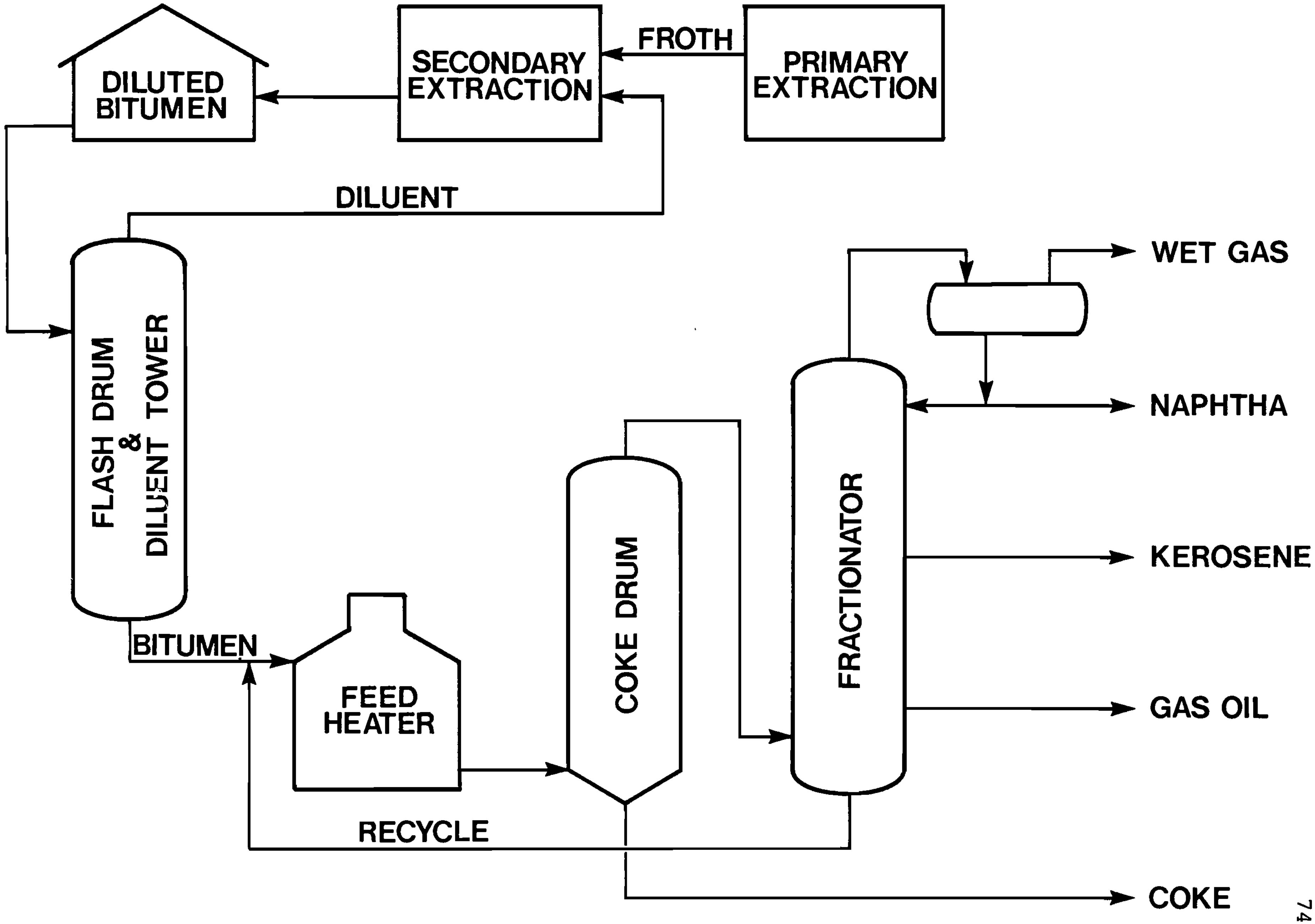

Figure 41-6.--Diluent recovery and coking sections

TABLE 41-3.--Comparison of bitumen and synthetic crude

	Bitumen	Synthetic crude
A.P.I. gravity	8-9	35
Boiling range (°F)	400-1,100	80-900
Sulphur (weight percent)	4.5-5.0	0.2
Nitrogen (weight percent)	0.5-1.0	0.1
Vanadium (ppm)	150	Nil
Colour	Black	Straw
Ash (percent)	1.0	Nil

deposited in the drum. A large proportion of the sulphur and virtually all of the metals are deposited in the coke. The hydrocarbons pass overhead into a fractionating tower where they are separated into four main components:

1. Light gases, which are desulphurized and used as heating fuels; or charge gas for the manufacture of hydrogen, which is used in treating the final liquid products.

2. Naphtha or components which can be upgraded to gasoline.

3. Kerosene or components from which jet fuels can be manufactured.

4. Gas oil, the heaviest component, which is used as a heating fuel or as feedstock to catalytic cracking units in refineries.

Each of the three liquid components is then charged to a separate hydrodesulphurizer where most of the remaining sulphur, nitrogen, and trace metals (if any) are removed and some of the unsaturated compounds hydrogenated. Figure 41-7 shows a typical arrangement for this type of unit, in which the stock to be upgraded is heated to temperatures of 315°C to 400°C and introduced to a reactor tower in the presence of hydrogen and a catalyst. The naphtha system operates at about 600 psi and the other two (gas oil and kerosene) at about 1,400 psi.

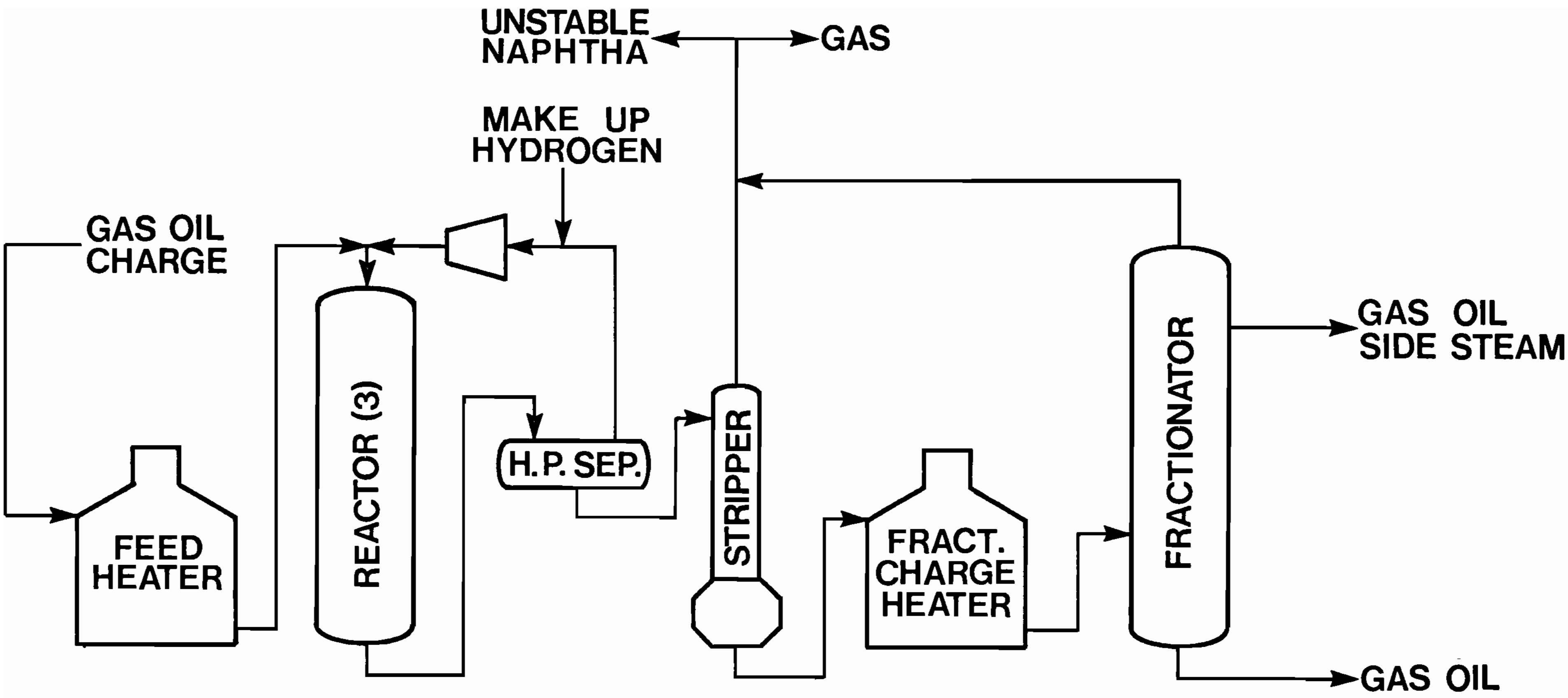

Figure 41-7.--Gas oil unifiner

After upgrading, the three components are then blended together and the resultant synthetic crude is shipped via pipeline 266 miles south of Edmonton. There the synthetic crude is fed into the Interprovincial Pipeline system and shipped to refineries in Canada and United States as far east as Ontario and Ohio. Average daily production figures are given in Table 41-4.

TABLE 41-4.--Synthetic crude production rates

Year	Production (10^3 barrels/day)
1969	27.3
1970	32.7
1971	42.2
1972	51.0
1973	50.0
1974	45.7
1975	43.0

PART D--OIL SANDS DEVELOPMENT RISKS, ECONOMICS, AND OUTLOOK

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INTRODUCTION

In 1974 a Canadian oil industry Task Force on oil sands and heavy oil prepared and has since updated a report to assist governments in formulating policies which will encourage oil sands development.

The study is designed to introduce the problems of oil sands development, not advance specific solutions to the problems. The study is in four parts: petroleum supply and demand; potential limitations of oil sands development; a review of the economics; and a discussion of the uncertainties affecting oil sands development.

SUPPLY AND DEMAND

As Canada strives to reduce its future dependency on foreign crude oil, development of the oil sands reserves of Western Canada becomes a high priority. The Canadian supply and demand for indigenous feed stocks, according to the latest forecast by Canada's Department of Energy, Mines and Resources, shows that by 1985 the demand will be approximately 2.4 to 2.5 $\times 10^6$ barrels/day. The total available supply from presently established Canadian sources plus the supply from oil sands as forecast by the Department will decline to about 1.3 to 1.4 $\times 10^6$ barrels/day. If exploration of frontier areas fails to achieve the desired results during the next several years, it is apparent that oil self-sufficiency for Canada in the 1980's is an unattainable goal, even with considerable oil sands production.

At an energy requirements hearing before the Alberta Energy and Resources Conservation Board in October 1972, major petroleum companies presented forecasts of oil sand production which ranged as high as 1×10^6 barrels/day by 1983 and 3.5×10^6 barrels/day by 2001. These same companies are today forecasting that only 0.3×10^6 and 1×10^6 barrels/day will be available by 1983 and 2001 respectively. The buoyant optimism of 1972 has disappeared. The current pessimistic view is attributable primarily to the projected high development costs and the uncertainties with respect to future prices, taxes, and royalties.

The most recent forecast of oil sands production by Canada's Department of Energy, Mines and Resources, based on a "high-price scenario," shows only one more mining project (in addition to the two projects either operating or under construction) beginning production in 1982 and another mining or in situ project beginning production in 1986. In the Department's "low-price scenario," no oil sands developments additional to those already underway are foreseen over the next 15 years.

LIMITATIONS OF OIL SANDS DEVELOPMENT

The capability of the Canadian economy and the petroleum industry to develop significant oil sands production by the end of the 1980's depends on the current dedication of men, money, and materials to that goal. The following represent practical limitations to the speed at which plants can be designed and constructed

1. Adequate engineering and technical staff for planning, design, and construction supervision must be available. Approximately 750 engineers will be employed directly by the developer, by the contractor, and through consulting firms for each project. There is at least a 2 to 3 year engineering lead time required prior to commencing project construction.

2. Adequate skilled labour is needed for on-site construction. Peak skilled construction labour demand is estimated at over 6,000 men for each project, with total labour requirements of up to 20,000 man-years over the 5 to 6 year construction period of a project.

3. Equipment and material for a project must be secured on a timely basis. Shop fabrication space and time may be difficult to obtain. The availability of some specialized equipment, such as the large mining draglines, may constrain the development schedule. Delivery of such equipment can take at least 3 to 6 years from order to receipt.

4. Project schedules will be dictated by capital availability. Industry's limited capability to generate capital, coupled with the overall demand for large quantities of capital, has made this a critical criteria.

5. A skilled operating and maintenance labour force of about 2,200 men will be required for each project. Attracting, training, and retaining this size labour force as each plant comes on stream will be a problem that industry, with government help, must solve.

ECONOMICS

The task force has constructed economic models for both oil sands mining and in situ projects. The basis for these models does not relate to any specific venture, such as Syncrude, but it is believed that the assumptions used are representative of projects now being planned.

The initial investment required for nominal 100 x 10^3 barrels/day in situ and mining projects is estimated to be \$19,000/daily barrel of rated capacity expressed in 1976 dollars. In actual dollars spent, a project of this size could cost \$2.4 x 10^9 if construction were to start today. The constant dollar figure of \$19,000 does not include any interest charges incurred during construction. Additional annual capital requirements for plant modifications and new equipment are assumed to by \$10 x 10^6/year for a mining project and \$40 x 10^6/year for an in situ project. It should be noted that the technology for in situ recovery processes is significantly behind that of surface mining with the result that the quality of in situ capital and operating cost estimates is less certain than for mining cost projections.

A direct operating cost of \$5.00/barrel expressed in 1976 dollars was used for mining and \$3.75/barrel for in situ models.

Synthetic crude was priced at \$13.86/barrel (1976 dollars), which remained constant throughout the life of the project. This compares to the current plant gate price at Fort McMurray of \$9.50/barrel and a landed price for imported oil in Montreal of approximately \$13.00 to \$13.50/barrel.

Inflation of costs is an important factor when making business decisions, particularly with investments of this size. Since constant dollar economics were employed as the basis for comparison, it is felt that expectations regarding acceptable rates of return and debt interest rates should be adjusted accordingly.

The results of the model studies show that the base case discounted cash flow rates of return for mining and in situ projects are 10.1 percent and 10.8 percent respectively, exclusive of royalties and income taxes.

The criteria for acceptable oil sands economics will vary with each prospective developer. Some companies prefer to emphasize rates of return, while others use a combination of several profitability yardsticks. Nevertheless, it is felt that after making provision for risk, the DCF rate of return on total capital employed, after taxes and royalty, should range from 9 to 12 percent, assuming constant dollar economics. If current dollar economics are being discussed, the rule of thumb is to add the long-term inflation rate to the required constant dollar return to arrive at a DCF return expressed in current dollars. In this range, oil sands projects may be attractive enough that a developer could raise sufficient funds on reasonable terms. However, industry could still have difficulty obtaining both equity and debt financing because of the technical risks associated with oil sands development. The oil sands industry is young. It does not have a record of proven performance under a wide range of operating conditions. Consequently, a sponsoring developer may be required to provide his own assets--as well as the project itself--as security for financing.

The payout period is commonly used in industry as a rough measure of financial risk. The more quickly a developer can recover his capital, the more confidence he has in making his initial decision to invest. In the surface mining model, payout is expected to occur 16.6 years after start of construction. This lengthy payout period warns a potential developer and/or lender of the high risk and poor liquidity of this project. The following table summarizes the unit costs for the two types of projects, amortized at 10.5 percent in constant 1976 dollars:

	SURFACE MINING	IN SITU
Capital	\$ 8.60/bbl	\$ 9.50/bbl
Operating	\$ 5.60/bbl	\$ 4.10/bbl
Total	\$14.20/bbl	\$13.60/bbl

In summary, the economics developed from the model studies are concluded to be marginal, even assuming no payments to governments in the form of taxes and royalties. In view of the economic and technical uncertainties surrounding these projects, industry views the economics of the two recovery approaches as being essentially equal.

OIL SANDS DEVELOPMENT UNCERTAINTIES

Because of the enormous expenditures required for a large-scale oil sands facility, a prospective developer must have confidence in his technology if commercial oil sands development is to proceed. However, he must first perceive there will be an opportunity for economic application of hard won technology if development of the appropriate technology is to occur.

Prospective developers today are faced with two major classes of uncertainty--technological uncertainty and business economic uncertainty.

Technological Uncertainty

1. Nature of Oil Sands

An understanding of the nature of the oil sands is fundamental in considering oil sand technology. The source and disposition within the sand, and subsequent geologic activity, result in very complex oil sands accumulations. The oil sands have four key controlling characteristics:

(1) the heavy oil or bitumen is too viscous to flow naturally--it lacks any mobility or fluidity in its natural state,

(2) the oil saturated sands are essentially impermeable--there is no natural communication within the oil sands reservoir,

(3) oil sands reservoirs have little or no internal natural expulsive energy drive--oil recovery requires the application of external energy, and

(4) the oil sands reservoir is not homogenous--it is a highly variable, unconsolidated, heterogenous

mass. When examined vertically, all oil sands deposits will exhibit varying proportions of bitumen-saturated sands, water-bearing sands, shaley or barren sands, and gas-bearing sands. Horizontally, individual oil-bearing sections may extend less than 50 feet. Intervening shaley sands may interrupt continuity. In addition, the quality, quantity, nature, and extent of the oil sands varies from one deposit to another as well as within each deposit.

Any recovery process must recognize the above conditions. In its natural state, heavy oil, or bitumen, is only a potential resource. Its recovery and conversion to a useful product requires that some characteristic of the oil sands system must be altered or changed. Whether produced by surface mining or in situ processes, the viscous oil must at least undergo sufficient on-site processing to render it transportable. Technology development has and will continue to focus on understanding the nature of oil sands and determining how and what changes can be accomplished at various cost levels.

2. Surface Mining Operations

Oil sands surface mining techniques involve three basic steps:

- Overburden removal and disposal
- Ore body mining and transport to a separation facility
- Separation of the bitumen from the oil sand.

The question is not whether the processes of mining through extraction to upgrading are possible, but at what cost. Each project will have its own particular overburden removal and disposal problem. Surface and subsurface drainage and the presence and depth of muskeg are critical factors.

The degree and nature of oil-sand ore-body discontinuity will affect the type of mining system. Conceptually, there are many alternative schemes. However, the lack of widespread experience makes selection of optimal systems and equipment almost impossible. Ore body variability will also impact on the design and efficiency of the bitumen/sand separation facility. Flexibility must be built into the facility to handle the varying feed qualities which can be anticipated but not accurately defined prior to implementing the project.

In view of the long lead times necessary to design and construct a facility, there is little chance that the design decisions of prospective developers over the next 10 to 15 years will be able to fully benefit from the operating experience of others. A significant level of technological uncertainty will continue to be associated with mining operations.

3. In Situ Operations

A significant number of major experimental field pilot tests has been undertaken to evaluate and develop different in situ recovery methods but none has advanced to the point where commercial-scale development is imminent.

The three major technological obstacles to in situ oil sands development are:

(1) the ability to compare alternative competing in situ recovery processes without significant field testing,
(2) the need for real time, site-specific field tests,
(3) the inability to confidently extrapolate field tests results to commercial-scale operations.

The most significant problem associated with recovery of bitumen or heavy oil is its lack of mobility. The direct application of energy to move bitumen in the reservoir is ineffective without some prior preparation to make it flow more easily. This can be achieved through the addition of heat, such as steam, or by chemical means, such as solvents or emulsifiers. Energy must then be added to the system to attain production. The major difficulty is to find a cost-effective method to penetrate and intimately contact the impervious oil sands mass.

The first major technological uncertainty is the difficulty in comparing competing recovery processes, particularly in different oil-sands reservoir systems. The development of a recovery technique to the level of technology required for commercial application is fraught with many difficulties. There is little doubt that most of the recovery processes that have been proposed will result in some oil production. But how much, for how long, at what rate, under what conditions, and at what cost are critical unknowns. Laboratory research, as well as engineering studies, have and will continue to contribute significantly to the theoretical development of a given process. But the major advances have come from applying the processes in the field. Here real operating problems can be identified and addressed and key operating results, such as productivity, well life, oil recovery, and operating costs, can be defined. However, this is a long-term and costly process and there is only limited real-life experience. Today there is no satisfactory way to compare competing processes without field testing.

There are a number of processes and variations of processes that can be considered for upgrading these hydrogen-deficient heavy oils. These processes involve the addition of hydrogen and/or removal of carbon at elevated temperatures and pressures. The choice and sizing of a given process scheme depends on a number of factors, including the specific qualities and variation of the bitumen feed to the plant, over-all fuel requirements, and product market opportunities. Minor variations in feed quality can have marked impact on design and sizing of process vessels and ancillary equipment. The demonstrated operability of various steps in a process scheme, their flexibility and/or cost performance over a wide range of operating conditions are also important inputs to the process selection. While most processes have been demonstrated, there is still uncertainty associated with their overall application in the oil sands. In view of the interaction of various portions of the project, it is difficult to justify the risk involved in incorporating a new process.

Business/Economic Uncertainty

While the state of current technology limits the potential of the oil sands, technology is not the prime barrier to oil sands development today. The dominant consideration is business/economic uncertainty. This uncertainty is characterized by changing conditions with respect to future capital and operating costs, cost inflation, energy prices, royalty, taxes, and availability of manpower, materials, and capital.

In view of the long lead time from pilot testing to commercial project conception, planning, design, and construction, a prospective oil sands developer must perceive a future business climate which offers an opportunity for economic development with a project return commensurate with his analysis of project risks. The degree and extent to which a business climate is judged to provide fair opportunity to potential oil sands developers can only be measured by the amount of activity which results.

Expected development costs are well beyond previous expectations. Notwithstanding the technological risks, the prospective developer is faced with projecting costs in a business environment which he cannot predict. Continued inflation hampers project planning, restricts the number of potential developers, reduces developers' confidence in the projected economics of oil sands ventures, and places increased emphasis on having proven workable technology.

On the income side, the prospective developer must have confidence that future energy prices will be sufficient to permit economically viable development of projects with capital costs at a level of $19,000/daily barrel. Particularly important in this regard are the royalty and income tax terms which will prevail. On the basis of the economic studies the task force has reviewed, there is little or no excess revenue to be shared with governments if oil sand development is to become a reality at current price expectations.

CONCLUSIONS

The overall place and level of future development of Canada's oil sands deposits is highly uncertain despite the widening gap between domestic oil supply and demand that Canada will surely face in the next decade. Economics of oil sand development as currently perceived by prospective developers are marginal at best and forecasts of new plants in the near future must be considered optimistic.

While the technology exists to obtain synthetic crude production from mineable oil sands, there are only a few prime sites which might support the current first generation technology.

No economic in situ process has been developed and perhaps a further 10 years of additional research is required to confirm the economic viability of processes under current development. Improvements in technology can be expected but it would be unrealistic to anticipate a major technological breakthrough which would radically change the cost.

In view of the long lead times from project conception through planning, design, and construction of an oil sands facility, it is very important that government policies provide a stable, predictable basis for long-range planning. This is essential to allow industry to assess the potential for economic viability and to encourage the necessary research and development.

CHAPTER 42

ACTIVITY ON THE PRODUCTION OF ENERGY FROM TAR SANDS OF THE UNITED STATES

L.C. Marchant[1], C.S. Land[1], and C.Q. Cupps[1]

INTRODUCTION

Shown dramatically by the recent crisis involving petroleum and natural gas, shortages and rising prices foreshadow an end to unlimited consumption of natural resources at traditionally low prices. Alleviating these growing shortages of fossil fuels will require increased production from traditional sources and development of new sources. Thus the prime mission of the U.S. Energy Research and Development Administration (ERDA) is to insure a timely supply of fossil fuels at the lowest possible economic, occupational, environmental, and social costs. As part of this mission, ERDA is conducting research aimed at production of energy from several unconventional resources, including tar sands.

DEFINITION OF TAR SAND

Though the term tar sand is applied to a variety of rock types that contain some form of bituminous material and is reasonably descriptive of certain types of rocks and their associated viscous hydrocarbons, it is a misnomer. Tar is a refined product [1] and sand properly describes unconsolidated particulate mineral matter. Specifically, tar sand refers to

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consolidated or unconsolidated rocks with interstices that contain very viscous to solid bitumen which, in its natural state, cannot be recovered by primary petroleum production methods. Other terms applied to this material have included bituminous sandstone, oil-impregnated rock, oil sand, and rock asphalt. Any distinction that can be made between tar sands and so-called "heavy oil" deposits would relate to differences in viscosity of the contained bitumen or oil. In tar sand the bitumen is so viscous or immobile as to prevent displacement and production by primary petroleum production methods, whereas the "heavy oils" can be produced by primary methods, but not at economic rates. In this report, the hydrocarbon in tar sands is referred to as "oil" or "bitumen" interchangeably.

U.S. TAR SAND RESOURCE

About 546 tar sand occurrences have been reported in 22 states [2]. Partial resource estimates have been made in seven states. The resource in known deposits in five of the states (California, Kentucky, New Mexico, Texas, and Utah) is estimated to be as much as 30×10^9 barrels of oil (Table 42-1). Most of this estimated resource is in Utah, where 27 deposits contain an estimated 29.5×10^9 barrels of oil. Six (Fig. 42-1) are classed as giant deposits, containing from about 1×10^9 to as much as 16×10^9 barrels of oil each. Four, Asphalt Ridge, Hill Creek, P.R. Spring, and Sunnyside, are in the Uinta Basin and contain over 10×10^9 barrels of low sulphur (less than 0.5 weight percent) oil, a prime target for current interest in developing production from tar sands. Table 1 lists known tar sand deposits in the United States which contain at least 1×10^6 barrels of oil in place.

EARLY TAR SAND PRODUCTION EFFORTS

Efforts to utilize the U.S. tar sands date back at least 80 years [3]; however, they have been largely ineffective and have involved mainly small-scale mining operations for production of tar sand for direct use in road paving. Some

TABLE 42-1.--Deposits of bitumen-bearing rocks in the United States with resources over 1,000,000 barrels [4, 5]

State and name of deposit	Estimated resources (10^6 barrels)	
California:		
Edna	141.4-	166.4
South Casmalia	46.4	
North Casmalia	40.0	
Sisquoc	26.0-	50.0
Santa Cruz	10.0	
McKittrick	4.8-	9.0
Point Arena	1.2	
California total	269.8-	323.0
Kentucky:		
Kyrock area	18.4	
Davis-Dismal area	7.5-	11.3
Bee Spring area	7.6	
Kentucky total	33.5-	37.3
New Mexico: Santa Rosa	57.2	
Texas: Uvalde	124.1-	140.7
Utah:		
Tar Sand Triangle	12,504.0-	16,004.0
P.R. Spring	4,000.0-	4,500.0
Sunnyside	3,500.0-	4,000.0
Circle Cliffs	1,000.0-	1,300.0
Asphalt Ridge	1,000.0-	1,200.0
Hill Creek	300.0-	1,160.0
San Rafael Swell	385.0-	470.0
Raven Ridge	125.0-	150.0
Argyle Canyon	100.0-	125.0
Asphalt Ridge, Northwest	100.0-	125.0
Whiterocks	65.0-	125.0
Cottonwood-Jacks Canyon	80.0-	100.0
Wickiup	60.0-	75.0
Minnie Maud Creek	30.0-	50.0
Rimrock	30.0-	35.0
Willow Creek	20.0-	25.0
Pariette	12.0-	15.0
White Canyon	12.0-	15.0
Littlewater Hills	10.0-	12.0
Lake Fork	6.5-	10.0
Nine Mile Canyon	5.0-	10.0
Chapita Wells	7.5-	8.0
Ten Mile Wash	1.5-	6.0
Tabiona	1.3-	4.6
Thistle	2.2-	2.5
Spring Branch	1.5-	2.0
Cow Wash	1.0-	1.2
Utah total	23,359.5-	29,530.3
U.S. total	23,845.1-	30,088.5

experimental efforts have involved mining and oil extraction in surface plants as well as in situ oil recovery. Mining and plant extraction processes have included the employment of petroleum solvents, hot water, and combinations of solvents and water. In situ processes have included injection of petroleum solvents, various steam applications through both vertical and horizontal well bores, and forward and reverse combustion processes. Apparently none of these early efforts resulted in a successful technology for the recovery of oil from tar sand deposits. Because all the deposits have overburden thicknesses ranging up to several hundred feet, some of them should be susceptible to oil recovery by strip mining and surface oil extraction, as is currently being done at Athabasca, Canada [6]. However, as at Athabasca, most of the deposits in Utah lie under overburden too thick for economical open pit mining, and in situ recovery methods will be required to produce most of the oil.

IN SITU RECOVERY OF OIL FROM TAR SANDS

In situ oil recovery methods are expected to have three distinct advantages over mining and plant extraction processes: (1) lower comparable costs per barrel of oil produced; (2) lower costs in manpower and material; and (3) lesser unavoidable environmental impact.

Physical recovery of oil from tar sands is hampered by the high viscosity of the bitumen and the lack of reservoir energy. The high viscosity renders the oil immobile for all practical purposes and thus unresponsive to the displacing action of other fluids that might be injected to provide the energy now lacking. Thus, reduction of viscosity is probably the single most important requisite for successful development of in situ oil recovery methods for tar sands.

Viscosity of tar sand oil can be reduced by dilution with solvents, by dissolution of gases, or by heating. An effect resembling viscosity reduction may also be realized through emulsification. Any of the methods of viscosity reduction, however, requires the injection of fluids into the tar sand and contact of the fluids with the bitumen. In any situation

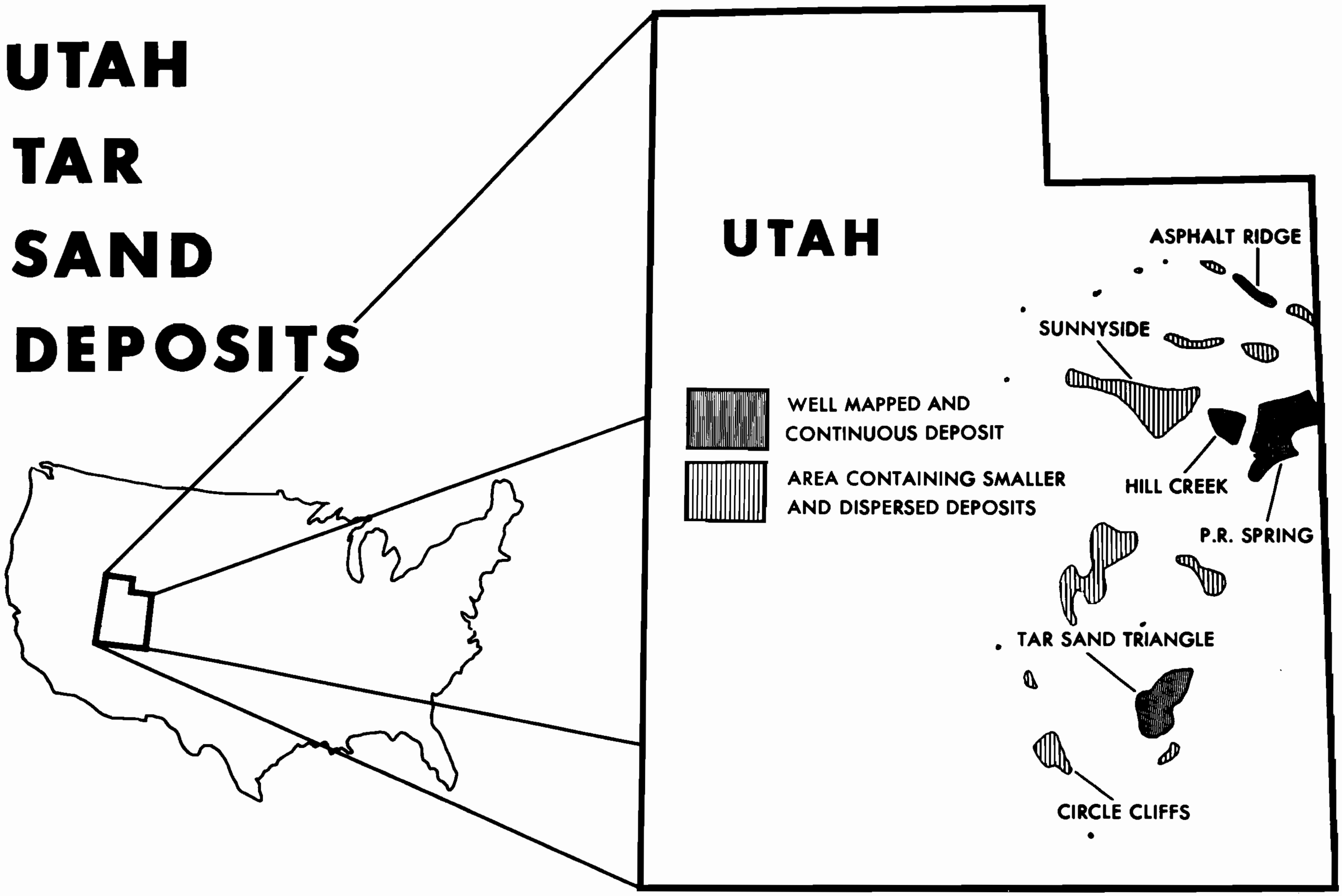

Figure 42-1.--Utah tar sand deposits

permeability must exist initially in the tar sand or be induced (for example, by hydraulic fracturing) to permit injection and flow of the required fluids. Furthermore, the process should not result in plugging of the permeability due to recongealing of the bitumen as it is moved through unaffected parts of the deposit toward producing wells.

Several solvents capable of reducing oil viscosity are available. But because these solvents are generally more valuable than the produced oil, economic success would demand a high percentage of solvent recovery. Viscosity could also be reduced by dissolution of gases (such as methane or other hydrocarbons and carbon dioxide) in the bitumen, but this process probably would not be practicable because the high pressure required would far exceed that possible at the relatively shallow depths of known tar sand deposits.

Reduction of viscosity by heating is possible with several available thermal recovery methods involving hot water injection, steam injection, hot solvent or gas injection, and in situ combustion. With these thermal methods, the reduction in viscosity will be proportional to the increase in temperature and thus to the efficiency with which heat is distributed through the tar sand and transmitted to the bitumen.

There are two in situ combustion processes: forward combustion and reverse. In forward combustion, ignition occurs at the air injection well and a combustion front moves through the formation in the direction of air flow toward the production well. In this process, coke deposited from the thermally cracked oil provides fuel for the combustion. In reverse combustion (Fig. 42-2), ignition occurs at the production well, and the combustion front is propagated toward the air injection well, moving counter current to the direction of air flow. In reverse combustion, movement of the burning front is a function of heat conduction ahead of the front; a fraction of the bitumen is burned; and coke from thermal cracking is left in the sand.

The forward combustion process is more easily controlled and requires a lower air flux than the reverse process. However, the heated bitumen flows ahead of the burning front into

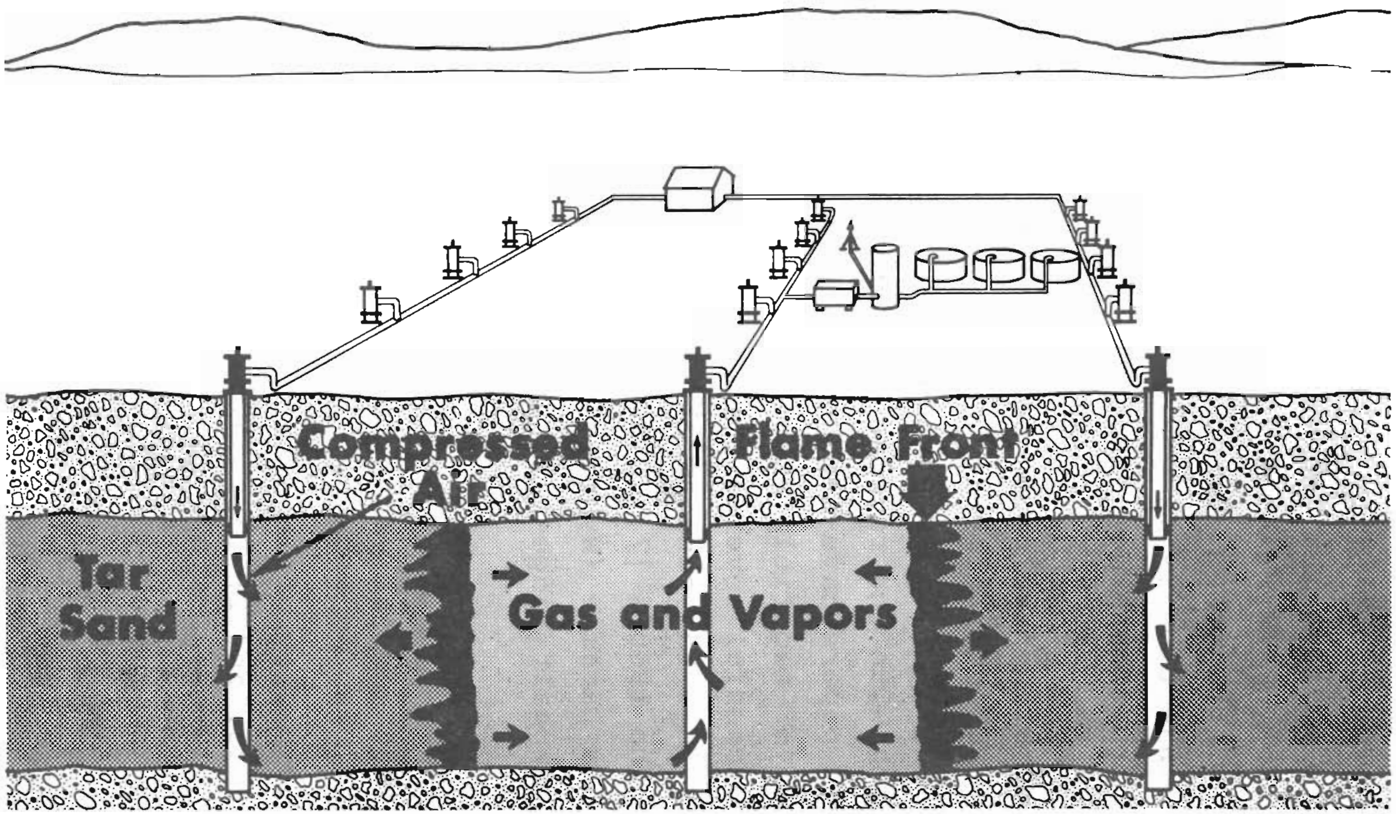

Figure 42-2.--Reverse combustion. Flame front moves against air flow; gas and vapor move through hot, burned zone

the unheated portion of the reservoir where it cools and again becomes very viscous; this condition tends to plug the flow channels in the tar sand.

The reverse combustion process is relatively more sensitive to air flux than the forward process; if the flux is less than a certain minimum the process may "turn around" and burn in a forward direction; as the flux increases, the quantity of bitumen burned increases. Spontaneous ignition might occur in the unburned portion of the reservoir as a result of low temperature oxidation if air injection is maintained for too long. However, in the reverse combustion process the vaporized fluids move through the burned-out portion of the reservoir with no possibility of plugging; they are produced at a high temperature and are condensed to a greatly upgraded synthetic crude oil.

Probably most major oil companies have conducted some laboratory research with the reverse combustion method, but only about a half-dozen papers have been published concerning this research. Results of two field experiments have been published. One tells of a successful reverse combustion test by Phillips Petroleum Company in a tar sand at about 60 feet of depth near Bellamy, Mo., in the 1960's [7]. The second discusses a test conducted by ERDA's Laramie (Wyoming) Energy Research Center in Utah's Northwest Asphalt Ridge tar sand deposit in late 1975

ERDA TAR SAND RESEARCH

During the last several years, tar sand research at ERDA's Laramie Energy Research Center has had two objectives: 1) to determine the feasibility of in situ oil recovery methods applied to tar sands, and 2) to develop a system for classifying tar sand deposits relative to those characteristics that will affect the design and operation of in situ recovery processes.

Tar Sand Characteristics

For the classification objective, cores and other samples from tar sand deposits are being analyzed [9, 10, 11, 12, 13].

Sample preparation and analysis techniques are slightly modified from those normally used for oil well cores. Heavily oil saturated core samples are cut with a drilling fluid composed of a sodium hydroxide solution rather than water to prevent sticking of sample coring bits. Samples of unconsolidated tar sand in which the sand grains are held together only by the bitumen are cast in epoxy to preserve the bulk volume configuration during analyses after the bitumen is extracted.

Samples are analyzed for porosity, permeability, oil and water saturation, and compressive strength. Routinely, porosity and permeability are determined twice for each sample, once with the bitumen in place and the other after the bitumen has been extracted. Porosity is determined by a gas expansion method and permeability from air-flow measurements, reported in darcy units. Oil and water saturations are determined using the Dean-Stark extraction method whereas compressive strength of selected samples is measured by destructive testing for both extracted and unextracted samples.

Figure 42-3 shows typical results of analysis of a P.R. Spring tar sand core. The tar sand section is about 30 ft thick and has an average porosity of 31 percent. Slightly less than 60 percent of the pore space is filled with oil and about 4 percent contains water; the remaining 36 percent is gas space. Composition of the gas in the tar sand deposits is not known; however, the pressure is essentially atmospheric since the deposits are open to the atmosphere. Based upon the samples analyzed so far, Utah tar sands typically have very low water saturations.

The permeability after bitumen extraction averages about 3,150 millidarcies. Before bitumen extraction permeability to air averages 121 millidarcies and is inversely proportional to the oil saturation. The permeability approaches zero as the oil saturation increases above 80 percent. Tar sand having 30 percent porosity and a bitumen content of 60 to 70 percent of pore volume (9 to 10 percent by weight) has sufficient permeability for fluid injection. These tar sands should be good candidates for testing of in situ recovery methods.

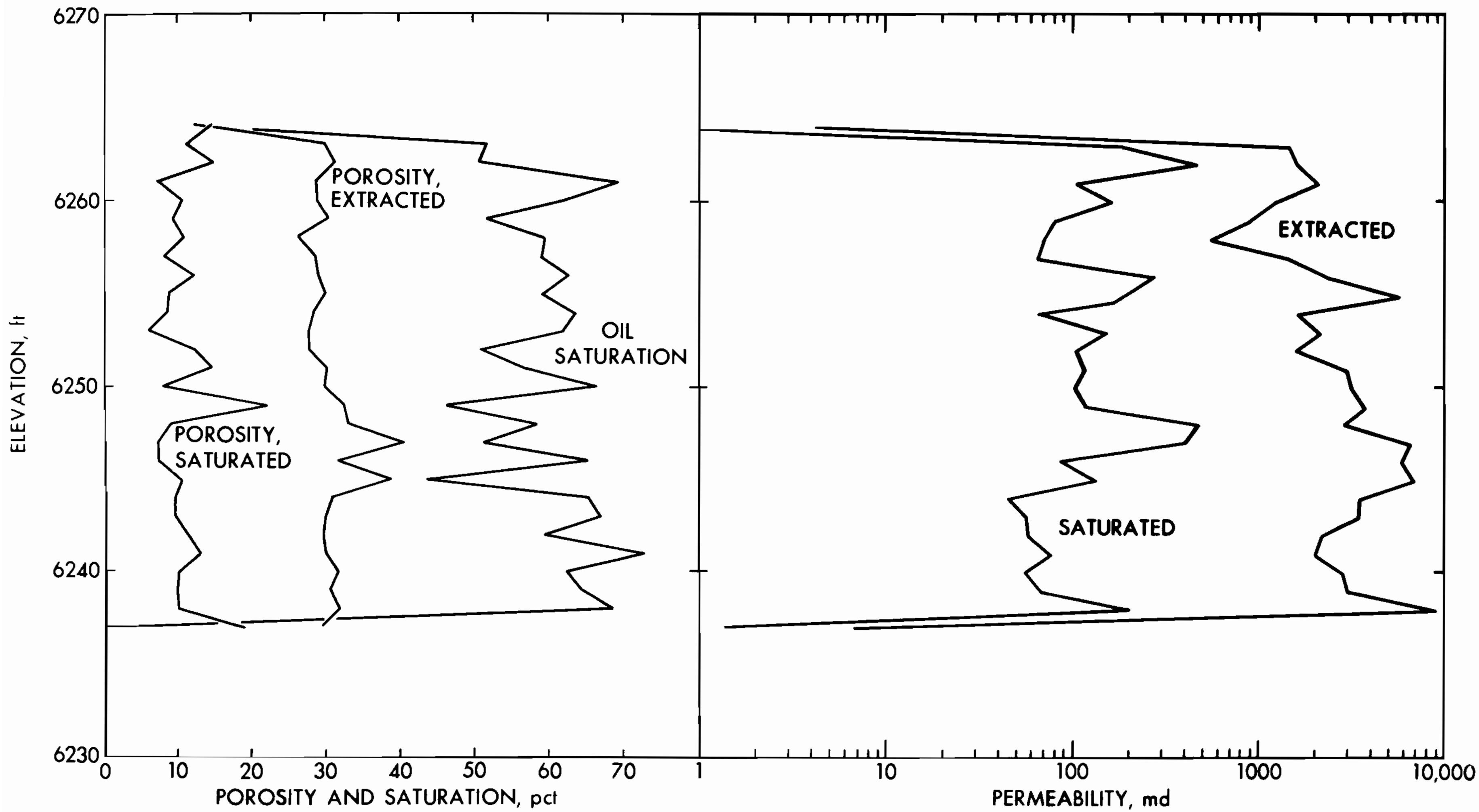

Figure 42-3.--Analysis of a P.R. Spring tar sand core

The bitumen extracted from the P.R. Spring [14] and Asphalt Ridge tar sand deposits appear very similar. Both have specific gravities close to 1, equivalent to 10° API. The viscosity at reservoir temperature is not directly measurable by standard viscosity methods, but is probably greater than 100,000 cp. Viscosity decreases rapidly with increasing temperatures, very similar to the viscosity reaction of the Athabasca tar sand bitumen. At 250°F the viscosity of these Utah bitumens is about 100 cp. Sulfur content is about 0.5 weight percent and is only about 1/10 of that found in the Athabasca tar sand.

Reverse Combustion Experiments

After a series of laboratory experiments were conducted, which indicated the technical feasibility of the reverse combustion process [15], a series of field experiments was designed.

The first reverse combustion field experiment was conducted in late 1975 in Utah's Northwest Asphalt Ridge deposit [8]. A nine-well line pattern (Fig. 42-4) was drilled through a section ten feet thick of Upper Cretaceous-Mesaverde tar sand at a depth of 300 feet. The pattern was 40 by 120 feet with two rows of three air injection wells and one row of three ignition-production wells. Wells were spaced 20 feet apart with 60 feet between rows. Six monitor wells containing thermocouples were located within and adjacent to the line pattern. Average rock properties for the pattern are listed in Table 42-2.

TABLE 42-2.--Average properties from core analysis

Porosity %	Effective gas permeability, md.	Absolute permeability md.	Oil saturation, %	Water saturation, %
26.1	132.	651.	62.0	7.9

Ignition was accomplished by igniting a charcoal fuel pack in the well bore with an electrical resistance heater. After ignition of the fuel pack, a 2 percent propane-98 percent air mixture was injected, temporarily, to facilitate transfer of the combustion from the well bore to the tar sand. A combustion front was propagated from the ignition wells toward the air injection wells.

Observed temperatures (maximum 350°F compared to laboratory experiment temperatures of 800°F) in the burned area were lower than expected, but a large portion of the tar sand within the pattern boundaries (Fig. 42-5) was heated to the extent that the bitumen became mobile enough to be produced. After 23 days of operation, the project was terminated because of the inability of the surface production equipment to accommodate the heavy hydrocarbons being produced.

Post-experiment core drilling and analyses indicate a burned zone thickness of approximately one foot corresponding to a zone of relatively high permeability. The velocity of the combustion front ranged from 0.67 to 2.73 feet per day (Table 42-3). About 75 barrels of oil and 167 barrels of water were

TABLE 42-3.--Average front velocities

Well	Time, days	Distance from P1, ft	Average velocity, ft/day
M1	9	6	0.67
M2	23	35	1.52
M4	16	16	1.00
M5	15	41	2.73
P3	18	24	1.33

produced in this experiment. About 1/3 of the produced oil was cracked by the combustion process to 22° API and about 2/3 of the produced oil had gravity of about 10° API.

Preparations for a second reverse combustion experiment are progressing. Production treating equipment for this experiment will be heated to enable treatment of crude oil with a pour point approaching 175°F.

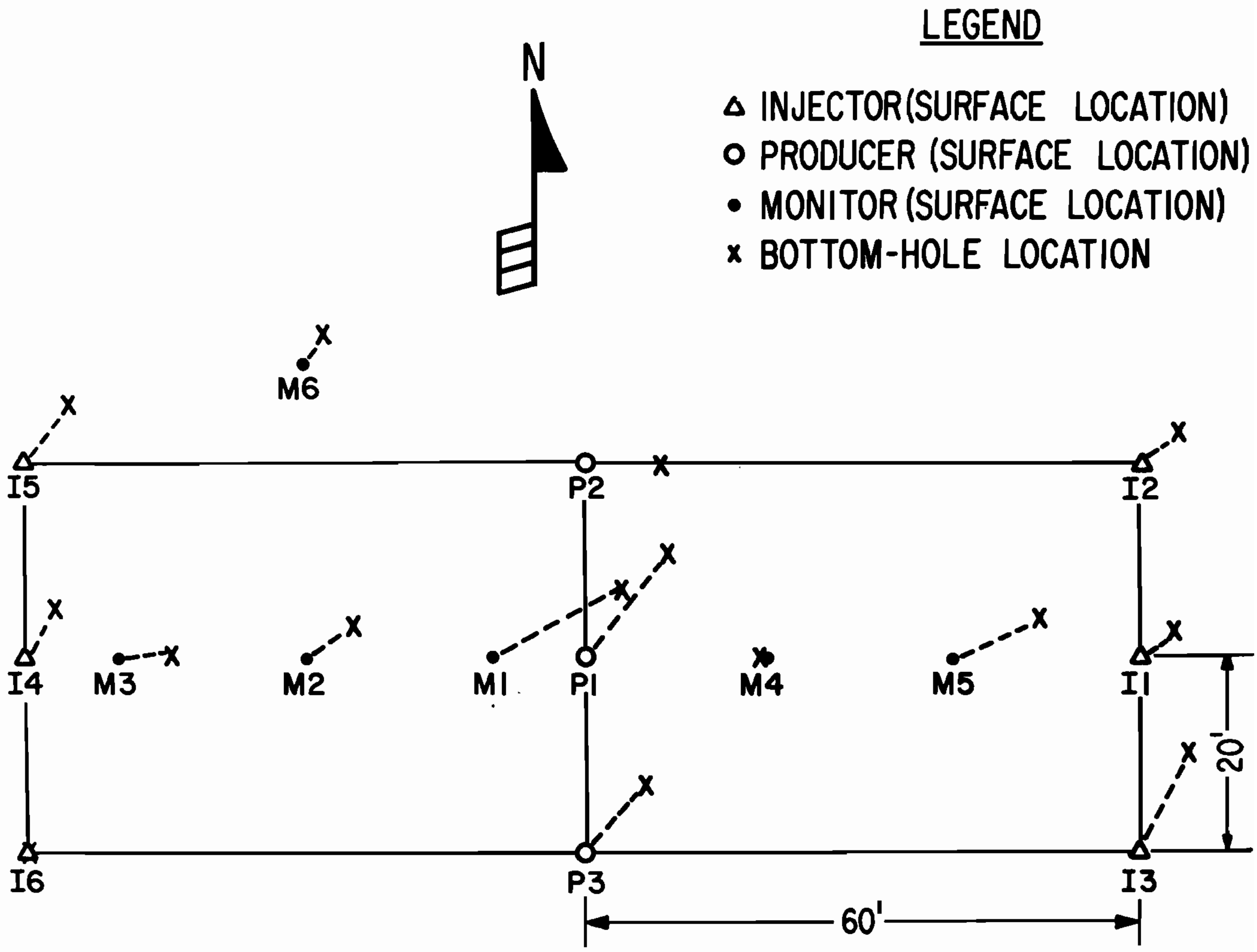

Figure 42-4.--Well pattern for USERDA tar sand in situ oil recovery field experiment

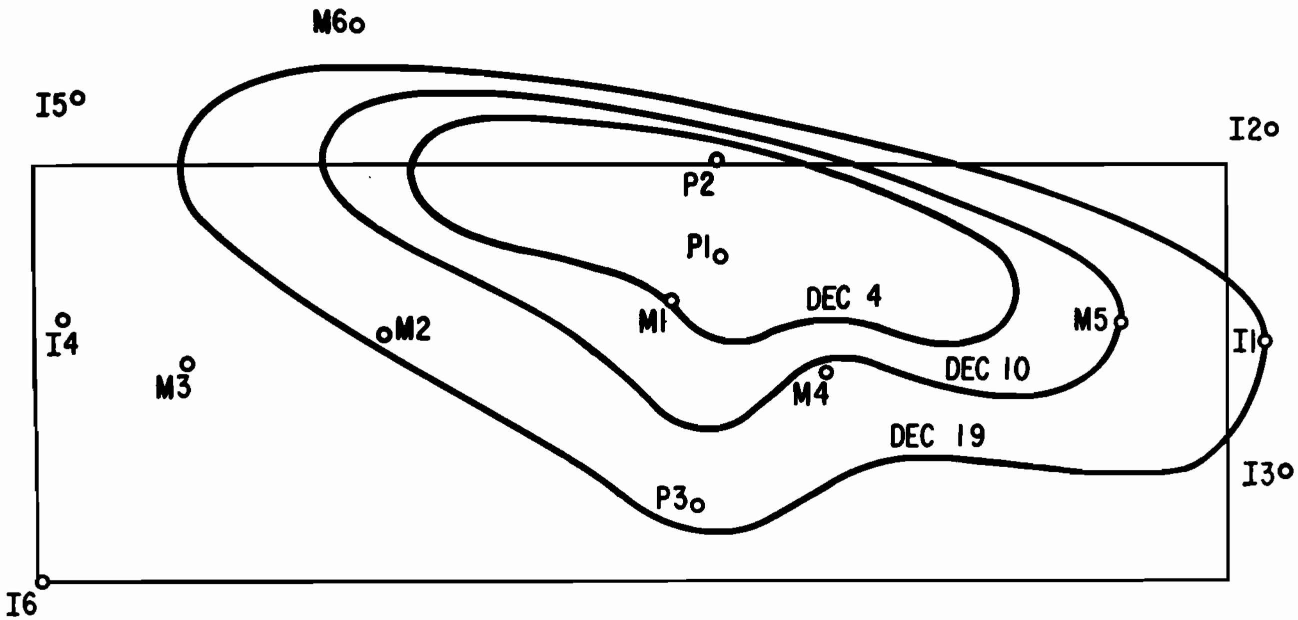

Figure 42-5.--Estimated areal extent of heated tar sand

OTHER CURRENT U.S. TAR SAND OIL PRODUCTION EFFORTS

A group of oil companies has equipped a tar sand strip mine-oil extraction plant on Utah's Asphalt Ridge deposit. This plant will employ a combination hydrocarbon solvent-hot water oil separation process. Major components of the plant are designed to produce 1,000 barrels of oil per day from the highly saturated Mesa Verde tar sand.

An oil producing company is equipping a pilot test in California's Vaca tar sand deposit. This project will utilize steam huff-and-puff, steam drive, and steam-solvent drive processes.

Several other tar sand oil recovery projects have been proposed by private corporations as shown in the following table.

TABLE 42-4.--Proposed tar sand oil recovery projects

State	Deposit	Type of process
New Mexico	Santa Rosa	Mining--plant extraction (enzyme-accelerated hydrocarbon solvent)
Utah	Tar Sand Triangle	In situ (forward combustion)
Utah	P.R. Spring	Mining--plant extraction (hydrocarbon solvent)
Utah	Tar Sand Triangle	Combination mining--in situ (thermal)

SUMMARY AND CONCLUSIONS

Known tar sand deposits in the United States contain an estimated 24 to 30 x 10^6 barrels of oil-in-place. Nearly 90 percent of this resource is in Utah and is contained in six giant deposits large enough to support relatively large production projects. However, the necessary oil production technology is presently only in the experimental stage.

Early commercial tar sand oil production efforts will probably consist of mining-plant extraction processes in the minor portion of the known resource with thin overburden. The major portion of the resource will require the application of yet-to-be-proven in situ technology. ERDA's efforts at development of the necessary in situ technology are progressing with reasonably encouraging results obtained in the first field experiment.

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NOTICE

CHAPTER 43

HEAVY CRUDES OF VENEZUELA: AN ALTERNATIVE FOR THE FUTURE

Francisco J. Gutierrez[1]

SUMMARY

It is logical to believe that the industrialized nations will not be paralyzed in their progress, nor will they become economically stagnant, under current levels of world oil prices. It can also be assumed that the remaining countries will tend towards an ever increasing development. If this is the case, it is also logical to believe that world demand for products derived from petroleum will continually increase. This makes necessary the evaluation not only of available petroleum world reserves and the possibility of increasing them, but also, fundamentally, the future alternatives for a more rational use of these reserves.

In the presence of large reserves of heavy crudes, and the decline of reserves of light crudes (percentage-wise), a change in the physical infrastructure of the oil industry does not seem logical, and it would be better to develop mechanisms which would allow the use of the existing refineries in the treating and processing of the heavy crudes.

Venezuela owns heavy crude reserves of large proportions, which constitute an incentive to the search for new technology to exploit them.

[1]Ministerio de Minase Hidro Carburos, Caracas, Venezuela.

INTRODUCTION

During the last 50 years, Venezuela and the rest of the petroleum world, have been intensively exploiting the light crude reserves. Enormous efforts are being made toward the discovery of new reserves, at an ever-increasing cost. Venezuela has developed techniques for the production of heavy crudes and continues to do so because such crudes have always been present in a significant proportion. However, methods of upgrading have not been applied fully because light crudes have been available to blend into an acceptable refinery charge.

At present, steam injection and some alternative techniques are being used, but it is necessary to seek an integrated system "production-upgrading" with a view to a better and more efficient utilization of energy.

EXPLORATION AND EVALUATION METHODOLOGY

During recent years the attention of oil explorers has been progressively attracted toward heavy crude areas. The bituminous sands of Canada, the shales in the United States, and others in the rest of the world, are viewed as future alternative sources of production.

In Venezuela, in addition to the traditional exploratory methods, procedures are being tried with a view to locating and quantifying the accumulations of crudes of such special characteristics. Geophysical methods are being combined with stratigraphic drilling and each exploratory well is subject to a special evaluation, considering it as an individual zone. Preliminary tests of the reservoirs are made, but it is only 3 or 4 months after completion that production tests are performed by pump, without the use of diluents, in order to determine the primary cold flow capacity and to obtain original samples of the crude for complete analysis. Subsequently, the production model is designed according to the characteristics of the reservoir and the crudes it contains.

PRODUCTION TECHNIQUES

The first stage of production is developed using steam injection techniques down to the maximum depth at which the steam is effective. In the second stage, to be developed at deeper levels, other techniques will be tried which include in situ combustion, chemical products, CO_2, and special pumps capable of managing considerable volumes of sands.

UPGRADING OF HEAVY CRUDE OILS

In a very general manner, for the purpose of this presentation, we can divide the natural components of crude oils into four categories:

Volatile Components

The volatile components of crude oils can be defined as those fractions which can be separated from the crude by atmospheric distillation. According to this definition, gases, LPG, naphtha, kerosene, and the atmospheric gasoils are considered volatile.

Vacuum Oils

Vacuum oils are low-volatility crude fractions which can be separated from heavier fractions by vacuum distillation of the atmospheric residuals. These oils, when separated from the heavier components of the crude, are generally used as feedstocks for catalytic cracking processes (for the production of high quality gasoline components and light gasoils), as feedstocks for the production of lubricants and waxes, or as feedstocks for desulfurization processes, for further reblend with heavier fractions in the preparation of low sulfur fuel oils.

Resins

The resins are extremely low-volatility components of crude oils. This fraction can be separated from the vacuum residuals by solvent extraction methods, generally referred to as de-asphalting methods. Although, resins will usually contain high concentrations of contaminants, such as sulfur, nitrogen, and metals, they can be treated by hydrocracking or coking processes for their conversion into volatile hydrocarbons.

Asphaltenes

Asphalts are the heaviest components of the crude oils. In general, the materials called asphalts are made of blends of resins and asphaltenes. The asphaltenes, when properly deoiled, are amorphous solids, dark brown to black in color, insoluble in n-pentaine or ether, but soluble in benzene, pyridine, or carbon disulfide. The asphaltenes are not simple hydrocarbon compounds, as they contain nitrogen, oxygen, and sulfur, in addition to carbon and hydrogen. Their molecular weight normally ranges from 30,000 to 40,000, their particle size range from 30 to 65 Angstroms, and their density from 1.20 to 1.25 gm/cm^3. Because of the above characteristics, and because most of the metals contained in the crude oils are concentrated in the asphaltenes, their conversion to light materials through hydrocracking processes is not recommended; in addition to the poisoning of the catalyst by the metal particles, the mechanism of the catalysis is handicapped by difficulties encountered by the large molecules in penetrating pores of the catalysts. Asphaltenes can be used to blend paving asphalts, fed to cokers, used as feedstock for partial oxidation units, or blended into fuel oils.

The crude oils can be classified as light, medium, heavy, or very heavy, depending on the relative contents of each of the different types of components mentioned above.

Very heavy crude oils will be defined as those with a low content of volatile components, and a correspondingly high content of resins and asphaltenes. Therefore, all the schemes applicable to the processing of very heavy crude oils are the same as those which can be applied to the heavy residuals of the lighter crude oils.

Crude Oils from the Orinoco Petroliferous Belt

The crude oils from the Orinoco Petroliferous Belt appear to be quite heavy. The API gravity of these oils ranges from 8° to 18°, and their sulfur content from 2 to 5 percent by weight. The sum of their nickel plus vanadium content varies from 200 to 500 ppm. Fortunately, even the lower API gravity crude oils from the Orinoco Belt appear to have less than 10 percent by weight of asphaltenes.

Upgrading of the Heavy Crude Oils

The upgrading of a heavy crude oil implies a refining scheme whose purpose is to produce a synthetic crude oil with a higher content of volatile components than the original heavy crude. This upgrading is accomplished by changing the hydrogen to carbon (H/C) ratio, so that in the upgraded crude it is higher than in the original crude.

The degree of upgrading resulting from processing a heavy crude oil is a function of the characterisitc of the crude, of the process used, and the severity of its application. Because of the differences among the heavy crude oils in terms of relative percentages of heavy constituents and the possible types of molecules present, a good estimate of the degree of conversion can only be obtained through pilot plant evaluations.

Upgrading Technologies

There are two possibilities for the upgrading of a heavy crude oil in terms of converting a low API gravity fraction into a higher API gravity reconstituted oil. These two possibilities are the addition of hydrogen or the carbon.

The addition of hydrocarbon can be accomplished with the use of hydrocracking processes. These are high pressure (1,000 to 1,400 psig) and high temperature (1,000 to 1,400°F) processes conducted in the presence of a catalyst. As it was stated before, these processes are quite efficient in the conversion of low-metal resins into light hydrocarbons, but, at the present state of development of the hydrocracking technologies, their use for the conversion of asphaltenes is limited. In the case of crude oils from the Orinoco Petroliferous Belt, this technology faces an additional handicap which is imposed by the presence of metals.

So far, all the existing commercial technologies use catalysts, which will be deactivated by metal deposition.

The removal of very high carbon content molecules, apparently a more complex process, in practice becomes easier to apply than hydrocracking, as it can be achieved by a high severity pyrolisis of the heavy molecules through utilization of commercially-available coking processes. These processes will produce a high yield of volatile hydrocarbons and leave coke as byproduct.

When hydrogen and low Btu gases can be successfully incorporated into the overall processing system, the partial oxidation of the heavy residues may present a third alternative.

INTEGRATION OF HEAVY CRUDE PRODUCTION AND UPGRADING SYSTEM

The development of systems for the production and upgrading of crudes in the Orinoco Petroliferous Belt has been conceived as an integrated system, in view of the circumstance that the generation of the steam necessary to obtain planned recovery levels will require an equivalent of 5 to 15 percent of the total energy value of the recovered crude.

The present stage of development of the technologies of conversion applicable to the upgrading of heavy crudes does not economically attain the complete conversion of these crudes into light liquid fractions. This leaves carbons or asphalts as by-products. The economic optimization of the "production-upgrading" system leads to the utilization, in the area of production, of those products which are of low commercial value in the generation of energy, in order that the system, from the economic point of view, may utilize the maximum of products most difficult to market.

The attainment of a "production-upgrading" system, whose internal energy requirements are balanced with the generation of components of low commercial value, will permit the maximization of the total value of the energy components extracted from the earth. The net product will be a reconstituted crude of high quality, whose percentage yield in relation to total heavy crude recovery will be maximized.

As the state of the technologies of production and upgrading advances and the intrinsic energy requirements of the system diminish, the percentage yield of the final net product (reconstituted crude) will increase. It is to be expected that, parallel with advance in production and upgrading techniques, technologies will be developed that will permit a wider direct utilization of crudes with high contents of contaminants, without damaging the environment, and that permit a greater efficiency in the recovery of the calorific value of the crude.

THE CHALLENGE

Due to the growing demand for petroleum products and the prospect of the exhaustion of light crudes, Venezuela faces the need to find mechanisms to allow for the gradual substitution of light crudes with products derived from the existing huge reserves of heavy crudes. For this it is necessary to:

1. Improve production techniques, which will require a technological advance such as to allow the attainment of recovery factors greater than 50 percent as well as a substantial decrease in costs.

2. Develop new technologies for upgrading the crudes, which will permit of the conversion of the heavy crudes into reconstituted crudes at costs competitive with those for exploring for new sources of light crudes. In this manner, the conventional refining systems can, for many years to come, count on the supply of crudes of similar gravities as those being processed now.

3. Continue the development of new concepts which will permit a more efficient utilization of heavy crudes in the generation of power, and in the production of light fuels and consumer goods. In this respect mention must be made of the new designs for ovens and boilers, the "Advanced Power Cycles,"

and the direct oxidation of heavy crudes for the production of chemical substances for massive use, such as alcohols.

PLAN FOR THE UTILIZATION OF VENEZUELAN HEAVY CRUDES

In Venezuela, approximately 70 percent of the reserves comprise heavy crudes, without including the abundant accumulations existing in the Orinoco Petroleum Belt.

Today, as in the past, the production of very heavy Venezuelan crudes has been absorbed by the international markets as heavy fuel and as asphalt (Fig. 43-1, Phase I).

For the short term, plans are being advanced which will lead to a second stage (Fig. 43-1, Phase II), in which is contemplated, as a first generation of equipment, the use of existing techniques of coking as a basic process of up-grading. The utilization of the byproduct "coke" as an energy base for the generation of steam will permit a more efficiency recovery. A second generation of up-grading plant envisages the application of hydrocracking processes.

Figure 43-1, Phase III indicates a longer term alternative to the challenge presented by the future availability of hydrocarbons.

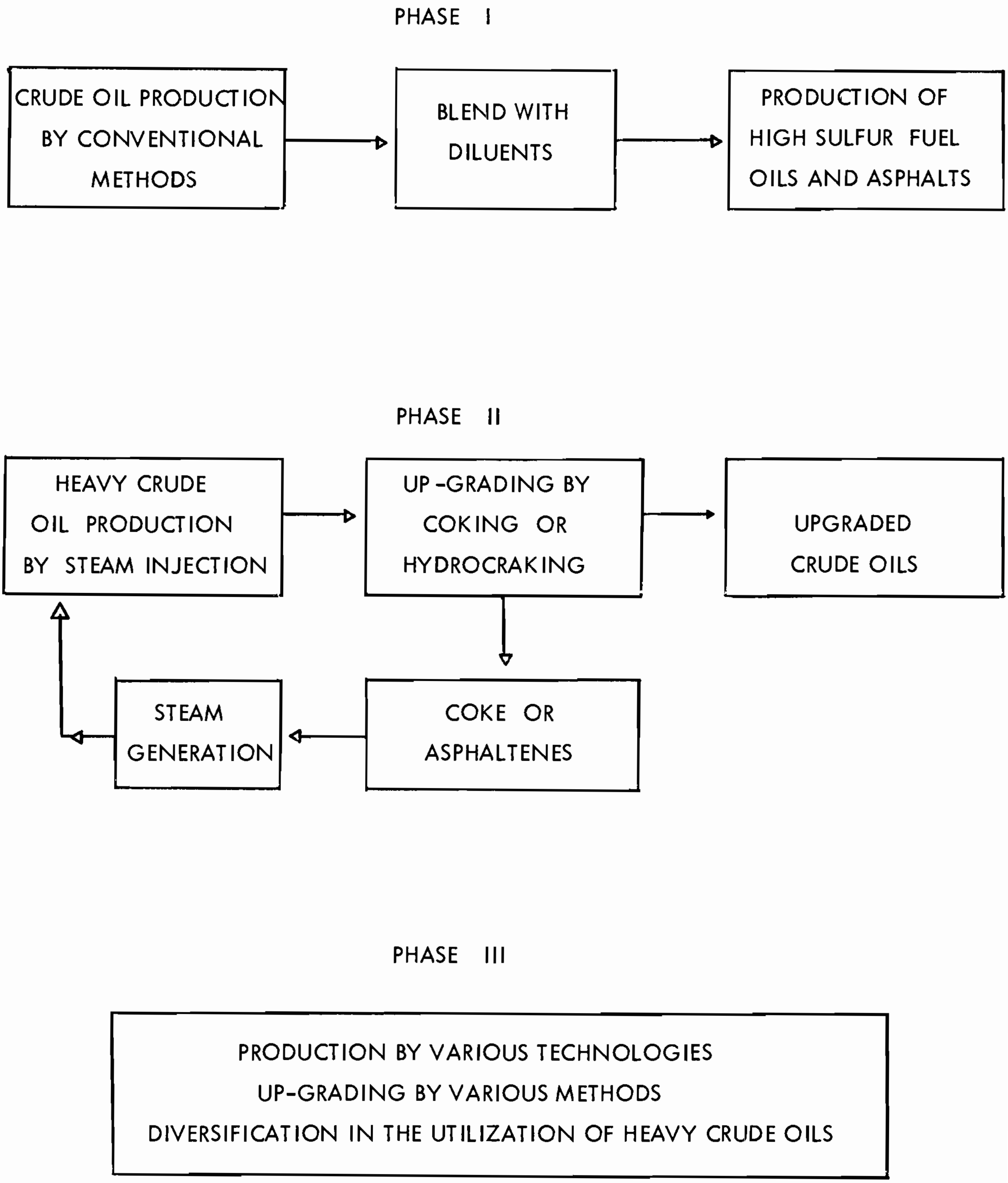

Figure 43-1.--Utilization schemes for Venezuela heavy crude oil

CHAPTER 44

ENHANCED RECOVERY OF HEAVY OIL IN CALIFORNIA

A. J. Leighton[1]

INTRODUCTION

During the past decade, California's consumption of petroleum has outpaced its production at an accelerated rate. In 1965, consumption exceeded production for the state by approximately 250,000 barrels per day and in 1970, the difference was about 370,000 barrels per day [1]. However, by 1975 the deficiency had risen to over 1,200,000 barrels per day and the volume of oil produced in the state is now less than the volume imported. Stated another way, the fraction of consumed oil produced within the state dropped from 75 percent in 1965 to less than 40 percent in 1975.

Until recently, most of the crude oil produced in California was light oil of relatively low viscosity. This low-viscosity oil flows more easily through the underground porous rock in which it is found than does the highly-viscous "heavy" oil and therefore a fairly large fraction is recoverable. However, reserves of this low-viscosity oil are rapidly being depleted and attention is turning increasingly to the recovery of heavy, viscous oils.[2] The quantity of heavy oil in place is believed

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[1]US Energy Research and Development Administration, Oakland, CA, USA.

[2]In this paper, the terms "heavy" and "viscous" will be used interchangeably although the relationship is not rigorously true in all cases.

to be substantial; estimates of the volume of oil having an API gravity of less than 20° (corresponding to specific gravity greater than 0.935) vary between 36 and 47 x 10^9 barrels [2].

THE HEAVY OIL RESOURCE

The fraction of oil that can be recovered from a reservoir is highly dependent upon the oil viscosity, as well as upon the reservoir rock properties and method of production. Table 44-1 shows the results of an unpublished study by the Energy Reserach and Development Administration (ERDA) of probable volumes and recoveries of three API gravity ranges of viscous oil.

The first column shows the API gravity range of the oils represented in each row. API gravity is inversely proportional to density and correlates approximately with it, so that oils having a low API gravity are usually more viscous than high-API gravity oils. Below 7° API, hydrocarbons are considered immobile at ambient temperatures and are usually not considered as crude oil resources.

Column 2 shows the estimated amount of oil originally in place in California's geologic formations and Column 3 shows the volume of oil left in the ground after production to date.

Column 4 represents estimate of how much oil in each category can be produced using methods widely known and applied today. These methods include primary recovery, which uses the natural energy of the dissolved gas, of gravity, and of formation water under pressure, and secondary recovery, in which gas or water is injected into the rock formation to bolster the pressure and increase oil production. Also included is cyclic steam injection, whereby steam is injected intermittently through the producing well and into the formation, in order to heat the oil, reduce its viscosity, and cause it to flow more readily, thereby increasing rate of production. This method is used mostly in zones containing thick, viscous oil.

Column 5 gives the percentages of original oil-in-place obtainable by presently commercial methods. These percentages decrease drastically for heavy oils.

TABLE 44-1.--California heavy oil resources[1]

Oil gravity range, °API	Volume of oil originally in place (10^9 barrels)	Volume of oil remaining in 1975 (10^9 barrels)	Volume recoverable by 1975 methods (10^9 barrels)	Percent of OOIP recoverable by 1975 methods Col (4) ÷ (2)	Volume recoverable by all 1985 methods (10^9 barrels)	Volume recoverable by enhanced 1985 methods (10^9 barrels) Col (6) - (4)	Percent of OOIP recoverable by enhanced methods Col (7) ÷ (2)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
20 - 15	17	14	7	41	12	5	29
15 - 10	32	30	6	19	16	10	31
10 - 7[2]	3	3	0	0	1	1	33
TOTAL.. 20 - 7[2]	52	47	13	25	29	16	31

[1]Estimates are probably optimistic by 20-25 percent owing to the discounting of some negative features which was a condition of the study.

[2]7° API is the approximate lower limit for oil mobility at ambient temperature.

Column 6 shows the total volumes of oil which likely will be produced using all methods which may be commercial in 1985. These include new enhanced oil recovery (EOR) methods, many of which are not commercial at the present time. The difference between the total recoverable oil (Column 6) and that obtainable by present technology (Column 4) is shown in Column 7 and represents an estimate of recovery using EOR methods. The last column shows the fraction of each category of oil originally in place and producible by EOR methods. This fraction is higher for the heavier oils, although the fractional recovery by all methods is lower below 15° API (see Column 5). This points out the greater amenability of heavy crude to enhanced methods. It should also be noted that a greater proportion is left in the ground after primary and secondary recovery. The more-or-less 100 percent figure for the 10° to 7° gravity range shows that practically none of this oil is producible by present-day methods. Only about a third is likely to be obtainable by even enhanced techniques. It is important to note that over 40 percent of the original heavy oil is not likely to be producible using any technique presently conceived.

METHODS OF ENHANCED RECOVERY

In general, oil recovery methods operate by (1) applying pressure, (2) loosening fluid globules from sand grains in underground formations, and (3) moving the fluids toward a well. Primary (dissolved gas, gravity, or aquifer pressure) and secondary (injection of gas or water) recovery rely mainly on pressuring and moving fluid. Enhanced recovery uses all three mechanisms.

Viscous oil can be made more mobile by heat and by chemical treatment or solvent dilution. Solvent and chemical action have been technically successful in increasing recovery in some wells, but costs have precluded widespread use in California.

Heat can be applied to a formation massively, rapidly, and with a relatively low cost. Two methods of applying heat formation-wide--that is, at least from well to well--are steam displacement and in situ combustion, otherwise known as fireflooding. These two techniques have been developed mainly within the past 15 years. They have been tested in a number of pilot projects involving a very few wells and now each method is ready for full scale demonstration of technical and economic feasibility.

In steam displacement, steam is injected continuously into one well and oil is produced from one or several wells around it. Usually the wells are arranged in a pattern. This pattern often resembles the five dots appearing on dice and is called "5-spot pattern." The steam gives up heat to the formation and the contained fluid as it passes through. The viscosity of these fluids is reduced. The condensing steam then acts similarly to regular waterflood, creating pressure and pushing the oil gradually to the producing wells.

Steam is effective where the formations are shallow--less than about 2,000 feet--and moderately thick--25 to 100 feet. Oil recovery averages about 40 percent, ranging from 30 to 50 percent or more in reservoirs having primary recovery usually less than 10 percent. Initial investment costs run from $200,000 to $500,000 for a steam generator, auxiliary lines, and other surface equipment. These costs are multiplied as additional equipment is brought in for project expansion. Total cost of steaming runs from $1.00 to $1.50 per barrel of produced and shipped oil. On the average, one out of three barrels of produced oil is used for fuel in the steam generator. A number of pilot and a few larger steam flood projects are underway in fields producing heavy oil, such as Kern River, San Ardo, and Midway Sunset.

The in situ combustion process is an intriguing and colorful one. The first firefloods were probably accidental. Fifty years ago, air was sometimes injected into wells to repressure the reservoir. Carbon dioxide was discovered in certain producing wells. This, in addition to the rise in temperature in the producers, led operators to believe that spontaneous ignition of the oil had taken place and that the oil continued to burn for some time.

Forward combustion is the most common process. A schematic diagram of the process is shown in Fig. 44-1. Air is injected

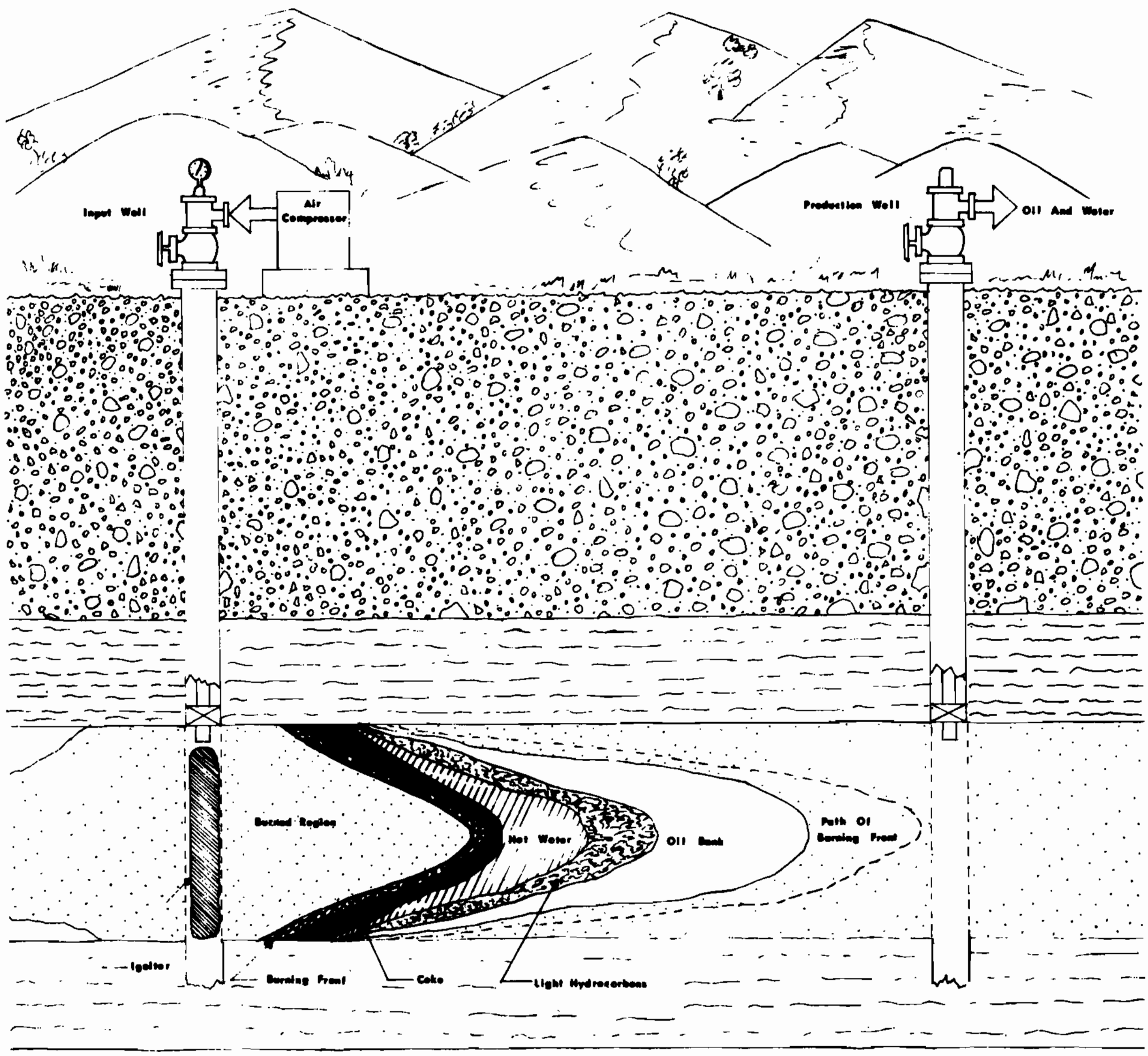

Figure 44-1.--Schematic represenation of in situ combustion process to recover oil

into a well for a short time, then the well is ignited using a gas heater or some other means. Normally the burning front forms several zones that move outward as the flame front moves away from the ignition well. Part of the oil is converted to coke which is then consumed to produce more heat. The water in the formation is turned to steam which in turn distills some of the oil ahead of the front, making it more mobile. Finally, partly heated oil banks up, causing it to move more readily to the producing wells. Temperature in the burning zone ranges from 600 to 1200°F. The process works best in isolated, uniform reservoirs with good permeability--reservoirs that conduct air and other fluids with relative ease. Depths should generally be less than 3,000 ft, with minimum sand thickness of about 100 ft. An oil saturation greater than about 40 percent is usually necessary so that sufficient oil will be there to support the burning and still have surplus for production. Oil recoveries are likely to be in the range of 60 to 90 percent; less if the area is not effectively swept by the burning. Costs vary from $100,000 to $800,000 for capital equipment, mainly for air compressors. Operating costs are difficult to estimate, however, air injection costs are in the neighborhood of $1.00 per barrel of produced oil. Frequently water is injected with the air (either simultaneously or intermittently) during and after the burn in order to sweep the heat ahead and achieve faster recovery of the oil.

STATE OF THE ART

For oil less than 20° gravity API, thermal methods are more effective. Because a portion of the produced oil is usually used as fuel for heating--underground as in fireflooding or above ground for steaming--there is an economic loss as well as an energy loss.

In general, both steamflooding and fireflooding are in the process of moving from the pilot stage to field demonstration. Steam flooding in particular is proving itself in many reservoirs. Both the technical and economic success of a project depend tremendously upon the particular characteristics of the rock formation from which the oil is to be produced. Such factors as sand continuity and isolation, porosity and permeability, and uniformity of formation thickness are critical. Constancy of oil saturation and minimization of high-water saturation zones are important. Numerous production problems occur, such as high temperatures and their effect on casing and other tubular equipment, severe corrosion, and plugging by sand from unconsolidated formations. The latter is particularly troublesome in California. All of the above render it imperative to test thermal recovery in many types of reservoirs and under different operating conditions.

Probably the largest single factor in determining success is oil viscosity. Evidence indicates that for light oils--arbitrarily denoted as being greater than 20° API or viscosity less than 10 or 15 cp--improved waterfloods would be most successful. Waterflooding is already the foremost <u>secondary</u> recovery technique; by addition of appropriate chemicals it can either be rendered a better secondary method or can sometimes yield a third crop of oil as <u>tertiary</u> recovery. In either case, it can be classed as an <u>enhanced</u> recovery method.

To aid in bringing this new technology on stream, the Federal government's Energy Research and Development Administration is funding a number of field demonstration projects. These projects are administered through cost-sharing contracts, with government sharing up to 50 percent of the cost. The objective is to accelerate commercialization of the new technology and to develop and report the pertinent data, so that other companies may also institute enhanced recovery projects. Methods chosen are those which previous laboratory and pilot field testing have shown to be promising of technical and economic success. Currently (1976) 15 demonstration projects are in operation in the United States, with two in California (one polymer waterflood and one fireflood). Several thermal projects and improved waterfloods are contemplated for funding in the near future. All these projects will be evaluated during their life and upon their completion and the results published. By describing the successful methods it is hoped that industry will adopt those that are successful and apply them on a large scale in many fields. Hence, production of oil will be increased in accordance with ERDA's national goals.

CONCLUDING STATEMENT

California's supplies of easily producible crude oil are decreasing rapidly. New methods for recovering heavy, viscous oil are being developed. Rapid implementation of these methods is necessary to narrow the gap between supply and demand for the next decade or longer.

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CHAPTER 45

STIMULATING RECOVERY FROM HEAVY OIL RESOURCES--MID-CONTINENT AREA

Larman J. Heath[1]

INTRODUCTION

There is widespread interest within the petroleum industry and State and Federal Governments concerning the large heavy-crude oil resource in the United States. This interest has been stimulated by a decrease in the rate of growth of the Nation's proved crude oil reserve, a forecast of increasing demand for crude oil, and recent advances in technology.

The heavy-oil reservoirs and tar sands have received much attention because of (1) recent increases in heavy-oil production from thermal-recovery operations, (2) the existence of over 2,000 known heavy-oil reservoirs, and (3) the fact that these reservoirs contain a high percentage of the oil originally in place.

Tar sands have been defined as oil-, bitumen-, asphalt-, tar-, or petroleum-impregnated rock from which little hydrocarbon material is recoverable by conventional crude oil production techniques. Several rock types as well as petroleum materials are included in the term "tar sands" [1]. The rocks may vary from consolidated and unconsolidated sandstone to shale, dolomite, limestone, and conglomerate. The hydrocarbons range from those difficult to soften in boiling water to those which ooze slowly from an outcrop on a warm day. In this report, heavy oil is

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[1]Bartlesville Energy Research Center, U.S. Energy Research and Development Administration, Bartlesville, OK. 74003

defined as oil having a gravity of 25° API or lower. Conventional secondary-recovery methods used to recover heavy oil are often impaired by the unfavorable mobility ratio between the driving and driven fluids. To find methods of producing heavy oil economically, much research has been done by the industry, including numerous field tests of thermal-recovery methods.

The technology for greatly increasing the recovery of viscous crude oil by raising its temperature is presently available. However, cost has limited the general use of thermal methods of recovery to reservoirs having characteristics considered to be most favorable. Significant improvements in technology or economic conditions could result in increased profitability and use of not only thermal but also other methods to recover crude oil.

The production potential for oil for U.S. heavy-oil deposits is poorly defined; neither industry nor government has made a comprehensive and conclusive examination of the physical extent and economic possibilities of such deposits. The U.S. Bureau of Mines [2] describes 546 occurrences of tar sands and 383 shallow oilfields. Reserve figures, however, are seldom available. Only a few of the large deposits in California and Utah have been surveyed carefully enough that the reserve figures are meaningful; accurate estimates for the remaining deposits are not available. Forty-two counties in Kansas, Missouri, and Oklahoma contain 40 percent of the recognized heavy oil deposits. Much of this is fairly shallow, less than 500 feet, and could be mined; however, because of costs and environmental considerations, research must be initiated for the economical recovery of this crude by in situ methods.

Statistics on cumulative oil production are available on most of the heavy oil productive reservoirs. A breakdown of heavy-crude oil resources in the United States [3] indicates a proved reserve of 5.2×10^9 barrels and an oil resource of 106.8×10^9 barrels; this resource includes 51.3×10^9 barrels of 20° to 25° API gravity and 55.5×10^9 barrels of oil of less than 20° API gravity. This resource is further classified by depth: 21.3×10^9 barrels in reservoirs less than 1,500 feet deep; 38.1×10^9 from reservoirs between 1,500 to 3,000 feet; and 47.4×10^9

from reservoirs deeper than 3,000 feet. These figures do not include oil-impregnated rocks which are known but from which no crude has been recovered. It is estimated that the total amount of heavy oil in the United States would be in excess of 150 x 10^9 barrels of oil in place if deposits were included such as those in western Missouri, eastern Kansas, and northeastern Oklahoma, and other reservoirs which have no reported individual oil-production statistics. Considering the low primary recovery from these accumulations, the potential recovery is tremendous. The geographical location of U.S. heavy-oil accumulations [4] is shown in Fig. 45-1.

REGIONAL DISTRIBUTION OF HEAVY OIL

In western Missouri, eastern Kansas, and northeastern Oklahoma, heavy-oil deposits occur over an area of roughly 8,000 mi^2 and extend for about 250 mi along the Kansas-Missouri border, reaching a width of about 80 miles (Fig. 45-2). Heavy-oil deposits are found throughout the region although lighter oil deposits do occur. Oil saturation and viscosity vary from one reservoir to another and from one depth to another in the same well. Formations of prime interest are the Wayside, Bartlesville, and the Burgess.

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION (ERDA) RESEARCH

A research project at the Bartlesville Energy Research Center of ERDA combines modern chemical explosive fracturing techniques with heat and solvent treatment to extract the crude oil. Of primary concern are the heavy-oil reservoirs which contain low gravity (high-viscosity) crude oil that cannot be produced by conventional means and reservoirs that have no reservoir energy and consequently have produced no oil. The oil will not flow into the wellbore at an economic rate, nor can it simply be pushed to the production well by the injection of water, as in waterflooding. Three elements must be present for production: (1) establishment of communication between wells, (2) reduction of oil viscosity within the formation, and (3) maintenance of the flow path once established. The purpose of

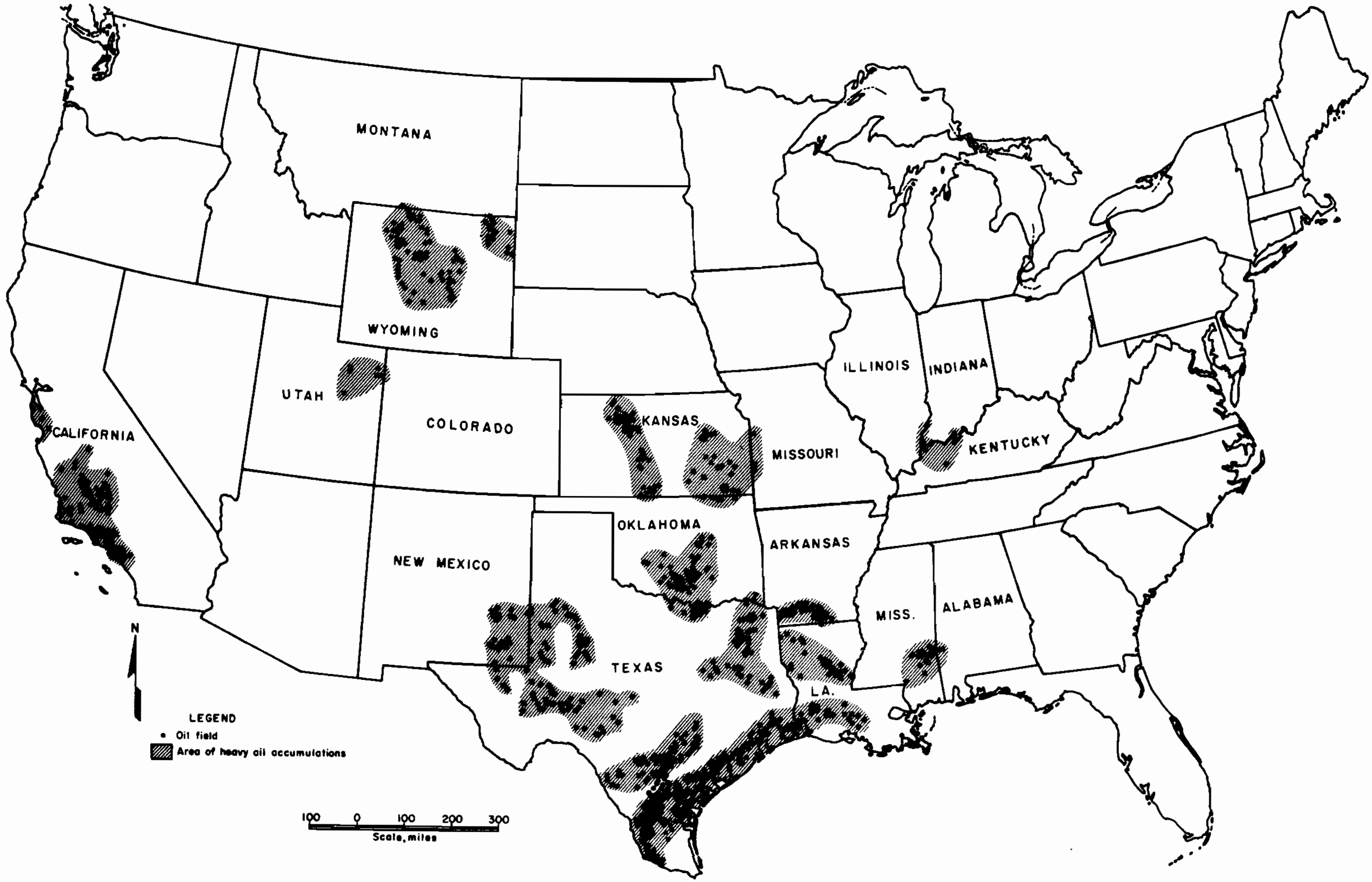

Figure 45-1.--Major area of heavy oil deposits in the United States (adapted from Dietzman et al., 1965)

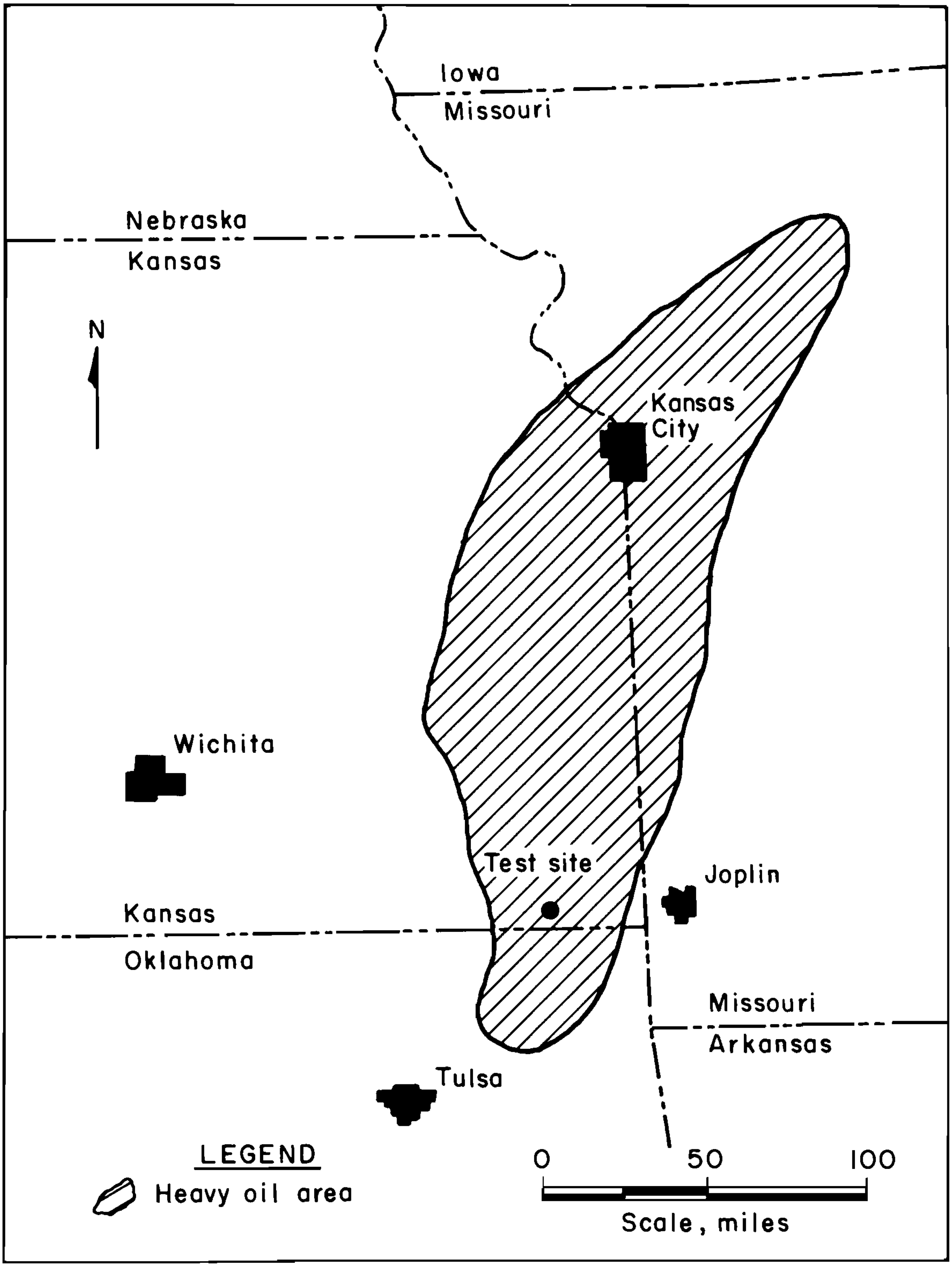

Figure 45-2.--Heavy oil deposits in the Tri-State area

this research is to study the several factors involved by which heavy oil can be efficiently and economically recovered from a consolidated sandstone petroleum reservoir. Two well-drilling and shooting programs were performed to prepare a 50 ft by 50 ft five-spot pattern and to establish communication by fragmenting the formation between the wells.

This method is one of several recovery methods which will be tried in this area. Future research plans include in situ combustion and carbon dioxide injection.

HEAVY-OIL RECOVERY TEST SITE

Engineers at the Bartlesville Energy Research Center of ERDA chose the Energy Recovery Corp. H. H. Leap lease in SE1/4 sec. 16, T. 34 S., R. 20 E. in Labette County, Kansas, near Bartlett, for a research project (Fig. 45-3). Eleven wells had been drilled on this property before the research was begun. Total production was about 25 barrels, mostly from steam injection. In addition to the wells drilled on the lease, wells were drilled in each of several quarter-sections in the area as a result of an intensive formation-testing program conducted jointly by several oil companies during the mid-1960's. Well-log information indicates the existence of a large heavy-oil reservoir extending over an area encompassing about four townships. Figure 45-4 is an isopachous map of this Bartlesville oil sand. A cross section (A-A') drawn through the Leap lease in an almost West-East direction is shown in Fig. 45-5.

FORMATION PROPERTIES

In this research, the first well (No. 7) was cored over the depth interval 260 to 375 feet with 100-percent recovery. This well was cored prior to explosive fracturing to determine formation properties such as permeability, porosity, and oil saturation. Core plugs were taken at 71 locations (273 to 375 feet) along the core and analyzed. The results of this core analysis are summarized in Table 45-1. Information obtained from core plugs and visual observation of the core from 260 to

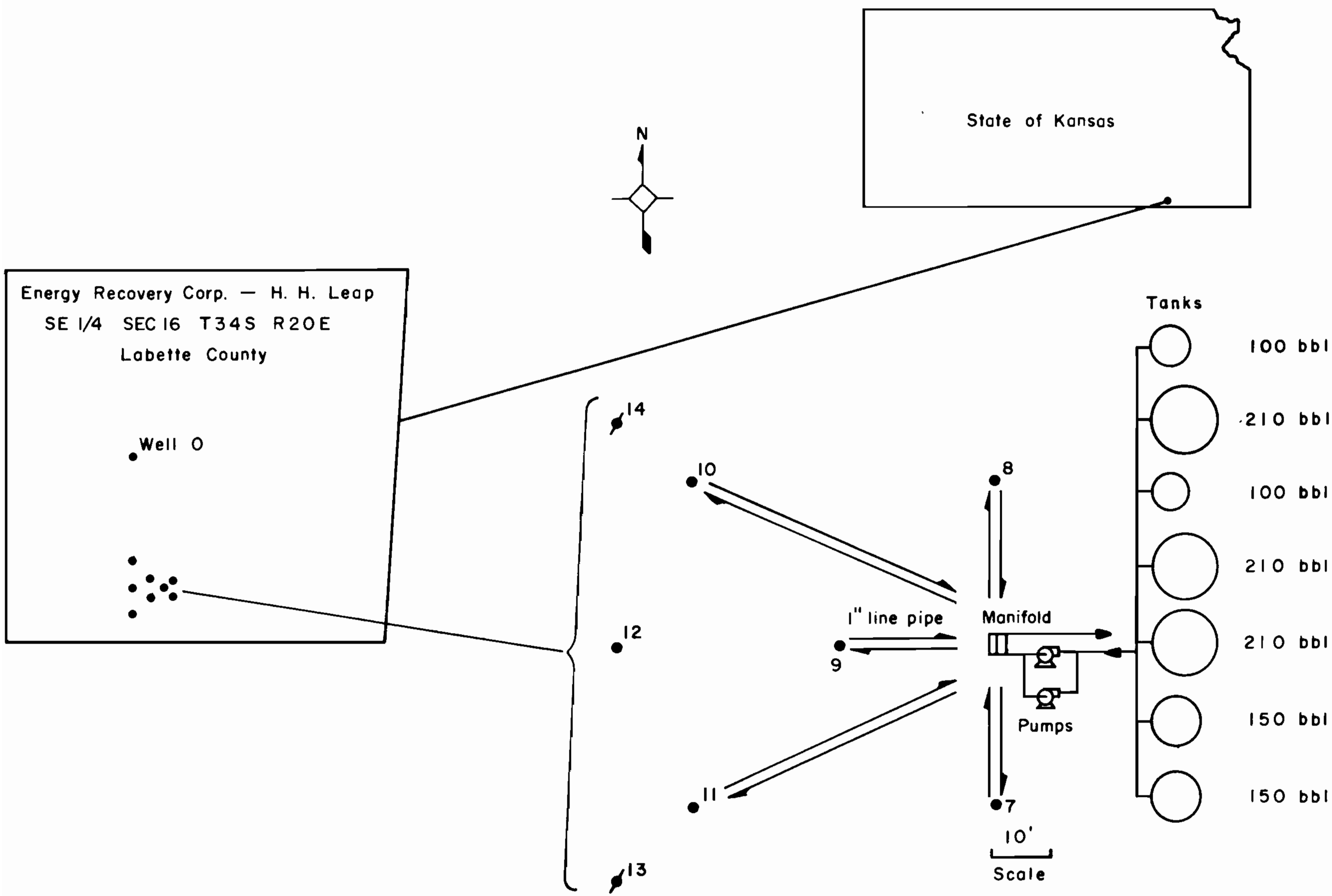

Figure 45-3.--Location of lease and simplified schematic of wells and tank battery, heavy oil test site

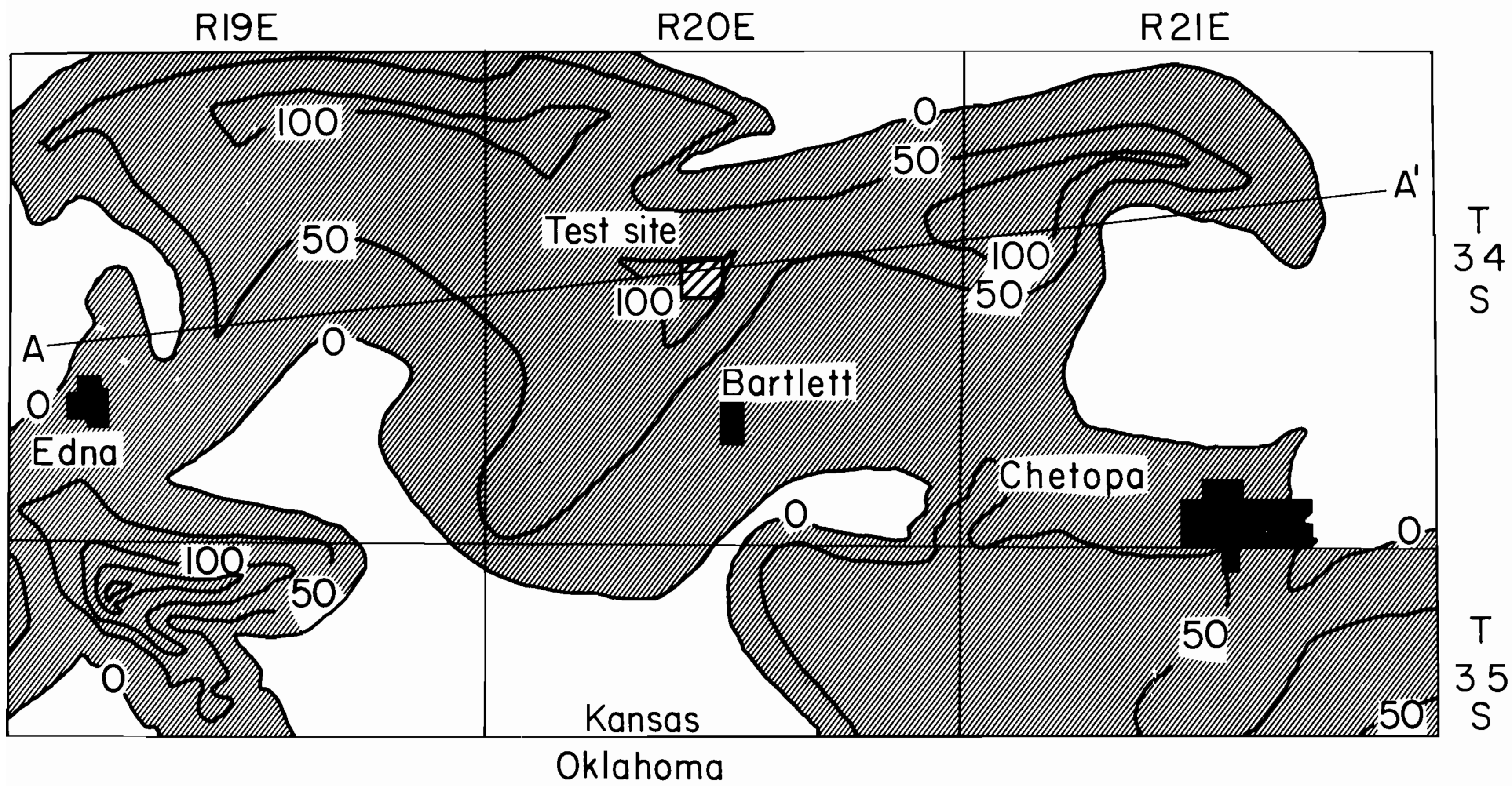

Figure 45-4.--Isopachous map of Bartlesville oil sand, Bartlett area

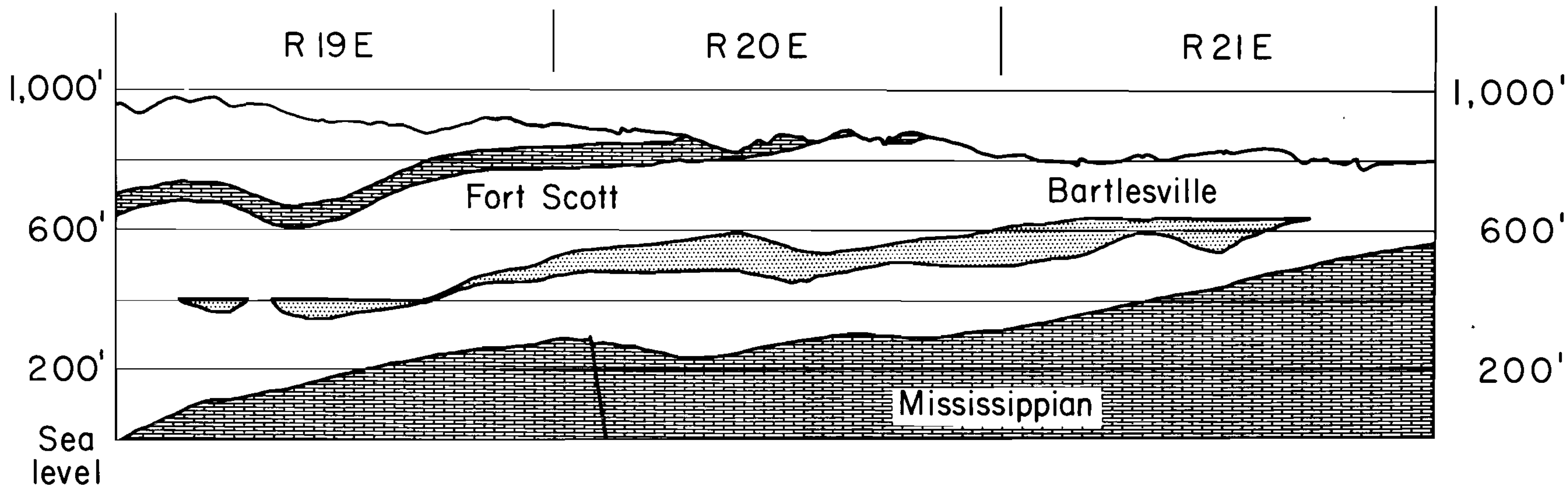

Figure 45-5.--Cross section A-A', Bartlett area

295 feet and 360 to 375 feet indicated little or no saturation in these intervals. Details of drilling, core analysis, and other site preparation activities have been published by Miller et al [5].

Using the data in Table 45-1 and Fig. 45-4, ERDA engineers have calculated that this one reservoir contains 1.7 x 10^9 barrels of oil in place.

An induction-electrical log was run on well 7 from the surface to a depth of 360 feet in a 13 1/2-in hole and from 360 to 375 feet in a 6 3/8-in hole. The logs indicated the top of the Bartlesville sand at approximately 246 feet, with no positive indication that the bottom of the formation had been reached. The well was plugged back to 360 feet and all subsequent wells were bottomed at 360 feet, all within the Bartlesville sand.

TABLE 45-1.--Core analysis

Depth, feet	Permeability, millidarcies	Porosity, percent	Oil saturation, percent	Oil in place, bbl/acre	Oil in place, bbl/acre ft
273-295	147.1	21.9	6.6	2,464	112
295-330	132.6	18.4	33.9	16,937	484
330-360	175.6	21.9	39.4	20,069	669
360-375	13.3	15.8	4.7	868	58

Prior to and concurrently with the drilling and shooting activity, laboratory tests were conducted to determine the proper type of solvent to use in both laboratory and field experiments. Selection of a solvent was based on tests using a sample of Bartlett oil. Results of tests used in selecting the solvent used in both the laboratory and field experiments have been published by Johnson and Johansen [6].

CORE-SOLVENT EXPERIMENTS

Fifteen experiments using the selected solvent (74 percent aromatic) were conducted on cores from the Bartlett lease. The purpose of these experiments was to investigate the optimum operating conditions that should be imposed on the reservoir. Factors such as soak time, temperature, pressure, flow direction, influence of water, recycling of solvent, and surface area exposed to solvent were investigated.

The procedures for and the results of these core tests have been published [7]. The runs representing three types of experiments were averaged, and the results are plotted in Fig. 45-6.

PRODUCTION

The first drilling, shooting, and producing program (Phase I) involved three wells, part of a five-spot having a distance of 50 feet between outside wells. All three wells were completed similarly. Two strings of 1-inch pipe were installed through a dual-string tubing head. One string was set at 330 feet, the other at 220 feet. Well 9 was the injection well, and wells 7 and 8 were the producing wells.

The injection well was initially filled with solvent to the depth of 330 feet. Subsequent solvent injection was through the 220-foot tubing. Production was accomplished by directing compressed air down the annulus of the production well to clean out all liquids above the 220-foot level. For the first 3 days, solvent injection was continuous. After that a normal injection-production day consisted of producing wells 7 and 8 in the morning, injecting solvent into well 9 for approximately 12 hours, and again producing wells 7 and 8 at the end of the injection period. This production phase was terminated on October 4, 1972.

The five-spot pattern was completed, and communication tests were made during the next few months.

The difficulties and costs encountered in cleaning out the first three wells after they were shot, compared with the cost of drilling a well to 360 feet, prompted the decision not to use explosives in the two additional corner wells needed to complete a five-spot pattern. There was also a need to see whether fracture communication could be established between wells

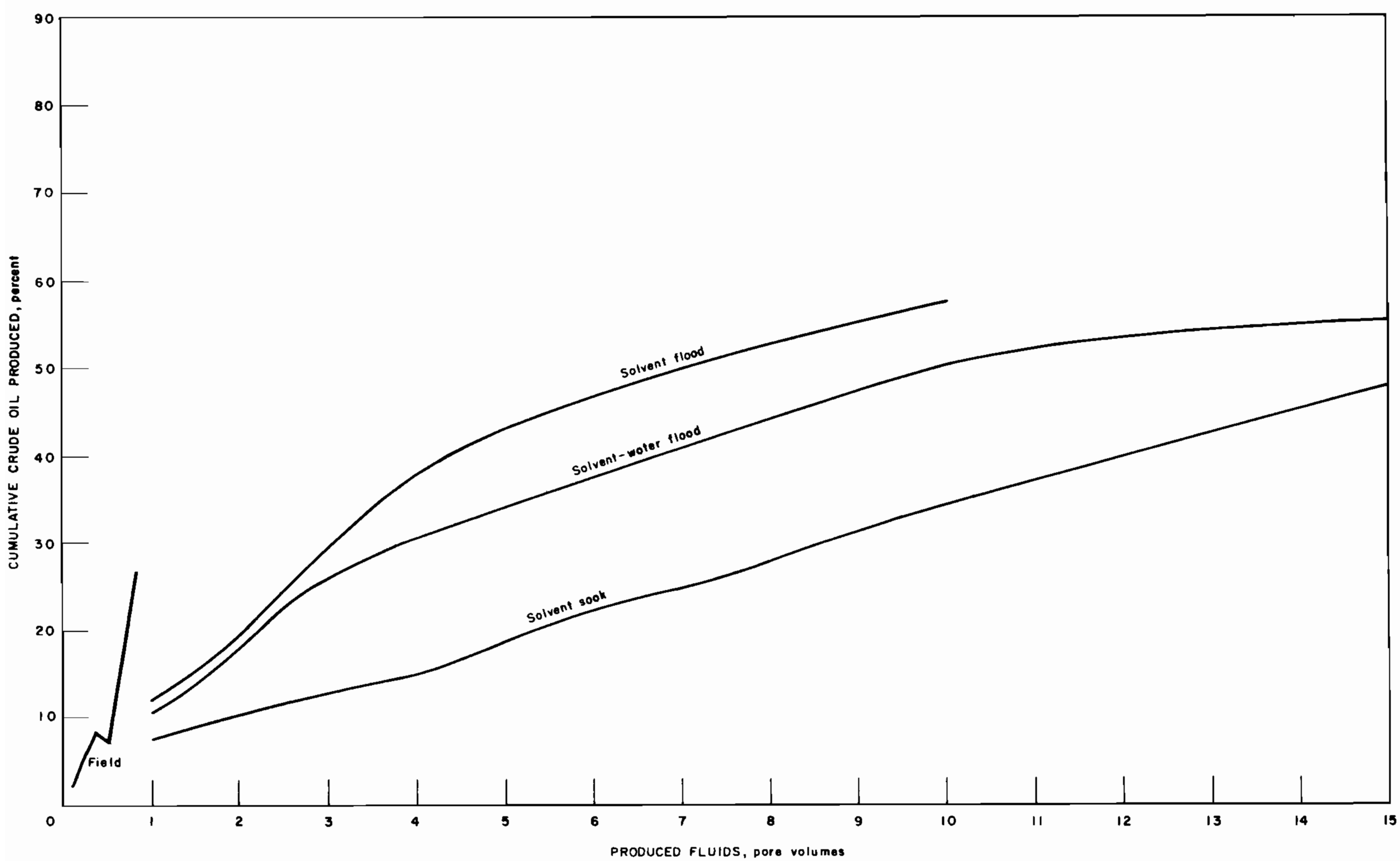

Figure 45-6.--Comparison of averaged laboratory data with field results

farther apart than 50 feet. Consequently, the two wells to be fractured were drilled 75 feet apart and diagonally from the two planned corner locations. These are wells 13 and 14 as shown in Fig. 45-3.

Wells 13 and 14 were drilled in September 1972 with a 13-1/2 inch bit to a depth of 360 feet. They were simultaneously fractured with pelletized TNT similar to treatment for the first three wells. After the detonations, they were plugged in accordance with Kansas State Corporation Commission regulations.

Well 12 was drilled midway between wells 13 and 14 to determine the extent of fracturing and as an observation well.

During the winter of 1972-73, a flash distillation unit was constructed to separate the produced oil from the solvent. Oil and solvent mix are pumped through a 15-kilowatt heater that heats the mixture to 360°F. A control valve next to the 5-foot-long, 8-inch diameter flash chamber reduces the pressure from 50 psi to atmospheric pressure. Vaporized solvent is produced through the top of the flash chamber and condensed. Oil, containing some solvent, is removed from the bottom of the flash chamber. The distillation unit will separate 18 barrels of solvent in 24 hours.

Injection-production operations (Phase II) were resumed on July 10, 1973, using wells 7, 8, 10, and 11 as injection wells and well 9 as the production well. Wells 10 and 11 were completed with dual 1-inch tubing strings similar to the completion of the other three wells. Solvent was injected down the 220-foot string, and well 9 was produced by compressing air down the annulus and displacing well fluids up the 220-foot string. A normal injection-production day consisted of producing well 9 in the morning, injecting solvent for about 3 hours, and producing well 9 at the end of the injection period.

In January 1975, after a soak period of 29 weeks, Phase III was begun. Very little solvent was injected during this period. Previously, production of fluid was limited to removing only the oil from the well cavity. During Phase III, all fluids were removed from the center well; water production varied from about 60 to 95 percent. Fluid removal was accomplished by the use of a sucker-rod pump installed on the production (center) well. Solvent-oil production remained about the same but the percent of oil in the oil-solvent mix increased two- to three-fold.

Phase IV was begun July 22, 1975 after the completion of eight water-injection wells drilled along the perimeter of a circle having an approximate 75 foot radius from the center well of the five-spot pattern. The drill bit encountered solvent that had migrated outside the pattern in several of the wells. Water rates were determined and set to predetermined rates twice a week by use of turbine meters. Waterflooding was discontinued in November 1975 after more than 30,000 barrels of water had been injected.

The production history is shown in Table 45-2. Soaking time, amount of daily solvent injection, and production techniques have been varied to establish the optimum ratio of oil produced to solvent injected. Soaking periods that have been tried include 1-, 1-, and 3-week periods; soaking only on weekends; and soaking on Tuesdays and Thursdays in addition to the weekends. The latter soaking period would probably give the highest percentage of oil in the solvent produced, but would give less total oil produced over a given period than soaking only on weekends. The amount of daily solvent injection has averaged 28, 10, 4.5, and 2.5 barrels per day during different periods. Daily production results indicate that the injection rate of 28 barrels per day caused overflushing of the fracture system between the injection wells and the producing wells and that the 4.5 barrels per day injection rate did not displace all of the solvent in the formation each day.

The calculated pore volume of the five-spot is 2,868 barrels with an oil content of 972 barrels. This is based on an interwell area of 0.0574 acre and includes the interval from 295 to 330 feet. Cumulative fluid produced from the zone is 2,538 barrels or 0.88 pore volume. Net crude oil production is 262.6 barrels, or 26.9 percent of the oil in place.

TABLE 45-2.--Injection and production data

Injection period	Solvent injected		Solvent-oil mixture produced		Crude oil produced		Water produced, barrels	Oil in mixture, percent	Oil in injected solvent, percent
	Barrels	Barrels per day	Barrels	Barrels per day	Barrels	Barrels per day			
1972 - Phase I									
Fill up	205.62	-	-	-	-	-	-	-	-
May 9-10	80.42	40.21	46.39	23.20	5.78	2.89	1.17	12.46	0
May 15-19	121.66	24.33	108.00	21.60	6.79	1.36	10.00	6.29	0
May 22-26	110.71	22.14	103.73	20.75	5.84	1.17	1.75	5.63	0
May 29-June 2	0	0	33.82	11.82	3.76	1.25	.58	11.11	0
(Soaked 3 weeks)									
June 26-30	91.46	18.29	82.56	16.51	6.85	1.37	16.48	8.30	0
July 5-6	0	0	8.46	4.23	.58	.29	1.73	6.86	0
(Soaked 3 weeks)									
July 31-Aug. 4	86.61	17.32	73.67	14.73	6.03	1.21	11.60	8.19	0
Sept. 27-29[1]	0	0	[2] 70.60	-	[3] 1.0	-	ND	-	0
Oct. 2-4[1]	0	0	[2] 149.90	-	[3] 3.92	-	ND	-	0
1973 - Phase II									
Fill up	403.59	-	-	-	-	-	-	-	-
July 10-13	113.74	28.44	30.61	7.65	2.90	0.73	22.11	9.47	0.04
July 16-20	133.76	26.75	79.06	15.81	5.34	1.07	12.97	6.75	.10
July 23-25	0	0	21.16	7.05	1.83	.61	8.64	8.65	0
(Soaked 2 weeks)									
Aug. 6-10	49.26	9.85	30.80	6.18	3.21	.64	32.97	10.39	.97
Aug. 13-17	35.88	7.18	27.07	5.41	2.54	.51	20.17	9.38	.50
(Soaked 2 weeks)									
Sept. 4-7	34.79	8.70	25.49	6.37	2.90	.73	17.86	11.38	.40
Sept. 10-14	48.34	9.67	40.04	8.01	2.75	.55	22.75	6.87	.35
(Soaked 3 weeks)									
Oct. 8-12	54.15	10.83	33.70	6.74	2.55	.51	25.77	7.57	1.05
(Soaked 3 weeks)									
Nov. 5-9	22.61	4.52	22.47	4.49	1.99	.40	22.75	8.86	3.49
Nov. 12-16[4]	12.36	2.37	15.42	3.08	1.48	.30	25.06	9.60	1.78
(Soaked 7 weeks)									
1974									
Jan. 28-Feb. 1	44.28	8.86	23.37	4.67	2.10	0.42	4.50	8.99	0.61
Feb. 4-8[6]	55.25	11.05	21.33	4.27	1.58	.32	7.55	7.41	.58
Feb. 11-15	50.46	10.09	41.22	8.24	2.75	.55	.15	6.67	.46
Feb. 18-22	48.01	9.68	37.59	7.52	2.36	.47	0	6.28	.23
Feb. 25-Mar. 1	47.49	9.50	38.31	7.66	2.04	.41	0	5.32	.06
Mar. 4-8	45.48	9.10	36.86	7.37	2.07	.41	0	5.62	.18

See footnotes at end of table.

TABLE 45-2.--Injection and production data--Continued

Injection period	Solvent injected		Solvent-oil mixture produced		Crude oil produced		Water produced, barrels	Oil in mixture, percent	Oil in injected solvent, percent
	Barrels	Barrels per day	Barrels	Barrels per day	Barrels	Barrels per day			
1974, Cont'd.									
Mar. 11,13,15[6]	28.25	9.42	20.75	6.92	1.08	0.36	0	5.20	0.21
Mar. 18,20,22	26.57	8.86	18.29	6.10	1.07	.36	0	5.85	.41
Mar. 25,27,29[7]	28.16	9.39	22.71	7.57	1.41	.47	0	6.21	13.24
April 1,3,5	33.82	11.27	20.46	6.82	1.66	.55	0	8.11	8.26
April 8,10,12	31.64	10.55	24.38	8.13	1.93	.64	0	7.92	6.23
April 15,17,19	31.20	10.40	22.20	7.40	1.66	.55	0	7.48	6.59
April 22,24,26	31.06	10.35	22.06	7.35	1.67	.56	0	7.57	6.92
April 29-May 3	32.65	10.88	21.48	7.16	1.64	.55	0	7.62	6.89
May 6-10	34.10	11.37	25.11	8.37	1.90	.63	0	7.56	7.33
May 13-17	30.04	10.01	21.62	7.21	1.73	.58	0	7.99	7.62
May 20-24	29.90	9.97	19.16	6.39	1.68	.56	0	8.79	7.66
May 27-31	26.85	8.95	16.40	5.47	1.51	.50	0	9.20	7.49
June 3-7	30.04	10.01	18.58	6.19	1.62	.54	0	8.74	7.92
June 10-14	40.20	13.40	27.86	9.29	2.32	.77	0	8.33	7.99
June 17-21	30.77	10.26	23.80	7.93	2.20	.73	0	9.23	8.38
June 24-28	35.12	11.71	25.69	8.56	2.28	.76	0	8.87	8.60
(Soaked 29 weeks)									
1975 - Phase III									
Jan. 20-24[8]	0	0	57.41	14.35	14.26	3.57	243.93	24.84	-
Jan. 27-31	35.93	11.98	17.25	3.45	4.08	.82	128.43	23.65	12.58
Feb. 3-7	107.94	21.59	99.19	19.83	17.37	1.47	157.89	17.51	12.35
Feb. 10-14	0	0	54.41	18.14	11.99	4.00	144.76	22.04	-
Feb. 19-21	0	0	28.70	14.35	5.54	2.77	114.79	19.30	-
Feb. 25-28	0	0	20.62	6.87	4.38	1.46	95.57	21.24	-
Mar. 3-7	0	0	28.55	7.14	6.65	1.66	69.54	23.29	-
Mar. 10-14	0	0	3.21	1.07	.87	.29	63.25	27.10	-
Mar. 17-21	0	0	21.32	7.11	4.27	1.42	97.11	20.03	-
Mar. 24-28	0	0	6.09	2.03	1.60	.53	69.78	26.27	-
Mar. 31-April 4	0	0	8.27	4.14	1.57	.79	40.74	18.98	-
April 7-11	0	0	10.88	3.63	2.12	.71	57.55	19.49	-
April 14-18	51.60	10.32	13.77	2.75	3.16	.63	57.14	22.95	18.52
April 21-25	0	0	11.73	2.35	3.06	.61	55.02	26.05	-
April 28-May 2	54.62	10.92	15.50	3.10	4.85	.97	47.27	31.59	18.52
May 5[9]	0	0	15.89	15.89	4.49	4.49	9.93	28.25	-
July 21[1]	0	0	222.49	-	67.49	-	-	30.34	-

See footnotes at end of table.

TABLE 45-2.--Injection and production data--Continued

Injection period	Solvent injected		Solvent-oil mixture produced		Crude oil produced		Water produced, barrels	Oil in mixture, percent	Oil in injected solvent, percent
	Barrels	Barrels per day	Barrels	Barrels per day	Barrels	Barrels per day			
1975, Cont'd. - Phase IV									
July 22-25[10]	0	0	2.32	0.58	1.22	0.31	0	52.59	-
July 26-Aug. 1	0	0	1.30	.18	.60	.09	2.05	46.15	-
Aug. 2-8	0	0	5.94	.85	2.17	.31	4.58	36.53	-
Aug. 9-15	0	0	2.32	.33	1.01	.14	5.27	43.53	-
Aug. 15-22[11]	0	0	51.29	7.37	10.07	1.44	82.92	19.63	-
Aug. 23-29	0	0	67.37	9.62	13.60	1.94	327.11	20.18	-
Aug. 30-Sept. 5	0	0	29.41	4.20	7.81	.76	476.51	17.99	-
Sept. 6-12	0	0	5.80	.83	.76	.11	474.55	13.15	-
Sept. 13-19	0	0	20.14	2.88	2.92	.42	509.27	14.50	-
Sept. 20-26	0	0	25.21	3.60	3.68	.53	383.73	14.60	-
Sept. 27-Oct. 3	0	0	28.26	4.04	4.01	.57	814.09	14.19	-
Oct. 4-10	0	0	22.46	3.21	2.96	.42	489.58	13.10	-
Oct. 11-17	0	0	33.32	4.76	4.95	.71	420.46	14.86	-
Oct. 18-24	0	0	11.73	1.68	2.97	.42	950.31	25.32	-
Oct. 25-31	0	0	.28	.04	.10	.01	768.61	35.71	-
Nov. 1-7	0	0	.87	.12	.28	.04	789.59	32.18	-
Nov. 8-14[12]	0	0	1.59	.23	.61	.09	582.94	40.67	-
Nov. 15-Mar. 9[13]	0	0	40.80	-	13.42	-	898.05	32.89	-
Total or average	2646.39	-	2537.87	-	[14]339.19	-	-	13.36	-

ND - Not determined.

[1] Emptied wells to prepare for next phase.

[2] Includes wellbore, fill-up volume.

[3] Includes oil from wellbore, fill-up volume.

[4] Injection into only one well each day for a 2-week period.

[5] Started flowing production well.

[6] Started injecting only 3 days per week.

[7] Started recycling solvent.

[8] Installed sucker-rod pump on center (production) well, Jan. 6, 1975.

[9] Perforated center well from casing seat to top of formation, May 2.

[10] Waterflood begun, July 22.

[11] Cleared solvent from outside four wells, Aug. 20.

[12] Water injection stopped, Nov. 14.

[13] Clearing fluids from wells to March 9, 1976.

[14] Re-injected 76.63 bbl.

SUMMARY AND CONCLUSIONS

There are many heavy oil deposits in the United States; much of this heavy oil is in the Mid-Continent Area. ERDA engineers are investigating one reservoir containing 15° API gravity crude, located in southeastern Kansas, to determine whether a method can be developed for economic production. The method being studied involves the use of explosives to rubblize the formation followed by the injection of a solvent.

The results of the field experiments, even though less than one pore volume of solvent-mix was produced, showed more oil recovered per pore volume of solvent mixture produced than did the laboratory experiments.

Intermittent injection of about 10 barrels every other day seems to be the most effective quantity to inject.

On March 25, 1974, reinjection of the produced solvent-oil mixture was started. Not enough additional oil was picked up during recycling of the solvent to justify this procedure.

During Phase III, the path for the flow of fluids was lowered to the depth of the pump setting. This helped remove some of the heavy oil from the lower fracture system and the net result was an increase in the percent of crude oil in the oil-solvent mix.

Net crude oil production was 263 barrels or 27 percent of the 972 barrels in place. Some of this oil could have been leached from the formation outside of the five-spot pattern.

The total net injection of solvent was 2,570 barrels while the net solvent produced was 2,199 barrels. The difference of 371 barrels (or 14 percent of the injected solvent) represents the amount of solvent lost to the formation.

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CHAPTER 46

MULTIPURPOSE UTILIZATION OF OIL SHALE

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INTRODUCTION

The need for energy for domestic and commercial purposes is world-wide and rapidly increasing. In most parts of the world, the most critically needed forms of energy are hydrocarbons, which are the source for motor fuels needed for transportation and for the easily-transportable, high-Btu-content gases used for domestic purposes and for power generation. The widespread occurrence of organic-containing rocks, or oil shales, throughout the world make this material a possible substitute, particularly for petroleum and natural gas, as a source of fossil energy.

Two general alternatives are available for utilization of oil shale: The first is to burn the shale directly as fuel and the second is to convert it to some other form of fossil energy. Direct combustion offers the simplest and least expensive approach to the utilization of oil shale, as only the fuel and combustion aspects of the process are unique. The remainder of the plant used to burn the material would be required regardless of the fuel used. This use assumes the availability of low-cost and sufficient water at the deposit site for operation of a power plant. If this assumption is not valid, the direct combustion approach would probably have to be eliminated from

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consideration because transporting a low-grade fuel for any appreciable distance is not economically feasible. In addition to the low-heating value, the high sulfur content of most oil shales will be a disadvantage in a system utilizing direct combustion. In most parts of the world today the removal of sulfur dioxide from stack gases and the recovery of sulfur from these gases is required. The use of oil shale for direct combustion has been practiced and is adequately documented in reports of the Estonian operations [1].

The second alternative requires conversion of oil shale to liquid or gaseous products. In the United States, oil shale has been considered almost entirely as a substitute for natural petroleum and gas and, consequently, this paper mostly will consider technologies directed towards these end products.

PROCESSING OIL SHALE

Over the years a number of studies have been made of means to extract the organic material from oil shales. The only practical technology that has been developed is the use of high temperatures, approximately 900°F (480°C), to retort or decompose the solid organic material by pyrolysis. The shale can be heated by direct or indirect methods. Utilization of solvents to remove the organic materials from oil shales has not been successful although in 1975 Robinson and Cummins [2] reported a method that uses carbon monoxide and water.

Retorting can be accomplished aboveground in retorting equipment. This method has been relatively well developed and operations have been conducted at modest levels. Retorting can also be accomplished underground by one of a number of less well developed in situ methods. Heating the oil shale can be accomplished by internal combustion, by circulating hot fluids, or even by circulating hot solids. Figure 46-1 is a diagrammatic representation of the possible processing methods for oil shales. These methods will be discussed individually in the sections to follow.

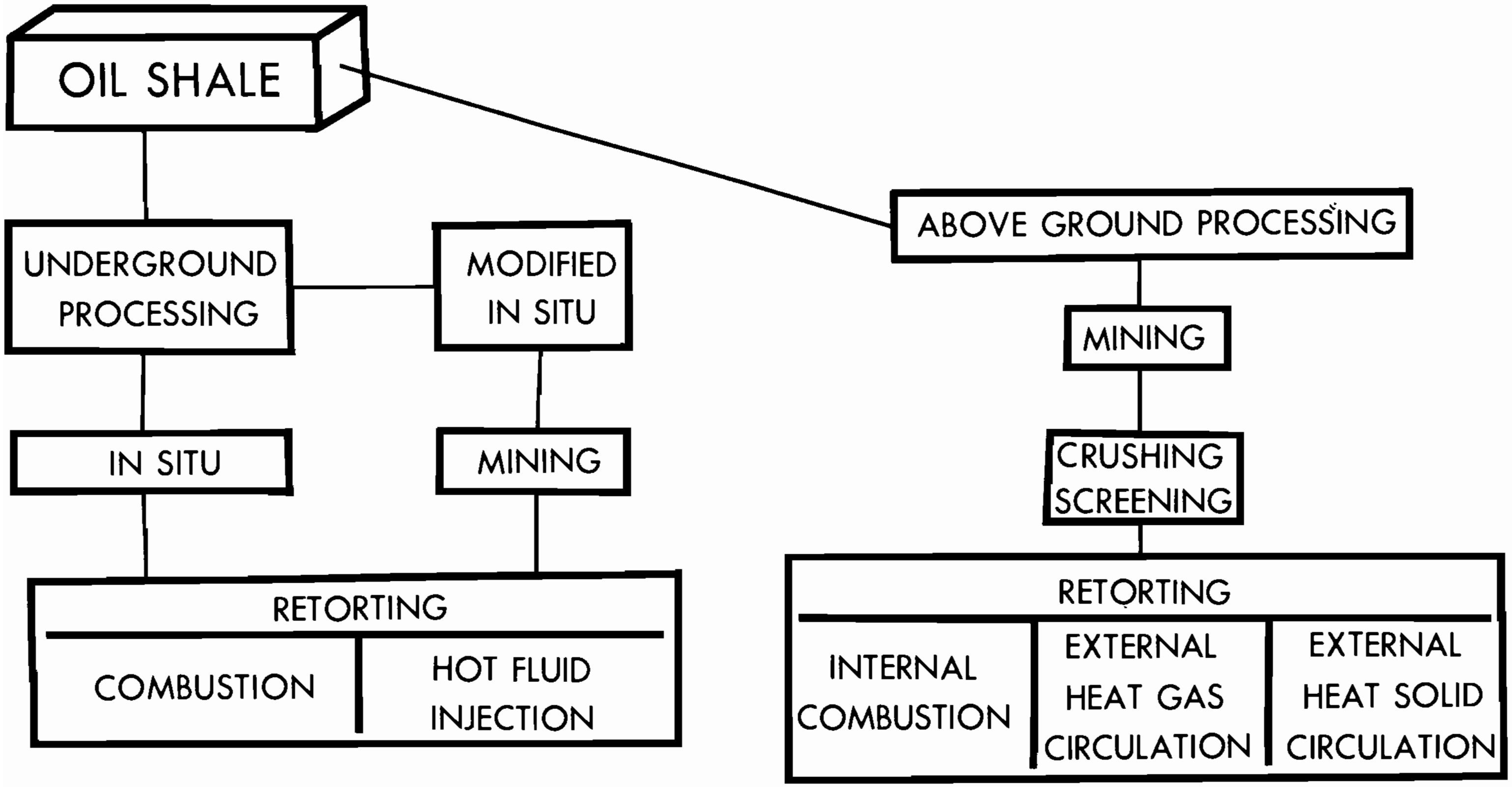

Figure 46-1.--Diagram showing possible processing methods for oil

Co-development of Other Minerals

Although complete use of spent shale has met with virtually no success in the United States, the mineral fraction of some oil shales may yield valuable products in addition to oil. A primary example is the possible production of three marketable materials--oil, alumina, and nahcolite--from Green River Formation oil shales occurring in Colorado's Piceance Creek Basin. A deposit of oil shale containing the minerals dawsonite [$NaAl(OH)_2$ $^1CO_3$] and nahcolite [$NaHCO_3$] occurs under 350 mi^2 of the basin's center. Appropriate processing of these oil shales will produce shale oil, alumina, and raw nahcolite, plus some additional soda ash [3,4]. Both the oil and alumina can supplement raw materials now imported by the United States. The raw nahcolite is finding application as an extremely efficient absorbent for removing sulfur dioxide from stack gas. The resource in this deposit is huge, offering 6.5×10^9 tons of alumina, 6×10^9 tons of soda ash from dawsonite, 29×10^9 tons of nahcolite, and more than 100×10^9 barrels of shale oil to simultaneous production [5]. Uranium occurring in the Devonian black shales of the midwest has been investigated as a possible co-product with shale oil. These shales yield about 5 weight percent oil, and their uranium levels average about 50 ppm [6]. At present development does not appear economic even with two products.

Aboveground Processing

Surface processing of shale has received the greatest amount of attention and various processes have been carried through the pilot-plant stage and demonstrated on a scale approaching commercial development. For aboveground processing it is first necessary to mine the shale, then to crush and screen it to some uniform particle size-distribution before retorting in aboveground equipment. The aboveground retorting can be accomplished by internal combustion for supplying process heat (direct heating) or by burning some fuel external to the retort and transferring heat to the oil-shale bed either by gas flow or flow of hot solids (indirect heating). Examples of retorts using direct and indirect heating are given below.

Figure 46-2 shows a simplified diagram of a Bureau of Mines gas combustion retort. This retort is an example of one utilizing direct heat and the various zones where reactions occur are shown. In the gas combustion retort, oil shale crushed and screened to between 1/2 in and 3 in, is fed at the top of the vessel through a gas-seal device. As the oil shale proceeds downward through the retort a stream of combustible gas and air is fed at the bottom. Heat resulting from the combustion of this gas-air mixture raises the temperature of the oil shale to retorting temperatures and hydrocarbons are liberated from the shale in the retorting zone by pyrolysis. Liquids which form a stable mist and gases are taken off the top of the retort vessel and separated in recovery equipment. Part of the gas is returned to the retort as recycle gas and the remainder can be used externally to the retort vessel; spent shale is removed at the bottom. Several variations of this configuration are possible. The mixture of recycle gas and the air can be burned externally to the retort and a flow of hot combustion gases into the bottom of the retort can be used to transfer heat to the column of broken shale. Another variation might be made by reversing the flow and having the oil shale flow upward through the retort by means of a mechanical device; the gas flow could be countercurrent or concurrent, depending on the design of the vessel. These variations include both of the major types of equipment available today. The gas combustion retort is the forerunner of the Petrosix process and the Paraho process. The upward-moving shale is typical of one of the early retorts developed by Union Oil Company, wherein the oil shale is moved upward through the retort by means of a "rock pump."

The TOSCO retort exemplifies those that use indirect heating. Figure 46-3 is a schematic representation of a TOSCO retort, in which heat transfer is accomplished by contacting the oil shale with ceramic balls that have been heated externally. Because no combustion occurs in the retorting zone, retorting temperatures can be low and gases produced by pyrolysis are not

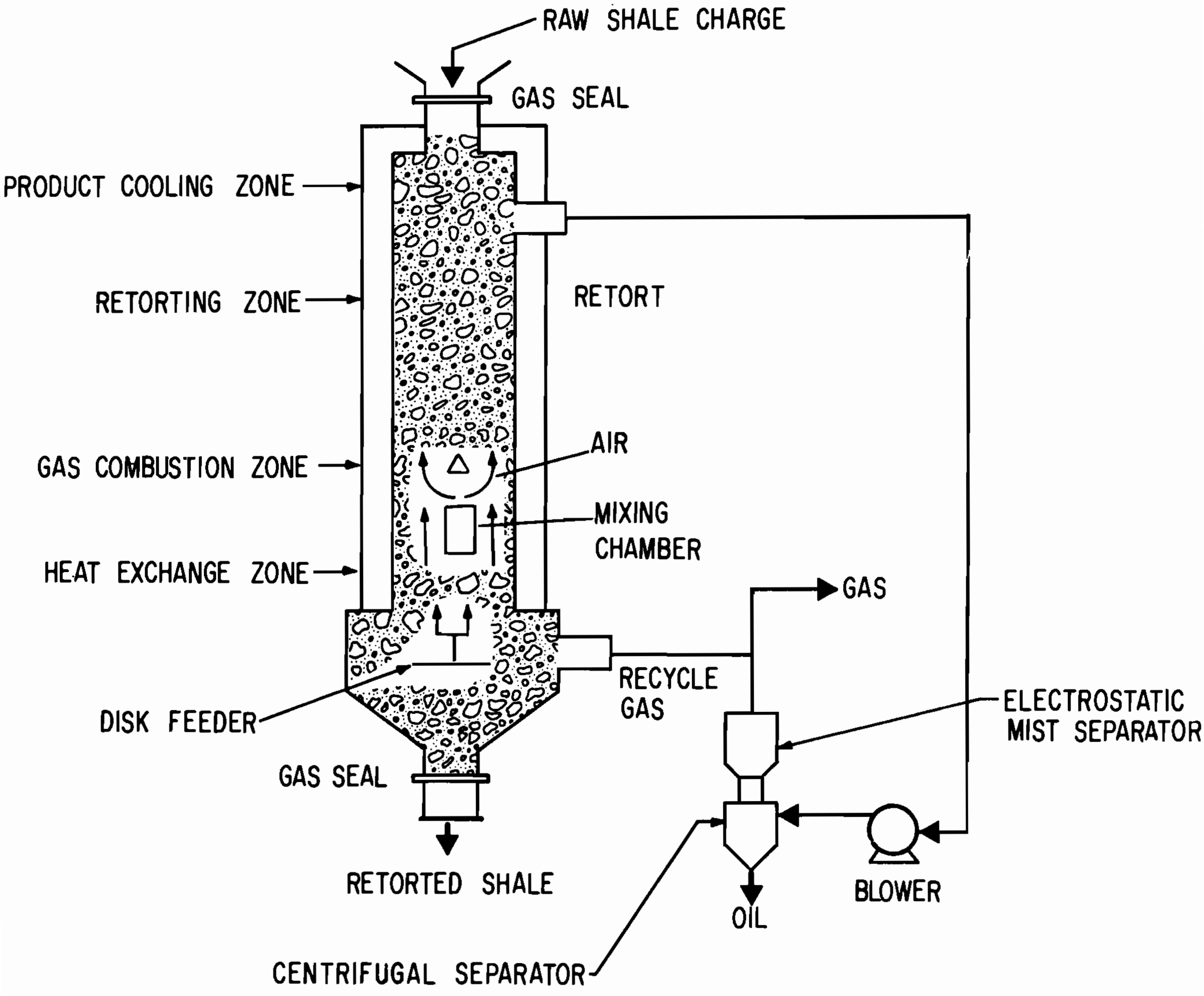

Figure 46-2.--Gas-combustion retort

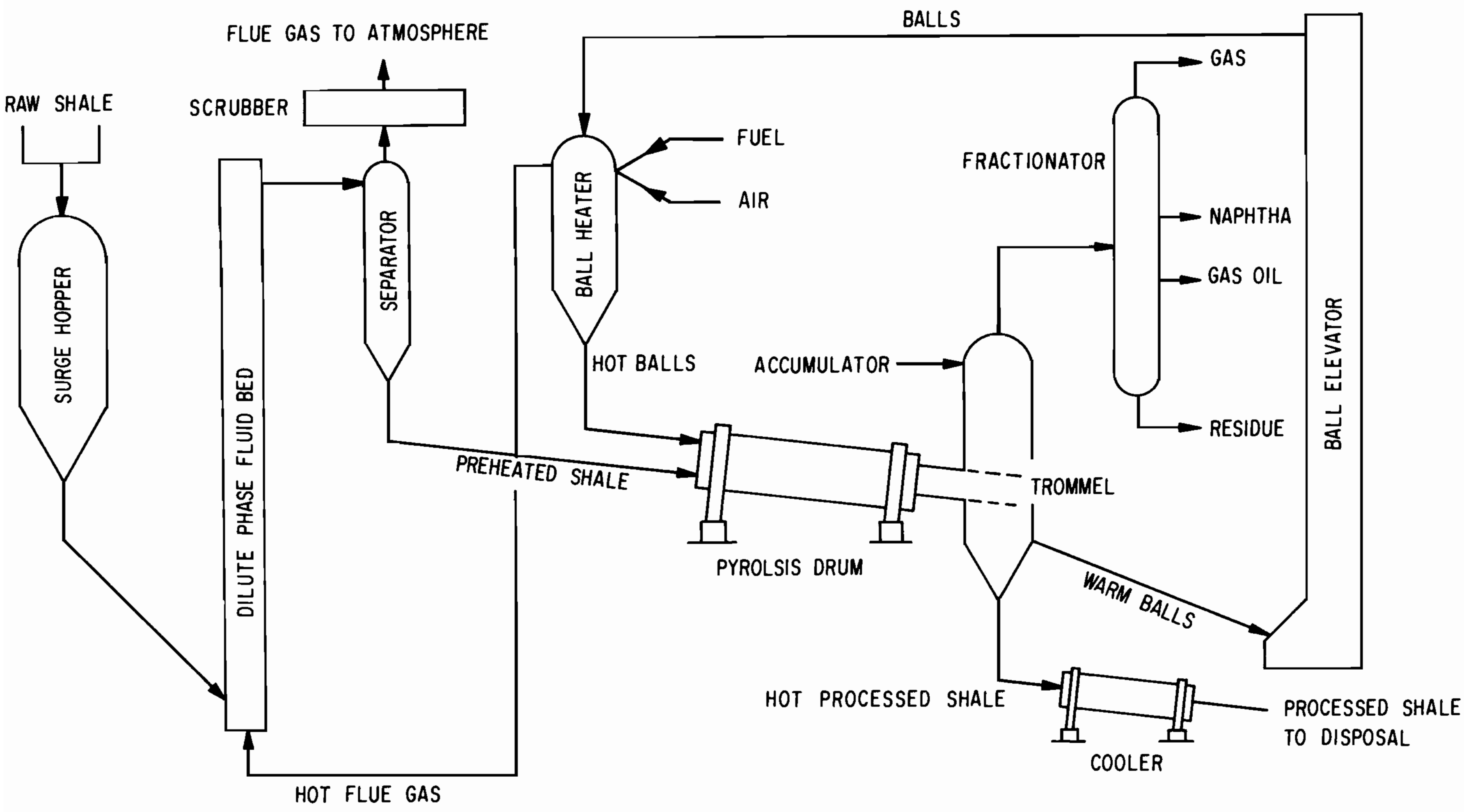

Figure 46-3.--TOSCO retort

diluted by combustion products and nitrogen from air, or by carbon dioxide that results from carbonate decomposition from certain oil shales. This technology is able to function on more finely divided shales than other retorts. It produces a more volatile liquid product, probably as a result of some thermal cracking due to the longer contact times of the product with the heated zone. The Lurgi process is somewhat similar to this process in that both use heated solids to transfer heat to the unretorted shale.

Underground Processing

Because mining and crushing account for a substantial part of the cost of producing shale oil by aboveground retorting, techniques for retorting oil shale in place (in situ) have received attention during the past 20 years. This in situ approach is also attractive for other reasons. It may be applicable to deposits of various thicknesses, grades, and depths of burial that are not readily available with conventional mining and it eliminates the necessity of disposing of large quantities of spent shale.

Two approaches to the development of in situ technology have been taken. One approach, termed "modified in situ," requires that some of the material be mined out to provide void volume and a free surface to facilitate fracturing the oil in place. After fracturing or rubblizing the oil shale, retorting is accomplished in situ. The technique is presently being actively developed in Colorado Green River oil shale by the Occidental Oil Shale Corporation; it is very similar to surface internal combustion retorting. Field tests for this process were started in mid-1972 and results of the tests have been reported by Ridley in 1974 [7], and by Cha and Garrett in 1975 [8]. Modified in situ retorting can be performed in either a horizontal configuration, which is applicable to thin oil shale deposits, or in a vertical configuration, which is more applicable to thick deposits. The Occidental process utilizes the vertical configuration. In addition to in situ recovery of oil, the oil shale that is removed during the mining operation for modified in situ retorting can be retorted on the surface. A variation of "modified in situ" technology could be considered in combination with room and pillar mining. Following shale removal during the mining operation the pillars could be fragmented and shale oil recovered by the in situ method.

The second in situ approach utilizes fracturing techniques to break the shale in place without mining or removal of any oil shale. In situ recovery of hydrocarbon products is then performed. This technique is called "true in situ." Experimental work on this technique is presently being pursued by ERDA's Laramie Energy Research Center [9]. In this technology air is pumped into a fractured oil shale deposit through a well, the air sustaining combustion in the oil shale, and produced shale oil is recovered from recovery wells as a mist and also as liquid from recovery wells.

In both in situ technologies, the kerogen is decomposed and resulting low-molecular-weight decomposition fragments are transported into the region ahead of the combustion zone. During this process great care must be taken to control the process so that burning of the products does not result in poor oil recovery.

Distribution of Liquid and Gaseous Products

During the thermal decomposition of kerogen, liquid and gaseous products are formed together with a carbonaceous residue that remains on the inorganic matrix of the oil shale. The yields of these products are determined by reaction kinetics and are related to reaction temperatures and times. By varying the operating parameters the equilibrium can be shifted to produce, in one case, maximum yields of liquids and in the other case maximum yields of gas. By applying this knowledge to either aboveground or underground processing, gases, liquids, or a combination of the two can be produced. Injecting steam onto hot retorted oil shale can also be used to remove some of the carbonaceous residue that would normally remain. Where retorting is accomplished by using air any gas stream formed would be diluted with nitrogen and, consequently, would have a relatively low heating value. This heating value could be improved by doing the retorting with enriched air or with oxygen.

Gasification of Oil Shale

Most oil shale recovery processes being investigated involve burning some part of the organic material contained in the oil shale to produce sufficient energy to process the remainder. During all of these processes some of the original organic material is converted to gases. The low heating value of the gases normally produced, collection and handling costs, and other problems have combined to prevent any widespread use of these gases.

The volume of gas that would be produced during a commercial-sized in situ oil shale process has been estimated to be in excess of 1×10^9 ft^3 per day. There is an obvious economic advantage to operating in a manner to produce a usable offgas. The ERDA Laramie Energy Research Center is conducting an experimental program to determine the operating variables that would maximize the quantity of gas produced as well as improve its heating value.

A small retort (Fig. 46-4) was assembled and instrumented to conduct this study. Using this equipment a number of experiments were performed to investigate the effects of pressure, oil shale grade, oxygen enrichment, and steam injection on the quantity and heating value of gas produced during forward combustion of oil shale. Studies [10] have shown that injection of sufficient quantities of water along with air, or air enriched with oxygen, will lead to removal of the carbonaceous residue from the retorted shale and produce a gas of high heating value (Figs. 46-5 and 46-6).

During this study the total energy recovery ranged from about 50 to 90 percent of the original organic material. Figure 46-6 shows the part of this energy that is recovered in the gas stream. The conclusions of this gasification study are: (1) production of usable low or medium heating value

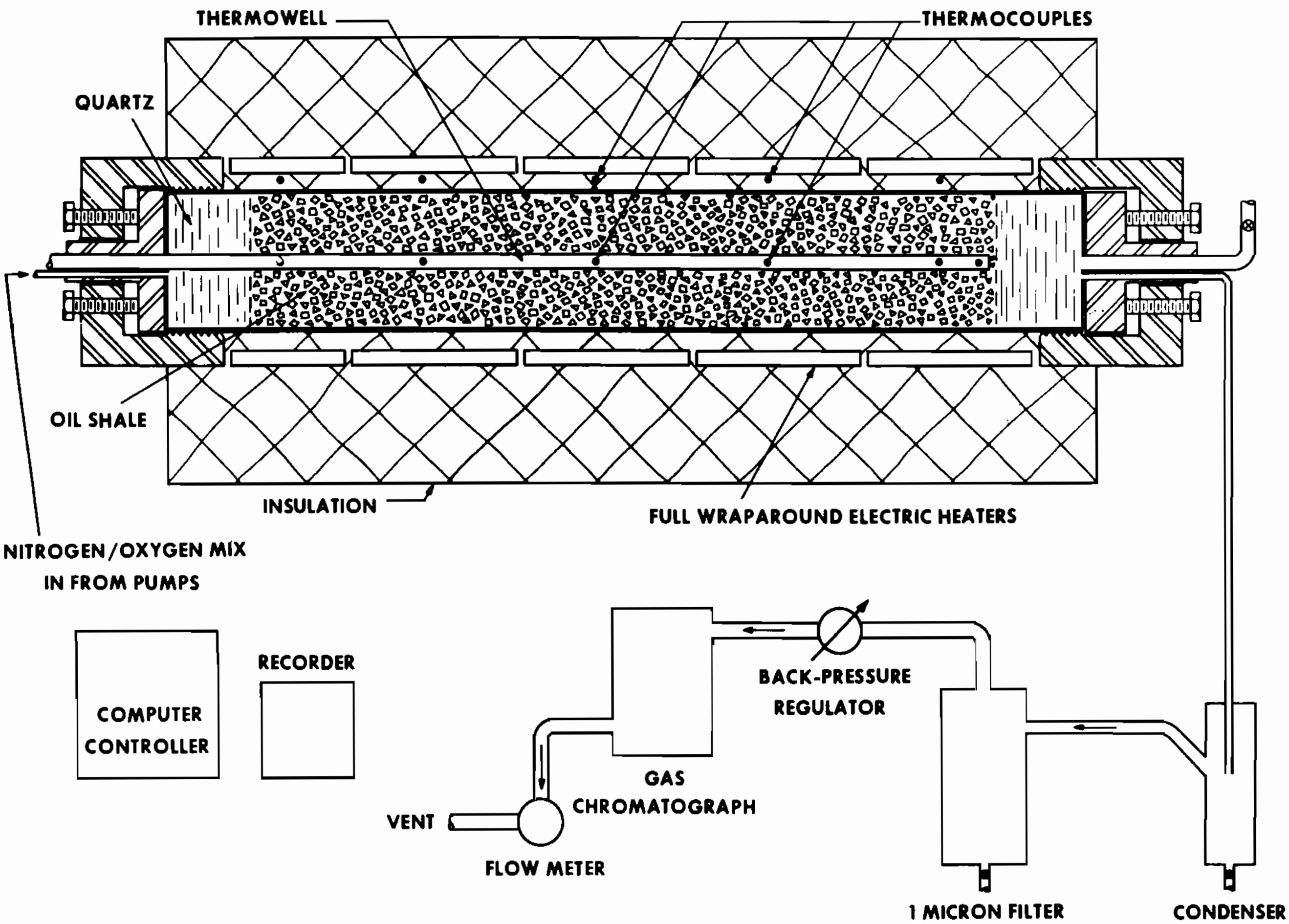

Figure 46-4.--Laboratory oil shale gasification retort

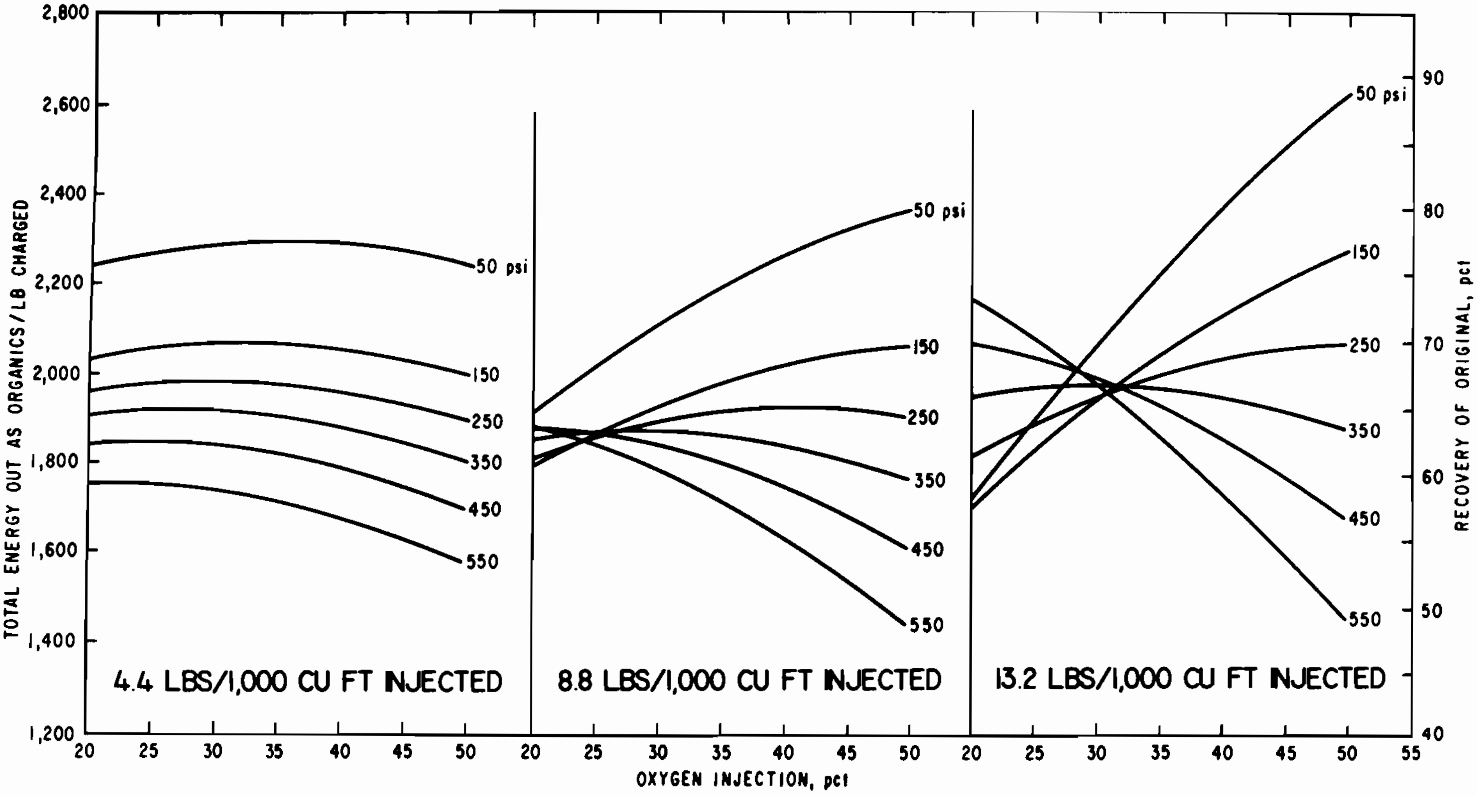

Figure 46-5.--Total energy production using enriched air and water injection

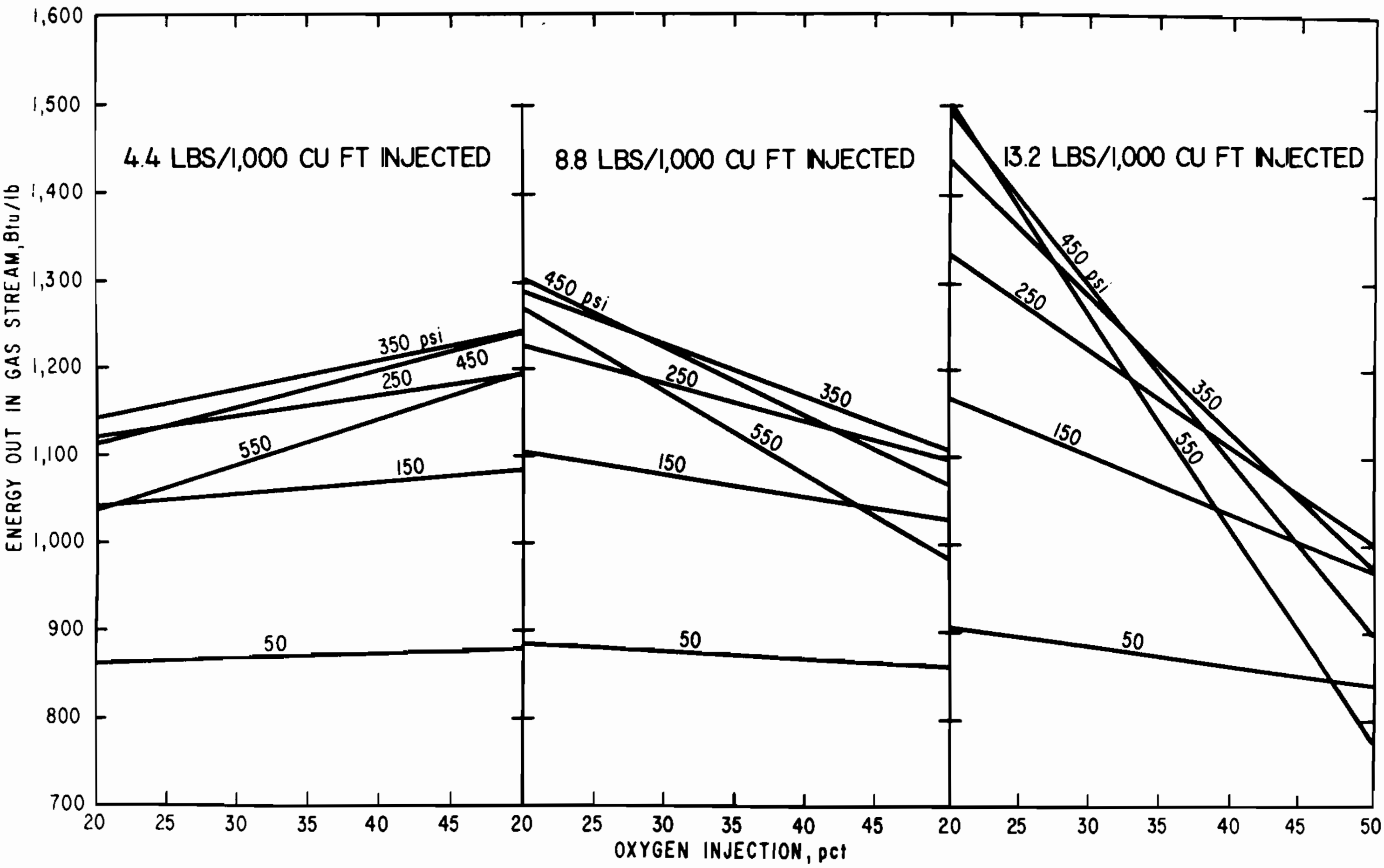

Figure 46-6.--Energy in gas stream using enriched air and water injection

gases during retorting appears feasible at practical levels of control variables; (2) large increases of heating value of the gas stream result from moderate increases of oxygen content in the injected gases; (3) addition of water in controlled amounts with the injection gases during combustion results in increases in oil recovery, increases in heating values of offgases, and large increases in the rate of thermal advance of the reaction zone; and (4) hydrocarbon recovery, as either gas or oil, of up to 84 percent or organic material originally present appears feasible. A complete report of the work on gasification can be found in Jacobson and Burwell, 1976 [11].

SHALE OIL

Shale oils produced from Green River Formation oil shales in conventional aboveground internal combustion retorts have remarkably similar properties. Oil vapors are swept out of such retorts as rapidly as they are formed, the retorting processes producing a high yield of oil (approximately 65 weight percent of the organic matter in the shale). Table 46-1 shows properties of oils produced by retorting Green River oil shale in a gas combustion retort.

TABLE 46-1.--Properties of oil produced by gas combustion retorting of Green River oil shale

Liquid properties	
Specific gravity at 60°/60°F......	0.94
Sulfur...........weight percent..	.7
Nitrogen.........weight percent..	2.2
Carbon...........weight percent..	84.0
Hydrogen.........weight percent..	11.4
Oxygen, by diff...weight percent..	1.7
Distillation at 760 mm	
IBP.........................° F..	407
5 percent rec...............° F..	502
10 percent rec..............° F..	538
20 percent rec..............° F..	601
EP..........................° F..	695
Rec..............volume percent..	37.5
Res..............volume percent..	62.5

The unique combination of molecular structures in the oil often requires the use of several refining steps to produce final products of desired quality. The shale oil contains compounds ranging from completely saturated to completely aromatic, with considerable quantities of compound types. In addition, large concentrations of sulfur, nitrogen, and oxygen compounds are found throughout the boiling range of the oil. Some of these compounds interfere with refining processes. Nitrogen compounds in particular are troublesome in that they limit application of catalytic cracking, a process that would be useful in producing high-octane gasoline components from the straight-chain aliphatics. Some of the unsaturated compounds also are detrimental in both thermal and catalytic processes because they readily form carbonaceous deposits in heaters and on catalyst surfaces. Different retorting schemes, for example those that heat the oil shale by circulating hot solids (indirect heating), subject the retort vapors to additional cracking before the vapors can be condensed. By indirect heating, some of the aliphatic compounds of high molecular weight can be converted to olefins of lower molecular weight for processing by standard polymerization methods. Some aliphatic compounds may be converted to cyclic and aromatic compounds and some of the unstable unsaturated cyclic compounds may be dehydrogenated further to stable aromatic structures. This aromatic oil or its fractions may then be converted to gasoline in a one-step hydrogenation process which, at the same time, removes the undesirable sulfur, nitrogen, and oxygen compounds. Oils produced by in situ retorting methods have properties that seem to lie somewhere between the oils produced in these two aboveground processes.

Some consideration has been given to using shale oil directly as burner fuel. This may be practical where the sulfur content of the shale oils is lower than 1 percent sulfur; however, in areas where concentration of sulfur dioxide in stack gases must be kept low the use of this oil directly as burner fuel may be prohibited. In this case some additional processing would be required to reduce the sulfur content of the oil to meet fuel oil specifications. If this desulfurization is accomplished, the resulting synthetic crude would be too valuable to be used directly as burner fuel because it could also be used as a refinery feedstock.

Thermal Processing of Shale Oil

During the early 1950's, the U.S. Bureau of Mines operated a small thermal cracking refinery in conjunction with retorting research at Anvil Point, near Rifle, Colorado. The motor fuel products produced by this refinery suffered in several respects. Sulfur and nitrogen content of the products was high, storage stability was poor, and the products had a tendency to change color in storage. Many of the undesirable properties of the products were improved by acid treating, but the economics of the overall process were questionable.

During one experiment, reported in January, 1953, asphalt was prepared to surface the roads at the oil shale demonstration plant. Many of those roads are still in use, nearly 25 years later. The experiment was divided into four test periods. The charge stock for three of the test periods was cracked residuum obtained from several crude shale oil recycle cracking operations and the charge stock for the final test was a reduced crude from flash distillation of tank bottoms. Only two products were obtained: A reduced asphalt from the flash chamber bottom and a gas oil from the fractionator bottom reservoir. An insignificant quantity of light material was taken overhead with the water. The products and their properties, resulting from this experiment, are shown in Table 46-2. Based on total crude oil rather than the residuum charge shown in the table, the yield of asphalt would have been about 18.7 volume percent of the total crude. This yield could be increased to perhaps 28 percent or more by recycle cracking of the crude and reduction of the residuum to asphalt. This experiment showed that a satisfactory asphalt-base stock for preparing road oil blends could be obtained from Colorado shale oil by atmospheric reduction of both recycle cracked residuum and reduced crude.

TABLE 46-2.--Asphalt production product yields and properties

	Recycle cracked residuum charge	Heavy gas oil	Asphalt
Yields (dry basis)...........volume percent......	100.0	44.0	54.5
Yields (dry basis)...........weight percent......	100.0	42.0	57.8
Properties			
Gravity........................° A.P.I.......	8.9	15.5	--
Pour point.........................° F.......	75	75	--
Flash, COC.........................° F.......	255	285	--
Viscosity			
S.U.S. @ 130°F.............................	--	76	--
S.U.S. @ 210°F.............................	118	50	--
S.F.S. @ 122°F.............................	134	--	--
Sulfur....................weight percent......	0.71	0.71	0.63
Nitrogen..................weight percent......	2.55	2.43	--
Ramsbottom carbon residue..weight percent......	9.5	0.5	--
Water.....................volume percent......	6.4	--	--
Specific gravity.............................	--	--	1.06
A.S.T.M. penetration @ 77°F....................	--	--	55
Solubility in CCl_4.........weight percent......	--	--	86.92

Catalytic Hydrogenation of Shale Oil

The high percentages of sulfur, nitrogen, and oxygen compounds, estimated at over 60 percent of one shale oil [12], render the raw oil unsuitable for refining to high-quality motor fuel by conventional thermal processing methods. Recycle hydrocracking at 3,000 pounds pressure was shown to produce a high yield of naphtha with low sulfur and nitrogen content, but the pressure greatly exceeded the capacity of ordinary refinery equipment [13]. Once-through hydrogenating-coker distillate fractions at 1,100 and 1,500 pounds pressure [14,15] produced products of poor quality and in lower quantity than were obtained in the 3,000 psi operation.

An investigation was made by Cottingham and Carpenter, 1967 [16] of the hydrocracking of prehydrogenated shale oil. Shale oil was hydrogenated at mild conditions and then hydrocracked at pressures of 1,000 and 1,500 psi, which is in the range of petroleum hydrocracking equipment in general use by the petroleum industry. The conditions for preparation of the prehydrogenated oil are given in Table 46-3. The prehydrogenation reduces the sulfur and nitrogen content of the oil slightly and improves the distillation characteristics by reducing the

TABLE 46-3.--Hydrocracking prehydrogenated shale oil

	Prehydrogenated oil	Hydrocracked oil	
Operating conditions			
Average temp............°F..	601	897	902
Maximum temp............°F..	607	903	905
Pressure..............psi..	1,000	1,000	1,500
H_2 rate..........cu ft/bbl..	2,000	3,000	3,000
H_2 consumed......cu ft/bbl..	320	1,220	1,290
Space velocity....V_o/V_c/hr..	0.5	0.25	0.25
Product yields, weight percent			
Liquid product.............	96.6	74.5	72.2
Catalyst deposit...........	.9	5.5	5.0
Water......................	1.4	.6	.6
Hydrogen sulfide...........	.3	.4	.5
Ammonia....................	.4	2.3	2.3
Gas........................	1.0	18.8	21.6
Product yields, volume percent			
Liquid product.............	98.2	-	-
Naphtha....................	-	46.8	51.5
Gas oil....................	-	32.6	29.1
Recycle oil................	-	3.5	1.9

amount of residuum. These oils were then hydrocracked in a single-pass operation using the conditions shown in Table 46-3. Product properties as functions of conversion are shown in Fig. 46-7 for the 1,000 psi operation. Removing tar bases from the naphtha by acid extraction reduced nitrogen content to low values, too low to be determined by the macro-Kjeldahl method. Because these naphthas have very low octane ratings, reduction of nitrogen is essential so that the naphthas can be upgraded by reforming techniques.

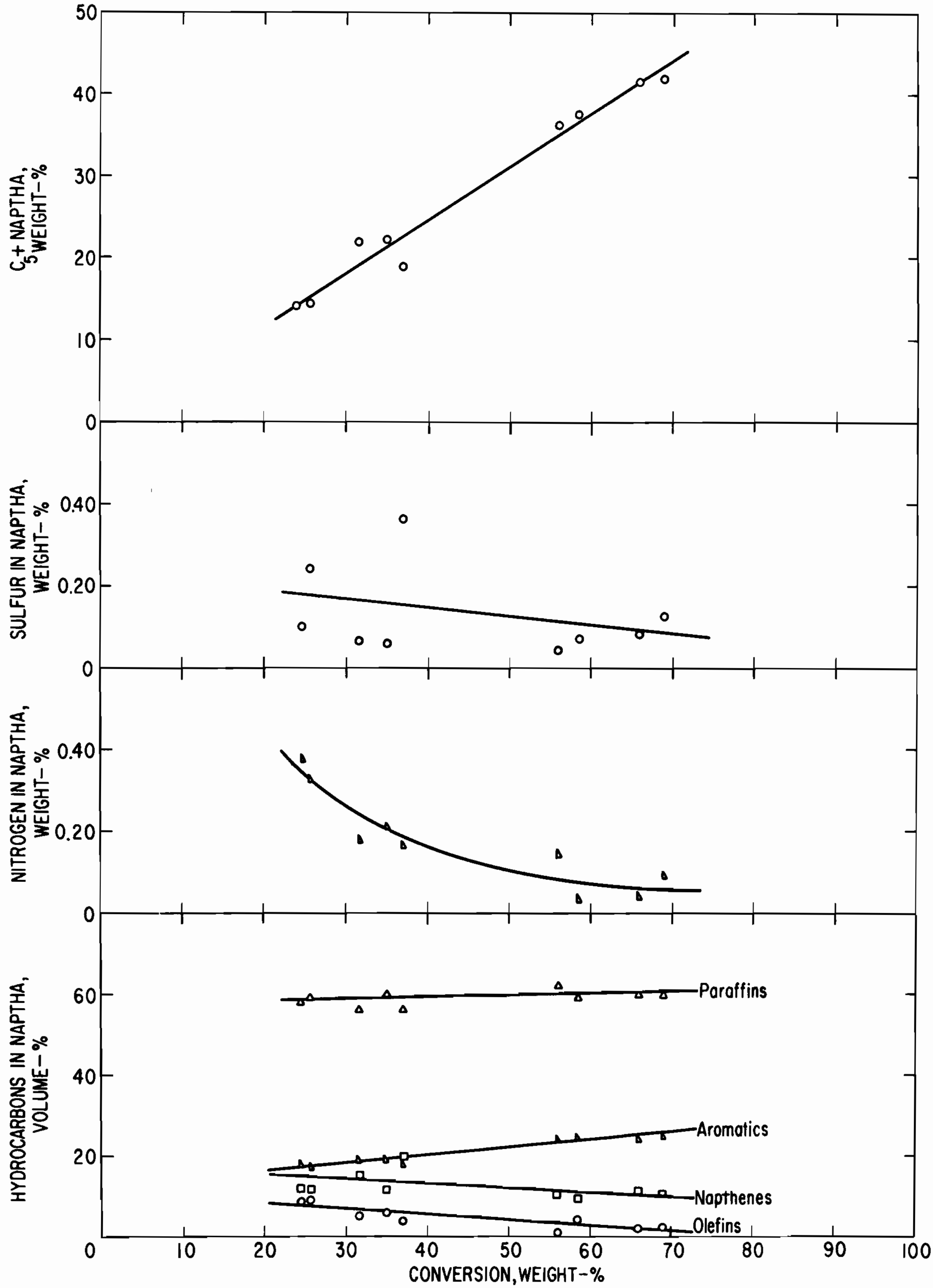

Figure 46-7.--Hydrocracking prehydrogenated shale oil at 1,000 psig

Reforming Shale Oil Naphtha

Shale oil naphthas produced during retorting or by thermal cracking have poor color and oxygen stability. They darken and form large amounts of gum soon after preparation. The instability of these shale oil naphthas and their high contents of nitrogen and sulfur make them poor feedstocks for modern noble-metal catalytic reforming processes. To overcome the problems of upgrading shale oil naphthas, production of stable naphthas by catalytic hydrogenation of crude shale oil or by coking crude shale oil, followed by hydrogenation of the coker distillate, is necessary. An investigation was carried out by Barker and Cottingham, 1976 [17-18] on catalytic reforming of hydrogenated naphtha produced by hydrogenation of crude shale oil. A high quality reformate was obtained by refining a clean naphtha at the highest temperature, 900° F, and the lowest pressure, 200 psig, that was used in the experimental work. Their product had a research octane number of 89, with the yield of reformate about 80 percent of the naphtha charged.

Gasification of Shale Oil

Barker, 1975 [19] and Cottingham and Carpenter, 1967 [20] have shown that it is possible to gasify shale oil catalytically at high temperatures using hydrogen and relatively high pressures. In all of these experiments satisfactory yields of gas containing 70 to 75 percent methane were obtained using relatively large amounts of hydrogen. Economic feasibility of this type of operation is questionable because the best feedstocks for gasification are the light hydrocarbons which are in demand for motor fuels or motor fuel production.

CONCLUSIONS

Oil shale development in the United States has largely focused on production of substitutes for petroleum and natural gas. Only minor attention has been paid to multiple uses of the oil shale directly or for the inorganic portion of the shale. Byproducts, such as asphalt, have also received minor attention.

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CHAPTER 47

GLOBAL OIL-SHALE RESOURCES AND COSTS

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OIL-SHALE RESOURCES

INTRODUCTION

Many estimates have been made of world energy stored in organic-rich rocks, including oil shales. One of the first appraisals was by Cadman [1], later followed by Duncan and Swanson [2], United Nations [3], Burger [4], and Matveyev [5]. Duncan and Swanson built on the base supplied by Cadman mainly adding additional information on the shale oil resources of the United States. The United Nations appraisal utilized with slight modification the basic material furnished by Duncan and Swanson. Burger and Matveyev used the United Nations appraisal and incorporated information from Schlatter [6], Padula [7], and others presented at the first United Nations Symposium on the development and utilization of oil shale, held in Tallinn, Estonia, USSR in 1968.

Types of Appraisal

Past estimates of world oil-shale resources have been closely associated with estimates of organic-rich shales. Organic-rich shale has been defined as shale containing more

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than 5 percent organic matter and estimates have been based on the probable percent of organic-rich rocks in the total volume of sedimentary rocks in the earth's crust [2]. Unfortunately for the purpose of evaluating the liquefaction possibilities of organic rocks the organic content is not directly relatable to the amount of extractable oil. The conversion percent ranges from a low of 26 in the Kvarntorp organic shales of Sweden to a high of 71 in the Mae Sot deposits of Thailand [4]. The percent of conversion, however, is directly related to the original organic material from which the oil shale was derived. A higher percent of sapropelic matter than humic matter converts to oil upon destructive distillation. Sapropelic organic matter is derived from spores, pollens, resins, and algae whereas humic matter is derived from cellulose, lignin, and other woody parts of plants.

Oil shale is defined, for the purpose of this report, as a fine-grained sedimentary rock containing organic matter but little or no free oil; it will yield little oil through the use of petroleum solvents but will yield considerable quantities of oil upon being subjected to pyrolysis.

Energy required to retort oil shale varies with the mineral composition of the rock. A recent study [9] indicates that with present-day technology, more energy is required to retort Green River oil shale yielding less than eight gallons of oil per ton than is derived from the products recovered. The same study considers only oil shale zones thicker than 10 feet for resource appraisal purposes. Some previous estimates have used 10 gallons of oil per ton as the minimum grade for resource appraisal [4]. Deposits of oil shale thinner than 10 feet and averaging less than 10 gallons of oil per ton may be exploited if they are associated with commercial coal beds or contain potentially valuable minerals that may be extracted as byproducts. However, 10 feet of shale averaging 10 gallons of oil per ton probably is the minimum thickness and grade to be considered in resource estimates.

Resource Estimates

Cadman [1] listed characteristics of many of the oil shale deposits of the world, including in-place resource estimates of some of the better known deposits. Duncan and Swanson [2] made the first attempt at compilation of resources on a continent by continent basis. Other compilations [4, 5] have made only slight modifications of these initial estimates. Table 47-1 depicts the known resources in the world in deposits yielding more than 10 gallons of oil per ton.

TABLE 47-1.--Known shale oil resources of the world land areas (10^9 barrels)

(Modified from Duncan and Swanson [2])

Continents	Recoverable under present conditions	Marginal and submarginal
Africa	10	90
Asia	24	84
Australia and New Zealand		1
Europe	30	46
North America	80	2,120
South America	50	750
	190	3,091

Known deposits, at least in part, have been sampled, mapped, and assayed. The oil shales that are being mined or may be mined in the near future under present day economics are considered to be recoverable. Lower grade oil shales or higher grade oil shales that are more difficult to mine are included in the marginal and submarginal resource category.

Reliability of Estimates

The deposits of the Leningrad and Estonian areas of the USSR and the deposits of the Green River Formation in the Rocky

Mountain area of the USA probably have been best explored of the major oil shale deposits of the world. Exploration associated with active mining operations in the USSR has delineated a resource of 11.3 x 10^9 tons [10] and assays of approximately 400 cores drilled through the shale have indicated a resource potential of 1.8 x 10^{12} barrels of oil contained in the Green River Formation of the USA [11]. Figure 47-1 illustrates the change in the magnitude of the resource base in the Piceance Creek basin, Colorado, between the years of 1923 and 1964 because of the increasing knowledge of the deposit based on geologic mapping, stratigraphic studies, and shale oil assays. Shale oil resource estimates of 40 x 10^9 barrels in 1923 [12] were based on a few assays from scattered surface samples and reconnaissance mapping. An intermediate resource estimate of approximately 500 x 10^9 barrels of oil in 1948 [13] was based on assays of a few cores and samples from wells drilled for oil and gas and detailed geologic mapping of small areas. The most recent estimate in 1964 [14] of 1.2 x 10^{12} barrels of oil was derived from assays of samples from numerous cores and wells drilled for oil and gas in conjunction with detailed mapping of large areas and stratigraphic studies utilizing abundant surface and subsurface information.

Unfortunately most oil shale deposits have not been subjected to the same detailed evaluation as the Green River deposits in the USA or the Kukersite deposits of the USSR. Some of the larger deposits of the world, such as the Irati shales of Brazil, have been intensively explored in small areas prospectively valuable for exploitation, however the major parts of the deposits have not been evaluated. Many of the countries containing oil shale deposits have analyzed some of them but offer no information on the thickness, character, or lateral extent of the shale. Oil shales are found in varied depositional environments and in rocks of many ages and yet no oil shale is reported from a few countries, presumably because there has been no effort to ascertain whether or not oil shales are present. On such country, India, at present reports no occurrence of oil shale yet it is almost inconceivable that such a large part of the earth's crust containing rocks formed in many

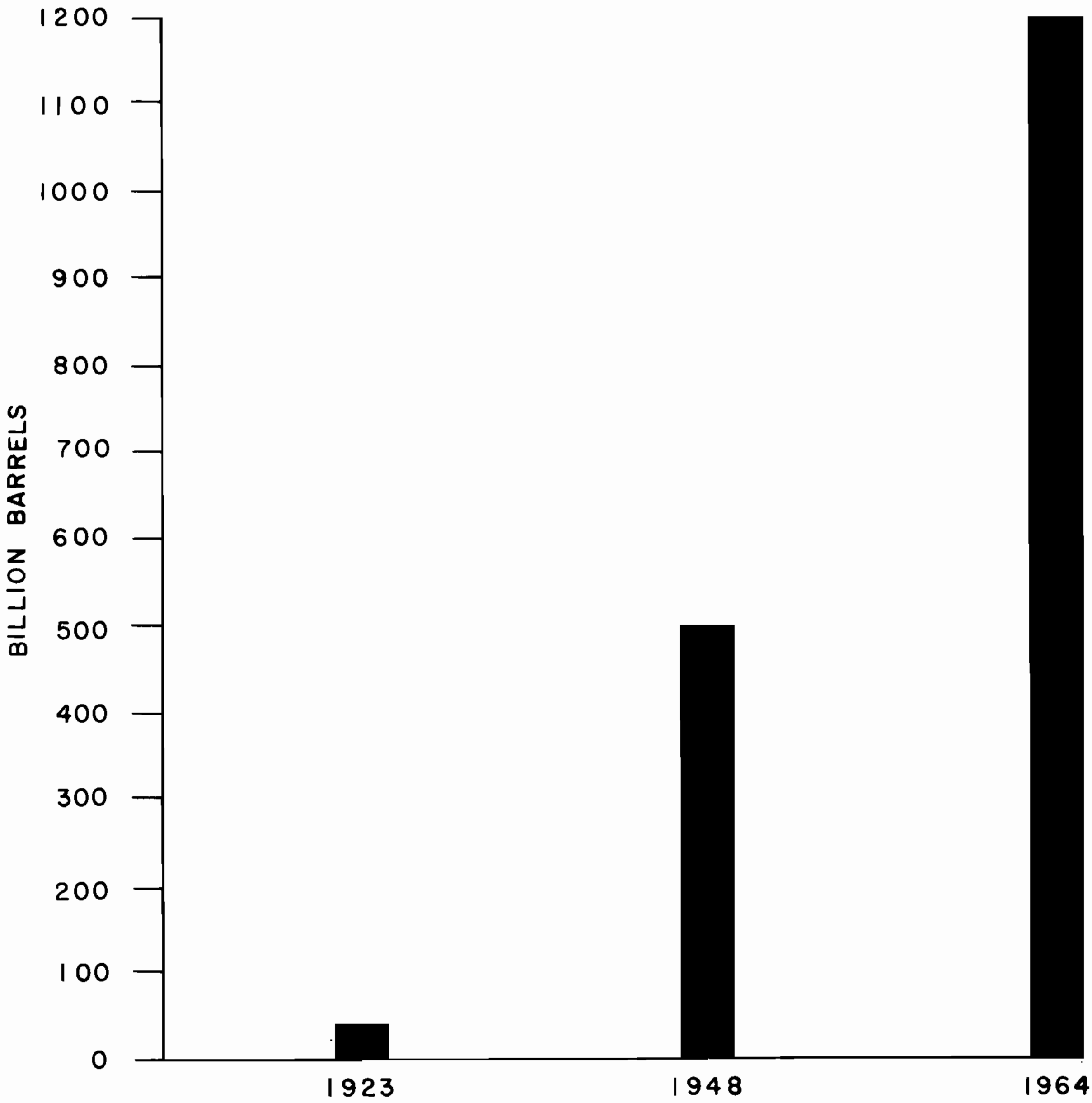

Figure 47-1.--Estimates of in-place oil shale resources of the Piceance Creek basin, Colorado, USA

differing environments of deposition, contains none. Future exploratory efforts will undoubtedly delineate as yet unrecognized oil shale deposits in India and other areas of the world.

A compilation of global oil shale resources is hampered by a lack of common terminology for reporting both assay value and resource potential of the deposits. Papers presented at the 1968 United Nations Symposium on the development and utilization of oil shale resources at Tallinn, Estonia, reported the quantity of oil in the shale as (1) U.S. gallons per ton, (2) imperial gallons per tonne, (3) litres per ton, (4) litres per m^3, (5) weight-percent oil, and (6) volume-percent oil. Oil shale resources have been reported in these same papers as (1) barrels, (2) tons of shale, (3) tonnes of shale, (4) tonnes of oil, and (5) m^3 of oil.

The standard analytical method for determining the oil content of shale is the modified Fischer assay. This method reports the oil content as weight percent and U.S. gallons per ton. Most of the oil shale values in the United States are reported as gallons per ton and in the rest of the world generally as weight-percent oil. Conversion from one to the other is accomplished by multiplying weight percent or dividing gallons per ton by 2.66. Figure 47-2 is a comparison of four oil shale deposits plotted graphically in gallons per ton. Initially the oil content of the Estonian and Brazilian shales was reported in weight percent but were converted to gallons per ton for ease of graphic comparison. This shows the value of reporting oil content using common terminology. If percent is used to designate the assay value of the shale, care should be taken to specifically state weight-percent oil to assure that there is no misconception that the figures presented are weight-percent organic or oil-percent by volume, terms that are commonly used to indicate the value of shale.

Oil reserves and resources are usually reported as barrels of oil in the United States and tonnes of oil in many other countries of the world. Oil shale resources have been reported as barrels, tonnes of shale, tonnes of oil, and m^3 of oil. Barrels may be converted to tonnes by dividing by eight and to

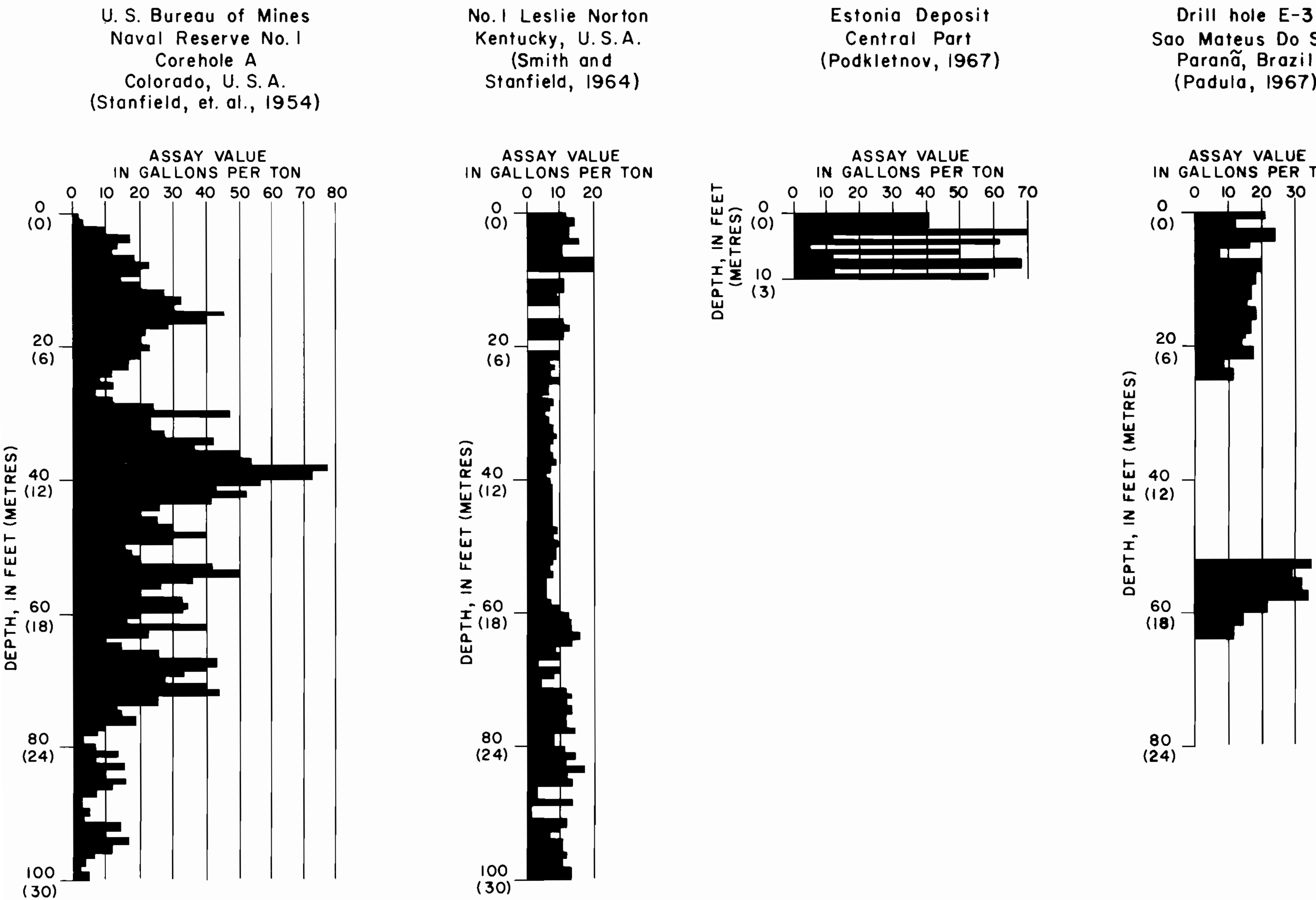

Figure 47-2.--Histograms showing thickness and value of Green River, Chattanooga, Estonian, and Brazilian shales

m^3 by multiplying by 0.159. Frequently oil shale resources are reported in tonnes with no indication whether the measure of the resource is of the rock or of the contained oil. Similarly resources reported in m^3, unless specifically designated, may represent either the amount of the rock or the contained shale oil.

Resource Size Categories

Oil shale industries active just before, during, and just after World War II in Scotland [18] and Sweden [19] produced as little as 1,525 tonnes of shale per day with as little as 14 tonnes per day throughput per retort. China, in recent years, has produced as much as 87×10^3 barrels of oil per day, mostly from the Fushun deposits in Manchuria [20]. No information is available on the individual retort capacities. As recently as 1967, 16.1×10^6 tons of shale a year were mined in Estonia, USSR, and it was estimated that production would increase to as much as 25.4×10^6 tons by 1975, or approximately 70×10^3 tons a day [21]. The minimum size commercial plant to be constructed to process the Green River oil shales of the USA is estimated to produce 50,000 barrels of oil per day with a throughput of approximately 66×10^3 tons of shale. The minimum size retort would process 7 to 10×10^3 tons of shale per day. The earlier oil shale industries in Scotland and Sweden and the present ones in Russia are not as capital intensive as the proposed industry in the USA and therefore will require a shorter period of time and smaller available resource to amortize the initial investment.

Because of the varying minimum resource requirements for oil shale industries the resource estimates by country will be presented in three categories: small (less than 100×10^6 barrels); moderate (more than 100×10^6 but less than 1×10^9 barrels); and large (more than 1×10^9 barrels).

The resource estimates quoted from Burger [4] are from shale deposits that average more than 10 gallons of oil per ton, however those from Matveyev [5] were listed without regard

TABLE 47-2.--Shale oil resources by country

	Small resources [4]	
	10^6 m^3	10^6 barrels
Chile	3	18.9
Israel	3	18.9
Jordan	7	44.0
Tasmania	3	18.9
Turkey	3	18.9
	10^6 tons	10^6 barrels [5]
Austria	1	8
Malagasy	4	32
Poland	6	48
	Medium resources [4]	
	10^6 m^3	10^6 barrels
South Africa	20	125.8
Argentina	60	377.4
Australia	40	251.6
Bulgaria	20	125.8
Spain	40	251.6
France	70	440.3
Luxembourg	110	691.9
New Zealand	40	251.6
Thailand	130	817.7
Yugoslavia	30	188.7
	10^6 tons	10^6 barrels [5]
Morocco	74	592
	Large resources [4]	
	10^6 m^3	10^6 barrels
West Germany	320	2,012.8
Burma	320	2,012.8
Brazil	127,320	800,842.8
Canada	7,000	44,030.0
Peoples Republic of China	4,430	27,864.7
Zaire Kinshasa	16,000	100,640.0
USA	250,000	2,000,220.0
Great Britain	160	1,006.4
Italy (Sicily)	5,600	35,224.0
Sweden	400	2,516.0
USSR	17,900	112,591.0

to average value. In addition to the shale-oil resources listed on Table 47-2 there are reported and possible occurrences of deposits that are unappraised [3].

Current Appraisal Activity

There is much current exploratory activity in oil shale. A press release dated February 3, 1976 by Southern Pacific Petroleum reported a newly delineated oil shale deposit in Australia that contains 1×10^9 tons of shale averaging approximately 20 gallons of oil per ton. Exploratory drilling in New Zealand has changed the status of the Nevis oil shale deposit from one that was prospectively valuable to one of little commercial interest [22]. In addition to these areas, exploratory drilling has been conducted along and near the outcrop of the Liassic shales along the northeast rim of the Paris Basin, the Mae Sot oil shale in Thailand, and one or more of the oil shale deposits in Morocco. Information on the results of exploration in these three areas is not readily available.

Some oil-shale areas, because of the thickness and richness of the shale, have a much greater resource potential than an oil-producing area of equal size. Figure 47-3 shows the comparison in size of oil shale lease tract C-a in Colorado with the offshore oil producing area in the Gulf of Mexico. The amount of recoverable oil in each area is estimated to be approximately 6×10^9 barrels, assuming that the mined and processed oil shale averages 25 gallons of oil per ton and that recovery is by open pit mining.

SHALE-OIL COSTS

The comparison cited in the previous section appears to be very much in favor of extraction of oil from oil shale; however, economic considerations favor exploration and development of conventional crude oil. A barrel of oil from Colorado oil shale averaging about 35 gallons of oil per ton is estimated to cost approximately $10, in contrast to about $6 for a barrel of Gulf Coast offshore oil. A large front-end capital investment of

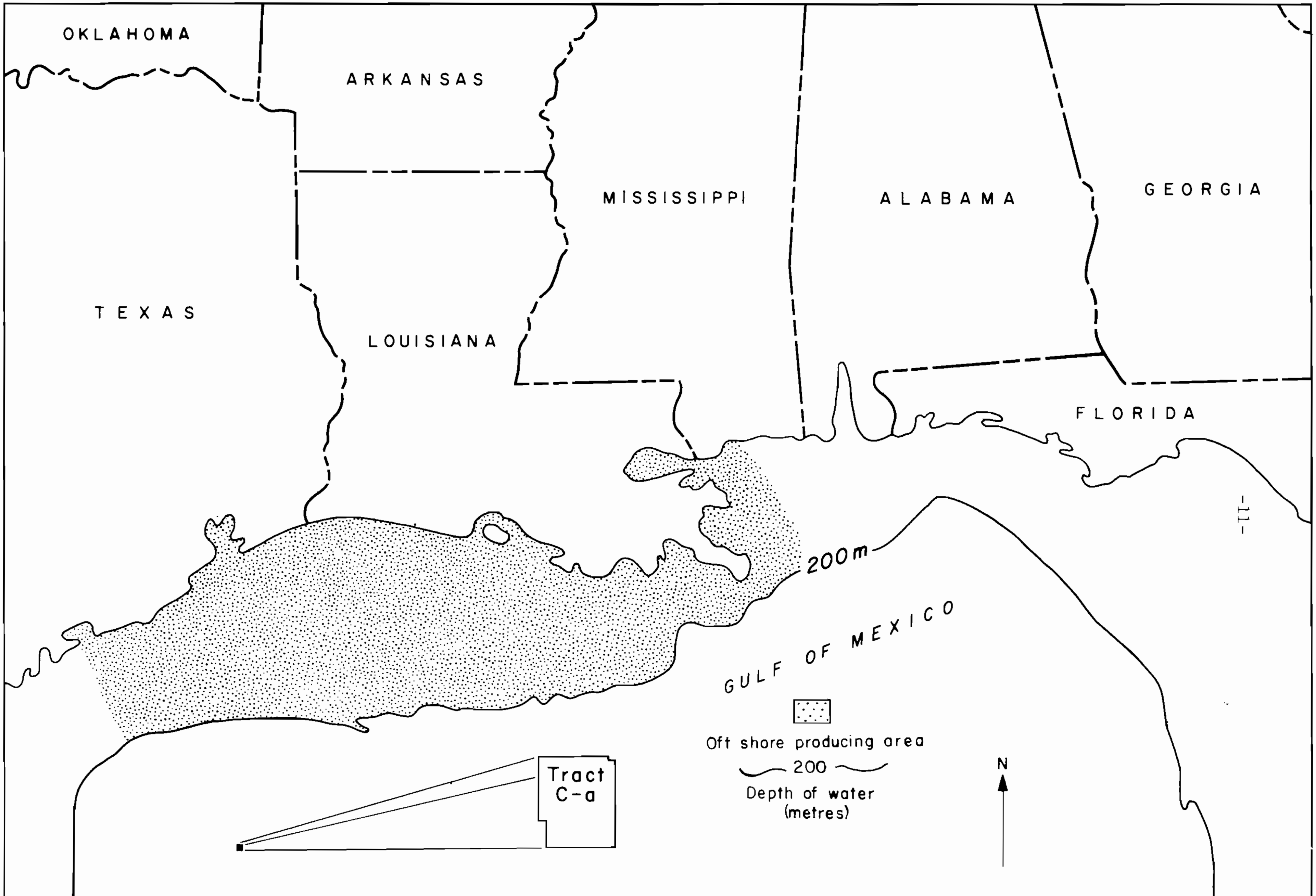

Figure 47-3.--Comparison of areas encompassing equal amounts of recoverable oil; oil shale lease tract, Colorado, and offshore production Gulf of Mexico

approximately $\$1 \times 10^9$ for a 50 thousand barrel a day industry necessitates a period of 20 years for amortization of the initial investment and therefore a recoverable reserve of 360×10^6 barrels. These data, cited in a recent news release by Colony Development, were based on September 1975 dollars and were reported together with the following table.

TABLE 47-3.--Rate of return for specified selling price of shale oil

DCF rate of return (percent)	Required oil selling price (dollars per barrel)
10	14.20
13	18.30
15	21.70

Occidental Oil Company has been engaged in a pilot study of a modified in situ recovery method for the Green River oil shales of Colorado. At present the company is engaged in retorting its first commercial-sized room. Although the method of in situ oil recovery entails mining approximately 20 percent of the shale, this involves no surface retorting and therefore considerably less initial capital expense. Occidental claims that the cost of oil produced from oil shale utilizing this process is competitive with domestically produced crude oil, however no hard data have been made available to verify this claim.

Figures have been published on the cost of producing shale oil in Sweden and Scotland but these figures are for the period of time just prior to the cessation of operations in the late 1960's and are no longer valid. No costs are available for oil shale operations in the only two countries now engaged in production, the USSR and China.

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CHAPTER 48

RESEARCH IN BITUMINOUS SHALE IN FRANCE

A. Combaz[1] and J. Goni[2]

INTRODUCTION

History

The oil shale industry, started in Europe in the early 19th century, was discontinued in our country after World War II; it was eliminated by the competition of low-cost crude oil. However, with the recent increases in crude rates and the threat of too-high dependence on outside sources of energy, a group of French companies, governmental and private, reconsidered the problem of oil shale exploitation (Fig. 48-1).

The "Groupe d'Etudes des Roches bitumineuses" (GERB) (Oil Shale Survey Group), set up in late 1973, is made up of:

- Bureau de Recherches géologiques et minères (BRGM)
- Charbonnages de France (CdF)
- Compagnie française des pétroles (CFP)
- Elf/Aquitaine
- Institut français de pétrole (IFP)

During the 19th and early 20th centuries, oil shale was exploited on a small scale on sites with limited reserves. This means that a new technology has to be devised for present-day exploitation. Moreover, no exhaustive inventory of oil

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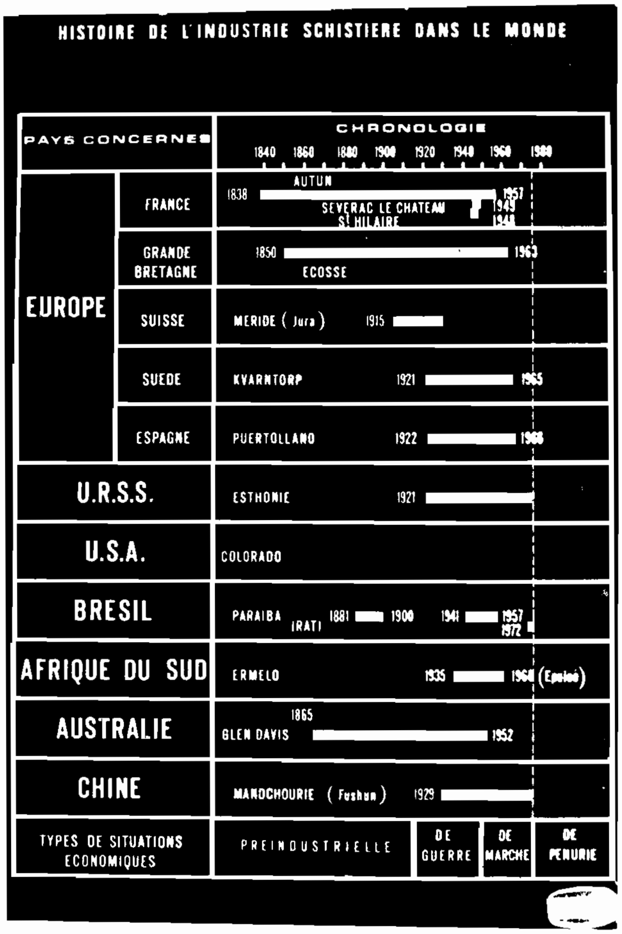

Figure 48-1.--Past European shale production, compared with other countries. The only countries with bituminous shale mining activity at present are China (Manchuria), the USSR (Estonia), and Brazil, which has reached the pilot-plant stage.

shale reserves has been drawn up in France or in other Western Europe countries.

GEOLOGICAL COVERAGE OF BITUMINOUS ROCKS IN FRANCE (INCLUDING TOARCIAN SHALE)

Many deposits or indications of bituminous rocks (shale and limestone) are known in France. The age of the deposits varies and their economic value differs (Fig. 48-2).

The oldest worthwhile deposits are of Carboniferous age and are generally associated with coal fields. They are located in Normandy (Littry, Le Plesis); in the Vendée (Faymoreau: small deposits of relatively high grade); in the Massif Central (Decazeville and Crujols in the Southwest; Blanzy and Machine in the Northeast); in the Maures (Fréjus: small, rich deposits, practically exhausted); and in the basins of Le Nord, Lorraine, Ronchamp (Vosges, Saint-Etienne).

Taken overall, the Carboniferous oil shale reserves seem quite substantial and relatively high grades have been discovered; however these deposits cannot generally be exploited independently of the coal with which they are closely linked.

The deposits of Permian oil shale are quite considerable. They contain, after those of the lower Toarcian stage, the main resources in France of shale oil. The most noteworthy basins are located in the Massif Central: Autun, the Aumance, Lodève, Bertholène, Gages, Saint-Affrique. The deposits are often thick but the oil content somewhat irregular (approximately 200 km^2), 10 m useful thickness, content: 60 to 110 liters of oil per tonne). Only the Autun deposit has undergone sustained industrial exploitation and this ceased more than 12 years ago. The minimum reserves still exploitable have been estimated recently at 30 x 10^6 tonnes, but are probably a good deal more than 100 x 10^6 tonnes.

Apart from a few indications found in the Hettangien and the Sinemurien stages to the East of the Paris basin, the "cardboard" shale of the lower (and sometimes middle) Toarcian stage form the main French resource of oil shale. These stages occupy the greater part of the Paris basin, with the exception

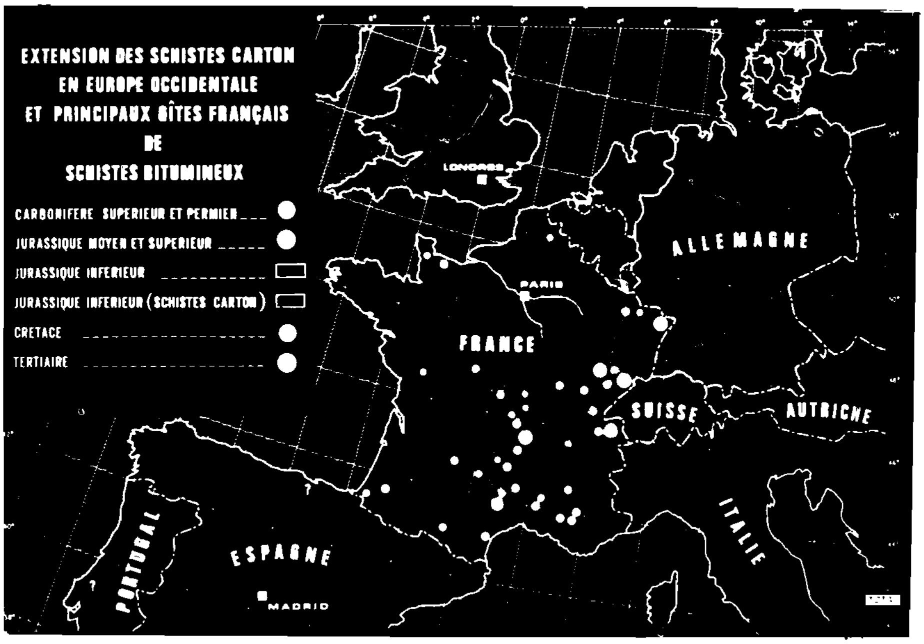

Figure 48-2.--"Cardboard" schist extensive in Western Europe and main French bituminous shale deposits. The major "old" deposits are Carboniferous but Permian deposits are extensive. Together with those of the lower Toarcean, they form the main French resources of shale oil.

of the Southwest, but more often than not they are buried at considerable depths. In the Northeast, East, and Southeast, they outcrop along a strip approximately 250 km in extent, and would seem accessible, using opencast techniques, across a width of approximately 2 km. The formation varies between 2 and 60 m in thickness with an average of 20 m. Grades are also very variable (30 to 60 litres of oil per tonne) and in places may exceed 100 litres of oil per tonne, or even more.

Within the upper Jurassic Kimmeridgian stage and the Lower Cretaceous Barremian stage, worthwhile deposits exist in the Ain (exploitation in progress at Orbagnoux and Seysse: oil content around 60 to 100 litres of oil per tonne). Worthwhile signs have also been found in the Lot and the Dordogne (Kimmeridgian).

In the Upper Cretaceous stage, there is the Vagnas deposit (Ardèche) which has a high oil content but is limited in extent and extremely fractured.

Oil shale deposits of Tertiary age are very minor and scattered: Massif Central (Menet: small rich deposits practically exhausted); Alsace (Froide-Fontaine); and Provence (Manosque, Forcalquier). Tertiary oil-bearing limestones form deposits of minor extent but are often rich enough for active exploitation even today (Pont-du-Chateau in Limagne; Alès region) for road products. Other deposits formerly exploited or known are located in Alsace (Lobsann), Aude (Malvezy), and, above all, in Provence (Manosque, Forcalquier, and Reillanne Basins).

The Toarcian Stage

The largest reserves, both in France and in Western Europe (Germany, Luxembourg) are located in the lower Toarcian shale (Fig. 48-3). These are found in many parts of France: Eastern border and probably southern Paris Basin, Southern Vosges region, Jura, Western edge of Bresse, and Causses. They have never been systematically listed; the only two mines (Crevenay, Severac-le Chateau) are nothing more than local workings.

At depth, these same shales are to be found under most of the Paris Basin but they could only be exploited by means of in situ mining techniques.

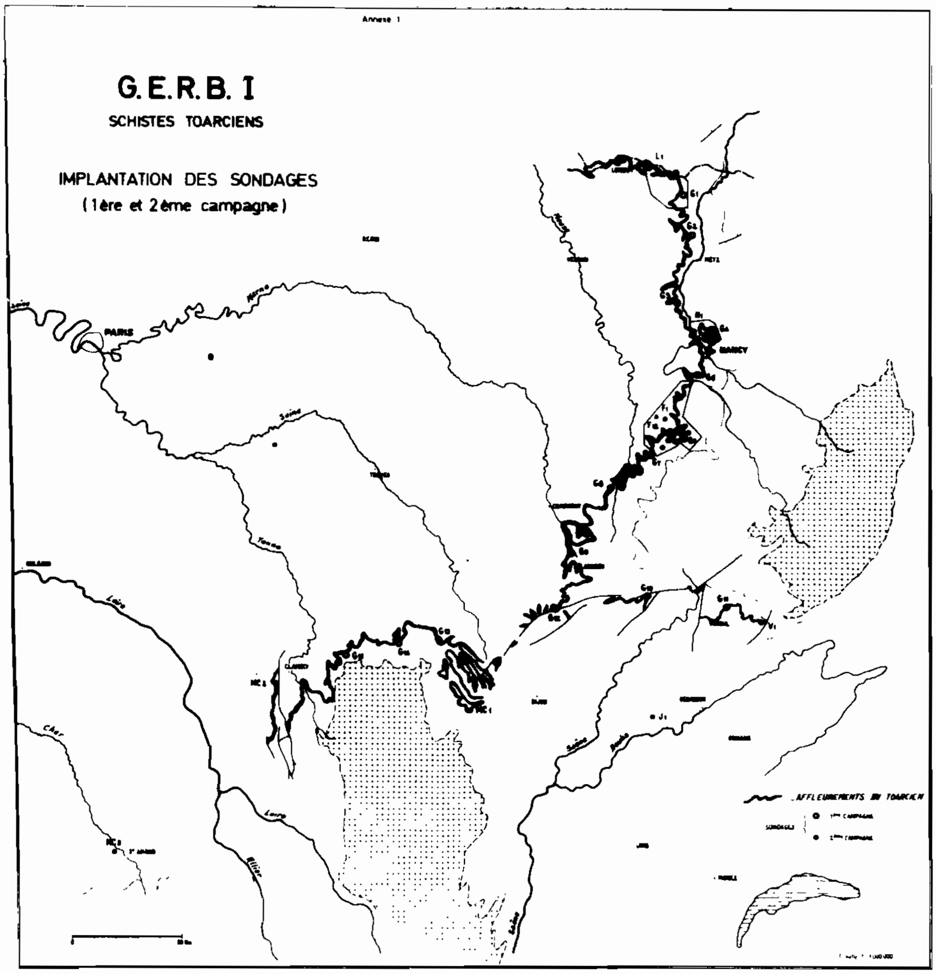

Figure 48-3.--Outcrops of Toarcean bituminous shales in the eastern part of the Paris basin. These shales are present at great depth over most of the basin.

The rarity of outcrops and the risks of surface alteration mean that small core samples are to be used as the basis for analyzing the Toarcian shales. These will extend from the Luxembourg border to Morvan, along the outcrop line of the formation (Figs. 48-4 and 48-5). Borings approximately 60 m deep and approximately 10 km apart will provide a better knowledge of the regional geology and enable the distribution of organic matter to be studied. This data will be checked by borings approximately 10 m in depth, basically concerning the bottom of the formation assumed to be the richest. The entire set of borings will be correlated using gamma-ray techniques (logging diagraphics).

In order to decide whether in situ mining techniques may be considered, air injectivity tests will be carried out in a supplementary borehole; this will be drilled close to an existing boring, so that air circulation tests can be carried out between the two.

THE PROGRAMME

1973 - 1975 Programme - GERB - 1

The following objectives were reached with the 1973-1975 programme:

- Reconnaissance and assessment of shale reserves in the lower Toarcian stage of the eastern edge of the Paris Basin, with localization of a site suitable for large scale opencast exploitation. Tests allowed analysis of these shales so as to determine their content in organic matter, oil yield, characteristics of the oil, and main component of the central matrix;
- Preliminary data on shale transmissivity properties were obtained on one of the wells for subsequent in situ exploitation;
- Technological knowledge was acquired with a general survey on present-day shale processing (U.S., Brazil).

Sampling Campaign By Continuous Core Sampling Of The Formation

A series of 30 borings to a depth of 50 or 60 m will be made in the neighborhood of outcrops from the Luxembourg border

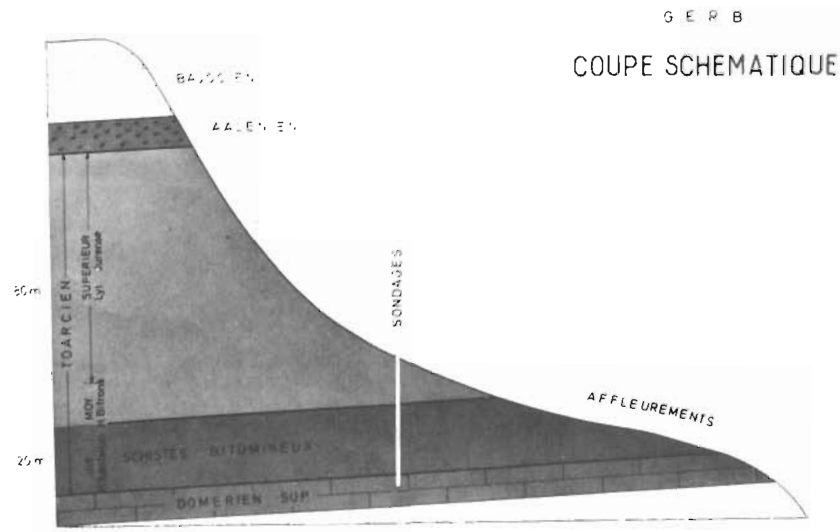

Figure 48-4.--Schematic geological section pointing out stratigraphical relationships between bituminous shale layer (lower Toarcean) and underlying and overlying strata (upper Domerean and middle and upper Toarcean)

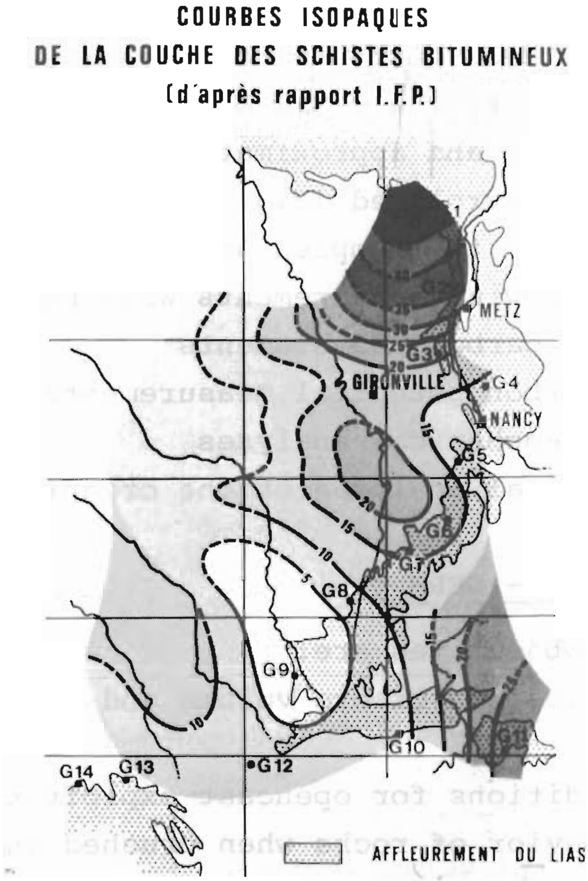

Figure 48-5.--Equal thickness curves of Toarcean bituminous shale layer

as far as Morvan, as well as in the Southern Vosges area (Fig. 48-6).

A series of 50 borings to a depth of 10 to 15 m will enable the extent of the deposits to be confirmed in the most favorable areas (Fig. 48-7).

Laboratory Tests

The purpose of these tests is to determine first of all the main parameters affecting the yield of the shale (content and type of organic matter) and approximate determination of the fraction which can be pyrolysed (Fig. 48-8) and secondly, the mineralogical nature of the samples and their metal content. To this end, the following measurements will be taken:

- 3,000 organic carbon measurements
- 1,000 hydrocarbon potential measurements (Fischer assay)
- 300 mineral geochemical analyses
- 50 petrographical analyses of the organic matter.

1976 - 1977 Programme - GERB II

The principal objectives are:

- detailed evaluation of ore volume and obtaining permit areas
- studying conditions for opencast exploitation
- studying behavior of rocks when crushed and ground
- studying optimum pyrolysis conditions in the laboratory
- testing retorting techniques (at pilot plant level) with existing process (Lurgi process)
- upgrading shale oil and gas obtained in the laboratory and in the pilot plant
- testing direct combustion of shales
- testing oxidation for preparing chemical feedstocks
- preliminary testing for in situ processing of shale
- preliminary survey on upgrading the mineral structure.

Special attention is given in the GERB II project to shale mining methods, geotechnical and hydrogeological problems, analysis of the stability of underground and opencast workings

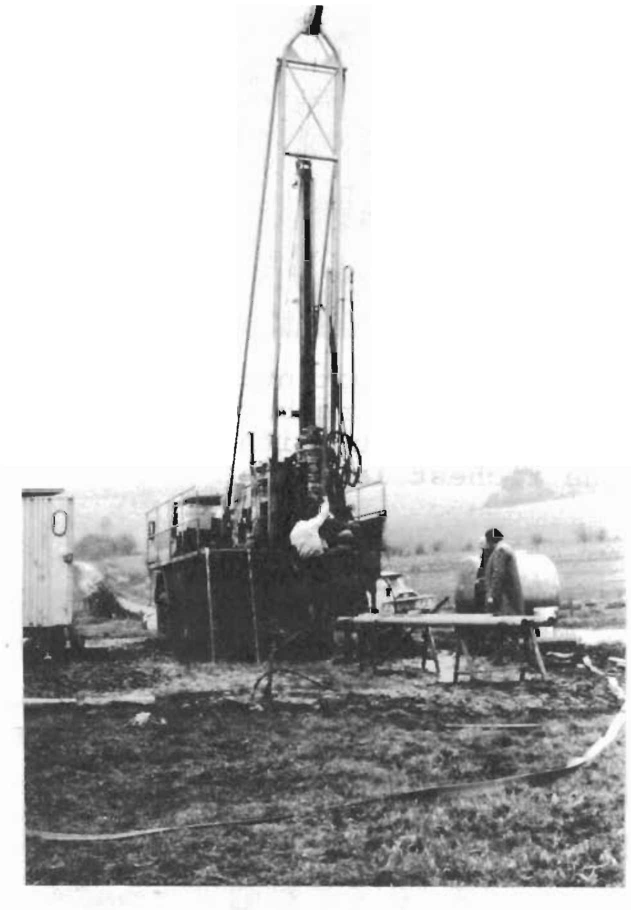

Figure 48-6.--Reconnaissance drilling for the determination of shale layer thickness and the removal of a continuous core of undisturbed samples for examination

Figure 48-7.--To cope with potential superficial alteration and the small number of outcrops, fast drilling was carried out with a motor drill to locate the richest layer

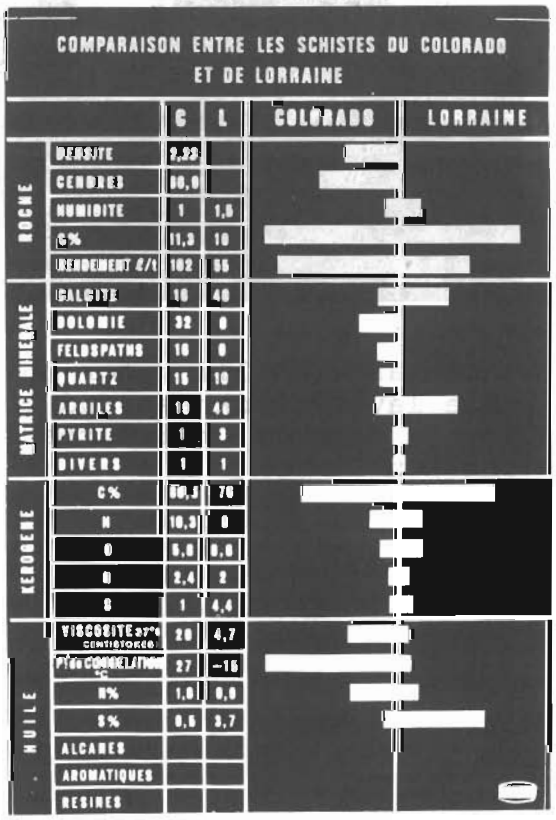

Figure 48-8.--Comparison between Colorado (USA) and Lorraine (France) shales with respect to rock properties, mineralogy, kerogen, and extracted oil

and quarry technology. Special regard will be given to protection of the environment (and of the country-side), with a view to rational redevelopment of opencast workings. This includes vegetation, drainage, access ways, sociology, ecology, assessment of nuisance factors, and pollution by water, dust, and noise (Figs. 48-9 and 48-10).

After 1977, if the results obtained when the programme is completed are positive, a semi-industrial stage will be reached with:

- construction of a pilot plant on the chosen site
- optimizing operation of this pilot plant
- studying environmental problems, especially hydrology, dust and effluents, revegetation
- advanced research on in situ exploitation processes
- reassessing economic data
- geological survey of new sites.

USE OF SHALES AS USEFUL SUBSTANCES

The chemical and mineralogical composition of these shales presents no outstanding features. Their direct use as useful substances would not appear possible. Actually, the substantial lime contents are a great nuisance both from the point of view of the extraction of aluminum by the acid method and from the point of view of their use as expansible materials. On the other hand, the presence of alkalines in the samples could be of benefit in obtaining mineral fibres; the chemical composition of the shales is such that simply adding $CaCO_3$ would enable them to be used in the cement industry.

CONCLUSIONS

Western Europe, especially France, relies on foreign imports for the largest share of its energy requirements and is now drawing the list of its own primary resources. The latter include oil shale, representing billions of tonnes of potential reserves. However, low oil content implies large scale investments and operating costs and necessarily involves a thorough

Figure 48-9.--Quarry in shale

Figure 48-10.--Blocks of bituminous shales showing a regular pattern related to variation in organic-matter content

study of project economics. To this should be added environmental problems raised by exploitation of oil shale with the opencast technique, at least in its first stage.

The main target of our study is estimating the cost of one barrel of shale oil. However, this does not exclude a subsequent option oriented towards petrochemical feedstocks as of 1980.

SECTION VII. GAS IN GEOPRESSURED RESERVOIRS

CHAPTER 49

THE SUPPLY OF NATURAL GAS FROM GEOPRESSURED ZONES: ENGINEERING AND COSTS

Myron H. Dorfman[1]

INTRODUCTION

In the United States of America the energy produced from wells in the form of natural gas is greater in quantity than that of crude oil. However, reserves and production of conventional natural gas are dropping. During 1975, approximately 19 x $10^{12}ft^3$ of natural gas were produced while only 8 x $10^{12}ft^3$ were added to reserves, which totaled approximately 210 x $10^{12}ft^3$. If present trends continue, there will be severe shortages in the next few years. The alternatives available during the next decade are coal, oil, and electricity produced from primary energy sources other than natural gas (Board on Mineral Resources, 1976). However, the recent sharp price increases of crude oil and natural gas have expanded the resource base for many types of hydrocarbon deposits which heretofore have been regarded as uneconomical. This factor has also added impetus to research into such unconventional geologic sources of methane as swamp gas, shale gas, gas occluded in coal, and other unusual occurrences of this premium fuel.

One of the unconventional geologic sources is methane contained in solution in waters of geopressured zones of the United States Gulf Coast Basin. A major research effort has been underway for some 3 years to evaluate the geologic and hydrologic

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regimes of this basin and the utilization technology for production of electricity and concomitant extraction of methane. Although the following analysis of natural gas in geopressured basins has been confined to the Gulf Coast Basin of the U.S., the study should serve as a model for similar basins known to exist worldwide, wherever predominantly clastic sediments have been rapidly deposited in Cenozoic (late geologic) time.

GEOLOGICAL BACKGROUND

The northern shoreline of the Gulf of Mexico extends more than 1,000 mi (1,609 km) from the Rio Grande River to the Florida panhandle. Underlying a large portion of this shoreline area, both onshore and offshore, in a strip 200 to 300 mi (322 to 483 km) wide are clastic sedimentary deposits of great thickness. Figure 49-1, from Hardin (1962), shows the thickness of Cenozoic deposits in the Gulf Coast Basin. The area described lies between the landward boundary of the Miocene deposits and the edge of the outer continental shelf. Sediments within this young basin exhibit a maximum thickness of some 50,000 ft (15,240 m) at major depocenters located slightly offshore Texas and Louisiana and subparallel to the present coastline.

The upper 25,000 ft (7,620 m) of deposits in this basin are composed primarily of alternating series of sandstones or shales. The lower section of sediments consists almost entirely of shales. These sediments were deposited by progradational delta systems ranging in age from Eocene to Recent, with some subsequent rearrangement of sands due to the effect of relatively high-energy wave action at the juncture of terrestrial and marine environments (Dorfman and Kehle, 1974). Rapid sediment loading from deltas throughout coastal Texas and Louisiana resulted in "leapfrogging" sediment distribution from a generally north to south direction. As younger systems deposited their sediment loads over the older units, great quantities of sands sank into the muds of the older delta systems. Sediments thus deposited became extremely thick on the south, or basinward, side. Continued downwarping due to sediment load resulted in "growth faults," or normal faults subparallel to the coastline and due to

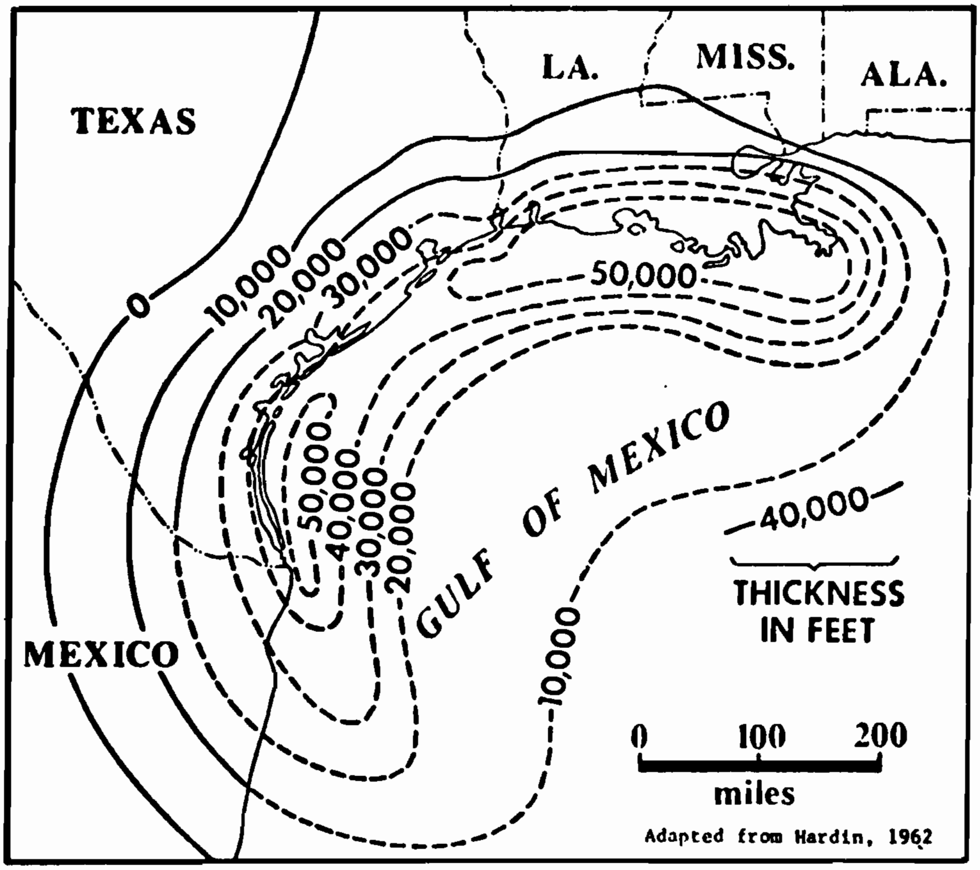

Figure 49-1.--Thickness of Cenozoic deposits in the Gulf Coast basin

differential compaction of sands and muds. A schematic cross section, Fig. 49-2, from Bruce (1973), shows the development of this process.

The penetration of sands into underlying pro-delta muds resulted in isolation of large sand members from continuous permeability channels to the overlying strata. Above the intervals thus isolated, pressures throughout the basin approximate 0.465 pounds per square inch per foot. This is considered normal hydrostatic pressure based on the fluid pressures exerted by a column of saline water. However, beneath the normally pressured zones the isolated units of sands and muds contain pressures far greater than normal. These abnormally pressured zones are now commonly referred to as geopressured zones.

The generation of geopressure is primarily the result of compaction phenomena. Newly deposited sediments have high porosities and are saturated with water. As they are overlain by younger sediments and buried deeper, the pressure of overburden seeks to reduce the thickness and porosities of these deeper sediments. As both the rock and water have very low compressibilities, the only way the rock volume can be appreciably reduced is by expelling water, with a consequent decrease in porosity. The rate of expulsion of water is controlled by the permeability of the overlying rocks. If none of the water can escape, then the weight of the overburden causes the fluids contained in the lower sediments to bear a portion of the overburden load. The result is a sudden and dramatic increase in sediment and fluid pressure. Pressure gradients in the geopressured regions often approach lithostatic pressure, or 1 pound per square inch per foot. Thus, fluids contained within these regions will flow naturally into wellbores and to the surface, and the hydraulic energy may be converted to useful purposes, such as generation of electricity. The geopressured interface in the Gulf Coast Basin occurs at depths of 5,000 to 15,000 ft (1,524 to 4,572 m), depending upon the age and distribution of sediments. All sediments below the general geopressured interface may be expected to contain increasingly abnormal pressure with increasing depth.

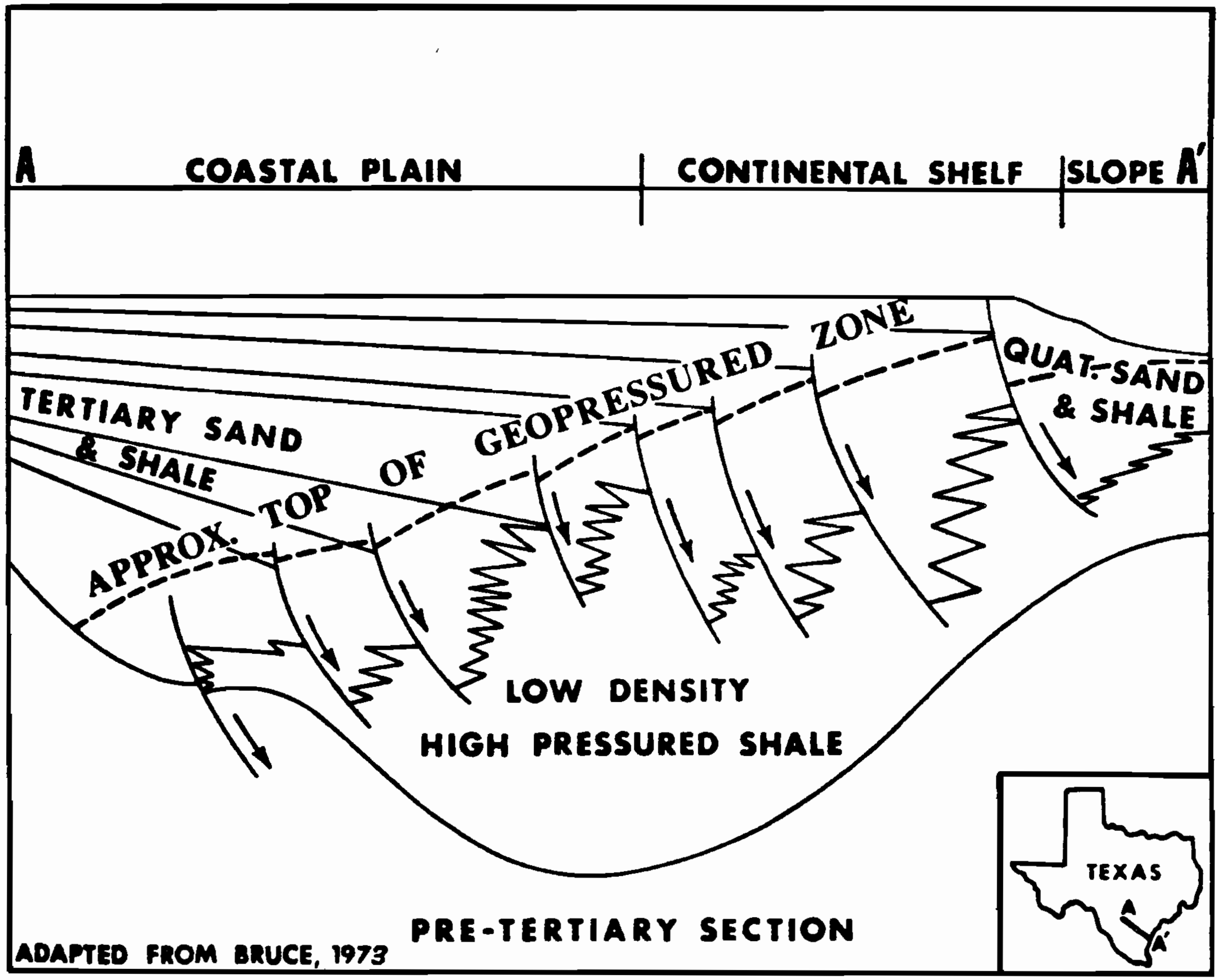

Figure 49-2.--Geologic dip section across South Texas Coastal Plain, showing growth-fault systems in major Cenozoic delta deposits and this relation to the top of the geopressured zone

Temperature is also an important parameter, since solubility of methane is dependent upon temperature, pressure, and water salinity. If the heat content of produced water is to be utilized as an energy source, it becomes doubly important. It is apparent from studies of well logs run in boreholes in the Gulf Coast that temperature gradients of approximately 1.5°F per 100 ft (9.5°C per km) of depth are found in hydropressured sediments of the Gulf Coast Basin, gradients in excess of 3°F per 100 ft (37°C per km) of depth are encountered in geopressured zones. Temperatures at depths of 10,000 ft (3,048 m) often range from 225° to 300°F (107 to 149°C), and at depths of 15,000 ft (4,572 m), it is not uncommon to encounter temperatures in excess of 350°F (176.6°C). Within the basin, temperatures of over 500°F (260°C) have been encountered in boreholes at depths of approximately 20,000 ft (6,096 m). Although these temperatures do not compare favorably with those found in the western United States volcanic-associated geothermal systems, they may be of sufficient magnitude to be useful in a variety of energy applications.

Source beds for most if not all hydrocarbons within the Cenozoic portion of the Gulf Coast Basin are believed to be the shales within the geopressured zones. These beds have provided adjacent sands within the geopressured regions with certain concentrations of methane in solution, and great interest has been evidenced in the recovery of appreciable volumes of methane from geopressured water. Evidence of methane concentration in geopressured zones is based upon inflows of gas and water from blowouts, and from the large number of "kicks" encountered in drilling into geopressured sandstones. Additionally, gas measuring devices on mud logs usually record significant indications of gas saturation while drilling is in progress. Theoretical studies by Culberson and McKetta (1951) indicate that between 30 and 50 ft^3 per barrel of water may be contained in solution in waters under high temperature and pressure encountered in geopressured zones, as shown in Fig. 49-3, from Jones (1975). Buckley, Hocott, and Taggart (1958) made extensive investigations into the distribution of hydrocarbons dissolved in waters in the hydropressured regions of the Gulf Coast Basin. Hundreds of

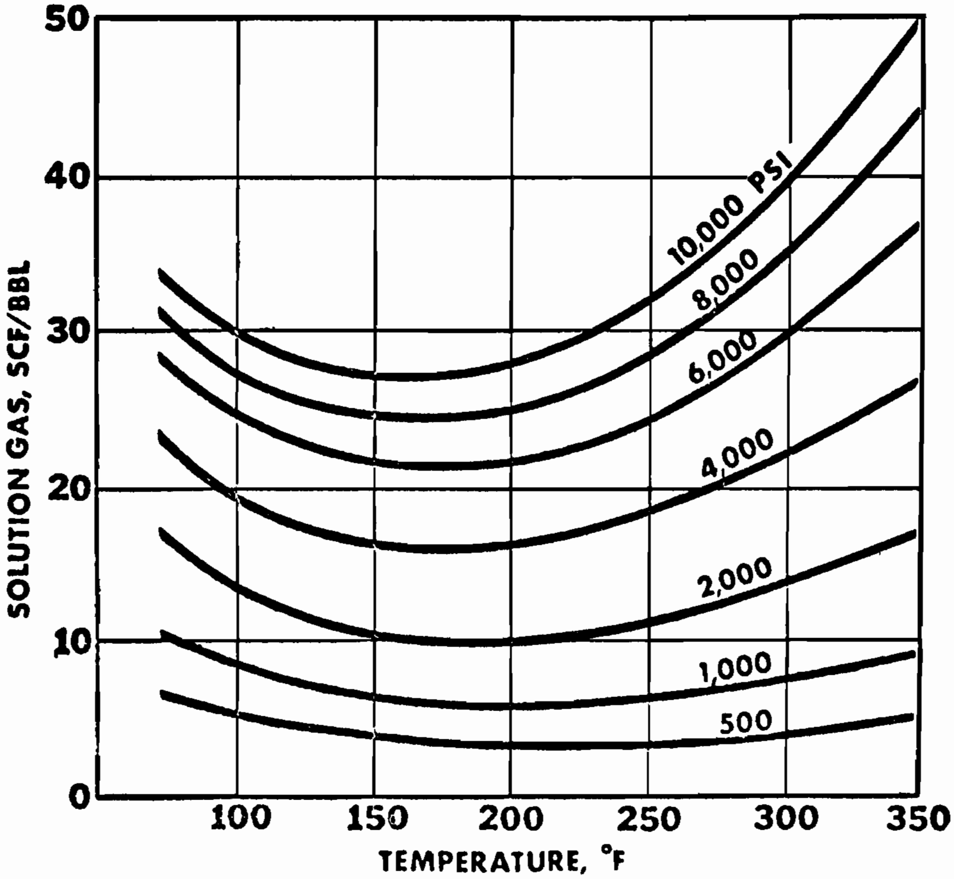

Figure 49-3.--Solubility of methane in fresh water
(from Jones, 1975)

drill-stem tests in wells in the Frio Formation indicated that the waters were essentially saturated at reservoir conditions. The dissolved gas was found to consist primarily of methane, with ethane and propane present only in minute quantities, and minimal concentrations of heavier hydrocarbons were present. Methane concentrations of up to 14 ft^3 per barrel of water were found in these studies of normally pressured zones. It is also known that plentiful dry-gas reservoirs exist in the Gulf Coast Basin in the uppermost portions of the geopressured zones, and that the gas is usually found to contain primarily methane with no evidence of hydrogen sulphide or other serious contaminates. Marsden and Kawai (1965) reported on "suiyoseitennengosu," or natural gas dissolved in brine, found in over a dozen fields throughout Japan. At least two of these fields near Niigata and Tokyo produce gas commercially, and the gas is composed of over 90 percent methane, with the remaining constituents being primarily carbon dioxide and nitrogen. Ritch and Smith (1976), in a recent report on an extensive coring and testing program in Pleistocene sediments in the Gulf Coast Basin, found that all formation waters were saturated with methane gas at reservoir temperature, pressure, and water salinities. Therefore, inferential evidence would indicate that waters in geopressured zones should be essentially saturated with methane.

Water salinity is also a parameter of interest in evaluating the geopressured resources. Empirical evidence, together with laboratory studies by Burst (1969), indicate that water salinities within the geopressured zones are considerably lower than those found in normally pressured horizons. This appears to be due to the fact that much of the water found within geopressured sands is derived from waters expelled from adjacent shales, due to thermal diagenesis of montmorillonite clays, the primary constituent of Gulf Coast shales. As waters filter thorugh clays, most of the solids remain in the clays causing waters within geopressured sands to contain salinities of less than 20,000 ppm compared with salinities of over 100,000 ppm in overlying hydropressured regions. Low salinity waters have two potentially beneficial effects; they can hold more methane in solution, and they may have direct usefulness for a variety of process heat or other applications.

Early mention of utilization of geopressured fluids for energy applications is found in U.S. Patents no. 3,258,069 and no. 3,330,356 by C. E. Hottman (1966), with assignment to Shell Oil Company. More complete studies of the geology and hydrology of the geopressured zones of the Gulf Coast Basin may be found in Jones (1969), Dorfman and Kehle (1974), and Jones (1975).

EXTENT OF THE RESOURCE

All of the information on the occurrences and characteristics of geopressured deposits in the Gulf Coast Basin comes from wells drilled in search of oil and gas. Well log data from several thousand of these wells are presently being used in an attempt to determine the specific areal extent and location of optimum aquifers in geopressured environments in the Frio Formation (Oligocene) in coastal Louisiana and Texas (Bebout et al., 1975a, 1975b). Although this assessment has not been completed, it is generally believed that geopressured zones cover an area of 100,260 mi^2 (278,500 km^2) extending from the Rio Grande River northwest to the Mississippi River and from the landward boundary of Eocene growth-faulting approximately 100 mi (161 km) inland from the present coast southward to the edge of the continental shelf (Papadopulos et al., 1976).

Recoverable gas from geopressured zones is dependent upon the quantity and quality of the sands within this environment, and reliable estimates of sand content and thickness are lacking. Based on resource assessment studies to date, it appears reasonable to assume an average thickness of 10,000 ft (3,048 m) of geopressured sediments within the basin, of which 15 percent is sandstone and the rest shale. The sandstone appears to have an average porosity of approximately 22 percent. A value of dissolved natural gas of 35 ft^3 per barrel would yield an in-place reserve of 5,735 x $10^{12} ft^3$. This estimate compares with a low estimate by Hise (1976) of 3,000 x $10^{12} ft^3$ and a high estimate by Jones (1976) of 49,000 x $10^{12} ft^3$. The United States Geological

Survey (White and Williams, 1976) has estimated the in-place reserve of natural gas at approximately 23,618 x $10^{12}ft^3$ in only the onshore portion of the Gulf Coast Basin. The wide variation in these estimates indicates the degree of uncertainty in assessing the in-place resource at this time. However, it should be noted that even conservative estimates of gas in place in the geopressured Gulf Coast Basin are at least an order of magnitude greater than the presently proven reserves of natural gas in the United States.

NATURAL GAS RECOVERY AND ECONOMICS

In order to produce substantial quantities of natural gas from geopressured fluids, it is obvious that enormous quantities of water must be produced as well. The volume of water in-place in the above calculations amounts to approximately 164 x 10^{12} barrels. Based on an effective compressibility for the reservoir system of 1 x 10^{-5} volume/volume/pounds per in^2 and a 5,000 pounds per in^2 drop in pressure, the total water volume available for production without respect to time, production rate or economics is calculated to be about 8.2 x 10^{12} barrels. If one assumes an average ratio of dissolved gas of 30 ft^3 per barrel, which can be produced along with this water, the natural gas which may be recovered is approximately 256 x $10^{12}ft^3$. This is a large reserve and is slightly greater than the presently proven reserve of natural gas from conventional sources. It should be emphasized that this figure represents the upper boundary under ideal conditions without regard to water produced or the economics of such production.

The economic problem of recovering natural gas from geopressured aquifers depends upon many factors. These include:

1. Value of natural gas, currently $2.00 per 10^3ft^3 in the U.S. free market;

2. The cost of drilling suitable wells for production of fluids, currently $1,900,000 (U.S.) per well to a depth of 15,000 ft (4,572 m) (Dorfman and Deller, 1976);

3. The ability of such wells to flow at rates in excess of 1,000 gallons per minute, which will require aquifers having sand thicknesses of over 200 ft (61 m) with good porosity and permeability;

4. The ability of such wells to produce without significant damage to the environment. Large fluid withdrawal could result in subsidence and activation of growth faults at the surface (Dorfman, 1975).

Based on a gas value of $2.00 (U.S.) per $10^3 ft^3$, a well producing at a rate of 40,000 barrels per day costing $\$1.9 \times 10^6$ (U.S.) would produce $1.2 \times 10^9 ft^3$ per day, or return approximately $876,000 (U.S.) per year. Using a cost of 1 cent per barrel of water for operating costs, the net return before royalty and taxes would amount to approximately $730,000 (U.S.) per year or a 3 year pay-out, which is reasonable. The major problems are locating aquifers which can produce at these large flow rates for many years, and disposing of effluent in a satisfactory manner. If sub-surface disposal of waters is requried, the cost of reinjection of effluents could significantly decrease economic incentives based on current costs.

However, if we add to this the possibility of using heat and pressure of waters to generate electricity or for process heat applications, economics improve even more. Research projects have studied several schemes for the generation of electricity based on total flow processes, flash steam systems, and secondary working fluid systems (House, et al., 1975; Underhill, et al., 1976). The total flow concept, shown in Fig. 49-4 from House, et al., 1975, calls for use of the entire wellhead production in the development of electricity.

Using either the flash steam or total flow processes, a resource containing 30 ft^3 per barrel of methane with a temperature of approximately 300°F (150°C) will generate a 15 percent rate of return on the investment with a sales price of between 42 and 50 mills per kilowatt-hour for electricity, as shown in Fig. 49-5 from House, et al., 1975.

In addition to generation of electricity by the use of geopressured fluids, the resource may also be used directly in a

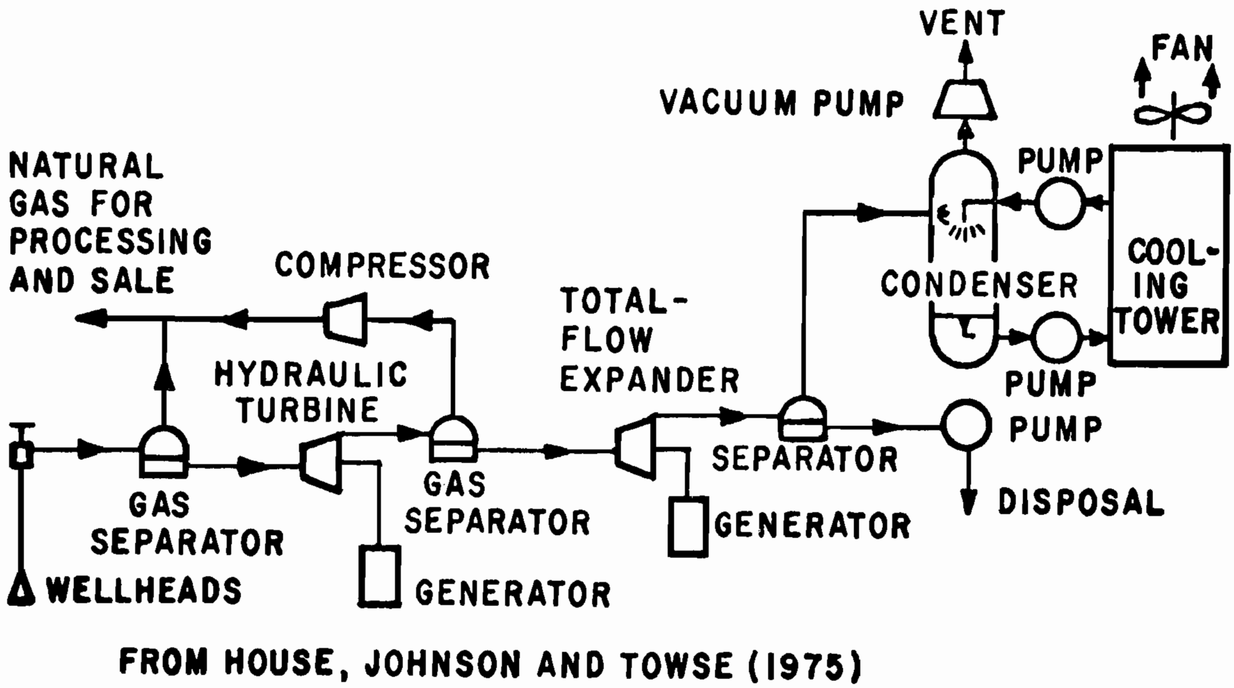

Figure 49-4.--Diagram of total flow power plant for geopressured resource

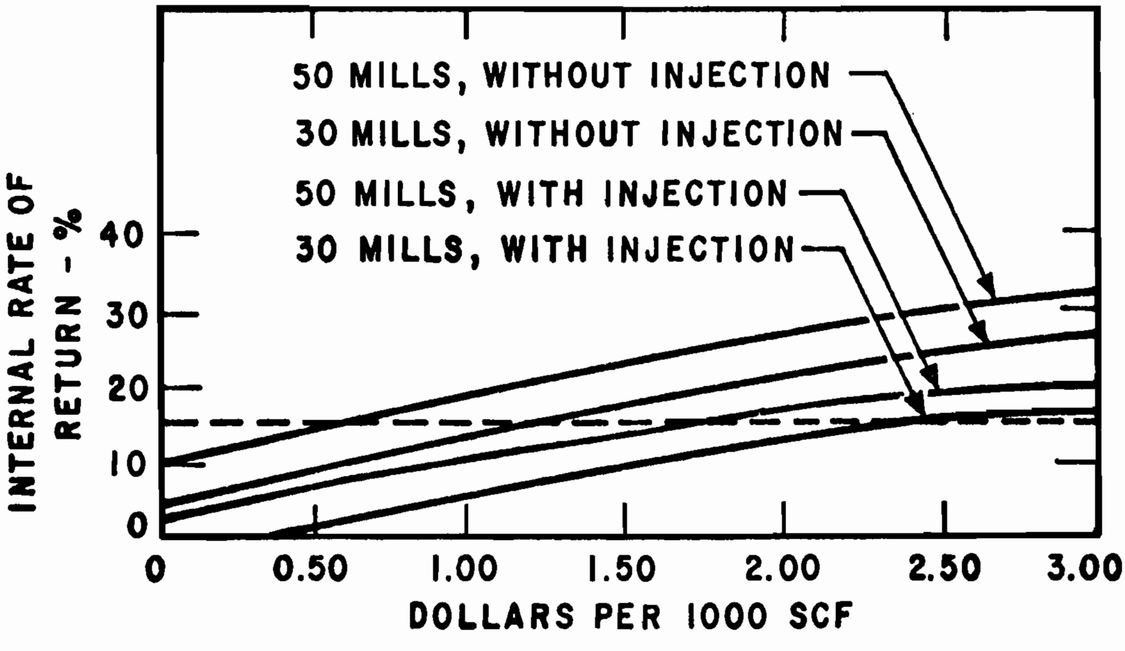

Figure 49-5.--Internal rate of return for geopressured wells as a function of electric and gas values. Under favorable circumstances acceptable rates of return are possible.

number of industrial processes which are indigenous to the Gulf Coast area. Possible application in pulp and paper, sugar milling, and sugar refining industries has been studied (Dorfman and Deller, 1976), and indications are that use of these fluids is both technically feasible and cost effective. Costs range from 8 to 33 mills per barrel of geopressured fluid depending upon well costs and on the credit one may assign to a barrel of fluid based on the value of extractable natural gas. Studies by Hornburg (1975) indicate a paper and pulp mill especially designed to use geopressured fluids could realize a 25 percent rate of return to the fuel supply.

Therefore, it appears, on the basis of preliminary studies, that extraction of methane coupled with generation of electric power or process heat applications using geopressured fluids provide sufficient economic incentives to justify development of the resource.

TIMETABLE FOR DEVELOPMENT

Studies presently underway in the United States Gulf Coast, under the sponsorship of the Federal Energy Research and Development Administration and various private investor-owned companies, have as their goal the determination of feasibility of production of geopressured fluids for electric power generation, using kinetic and thermal energy of waters, process heat applications, and extraction of natural gas. It has recently been estimated that the complete feasibility study in Texas and Louisiana will extend until 1985 and cost approximately $\$43 \times 10^6$ (U.S.). Based on this timetable, minimal production of natural gas from geopressured zones can be expected before 1985. Between 1985 and the year 2000, the following timetable would appear to represent a reasonable approximation for commercial development: assuming 10 drilling rigs available for exploration and development and a 75 percent success ratio, approximately 30 wells could be brought on line each year. This would represent an annual production of approximately $13 \times 10^9 ft^3$ of natural gas per year or approximately $200 \times 10^9 ft^3$ of gas per year by the year 2000. Beyond the year 2000 the rate of growth of resource will depend primarily upon the availability of drilling and production equipment and construction materials. Implicit in the rate of development will be the availability of sufficient industrial capital and, of course, a sufficiently high price for natural gas to make such ventures economically attractive.

It must be emphasized that at this stage of research, commercial feasibility will largely depend upon solution of certain critical problems. These include:

1. The ability to locate and drill reservoirs having suitable flow rates, temperatures, methane content, and long-term productivity to justify further development;

2. Demonstration that wells and surface equipment can successfully maintain sufficient mechanical efficiency over a long period of time;

3. Determination that environmental problems can be coped with successfully. These include potential subsidence, satisfactory water disposal, and resolution of thermal pollution effects.

In summary, the U.S. Gulf Coast Basin appears to contain a tremendous resource of natural gas. Research now underway should establish whether this resource can be used within 10 years. Thereafter, commercial development of the resource will depend on solutions to technical, legal, and environmental problems, availability of equipment, and economic incentives for such development.

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CHAPTER 50

GAS IN GEOPRESSURED ZONES

Paul H. Jones

INTRODUCTION

All Cenozoic oil-producing sedimentary basins of the world are geopressured at depth, but little oil is found in the geopressured zone; this is the domain of natural gas (Fertl and Timko, 1972). Associated formation waters are believed to be saturated in dissolved methane and the methane content of water in any reservoir at saturation can be estimated if data on the temperature, pressure, and salinity of the waters are known (Dodson and Standing, 1944; Culberson and McKetta, 1951; O'Sullivan and Smith, 1970).

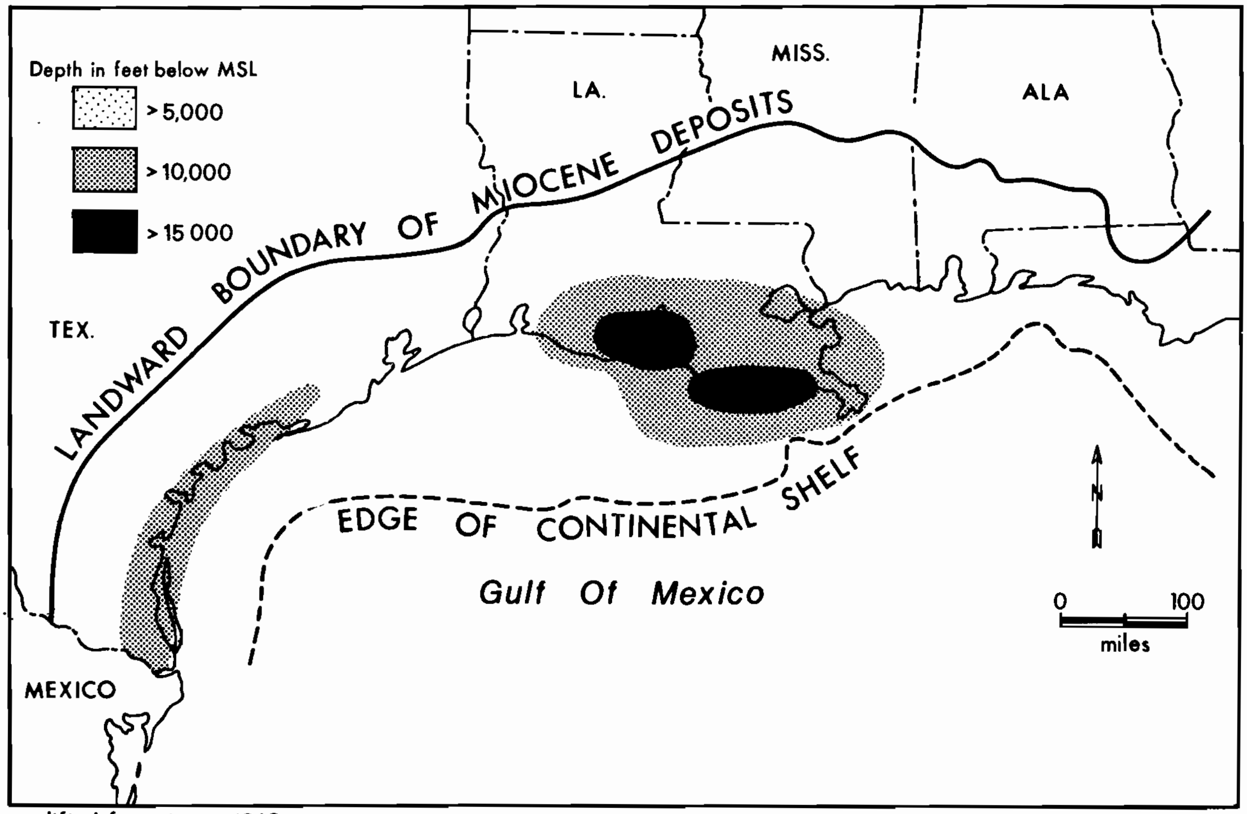
Generation and subsequent degradation of liquid hydrocarbons to methane within the geopressured zone may account for the world's major reserves of natural gas. Very large natural gas resources are believed to occur in water solution in the geopressured zones of the world, and formation waters in hydropressured zones associated with geopressured zones, now in their first cycle of pressure and temperature decline, are known to be near saturation in methane (Buckley, Hocott, and Taggart, 1958).

The natural gas resources in geopressured zones worldwide are very great indeed if conditions in them are comparable to those in the northern Gulf of Mexico basin. Formation waters, believed to be saturated, are associated with more than 8,000 producing gas reservoirs in the geopressured zone of the northern Gulf of Mexico basin, in a depth range from about 9,000 to 22,000 ft (about 3 to 7 km). Information on geopressured zones worldwide is scattered and sketchy, but published data (Fertl, 1972; Rehm, 1972; Deju, 1973) suggest that geopressured sedimentary basins in six of the seven continents may contain large natural gas resources dissolved in formation waters.

GEOPRESSURED ZONES

Geopressure may be defined as any interstitial fluid pressure in the subsurface that reflects a part of the overburden (rock) load (Stuart, 1970). It has been described in other terms, probably the most common of which is "abnormal subsurface fluid pressure." One of the earliest comprehensive papers describing its occurrence for Gulf Coast Louisiana was that of Dickinson (1953). Although many factors may be involved in the origin and preservation of geopressure, the most commonly recognized and accepted requirement for its occurrence is rapid deposition of fine-grained sediments (Bredehoeft and Hanshaw, 1968). The hydrodynamics of geopressure (Jones, 1969a) involve fluid release mechanisms of fine-grained deposits (Burst, 1969; Perry and Hower, 1972), hyperfiltration and osmotic forces (White, 1965; McKelvey and Milne, 1962), the modulus of elasticity and coefficient of thermal expansion of formation water (Parmigiano, 1973), and the effects of structural deformation (Jones and Wallace, 1974). The relatively low thermal conductivity of water, its high specific heat, and its rapid decrease in viscosity with rising temperature are very important factors in the hydrodynamic, hydrothermal, and hydrocarbon regimes of the geopressured zone.

Geopressure may occur in continuous belts underlying very large areas and extending to great depth. In the northern Gulf of Mexico basin it underlies an area of at least 150,000 mi^2 (375,000 km^2) (Fig. 50-1) and extends downward some 50,000 ft (15 km) to the base of Cenozoic deposits (Jones, 1975). The depth to the top of the geopressured zone in the Gulf basin ranges from less than 3,000 to about 18,000 ft (1 to about 6 km), and the pressure seal is generally an extensive marine shale. The pressure gradient through the seal can be low, or very high, as shown on Fig. 50-2. Pressure generally increases step-wise



modified from Jones, 1969

Figure 50-1.--Depth of occurrence of the geopressured zones in Neogene deposits of the northern Gulf of Mexico basin with depth until the gradient reaches some maximum value; on Fig. 50-2 the gradient approaches 0.87 psi/ft at a depth of 15,000 ft (4.7 km) and continues at that value to the bottom of the well. At a depth of 16,000 ft (5 km) the fluid pressure is about 14,000 psi, and the differential pressure (pressure at the well head with the tubing filled with salty water) is about 6,000 psi.

The top of the geopressured zone can be mapped by seismic methods, and can be detected during drilling by observation of mud flowline temperature increase, bit penetration rate decrease followed by a sudden increase, and measurement of the density of shale cuttings (Fig. 50-3). On the electric log, the pressure seal has high resistivity, and the geopressured shale below it has markedly low resistivity. There is an abrupt change in the depth-porosity gradient, with downward increases of 10 to 12 percent in both shale and sand, below the pressure seal (Fig. 50-4). It then decreases with depth in the geopressured zone, the trend paralleling that in the overlying hydropressured zone.

The geopressured zone of the northern Gulf of Mexico basin is compartmented by linear growth-fault trends associated with each of the eight major Cenozoic progradational cycles of sedimentation (Fig. 50-5). The top of the geopressured zone is at great depth in the oldest deposits because drainage with compaction due to overburden load is well advanced. It is at intermediate to shallow depth in the younger deposits, its depth being a function of sediment facies distribution, structural deformation, and diapirism of salt and shale.

The geopressured zone is a natural pressure vessel. Because heat flow in sedimentary basins is primarily a function of the upward flux of the interstitial waters, geothermal gradients in it are high. Temperatures are commonly greater than 400°F (204°C) at 20,000 ft (6.25 km) in the northern Gulf of Mexico basin (Fig. 50-6). Although the 200°F (93°C) isotherm is generally within or near the top of the geopressure zone, there is no consistent relationship between temperature and fluid pressure. And there may be 5,000 ft (1.6 km) of relief, or more, on the 200°F (93°C) isotherm in an area of 100 mi^2 (about 260 km^2).

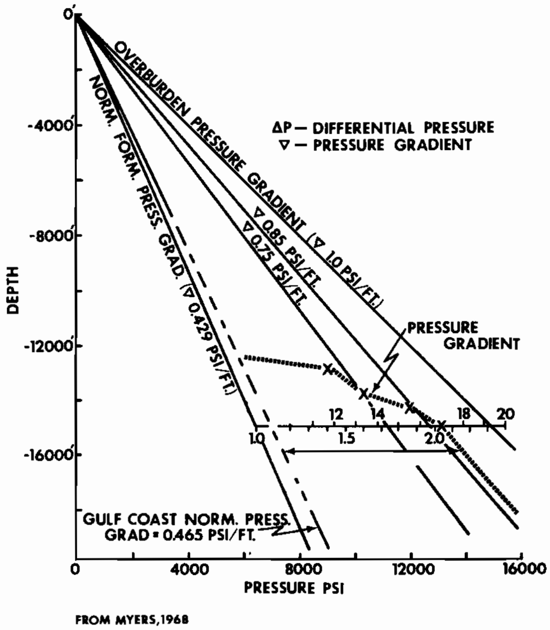


Figure 50-2.--Formation fluid pressure gradient of a Louisiana Gulf Coast well

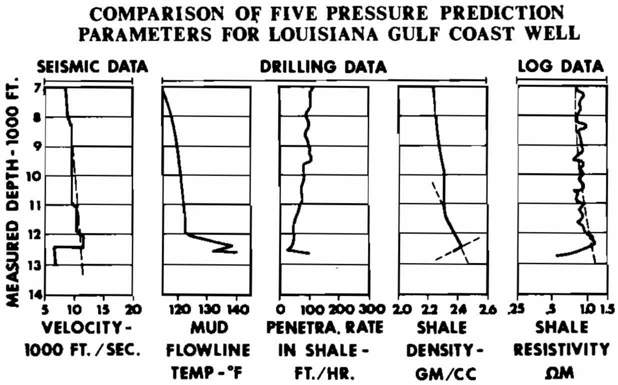


Figure 50-3.--Pressure prediction parameters for a Louisiana Gulf Coast well

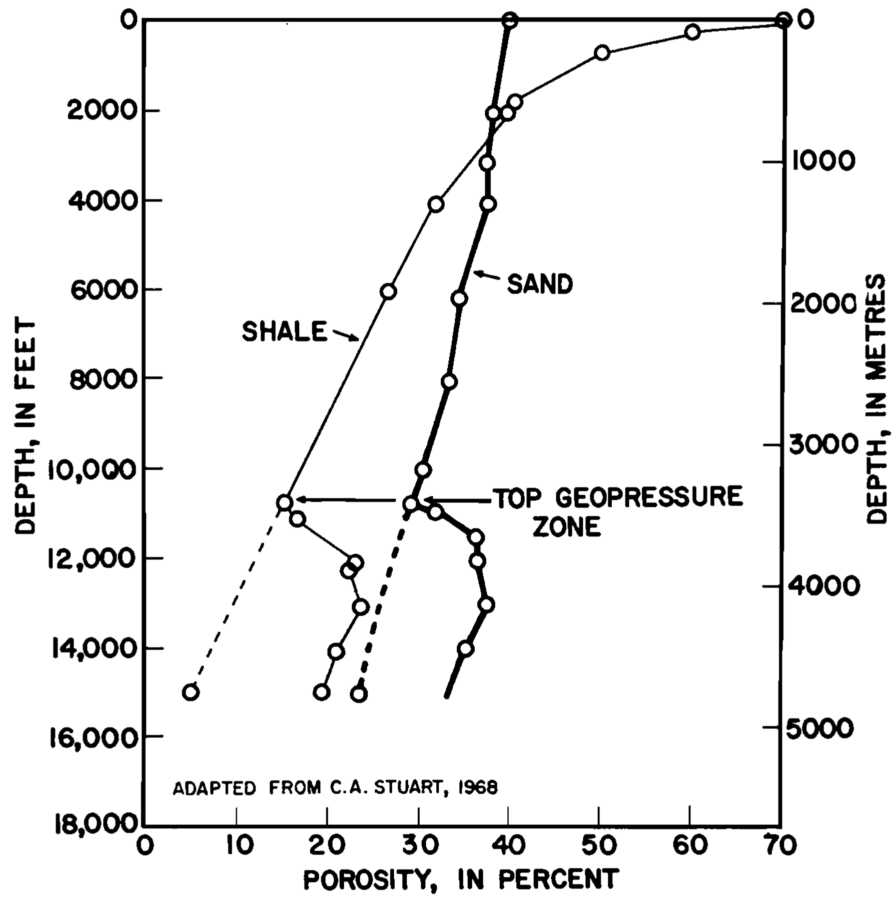


Figure 50-4.--Relation of the average depth-porosity gradients for sand and shale to the occurrence of geo-pressure in Louisiana Gulf Coast wells

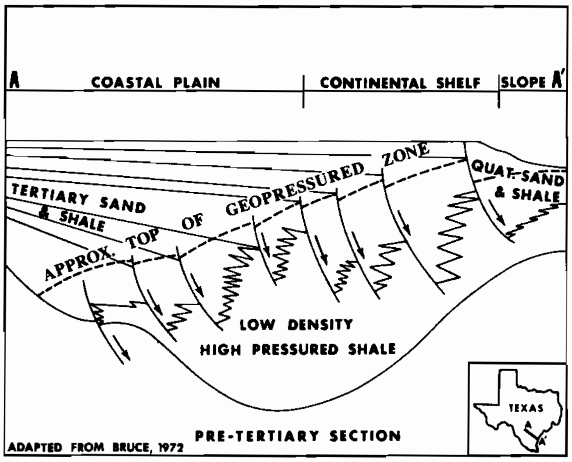


Figure 50-5.--Relation of sediment type, geologic structure, and age of deposits to depth of occurrence of the geopressured zone in the northern Gulf of Mexico basin

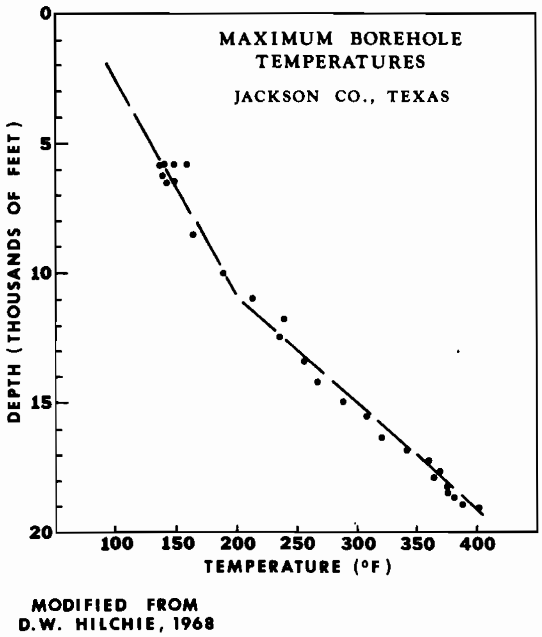


Figure 50-6.--Relation of average geothermal gradient in the occurrence of geopressure in the central Texas Gulf Coast

HYDROCARBON REGIME

Petroleum hydrocarbons formed by the thermal metamorphism (maturation) of organic matter dispersed in marine shales are highly soluble in interstitial waters at the temperatures and pressures common in geopressured zones (Price, 1973). As shown by the curves in Fig. 50-7, the rates of both hydrocarbon generation and clay mineral diagenesis increase markedly with depth below the top of the geopressured zone at temperatures above 170°F (76°C) in the Louisiana Gulf Coast (LaPlante, 1974). Oil and gas dissolved in waters of the geopressured zone are exsolved and accumulate in traps wherever water escapes from the geopressured zone (Myers, 1968; Fowler, 1970). Oil that does not escape from the geopressured zone is largely degraded to methane, and very little oil is found in reservoir rocks where temperatures exceed 300°F (150°C) (Fertl and Timko, 1973).

Methane produced by the thermal degradation of petroleum in the geopressured zone--a natural catalytic cracker of hydrocarbons--is dissolved in the formation waters of the zone (Fig. 50-8).

RESOURCE IDENTIFICATION AND ASSESSMENT

Wherever methane in the vapor phase occurs in the geopressured zone, associated formation waters must be saturated. In the Gulf Basin there are more than 8,000 producing geopressured-gas reservoirs; some of the fields in which they occur are shown in Fig. 50-9. Table 50-1 lists these fields together with reservoir depth, temperature, pressure, and geostatic ratio. These data are extracted from records compiled by the United States Federal Power Commission, National Gas Survey.

Identification and assessment of the natural gas resource in geopressured zones worldwide, basin by basin, is a very important consideration in estimation of the future supply of nature-made petroleum and natural gas. Nonassociated gas, largely from geopressured-zone reservoirs, accounted for more than 80 percent of the production in Louisiana in 1972, some $6.4 \times 10^{12} ft^3$. This gas in the vapor phase is part of an enormously larger resource

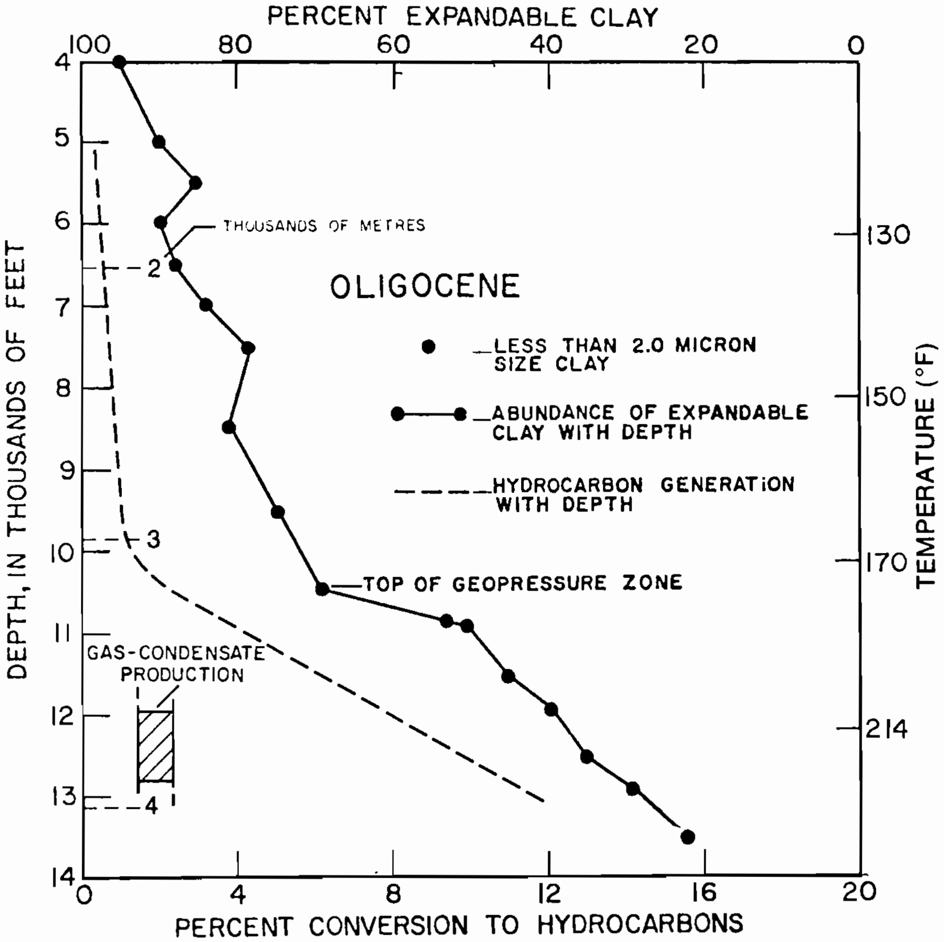


Figure 50-7.--Relation of formation temperature, clay mineral change, and hydrocarbon generation rate to the occurrence of geopressure in a Louisiana Gulf Coast well

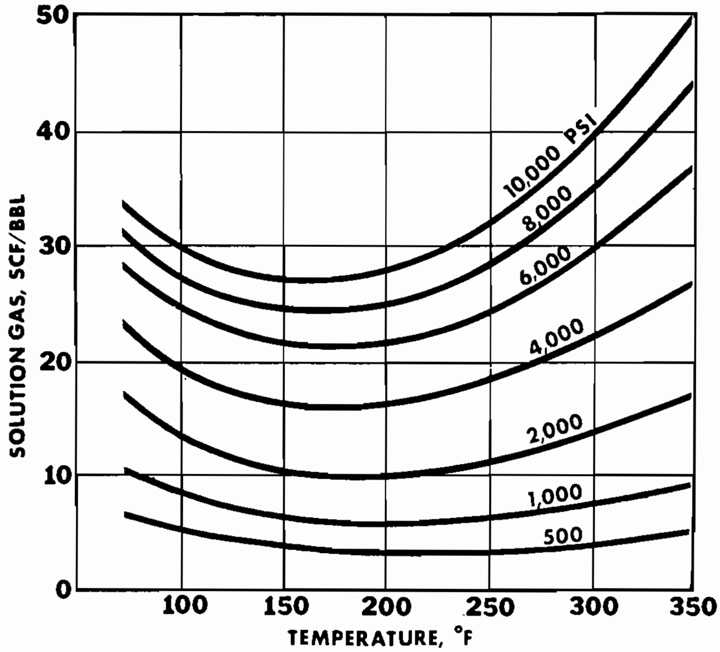


Figure 50-8.--Solubility of methane in fresh water as a function of temperature and pressure (Culberson and McKetta, 1951)

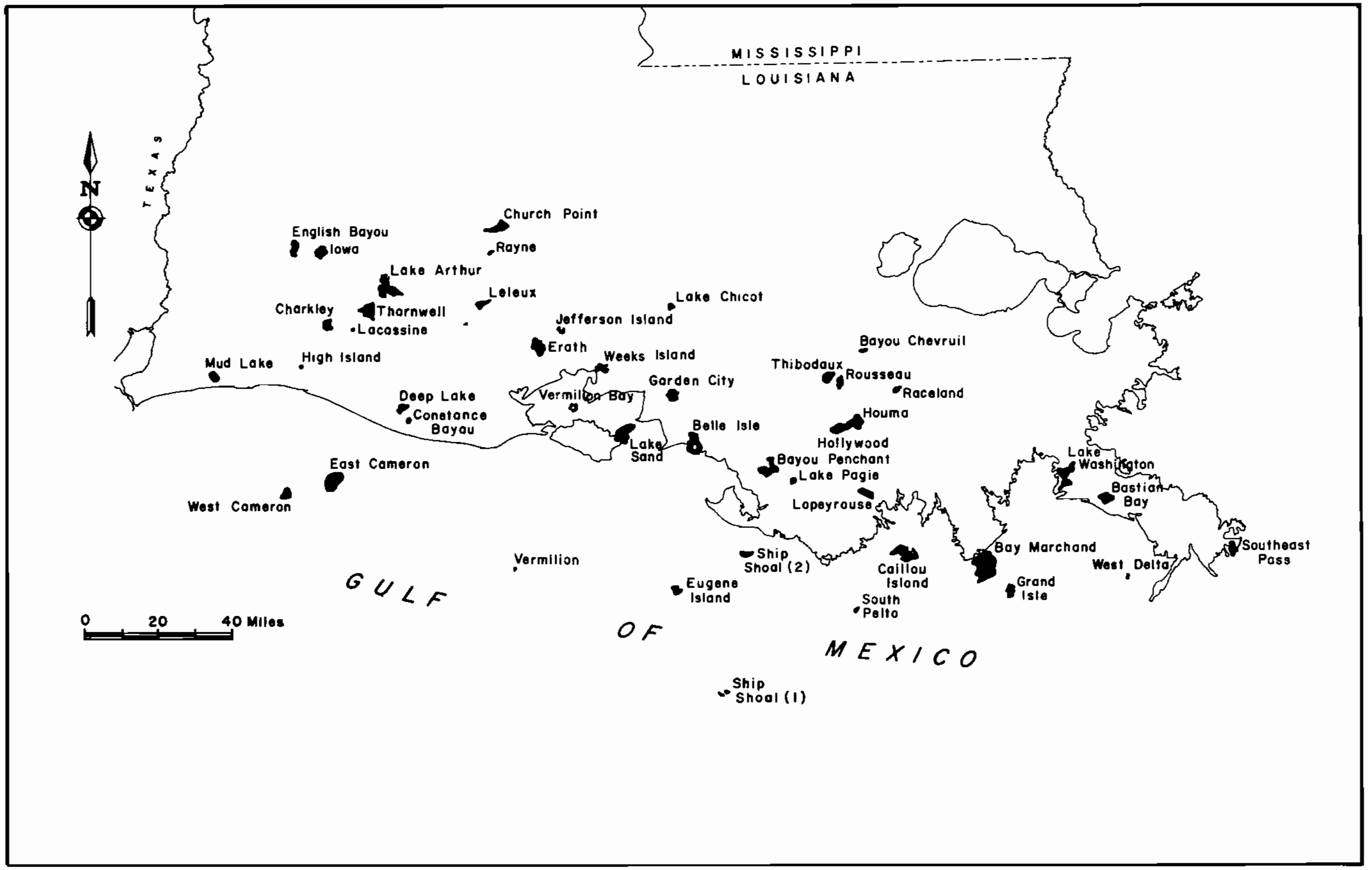


Figure 50-9.--Representative geopressured gas fields in the Louisiana Gulf Coast area described in Table 50-1

TABLE 50-1.--Representative geopressured gas reservoirs in southern Louisiana and adjacent areas of the Gulf Continental Shelf (partial extract of data in Exhibit "H," Southern Louisiana Rate Case AR61-2, Gas Supply Section, U.S. Federal Power Commission)

DEPTH (feet)	FIELD[1]	TEMP (°F)	PRESSURE[2] (psi)	GEOSTATIC RATIO	DEPTH (feet)	FIELD[1]	TEMP (°F)	PRESSURE[2] (psi)	GEOSTATIC RATIO
1355-1430	Bay Marchand	91	680	.502	12693-12757	Vermilion	235	8,276	.652
2674-?	Southeast Pass	106	1,390	.520	12900-12935	Bastian Bay	224	8,859	.687
5405-5433	Ship Shoal	140	3,132	.579	12942-12949	Bayou Chevruil	246	11,067	.855
6268-6311	West Cameron	163	3,205	.511	13200-13228	Lake Chicot	232	11,522	.873
7080-7090	West Cameron	173	3,712	.524	13265-13275	West Cameron	280	11,664	.879
7483-7507	West Cameron	179	3,993	.533	13617-13640	Thibodaux	237	10,418	.765
7996-8013	West Cameron	187	4,370	.546	13700-13735	Thornwell	272	12,282	.896
8400-8413	Vermilion Bay	208	4,580	.545	13708-13761	West Delta	239	10,782	.787
8700-8831	Vermilion Bay	211	4,680	.538	13753-?	Caillou Island	270	7,113	.517
9012-9047	Eugene Island	182	4,715	.523	13937-13950	Rousseau	241	10,635	.763
9033-9061	South Pelto	219	4,938	.547	14145-14178	Ship Shoal	261	7,109	.503
9401-9422	Church Point	201	6,417	.683	14150-14225	Houma	253	10,790	.763
9464-9533	South Pelto	225	5,416	.572	14300-14341	Lake Sand	263	10,975	.767
9824-9877	East Cameron	213	6,025	.613	14344-14376	Garden City	259	12,096	.843
9879-9906	East Cameron	213	6,001	.607	14594-14606	Garden City	263	12,295	.842
10005-10047	Iowa	246	7,169	.717	14602-14628	Constance Bayou	278	7,340	.503
10025-10039	Jefferson Island	194	5,379	.537	14600-14650	Lapeyrouse	264	9,075	.622
10410-10418	High Island	209	7,802	.749	14700-14731	Lapeyrouse	266	10,020	.682
10500-10517	English Bayou	233	8,154	.777	14900-14940	Lake Washington	266	10,180	.683
10585-10630	West Cameron	223	6,325	.598	15050-15084	Garden City	250	14,210	.944
10790-10816	Raceland	208	6,792	.629	15150-15160	Deep Lake	3[illegible]	9,390	.620
10800-10906	Mud Lake	231	5,724	.530	15249-15289	Lake Pagie	26[illegible]	10,819	.709
10950-10974	Churchpoint	243	7,686	.702	15318-15375	Thornwell	315	11,376	.743
11200-11389	Mud Lake	246	6,272	.560	15336-15407	Lake Arthur	329	13,933	.909
11330-11356	Rayne	217	6,900	.609	15580-15595	Leleux	277	13,570	.871
11650-11679	Chalkley	233	9,345	.802	15600-15800	Deep Lake	366	9,885	.634
11933-11943	Erath	231	6,602	.553	15871-15880	Lake Sand	296	12,505	.788
11950-11995	Bayou Penchant	230	9,031	.756	16000-16018	Lacassine	275	14,625	.914
12200-12246	Lake Arthur	262	10,100	.828	16450-16495	Hollywood	280	14,540	.884
12295-12328	Thornwell	303	11,800	.960	16570-16585	Weeks Island	266	9,495	.573
12450-12493	Belle Isle	231	6,690	.537	17300-17340	Belle Isle	316	11,420	.660
12550-12562	Grand Isle	263	8,745	.697	17395-17429	Lake Sand	318	13,477	.775

1- Locations are shown in Figure 36.

2- 1 psi = 2.31 ft of fresh water.

NOTE: DATA EXTRACTED FROM EXHIBIT H, SO. LA. RATE CASE AR61-2, GAS SUPPLY SECTION, FED. POWER COMM.

from which it derives by exsolution, as a consequence of supersaturation of formation waters in methane as natural catalytic cracking of liquid hydrocarbons trapped in the geopressure zone progresses, or as reservoir pressure and temperature decline with compaction and consolidation of deposits.

The evidence for exsolution of methane and its migration to structural highs--accounting for the origin of natural gas reservoirs in the geopressured zone and pressure maintenance associated with commercial gas production from reservoirs in the geopressured zone--is shown by the P/Z versus cumulative production curves for these reservoirs (Fig. 50-10). The slope of the curve during the production of the first 15 x $10^9 ft^3$ of gas is defined by both the rate of exsolution of dissolved gas and steady volumetric depletion of the reservoir. Then, as dissolved gas in the contiguous water-filled part of the sand-bed reservoir is depleted, the slope of the curve is defined by gas-law volumetric depletion alone. Unfortunately, no published technical reports of the oil and gas industry explain the P/Z versus cumulative production curves of geopressured-zone reservoirs in the above terms.

Perhaps the most serious impediment to gas resource assessment is the lack of methane saturation data for water at temperatures above 350°F (177°C) and pressures greater than 10,000 psi. Extrapolation of the curves of Culberson and McKetta (Fig. 50-8), and correction of solubility estimates for water salinity (O'Sullivan and Smith, 1970) are risky and difficult, and new laboratory studies are urgently needed in these areas. Fluid pressures at drilled depths commonly exceed 16,000 psi, and temperatures above 500°F (260°C) are known to occur in many basins.

In a recent paper, Jones (1976) suggested a way of developing the dissolved-in-water gas resource of the geopressured zone, which could increase greatly the recoverability of natural gas from this source. It is as follows:

> Withdrawal of formation water at large rates by multiple-well systems tapping large geopressured reservoirs will lower fluid pressure over broad areas. As reservoir pressure declines, dissolved gas throughout the reservoir will be released from solution; this gas, when its volume exceeds 4 or 5 percent of the

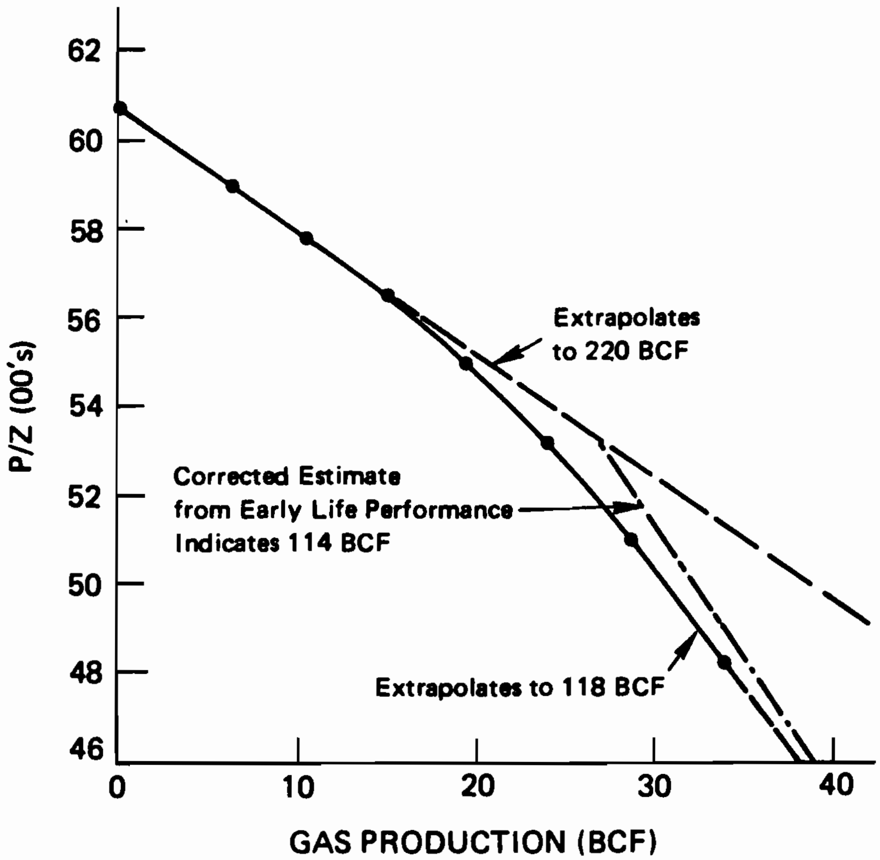


Figure 50-10.--Relation of P/Z to cumulative production from a Louisiana Gulf Coast geopressured gas reservoir

pore volume of the reservoir, will collect and move to structural highs in the reservoir, forming gas caps. When these gas caps have grown to sufficient size, they can be tapped by gas wells and produced in the same way as the some 8,000 gas reservoirs now in production. In effect, water production to obtain dissolved gas simply speeds up the natural process of pressure decline that has resulted in the known gas reservoirs.

Such artificially-formed gas caps can be found by seismic survey, first by locating the structural highs, and then by observing gas cap formation as resurveys detect it, by growth of a "bright spot" or "bright zone" in the record.

Quantitative estimates of gas dissolved in geopressured-zone formation waters can be made if usable information is available on key parameters, or can be estimated with confidence. Elements required for such estimates are listed and applied in Table 50-2 (Jones, 1976), prepared in connection with a study of natural gas resources of the geopressured zone of the northern Gulf of Mexico basin. The estimate is made for a prism of the deposits with a base 1 mi^2 and a height equal to the thickness of the geopressured zone above a depth of 25,000 ft (7.8 km)--chosen as the depth below which no sand-bed reservoirs can be expected to occur. The sample calculation was applied to an area of 1,902.95 mi^2 (5,155 km^2), on the basis of geologic knowledge, and the gas-in-water resource was estimated to be about 1,200 x $10^{12}ft^3$. Using this figure, the total volume of methane dissolved in sand-bed formations above a depth of 25,000 ft (8 km) onshore was estimated to be about 17,100 x $10^{12}ft^3$. (Jones, 1976). Other estimates based on different assumptions ranged from 3,000 x $10^{12}ft^3$ (Hise, 1976) to 24,000 x $10^{12}ft^3$ (Papadopulos, Wallace, Wesselman, and Taylor, 1975) for the same area. The total volume of dissolved methane in sand-bed formation waters onshore and offshore in the Gulf Basin geopressured zone is about 49,000 x $10^{12}ft^3$.

WORLDWIDE OCCURRENCE

The world's known geopressured zones occur in three principal geologic settings: (1) in rapidly deposited Mesozoic or Cenozoic fine-grained clastic rocks in deep sedimentary basins

TABLE 50-2.--Dissolved methane content of geopressured sand-bed formation waters at saturation, beneath 1 square mile of a selected area in the Texas coastal plain

Depth	ΔP	Pressure1/	Temperature	Gas in Solution2/	Sandbed Porosity3/	Cumulative Thickness of Sand	Volume of Water	Water	Gas in Solution
$ft \times 10^3$	psi/ft	$psi \times 10^3$	°F	scf/bbl	Percent	ft	$ft^3 \times 10^6$	$bbl/mi^2 \times 10^6$	$scf/mi^2 \times 10^{10}$
8	0.55	4.8	194	18.8	?	--	--	--	--
9	0.60	5.4	199	20.0	27.0	200	1,505	268	0.537
10	0.70	7.0	212	23.7	30.0	300	2,509	448	1.061
11	0.75	8.2	237	27.9	32.5	400	3,624	647	1.805
12	0.80	9.6	261	32.1	34.0	500	4,739	846	2.716
13	0.85	11.0	285	39.0	36.96	600	6,182	1,103	4.305
14	0.90	12.6	307	46.8	35.13	600	5,876	1,049	4.910
15	0.92	13.8	331	55.0	33.30	600	5,570	994	5.470
16	0.95	15.2	354	64.0	31.47	500	4,386	783	5.013
17	0.95	16.1	376	73.0	29.64	400	3,305	590	4.308
18	0.96	17.2	397	82.0	27.71	300	2,317	413	3.393
19	0.97	18.4	414	92.0	25.98	400	2,897	517	4.759
20	0.97	19.4	434	103.0	24.15	500	3,366	601	6.191
21	0.97	20.3	450	114.0	22.32	500	3,111	555	6.333
22	0.97	21.3	466	125.0	20.49	400	2,284	408	5.100
23	0.98	22.5	480	137.0	18.66	300	1,560	278	3.817
24	0.98	23.5	500	150.0	16.83	200	938	137	2.513
25	0.98	24.5	520	164.0	15.0	100	418	74	1.224
									63.455

1/ Fertl and Timko (1972)

2/ Culberson and McKetta (1951) curves extrapolated by Jones (this volume)

3/ Stuart (1970)

along or near continental margins, extending downward from depths generally less than 15,000 ft (4.7 km); (2) within or below evaporite sequences in deposits ranging in age from earliest Paleozoic to late Cenozoic; or (3) in active tectonic belts associated with crustal plate movement or mountain building, in deposits of any age, and at any depth. These occurrences may be classed as "depositional," where due mainly to rapid deposition and slow drainage of the deposits, or "tectonic" where due mainly to crustal movement. Both types probably involve igneous activity, at great depth in "depositional" occurrences, and at moderate depth in "tectonic" occurrences. Both show the effects of strong and long-continuing upward hydrothermal flux.

In North America, geopressured zones of the "depositional" type are found in a belt almost circling the Gulf Basin, from southern Mexico to western Florida; in the Anadarko Basin of Oklahoma; in the Permian Basin in West Texas; in several Rocky Mountain basins (Colorado, New Mexico); in the Williston Basin (North and South Dakota); perhaps in some of the California basins; in the Alaska North Slope and the Sverdrup Basin of the Arctic Ocean margin; and in some places in the Western Canada Basin. Geopressured zones of the "tectonic" type are found in the coastal basins and Great Valley of California; Utah and Wyoming; the Cook Inlet area of Alaska; the Newfoundland offshore area, and the South Mississippi Salt Basin.

In South America, "depositional" geopressured zones are found in northern Colombia (Magdalena Basin), Venezuela (Maricaibo Basin), and Brazil (offshore). "Tectonic" geopressured zones are found in eastern Venezuela, Trinidad, Guiana, Argentina (Andes marginal zone, Mendoza area), Chile (Puenta Arenas), Peru (offshore), and Ecuador.

In Europe, "depositional" geopressured zones are found in France (Aquitane Basin), Holland (the Northwest European Permian Basin, and the Groningen gas field), Germany (Northwest European Permian Basin), Ireland (offshore), United Kingdom (offshore), Norway (offshore), Hungary (inner Carpathian Basin), Italy (Po Basin, Apennine Foredeep), and Austria (Vienna Basin). "Tectonic" geopressured zones are found in Rumania, Bulgaria, Yugoslavia, Russia, and Poland, associated with folding and thrust faulting in the Carpathian, Transylvanian, and Dinaric Alps; Italy (offshore), France (along the foothills of the Pyrenees), and Austria (in the Inner Alpine Basin).

In Africa, "depositional" geopressured zones are found in Nigeria (Niger Delta, and offshore), Egypt (Nile Delta), and Mozambique. "Tectonic" geopressured zones are found in Morocco (Atlas Mountains fold belt), Algeria (evaporite beds form the seal), and Ethiopia (offshore Red Sea rift zone).

In Asia, "depositional" geopressured zones are found in Pakistan (Indus Basin), India (Gulf of Cambay, offshore, and Bengal Basin), Bangladesh, Burma (Irrawaddy Basin), and Arabian Gulf (sealed by evaporites). "Tectonic" geopressured zones are far more common than the "depositional" type in Asia, forming broad belts along the Caucasus, Zagros, and Himalaya Mountain chains. Such zones are found in Russia, Iran, Iraq, Arabia, Pakistan, India, and Burma.

In Australia and Oceania, "depositional" geopressured zones are commonly subject to tectonic effects, but several may be identified. These include New Guinea (Mamberamo River Basin), Papua (Gulf of Papua), Timor, Borneo, Sumatra, and offshore in the South China Sea; northern New Zealand; and northwestern Australia (offshore). "Tectonic" geopressured zones occur along the northern flanks of Java and the islands to the east as far as Timor, and are probably related to volcanism and island arc tectonics.

In the Far East, "depositional" geopressured zones are found in Taiwan and Japan, and are likely to occur in the major deltaic systems of the China coast. Information on possible occurrences of "tectonic" geopressured zones in China and eastern Russia is not available.

CONCLUSIONS

The maturation of hydrocarbons is primarily a temperature-controlled process. In deep sedimentary basins the conversion of kerogen to petroleum hydrocarbons progresses with increasing depth of burial in accord with the geothermal gradient. At depths where temperatures exceed 170°F (77°C) conversion accelerates; at greater depths, where temperatures exceed 300°F (150°C) and fluid pressures exceed 10,000 psi, natural catalytic cracking of petroleum begins. These conditions occur in geopressured zones at depths from about 9,000 to 22,000 ft (about 3 to 7 km) in the Gulf of Mexico basin, and at comparable depths in other geopressured basins of the world.

When the escape of petroleum hydrocarbons generated in the geopressure zone is sufficiently retarded, the natural cracking process yields sufficient methane to saturate all of the associated formation waters, and more. The excess methane, in the vapor phase, collects in reservoir rocks at structural highs, forming the gas reservoirs tapped by wells for commercial production. Exsolution of dissolved methane from waters escaping from the geopressured zone, as pressure and temperature decline, accounts for much of the nonassociated natural gas found in or adjacent to petroliferous basins of the world.

Natural gas in water solution in geopressured zones of the world can contribute greatly to future supplies, either by methane separation from waters produced by large-capacity flowing wells, or by production of gas exsolved in the reservoir as a consequence of water production from carefully-engineered fields, designed to lower the formation pressure regionally. We now can cultivate the resource, instead of just searching for and developing accidental gas occurrences.

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SECTION VIII. OTHER UNCONVENTIONAL DEPOSITS

CHAPTER 51

GEOCHEMICAL INTERRELATIONSHIPS AMONG FOSSIL FUELS, MARSH, AND LANDFILL GAS

Irving A. Breger[1]

It is generally accepted theory that fossil fuels arise from the residues of living systems. Bearing this in mind, there are four major potential precursors to fossil fuels: carbohydrates, proteins, lignin, and lipids (Breger, 1963). Each of these substances is produced in enormous quantities by animals and plants, and from a quantitative point of view, each could easily account for such biomasses as coal, crude oil, or kerogen, the insoluble organic matter of oil shales. By following the fate of each of these substances, that is, the carbohydrates, proteins, lignin, and lipids, in the geological environment, it is possible to establish clearly-defined interrelationships among the various fossil fuels.

Carbohydrates, the most important of which is cellulose, and proteins both suffer the same fate in the natural environment. These compounds readily undergo hydrolysis to simpler more or less water-soluble compounds that are metabolized by organisms to produce carbon dioxide or methane, water, ammonia, and hydrogen sulfide. Consequently, although available in enormous quantities, neither proteins nor carbohydrates make significant contributions to the formation of solid and liquid fossil fuels.

Lignin is a major constituent of most terrestrial plants, has a highly aromatic structure, and is not subject to hydrolysis or microbiological attack, as are proteins and carbohydrates.

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Transformations of lignin, particularly in its peripheral structure, in the soil environment lead to the formation of humic substances, and accumulation of such substances in a reducing environment leads to peat, the first stage in the formation of humic coals.

Lipids, the fourth geologically significant class of biologically derived substances, occur in enormous quantities in micro and macro fauna and flora. These are to a degree of terrestrial origin, but are primarily aquatic. These substances have essentially aliphatic structures, in sharp contrast to the aromatic structure of lignin. Although the mechanisms are not understood, some lipids can apparently be transformed into the hydrocarbons of crude oil. Other lipids, because of their unsaturated chemical structure, are prone to enter into condensation reactions to produce part or all of the kerogen of oil shales. Lignin and lipids, therefore, stand out as the major precursors of our fossil fuels.

A continuum can be visualized in which humic coals, derived from the lignin of terrestrial plants, and boghead coals, derived from accumulations of algal lipids in aquatic environments, may be considered as two end-points in a sequence of solid fossil fuels. As shown in the simplified diagram, Fig. 51-1, organic matter derived from both lignin and lipids, in varying proportions, can contribute to produce the insoluble organic component, the kerogen of carbonaceous shales. To understand differences among oil shales, or even variations in composition within a single shale, it is necessary to recognize contributions from these two very different organic substances.

As illustrated in Fig. 51-1, lipids may be transformed under geological conditions either into macromolecular material, such as boghead coal or kerogen, or into the far less complex hydrocarbons of crude oil. The product obtained is undoubtedly related to the nature of the progenitor lipids which, in turn, reflect the environment in which the organisms that produced the lipids flourished. An excellent example is the Green River Shale of Colorado, Wyoming, and Utah, where such substances as ozokerite, asphalt, gilsonite, and wurtzilite were each formed in a

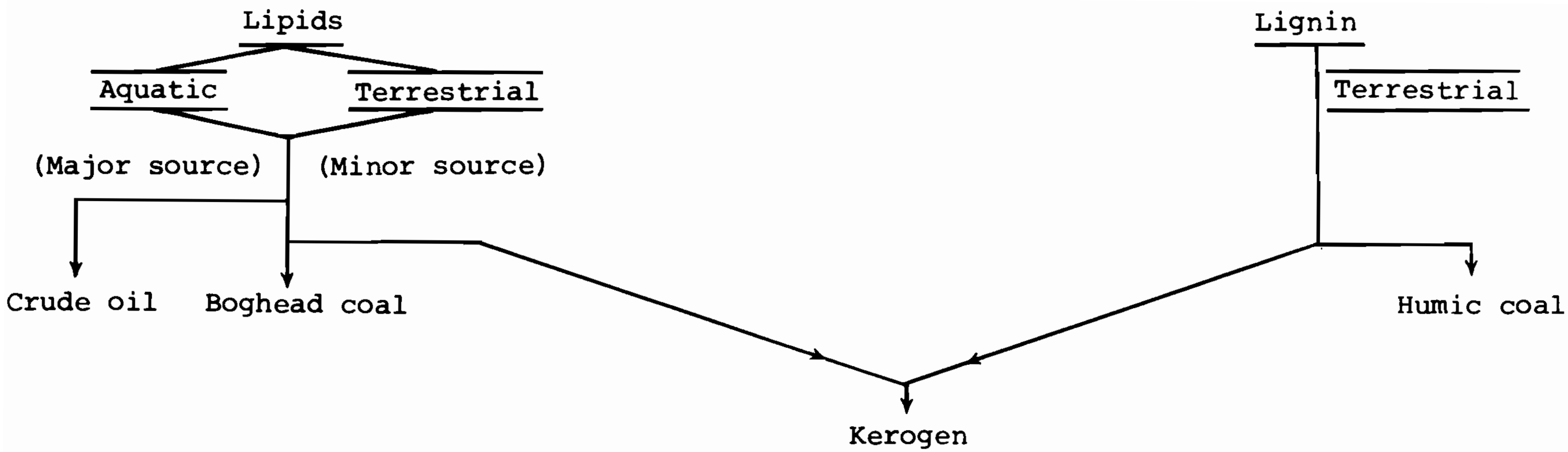

Figure 51-1.--Interrelationships among fossil fuels:
A simplistic presenation

particular stage of the lacustrine environment of the lakes of the ancient Uinta and Piceance Creek Basins. That these various substances, especially the asphalt, were produced is evidence that the lipids could be transformed into a number of organic substances at least one of which approached crude oil in composition and properties. The importance of the nature of the lipids in terms of the products derived from them is clearly evident.

Recognition of the origins of the organic contributions to the kerogen of a shale is, therefore, a key factor in understanding the interrelationships among various fossil fuels. Thus, the difference between a coal and a coaly shale is only the ratio of organic to inorganic constituents. Similarly, the difference between a boghead coal and an oil shale, such as the Green River Shale, especially where the contribution of terrestrial organic detritus is low, may reflect primarily the proportion of mineral matter to organic matter.

There still remains a segment of this picture that has not received much attention but which may have considerable significance in considering future sources of energy. Thus, although carbohydrates and proteins do not appear to be precursors for solid or liquid fossil fuels, they can in the course of their biochemical degradation be converted into useful quantities of methane. In this respect, the methane dissolved in coal may well be derived from the microbiological decomposition of the cellulose of the plant debris that fell into the peat bog. This, of course, suggests that peat bogs or other regions where cellulose or proteins undergo anaerobic decay may be potential sinks for methane from which the gas might be recovered.

Little is known about the yield of methane from such natural sources as bogs, marshes, lakes, or ponds. One report, however, provides a clue and suggests the need for quantitative studies. Beauchamp (1964) has noted that phenomenal amounts of methane and carbon dioxide can be released merely by stirring the bottom sediments of Lake Kivu, a lake which lies in the rift valley of Africa in the Republic of the Congo-Rwanda. Such an easily recoverable source of gaseous fuel could be of extreme importance to an energy-poor country.

Drawing an analogy from the origin of shales, where organic substances from various sources are mixed in variable proportion and with mineral matter, a new and significant source of energy is recognizable in systems commonly known as "sanitary landfill." The burial of human and municipal waste within intermittent layers of soil leads to a product that can be viewed, in reference to the above discussion, as "unconsolidated shale." There is one great difference, however, in that oil shales are formed from organic residues from which cellulose and proteins have been eliminated, whereas human and animal waste in landfill consists primarily of cellulose and proteins. Bovine waste, sewage sludge, urban refuse, and agricultural residues, when subjected to anaerobic fermentation under conditions of landfill, are all effective precursors of methane. Considering that 700×10^6 dry tons of organic waste are generated annually in the United States, the amount of energy potentially recoverable is enormous and has been estimated at 10^{15} Btu each year. Besides this, waste from the wood and pulp industry alone is an additional potential source of 540×10^{12} Btu annually (Poole, 1975).

Gas produced from the fermentation of organic residues under geological conditions generally contains from 35 to 55 percent methane, most of the remainder being carbon dioxide. The proportion of methane depends upon the nature of the starting material and other factors. A recent report outlines the conditions under which landfill in Palos Verdes, California, is now being tapped for the production of gas consisting of 99 percent methane (Anon., 1975). With a daily deposition of 3,000 to 4,000 tons of refuse during the life of the landfill, it has been estimated that it will be possible to continue to draw methane for 15 to 20 additional years. An economic evaluation of processing urban waste to recover pipeline quality gas has demonstrated that methane can be produced for $\$2.09/10^3ft^3$ ($\$0.074/m^3$), an acceptable price when compared to the anticipated cost of synthetic or natural fuels (Kispert, Sadek, and Wise, 1976).

From a geochemical point of view, the formation of peat or an oil shale represents the accumulation of solid residues of a fermentation process in which the gaseous products have either been lost or ignored. Spurred by the need for readily available sources of gaseous fuels, bogs should be examined as potential sources of fairly readily recoverable gas. In this respect, landfills of various types are analogous to shale and coal-forming environments in which fermentation is accelerated and from which it is possible to extract methane as an inexpensive by-product fuel.

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CHAPTER 52

THE ROLE OF CONTINENTAL GLACIATION AND HYDRATE FORMATION ON PETROLEUM OCCURRENCE

A.A. Trofimuk, N.V. Chersky, and V.P. Tsaryov[1]

Starting with Precambrian time, periodic global cooling was accompanied by continental glaciation and rock freezing to depths of two or more km. In its turn glacial movement resulted in displacement of fluids in the underlying sedimentary rocks. At the same time hydrate formation zones (HFZ) developed where natural gas interacting with water formed clathrate compounds--gas hydrates in continental sediments and the world's oceans.

Paleoglacial ice sheets were similar to those of modern Greenland and Antarctica in size and thickness. The ice cover was 1,000 km long, 3,000 to 4,000 m thick, and its retreat lasted about 40,000 years. The formation of ice 3 to 4 km thick increased geostatic load on underlying rock by 270 to 360 kg/cm^2. This resulted in fluid (water, oil and gas) displacement from low-permeability beds into horizons with good reservoir properties. In the latter, fluid displacement resulted from the extra load, from the ice-covered areas outward to the ice margins.

Glacier-induced fluid displacement in the sedimentary cover led to hydrocarbon migration in the direction of glacier movement and partial oil and gas reservoir failure due to intensive water movement. The displaced hydrocarbons supplemented the existing oil and gas reservoirs and formed new ones in the sediments marginal to the ice sheet.

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[1]USSR.

Calculations show that in the course of one cycle (advance and retreat of glacier) there might be displacement of about 10 percent of the hydrocarbons in reservoirs beneath the ice field. No less than five to eight cycles of this sort took place in Europe, North America, and West Siberia in Quaternary time. Thus, glaciations may have influenced greatly the redistribution of hydrocarbons in reservoirs. This is why enlarged hydrocarbon reserves (other conditions being equal) should be characteristic of areas which correspond to the margins of ancient ice sheets, for example, Permo-carboniferous in the southern hemisphere, Quaternary in the northern one, and Recent in Greenland and Antarctica.

Y.F. Macogon experimentally established that when hydrate films form at the gas-water interface, the equilibrium between free and dissolved gas in water is broken, i.e., the quantity of the latter decreases by two to four times. Thus, in HFZ large amounts of dissolved gas come out of solution from the formation water. Assuming this to be the case, natural gas accumulation processes may be shown by the following model.

As the climate cools, formation temperatures are lowered, leading to frozen rocks and HFZ. In the HFZ, intensive dissolved-gas recovery from the water and its conversion to hydrates occurs. On reaching maximum HFZ thicknesses of 1,600 to 2,000 m (Siberia) at temperature minima, successive warmings raise reservoir temperatures and therefore decrease HFZ thickness. Thus the lowest HFZ margin growth, 500 to 800 m, took place during Interglacials. As HFZ decreased in thickness, the hydrates below HFZ decomposed and by diffusion and effusion the gas migrated to the HFZ. As the HFZ thicknesses decreased in this way the quantity of gas in it remained practically constant, i.e., it became more concentrated. As the base of the HFZ moved upward with the warming, HFZ into the cap-rock, the gas that accumulated in the form of hydrates remained below this seal. Then the hydrates decomposed and the free gas thus formed was trapped in the gas reservoir rock.

Thus favorable conditions for forming large gas accumulations existed in high latitudes (maximum cooling areas), to

2,000 m depth. Observation of the relationship of the Permo-Carboniferous and Quaternary ice sheet margins to oil and gas bearing regions shows that, under favorable geological conditions, large oil and gas accumulations are associated with peripheral glacial zones in Europe, Asia, North and South America, and Australia. In high latitudes, to depths of 2,000 m, high gas-reservoir densities are several times more prevalent than limited ones.

Intensive biochemical gas hydrate accumulations also occur in World ocean-bottom sediments. Water depths at which hydrate formation is possible for different temperature zones are shown in Table 52-1. The HFZ thicknesses in sea-bottom sediments are given in Table 52-2. Table 52-1 suggests that the hydrate-formation zones occupy more than 90 percent of the world ocean area, to an average thickness of about 300 m.

TABLE 52-1.--Gas hydrate distribution by temperature zones and sediment depth

Temperature zones	Gas distribution (Latitude)	Depth of upper surface of HFZ (m)		
		CH_4+CO_2	H_2S	N_2
Polar	Up to 76° N. Up to 61° S.	250	10	1600
Temperate	76°-46° N. 61°-46° S.	350	30	1600
Subtropical	46°-25° N. 46°-25° S.	600	70	2100
Tropical	25°N-25°S	650	100	2300

Organic matter decomposes due to microbiological processes on reaching the sea floor. CH_4, CO_2, N_2, and H_2S gases which are produced as a result are not dispersed in water but are converted to hydrates which are mechanically bonded to the sediments. Such a process lasts for about 10 million years. Calculations were carried out for benthic sediments of 300 m thickness, taking into account the amount of organic substance reaching the bottom.

TABLE 52-2.--HFZ deposit depth in sea floor sediments for gas mixtures CH_4-80% and CO_2-20%

Depth to sea floor (m)	Sea floor temperature (°C)			Average geothermal gradient, Sea floor (°C/km)	Pressure, sea floor (atm)	Depth, sea floor to base of HFZ		
	Tropical and subtropical	Temperate	Polar			Tropical and subtropical	Temperate	Polar
200	16	5	0	50	20.5	0	0	0
400	10	4	0	50	41.5	0	15	90
600	8	3	0	50	61.5	0	110	150
1000	4	2	0	70	102.5	135	170	200
1500	4	1	0	70	153.7	185	225	245
2000	3	1	0	70	205.0	240	270	290
3000	2	1	0	70	307.5	285	300	310
4000	2	1	0	70	410.0	310	325	340
6000	0	0	0	60	615.0	470	470	470

Results of the calculations show that methane reserves of the World ocean may be several orders of magnitude higher than those of continental sedimentary rocks. The CH_4 concentrations of sea bottom sediments compare in magnitude with the gas content in conventional deposits and may even be larger. Thus the sedimentary gas factor is of the order of 10 to 80 m^3 per m^3 of rock and gas density ranges from 2,000 to 5,000 m^3 per m^2 of sea bottom; the total methane reserves of the world ocean are estimated to be more than 16×10^{12} m^3.

Natural gas accumulation in the HFZ has been taking place not only in sea floor sediments but also on continents in sedimentary rocks down to about 1,500 m. The distribution of HFZ areas on the continents corresponds at the present time to places where the soil has been frozen for long periods of time and may even have been displaced to lower latitudes. Orenburgh gas-condensate field may serve as an example of such a displacement, where conditions of hydrate sedimentation in productive horizons are observed at formation temperatures above +30°C.

We have already observed the upward migration effect of the HFZ base on concentration of gas in reservoirs in strata below present HFZ. Within the HFZ existing today the gas accumulation (solid phase) occurred as a result of the observed mechanism.

Even under unfavourable conditions of accumulation, without seals and traps in the HFZ, gas hydrate reservoirs may form. The calculations showed that even at a recovery ratio of 0.1, the average gas reservoir density is 5×10^6 m^3 per km^2 in Viluy syncline, with no regional seals present. In North West Siberia the HFZ gas reservoir density in regional gas deposits of Cenomanian age should be an order of magnitude higher.

Thus the cryosphere and the HFZ associated with it greatly influenced the formation and the distribution of gas resources in sedimentary rocks.

Table 52-3 shows the cryosphere and HFZ distribution. Table 52-4 gives the data on their possible effect upon hydrocarbon reservoir distribution.

Principles for evaluating the resources of oil and gas in higher-latitude regions, beyond the HFZ, include:

TABLE 52-3.--Hydrate formation zones, and ice sheet distribution on the Earth (average thickness of HFZ on continents, 700 m; on ocean floor, 300m)

Age	Continental glaciers			Hydrate formation zones				
				Continents (northern hemisphere)			The world ocean	
	Area ($10^6 km^2$)	Area (%)	Volume ($10^6 km^3$)	Area ($10^6 km^2$)	Area (%)	Rock volume in HFZ ($10^6 km^3$)	Area ($10^6 km^2$)	Rock volume ($10^6 km^3$)
Permo-Carboniferous period	70	--	175	--	--	--	--	--
Quaternary (temperature minimum)	45	30	60	75	50	52	333	100
Recent	15	9	24	40	27	28	335	100

TABLE 52-4.--Distribution of world oil and gas resources relative to Quaternary glaciation

Region	Distribution		Resources in glaciated areas (%)	
	Continental glaciation	HFZ	Oil	Gas
North America	38-46° N.Lat	35° N.Lat	95	40
West Europe	49° N.Lat	50° N.Lat	95	90
East Europe	--	47° N.Lat	--	40
West Siberia	59° N.Lat	56° N.Lat	80	98
Total northern hemisphere	50° N.Lat	45° N.Lat	60*(8**)	60

* - excluding the USSR.

** - excluding the USSR and Athabaska.

1. The area where thick aquifers, overlapped by cap-rocks, were present in the earlier HFZ are prospective for gas.
2. The base of a recent HFZ, independent of structural conditions, is a prospective regional gas accumulation area.
3. In zones 60 to 300 km wide on both sides of overlying Quaternary glaciers, both new and supplemental oil and gas accumulation zones were formed in association with glacier joint systems.
4. Sediments covering more than 90 percent of the world sea floor in basins with water depths above 300 to 600 m contain methane in solid phase with high concentration values.

If the foregoing hypothesis on gas hydrates is correct, it seems reasonable that hydrocarbon production soon will shift to the areas where cryosphere and the resulting HFZ were dominant factors influencing oil and natural gas resource accumulation and distribution, that is, the World ocean, Greenland, Antarctica, and high latitude areas of Europe, Asia, and America.

CHAPTER 53

METHANE HYDRATE IN THE SEA FLOOR--A SIGNIFICANT RESOURCE?

Daniel J. Milton[1]

INTRODUCTION

About 30 years ago it was noted that beneath the thicker zones of permafrost in arctic regions, temperatures are low enough and pressures high enough to fall in the field of stability of the hydrate of natural gas, an ice-like clathrate compound with an ideal formula (CH_4,C_2H_6, etc.)· 5-3/4 H_2O. In 1970, well logging and formation tests in the Messoyakha gas field in Western Siberia indicated some tens of billions (10^9)m^3 of gas frozen in the hydrate form, the extraction of which on an economic basis remains problematic (Makogon, Trebin et al., 1971; Makogon, Tsarev, and Cherskiy, 1972). More recently, gas hydrates have been discovered in the Mackenzie Delta, Northwest Territories (Bily and Dick, 1974), and one must assume that they are widespread in the Arctic.

Sokolov in 1966 was apparently the first to point out that temperatures and pressures over much of the sea bottom fall in the stability field of natural gas hydrate, and Stoll, Ewing, and Bryan (1971) first presented observations suggesting its actual presence in sea floor sediments. The possible occurrence of submarine hydrate deposits is being actively investigated, particularly by Trofimuk, Cherskiy, Tsarev, and Makogon in the Soviet Union (Trofimuk et al., 1973; Makogon et al., 1973) and several investigators in the United States associated with the

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Deep Sea Drilling Project (see especially Kaplan, 1974). In December 1975, Trofimuk, Cherskiy, and Tsarev published a calculation showing that over $10^{18} m^3$ of methane are frozen in the submarine zone of hydrate formation. Because previous estimates put the quantity of natural gas in the entire lithosphere and hydrosphere of the earth at one-sixth this amount, evaluation of the evidence is clearly of importance.

GAS HYDRATE IN RECOVERED SUBMARINE CORES

Perhaps the only person who may have been favored with the actual sight of naturally formed gas hydrate was A. G. Yefremova, who saw in large cavities in sediment cores lifted from the bottom of the Black Sea microcrystalline aggregates resembling hoarfrost that disappeared before her eyes (Yefremova and Zhizhchenko, 1974). In a number of sediment cores taken during the Deep Sea Drilling Project, gas evolved, sometimes for several hours, after the cores were lifted on deck. The gas pressures generated were on occasion sufficient to extrude cores from the barrel or rupture sealed containers. The quantity of gas evolved and the slow rate of evolution have been interpreted as indicating decomposition of gas hydrate, although the solid was never actually seen. Formation of ice on exposed cores in conjunction with gas discharge, mentioned by Stoll et al., supports this possibility. Dissociation of hydrate, which requires 13,000 cal/mol of CH_4 in methane hydrate, would cool the system much more than release of gas from aqueous solution, which requires only 4,600 cal/mol, or than Joule-Thompson cooling of gas on expansion.

INDICATIONS OF HYDRATE FROM SEISMIC SURVEYING AND DEEP SEA DRILLING

Information on sea floor sediments in situ comes largely from seismic exploration. Arguments for indications of gas hydrate are persuasive, but when examined closely are far from simple or self-evident. The most striking phenomenon is the bottom-simulating reflection. The reflector (known as the "BSR") parallels the water-sediment interface and lies several hundred metres lower. Where stratification is conformable with the interface, the BSR is difficult to detect, but elsewhere it appears transecting bedding reflections. A BSR was apparently first noted on the Blake-Bahama outer ridge of the North Atlantic Ocean (Markl et al., 1970; Ewing and Hollister, 1972), and one has since been reported from the Bering Sea and elsewhere in the North Pacific (Scholl and Creager, 1973) and the Beaufort Sea in the Arctic Ocean (Grantz, et al., 1976).

The only physical surface that would be expected to cross-cut bedding but parallel the bottom is an isotherm; it is therefore logical to conclude that the BSR represents a temperature-controlled phase change or diagenetic effect. Roughly the BSRs lie at depths that correspond to the univariant equilibrium gas + water = hydrate. But when one attempts to be more precise, a number of problems are encountered. The P-T conditions of the equilibrium depend on the composition of the gas phase. For the two localities which have been drilled (Blake-Bahama outer ridge and Bering Sea), the gas released from the cores has been analyzed and found to be essentially pure methane or methane with a few percent of carbon dioxide, which changes equilibrium conditions only slightly. In the Beaufort Sea, however, offshore from the Alaska North Slope gas fields, higher gravity gases could well be present, and would raise the temperature and pressure of the univariant equilibrium. Pressures at depth can be calculated fairly straightforwardly, but temperatures, except for a few downhole measurements, must be estimated from the heat flow at the top of the sediment layer and from assumptions as to the conductivities below (which are indeed not independent of whether a hydrate occupies the pores). Finally, conversion of seismic reflection times to depth requires a knowledge of the velocity profile (which again depends on whether a hydrate is present).

Two DSDP holes were drilled to investigate the BSR on the Blake-Bahama outer ridge, site 102 on the crest of the ridge in 3,426 m of water and site 104 on the flank in 3,811 m (Hollister et al., 1972). The reflection occurred at 0.62 sec at site 102 and 0.61 sec at site 104, although Markl et al. indicate a deepening by about 0.1 sec as the water depth increases along the axis of the ridge from 2,500 to 4,500 m. The indicated depth is reasonable for the hydrate equilibrium (thermal data are lacking), as is the apparent deepening down the ridge axis. Drilling in hole 102 underwent marked slowing of penetration at about 620 m and hard drilling continued to the total depth of 661 m. The break occurred in hemipelagic muds and does not correspond to any marked lithologic change although there is a general downward increase in siderite nodules and lenses in that part of the section. Hole 104 unfortunately was terminated at 617 m, but after encountering 15 cm of very hard ankerite in either a layer or nodule at 615 m. The DSDP team correlate the drilling breaks with the BSR which, as the break falls no higher than middle Miocene at site 104 and at the Miocene-Pliocene boundary at site 102, would thus transgress stratification as it is seen to do on the seismic records. The entire section in these holes was gassy; voids in the core produced by gas expansion were noted in the log (including cores at 634 to 636 m and 659 to 661 m at site 102, below the presumed BSR). If the BSR is at 615 to 620 m, it means seismic velocities in the section above average 2.0 km/sec rather than the 1.6 km/sec normal for the upper few hundred metres of deep sea sediments. Such high velocities have been independently confirmed by sonobuoy measurements in the area (Bryan, 1974). Stoll et al. (1971) proposed that the anomalous velocity occurs in a frozen hydrate zone above the BSR and they demonstrated experimentally that crystallization of hydrates in sediments does indeed increase the acoustic velocity.

Beneath the flat seabed of the Umnak Plateau of the Bering Sea at about 1,900 m depth the time interval between the bottom reflection and the BSR is constant within ± 3½ percent (J. Howell, personal communication). The apparent depth to the BSR as seen on the record published by Scholl and Creager (1973) appears, however, to decrease markedly as the water deepens to 3,100 m; this behavior is opposite to what would be expected for the hydrate equilibrium surface. If a velocity profile of 1.7 km/sec in the top 400 m and 2.62 km/sec below is taken, the

BSR lies at 600 to 610 m beneath the bottom. These velocities are based on measurements on cores (the properties of which would change if hydrates thawed during the lift) but are also supported by sonobuoy velocities, which appear to be the same in nearby areas where the BSR is present and where it is not (Howell, personal communication).

Three DSDP drill holes in the Bering Sea (Creager, Scholl, et al., 1973) penetrated to the probable depth of the BSR, revealing a transition from diatom ooze or highly diatomaceous deposits downward to mudstone or claystone nearly barren of siliceous microfossils. In two holes the change occurs within a few metres; in one it is transitional through about 100 m of section. The horizon is time-transgressive, and because it is unlikely that pelagic diatom ooze would transgressively bury a gently sloping bottom, it is assumed to be a diagenetic boundary. The bulk density and acoustic velocity on cores are much greater in the lower unit and the contrast could cause the reflection event.

Downhole temperatures were measured at DSDP site 184 (water depth 1,910 m) where the BSR appears to be at 600 m depth (Erickson, 1973). The bottom water temperature was 2°C; the temperature measured at 174 m, 16.25°C, and at 342 m, 18.5°C, but technical difficulties during the operation led Erickson to question the latter measurement. Thermal conductivities of cores from the bottom to 600 m subbottom measured on shipboard were rather constant at about 2.16 mcal/cm sec °C. From this conductivity and the termal gradient to 174 m, Erickson calculated a heat flow of 1.77 $\mu cal/cm^2$ sec, a reasonable value for a marginal basin behind an active island arc. Extrapolating this gradient to 600 m subbottom gives a temperature of 49°C, far too high for methane hydrate to exist at the prevalent pressure. On the other hand, if the measurement at 342 m is accepted and the gradient between 174 and 342 m is extrapolated, it gives 23.6°C at the BSR, which is not far from the 18°C expected for a methane + water = hydrate equilibrium. The measured conductivities are reasonable for sea floor sediments. The conductivity in a frozen water-saturated sediment can be calculated by the formula:

$$K_f/K_t = (K_i/K_w)^{\Phi} = 4^{\Phi}$$

involving the conductivities of the frozen and thawed material, ice and water, as indicated by the subscripts, and Φ, the volume fraction of pore space (Gold and Lachenbruch, 1973). The conductivity of a clathrate ice has never been measured, but a reasonable guess would be 13 percent less than that of ordinary ice, corresponding to the lower relative density of the empty clathrate lattice. Water content and density measurements on cores from site 184 indicate $\Phi = 0.73$, so that:

$$K_f/K_t = (3.5)^{0.73} = 2.5.$$

This does not account for the sixfold increase in thermal gradient (which would require an impossible porosity) but it goes far enough in the right direction that the correctness of the measurement at 342 m and the presence of a hydrate zone below some level approximating 175 m are attractive possibilities.

Various suggestions for the nature of the actual reflector at the BSR have been advanced. At the Blake-Bahama outer ridge, the normal densification of sediments with depth would put the velocity below the BSR at just about the abnormal (hydrate-enhanced?) velocity above, so there would be little velocity contrast to generate a reflection. Bryan (1974) suggests that the contrast is between a high velocity hydrated section above the equilibrium isotherm and a thin low velocity zone rich in free gas trapped beneath the hydrate zone. An alternative hypothesis for this locality was suggested by Ewing and Hollister (1972): that the equilibrium isotherm is at slightly greater depth and the reflector is a thin high velocity hydrate-rich zone produced at the base of the zone of stability as gas migrated upward and was trapped by freezing. This, however, would not explain anomalous velocities higher in the section, the original reason for postulating the presence of hydrate.

Claypool and Kaplan (1974) suggest that at both localities the reflection comes from a horizon of lithologic change produced by diagenesis but related in an indirect way to the hydrate equilibrium boundary. They interpret the subreflector unit at both localities as having been lithified by the dissolution of carbonate and silica from microfossils and reprecipitation as cement. These processes depend on the pH of the pore water, which depends on the concentrations of CH_4 and CO_2, which in turn depend on various processes of bacterial action. Claypool and Kaplan suggest two ways in which the hydrate equilibrium may be involved: first, bubbles of free gas trapped beneath a hydrate layer could create open spaces in the sediment in which precipitation takes place; or second, CO_2 in the hydrate zone could be locked up in the hydrate and unavailable for reaction. The latter hypothesis may perhaps be taken as representative of a host of possible effects on pore water chemistry of reaction with hydrates.

Recently a BSR has been found in the Beaufort Sea on the continental slope north of Alaska, recognizable on about 60 percent of seismic lines run (Grantz et al., 1976). The BSR appears to be 100 to 300 m beneath the bottom. It extends shoreward from the limit of survey in water more than 2,500 m deep to a disappearance at a water depth of 400 to 600 m. It is most strongly developed beneath bathymetric highs and is weak or absent beneath bathymetric lows. In a few places where it is particularly well developed beneath highs, the underlying reflectors appear on time sections to be bowed downward. The investigators conclude that a hydrate zone has formed pseudo-anticlinal traps beneath which free gas has accumulated in sufficient quantity to create an interval of anomalously low seismic velocity. In the Arctic Ocean where low water temperatures allow the zone of hydrate formation to extend to shallower water, the seaward deepening of the BSR beneath the bottom should be apparent, if it indeed represents the base of the zone of hydrate formation. No drilling has been done in this area; higher gravity gas of thermocatalytic origin similar to that in the nearby onshore gas fields could well be involved.

NECESSARY CONDITIONS FOR THE ACCUMULATION OF HYDRATE

For a gas hydrate to exist, not only must the temperature and pressure fall within the range of stability of the hydrate, but the content of gas in the system must exceed the limit of solubility in the coexistent water. This point has not always been properly appreciated. The solubility of methane in water in equilibrium with free gas (represented by the surface L—V+L in Fig. 53-1) increases with pressure (at constant temperature) and decreases with temperature (at constant pressure) to a minimum at 70°C or 80°C, above which it increases. The solubility as temperature or pressure approach the univariant equilibrium L-V-H can be determined by extrapolation of standard experimental measurements, such as those of Culberson and McKetta (1951), with minor corrections if the anomalous decrease in solubility with decreasing temperature just before univariant curve reported by Makogon (1974) is correct. The question is the solubility in equilibrium with hydrate, represented by the surface L—H+L. Makogon (1974) in his book[2] reports that the solubility undergoes an immediate and drastic decrease at the univariant curve, for example from about 90 to about 18 mmol/kg at 10°C and 72 atm, a phenomenon which he ascribes to a change in the structure of liquid water. Thereafter the solubility slowly increases with pressure. His findings, which have been accepted explicitly by Claypool and Kaplan (based on an earlier report by Makogon et al., 1972) and implicitly by Trofimuk et al. (1973), make almost inevitable the accumulation of hydrate in sea floor sediments at the level where water suddenly loses its ability to contain dissolved methane. However, such a discontinuity in the solubility of a component in a phase violates thermodynamic principles. The boundaries L—V+L and L—H+L must intersect at the univariant equilibrium. A change in the properties of water could only lead to an anomalous curvature in either of these boundaries, and it is difficult to see why such behavior, if it does occur, should occur at temperatures and pressures that correspond to the methane hydrate univariant equilibrium. The solubility on the divariant surface L—H+L must decrease with increasing pressure because formation of the hydrate results in a decrease in volume. The volume change for the reaction

$$CH_{4(liq)} + nH_2O_{(liq)} \longrightarrow CH_4 \cdot nH_2O_{(hyd)}$$

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[2] I have not had the opportunity to read the original report of the experiment (Makogon, Koblova, and Khalikov, 1971).

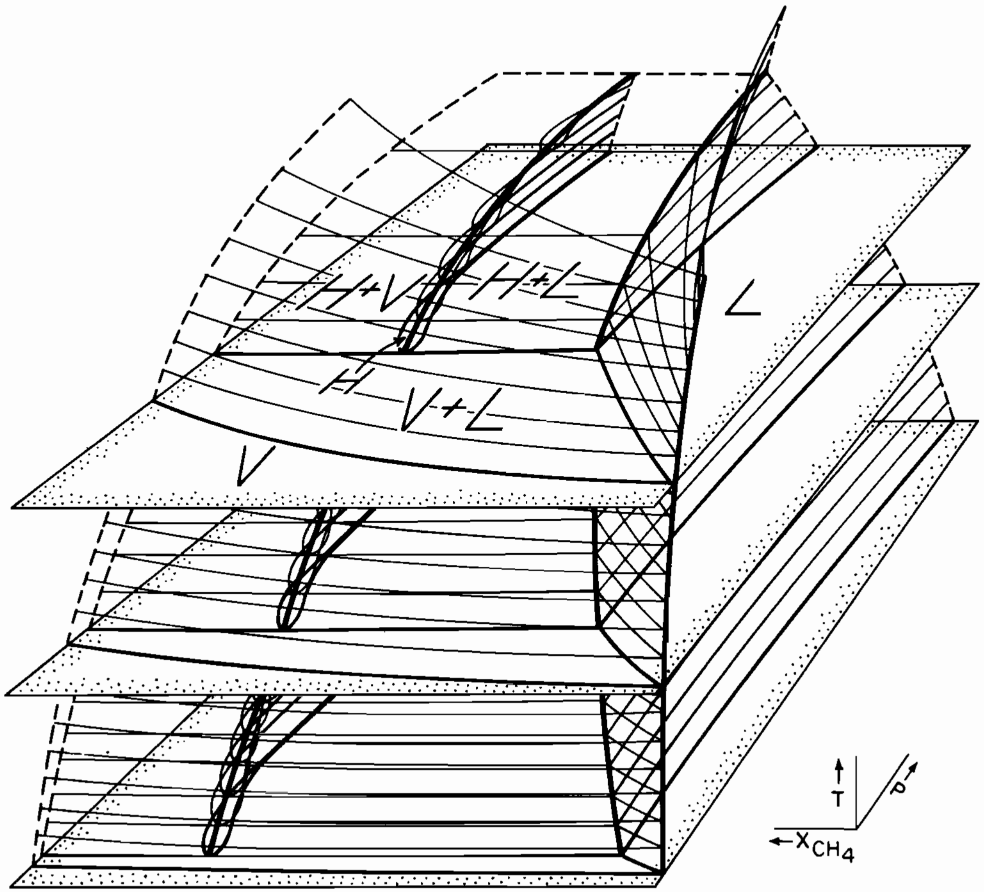

Figure 53-1.--Schematic phase diagram for a part of the CH_4-H_2O system, showing univariant curves (heavy lines) and traces of divariant surfaces in isothermal planes (light lines)

may be calculated from the volume of hydrate per mol water, the partial molal volume of methane in aqueous solution, and the mol volume of liquid water:

$$\Delta V = nV_{(hyd)} - \bar{V}_{CH_4(liq)} - nV_{H_2O}$$

$$\Delta V = 22.68n - 35.0 - 18.02n.$$

The occupancy of vacancies in the clathrate structure increases with pressure, so that n decreases from about 7.25 at the quadruple point to nearly the ideal 5.75 above 1,000 bars. ΔV thus increases from $\Delta V = -1.22$ to $\Delta V = -8.09$, indicating that the pressure effect on solubility will be negative, and greater at greater pressures, as indicated by the curvature of lines L—H+L on the isothermal sections of Fig. 53-1.

An experiment by Hemmingsen (1975) yielded results conflicting with Makogon's. He placed a beaker of water in a CH_4-filled pressure chamber and measured the flux of CH_4 into a Teflon tube completely immersed in the water and brought to the outside via a capillary tube. The flux of CH_4 through the Teflon barrier at 5°C increased by a factor of three as a linear function of the gas pressure as the gas pressure was increased from 20 to 68 atm. The gas flux is directly related to the fugacity of the gas in solution. Since the fugacity for real gases in aqueous solution at constant composition increases only about 15 percent to 100 atm (Enns et al., 1965), the experiment may be taken as indicating an approximately linear increase in solubility with pressure not only to the univariant equilibrium but beyond this point in the metastable liquid. In the presence of hydrates (which formed spontaneously only when the pressure was raised to about 70 atm) the gas flux remained unchanged at pressures between 52 and 82 atm at the same flux as for hydrate-free water at the three phase equilibrium pressure of 44 atm. If the fugacity of methane in solution in equilibrium with its hydrate depends only on the temperature, as this experiment would seem to suggest, then solubility along the L—H+L boundary would have the value at the univariant equilibrium reduced in accordance with the pressure effect on Henry's law constant. The solubility of methane in sea water in a frozen zone of bottom sediment at 2°C would thus decrease from about 70 mmol/kg at a water depth of 350 m, the minimum for hydrate stability, to about 40 mmol/kg at a water depth of 4,000 m (Fig. 53-2). Actually, as there is no reason why the fugacity on the phase boundary should be perfectly constant, this extrapolation should not be taken as more than an indication of the general magnitude of the solubility. Along the base of the hydrated zone in the sediment column from shallow to deep water the solubility increases along the univariant curve from 70 to about 200 mmol/kg below 700 m of sediment and 4,000 m of sea water. In any vertical section through the hydrated zone, the concentration of dissolved methane in water in equilibrium with the hydrate will decrease from bottom to top, with the steepness of the gradient greatest under the deepest water. This is indicated in Fig. 53-2, which also shows the solubility in equilibrium with free gas at greater depths.

Is the concentration of biogenic methane in interstitial water likely to reach the minimum value for hydrate formation? Hammond (1974) found about 20 mmol/kg methane (no more accurately than a factor of two) in DSDP cores from the Carioco Trench off Venezuela, where high productivity of the water and anoxic bottom conditions favor methane genesis and high bottom water temperatures exclude formation of hydrate. Claypool and Kaplan estimate from the δC^{13} data on deep sea cores that only 20 to 30 mmol/kg of methane form biologically. If these values prevail, there is no reason to expect hydrates to form from biogenic methane. Our knowledge of sea floor biogeochemistry, however, is far too incomplete to place a limit on methane concentrations in sediments.

Consider a column of sediment with methane being generated throughout. Leakage to sea water or destruction by methane-consuming bacteria at the shallowest levels (Barnes et al., 1976) will keep the concentration at the water-sediment interface near zero, so methane will diffuse upward through the pore water. As the concentrations increase, at some level the solubility limit is reached. This may occur within the zone of hydrate stability, more likely in the upper part where the solubility is lowest, rather than at the base as predicted from the Makogon model. Or it may occur first at a greater depth, producing free gas that

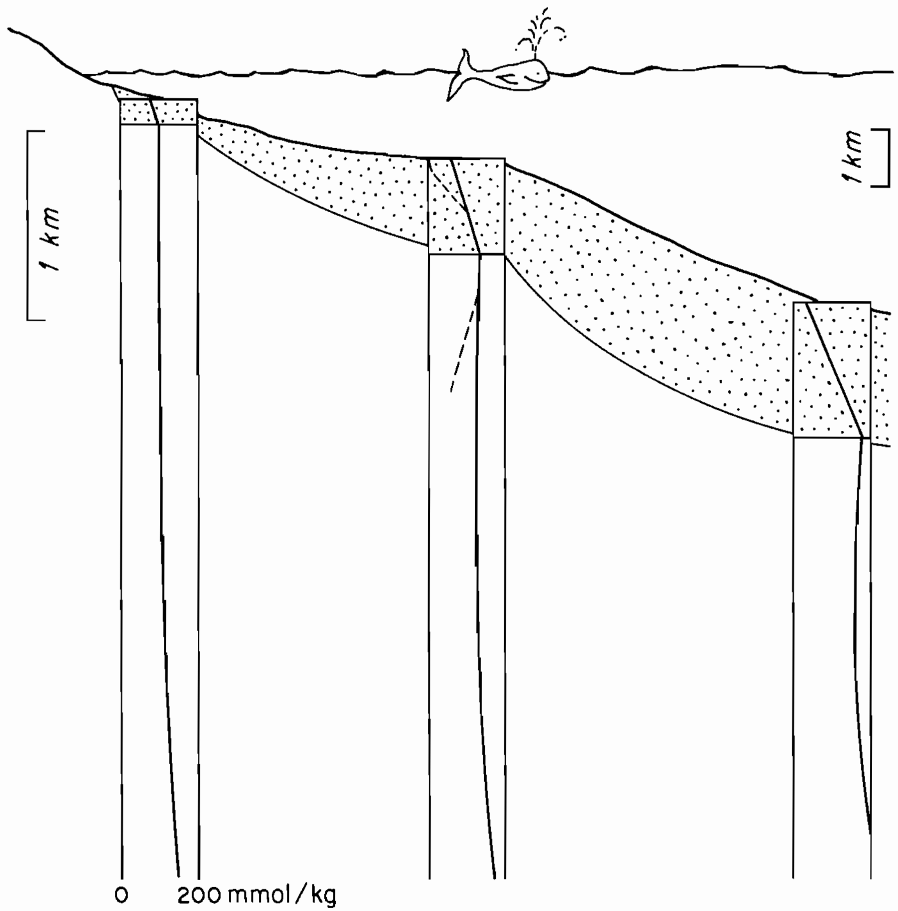

Figure 53-2.--Profiles of methane concentration in pore water in the potential hydrate zone (stippled) and below for average geothermal and ocean temperature gradients. Solid lines indicate solubility limit; dashed line gives an example of possible concentrations consistent with the existence of hydrate close above and free gas close below the equilibrium depth. Note difference in scales in water and subbottom depths.

would bubble upward, extending the interval of saturation until hydration occurs at the limiting isotherm. When hydrate forms, six or seven molecules of H_2O are frozen for every molecule of CH_4. But since there are a thousand molecules of H_2O for every two or three of CH_4, the effect on the permeability is negligible. The concentration gradiant in the pore water in the presence of hydrate will be that along the hydrate-liquid equilibrium curve, which would be steeper than that in the unfrozen section below and less steep than in an unfrozen section above (dashed line in Fig. 53-2). If the initial concentration gradient through the column was at a steady state for diffusive equilibrium, then the effect of hydrate formation paradoxically may be to facilitate transport of methane through the hydrated zone. Accumulation of hydrate to the extent where it would destroy the connectivity of the pore water system or extension of the depth interval of hydrate formation depends not only on the equilibrium conditions, which are functions of temperature, pressure, and composition, but on such factors as the rate of methane genesis, the kinetics of the hydrate reaction, the permeability of the pore water system, and particularly on local irregularities and perturbations in these factors. Theoretically, the problem can be solved, but practically not until more is learned about conditions and processes in sea floor sediments, both by actual exploration and by laboratory investigation of simple models.

CONCLUSIONS

The "zone of hydrate formation" is better considered a zone of potential hydrate formation. We do not know enough to state whether in any particular environment it will or will not occur. It is perhaps slightly easier to explain why hydrate should fail to accumulate, even in sediments with fairly active methane genesis, than to explain why it should accumulate. Nevertheless, it appears that hydrate does exist in submarine sediments. The best evidence is the behavior of cores outgassing slowly and endothermically after recovery. The correspondence of the location and configuration of the bottom simulating reflector with the expected base of the zone of hydrate formation is highly suggestive, but drilling at the two best known localities has not provided definitive evidence for the presence of hydrate.

Recovery of cores at bottom pressure is an obvious desiderandum and may be necessary before the BSR is accepted as an indicator of hydrate. Attempts have been made but without success (Creager et al., 1973). Measurements in situ in deep sea drill holes of such properties as thermal conductivity or acoustic velocity (which have been measured successfully during shallow coring) or even gas fugacities would be valuable in understanding subbottom conditions.

Outstanding problems in the chemistry of hydrates critical to understanding their occurrence in nature concern not only the incompletely mapped phase space, as discussed above, but despite much work that has been done already (Makogon, 1974), aspects of the kinetics of hydration and decomposition.

Commercial recovery of gas from submarine hydrate itself would seem a very difficult task. A hydrate zone, however, could have direct economic importance as a trap for natural gas, perhaps of themocatalytic rather than biogenic origin, migrating from greater depths. Nonrecognition of a hydrate zone, or false identification where one does not exist, during the exploration of an offshore gas field would be hazardous to both the success and safety of a drilling program. Finally, a stage of clathrate freezing may have figured in the history of apparently ordinary gas fields and sedimentary sequences with geologic consequences that remain to be investigated.

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CHAPTER 54

METHANE GAS RECOVERY FROM LANDFILLS--A WORLDWIDE PERSPECTIVE

Robert A. Colonna[1]

INTRODUCTION

The global potential of methane gas recoverable from landfills is large. I will discuss in order the economics of natural gas, or the demand side of the equation, the United States' landfill gas potential, the demonstration project in Mountain View, California, and estimates of landfill gas potential in other nations.

The generation of methane gas as one of the products of waste decomposition in a landfill has been viewed historically as a problem to be solved. At concentrations of 5 to 15 percent in air this gas can be explosive, and therefore precautions must be taken to vent the gas to the atmosphere, usually "flaring" it to get rid of it. The escalation of energy prices over the past 3 years has forced all nations to seek new energy sources. One such potential source of energy is methane gas recovered from sanitary landfills. While this source represents only a small fraction of the total worldwide demand for energy, all sources are currently under investigation by public officials, as well as private industry. Moreover, the recovery and use of this gas solves the potential safety problem posed by such gas if allowed to generate in an uncontrolled manner.

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[1]Environmental Protection Agency, Washington, D.C., USA.

THE ECONOMICS OF NATURAL GAS IN THE UNITED STATES

The case of natural gas has been one of severe price escalation and shortages in supply. While the demand for natural gas continues to climb because of expensive energy alternatives, the annual supply to distributors, according to the American Gas Association, has been reduced from 16.5 to 14.9 x $10^{12}ft^3$ between 1973 and 1975. This discrepancy will have a profound long-term effect on gas prices. The effect is not immediate because most utilities, which are the major gas purchasers, sign long-term contracts for a specified quantity of gas at a specified price. Therefore, while the utilities' new contracts reflect significantly higher prices, e.g., \$1.50 to \$2.00 per 10^3ft^3, their increase in average price has lagged behind because they still have several years to run on most existing contracts. As these contracts expire, the average price will approach current prices. Moreover, all utilities buy "peak shaving" gas for surges in gas demand. Currently, the price for peak shaving gas ranges from \$3.00 to \$5.00 per 10^3ft^3. Peak shaving gas used in the United States is commonly LNG (liquefied natural gas) or SNG (synthetic natural gas) from Canada, the Far East, or the Middle East. Some of the developmental projects, such as coal gasification, will result in gas at even higher prices than the \$3.00 to \$5.00 range. In light of this situation, any source which can deliver gas at \$2.00 to \$3.00 per 10^3ft^3 will be very competitive right now.

If natural gas for interstate shipment is deregulated, as proposed by many in Congress and the Administration, the price of gas may double or triple, which will make any new source of gas at \$2.00 to \$3.00 per 10^3ft^3 even more price competitive. The most recent such proposal is S.3422, introduced in the United States Senate on May 12, 1976. This bill, among many other provisions, calls for a base price at the well head for interstate gas of \$1.35 per 10^3ft^3, as compared with the current ceiling of \$.52.

MARKETABILITY OF LANDFILL GAS

In 1974, the Systems Management Division of the Office of Solid Waste Management Programs in the Environmental Protection Agency (EPA) conducted a market analysis for landfill gas, based on interviews with some of the largest gas purchasers in the country. Briefly the conclusions of the study were these:

- Major metropolitan areas have sufficient quantities of waste in-place to justify gas recovery.

- These same major metropolitan areas will continue to put into landfills sufficient quantities of new waste to generate economically recoverable quantities of methane gas at least for the balance of this century.

- Recovery of gas requires a relatively low capital investment compared to other alternatives for recovery of energy from solid wastes.

- The major markets for the gas are located in or near these major metropolitan areas so that transmission costs will not be excessive.

Table 54-1 provides some indication of the potential for landfill gas in the twenty largest major metropolitan areas of the country. These estimates are based on very conservative assumptions, considering, for example, only waste currently generated and discounting the millions of tons already in place. This is an important point, for landfills which are less than 15 years old still have potential methane gas for recovery; thus, the total potential could be much larger than the figures in Table 54-1 would indicate. However, since these estimates are based on current waste generation, they represent sustainable rates of gas production.

In addition, the last point, about the proximity of gas markets to large landfills, should be emphasized. In most parts of the world, large metropolitan areas are also the center of the natural gas consumption market. Therefore, estimates of the global potential of landfill gas recovery are most meaningfully expressed on a city-by-city basis rather than in terms of national potential.

In the United States, 35 percent of the population lives in these 20 cities, where large quantities of natural gas are

TABLE 54-1.--Estimate of potential annual recoverable methane gas from landfills for the 20 largest metropolitan areas

Metropolitan areas (1973)	Annual potentially recoverable methane ($10^6 ft^3$)
New York, New York-New Jersey	5,630
Chicago, Illinois	4,020
Los Angeles-Long Beach, California	4,000
Philadelphia, Pennsylvania-New Jersey	2,820
Detroit, Michigan	2,530
Boston, Massachusetts	1,960
San Francisco-Oakland, California	1,780
Washington, D.C.-Maryland-Virginia	1,730
Nassau-Suffolk, New York	1,500
Dallas-Ft. Worth, Texas	1,380
St. Louis, Missouri-Illinois	1,380
Pittsburgh, Pennsylvania	1,380
Houston, Texas	1,210
Baltimore, Maryland	1,210
Newark, New Jersey	1,210
Cleveland, Ohio	1,150
Minneapolis-St. Paul, Minnesota-Wisconsin	1,150
Atlanta, Georgia	977
Anaheim-Santa Ana-Garden Grove, California	920
San Diego, California	862

*Assumptions:

1. 3.5 lbs municipal solid waste generated per person per day.

2. Estimated annual potential gas recovery rate of .45 ft^3 CH_4/lbs municipal solid waste generated.

consumed. Therefore, no attempt has been made to estimate the gas potential for the entire United States; the landfills in smaller communities cannot be economically tapped for the cleaning and sale of landfill gas.

THE MOUNTAIN VIEW, CALIFORNIA, PROJECT

Based on these findings, the Systems Management Division initiated a demonstration project to recover and clean the gas from the large sanitary landfill (2,400 tons/day) in Mountain View, California. In addition to EPA and the City of Mountain View, Pacific Gas and Electric (PG&E) elected to assume a major role in this project and has made a major commitment of funds to the second phase of the project. This project was not the first of its general type to be conducted. Two communities in Southern California had experimented with gas recovery for direct use and for conversion to electricity. In fact, NRG NuFuel (now Reserve Synthetic Fuels, Inc.) has a gas recovery and cleaning project in Palos Verdes in which $2 \times 10^6 ft^3$ of gas per day are being recovered.

The first major difference between the Mountain View Project and the other projects in Southern California is that Mountain View is a shallow fill, with an average depth of 40 feet, whereas the other projects are deep (100 to 150 feet). While the conditions in the deep fills of Southern California are more conducive to gas recovery, the shallow Mountain View site is more representative of landfills throughout the country. The premise for the EPA demonstration project was as follows: If gas can be economically recovered from Mountain View, it can be recovered elsewhere in the country.

The second major difference is that the Mountain View site is a Class 2 landfill, which means that it does not accept toxic industrial wastes. The Palos Verdes site is a Class 1 landfill and accepts toxic materials.

In July 1974, the pilot project was begun in Mountain View. The objective of the initial phase was to drill four wells and pump gas under varying conditions. The major parameters to be tested were:

- gas composition
- pumping rate
- radius of influence of each well.

GAS QUALITY AND PUMPING CONDITIONS

The three parameters are interrelated; therefore varying one affects the other two. Ideally a high pumping rate is desirable, but in a shallow fill, higher pumping rates draw air through the cover material and introduce the contaminants nitrogen and oxygen into the gas. In light of the relatively tight clay cover, this effect was originally thought to be minimal, but that did not turn out to be the case. This effect was most pronounced in the top 10 ft of the fill, but in a fill which is only 40 ft deep, the top 10 ft cannot be abandoned without significant wastage of gas potential. Therefore, the pumping rate was reduced incrementally, until a rate of 50 ft^3 per minute was found to produce an acceptably low percentage of nitrogen and oxygen. The gas composition at this pumping rate is shown in Table 54-2. In the coming year, a polyethylene sealer will be placed experimentally 1 or 2 feet below the surface around each well to further reduce air infiltration, and therefore permit a higher pumping rate.

The "radius of influence" is the circular area around the well from which gas can effectively be pumped. The radius of influence is a direct function of pumping rate, so that a 50 ft^3 per minute pumping rate results in a radius of influence of 130 feet (assuming a negative pressure of 0.1 inches of water as the limiting pressure). If the pumping rate can be increased without an unacceptable introduction of air, then the radius of influence for each well can be increased, and the total number of wells required can be reduced. The rule of thumb for pumping rate is 1 ft^3 per minute per foot of well depth in the deep fills. This rule of thumb appears to apply also to the shallow fill. Therefore, the deep fills are able to be pumped at 150 ft^3 per minute or more, and shallow fills at only 50 ft^3 per minute.

TREATMENT PROCESSES

The gas retrieved is 45 percent methane at the current pumping rate. Since pure methane gas has a heating value of approximately 1,000 Btu/ft^3, the landfill gas at Mountain View, containing 45 percent methane, has a dry heating value of approximately 450 Btu/ft^3. Pipeline quality natural gas is between 975 and 1,000 Btu/ft^3, so it is necessary to remove contaminants

TABLE 54-2.--Measured gas composition[1]

Constituent	Volume - Percent		
	Average	High	Low
Methane	44.03	46.49	41.38
Carbon dioxide	34.20	36.80	20.73
Nitrogen	20.81	23.51	19.98
Oxygen and argon[2]	0.96	1.69	0.48
Water	saturated at 14.7 psia and 90°F.		
	grains per 100 ft^3 [3]		
Hydrogen sulfide		0.40 -	0.91
Mercaptan sulfur		0.00 -	0.33
Sulfides		0.41 -	1.80
Disulfides and residuals		0.93 -	1.65

[1]These figures are from an unpublished report by PG&E, with contributions from the city of Mountain View.

[2]Argon represents at least 50 percent of the total.

[3]Multiply by 4.3 to obtain ppm.

in order to upgrade the gas to near pipeline quality. PG&E first examined the option of simply removing the water vapor, and selling the resulting 500 Btu gas to an industrial user. Industrial users can burn lower grade gas because they can retool their burning orifices to accommodate it. However, most public utility regulations require a uniform, high quality gas for home consumption so that burners can be designed and set one time, to simplify adjustment and to maintain uniform billing procedures. The option of producing low quality industrial gas was rejected by PG&E because a suitable nearby customer could not be found.

The second option examined by PG&E was a "medium-quality" gas of approximately 750 Btu/ft^3. If injected into highflow pipelines in small quantities, such gas would not reduce the overall concentration below acceptable tolerances. Moreover, the cost of upgrading the gas to 750 Btu would be substantially less than upgrading it to 975 Btu. The third option, to upgrade to pipeline quality, is too costly. The second option was chosen for the following reasons:

- The experimental nature of the project made it impractical to sell to nearby industry because it was not a sufficiently reliable supply.

- The close proximity of a large transmission line which does not depend on landfill gas, but which can use it as a supplement, permitted cheap and easy transmission of the landfill gas.

Several cleaning methods exist for upgrading gas quality:

- Selexol for both dehydration and CO_2 removal
- Molecular sieves for dehydration and CO_2 removal
- Diglycolamine for dehydration and CO_2 removal.

Selexol is a proprietary process which dehydrates landfill gas and removes carbon dioxide. Landfill gas is compressed and cooled by exchange with the treated gas. Condensed water is separated prior to contact with the Selexol solvent, which physically absorbs carbon dioxide. The solvent is the dimethylether of polyethylene glycol (DMPEG).

Molecular sieves are crystalline alumino-silicates, honeycombed with cavities which are interconnected by pores varying from about 3 to 10 angstrom units in diameter, depending on the particular crystal.

Molecular sieves have the largest surface area per unit volume of any solid absorbent. In addition, molecular sieves have highly localized polar charges. These localized charges explain the very strong absorption of polarizable compounds on molecular sieves.

Diglycolamine is another "wet" process in which the sour gas to be purified is pumped upward in an absorber (bubble tower). The tall absorber allows the gas to be exposed to an aqueous amine solution for an adequate cleansing time. This aqueous amine solution at a temperature of 80 to 100°F enters from the top of the absorber and flows countercurrent to the gas, extracting the CO_2 and H_2S.

Further details of each of these processes can be obtained from the author and a complete published report on the project, written by PG&E, will be available in late summer of 1976. All three processes have been proven in other applications of gas cleaning. Once the available processes were narrowed down to three by the PG&E engineering staff, the decision became one of economics.

ECONOMICS OF GAS CLEANING

The economics of gas cleaning are largely dependent on the quantity of gas to be cleaned, with significant economies of scale achievable for larger quantities.

Two production rates were chosen for analysis: 5 x $10^6 ft^3$ per day and 1 x $10^6 ft^3$ per day. Table 54-3 shows cost estimates for the smaller system. For each of the three processes the cost/10^6 Btu is very competitive with current peak shaving gas. The molecular sieve is the least-cost system, estimated to be \$2.56/10^6 Btu. Because 1 x $10^6 ft^3$ per day is the production level for which capital funds are available, the molecular sieve will be used in Phase II of the Mountain View project. Table 54-4 shows cost comparisons between the 1 x $10^6 ft^3$ per day and the 5 x $10^6 ft^3$ per day systems.

By scaling up to a production level five times as great as that being used in Mountain View, unit costs would decrease from \$2.56/10^6 Btu to \$1.66/10^6 Btu. For application in larger fills in other cities, this economy of scale may be incorporated to make the price even more competitive.

The system chosen will consist of 20 wells. This array will cover only 20 acres of the total fill area of 250 acres. Therefore, there is still enormous untapped potential in this landfill. Equipment orders have been placed and ground breaking should take place in early fall 1976. Production pumping is expected to begin by early 1977. PG&E has invested over \$400,000 in this project; the U.S. EPA has invested \$260,000.

TABLE 54-3.--Comparative cost estimates for compression and treatment of landfill gas basis: 1 x $10^6 ft^3$ per day of raw landfill gas ($450 Btu/ft^3$)

PROCESS	Process Cost ($)	Compression Cost[1] ($)	Gathering System 18 wells Analytical ($)	Total Inst. Cost[2] ($)	Process Efficiency (%)	Overall Efficiency[3] (Process + Comp.) (%)	Mainte-nance[4] ($/Year)	Man-power ($/Yr)	Fixed Charges[5] ($/Yr)	($/$10^6$Btu)[6]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
SELEXOL	600,000	200,000	70,000	1,320,000	78	64	35,500	30,000	327,500	4.40
MOLECULAR SIEVES	245,000	200,000	70,000	788,000	85	70	24,900	30,000	195,500	2.56
DIGLYCOLAMINE	250,000	200,000	70,000	795,000	69	54	25,000	30,000	197,000	3.35

[1] Based on Pressure of 400 psig at the plant gate

Basis: 310 days of Operation/Year

[2] Total Installed Cost: 1.5(1) + 1.75(2+3)

[3] Energy Outputs:
- Selexol - 89,280 MMBtu/Year
- Molecular Sieves - 97,650 MMBtu/Year
- Diglycolamine - 75,330 MMBtu/Year

[4] Maintenance = 0.03(1) + 0.0875(2)

[5] Fixed Charges = 0.248(4) on the Basis of a 10-year life

[6] $/MMBtu = (7+8+9)/Energy Outputs

TABLE 54-4.--Cost comparison between 1 x $10^6 ft^3$ per day and 5 x $10^6 ft^3$ per day production rates using molecular sieves

Production Rate	Process Cost $	Compression Cost $	Gathering System + Analytical $	Total Installed Cost $	Maintenance Cost $	Manpower Cost $	Fixed Charges $/Yr	Cost/ MMBtu $
1 x $10^6 ft^3$/ day	245,000	200,000	70,000	788,000	24,900	30,000	195,000	2.56
5 x $10^6 ft^3$/ day	644,000	852,000	310,000	2,765,000	94,000	30,000	686,000	1.66

GLOBAL POTENTIAL

Any attempt to estimate the global potential of anything is a difficult and dangerous undertaking. A more realistic approach for estimating the global potential for landfill gas is to identify the main determinants of this potential and describe the economic and other constraints. Then, each nation can determine, based on its specific circumstances, the feasibility of landfill gas recovery. This section discusses the major criteria for gas recovery, then provides available figures for some nations and cities to provide "order of magnitude" estimates of their potential. The main criteria are as follows:

- Population and generation rate
- Decomposable portion of waste and percentage landfilled
- Amount of waste in place
- Quality and configuration of landfills
- Location and size of gas markets.

Population and Waste Generation Rate

In this paper, the estimation of waste generation quantities was based upon population and generation rates because no better source of information was available to the author. Generation rates in the countries studied range from 1.1 pounds per person per day in Italy and Ireland to 3.5 pounds per person per day in the United States. This only includes municipal waste, not construction, demolition, or industrial wastes.

Decomposable Portion and Percentage Landfilled

An additional factor to be considered is the decomposable portion of the wastes, which we assume to be approximately 50 percent in the United States (paper and food wastes). In the United States approximately 90 percent of the municipal wastes are landfilled. This percentage may decline as resource recovery systems are implemented, but it will still be high for at least the next 20 years. In Japan, for example, only approximately 47 percent of the wastes are landfilled, so there would be proportionately less landfill gas available in Japan.

Amount of Waste In Place

This figure is very difficult to estimate in any nation. The best method of estimation would be to extrapolate annual tonnages filled for the past 5 years in currently active sites. It is reasonable to assume that recently filled waste would be a prime resource for gas recovery. Older fills, especially those with incomplete data on the type and quantity of waste placed, would be less acceptable for gas recovery projects.

Quality and Configuration of the Landfill

One of the most important criteria in determining gas potential is the quality of the landfill. If toxic chemicals have been placed in the fill, then toxic gasses will be pumped out along with the methane, further complicating the cleaning process.

The pH of the fill is also important since neutral to slightly alkaline fills (pH 6) provide the best environment for survival of the anaerobic bacteria which are essential to gas generation. As already discussed, the depth of the fill is important, since deeper fills offer better conditions for gas collection and recovery. Finally, the design and operational quality of the fill is important. A well-designed and well-run fill will contain the gas and allow a high recovery rate. A poorly designed and operated fill will allow lateral migration of the gas underground.

Location and Size of Landfills Relative to Gas Markets

The location and size of the gas markets are important since it is very costly to transmit small quantities of gas long distances. While the transmission costs will vary from country to country, a general rule is that the landfill should be within normal local transmission distance from the market (e.g., 20 to 30 miles). The minimum size of the landfill for economic recovery of gas is a potential production rate of $1 \times 10^6 ft^3$ per day per landfill. A more economically attractive rate would be $5 \times 10^6 ft^3$ per day per landfill. Table 54-5 shows the method of

TABLE 54-5.--Estimated total annual methane recovery potential

Assumptions	CH_4 Remaining After Each Assumption
Theoretical methane generation/lbs typical waste	4 ft^3/lb
50% decomposables actually volatilize[1]	2 ft^3/lb
50% capturable	1 ft^3/lb
50% landfills operating with pH 6 (assumed necessary for proper methane prediction)	.5 ft^3/lb
90% total municipal waste landfilled[2]	.45 ft^3/lb

[1]50% decomposables in United States municipal waste stream

[2]90% refers to the United States percentage of wastes landfilled

arriving at a practical methane gas recovery rate as a function of waste generation rate. The percentage decomposable and the percentage landfilled differs for each nation, so the percentages should be adjusted accordingly.

Estimates for Methane Gas Potential in Japanese and Western European Cities

Estimates were made for Japanese cities based on a generation rate of 2.6 lbs/person/day and 47 percent of municipal wastes being taken to landfills. Table 54-6 shows the potential for the 14 largest Japanese metropolitan areas. Only the top five of these have 1 x $10^6 ft^3$ per day of production potential. However, depending on the price of natural gas in Japan, a lower production rate may prove to be feasible.

For Western Europe, the EEC nations were chosen because most of the necessary data were available for them. Tables 54-7 and 54-8 show these estimates. Percentage of landfilled wastes ranges from 58 percent in Denmark to 90 percent in the United Kingdom. Generation rates range from 1.1 lbs/person/day in

TABLE 54-6.--Estimate of potential annual recoverable methane gas from landfills serving Japan's large metropolitan areas

Metro Area	Population	Annual Potentially Recoverable Methane ($10^6 ft^3$)[1]
Tokyo	11,454,000	2,657
Osaka	2,980,000	691
Yokohama	3,342,000	543
Nagoya	2,052,000	476
Kyoto	1,419,000	329
Kobe	1,289,000	299
Kitakyushu	1,042,000	242
Sapporo	1,010,000	234
Kawasuki	973,000	226
Fukuoka	853,000	198
Amagasaki	554,000	129
Sendai	545,000	126
Hiroshima	542,000	126
Nagasaki	421,000	98

[1]Assumptions:

1. 2.6 lbs. of municipal solid waste generated per person per day
2. 47% municipal solid waste landfilled
3. Estimated annual potential gas recovery rate of 0.5 ft^3 of methane per pound of municipal waste landfilled

Italy and Ireland to 1.7 lbs/person/day in Belgium and Denmark. These are the metropolitan areas which have sufficient landfill gas potential to be economically feasible by United States prices. Where prices are higher, additional cities may be added to this list. Finally, Table 54-9 shows the gas potential for the larger metropolitan areas of the USSR. Most of the population of the world is not covered by the few examples presented in these tables because data were not available on generation rate and percentage landfilled. Many other nations would have some cities large enough to meet the criteria for feasible gas recovery stated in this paper. Individual computations would have to be made for each city once the information was available.

TABLE 54-7.--Estimate of potential annual recoverable methane gas from landfills--large metropolitan areas in the EEC

Country	Greater Metro Area	Population	% Land Disposal[1]	Per Capita Daily Generation Rate	Annual Potential Recoverable CH_4 ($10^6 ft^3$)
Belgium-Luxembourg	Brussels	2,000,000	80	1.7	514
	Antwerp	1,155,000	80	1.7	297
Denmark	Copenhagen	1,383,000	58	1.7	258
France	Paris	9,251,000	70	1.4	1,560
	Marseille	894,000	70	1.4	151
Germany	Berlin	2,134,000	78	1.4	468
	Hamburg	1,817,000	78	1.4	398
	Munich	2,326,000	78	1.4	291
Austria[3]	Vienna	1,940,000	78[2]	1.4[2]	850

[1] Bailly, Henri-Claude, Charles Tagart de Borms, Materials Flows in the Post Consumer Waste Stream of the European Economic Community, Commission of the European Communities, Environment and Consumer Protection Service, 1974.

[2] Estimated.

[3] Not in EEC.

TABLE 54-8.--Estimate of potential annual recoverable methane gas from landfills--large metropolitan areas in the EEC

Country	Greater Metro Area	Population	% Land Disposal[1]	Per Capita Daily Generation Rate	Annual Potential Recoverable CH_4 ($10^6 ft^3$)
Ireland	Dublin	569,000	80[2]	1.1	91
Italy	Rome	2,800,000	80[2]	1.1	450
	Milan	1,724,000	80	1.1	277
	Naples	1,277,000	80	1.1	205
	Turin	1,184,000	80	1.1	190
Netherlands	Amsterdam	1,055,000	60	1.5	178
	Rotterdam	1,019,000	60	1.5	172
United Kingdom (England)	London	7,418,000	90	1.5	1,876
	Birmingham	1,013,000	90	1.5	255

[1] Bailly, Henri-Claude, Charles Tagart de Borms, Materials Flows in the Post Consumer Waste Stream of of the European Economic Community, Commission of the European Communities, Environment and Consumer Protection Service, 1974.

[2] Estimated.

TABLE 54-9.--Russia

Metro Area	Population	Daily Per Capita[1] Generation Rate (lbs)	% Land[1] Disposal	Annual Potential CH_4 Availability ($10^6 ft^3$)
Moscow	7,300,000	1.2	95	3,341
Leningrad	4,066,000	1.2	95	1,861
Kiev	1,764,000	1.2	95	807
Tashkent	1,461,000	1.2	95	669
Kharkov	1,280,000	1.2	95	585
Gorky	1,213,000	1.2	95	555
Novosibirsk	1,199,000	1.2	95	549
Kuibyshev	1,094,000	1.2	9.5	501

[1]Grey, Val, R. A. Colonna, F. Green, International Trip Report, U.S. EPA Office of Solid Waste Management Programs, August, 1975.

SUMMARY

In summary, landfill gas recovery is feasible today in large metropolitan areas of the world. Where natural gas prices are high it becomes economically feasible for smaller cities as well. Other major constraints on recoverability are fill depth, type of material placed in the fill, and quality of fill design. Finally, a relatively small capital investment is needed for this energy recovery process.

CHAPTER 55

APPRAISAL OF MARSH GAS AS A POTENTIAL DOMESTIC NATURAL GAS RESOURCE IN THE UNITED STATES

Lloyd E. Elkins[1]

INTRODUCTION

Methane-rich gas is being generated and steadily released into the atmosphere from marshes in tropical and semitropical climates. The feasibility and cost of collecting and concentrating this gas for market consumption has been addressed and results are reported herein.

CONCLUSIONS

1. Methane-rich gas production rates with ideal soil and temperature conditions can range from about 75 to 100 ft^3 per day per acre.

2. Methane content typically may vary from about 50 percent to perhaps 80 percent, with nitrogen as the principal contaminant.

3. To provide air-free collection a "tent-like" apparatus hovering over the marsh areas, with water seals at its edges, would be one key step in the collection process.

4. The gas collected could best be used as boiler fuel because of its varying methane content. Otherwise, costly separation processes would have to be provided.

5. On a commercial scale, the cost of collecting impure methane gas (at about 75 percent purity) would be about $130

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[1]AMOCO Production Co., Tulsa, OK, USA.

per $10^3 ft^3$ of methane. This is approximately 30- to 50-fold higher than price ranges indicated respectively for synthesis gas from coal or recent upper range contract prices in intrastate gas markets.

6. Although immense volumes of this type of gas escape to the atmosphere in some semitropical marshlands in the United States, its collection is too difficult and costly for it to contribute significantly to the future energy supplies in this country.

MECHANISM OF GAS GENERATION

When organic matter in an aqueous environment is decomposed by bacterial action, the high-energy reactions with dissolved oxygen first occur, yielding CO_2, H_2O, and nitrates. When all the oxygen is consumed, the anaerobic reactions proceed. Favored in the anaerobic energy yield sequence are oxidation reactions by the nitrate ion to yield N_2, CO_2, and H_2O and by sulfate ion, to yield sulphur, H_2S, CO_2, and H_2O. When sulfate and nitrate ions are depleted, methane production by anaerobic digestion proceeds. This usually is considered as a two-stage process, in the first stage of which the larger organic molecules are broken down into alcohols, fatty acids, CO_2, and H_2. In the second stage, these compounds are reduced by bacterial action to methane by such reactions as:

$$CH_3\,COOH \longrightarrow CH_4 + CO_2$$

$$CO_2 + 4H_2 \longrightarrow CH_4 + 2H_2O$$

It is apparent that the rate and composition of gas generated by bacterial action in sediments can vary widely depending on the specific conditions existent.[1]

GAS PRODUCTION RATE DATA

Koyama [2] has collected samples of paddy soils in Japan and measured the rate of methane production in laboratory incubation apparatus. Figure 55-1 presents his data on the rate of methane production from several soils as a function of incubation

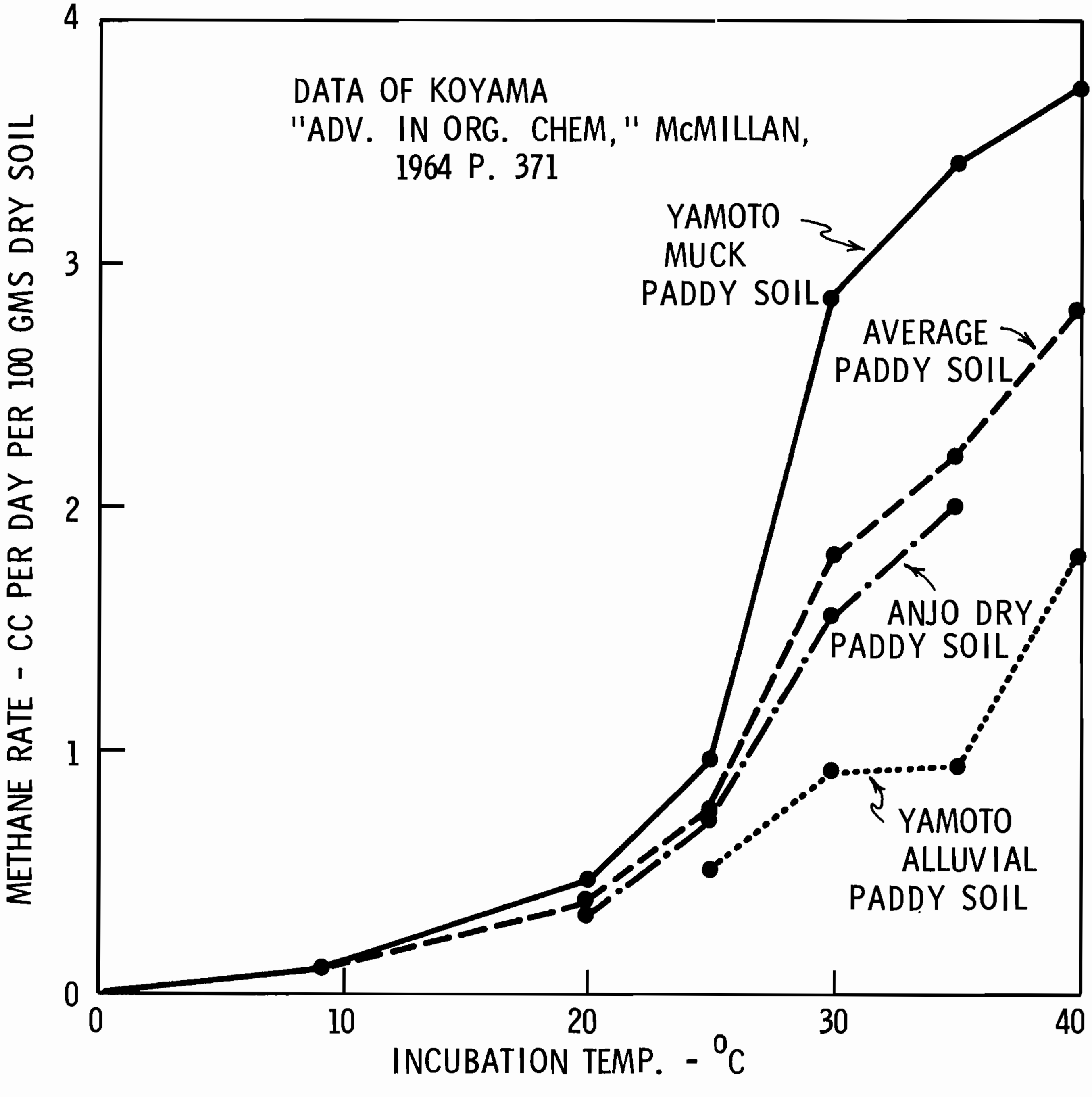

Figure 55-1.--Production rates of methane from Japanese paddy soils

temperature. These data illustrate the high sensitivity of the methane rate to temperature and type of soil. A wide variation in gas composition was observed with methane content ranging from 54 percent to 82 percent, the major contaminants being CO_2, N_2, and H_2. Koyama estimated an average methane production rate for paddy soils in Japan equivalent to 44 ft^3 per day per acre. Measurements made on Japanese upland and forest soils indicated much lower gas rates, less than 1/200 and 1/1,000, respectively, of the paddy soil rates.

Conger [3] reported rates of gas evolution from a stagnant eutrophic lake at Drum Point, Maryland. Sediments from a 3-mi^2 drainage area have almost filled the lake, which has a water depth of about 6 ft. During August 1942, with water temperature of about 27°C, the average measured gas rate was 90 ft^3 per day per acre. The methane content varied from 58 percent to 82 percent, the major contaminant being nitrogen. Assuming an average methane content of 70 percent, the summer methane rate was about 63 ft^3 per day per acre.

Unpublished data have been secured on gas evolution at room temperature (20°C) in a laboratory aquarium containing a 4-inch layer of mud from the White Rock Lake in Dallas, Texas. During initial weeks of the experiment, the methane rate was 75 ft^3 per day per acre. During a 16-month test period, the rate gradually declined to less than 4 ft^3 per day per acre, presumably due to depletion of the bacterial nutrients.

Based on these limited data from a preliminary review of the literature, it is presumed for purposes of expediting this evaluation that a favorable marshy site can be located wherein an average methane production rate of 75 ft^3 per day per acre can be sustained.

As a matter of interest, substantially higher methane production rates can be attained in digesters operating at higher temperature and with carefully controlled feeds and selected bacterial strains. For example, Pfeffer [4] of University of Illinois demonstrated rates up to 1.0 ft^3 per day of methane (55 percent purity) per ft^3 of digester volume from a 20 wt percent garbage slurry at 60°C. For a one-foot-thick layer of slurry, this corresponds to a rate of 43,560 ft^3 per day per acre.

Gas Collection System

To collect the gas, it is proposed that one acre of marshy area be covered with a reinforced plastic sheet. To prevent displacement by wind or wave action, the sheet will be held in place by steel stakes tied to grommets at intervals sufficient to hold the edges of the sheet below the water level. For gas removal, a small diameter plastic line is attached to a fitting at the center of the sheet, which is supported at this point to prevent blocking of the drawoff opening. It is apparent that the area selected must be free from brush and debris to prevent film puncture. The weight of the sheet is about 62 lbs per 1,000 ft^2, which can be supported by a gas pressure of 0.012 inches of water.

The gas from each isolated sheet is collected by a header system feeding a blower which delivers the gas to a boiler or gas turbine installation for power generation. The low quality of the gas renders it unacceptable without further processing for distribution and sale as natural gas.

Economics

Based on a quote from the Griffolyn Company, the cost of a 210 ft^2 (one acre) sheet of 4-ply, nylon thread reinforced polyethylene with a 9-year outdoor exposure life is $0.20 per ft^2, f.o.b. Houston. To allow for transportation and installation of sheet and lines, an additional cost of $0.05 per ft^2 is (optimistically) assumed. Operating costs assume only sheet maintenance at 3 percent per year on the investment, with overhead and miscellaneous costs at 2 percent per year. A utility level rate of return is assumed amounting to 12 percent per year on the average investment (100 percent equity) with a 10-year project life. The following costs apply on a one-acre basis:

<u>Investment</u>	
Plastic Sheet @ \$0.20 per ft^2	\$ 8,700
Piping & Installation @ \$0.05 per ft^2	2,200
Total	\$10,900
<u>Operating Cost per Annum</u>	
Maintenance @ 3% per year	\$ 330
Overhead & Misc. @ 2% per year	220
Total	\$ 550
<u>Capital Costs per Annum</u>	
Depreciation @ 10% per year	\$ 1,090
Federal Tax @ 48% of gross profit	600
Net Return @ 12% per year on avg. invest.	650
Total	\$ 2,340
Net Annual Revenue Required for Gas Sale	\$ 2,890
Royalty @ 12.5% of Gross Revenue	450
Severance Tax @ 7.0% of Gross Revenue	250
Gross Revenue from Gas Sale	\$ 3,590
Annual Gas Sales - 10^3ft^3 @ 75 ft^3/day	27.5
Gas Sales Price - \$/10^3ft^3	\$ 130

Discussion of Results

The preceding calculations indicate a gas sales price of \$130 per 10^3ft^3 of methane content would be required to obtain a 12 percent return on invested capital. To reduce the price to a high range of some intrastate contract prices (\$2.50 to \$3.00 per 10^3ft^3) or to some estimated gas prices needed for coal gasification (\$4 plus per 10^3ft^3) appears out of reach. Yield, already optimistically high in this calculation, would have to be increased at least by a factor of 30 and perhaps 50.

In addition to the unfavorable economics, there might be environmental objections to destruction of marine life due to exclusion of air from the covered surface. The gas production-rate decline curve also is uncertain. If maintenance of the gas rate is dependent on a continuing supply of fresh sediments, covering of large areas might interfere with the depositional process with resulting rapid decline in the gas production rate.

A more attractive approach to production of methane by microbial reaction appears to be via plant digesters processing garbage, sewage, or waste effluents under closely controlled temperature, organic content, and bacterial species.

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SECTION IX. TECHNOLOGY TRANSFER

CHAPTER 56

TECHNOLOGY TRANSFER: IMPACTS AND IMPLICATIONS OF PROSPECTS OF FUTURE AVAILABILITY OF OIL

Alexander A. Mironov[1]

INTRODUCTION

Technology transfer in the international context is a complex multidimensional problem relevant to the present and important for the future, which involves many issues of a political, economic, technological, social, legal, financial, and other character. It is a dynamic problem because the attitudes of various parties dealing with issues of technology transfer have been undergoing a considerable and radical change in many respects.

In the United Nations, many organizations and groups have been dealing with technology transfer, especially with the aim of promoting international cooperation and of contributing to the advancement of the developing countries. At the sixth special session of the UN General Assembly in early 1974 a resolution on a "New International Economic Order" was adopted. This New Economic Order consists of a set of principles and guidelines intended to correct imbalances in the present global economic structure, with the emphasis on facilitating the progress of developing countries.

Among many issues, two deserve our particular attention: rational management of natural resources under conditions of full national sovereignty, and the industrialization of developing countries. In the framework of the new international economic order, these two issues are most explicitly connected with the

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[1]UNITAR, New York, NY, USA.

problems of technology transfer and the future availability of energy.

The above does not, of course, imply that other aspects of the New International Economic Order, such as the issues concerned with international trade and finance, or an equitable system of prices for commodities and manufactured goods, are not connected with technology transfer. They are, and this will be indicated later.

There are intimate relationships between the development of technology for the exploitation of energy resources and problems concerning the environment, population growth, employment, social structure and social values, nutrition needs, and lifestyles.

It should be indicated that at the Second General Conference of UNIDO (United Nations Industrial Development Organization) in Lima in March 1975, which was devoted to the problems and needs of accelerating the industrialization of the developing countries, the main recommendation adopted provided that the share of developing countries in world industrial production should reach 25 percent of the world production by the year 2000. At present, this share constitutes only 7 percent, of which more than half is constituted by only three of the developing countries.

Naturally these objectives of total development are crucially dependent on the availability of energy, including oil and gas. As is well known in development, especially in industrial development, energy production should exceed the rate of development of other sectors of a modern economy. From this standpoint, it is clear that technology transfer in the energy field is of paramount importance.

According to estimates which are in line with numerous demographic forecasts, there will be not less than 7.5×10^9 people by the year 2000. This doubling of the globe's population will take place mainly as the result of population growth in the developing countries.

This factor adds a new and important dimension to the problem of the satisfaction of the world's energy needs and thus to technology transfer, both in the energy production field and in other areas of human activity.

CONTENT OF TECHNOLOGY TRANSFER

- Subjects of transfer: machines, tools, skills, training, production processes, management and marketing techniques, patents, know-how;
- Form of transfer: packaged or unpackaged. Technology can be transferred:
  a. vertically (displacement of old processes by advanced processes either within a country or at regional or international level), or
  b. horizontally (spread of already existing technologies by making them available to more producers in more locations, sometimes with or without modifications).
- Objectives of transfer: development of national and local potential, import substitution or export development, investment decisions, programs, market strategies, product life cycles, profit maximization, cost/benefit considerations;
- Sources and agents of transfer: private companies, national governmental organizations, multinational corporations, international agencies;
- Recipients of transferred technology; private or public sector, individual companies or governmental bodies;
- Conditions of transfer: cash payments, loans, royalties, taxes, aid assistance, profit sharing, production sharing, co-ownership, turn-key arrangements, patent protection, restrictive practices, legal obligations and responsibilities;
- Methods of transfer: commercial deals, foreign direct investment, joint ventures, portfolio investments, foreign or international aid programs;
- Motivations and constraints: availability of capital, restrictive business practices, export and import policies based upon export promotion or import substitution.

EVOLUTION OF THE CONCEPT OF TECHNOLOGY TRANSFER

For the past 20 years in the UN, the concept of technology transfer has undergone a considerable evolution and change, passing through the following stages:

- Adapted technology;
- Intermediate or appropriate technology;
- Naturalized technology.

Now it has come to encompass a broader meaning best denoted as:

- Transfer, transformation, and generation of technology for development.

The change is not only a change in name; in fact, it reflects the large-scale, deep-rooted, socioeconomic processes which are taking place at various levels and within individual countries and societies internationally. These processes, which mirror changing world conditions, are based on new aspirations and needs stemming from acquired political independence, liquidization of colonialism, and a greater sense of national identity among newly independent countries. The search for new avenues of economic cooperation among various countries belonging to different political and social systems, has resulted in a greater awareness of the problems of global interdependence, a rejection of "neo-colonialism," which is associated with economic and technological dependence, and a greater understanding of the issues and possibilities of a new international division of labor. An unprecedented advance over the last 30 years in science and technology (sometimes referred to as a "scientific and technological revolution") has also contributed to a considerable change in "man-machine" relationships and in life styles (communications, transportation, computers, automation).

In spite of the greater advantages, both immediate and potential, which these scientific and technological changes offer to mankind, the distribution of their benefits, due to many reasons, remains unequal. Apart from that, the unequal distribution of natural resources and population also affects the direction of technology transfer. One can identify four categories of countries, according to the size of their population and resources:

- Large natural resources and population;
- Large natural resources and small population;
- Small natural resources and large population;
- Small natural resources and population.

Due to various factors, the performance of individual countries differs. Some developing countries do better than others, but generally the development gap between industrially-developed countries and developing countries is not being reduced; on the contrary, it is widening, and this gives much concern to the UN.

Transfer and transformation of technology, if exercised properly, is a practical way of diminishing the gap, of contributing to a more balanced international division of labor, and of improving the utilization of world natural and other resources. Energy technology is certainly most important, because as food technology is indispensable for meeting nutritional needs of people, energy technology is indispensable to most forms of modern human activity, but especially production and transportation.

In principle, technology transfer can and does take place between:

- Developed countries;
- Developing countries;
- Developed and developing countries.

It is the process of transferring technology from developed to developing countries which, in the international and UN context, is usually referred to and understood as a "technology transfer." For reasons indicated above, it is a subject of real concern in the UN and the object of activity and scrutiny in many of its bodies. For example, UNCTAD (United Nations Trade and Development Organization) has been working on an "International Code of Transfer and Transformation of Technology," which should provide basic rules and guidelines for international policies on the transfer of technology. The development of this code became a necessity because restrictive practices and indiscriminate import of technology resulted in negative effects which hampered development and international cooperation.

As the UN experience shows, the original notion that foreign technology simply can be transferred and, with the help of foreign technical experts, adapted to the local environment resulted in many project failures. The main argument was and is that technology developed for particular conditions in developed countries simply cannot be "adopted" by a society where socio-economic conditions are different, especially when the degree of this difference is considerable. Because of this, and because advanced technology is highly sophisticated, automated, and capital intensive (rather than labor intensive, a factor of importance under conditions of rapid population growth), a concept of "appropriate" or "intermediate" technology was introduced. This emphasizes labor-intensive (versus capital-intensive), cheap, small-scale, less wasteful, and environmentally safe technologies. The motivations are to provide jobs for a growing population, especially younger people, to keep the environment undamaged, to preserve national life styles, and, at the same time, to achieve industrial and economic growth and technological and economic independence. Indeed, when a technology is adopted that is geared to the interests (e.g., capital budget, labor input, size of plant, production rate) of the foreign market or supplier of the technology, rather than to the fulfillment of national development objectives and needs, it creates obvious but undesirable problems.

In connection with the "intermediate" technology concept, it should be stated that it cannot be applied automatically to all technologies. It is true that each technology can be modified, but it is equally true that with advanced modern technologies which are usually associated with large-scale industrial enterprises (steel production, electric power generation, oil refining, etc.), the capital/labor ratio is actually pre-set for clear technological imperatives and cannot be changed without detriment to the qualitative or economic indicators associated with the technological process. Any additional changes which may improve the efficiency of the technological performance, are the results of extensive R&D efforts which usually add to the capital cost.

The development of special "intermediate" technologies specifically geared to the needs of individual developing countries, especially in the advanced areas of technology, was not widely successful (at least to the degree which was advocated) due to a number of reasons including those of required additional R&D technological imperatives, financial implications, risks, and unclear cost/benefit expectations, etc.

In addition, the concept of "intermediate" technology has not been accepted socially in many developing countries, being implicitly connected or identified with the lower rate of "second" class technology, which emphasizes not so much the labor intensity as technological dependence.

It has to be mentioned also that each technology researched, developed, selected, and transferred has a certain intrinsic "genetic code" which influences socioeconomic values and processes in the "host" countries. For example, import substitution technology for manufactured consumer goods favors the interests of more affluent segments of the population. Selection of transportation technology also might be more favorable to some or the other group or groups of the population. The development of a national energy base is of no exception to this principle, though in the latter case the availability of different energy resources (or the lack of them) and their potential brings both needs and constraints closer together thus reducing the available options to one or a few alternatives.

A specific feature of energy resources, and oil in particular, is that they are distributed unevenly among regions and countries of the world. Oil, especially, is consumed mainly in industrially-developed countries, but is produced (with certain exceptions) outside of these countries.

In general, considering domestic production/consumption ratios of oil, one can identify four groups of countries:

1. Level of consumption is compatible with production;
2. Level of consumption considerably exceeds domestic production (if any), and thus, dependence on foreign sources and import of oil is either great or increasing;

3. Level of production considerably exceeds level of consumption;
4. Level of production of oil might be compatible in the near future with growing consumption (at present it is not) because of current exploration and good prospects for future recovery; in the future, these countries may join either group "1" or group "3."

The fact is that the excess or over-supply of oil in certain countries and regions and shortages in others does and will continue to influence the development of world economic structures and to affect problems of the international division of labor and cooperation at bilateral, regional, and international levels.

The concept of naturalized technology is a relatively new one in technology transfer. It reflects greater awareness by developing countries of their collective and individual strengths, needs, and expectations, especially in transferring and adapting so-called "modern technology." Technology is not a free good; it is sold and bought in the international market for a price. When a developing country spends its scarce financial reserves on a technology, naturally it wants that technology to serve its development objectives, technical, economic, and social, in the most rational and optimal way. For this purpose, developing countries advocate more and more application of vigorous screening processes for technology shopping and transferring. The concept of naturalized technology ideally involves a blend with traditional methods and a combination of imitation with more vigorous use of elements of local creativity.

One of the problems in developing countries, associated with growing technological and balance-of-payments gaps, is the lack of proper research and development potential. However, the growing level of education, greater awareness of national needs, acquired experience, and better knowledge of the sources and conditions of technology availability in the international market, gave rise to the emergence of a new concept of naturalized technology. This concept combines transferred (imported) with internally developed technology.

This combined approach includes:

1. Technology transfer (or rather transfer of the most crucial processes and components);
2. Imitation and production of those components which can be produced domestically to suit both technological and social needs;
3. Creation or innovation of new technologies.

The main difference between the concepts of adopted and naturalized technology is that naturalized technology, though based on imported technology, encompasses a considerable element of local creativity which is being encouraged and developed and hence meets local demands and needs more effectively. In a way, it provides a link (productive and social) between modern technology and traditional technology as practiced in the particular environment of each developing country. This is of particular importance from the point of view of infrastructure development and of meeting the basic needs of the mass of people for productive and fulfilling jobs, considering the expected growth of population and the desire for industrial development.

A multilevel approach and examination of problems associated with technology transfer and the needs of development has led to the emergence of a new principle, "transfer, transformation, and development of technology" (TTDT). This sophisticated approach combines separate elements and techniques of the various technology transfer principles considered above. It reflects the rapid technological, economic, and social changes on the international level, especially in relations between countries and groups of countries. As far as developing countries are concerned, this TTDT principle corresponds to the desire and determination to use available national potential more fully. This may be done through greater mobilization of internal resources and by the achievement of greater national self-reliance and economic independence, under conditions of global interdependence and the international division of labor.

PETROLEUM AND GAS TECHNOLOGY TRANSFER

Technology which is associated with oil, and gas, and consequently relevant to technology transfer, can be divided into several functional categories:

- Exploration;
- Development (pilot or test operation);
- Production (recovery);
- Transportation and storage;
- Processing;
- Distribution and consumption.

These cannot be separated entirely from one another since they interact at all levels of development.

Successful utilization of transferred technology requires appropriate planning, administration, and legal regulations which should secure proper functioning and balance among various sectors of the national economy including the development of total energy sector. Every technology transfer has to be supplemented also with adequate training, which should lead to creation of appropriate R&D potential, as needed.

Activities related to technology transfer in oil and gas industries also can be looked upon from two angles: operational, associated with each element of field activity, and nonoperational, which embrace various forms of training and nontechnical assistance.

The scale of operational technology transfer projects can vary from the provision of a consultant for a short period of time to large, multi-million dollar projects lasting several years.

Nonoperational activity may include transfer of experience and assistance in the economic, legal, administrative, and environmental aspects of the oil and gas industry, as well as training.

In the following selected areas, technology transfer might be stimulating (though, of course, they represent only a small fraction of the existing or possible projects):

- Techno-economic feasibility studies of offshore and land oil and gas development;

- Preparation of master development plans for offshore and land oil and gas fields;
- Geological and geophysical surveys designed to locate sites for exploratory wells;
- Deep-drilling technology;
- Establishment of laboratory complexes to support oil and gas exploration and development activities;
- Establishment of training complexes;
- Preventing marine pollution;
- Improving petroleum and gas drilling technology;
- Establishment of data centers;
- Oil and gas transport.

IMPACTS AND IMPLICATIONS OF THE FUTURE AVAILABILITY OF OIL

Future availability of oil is a part of many problems--present and future--for scientists, engineers, environmentalists, and policy- and decision-makers. It is a part of the industrial development problem (since oil is used as energy source and as an initial product or subproduct in many processing and manufacturing industries), it is a subsystem of other systems, and it is a serious economic issue with global dimensions and national as well as international implications.

Let us take for example the problem of meeting nutritional needs at the global level and increasing food production in connection with the doubling of population. Modern agriculture is heavily dependent on oil. Significant increase in food production (in addition to the search for new and additional sources of protein) can be achieved mainly through the intensification of the agricultural production process, including more fertilizers, irrigation, use of hard-to-get lands, tropical agriculture, storage facilities, and the transportation network. If the present oil consumption pattern is retained unchanged in the future, it may limit food production and affect other sectors of the economy, either through the price mechanism, by allocations of energy, or both.

Therefore, estimates concerning availability of oil at various quantities and prices, and under relevant technologies, will have a tremendous effect at various locations and at different consumption levels, for medium-range and long-range decisions. This will influence not only the economics and technology of the oil and gas industry per se, but will affect issues of growth rates, national planning, economic negotiations and cooperation, alternative strategies of energy and industrial development, educational policies, consumption patterns, and lifestyles and values of considerable segments of the population. Because of the magnitude of the impacts, the issues concerning the future availability of oil should be dealt with the utmost responsibility and care.

If estimates are realistic that available oil resources and reserves are sufficient for the near future to maintain the present 5.5 percent increase in growth, then demand will increase even as do prices. The principal centers of petroleum consumption are in developed countries. The oil-short developing countries account for 82 percent of the Gross National Product generated in the developing world; with their further industrial growth (the objective of developing countries is to reach a 25 percent share of world industrial production by the year 2000), dependence on imported oil will become more critical. To satisfy growing demands both in developed and developing countries, exploration and development of hard-to-get sources of oil will be a necessity. Therefore, a more sophisticated and capital-intensive oil and gas technology will be necessary, assuming that this technology exists or can be developed. In economic terms it will mean at least two things. First, the average price for oil will most likely go up, and second, the price will act as a considerable deterrent to increased oil consumption.

Consequently, it means that oil will be less available to those countries or to those segments of the population which are less affluent or poor. At present, about 85 percent of all oil is consumed in industrially developed countries, the population of which is less than 30 percent of the world total. According to UN forecasts, the global population will double by the year 2000, and reach 7.5×10^9 people or more, but the population of those countries which today are known as "industrially developed" will not exceed 20 percent. If the broadening of the oil resource base, natural and synthetic, in economic terms is a function of the international market price, then prices will go higher if the commodity is scarce and demand is growing. Increases in the price of oil as a compensation for future depletion exacerbates this situation.

The problem of future availability of oil, taken in economic perspective, calls for:

1. Broadening R&D efforts for evaluation of oil reserves and resources.
2. Development of new, environmentally sound, and relatively inexpensive technology to increase recovery from already operational fields and to start recovering from those sources now considered to be uneconomic.
3. Intensification of search for and development of alternative sources of energy, together with relevant technology.
4. Comprehensive systems analysis at national and international levels of the feature interchangeability and compatibility of various energy sources and their respective share in the total energy balance.
5. Optimization of national energy economy.

CONCLUSIONS

Technology transfer involves at least two parties, supplier and recipient, whether companies, organizations, countries, or individuals. The interests of these parties may coincide or not and the process of negotiation does not lead necessarily to the conclusion of the transaction. For the purposes discussed in this paper it might be assumed that the evaluation-processing cycle is technology oriented and the distribution-consumption cycle, socially oriented. This statement has to be understood in light of the fact that if oil is used for generating electric power at power stations, it may have one social effect; and if it is consumed exclusively as fuel for cars, it has a different social effect. Other factors in technology transfer include availability of investment capital, sources of secure supplies, technical and managerial expertise, structural balances and imbalances, and economies of scale.

As far as future energy technology transfer is concerned, especially to those developing countries where major global oil resources are concentrated, the following factors have to be considered for selecting alternative technologies:

1. Economic factors: management of natural resources; production of energy; population and natural resource endowments; intensity of capital and labor and their ratio; employment structure; ratio between urban and rural development; centralized versus decentralized technologies; large- or small-scale production; export developments or import substitution; transport conditions; need for imported materials; contribution to the development of other industries and sectors of the economy; balance of payments situation; conditions of payment (hard currency, totally manufactured goods, compensation deals).
2. Social factors: social-acceptability preferences of various segments of population; impact on quality of life and lifestyle (change or preservation of traditional values); employment in manufacturing or in extracting industries (the former increases educational needs); transfer of foreign cultural values; creative work or mechanical operations; migration of population; problems of age groups; rural, communal, or urban development; social participation versus alienation; social control.
3. Environmental factors: environmental hazards and safety; problems of waste and its disposal; recycling; emissions or other pollution problems; land use and conservation; impact on wildlife; preservation of natural ecosystems; level of depletion; replenishable materials.

In the future on the international scene there will be more feedback between energy policies, transfer of energy technology, and these categories of factors. Oil is important for the economy of both producing and consuming countries, and the advancement of industrial and economic growth under the present system of technological and economic infrastructure depends on the availability of oil. It therefore appears that the process of technology transfer, in particular technology dealing with the exploration and production of oil, will be continued at the international level. Economic incentives and limits will become pronounced and will produce a double effect, encouraging or discouraging certain energy policies, and economic and technological options and solutions. This will produce complexities which will vary according to particular national and international situations. The time and scope of these processes will have a direct impact on the period of maturation of a new energy economy.

CHAPTER 57

TRANSFER AND DISSEMINATION OF OIL AND GAS TECHNOLOGY

F. Sager[1]

INTRODUCTION

To the outsider the oil and gas industry used to be surrounded by a wall of mystery brightened only by a touch of romanticism, exploited by a certain type of literature. More recent events--amongst which the controversy about the findings of the Club of Rome on limits to growth, and the wind of change in oil-producing countries--have had in some areas the effect of an alarm clock, not to say of a tocsin.

News about oil and gas reserves, and their depletion, balance of payments effects of oil and gas consumption, and recycling of petrodollars are now current priority items in the mass media of information and have largely contributed to the final demystification of the subject.

What has clearly emerged is a better appreciation of the crucial role of oil and gas in the economy, as a source of energy and as raw material for the chemical industry and related downstream sectors and linkages.

The developments on the oil market since 1973 include structural changes in established multinational oil companies, and the emergence of new ones as a national basis. These actions have speeded up the pace of investment in the oil and gas industry in producer countries of the Third World, and indirectly in other developing countries, and have added to the

[1]UNIDO, Vienna, Austria.

acuteness of the problems of technical and economic cooperation in this sector.

The execution of projects, whether in the subsectors of exploration, exploitation, or manufacturing, imposes definitive responsibilities on both the receivers and the suppliers of services, equipment, and knowhow, largely depending on the type of partnership in the operation. Such partnership may involve participation in the venture in one form or another, or merely commercial customer/supplier relationship. Misunderstanding of the scope, wrong approach, and incomplete or erroneous information on local conditions, and lack of appropriate follow-up measures figure among the main causes for shortcomings or failures of otherwise promising projects.

All inputs for an industrial project, or for industrial development in general, of material, financial, or intellectual nature, including patents and licenses for proprietary knowhow, can at least theoretically be secured on a short-term basis through commercial channels or through technical and economic cooperation in one form or another. The provision of indigenous technical capabilities for making the correct use of each input, which is crucial for the success of a country's social, economic, and technical development policy is, however, more difficult to attain and can be secured only through sustained, energetic efforts and appropriate institutional measures to this end.

Before elaborating on the subject matter of transfer of technology it will be necessary to clarify the related semantics, which in the last few years have acquired a somewhat chameleon-like aspect on the public forum. In analogy to the terms used in connection with computer technology in this context, software is sometimes used in contrast to the related hardware. Again, the adjective "soft" is sometimes used to identify simple in contrast to advanced technology. Other schools of thought have created the concepts of adapted, appropriate, and intermediate technology. Viewed from a different angle we have to distinguish between proprietary and generally accessible technology, although the former is in fact also accessible--provided it is paid for. In this respect it should be remembered that specific proprietary technology, commanding a high price today, may not do so in the near future.

For the purpose of the present discussion, transfer of technology is intended as an operation aimed at increasing indigenous technical capabilities in the widest literal sense of the word for mastering the inputs to industrial development and strengthening self-reliance.

In contrast hereto, technology in the narrow sense will simply be understood as what it always was meant to be, that is, the sound application of engineering principles for producing optimal results in accordance with requirements, and within a set of given conditions.

In this context it is irrelevant whether transfer of technology is taking place between partners from developed countries, or between such from developed and developing countries, or from developing countries exclusively.

In the case of the established oil companies the transfer of technology took and takes place either as an in-house operation or by transmittal from outside sources. The instrumental functions are as a rule adequately staffed with skilled professionals and manuals covering specifications and procedures spell out the duties and methods to be followed.

New companies in developing countries are in general in a less fortunate situation as far as the mechanism of transfer of technology is concerned. In-house generation of related knowhow is with a few exceptions mostly in its infancy. Outside sources therefore have to be mobilized to assume the role of technology transmitters. A condition for effective technology transfer is the establishment of efficient receiving functions and the channeling of the information received into and through the whole receiving organization. As most new companies in developing countries have had little time to build a base of experienced professionals the result--for the time being at least--is an increased imbalance between the transmitting and receiving side of technology, or otherwise expressed, an increased techological gap requiring urgent remedy if the system on which the availability of natural hydrocarbons rests is to be kept vigorous.

Transfer of technology therefore should constitute an integral part of every developing country's national plan and be judiciously built into the system. A minimum requirement is the elaboration of a catalog of necessary knowhow appropriately grouped by priorities, with the optimum being a thorough review of requirements, including a network analysis superimposed on a tentative schedule for proposed industrial activities. In programing the transfer of technology in conjunction with an existing national plan for industrial development, or with the development of an industrial project it may well happen that the resulting feedback could indicate the necessity for major revisions of the original plan and thus save the planners from unexpected and unavoidable setbacks and their effect on a developing economy.

For planning purposes the transfer of technology should be looked at with respect to:

1. Area, or specific objective of the transfer of technology and professional functions involved;
2. The steps of industrial sector or project development to which the transfer of technology is specifically related;
3. The instruments of transfer of technology; and
4. The channels for the transfer of technology.

Cost is an implicit factor in this analysis, and so are the training aspects.

The areas or specific objectives of transfer of technology and the related professional functions involved are suitably derived from the following list of pertinent inputs required for the realization of a project or the carrying out of an industry sector development whereby the order in which these inputs are enumerated in no way is intended to reflect their relative importance or priority which will obviously vary in accordance with local conditions.

AREAS OR SPECIFIC OBJECTIVES

List of: (a) Project inputs, with indication of:
(b) Related areas or specific objectives of transfer of technology, and
(c) Professional functions involved.

1. (a) Raw materials, principal and auxiliary, utilities, and chemicals:
   (b) Exploration and exploitation, preliminary upgrading where applicable, storage and transport, testing
   (c) Technical, economic.
2. (a) Markets, domestic and foreign:
   (b) Market research, marketing, quality control
   (c) Commercial, economic, technical.
3. (a) Capital:
   (b) Technical and economic project evaluation, methods of financing, capital structure, company structure
   (c) Economic, technical, legal.
4. (a) Technical, commerical, and administrative managers:
   (b) Production, process and related utility engineering, supervision of plant operation, operating safety, maintenance, commercial and administrative management
   (c) Technical, commercial, administrative.
5. (a) Technicians and skilled labor:
   (b) Equipment and plant operation, maintenance
   (c) Technical.
6. (a) Production and processing equipment, and plants:
   (b) Selection and procurement of equipment and plants, contract engineering, tender specification and evaluation, mechanical and purchasing specifications, testing and inspection, erection and operation, maintenance, safety
   (c) Technical, commercial, legal.
7. (a) Proprietary knowhow connected with the use of patents and licenses for production and manufacturing processes and related equipment:

(b) Selection, evaluation, and acquisition, license agreements, patent law
(c) Technical, commercial, legal.

8. (a) Infrastructure:
(b) Engineering disciplines related to infrastructure, environmental engineering, laws, and regulations,
(c) Technical, economic, legal.

INDUSTRIAL SECTOR OR PROJECT DEVELOPMENT

The next aspect to be considered is the timing and co-ordination of transfer of technology in relation to the steps of industrial sector or project development, or in other words its scheduling with respect to a project or sector development plan. Following appropriate identification and definition, each area or specific objective of transfer of technology may be assigned the role of an activity-node in a network analysis, superimposed on the overall schedule for project implementation.

The main steps for such a schedule are given here in a simplified and condensed form which may suitably be broken down for further analysis in accordance with requirements:

1. Preliminary studies, selection and evaluation of candidate projects, costs/benefit studies, feasibility studies, inventory of potential project inputs, local and foreign,
2. Negotiations for securing the required inputs, preliminary selection of sources and channels for supply,
3. Commercial implementation of project(s), tenders, contracts, procurement, construction, commissioning.

INSTRUMENTS OF TRANSFER

As to the third facet of transfer of technology, the instruments of transmittal, there are hosts of potential candidates available, among which are individual foreign experts, consulting firms, banking organizations, contractors, equipment suppliers, licensers, universities, and specialized technical and scientific institutions like national petroleum institutes.

The main responsibility here rests on the counterpart functions of the partners involved in the operation of transfer of technology, where the requirement for mutual understanding and spirit of cooperation is of the highest. Provisions for solving the counterpart problem have to be made at an early stage of planning, implying the advance selection of nationals for specific areas of transfer of technology. Where the required core of candidates for this function is not available, advance training in pertinent disciplines should be arranged as implementing an industrial project without concomitant transfer of technology will obviously mean a total failure as far as strengthening of self-reliance is concerned. In extreme cases a company or a government may engage foreign independent consultants to temporarily act as local counterparts to the suppliers of technology while training local professionals for an early takeover of this function.

CHANNELS FOR TRANSFER

The channels through which the instruments for the transfer of technology are supplied are strictly commercial arrangements between supplier and receiver and/or technical cooperation on a bilateral, multilateral, or international basis arranged for on government level or a combination of these.

IMPLEMENTATION OF TRANSFER

The foregoing discussion has highlighted the complexity of the operations and steps concerned with the transfer of technology, as well as the importance of all related activities for the success of an industrial project, and for social, economic, and technical advancement in general. Metaphorically, transfer of technology can therefore be compared to the role of yeast in getting dough to rise.

It would be beyond the scope of this presentation to deal in depth with all the aspects of transfer of technology highlighted here. However, it may be of interest to briefly cite a few examples of the kind of problems a new company may be faced with in the implementation of an industrial project.

To this end, we shall focus our attention for a short while on aspects of the transfer of technology concerned with the acquisition of technology in the narrow, literal sense of the word, as reflected in items 6 and 7 of our list of project inputs, which are production and processing equipment, plants, and related proprietary knowhow. Looking at these problems in the chronological sequence in which they may present themselves, the first requirement will obviously be the elaboration of a clear concept about the most suitable type of materials, equipment, and services necessary. One danger here is the indiscriminate use of seemingly adequate equipment and process design for the simple reason that such equipment or plant already exists and is used elsewhere. The problem is the judicious choice between an off-the-shelf design and one specifically intended for the customer's requirements and conditions. Just to name a few criteria in this respect, the type, availability, and reliability of utilities, provision of spares and standby equipment, and instrumentation may be quoted. Although the special design may be more expensive the extra cost will be more than offset by better operating efficiency and resulting increase of the rate of return on investment.

Another problem, closely related to the one just discussed, is the optimal selection of potential suppliers, with whom the initial contacts are either established through public invitation for prequalification or by direct approach. A new company needs to know as much as possible about the suppliers' capabilities in regard to project management, design, construction, availability of personnel, and experience on similar jobs and past performance. The related information should be gathered from potential suppliers as well as from users in the industry and from the technical press. Such measures will prevent a new company serving as a guinea pig for aggressive salesmen.

The choice of the type and conditions of contract best suited for a new company in a developing country represents another major challenge for the planners and promoters of transfer of technology.

The main types of contract may for the present purpose be simplified and grouped under two categories:

1. Grass roots, turn-key contract, on the basis of which the prime contractor supplies all materials, equipment, services, and licenses for the total project, erected, and ready for operation, on a lump-sum basis, and
2. Contract or subcontract for the supply of materials, equipment, services, and licenses, or any of these items separately, for part of a project, whereby materials and equipment are invoiced at market prices, services at fixed price, cost plus, or hourly basis, and licenses on the basis of throughput or production, paid up, or at regular intervals for an agreed duration of time.

The optimal contracting arrangements will be dictated by the extent to which it has been possible to develop the technical capabilities in the country. Where transfer of technology has been successfully institutionalized, partial contracting or subcontracting will be the best solution. In some countries, however, where due to a concomitance of circumstances the bulk of technological knowhow has to be obtained by means of transmittal through contractors, the turn-key type contract with built-in provisions for function oriented training, sometimes called the total contract or method, has been used with success.

Whatever the situation may be, a developing country will always be well advised to start building up contracting-engineering companies first. These companies should deal with infrastructure and civil engineering in general, then go over to include off-sites, and finally round out their activities by including the erection of process plants within their program. With the aim of encouraging indigenous technical capabilities, contracts with foreign companies should always include a stipulation for subcontracting to local engineering-contracting firms within their limits of competence. The same considerations apply to the supply of local materials and equipment.

PROPRIETARY DATA

The subject of restrictive business practices in connection with licensing agreements for proprietary knowhow needs to be mentioned. It should be noted that national and international legislation may invalidate or limit any inadmissible contractual arrangements in this respect.

A potential licensor may be exposed to geographical and quantitative restrictions for product outlets, and unjustified exclusivity clauses limiting the application of the agreement, including limits set on the licensee's in-house research and development efforts.

The so-called grant-back provision, which may take a larger place in contracts concerned with customer-oriented downstream manufacturing sectors, are, in the oil and gas industry, normally taken care of on a reciprocal basis acceptable to the interests, laws, and regulations of all parties involved. The license agreement in that case provides that all parties shall benefit, through the licensor, from any improvement that may be made to the patents underlying the proprietary knowhow, by either the licensor or any of the licensees.

CONCLUSION

It is hoped that this modest contribution to a systematic approach in dealing with the many facets of transfer of technology will be of some use in making the opposite numbers in the oil and gas industry better understand each other's position and possibilities for cooperation.

APPENDIX

ESTIMATES OF UNDISCOVERED PETROLEUM RESOURCES--A PERSPECTIVE

Richard P. Sheldon[1]

Present and impending energy shortages clearly call for reliable estimates of the magnitude of the Nation's petroleum resources. Planners and policymakers must have an idea of petroleum production potential in terms of magnitude, life, and cost in order to define the actions needed to achieve this potential and also those required for the timely development of alternative sources of energy supply.

One part of the Nation's petroleum resources is the oil and gas remaining in fields that have been discovered and tested and partially produced. Estimates of the magnitude of the remaining producible oil and gas in these fields can be made with some assurance, even though they may be subject to some dispute on both engineering and economic grounds. These oil and gas field estimates can be added up to give an inventory of the amount of petroleum reserves available to the country.

The other part of the Nation's petroleum resources consists of the oil and gas that has yet to be discovered. This presents a different problem. How can the magnitude of undiscovered oil and gas fields be estimated? Perhaps it is better to ask: Can their magnitude be estimated at all when it is not even certain that they exist in the first place? Several approaches to this problem have been devised, but all have one thing in common.

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[1]U.S. Geological Survey, Reston, VA., 22092, USA. Article reprinted from U.S. Geological Survey Annual Report, Fiscal Year 1975, pp. 11-22.

They are predictions or projections into the future, based on one theory or another, using a number of assumptions and some set of data. About the only thing that any estimator can say with certainty about his estimate is that it is wrong. There is simply too much uncertainty in all the approaches to allow the kind of accuracy of estimation that can be achieved for the already discovered petroleum resources.

Perhaps the next question to be asked is: Should such unpredictable resources be predicted? The answer clearly is yes, because essential national planning depends on our ideas about our future resources. The Nation at its inception had an expansionist policy based on faith in resource abundance, because not too much financial investment was at stake. The Louisiana Purchase cost only $15 million, and Alaska cost only $7.2 million. Now we must decide on multibillion-dollar investments in energy research and development to achieve national expansion. The stakes are too high to proceed on faith alone, and so an objective assessment of national resources is necessary. The assessments must be as reliable as we can reasonably make them.

How reliable are the present estimates of undiscovered petroleum resources? The different approaches or methodologies give different numbers. Is one more reliable than the others? The central controversy so far has begun with this question. This point of departure is valid only if the methodologies yield different estimates of the oil and gas that will be available to the Nation in the future. The contention of this paper is that this point of departure is not valid, because the estimates from the different methodologies are different partly, if not largely, because they are not all estimating the amount of oil and gas that will be available in the future. One method yields estimates of the amount of petroleum resources that there is to look for. Another yields estimates of the amount that there is to look for, as in the first case, but reduces the estimate by the amount that would be left in the ground if it were produced by using only the recovery technology available today. Both of these estimates are of the geologic availability and do not try to take into account the even more difficult problem of economic availability, which is what the national planner or policymaker is really interested in. The last method estimates economic availability in a limited way by analyzing the past results of our petroleum supply system with all of its economic, technologic, and political complexity and, using historic trends of discovery and production, by projecting into the future. This estimate would be equal to the first estimate of undiscovered resources only if our petroleum supply system were effective enough to find and recover what geologists think is there to find and what petroleum engineers think can be recovered in the long run. In fact, this estimate is lower, which indicates one of two things: Either the geologists and engineers are too optimistic and their estimates are too high, or our petroleum supply system has room for improvement in the future, given the proper economic stimulus, government policy, and scientific and technologic research.

If this line of reasoning is followed, the three estimates may not be incompatible but reinforcing. This does not put aside the question of how close one or all are to the unknowable "truth." That remains to be studied and is the substance of the question of reliability. The difference between estimates, then, includes both the substantial differences of reliability and the insubstantial differences of terminology. This perspective is presented in this paper.

DIMENSIONS OF PETROLEUM RESOURCE ESTIMATES

Petroleum resource estimates have many dimensions. To begin with, there are the several commodities: crude oil, natural gas liquids (NGL), and natural gas. Crude oil and NGL are commonly combined and reported as petroleum liquids. Additional potential sources of hydrocarbons that are usually not included in conventional resource estimates of petroleum are synthetic oils and gases from tar sands, oil shale and black shale, and natural gas in tight reservoirs, occluded in coal beds, and dissolved in geopressured subsurface water. Petroleum occurs in many provinces, some maturely explored, some virgin, some partly explored, some onshore, some in deep water offshore, and some in shallow water offshore. Resources within these provinces include the presently known deposits as well as the deposits that will be discovered in the future by using present exploration techniques. They also include the petroleum that will remain undiscovered by using present techniques but that could be found if better techniques were developed. Petroleum resources also include the petroleum that is left in the ground by past and present extraction technology and prices but that could be produced at higher prices or by technology yet to be developed.

If two petroleum estimates are to be compared, it is necessary to make sure that the estimates cover the same things. The dimensions of the estimates must be the same in relation to:

1. Commodity (crude oil, NGL, natural gas).
2. Time of the estimate relative to the stage of technology and economics as well as to the data source.
3. Coverage of petroleum provinces.
4. Resource category (identified, undiscovered, economic, subeconomic).

The first three dimensions are relatively easy to deal with theoretically, even though in practice the complexities that they introduce make it difficult to keep estimates consistently comparable. The fourth dimension, resource category, is more difficult to deal with theoretically because of a lack of a generally accepted resource terminology.

RESOURCE TERMINOLOGY

"As Mark Twain is reported to have remarked, most disputes arise because people use the same word to refer to different things or different terms to refer to the same thing. The report that follows is an attempt to help confine disputes over the size of resources and reserves of energy resources to substance," wrote Hans Landsberg in the foreword to J. J. Schanz's outstanding review of mineral resource terminology ("Resource terminology: An examination of concepts and terms and recommendations for improvement," unpublished report to Electric Power Research Institute, 1975). Uniform resource terminology is critical to lucid discussion and analysis of petroleum resource problems.

Petroleum accumulations in the ground are both known and unknown and range in size from a trace to billions of barrels of oil or to trillions of cubic feet of natural gas. These accumulations occur at various depths beneath the surface from a few hundred feet to as much as about 30,000 feet and in various parts of the country from the flat midcontinent area, to the mountainous regions of both the East and the West, to the continental margins offshore, and to the remote and hostile regions of Alaska. Many of the accumulations are too remote, too deep in the earth or too far underwater, too obscure, or too small to make them worthwhile to search out, or to produce if discovered, and are not classed as resources.

The total petroleum resources of the country consist of that part of the petroleum in the ground that has been or can be discovered and can be recovered either now at present prices and technology or in the future at whatever prices and technology then exist.

McKelvey (1972) classified resources according to the geologic certainty of occurrence and the economic feasibility of recovery (Fig. 1). This classification is described in other places and need not be redescribed here except to say that the "reserves" category in the upper left corner of the diagram includes petroleum that has been found and is now economic to produce, whereas the remainder of the resource field includes petroleum that has not yet been found or has been found but is not economic to recover at present prices and technology. Undiscovered resources were divided into hypothetical and speculative resource categories by Brobst and Pratt (1973) and defined as follows:

> Hypothetical resources here are defined as undiscovered resources that we may still reasonably expect to find in known districts; speculative resources are defined as undiscovered resources that may exist elsewhere--either conventional types of deposits in broad geologic terrains in which as yet there are no discoveries, or else unconventional types of resources that have only recently been recognized (or are yet to be recognized) as having some potential.

These categories were created to allow the resource specialist the opportunity to separate undiscovered resources, which he

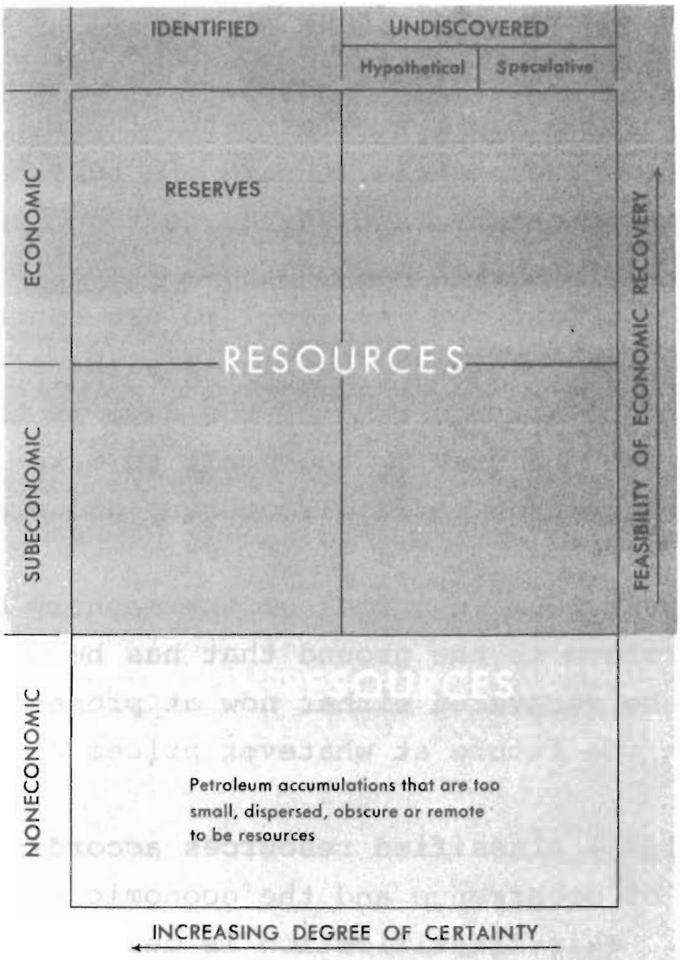

FIGURE 1.--General classification of petroleum resources (McKelvey, 1972)

feels fairly sure could be predicted by using well-established geologic theory in areas where known deposits exist, from undiscovered resources, which he feels might not exist at all and whose magnitudes, if they did exist, could be estimated only very crudely within several orders of magnitude. The problem does not really stop there, because every resource geologist recognizes that resources probably exist that he has no basis to speculate on and that he would not include even in his speculative resource estimates. These resources could be set up as a category, but it would be mere sophistry. It is worthwhile to remember, however, that estimates of undiscovered resources tend to grow as knowledge increases.

It has been difficult to fit undiscovered resource estimates of petroleum into these hypothetical and speculative categories, and so far the categories have not been used by Geological Survey petroleum specialists. Most recently, the concept of probability of occurrence has been used (Miller and others, 1975). One can report these estimates in the McKelvey classification in one of two ways. The estimates can simply be shown as a range and placed in the undiscovered economic category (Miller and others, 1975, Fig. 13), or the probability definitions can be adopted as part of the terminology and substituted for the hypothetical and speculative categories (Fig. 2). Perhaps an acceptable correlation between the two systems would be to equate hypothetical resources with the mean estimates of resources, and speculative resources with the higher estimates at lower probabilities. In the rest of this paper, this procedure is adopted.

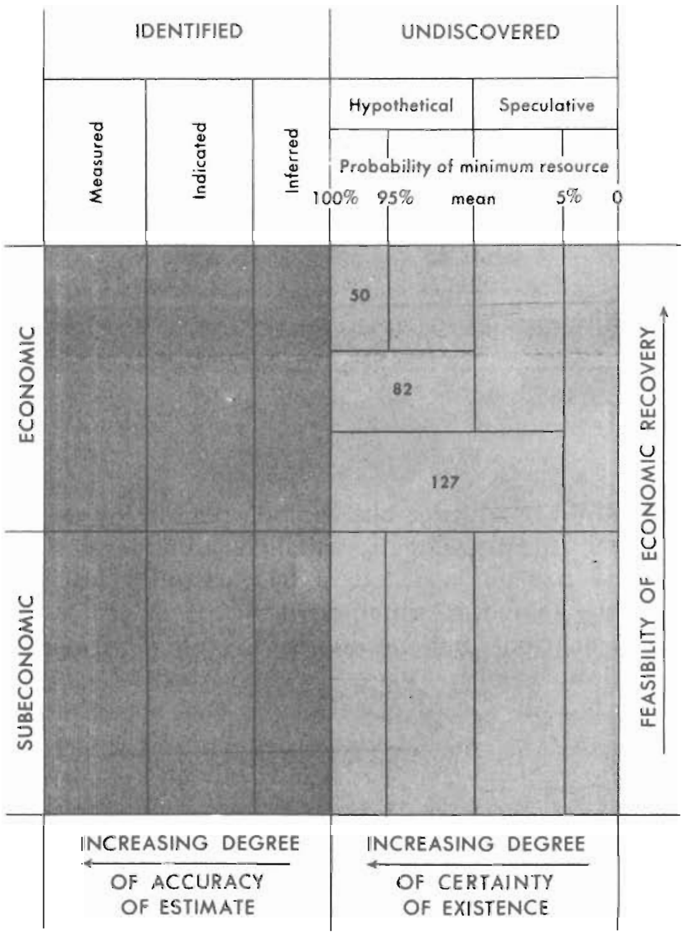

FIGURE 2.--Resource Appraisal Group (RAG) estimates of undiscovered recoverable crude-oil resources (in billions of barrels) as categorized for this discussion

It is important to realize that the estimation of these resources does not imply that they will, in fact, be found or will, in fact, be produced. It is implied, however, that material classified as a resource has some chance of existing, being found, and being used in the future and is a target for exploration and technologic development.

DYNAMICS OF PETROLEUM SUPPLY SYSTEM

The movement of petroleum resources from one category to another over time transforms the McKelvey diagram from a simple static report of resources at one time into a dynamic model of the petroleum supply system if production is added as an outlet from the reserve box (Fig. 3). The movement of material is to the left in the McKelvey diagram as deposits are identified through exploration and upward as more costly or lower grade deposits are developed with higher price-cost ratios or technologic advances.

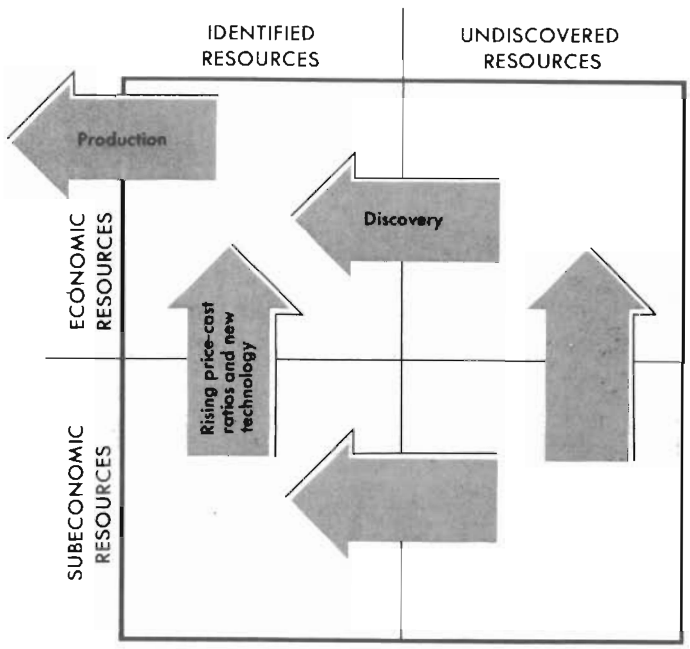

FIGURE 3.--Simplified model of petroleum supply system

A more sophisticated model of the dynamics of the complete petroleum supply system has been conceived and is being developed by Allen Clark and Lawrence Drew of the Geological Survey (Fig. 4). Their model includes three basic parts: (1) An occurrence model, (2) a search model, and (3) a production model, which describe, respectively, (1) the field size distribution of total resources, (2) the field size distribution of deposits discoverable at different levels of cost and technology, and (3) the production curves over time using various socioeconomic assumptions. Thus, when the occurrence model is operational, it would give estimates of economic and subeconomic undiscovered resources of the McKelvey classification, and the search model, using current prices and technology, would give estimates of the undiscovered economically producible resources.

CRUDE-OIL RESOURCE ESTIMATES

These concepts of classification can be applied to the many crude-oil resource estimates that have been made by scientists of various organizations, which will be discussed later, and a summary (Table 1) shows the classificatory relationship of most of the modern estimates from various sources. This paper, however, will focus on the crude-oil resource estimates made recently by members of the Geological Survey to illustrate the principal effects of confusion of terminology.

Three series of estimates of undiscovered crude-oil resources have been initiated by Survey scientists. The discovery-production trend series of six estimates was begun by Hubbert (1956, 1962, 1966, 1967, 1969, 1974) while he was employed by Shell Oil Company but was extended when he joined the Geological Survey in 1964 as a senior scientist. The volumetric series of five genetically related estimates was made by a number of authors, including Duncan and McKelvey (1963, Table 9), Hendricks (1965), T. A. Hendricks and S. P. Schweinfurth (written commun., 1966), Schweinfurth in works by McKelvey and others (1973), and Theobald and others (1972), and the U.S. Geological Survey (1974), using the basic estimation technique developed by A. D. Zapp and T. A. Hendricks. The geologic estimates published in Circular 725

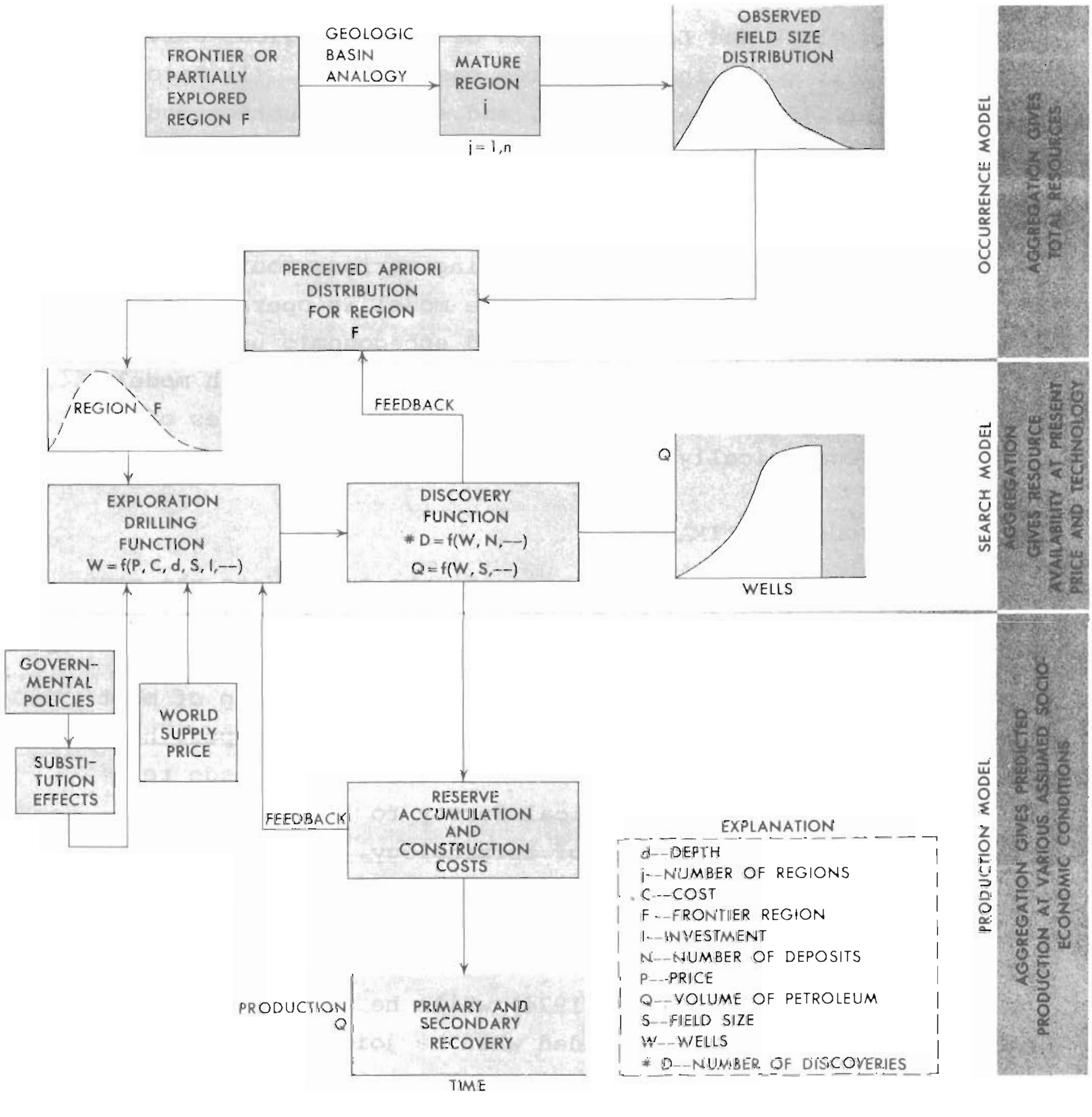

FIGURE 4.--Clark-Drew conceptual model of petroleum supply system

TABLE 1.—*Comparison of crude-oil resource estimates (in billions of barrels) for the entire United States onshore and offshore to 200-metre water depth*

[If an original estimate was revised for this paper in order to express it in comparable dimensions and if the change involved implicit assumptions, the revised estimate is preceded by ca]

Estimator	Original estimate	Undiscovered economic and subeconomic crude-oil resources (60-percent recovery)	Undiscovered economic crude-oil resources (using present technology)	Ultimate crude-oil production from future discoveries	Original crude-oil resources (60-percent recovery of discovered and undiscovered crude oil in place)
Hendricks (1965)	400 [1]	285 [2]	ca 152 [3]	----	600
Theobald and others (1972)	459 [4]	ca 585 [5,6]	ca 312 [3]	----	ca 900 [6,7]
U.S. Geological Survey (1974)	200–400 [4]	ca 255–510 [5,6]	ca 136–272 [3]	----	570–825
National Petroleum Council (1970)	107	199	107 [3]	----	514
Resource Appraisal Group (Miller and others, 1975)	50–127 (82 mean)	$\geq$94 to $\leq$238 [8]	50–127 (82 mean)	----	408–553 (468 mean)
Oil Co. A (Weeks, 1960)	----	----	ca 62 [9]	----	----
Oil Co. D (National Academy of Sciences, 1975)	89	----	76 [6]	----	----
Oil Co. E (National Academy of Sciences 1975)	90	----	77 [6]	----	----
Shell Oil Co. (R. H. Nanz, oral commun., 1975).[10]	65–155	----	65–155	----	----
M. K. Hubbert (1974)	----	----	----	55 [11]	----
C. L. Moore (written commun., 1975)	----	----	----	ca 156 [11,12]	452

[1] Includes past production and identified resources.

[2] Corrected for past production and all categories of reserves at 60-percent recovery. Hendricks gives 1,000 billion barrels of discoverable in-place crude oil.

[3] 32-percent recovery.

[4] Includes NGL.

[5] The original estimate includes NGL and is here reduced by 15-percent in order to subtract NGL.

[6] Estimate was classified as an undiscovered economic resource at the time of release and is reclassified here as an undiscovered resource.

[7] Estimates of crude oil on continental slope is subtracted from original estimate.

[8] The 95- and 5-percent probability levels of estimates of economic and subeconomic resources are not arithmetically additive. The proper aggregated 95- and 5-percent probability estimates would be greater than or equal to the sum of the 95-percent estimates and less than or equal to the sum of the 5-percent estimates. Estimates at 60-percent recovery.

[9] Weeks (1960) reported a figure of 270 billion barrels of ultimate resources of crude oil and NGL for the United States. This figure is adjusted by assuming crude oil is 85 percent of this and subtracting past production and all categories of reserves as of the end of 1974.

[10] Nanz, R. H., 1975, The offshore imperative—the need for a potential of offshore exploration: talk presented at colloquium on Conventional Energy Sources and the Environment, University of Delaware.

[11] Assumes continuation of pre-1974 socioeconomic conditions.

[12] Calculated by subtracting from C. L. Moore's 471 billion barrels ultimate recovery the 168 billion barrels of past production and present reserves plus an additional 147 billion barrels from identified resources at a 60-percent recovery.

by Miller and others (1975) are the first of the Resource Appraisal Group (RAG) to use a different, more sophisticated approach. Each of these series is an estimate of a different level of the petroleum supply system (Fig. 5).

The volumetric series is a geologically controlled subjective volumetric estimate of the portion of oil in the ground that is discoverable and recoverable over the long term. The estimation, the technique of which is described in detail by Hendricks (1965), is made in the following way. The area of the United States that is favorable for the occurrence of petroleum is estimated on the basis of geologic concepts. The success of past exploration is used as a yardstick to predict the success of future exploration in the unexplored area. A number of assumptions are involved: (1) the number of wells required to totally explore an area, (2) the average depth of an exhaustive exploratory well, (3) the thickness of the petroleum-bearing rocks, (4) the comparative incidence of petroleum in the unexplored area relative to that in the explored area, (5) the extent of the unexplored area that probably will be explored, and (6) the percentage of the oil found that will be recovered.

The volumetric series of estimates has never been broken down, but it covers both the hypothetical and the speculative parts of the undiscovered economic resource field of the McKelvey diagram (Fig. 6), because the analog methodology used assumes that past exploration has discovered accumulations from both the hypothetical and the speculative resource categories and thus should serve as an estimation device for both categories in the unexplored areas. The speculative resources may have been underestimated, however, because most wildcat wells have been drilled on hypothetical resource targets. It is impossible for any analog methodology to estimate the speculative resources that are not analogous to known resources, since these fall into what might be termed an unconceived category, or resources that the estimator will not speculate about. Thus, the volumetric series covers as much of the undiscovered economic field as it is possible to cover. The Geological Survey volumetric estimates cover, in addition, the portion of the undiscovered subeconomic resource field that lies between the historical average of

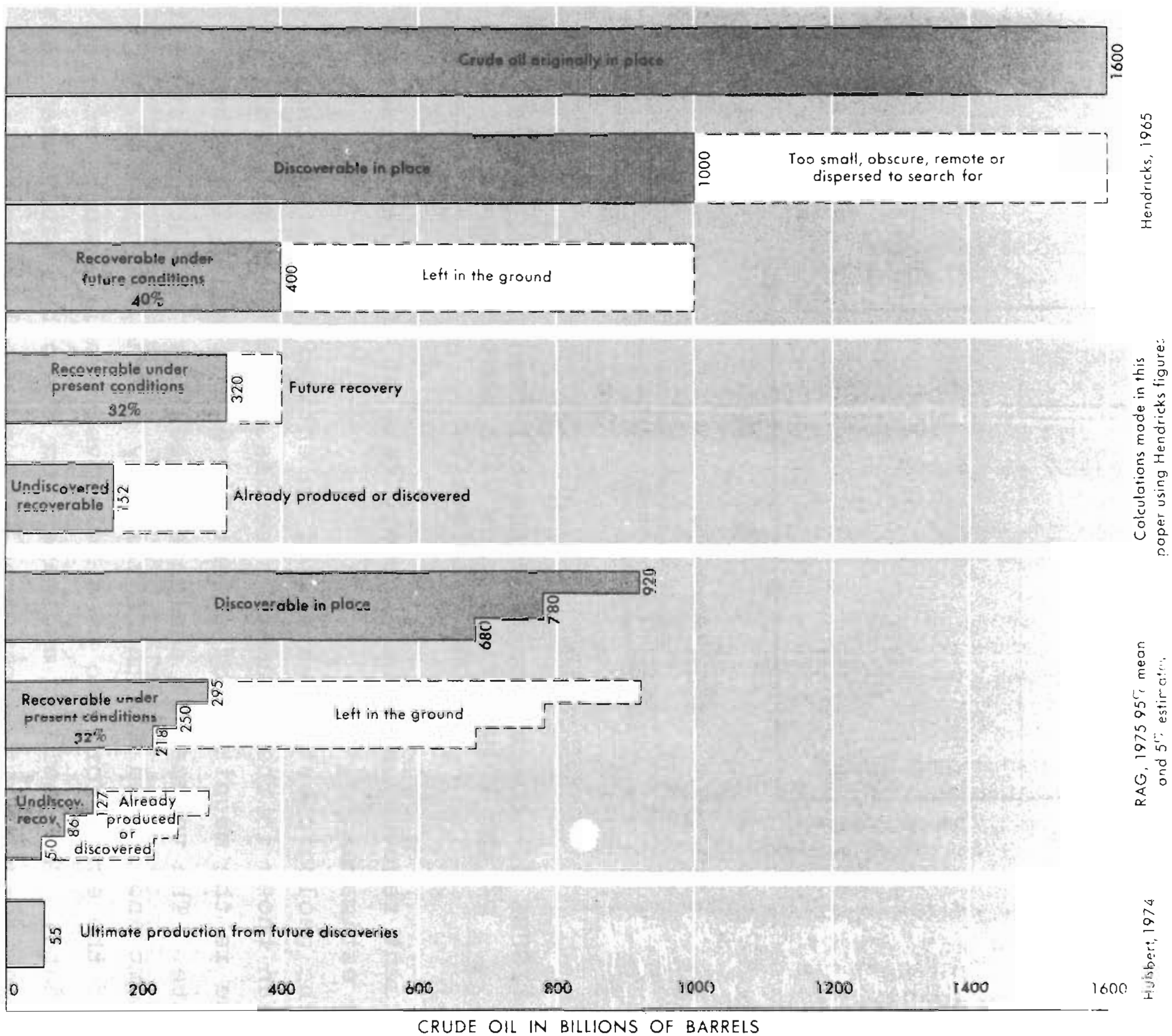

FIGURE 5.—Relationship between the crude-oil estimates of Hendricks (1965), Miller and others (1975), and Hubbert (1974).

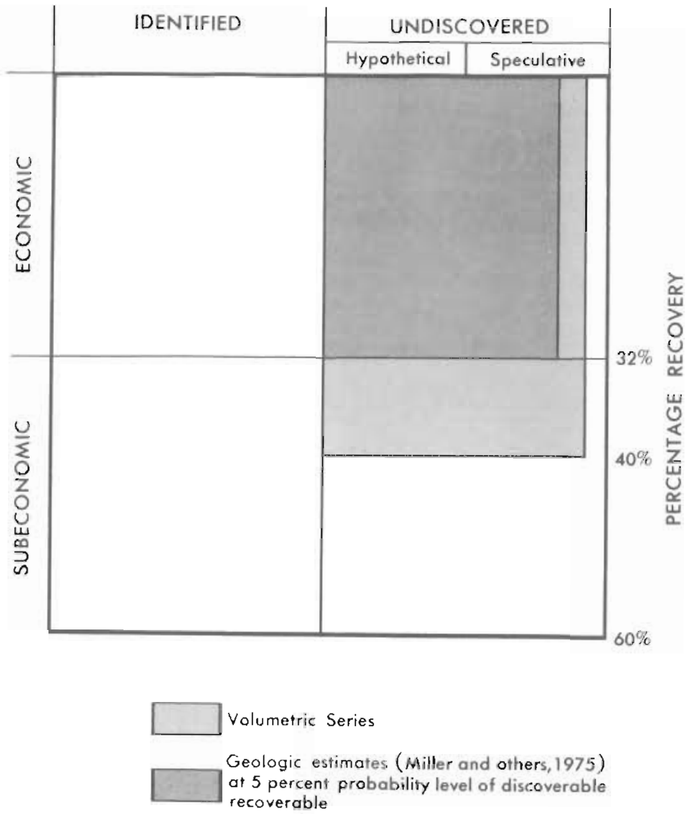

FIGURE 6.--Comparison of crude-oil resource estimates of the volumetric series with those of the geologic series

32-percent recovery and the recovery rate of 40 percent assumed in the estimates.

The geologic estimates are of an entirely different character than those in the volumetric series. The first major difference is the magnitude of scientific effort going into the estimate. The volumetric estimates used about one scientist-year of effort and relied for their validity on the experienced judgment of the estimator, who used relatively small amounts of geologic data. The geologic estimates, on the other hand, used tens of scientist-years of effort from 70 areal-geology specialists and 8 experienced petroleum resource geologists, who used large amounts of geologic data. The methodology is described in detail in Circular 725 (Miller and others, 1975) and consists of making estimates by assuming then-present technologic and pre-1974 economic conditions of the occurrence of undiscovered economic petroleum resources at several subjective probability levels for over 100 different petroleum provinces by means of several appraisal techniques. These geologically controlled results were then aggregated according to statistical theory. The results are explicitly reported at the 95-percent and the 5-percent probability levels of occurrence, with the idea that a 19-in-20 chance of the occurrence of a given quantity of oil is a fairly sure estimate, and a 1-in-20 chance of the occurrence of a larger quantity of oil is as unsure an estimate of the occurrence of additional petroleum as it is prudent to make. However, the technique estimates additional undiscovered recoverable oil at still lower probabilities, even though these estimates are reported only graphically. The 95- and 5-percent probability estimates do not cover all the undiscovered economic field of the McKelvey diagram. What is lacking is undiscovered economic resource estimates from the 5-percent level down to very small probability levels. The reported RAG estimates, when they are arrayed in vertical columns as they are in Fig. 2, therefore cover a smaller part of the undiscovered economic field than the volumetric series, particularly the later ones. Because the geologic estimates of undiscovered economic resources use the presently economic recovery factors most appropriate to the potential reservoir rocks in the basins being appraised, they did not incorrectly include any subeconomic resources and thus did not lap into the subeconomic field at all (Fig. 6).

The discovery-production trend series of resource estimates is of still a different character. Hubbert analyzed the yearly trends of production and the additions to reserves through exploration by year and by exploratory drilling footage. He pointed out the dependence of the former on the latter and then projected their historic trends into the future by using logistics or growth curves. These estimates are predictions of ultimate discovery and ultimate production assuming no significant changes of exploration incentive or access to prospective land or no significant change in the rate of technological development.

RELATIONSHIP BETWEEN ESTIMATE SERIES

It was contended at the outset of this paper that part of the disagreement about estimating resources stems from using the same words for different things. This contention applies to the differences between the volumetric series and the geologic series. Both the 1972 volumetric estimate (Theobald and others, 1972, Fig. 5) and the geologic estimates (Miller and others, 1975, Fig. 13) are shown filling diagrammatically the complete undiscovered economic resource field (Fig. 6). But, as discussed above, the volumetric series, particularly the later estimates, fills more than the undiscovered economic resource field, whereas the geologic estimate fills less, so that each series uses the term undiscovered economic resource in a different way. The true relationship between the two series, using the estimates of Hendricks (1965) and Miller and others (1975), are shown in Figs. 5 and 6.

The validity of the idea that differences between undiscovered economic estimates are partly due to a difference in assumptions of recoverability rates can be tested by comparing the estimated original crude-oil resources--that is, 60-percent recovery of original oil-in-place, estimated by each series (Table 1). Hendricks' (1965) estimate of a 60-percent recovery would be 600 billion barrels, and the RAG 5-percent probability estimate is 553 billion barrels. Thus, both Hendricks and Miller and others were estimating similar amounts of undiscovered crude oil but drew different boundaries between economic and subeconomic resources. On the other hand, Schweinfurth's (Theobald and others, 1972) estimate is about 900 billion barrels, almost twice the RAG 5-percent probability estimate. It can be assumed that the additional amount would be classed as speculative undiscovered and should be compared with the additional amount of crude oil estimated by RAG to occur at less than 5-percent probabilities, in both the economic and the subeconomic categories.

McKelvey developed and published his classification in 1972, after the first volumetric estimates had been made. However, the volumetric estimates of 1972 and 1974 were categorized as undiscovered economic resources rather than undiscovered resources.

In hindsight, the assumptions of the volumetric methodology should have been adjusted to better fit the McKelvey classification. The geologic estimates, on the other hand, have followed the McKelvey classification as closely as possible. This difference has been a major source of confusion and controversy.

How do these estimates relate to the petroleum supply system model of Clark and Drew (Fig. 4)? As a first approximation, the volumetric series is analogous to the resource estimates of the occurrence model. The geologic estimates are most closely analogous to the resource availability estimates produced by the search model. The discovery-production trend estimates are most similar to a production model prediction based on the assumption that the socioeconomic conditions prevailing over the last several decades will continue.

Thus, one can compare the estimates by saying that the volumetric estimates are the total undiscovered resource (to a 40-percent recovery level) and the geologic estimates are that part of the volumetric estimate that could be discovered and recovered under pre-1974 economic and technologic conditions, whereas the discovery-production trend estimates are that part of the geologic estimates that would be discovered and produced under the socioeconomic conditions of the last several decades.

UNCERTAINTY OF ESTIMATES

The above analysis asserts the relationship between these three petroleum resource estimates but does not deal with the uncertainty inherent in the estimates. The relationship requires that the volumetric estimates must be larger than the geologic estimates, which in turn must be larger than Hubbert's discovery-production trend estimates. But are the existing differences larger or smaller than they should be? Or, stated another way, is the accuracy of the estimates satisfactory?

The degree of certainty of the existence of resources decreases to the right of the McKelvey diagram. The feasibility of economic recovery decreases downward and implies a decreasing certainty of technological development and increasing economic incentive necessary to recover the resources. Thus, the volumetric estimates, which include resources that are either less well known or subeconomic, are by their nature less certain than the resources that were associated with the 5-percent probability estimated in the geologic estimates. Each series used a different technique to handle its inherent uncertainty.

Hendricks (1965, p. 3) gave a single resource figure but stated that:

> The statistical data from drilling in the United States are utilized to estimate the minimum total quantities originally underlying the United States and its adjoining continental shelves. As will be seen, none of the factors that enter into such a computation can be actually determined; many are purely matters of opinion. However, the analysis is given in such a manner that any reader who disagrees with any of the values assigned, or assumptions made, may substitute other values or other assumptions and derive his own estimates.

In effect, he said: Here are my judgments; if you disagree, I've given you a formula into which you can substitute your own judgments. This caveat also applied to the 1966, 1969, and 1972 estimates of the series, in which other judgments were made with the purpose of estimating not the "minimum" but the more likely (in the minds of the estimators) larger quantities of crude oil underlying the United States. As a result, estimates increased to finally the largest estimate of about 390 billion barrels of crude oil in 1972. Thus, the inherent uncertainty of the estimates was not dealt with directly until 1974 (U.S. Geological Survey, 1974) when a range of estimates was introduced that almost covered the span of estimates from 1965 through 1972. It is likely that, if additional petroleum geologists would make petroleum resource estimates by means of the Hendricks technique, the range of estimates would increase still more. For example, a number of petroleum geologists, including Halbouty (1975, p. 10), past president of the American Association of Petroleum Geologists (AAPG) and a leading analyst of petroleum resources as well as a highly successful explorationist, feel that the volumetric series estimate of 1974 is reasonable and acceptable and, if anything (Michel Halbouty, oral commun., 1975), is too low. The Panel on the Estimation of Mineral Reserves and Resources of the Committee on Mineral Resources and the

Environment of the National Academy of Sciences (1975, p. 90), which included John Moody, the incoming president of AAPG and retired Senior Vice President for Exploration and Production for Mobil Oil Company, felt that even the lowest of the volumetric series estimates is too high. It is likely that some of this difference of opinion reflects a misunderstanding of what is being estimated, but, even so, it is probable that the full range of uncertainty inherent in the Hendricks estimation technique has not been established.

The uncertainty of the RAG estimates, as discussed above, was handled by presenting the estimates at several probability levels and by showing the probability of any estimate by a curve. It is possible that broadening the number of resource specialists beyond the eight in the Resource Appraisal Group would increase the range of resources estimated at the 95- and 5-percent probability levels, because it is unlikely that the RAG specialists represent the full possible range of experienced resource judgments. In addition to this, although the Resource Appraisal Group was concerned about the effect on the estimates of using a group discussion to arrive at a consensus estimate for each province, the members felt that the benefits of group discussion to the quality of the estimate outweighed any possible bias introuced. It has been suggested that the effect of group behavior might tend to reduce the range of estimates, and the generalization pointed out by Myers and Lamm (1975, p. 297)--that "group discussion tends to enhance the average pregroup inclination of the group members"--supports this suggestion. An alternative procedure for avoiding this pitfall would be to have the resource specialists make their province estimates independently and then aggregate them for each province according to statistical theory. It appears then that, even though the full range of uncertainty inherent in the geologic estimates has not been established, it is certainly better established than the range of the volumetric estimates, because probabilities were dealt with directly, more views were represented in its preparation, and statistical theory rather than intuition was used to aggregate probabilities of the occurrence of oil by province.

The inherent uncertainty of the discovery-production t estimates is more difficult to assess. The internal precisic of the projection technique--that is, the goodness of fit of t points to the curve--has been estimated by Hubbert (1975) at about ±20 percent. However, the effect of significant changes in the socioeconomic factors which would influence Hubbert's prediction of ultimate production have not been analyzed. For example, if the OPEC cartel were to break up and the world oil price return to a level more closely related to the cost of finding and producing petroleum, the effect on the American domestic petroleum industry, which has already lost the depletion allowance, would be extremely depressing, and it is possible that Hubbert's predicted ultimate production would be too large, at least within the time range of his projections. Similar effects in the opposite direction are conceivable. Thus, it is apparent that a part of the uncertainty of Hubbert's estimate is inherently tied to the uncertainties of future political events. Also, if other types of curves are adopted, the same data give widely different results. Hubbert uses a symmetrical curve to predict 170 billion barrels of ultimate crude-oil production,[2] whereas C. L. Moore (written commun., 1975), using an asymmetrical curve with the same data plus Alaskan data, predicts an ultimate crude-oil production of 471 billion barrels. I can see no evidence produced by either Hubbert or Moore that makes one curve or one manner of curve fitting preferable to the other, much less requires the use of one curve or the other. Furthermore, these particular curves are useful, mainly because they are mathematically simple. This simplicity facilitates the analysis of the data, but does it mean that other mathematically more complex curves, which would give still different results, are more or less valid? Finally, it is difficult to say, even though past frontiers are included in the historic discovery and production data, whether future frontier petroleum provinces are adequately handled in the projections, and, thus, additional uncertainty is

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[2]He adds an additional 43 billion barrels derived from a geologic estimate to account for Alaska, giving an ultimate U.S. production of 213 billion barrels.

introduced into the estimates. Thus, there is a large amount of inherent uncertainty introduced into Hubbert's estimates from these three sources--that is, (1) uncertainty of future socio-economic events, (2) choice of alternative curves and method of fitting used for prediction, and (3) the geographic extent of the prediction. However, it must be recognized that Hubbert's predictions, made 13 years ago, accurately predicted the peaking of domestic production in 1972, a significant achievement.

To repeat the question asked at the outset of this section, are the existing differences between series estimates larger or smaller than they should be? The question cannot be answered now because the full range of uncertainties inherent in the production, search, and occurrence models has not been assessed. It is too early to judge.

Other Recent Estimates

A number of other estimates of undiscovered petroleum resources have been made. Some of these have been described and analyzed by Theobald and others (1972), McCulloh (1973), and Miller and others (1975), and six of them are shown in Table 1 along with estimates of Geological Survey scientists. One difficulty in comparing these estimates is caused by the combination of their aggregated nature and their dimensional differences.

The industry estimates given in the report of the Committee on Mineral Resources and the Environment of the National Research Council of the National Academy of Sciences (1975, p. 89) and the Shell Oil estimate apparently are estimates of undiscovered recoverable resources under pre-1974 economic conditions and technology. The estimates of the National Petroleum Council and the AAPG are very difficult to categorize owing to the varying methodologies and resource terminologies used by scientists for different regions. Still, we can be confident that the overall methodology of deriving these estimates was similar to that used by RAG. The resource is reported as undiscovered oil in the ground, and several recovery factors are reported. The resulting estimates are comparable in magnitude at a 32-percent recovery factor with the RAG estimate. The ultimate production estimates of C. L. Moore (written commun., 1975) are analogous to Hubbert's estimates as discussed earlier.

All these estimates are listed in Table 1 according to the resource categories that correspond to the crude-oil supply model as proposed by Clark and Drew--that is, undiscovered crude oil (equaling the occurrence model estimates), undiscovered economic crude oil (equaling the search model estimates), and production from future discoveries (equaling part of the production model estimates). These non-Survey estimates fall within the ranges of Survey estimates, except for Moore's estimate, which is more than twice that of Hubbert's.

SUMMARY AND CONCLUSIONS

A full analysis of the Nation's petroleum supply system requires knowledge of (1) the total petroleum resources discoverable and recoverable under future technologic and economic conditions, (2) the portions of those resources that are discoverable and recoverable under present technologic and economic conditions, and (3) the ultimate production possible under a range of socioeconomic conditions. As an approximate characterization, the volumetric series of estimates was an attempt to estimate the first category, the first geologic estimate was an attempt to estimate the second category, and the discovery-production trend series of estimates was an attempt at the third category, but only under the assumption of continuing socioeconomic conditions prevailing over the last several decades. Thus, even though these estimates have inherent uncertainties that can and should be narrowed with additional work and even though they are only first approximations of their categories, they are not necessarily incompatible with one another.

It is important for policymakers to recognize these relationships so they can address substantive resource problems.

Agreement exists on all sides on the magnitude of the fairly well assured undiscovered economic resources under pre-1974 technologic and economic conditions, that is, the geologic estimates. The estimates should be improved, but little change in their magnitude is expected until substantial exploration is carried out in the frontier areas. Better estimates of undiscovered resources--that is, the occurrence model estimates--are badly needed, because the present volumetric estimates are too uncertain and too general to allow full development of the search model estimates or, in turn, the production model estimates. Finally, although the discovery-production trend estimate is valuable for the assessment of the petroleum supply system operating in 1973, the effects of a range of differing socioeconomic factors on ultimate production badly need to be evaluated in order to demonstrate the options available for policy considerations.

PLANS FOR FURTHER RESOURCE STUDIES

The Geological Survey has the responsibility to continue to improve resource estimates. The critical needs have been discussed in this paper, and plans to meet some of these needs have been made and partially implemented.

Occurrence Modeling

The Resource Appraisal Group and the Office of Resource Analysis of the Geological Survey are developing the computerized analytical techniques required for occurrence modeling. This process involves the development of field size distributions in the petroleum provinces of the country and the application of mature geologic basin analogs to each of the frontier basins and the partially explored basins. The data required to implement these studies are being developed cooperatively by the Geological Survey, various State geological surveys, the AAPG, the International Oil Scouts Association, the U.S. Bureau of Mines, and the University of Oklahoma or are being purchased through Petroleum Information, Inc.

A novel geophysical technique for helping to estimate petroleum resource potential is being developed by T. H. McCulloh of the Geological Survey. It consists of applying to the partially explored or frontier basins the relationship between the average lightness of a petroleum basin (that is, the average difference between the gravity of the rocks in the basin and the gravity of the surrounding area) and the average petroleum richness of the basin that McCulloh established for the well-developed basins. This technique shows promise in sharpening the analog methodology for appraising the total petroleum resources of the Nation, both onshore and offshore, thus providing the improved reliability of resource estimates necessary for the search model.

Search Modeling

The Office of Resource Analysis is developing the techniques for a computerized analytical search model to generate the field size distributions, by basin, of petroleum discoverable and recoverable under present as well as alternative economic and technologic conditions. The geologic information necessary to implement this modeling is being generated by the Resource Appraisal Group and the Oil and Gas Resources Branch of the Geological Survey. This estimate will be the next in the RAG series.

In 1975, the AAPG was asked by Acting Secretary of the Interior Kent Frizzell, with the strong endorsement of the Director of the Geological Survey, to undertake a petroleum resource appraisal of the country. This effort will allow a major input to petroleum resource estimation by the petroleum explorers of the Nation.

The Resource Appraisal Group, in addition to providing input to the above modeling, will continue its ongoing resource studies on a province-by-province basis for the entire Nation. This effort will include the updating and revision of earlier appraisals, the development and improvement of appraisal methodology, Outer Continental Shelf area evaluations, wilderness area appraisals, finding-rate studies, and a series of maps showing the petroleum basins of the world.

Production Modeling

The Geological Survey does not normally engage in production modeling, which gives long-range supply curves. Occurrence and search modeling are, however, necessary inputs to production modeling, and the Survey is undertaking research in the application of its occurrence and search models to production modeling in order to facilitate cooperation with these organizations that are engaging in production modeling.

These plans constitute the next steps in appraising the Nation's petroleum resources. When these steps have been taken and when an appropriate organization undertakes production modeling studies, a resource information system will have been set up to allow for continuing monitoring and assessment of the Nation's petroleum resources. Only then will a firm base have been laid for making energy policy in relation to petroleum resources. Such steps will, however, require several years to complete. In the meantime, necessary policy decisions on offshore leasing, petroleum pricing, and alternate energy source development must be made on the basis of the incomplete and uncertain petroleum resource estimates that we now have.

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