NBSIR 80-2044 (DoE)

An Annotated Restatement of the Midterm Oil and Gas Supply Modeling System Methodology

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National Bureau of Standards
U.S. Department of Commerce
Washington, D.C. 20234

July 1980

with portions contributed by:
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U.S. DEPARTMENT OF COMMERCE, Philip M. Klutznick, *Secretary*

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NATIONAL BUREAU OF STANDARDS, Ernest Ambler, *Director*

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PREFACE

Under contract to the Office of Analysis Oversight and Access, the Operations Research Division of the National Bureau of Standards was charged with the development of methodologies for the assessment of energy models. The Midterm Oil and Gas Model (MOGSM) was to be used as the vehicle for testing these methodologies.

A natural first task was to read the documentation related to this model in order to obtain an understanding of the methodology and mathematics of the model. The tasks of assessing the MOGSM documentation and developing and testing generic guidelines for energy model documentation took place concurrently. The results of this research are reported in [15].

One conclusion of this documentation assessment was that the existing documentation for MOGSM did not contain information sufficient for us to obtain a thorough understanding of the mathematical/logical structure of the model. However, through many discussions with the model developers, the structure of the model was exposed and the model assessment activities continued. Since a number of people were involved in a variety of assessment tasks, we decided to produce an internal document describing the model's mathematical/logical structure as we understood it. This document is an outgrowth of that activity.

We note, however, that notwithstanding the overall inadequacy of the model documentation, substantial portions of this report were extracted with minor emendations, from the existing model documentation. The authors of those reports, whose names are listed on the title page of this one, supplied additional contributions through conversations and letters.

We never intended as model assessors to supplement the "primary" documentation of the model we were assessing, especially since our major concern is the development of assessment methodology, not the actual assessment of the model. However, the need for at least an internal document became apparent. As the production of this document progressed, we realized that this activity was advancing our general methodology-development goals. It clarified and synthesized many of our notions about documentation which later were incorporated into the guidelines presented in [15] and reinforced the recommendations presented in that report. We also believe that the existence of this report will help advance the most important by-product of proper model assessment--that of making the models more "transparent", i.e. more open to peer review and more understandable to policy makers who rely on information produced by models.

A number of caveats must, however, accompany this document. MOGSM consists of three submodels: the Economic Submodel, the Resource Base Submodel, and the Drilling Submodel. Descriptions of both the Economic Submodel and the Resource Base Submodel are based on the verbal descriptions provided by the model developers. No computer code listings were examined to see if there were discrepancies between the structure described by the modelers and the computer implementation. We have, however, requested the model developers to review a draft of this document to insure that what we have written is consistent with their "conceptual" model.

On the other hand, information on the Drilling Submodel was obtained by reading the computer code labeled "OILDRL 78". This exercise uncovered discrepancies between the computer implementation and descriptions in either the existing documentation or in verbal statements made by the developers. These discrepancies are noted in this report.

A major portion of the model and its methodology was totally undocumented at the outset of the present exercise. Thus, the methodology used to determine the costs of exploratory and developmental drilling are presented for the first time in this document, thereby allowing previously unavailable review of this submodel.

It is a difficult task to document work performed by others and to record verbal explanations of a highly complex model. Furthermore, we do not believe that the task is complete until the computer code of both the Economic Submodel and the Resource Base Submodel have been reviewed by a third party and any discrepancies between the implementation and the "conceptual" model documented. We hope that this document will assist others in understanding the mechanics of this model.

ABSTRACT

The Midterm Oil and Gas Supply Modeling System is a computer model based on economic and engineering factors, that projects yearly domestic oil and natural gas production over a 30-year period. The regional oil and gas supply curves developed by MOGSM are input to the Midterm Energy Forecasting System (MEFS).

The Oil Supply Model consists primarily of three interconnected submodels: a Drilling Submodel that projects regional exploratory drilling on the basis of information about the economic gradations of the resource base, the level of future expected prices, and various constraints to exploratory drilling activity; a Resource Submodel that derives annual regional production quantities based on exploratory drilling, the prospects for finding oil, the intensity of development, the fraction of oil-in-place (OIP) which can be recovered by either primary, secondary, or tertiary methods, and the fraction of proved reserves which can be produced each year; and an Economic Submodel that calculates a minimum acceptable price for each year's quantity of reserves proved.

The Gas Supply Model produces supply projections for non-associated natural gas and its coproducts and is identical to the Oil Supply Modeling System with the following exceptions: gas finding rates are estimated as a function of total drilling (exploratory and developmental) rather than exploratory drilling; the components of the oil model which represent enhanced recovery--secondary and tertiary processes--are not present, and the Gas Supply Model has disaggregated the Eastern states into two regions.

Also included in the Midterm Oil and Gas Supply Modeling System is a Financial Model which tabulates detailed costs and revenue information, calculated from the economic model into regional income statements and selected balance sheet items for the oil and gas producing industry. This model is used to determine the capital expenditures necessary to provide the projected production quantities. It provides the capability to permit the MEFS oil and gas supply solutions to be translated into detailed schedules of oil and gas expenditures, defined in terms compatible with the national income accounts.

KEYWORDS: Documentation of DOE supply model; economics of oil and gas supply; gas supply; oil supply; resource modeling; supply projections.

MIDTERM OIL AND GAS SUPPLY MODELING SYSTEM

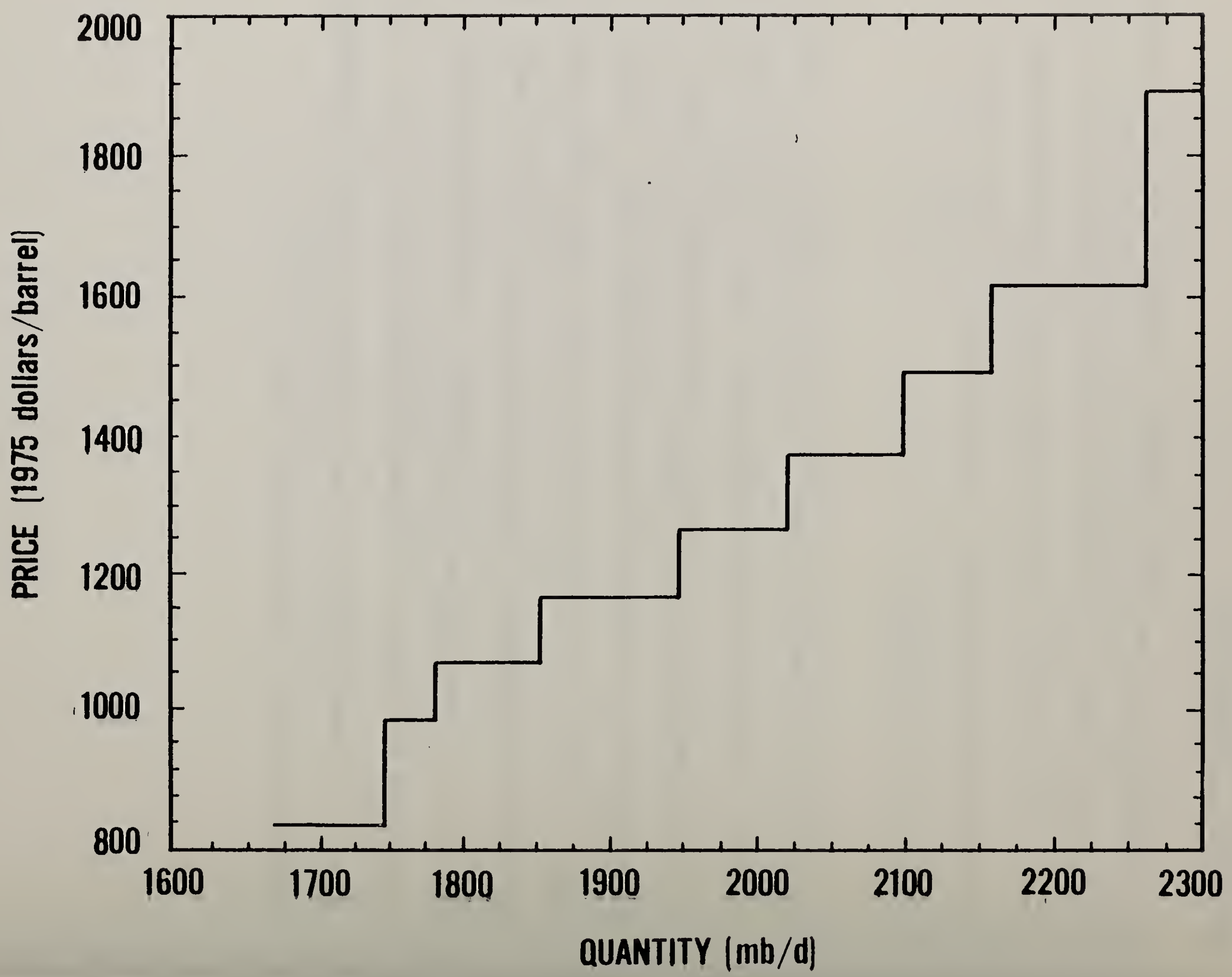
DESCRIPTION

SECTION I: INTRODUCTION

The Midterm Oil and Gas Supply Modeling System (MOGSM) uses computer-based models which project the onshore and offshore supply of oil and natural gas for the lower 48 states and for Alaska south of the Brooks Range. The forecasting procedure incorporates engineering and economic factors to estimate the supply of oil and gas.

The estimating procedure focuses on two major areas: (1) crude oil and the coproducts of associated (and dissolved) natural gas and natural gas liquids and (2) non-associated natural gas and natural gas liquids. The results of the estimation are regional oil and gas supply curves. Figure 1 represents a typical regional oil supply curve for 1985. These curves are part of the data base for the Department of Energy (DOE) Midterm Energy Forecast System (MEFS). MEFS uses a linear programming technique to balance these supply estimates with demand estimates for refined petroleum products and gas. MEFS also accounts for transportation, prices of imports, prices of alternative fuels, and other factors (for a description of MEFS see [46]).

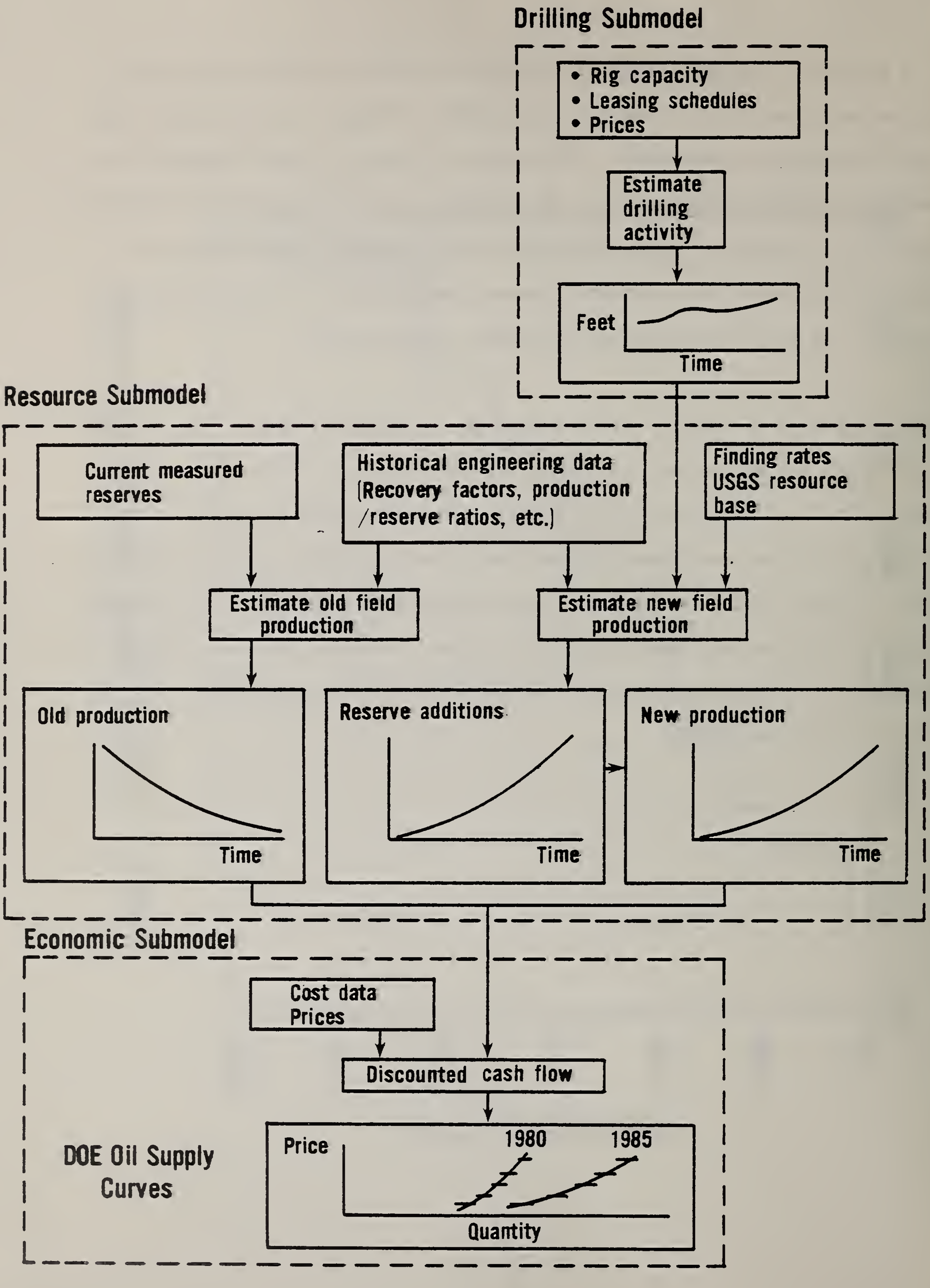
Figure 1. 1985 OIL SUPPLY WESTERN GULF BASIN



As a preview of the more detailed discussion to follow, a flow chart of the estimation process for oil supply is presented in Figure 2 (natural gas would have an equivalent flow chart). The process consists of three separate estimating activities or sub-models: (1) estimation of future profitable drilling levels; (2) estimation of new production from these drilling levels and old production directly from currently booked reserves; and (3) economical graduation of new and old production to produce a supply curve.

This document describes the methodology used by the Department of Energy (DOE) to estimate oil and natural gas supply curves for use by MEFS. It first describes the key features of the oil and natural gas supply process simulated in the estimation procedures. It next describes, in general terms, the model used to project future oil supply as a function of various Federal and Corporate policy actions and market prices for crude. Finally, it discusses the estimation of natural gas supply, highlighting the differences between it and the oil supply estimation.

Figure 2. ESTIMATION PROCESS FOR OIL SUPPLY



SECTION II. THE SUPPLY PROCESS

DOE projections of oil and gas supply are based on the economic and engineering factors which affect domestic oil and natural gas supply decisions. This section describes the major features of this supply decision-making process. For a more detailed description of the underlying process, see [10,11,17,21, 47].

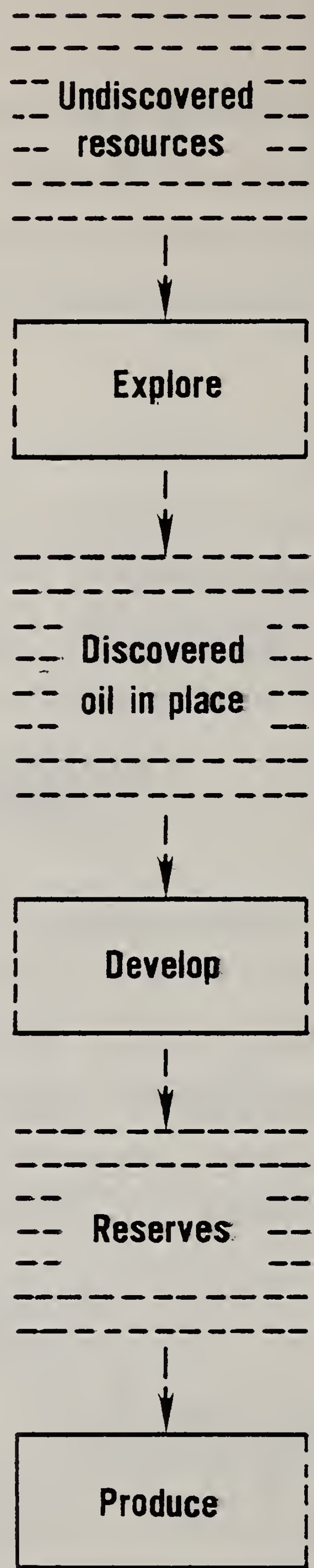
The Oil Supply Model consists of an analytic framework which represents the real-world activities and events associated with domestic oil exploration, development and production. In particular, it includes the important economic and engineering factors which are known to affect future production, as well as the way these factors interact in oil supply decision making by private firms. Since the basic investment decisions center mainly around individual reservoirs, the discussion begins there.

II.1 The Reservoir

A reservoir is a continuous, interconnected volume of rock containing oil and gas as a hydraulic unit. The life cycle of a typical reservoir spans three kinds of activities: exploration, development, and production (Figure 3). Exploration converts "undiscovered resources" to discovered "oil-in-place";* development converts "oil-in-place" to "reserves"; and production brings "reserves" to the surface so they can be transported, refined and consumed. (Oil and gas which has already been found and is considered producible under present prices and technology are known as "reserves.") These activities overlap in time and, taken together, encompass the useful life of the reservoir from time of discovery to time of abandonment (Figure 4).

*Throughout this report, the term "oil-in-place" will mean discovered "oil-in-place" rather than all existing resources (whether found or not yet discovered).

Figure 3. ACTIVITIES AND EVENTS OF ONE RESERVOIR



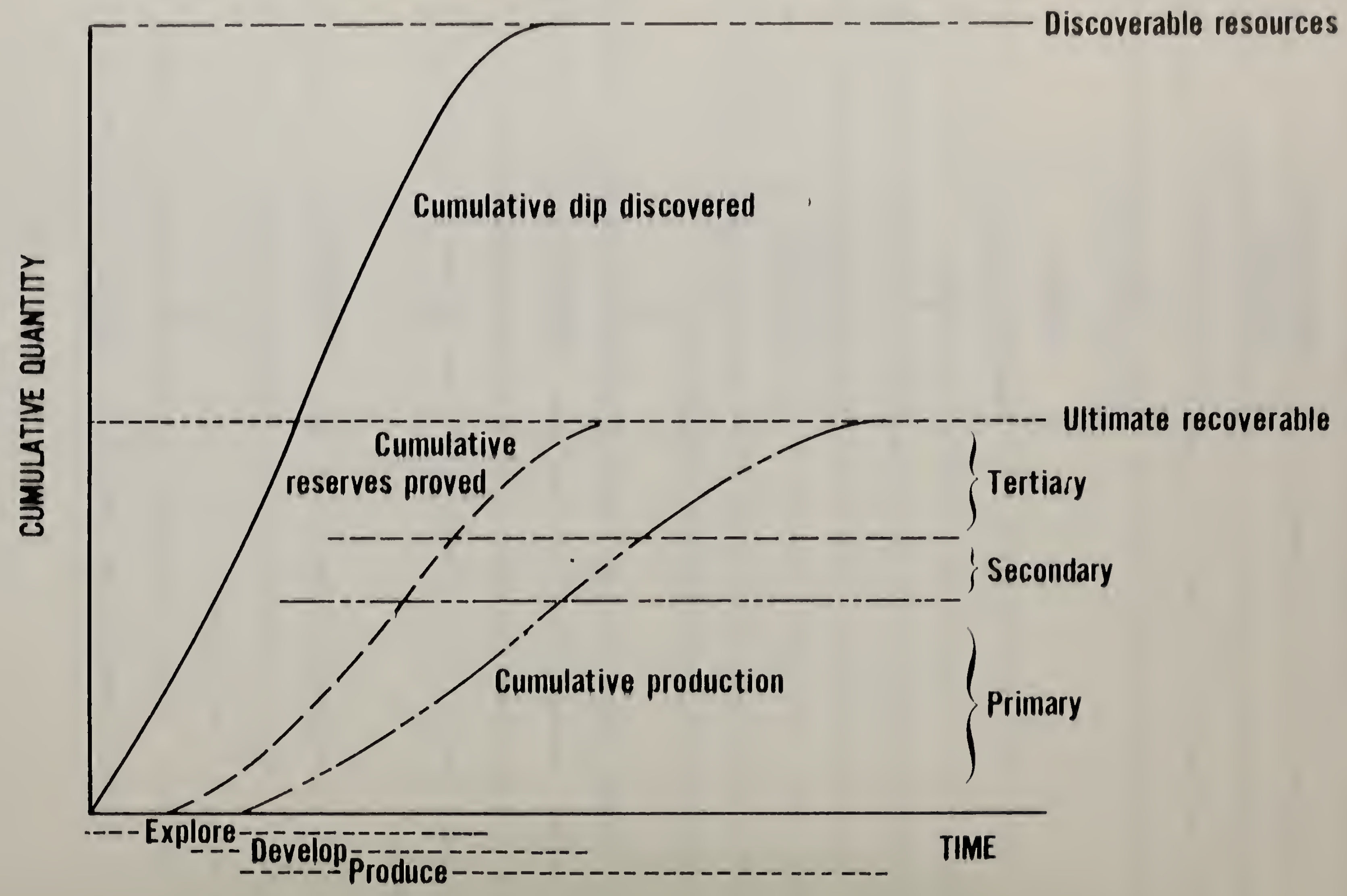
The exploration process begins first, continuing until the reservoir's physical dimensions and other engineering aspects are determined sufficiently to estimate the economic feasibility of recovering these resources. During this period, the reservoir's total oil-in-place is continually reassessed until this total approaches the limit of the ultimate discoverable resources present.

After exploration (and discovery), the development process begins with the formulation of an initial plan to convert the deposit to reserves. As reservoir knowledge improves, the plan is modified to show more "proven" reserves, until the economic limit of the reservoir is achieved and development ceases. At this point, the cumulative amount of proven reserves has reached the level ultimately recoverable under the economic and technological conditions expected to prevail over the reservoir's producing life.

As development begins to prove reserves, production commences. After development ceases, production declines over time, at a rate defined by the reservoir's physical properties and the intensity with which the reservoir has been developed. When all of the reserves have been produced, the reservoir is abandoned.

There are three general methods of recovery corresponding to stages in oil production. Early on, when the natural reservoir pressure is high, crude will flow to the surface unaided; at this stage, production is classified as "primary recovery". As more and more oil is produced the natural reservoir pressure is generally reduced. At some point, additional developmental investment

Figure 4. RESERVOIR LIFE CYCLE



is necessary to institute "secondary recovery". Secondary methods reintroduce natural gas into the reservoir and/or inject water to increase or maintain reservoir pressure. Later, it may be necessary to employ more rigorous, sophisticated (and costly) methods. These processes are designed to free oil from the reservoir rock, and are referred to as "tertiary recovery" techniques.

(The technologies used to produce shale or synthetic fuels are quite different. Since the production of these fuels is outside the scope of this modeling effort, no discussion of these technologies will be presented.)

II. 2 The Reservoir Investment Decision

Exploration, development, and production will be undertaken only when expected oil prices (and natural gas prices, in the case of associated-dissolved gas) are sufficient to yield a return on investment competitive with alternative investments of similar risk. Typically, reservoir investments are evaluated by means of a discounted cash flow (DCF) technique. The DCF technique considers the time value of money in comparing the cash expenditures and cash revenues of a reservoir investment. The basic variables are the expected costs (including taxes and the costs of capital, discounted) to find, develop, and produce a deposit; the expected time-profile of production from the deposit; and the expected selling price for the reservoir's output.

One way to use the DCF technique is to calculate a "minimum acceptable price". This is the lowest market price required to pay the costs associated with finding, developing and producing a given quantity of reserves and, in addition, provide a competitive return on the capital employed. If the minimum acceptable price for a particular reservoir is less than or equal to the market price expected in the future, the reservoir would be economically viable. If, however, the minimum acceptable price is greater than expected prices, the reservoir would not be a competitive investment.

In the early life of a reservoir, these economic evaluations are based on uncertain assumptions, incomplete data, and little actual experience with the reservoir. Consequently, a reservoir usually is developed in stages. As knowledge of the reservoir improves, the minimum acceptable price required for additional development is repeatedly revised.

Once a reservoir's economic viability is established, the operator will develop it to the point where incremental costs (which includes competitive return on capital) equal incremental revenues. For example, additional producing wells will be planned until the additional costs of one more well would exceed the additional revenues that would accrue from it (including the time value of money and the effects of such intensive development on the ultimate recovery and production over time).

II. 3 Exploration Versus Development

Investments in oil supply can be allocated across different kinds of opportunities. For instance, investments can be made in exploration to discover new oil reservoirs. Investments can also be made to increase the development of known reservoirs. The range of choices can be illustrated by considering the status of the domestic resource base. The resource base is analogous to a complex inventory, organized along two dimensions (Figure 5). The first dimension distinguishes between discovered (identified) and undiscovered resources. A second distinction is between economic and subeconomic resources with <u>measured</u> reserves being the most economic to develop, followed by <u>indicated</u>, <u>inferred</u>, and finally <u>undiscovered</u> resources in that order.

II. 3. 1 Proved Reserves

The most assured portion of the resource base is "proved" reserves. This portion has been discovered and is economically recoverable. Measured reserves support today's production. All or most of the developmental investment needed to produce these reserves have been made. The additional cost of withdrawing these reserves will be small compared to the cost of locating, developing, and proving undiscovered resources.

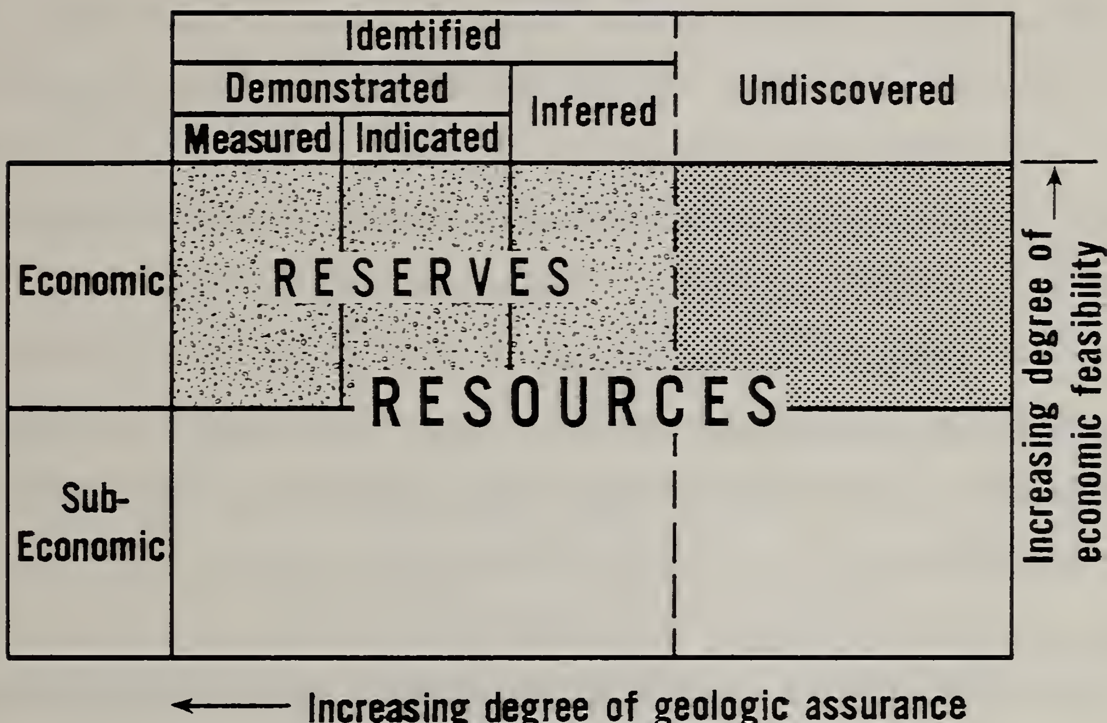
II. 3. 2 Indicated Reserves

"Indicated" reserves are also reasonably assured of being produced in the future. Such reserves consist of additional recovery from known reservoirs when engineering knowledge and judgment indicate that secondary recovery is economically feasible. However, additional investment, e. g. in fluid injection wells and equipment, is necessary to initiate production from indicated reserves.

II. 3. 3 Inferred Reserves

"Inferred" reserves are the last category within the discovered and economic portion of the resource base. These reserves result from extensions and revisions of knowledge about reservoirs. Extensions arise through exploratory drilling that extends the knowledge about the size of a deposit and the amount of resource it contains by drilling outside the proven perimeter of a reservoir. Revisions usually arise from drilling and other experience within the known perimeter of a deposit which provide new information concerning the reservoir's characteristics. Like indicated reserves, inferred reserves require additional investment to initiate productions.

Figure 5. U.S. RESOURCE BASE



II. 3. 4 Undiscovered Resources

Finally, "undiscovered" resources account for the remaining share of the resource base. These resources require the full range of exploration and development investment in order to initiate production.

For these four types of resources, the time required to increase oil production varies widely. Production from producing portions of known reservoirs can be increased in the short run, but such additional production is usually small. Increased development of discovered, but not fully developed portions of known reservoirs yields more substantial results. Although production increases from increased development of known reservoirs may appear very quickly, the total impact of this development is usually spread over a three to five year period. Finally, exploration produces large results over a much longer period of time (five to twenty years), especially in areas remote from known reservoirs.

This section has provided a very brief introductory description of the oil supply process. For more detailed discussions see [10,11,17,21,47]. The next four sections will describe the methodology of MOGSM.

SECTION III: OVERVIEW OF THE OIL SUPPLY MODELING SYSTEM

The United States oil producing areas considered by this model are divided into 14 regions whose petroleum-bearing lands are somewhat homogeneous. "These regions correspond closely to province boundaries established in the American Association of Petroleum Geologists (AAPG) Memoir 15 [Cram, 1971]. The numbering of these regions and the location of the boundaries generally conform with those used by the AAPG and the National Petroleum Council (NPC)" (USGS Circular 725, p. 14). The 14 oil producing regions are shown in Figure 6 as Regions 1a,[1] 2, 2a, 3, 4, 5, 6, 6a, 7, 8, 9, 10, 11 and 11a. Regions 8, 9 and 10 have been aggregated into one region for modeling oil supply. Regions 8 and 9 are combined in the gas submodel with region 10 becoming a separate region. There are, therefore, 12 regions in the oil model and 13 in the gas model.

Other oil producing provinces, such as the North Slope and Alaskan Outer Continental Shelf (OCS) North of the Brooks Range, as well as tertiary recovery and unconventional petroleum (synthetics and shale) are treated outside this modeling framework in other DOE models (e.g., the Enhanced Oil Recovery Model [43,44,45], and the Alaskan Hydrocarbon Model [38,39,40,41,42]).

The Oil Supply Model follows the process described in the preceding section. It consists primarily of three interconnected submodels:

Resource Submodel - A model component that translates the following information into annual regional production quantities: exploratory drilling, the prospects for finding oil, the intensity of development, the fraction of oil-in-place which can be recovered by either primary or secondary methods, and the fraction of proved reserves which can be produced each year.

[1]Region 1 includes both onshore and offshore petroleum-bearing lands south of the Brooks Range. For modeling purposes, Region 1 is treated as an "offshore" region.

Figure 6. REGIONAL BOUNDARIES FOR OILAND GAS MODEL

Economic Submodel - A model component which calculates a minimum acceptable price associated with a given quantity of proven reserves.

Drilling Submodel - A drilling profile and regional allocation model component which uses economic gradations of the resource base, expected price levels, and constraints on exploratory drilling activity as a basis for projecting regional exploratory drilling.

These three submodels will be discussed separately with their interactions noted. The first submodel discussed is the Resource Submodel, an engineering simulation model which translates the resource base into production. This model component forms the core of the modeling process.

SECTION IV. THE RESOURCE SUBMODEL (TRANSLATING THE RESOURCE BASE INTO PRODUCTION)

The Oil Supply Model estimates regional reserve additions and annual production quantities according to the U. S. Geological Survey Division of the domestic resource base (see Figure 7).

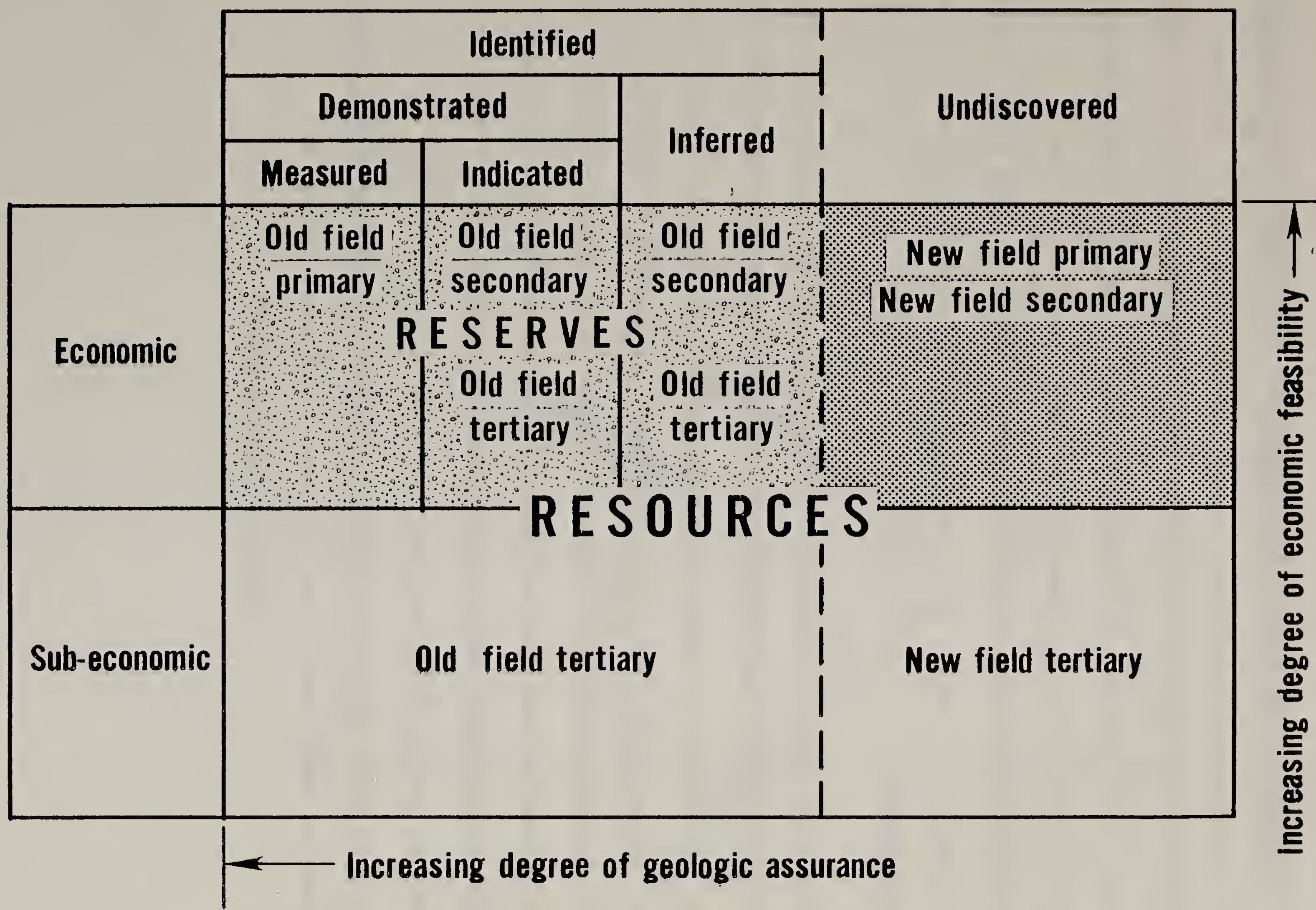
The dominant partition of the resource inventory is divided into identified (known) and undiscovered resources--old fields and new fields. This division represents principally the choice between exploration and development investment. The lesser separation involves the different types of recovery--primary and secondary. This division represents the life cycle of reservoirs after discovery and the short and intermediate run development intensity investment choice. The methodology for translating the resource base into production in old fields is different from that in new fields. This section will first describe the methodological approach used for estimating reserves in old fields and then contrast that with the approach used in new fields.

IV. 1. Production from Existing Fields

The proved reserves segment of the resource base is the most assured, and its translation into production quantities is easily achieved. Each region's reported reserve figure as of January 1 of the beginning year of the forecasts is multiplied by a (constant) decline rate[2] which represents the expected percentage of remaining reserves that will be produced for a given year. These decline rates are based on historical data for each of the regions.

[2]We note that "decline rate" is the term used by DOE modelers to denote the rate of production (extraction) of oil.

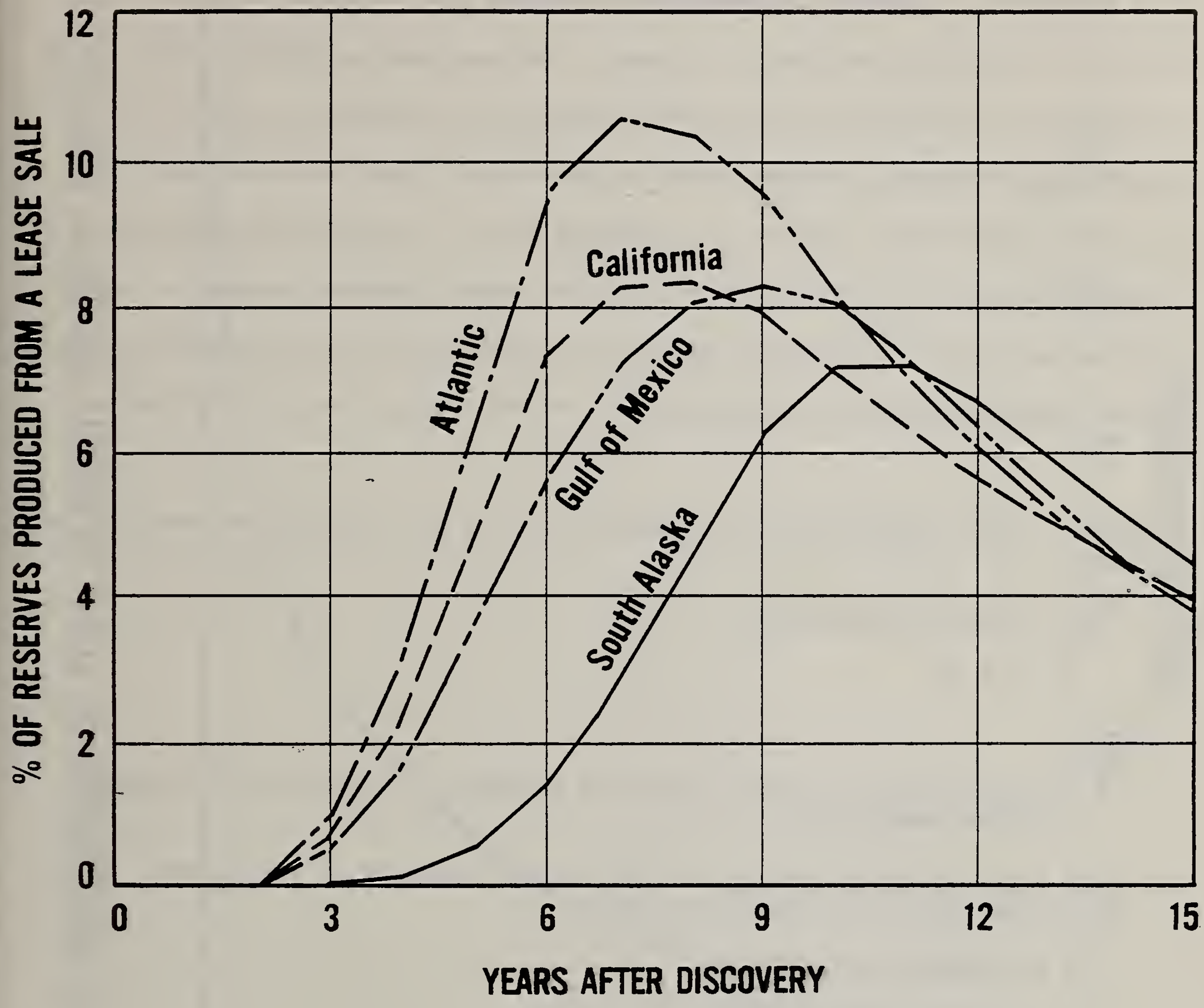
Figure 7. TRANSLATING THE RESOURCE BASE INTO PRODUCTION ACTIVITIES



The decline rates for onshore regions are approximated by the production-to-reserves ratio. This production-to-reserves (P/R) ratio is estimated from the last year of actual experience in each region, which can be obtained from data published by the American Petroleum Council. Tables 1A and 2A in Appendix A of this report present the actual data used in the _1978 Annual Report to Congress_ for Initial Oil Reserves and Decline Rates, respectively. For the onshore region, peak production is assumed to occur the year after discovery and to decline at a constant rate thereafter. (No production occurs the year of the discovery.)

Decline rates for offshore regions and for Region 1 (South Alaska) are handled differently since lags between exploration and production typically exceed one year. Consequently, a specific annual production profile is used for each of these regions which recognizes these lags and results in a gradual build-up of the production levels from reserves. These production profiles are derived using production and reserves data from Environmental Impact Statements prepared for the latest lease sales in each of these regions. As an example, the production profile from new reserves in South Alaska (Region 1) might peak the tenth year after discovery (Figure 8 and Table 3A of Appendix A present more information about production profiles for offshore regions).

Figure 8. OFFSHORE OIL PRODUCTION PROFILES (Percent)



The next most assured portion of the resource base consists of inferred and indicated reserves. These are additions and extensions to known reservoirs through additional drilling experience or through investments in fluid injection equipment. The USGS assessment of inferred and indicated reserves is based on a procedure outlined by Hubbert. He developed multipliers that could be applied to identified oil-in-place which would represent the growth (from extensions, revisions, and new pays) in reported ultimate recovery over time from known reservoirs (Figure 9). Although Hubert calculated multipliers on a national basis, the Oil Supply Model applies these "Hubbert factors" to annual discoveries since 1920 in each region and translates them into regional annual reserve additions from the indicated and inferred categories in old fields.

Hubbert's (1974) equations for estimating oil and gas ultimate recovery are as follows:

Y_U = Ultimate production,

$= Y_T * M,$

where:

T = elapsed time, in years, from the beginning of the year of discovery of the reservoir;

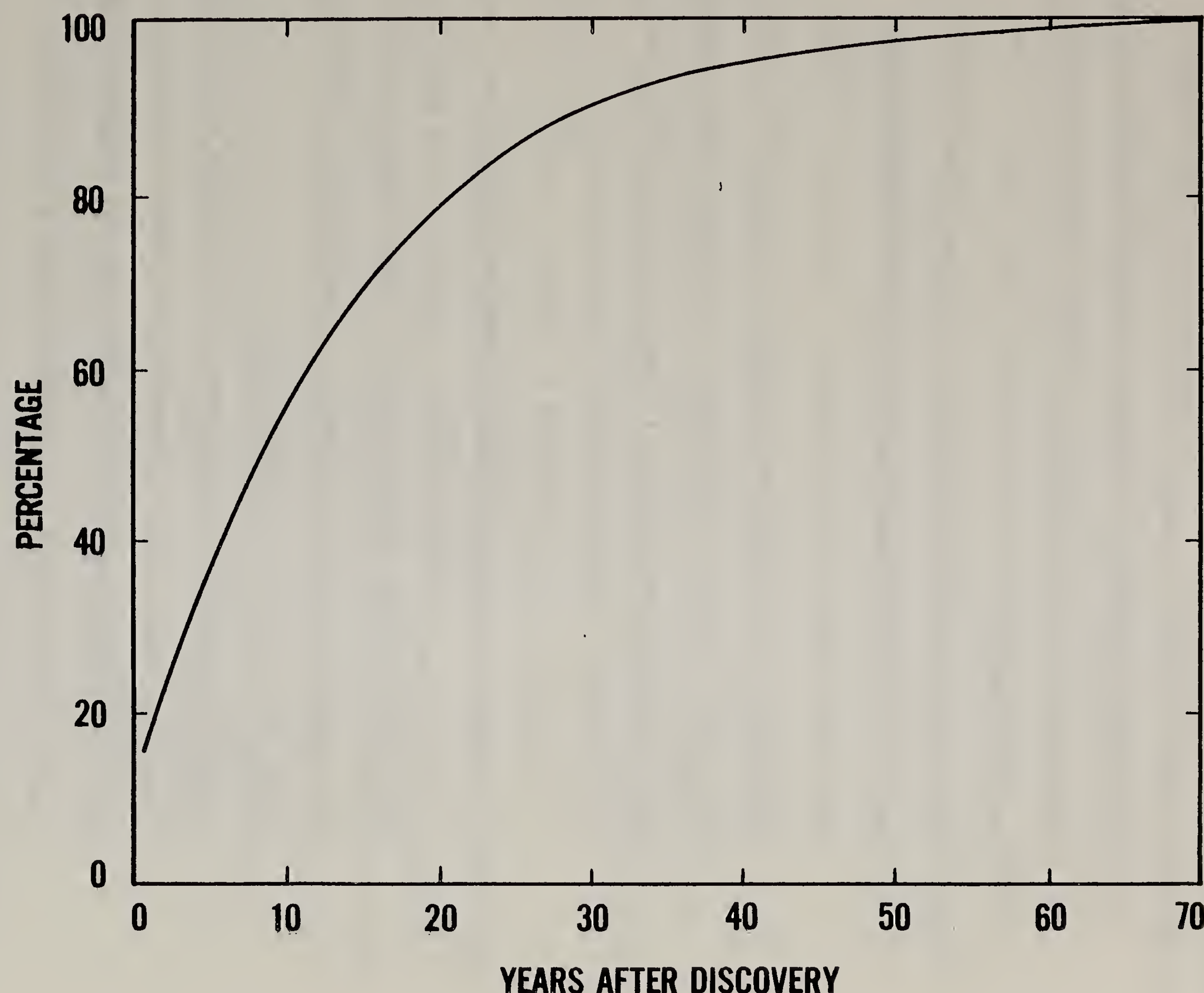
Y_T = total past production plus the current estimate of the proved reserves of the reservoir; and

M = the Hubbert Multipliers,

$= 1/[1-e^{-0.076(T + 1.053)}]$.... for oil,

$= 1/[1-e^{-0.063(T + 4.343)}]$.... for gas.

Figure 9. HUBBERT'S PERCENTAGE OF TOTAL ULTIMATE RECOVERY PROVED AS RESERVES



The Hubbert factors are used to predict the quantities of inferred reserves to be added to old fields, based on the American Petroleum Institute (API) estimate of ultimate recovery found in their <u>Reserves of Crude Oil,</u> [3]. This exercise is performed outside the model and has the following steps:

- First, API state data on ultimate recovery (defined as cumulative production to date plus current proved reserves) are aggregated into NPC regions.
- Then, Hubbert equations are used to determine how these ultimate recoveries will increase during successive 5-year periods. An example might clear up any confusion. In the Gulf of Mexico, fields discovered in 1971 have an ultimate recovery of 298.5 million barrels after 7 years. The Hubbert oil equation would suggest that the ultimate recovery after 12 years would be 298.5 times the ratio of the Hubbert equation at year 12 and at year 7:

  Year 12: $1/[1-e^{-0.076(12 + 1.503)}] = 1.5585.$

  Year 7 : $1/[1-e^{-0.076(7 + 1.503)}] = 2.1009.$

  ratio = 1.348

  Thus, the ultimate recovery after 12 years would be 1.348 x 298.5 = 402., and 103.9 million barrels of reserves must have been added to reach that ultimate recovery figure.
- A similar procedure is performed for all fields within a region discovered since 1920, aggregated over fields discovered in a given year. Estimates for all discovery years are summed to provide the total reserves addition estimate for each 5 year period.

- Then the 5-year reserve addition estimates are divided by 5 and then by the estimate of initial oil-in-place to derive the quinquennial factors used by the model. The model receives, as input, these quinquennial factors.
- Since the Hubbert factors predict "ultimate recovery" from all recovery methods (primary, secondary, and tertiary), these estimates include some oil obtained from tertiary recoverv. Therefore, DOE estimates how much of this oil is tertiary (using the Enhanced Oil Recovery Model [43,44,45]) and subtracts that amount from the total.

Tables 4A and 5A of Appendix A present the Initial Oil-in-Place Data and the Quinquennial Factors, respectively, used in the 1978 Annual Report to Congress (ARC). The quinquennial factors used in the 1978 ARC are those estimated for the 1977 ARC.

To summarize, the calculations performed for determining future oil production in existing fields are as follows: (1) The Hubbert equations for estimating ultimate oil recovery are used to provide an estimate of the reserve additions for each year of the forecast; (2) Additions for any given year are added to the existing oil-in-place at the beginning of that year; (3) Production is then obtained by multiplying the oil reserves by the decline factor.

A number of assumptions are made when calculating oil production in this manner. Some are presented below.

(1) For onshore regions, the decline rate is obtained by calculating production-to-reserve ratios based on the last year of available information. The implicit assumption imbedded in the approach is

that what the oil companies did that year represents the most economic way to extract proven reserves and that they will, therefore, continue to produce at this rate.

(2) A decline rate (i.e. extraction rate), independent of price, implies that oil proven in existing fields will be produced by both primary and secondary methods at this rate and that neither intensification of oil extraction efforts nor capping of wells for later withdrawal are likely.[3]

(3) The Hubbert's equation includes oil from inferred reserves. These reserves result from extensions and revisions of known fields by additional exploratory drilling. However, the model assumes all exploratory drilling will take place in "new fields," and only developmental costs are applied when evaluating the economics of developing old fields. Thus, the output from this model (the amount produced in a region) may overestimate the actual production for low price scenarios, since the cost of producing oil in old fields will be represented to be lower than it would actually be, because exploratory costs are not included.

(4) Hubbert obtained these factors by examining trends of past data aggregated to a national level. Using these estimates assumes that what has happened in the past nationally will continue in the future on a regional level and is independent of economics (i.e., the time path for finding extensions and revisions is independent of price).

[3]The model developers were well aware that decline rates, development intensities, recovery factors, and other aspects of the process by which resources are brought to market respond directly to economic factors. However, the data upon which a price dependent relationship for these factors could be constructed were not available and they, therefore, chose to model using this simplifying assumption.

IV. 2 Discovery and Production from New Fields: Finding Rates

The methodology for estimating projections of production from new fields is more complicated than that used in old fields. Under an economically rational drilling program, the more exploratory drilling performed the more likely one is to find oil. However, since the largest reservoirs will usually be found first, average reservoir-size discovered will continue to decline over time. The model uses a "finding rate curve" as a mechanism for relating amount of oil discovered to the amount of drilling performed, where the "finding rate" is defined to be the measure of the quantity of oil resources "found" by drilling one exploratory foot.

The finding rate curve used in the model assumes that the relationship of cumulative oil-in-place discovered to cumulative exploratory drilling has the following form:

$$\begin{aligned} COIP &= \text{Cumulative oil-in-place discovered,} \\ &= Q\,(1-e^{-bCMFT}), \qquad (1) \end{aligned}$$

where:

$$Q = \frac{\text{USGS Ultimate Recoverable Resources}}{\text{USGS Total Recovery Factor}} + \text{1956 to 1974 cumulative oil-in-place discoveries;}$$

CMFT = Cumulative exploratory drilling; and

b = Constant

The finding rate can be calculated by differentiating (1) with respect to CMFT, yielding $FR = \frac{d(COIP)}{d(CMFT)} = bQe^{-bCMFT}$. This finding rate function states that the rate at which oil will be found will decline exponentially as drilling progresses.

The variable Q in the above equation represents the upper limit of cumulative discoveries and is defined to be total amount of oil already discovered, plus the estimated quantity remaining to be discovered. It was decided, that for this modeling effort, estimates of oil already discovered include the resources discovered between 1956[4] and 1974 (the year of the USGS Circular 725 forecast). Estimates for remaining oil-in-place to be discovered were obtained by taking USGS Circular 725 [51] undiscovered recoverable oil estimates and dividing those estimates by USGS estimates of total ultimate regional recovery factors (Tables 9A and 10A of Appendix A present these primary and secondary recovery estimates, respectively). It should be noted that the USGS excludes resources beyond 200 meters water depth offshore. To compensate for the 200 meters depth constraint, the USGS offshore estimates were multiplied by 1.6 (except for the Alaskan offshore, where depths greater than 200 meters are not expected to produce discoverable resources). This factor is based on the NPC Ocean Petroleum Resources Report [29] which estimates that oil resources beyond 200 meter water depth exceed by .6 the resources within 200 meters.

[4]Data does not exist on a regular and reliable basis for years prior to 1956.

Finding rates for regions 2 through 10 (excluding region 2a) are based on analysis of the historical relationship between cumulative exploratory drilling footage and cumulative oil-in-place. Linear regression analyses, performed outside the MOGSM computer code, are performed on a region-by-region basis to fit a function of the form (2) shown below obtained by rearranging (1) and taking logs.

$$\ln(Q-COIP_t) = \ln Q - bCMFT_t \tag{2}$$

where

$$Q = \frac{\text{USGS ultimate recovery}}{\text{recovery factor}} + \text{1956–1974 cumulative oil-in-place discoveries},$$

$COIP_t$ = cumulative oil-in-place discovered through time t,

$CMFT_t$ = cumulative exploratory drilling through time t, and

b = constant.

The linear regression estimates the value of the constant b defining the shape of the curve for each region. The analysis uses both historical data of oil found per exploratory foot drilled and the USGS estimate of undiscovered resources in each region.

Cumulative oil-in-place discovered was selected as the dependent variable (before the log transformation) because it represents the total oil resource present in the ground. As t approaches infinity, cumulative discoveries must approach the amount of oil-in-place already discovered plus that remaining to be discovered. Oil-in-place discoveries were obtained from the NPC study for 1966-69 [28]. For the years 1970-74, the source is the API <u>Reserves of Crude</u>

Oil [3]. Reserve additions due to exploration were determined, first, by summing New Reservoir Discoveries in Old Fields, New Field Discoveries and Extensions, as reported by American Petroleum Institute (API) [3]. Then, these reserve additions were converted into oil-in-place by dividing reserves by regional primary recovery factors. These factors were developed by the NPC for each oil region and represent the proportion of oil-in-place that can be recovered using primary recovery methods.

The source of historical exploratory drilling is the NPC, U.S. Energy Outlook: Oil and Gas Availability, for 1956-1969 [28]; (based on API drilling data). For 1970-74, exploratory drilling is obtained from the API Quarterly Review of Drilling Statistics [2]. Consistent with the NPC, dry hole footage is allocated to oil according to the proportion of successful oil exploratory drilling to total successful gas and oil drilling. For the specific data used for these regressions, see Hirshfeld [18]. Tables 6A, 7A, and 8A of Appendix A of this report collect the regression analysis results for the 1978 ARC, the initial finding rates, and the regression analysis results for the 1977 ARC, respectively.

The values of b, Q and (initial) values for CMFT are input parameters of the MOGSM computer code. Finding rates for any value of cumulative footage drilled is calculated within MOGSM for regions 2 through 10 using the following formula:

$$FR = bQe^{-bCMFT}$$

Finding rates for Regions 1, 2a, 11, and 11a cannot be calculated with the above procedure due to historical data inadequacies. In these cases, the finding rates are estimated using the following formula:

FR = finding rate (barrels per foot drilled)

$$= Q(1-e^{-[(Y/Q)*CMFT]}),$$

where:

Y = initial finding rate (Y intercept or ordinate);

Q = discoverable resources remaining in barrels; and

CMFT = cumulative exploratory drilling (in feet).

This calculation requires two data inputs. The initial finding rate, Y, is the oil found during the first year of exploratory drilling. The remaining discoverable resources, Q, is the USGS estimate of recoverable resources divided by the regional primary recovery factor. The input data to the model is the variables b(where b=Y/Q) and Q.

Data from Environmental Impact Statements prepared for the most recent lease sales in each of these regions are analyzed to determine the expected outcome of the search process within the leased area and used to estimate the initial point of the finding rate curve. Finding rates then are assumed to decline exponentially to the point where all discoverable oil-in-place would be found.

Thus, to determine new field production, one begins by estimating parameters of the finding rate curve for each of the onshore and offshore regions. These parameters are input into the computer code MOGSM. MOGSM then calculates the amount of oil-in-place discovered in that region by multiplying the annual regional exploratory drilling footage (from the drilling allocation section described later) by the finding rate. The model then translates oil-in-place to reserves by using regional recovery factors (see Tables 9A and 10A, Appendix A) for each recovery method on new fields. Regional time lags between discovery and each subsequent phase of development are imposed. The model assumes all oil which can be extracted using primary recovery methods will be discovered the year the exploratory drilling takes place. Production will begin the following year.[5] Similarly, all oil which can be recovered in the first phase of secondary recovery will be found five years after the exploratory drilling took place and production of that oil will take place in the sixth year. The resulting pattern of reserve additions from new discoveries is shown in Figure 10.

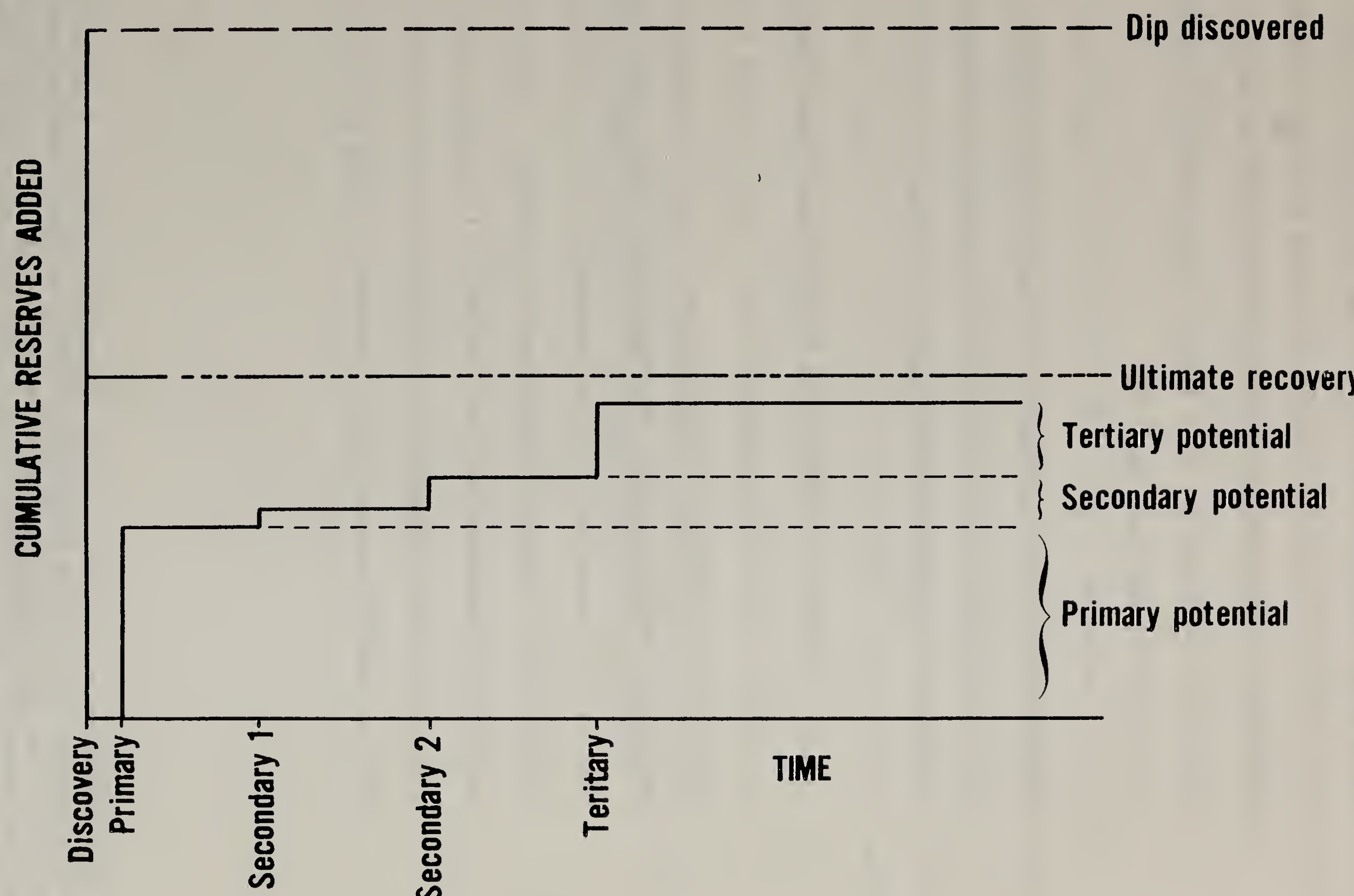
The reserves proved by each of the recovery methods (primary and secondary) are then produced according to the regional decline rates noted earlier.

A number of implicit assumptions were made when estimating the production of oil from new fields using the methodology described above. These are collected below.

(1) In the DOE reports [36,37] that describe the methodology and data sources for MOGSM it is stated that the finding rate curve-form in the onshore regions "was selected to reflect the log-normal distribution of reservoirs in a field and was suggested by the theoretical and empirical work of Kaufman [5,6,21] and Arps and Roberts [1]."

[5]The model has subsequently been modified to address the "vintaging of primary production" issue. The reserve addition process in the model used for the 1979 ARC is spread out over a five-year period to reflect the gradual build-up of reserves following a discovery.

Figure 10. TRANSLATING OIL-IN-PLACE TO RESERVE ADDITIONS



These works examine whether pool sizes in a play (the terms "pools" and "play" are technical, geological terms which are explained in most texts on oil geology) are lognormally distributed and do not examine the lognormality on a regional aggregation. For more analysis of this assumption, see [16].

(2) Included in the past data used to estimate finding rates are new field discoveries, new reservoirs in old fields, and extensions to old fields. The model will allocate all of this oil to new fields.[6]

(3) In regions 1, 2a, 11, and 11a the finding rate curve is based on two data points: the initial finding rate $\bar{Y}$ (the oil found during the first year of exploratory drilling) and the USGS estimate of remaining oil. This formula, like that used in regions 2 through 10, reflects the assumption that the probability of a certain-sized reservoir being found is proportioned to its size. When this assumption is translated into the deterministic equation used in the model, the largest reservoirs are found first and cumulative finds over time decline exponentially. However, having only one data

[6]The model developers maintain that the relationship between a given year's OIP additions and that year's exploratory drilling (which has applied to fields discovered <u>over several years</u>) is a good <u>proxy</u> for the relationship between the amount of oil-in-place which will be eventually added (probably over several years) to a discovery taking place in a given year and the amount of drilling these OIP additions will require.

point might make use of this formula specious. (The first year of exploratory drilling might be relatively unsuccessful. Corrections to this initial estimate should be made as more data becomes available.)

(4) The assumption that all oil which can be extracted using primary recovery methods will be discovered the year the exploratory drilling takes place, and that all oil obtained by the first phase of secondary drilling will be found five years later, has the effect of overestimating oil production in the short term, since this methodology actually telescopes the discovery process.[7]

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[7] As noted earlier, the model used for the 1979 ARC has corrected this deficiency; at present, reserve additions are spread out over a five-year period to reflect the gradual build-up of reserves suggested by Hubbert.

IV. 3. Production of the Coproducts of Oil

Production estimates for the principal coproducts of oil wells (associated-dissolved natural gas and associated-dissolved natural gas liquids) are projected using historical ratios. Historical data is used to develop a gas-oil ratio for each region which is the ratio of the previous year's marketed associated-dissolved wellhead gas production to the total oil production. This factor sets the gas-oil ratio for the first year of the forecast. The ratio expected at the end of the forecast period represents an engineering judgment influenced by regional geology (particularly the ratio of remaining undiscovered associated-dissolved gas and oil reserves) and the likely trends of enhanced recovery techniques. Ratios for associated-dissolved natural gas liquids are derived in a similar fashion.

Given the gas-oil ratio for the first and last years of the forecast, the modeling system calculates annual ratios by linear interpolation through these end points. It then multiplies the quantity of each year's primary product (oil in the case of associated-dissolved gas, and associated-dissolved gas in case of associated-dissolved natural gas liquids) by the appropriate ratio to calculate the coproduct production level. Table 11A of Appendix A presents the oil/gas ratios used for the 1978 ARC. For the scenarios described in that report, the gas/oil rates for 1991 were the same as those given for 1978.

SECTION V: THE ECONOMIC SUBMODEL (CALCULATING MINIMUM ACCEPTABLE PRICES)

The second major part of the Oil Supply Model is the Economic Submodel which estimates the minimum acceptable price associated with each reserve addition (by region, by year, by type of recovery). Only that oil which has a selling price greater than or equal to the minimum acceptable price will be produced. The model assumes that the relevant costs are the incremental expenditures required to convert resources from their present state (measured, inferred, or undiscovered) to the "proved" category and, subsequently, to produce them. For example, the incremental costs of producing today's proved reserves (principally well-operating costs) are much less than the costs to produce undiscovered resources (exploration, development, and production investments, plus well-operating costs).

In the model, each activity requiring expenditures has a cash flow category associated with it. These cash flow categories form the basis for the minimum acceptable price calculation (see Table 1). The basic computation of the minimum acceptable price associated with each reserve addition is through a discounted cash flow analysis (see Appendix C for a simplified description of the basic calculations). All cost elements, including return on investment, are discounted to a common year, as are all production quantities. Production quantities are discounted to represent the time value of the revenues which would accrue from the production over time. This discounted production quantity can then be multiplied by a price (which can be ramped--i.e., allowed to increase a constant rate each year to reflect the price of oil increasing at a rate faster than inflation) to provide discounted revenues. In this case, discounted costs divided by discounted quantity equals the minimum acceptable unit price (i.e., price per barrel) required to generate sufficient revenue to cover costs plus provide a competitive return. A project, either exploratory or developmental, is included in the forecast only if its minimum acceptable price is less than or equal to the expected future market price.

TABLE 1. CASH FLOW CATEGORIES

INVESTMENT EXPENDITURES (Expensed)

- Dry holes
- Successful wells (intangible portion)
- Lease rentals
- Preproduction overhead

INVESTMENT EXPENDITURES (Capitalized)

- Lease bonus
- Successful wells (tangible portion)
- Preproduction geological/geophysical
- Gas plant
- Other lease equipment
- Environment/safety

GROSS ANNUAL REVENUES

- Crude oil
- Associated and dissolved natural gas
- Natural gas liquids

ANNUAL EXPENDITURES

- Producing well and lease operating
- Gas plant
- Production geological/geophysical
- Production overhead
- Royalties
- Ad valorem and severence tax
- Federal/state income tax (net of tax credit)

ANNUAL NON-CASH EXPENSES

- Depreciation
- Depletion

Note: Primary data source for all cash flow items is the Joint Association Survey of the U.S. Oil and Gas Producing Industry, and the Bureau of Census, Annual Survey of Oil and Gas.

V.1 The Minimum Acceptable Price Calculations

The calculation of minimum acceptable prices (MAPs) is straightforward. It is the constant, real unit breakpoint price (i.e. dollars/Bbl if oil, or dollars/Mcf of gas) that enables the producer to recoup his costs plus bring him his desired minimum return. It is calculated as follows:

$$\text{MAP} = \frac{\text{Costs (after tax, discounted)}}{\text{Production (discounted)}}$$

Thus, one will invest if the price is greater than or equal to the costs (where costs include the return on investment). Costs are basically of five types:

- o Investments which must be capitalized
- o Investments which can be expensed for tax purposes
- o Cash expenses
- o Non-cash expenses
- o Tax credits.

Before describing each of these five different cost calculations, the methodology used for calculating the present value equivalent of the revenue stream will be discussed.

As stated earlier, revenues equal production quantity (discounted) times price. The present value equivalent of a revenue related to a continuously declining production stream (PVE1)[8] is:

[8]See Appendix C for a more detailed discussion of the discounting procedure.

$$PVE1 = \frac{1-e^{-(D+DR)T}}{D+DR} \quad \text{, if prices are held constant, and}$$

$$PVE1 = \frac{1-[G*(e^{-(D+DR)})]}{\ln(G*e^{+(D+DR)})} \quad \text{, if prices are allowed to grow,}$$

where D = production decline rate (P/R ratio)

DR = discount rate (real, after taxes) [i.e., the rate of return][9],

T = project life, and

G = price growth rate.

Thus Present Value equivalent production (PVEP)

$$PVEP = R * D * PVE1,$$

where R = Reserves, and

D = production decline rate

Thus the Minimum Acceptable Price is simply

MAP = COSTS/PVEP[10]

We will now discuss (in Sections V.2.1 through V.2.5) how each of the five types of costs are entered into the total cost stream calculations.

[9] See Page 1 of Appendix B for a discussion of the assumptions implicit in a choice of the value for the discount rate.

[10] We note that the calculation of PVEP assumes a constant production decline rate, D. This assumption is inconsistent with the assumption made in the Resource Submodel that the production function for offshore regions is nonlinear (see page 20 of this report). The model developers acknowledge this inconsistency, but argue that lease-constraints rather than economics (see Section V.1 for details) determines the amount of production in the offshore regions.

V.1.1 Investments Which Must Be Capitalized

Investments which must be capitalized are assumed to occur during the discovery year and are, thus, added dollar-for-dollar to the cost stream as follows:

$$CI = TSDC + LAI + GGI + ESI + LEI + GPI$$

where: CI = investment costs,

TSCD = tangible portion of successful drilling costs,

LAI = lease acquisition investment,

GGI = geological/geophysical investment,

ESI = environmental/safety investment,

LEI = lease equipment investment, and

GPI = gas plant investment.

Most investments are a function of drilling costs, either total drilling costs, dry hole costs, or successful drilling costs. Drilling costs are calculated from depth-sensitive drilling cost curves (drilling cost per foot vs. average depth)

- Total drilling costs (TDC)

$$TDC = EF*EFC+DF*DFC$$

where: EF = exploratory footage,

EFC = exploratory cost per foot,

DF = developmental footage, and

DFC = developmental cost per foot.

Tables 1B through 4B, and the related discussion in Appendix B, explain how exploratory and development footage costs are calculated.

- Dry hole costs (DHC):

  $$DHC = EF*EFC*EDHF + DF*DFC*DDHF$$

  where EF, EFC, DF, DFC are as defined above,

  $EDHF$ = exploratory dry hole factor (%), and

  $EDHF$ = developmental dry hole factor (%).

Tables 5B of Appendix B presents the data used for the exploratory and developmental dry hole factors.

- Successful drilling costs (SDC):

  $$SDC = TDC - DHC.$$

Since only the tangible portion of the successful well expenditures need to be capitalized rather than expensed:

$$TSCD = SDC * (1-IDF),$$

where $TSCD$ = tangible portion of successful drilling costs, and

IDF = intangible drilling factor

Table 7B of Appendix B presents the Intangible Drilling Factors used in the 1978 ARC.

Other investments (e.g., lease acquisitions, geological/geophysical investments) are calculated as multiples of drilling costs from factors derived from historical data. These are given below.

o Lease acquisition investment (LAI)

LAI = TDC*LACF

where LACF = lease acquisition cost factor

This factor is set to zero within MOGSM since lease acquisition costs are considered by the model developers to be part of "economic rent," which is an input parameter to the MEFS integrating effort.

Geological/geophysical investment (GGI)

o GGI = TDC*GGCF

where GGCF = geological/geophysical cost factor

Environmental/Safety investment (ESI)

o ESI = DHC*ESCF

where ESCF = environmental/safety cost factor

Lease equipment investment (LEI)

o LEI = DHC*LECF

where LECF = lease equipment cost factor

One investment is not a function of drilling costs:

Gas plant investment (GPI)

o GPI = IGP*GPIF

where IGP = increased gas production

GPIF = gas plant investment factor

Pages 102, 106, 107, and 108 of Appendix B provide information relating to the geological/geophysical cost factors, environmental/safety cost factor, lease acquisition cost factor, and Gas Plant Investment Factor.

V.1.2 Investments Which Can Be Expensed

Investments which can be expensed for tax purposes are reduced by the tax effects; they are collected and handled as follows:

$$CE = (DHC + ISDC + LEI + DOI) * (1-TR)$$

where CE = expensable investment costs,

DHC = dry hole cost,

ISDC = intangible portion of successful drilling costs,

LEI = lease equipment investment

DOI = drilling overhead investment, and

TR = tax rate (federal and state);

Dry hole costs are discussed in the previous section. The remaining terms in the equation for CE are discussed below.

$$ISDC = SDC * IDF$$

where SDC = successful drilling costs, and

IDF = intangible drilling factor (see Table 7B of Appendix B for values).

Methods for calculating successful drilling costs and dry hole costs are given in Tables 1B through 4B and the corresponding text in Appendix B.

LEI = DC * LRIF

The lease rental investment factor (LRIF) is set to zero in MOGSM since it is considered by the model developers to be part of "economic rent" which is an input parameter to the MEFS integrating effort.

DOI = TDC * OCF

where

DOE = drilling overhead investment

OCF = overhead expense rate

TDC = total drilling cost

The drilling overhead expense rate used in the 1978 ARC is .133 for all years.

The tax rate is composed of a variety of taxes and is calculated as follows:

TR = FR + SR

where

FR = Federal Tax Rate, and

SR = State Tax Rate.

Appendix B, Section B.11 presents the values for these tax rates.

V.1.3 Cash Expenses

Cash expenses (E) are reduced by their tax effects in a manner similar to that of expensed investments discussed above.

$$E = (PC + POE + GGE + LEE + ESE + GPE + PTE + RE) * (1 - TR),$$

where E = cash expenses,

PC = producing costs,

POE = producing overhead expense,

GGE = geological/geophysical expense,

LEE = lease equipment expense,

ESE = environmental/safety expense,

GPE = gas plant expense,

PTE = production tax expense,

RE = royalties expense, and

TR = tax rate (federal and state).

Most expenses are a function of producing costs. Producing costs are calculated using annual producing cost per well factors, as follows:

- First, the present value equivalent of a constant continuous expense (PVE2) is:

$$PVE2 = \frac{(1-e^{-(DR*T)})}{DR}$$

where DR = discount rate (real, after tax) [i.e. return on investment], and

T = project life.

- Producing costs (PC) are calculated as:

$$PC = W*PCF*PVE2$$

where W = number of producing wells in project, and

PCF = producing cost per well.

Tables 10B and 11B of Appendix B provide regional data on initial oil wells and operating costs per well, respectively. Other investments are calculated as multiples of production costs from factors derived from historical data:

- Production overhead expense (POE):

  POE = PC*OCF,

  where OCF = overhead cost factor.

- Geological/geophysical expense (GGE):

  GGE = PC*GGCF,

  where GGCF = geological/geophysical cost factor.

- Lease Equipment Expense (LEE):

  LEE = PC*LECF,

  where LECF = lease equipment cost factor.

- Production Tax Expense (PTE):

  PTE = PC*PTF,

  where PTF = production tax factor (see Table 8B for actual regional data).

- Royalty Rate Expense (RE):

  RE = PC*REF,

  where REF = royalty expense factor (see Table 9B for regional data on royalty rates).

Other expense items are calculated separately:

- Environmental/safety expense (ESE):

  ESE = W*ESF*PVE2,

  where W = number of wells, and

  ESF = environmental/safety cost per well.

Data related to overhead expenses, geological and geophysical expenses, environmental/safety costs, and lease equipment expenses can be found on pages 88 and 89 of Appendix B.

Finally one expense is calculated as a function of production decline over time.

- Gas plant expense (GPE):

  GPE = GOR*GDF*GPCF*IPO*PVE1

  where GOR = gas/oil ratio,

  GDF = gas drying factor,

  GPCF = gas plant cost factor,

  IPO = initial oil production, and

  PVE1 is as defined in the beginning of Section V.1.

V.1.4 Non-Cash Expenses:

Depreciation expense (DF) is a non-cash expense which provides a tax shield and is calculated on a unit of production basis (that is, the depreciation schedule looks exactly like the production schedule), and is discounted as follows:

DF = CI*D*PVE1

where DF = depreciation expense,

CI = capitalized investment,

D = production decline rate, and

PVE1 = present value equivalent of a cost related to a declining production stream.

Now, the amount of depreciation (DE) allowed for tax calculations can be defined as:

$$DE = DF*ADR$$

where ADR = accelerated depreciation rate, and

DF = actual depreciation expense.

Then the depreciation tax shield (DTS) is calculated as:

$$DTS = DE*TR$$

where DE = depreciation expense, and

TR = tax rate.

V.1.5 Tax Credits

Finally, several items qualify for an investment tax credit (ITC), which is calculated as follows:

$$ITC = (TSDC + ESI + GPI + LEI) * TCR$$

where TSDC = tangible successful drilling costs,

ESI = environmental/safety investment,

GPI = gas plant investment,

LEI = lease equipment investment, and

TCR = tax credit rate.

V.2.6 Calculating Total Cost and Minimum Acceptable Price

To summarize, total costs are obtained from the five cost categories presented above:

- o Investments which must be capitalized (CI),
- o Investments which can be expensed for tax purposes (CE),
- o Cash expenses (E),
- o Non-cash expenses (DTS), and
- o Tax credits (ITC).

Total costs, then, are:

$$COSTS = CI + CE + E - DTS - ITC,$$

and the minimum-acceptable-price (MAP) is:

$$MAP = COSTS/PVEP$$

where PVEP = present value equivalent of production = $q_o * \frac{1-e^{-DT}}{D}$,

D = production decline rate (P/R ratio),

T = project life, and

q_o = reserves.

When calculating the minimum acceptable price for a project, the costs and revenues generated from both primary recovery alone and primary and secondary recovery combined are calculated. If the production obtained through secondary recovery methods is found to be economic, then both primary and secondary development will take place. This approach reflects the common practice of establishing early a proposed development program which will consider the application of secondary recovery methods.

To calculate the secondary recovery costs, two additional terms are added to the cost stream. A secondary investment cost (SIC) is added to the Investment Costs and calculated as follows:

SIC = SCR * SCDCF,

where SIC = secondary investment cost,

SCR = secondary reserves, and

SCDCF = secondary drilling investment recovery cost factor (additional cost/barrel).

Similarly, a secondary operating cost (SCOC) is added to the expensed costs and calculated as follows:

SCOC = SCR * SCOCF * PVE1 * D,

where SCR = secondary reserves,

SCOCF = secondary drilling operating factor (additional cost/barrel),

PVE1 = present value equivalent of a cost related to a declining production stream, and

D = decline rate.

Tables 14B and 15B of Appendix B provide the data used in the 1978 ARC on secondary investment and cost factors, respectively.

SECTION VI: THE DRILLING SUBMODEL (CONSTRUCTING THE DRILLING PROFILE AND REGIONAL ALLOCATION)

The last section of the Oil Supply Model is the Drilling submodel which projects levels of exploratory drilling for each region and year. Offshore regions and South Alaska (Region 1) are constrained by lease agreements which dictate the maximum amount of drilling possible, while for all other onshore regions only the price of oil constrains the amount of exploratory drilling. For this reason, the model treats the lease-constrained regions differently. We will first present the methodology for determining the constraints on exploratory drilling in offshore regions and South Alaska and then present the methodology used to determine the drilling for both the onshore and the offshore regions.

VI.1 Constraints to Drilling in the Offshore Regions

Because leasing constraints hamper access to more attractive prospects in the Federally-owned Outer Continental Shelf (OCS) and South Alaska, drilling profiles for these four regions are constrained by leasing schedules. Thus even if it is economic to do more exploration in these regions, the maximum amount of drilling possible will be that offered in the leasing schedule. If, however, less than that amount is economic, then only that amount of drilling which yields a price greater than the minimum acceptable price (MAP) will take place.

For these regions, drilling trajectories are calculated to conform with leasing schedules supplied by DOE, and with resource estimates supplied by the USGS. The calculation is as follows.

1. Annual lease acreage for Regions 1a, 2a, 6a, and 11a are derived from Department of the Interior/Bureau of Land Management Leasing Schedule Projections. Such schedules exist for the next three to five years and data thereafter is extrapolated by DOE staff. Lease acreage schedules are shown in Table 2.

TABLE 2

Outer Continental Shelf Leasing Schedule
(Thousand of Acres Leased)

Year	1a	2a	6a	11a
1977	144	146	1068	110
1978	171	134	1039	183
1979	152	170	1028	255
1980	149	281	1006	307
1981	206	360	1106	279
1982	255	403	1234	240
1983	264	456	1315	212
1984	258	438	1348	177
1985	221	436	1375	161
1986	202	520	1251	131
1987	210	563	1024	130
1988	206	593	818	161
1989	205	592	774	192
1990	202	544	800	213
1991	202	442	731	229
1992	196	389	639	232
1993	174	353	593	235
1994	163	303	594	242
1995	157	271	595	250
1996	151	273	597	250
1997	151	379	598	227
1998	152	536	600	192
1999	152	622	601	175
2000	152	690	602	163
2001	152	732	604	157
2002	152	746	605	157
2003	152	760	606	157
2004	152	775	608	157
2005	152	789	609	157
2006	152	804	611	157

2. The oil drilling trajectory is developed by splitting annual lease acreage into oil and gas acreage. DOE estimates of reservoir volumes of oil and gas in place are used to determine the proportion of oil or gas bearing fields in each region. Lease acreage is then split into oil and gas acreage according to the proportion of oil and gas present in a region. The fractions in Table 3 indicate the oil and gas proportions used.

TABLE 3

Oil/Gas Lease Acreage Split

Region	Oil Fraction	Gas Fraction
1a	69.5	30.5
2a	97.7	2.3
6a	44.0	56.0
11a	72.0	28.0

3. After annual oil lease acreage is calculated, the proportion of lease acres to be drilled each year must be determined. These are obtained from Bureau of Land Management estimates of the time pattern of exploratory drilling efforts. These estimates are published in varying detail in environmental impact statements (EIS) which must be filed for each lease sale. An important assumption here is that the latest exploratory activities are representative of future activities in a particular region. The following lease sale EIS reports were used are given in Table 4.

TABLE 4

Environmental Impact Statements

Lease Sale Number	Sale Date	Region
#39	April, 1976	la
#C1	February, 1977 (tentative)	la
#35	December, 1975	2a
#41	February, 1976	6a
#44	August, 1976	6a
#40	August, 1976	11a

The schedule in Table 5 presents the fraction of a regional lease sale that will be explored each year following the sale.

TABLE 5

Oil Lease Acreage Exploratory Drilling Schedules

Years After Sale	la	2a	6a	11a
1	6%	6%	8%	6%
2	15%	15%	24%	15%
3	26%	26%	36%	26%
4	26%	26%	24%	26%
5	15%	15%	8%	15%
6	8%	8%	-	8%
7	4%	4%	-	4%

4. Exploratory drilling schedules were converted into exploratory wells through the following procedure. The lease acreage designated for exploratory drilling in each year from 1977 to 1991 by the drilling schedules were divided by a well-density factor. These factors are DOE's judgmental estimates of the number of exploratory wells per 1000 acres. These factors are listed in Table 6.

TABLE 6

Well-Density Factors

Region	Exploratory Wells Per Thousand Acres
1	.071
2a	.5
6a	.5
11a	.071

5. The number of exploratory wells was next converted into exploratory drilling footage. This was accomplished by multiplying the number of wells to be drilled each year by an exploratory depth factor corresponding to the cumulative drilling that has occurred. Exploratory well depths increase with cumulative footage. The initial oil drilling depths for 1976 drillings are given in Table 7.

TABLE 7

Initial Depth

Region	Feet
1	10,096
2a	4,286
6a	8,650
11a	10,000

6. The final calculation converts exploratory oil drilling to total oil drilling. Total oil drilling is the sum of successful exploratory and developmental drilling plus dry hole drilling. This calculation is done by multiplying exploratory drilling footage by a total to exploratory (T/E) ratio. (This ratio is described in Appendix B, Table 5B.) The ratio for Region 6a is based on historical experience. The ratios for 1a, 2a, and 11a are calculated as follows.

   (a) Average and peak oil production for oil acreage are determined from estimates published in EIS reports.

   (b) Production is converted into oil wells by dividing peak oil production by the Bureau of Mines' estimate of average daily well production of 500 barrels per day.[11]

   (c) The number of exploratory wells drilled, calculated previously, is multiplied by a success ratio derived from API data (see Table 6B of Appendix B). The result is the number of producing exploratory wells.

[11]EIS on Accelerated OCS Leasing, 1975, Vol. 2, p. 3, Table 105.

(d) The number of producing exploratory wells is subtracted from the number of total producing wells calculated in (b). This is the number of producing developmental wells.

(e) The number of producing developmental wells is divided by a developmental success ratio. This ratio is derived from NPC data. This yields total developmental drilling footage.

(f) Service wells are included as indicated by the EIS's.

(g) The number of exploratory developmental wells is added to the number of service wells and the total is divided by the number of exploratory wells to yield the total to exploratory drilling ratio.

Table 8 presents parameters calculated to produce total to exploratory ratios:

TABLE 8

Total to Exploratory Ratio Calculation

Region	Peak Oil Production	Total # Producing Wells[12]	Exploratory Success Ratio	Developmental Success Ratio	# Service Wells	# Exploratory Wells	# Developmental Wells
1	290,500	765	.299	.915	118	581	66
2a	201,600	806	.267	.9767	0	202	601
11a	132,000	264	.215	.756	44	45	264

[12]We asked Charles Everett (of DOE's Division of Oil and Gas Analysis) why total number of producing wells did not agree with the directions for how to calculate them (take peak production and divide by 500 Bbl/day) and he could not explain the discrepancy.

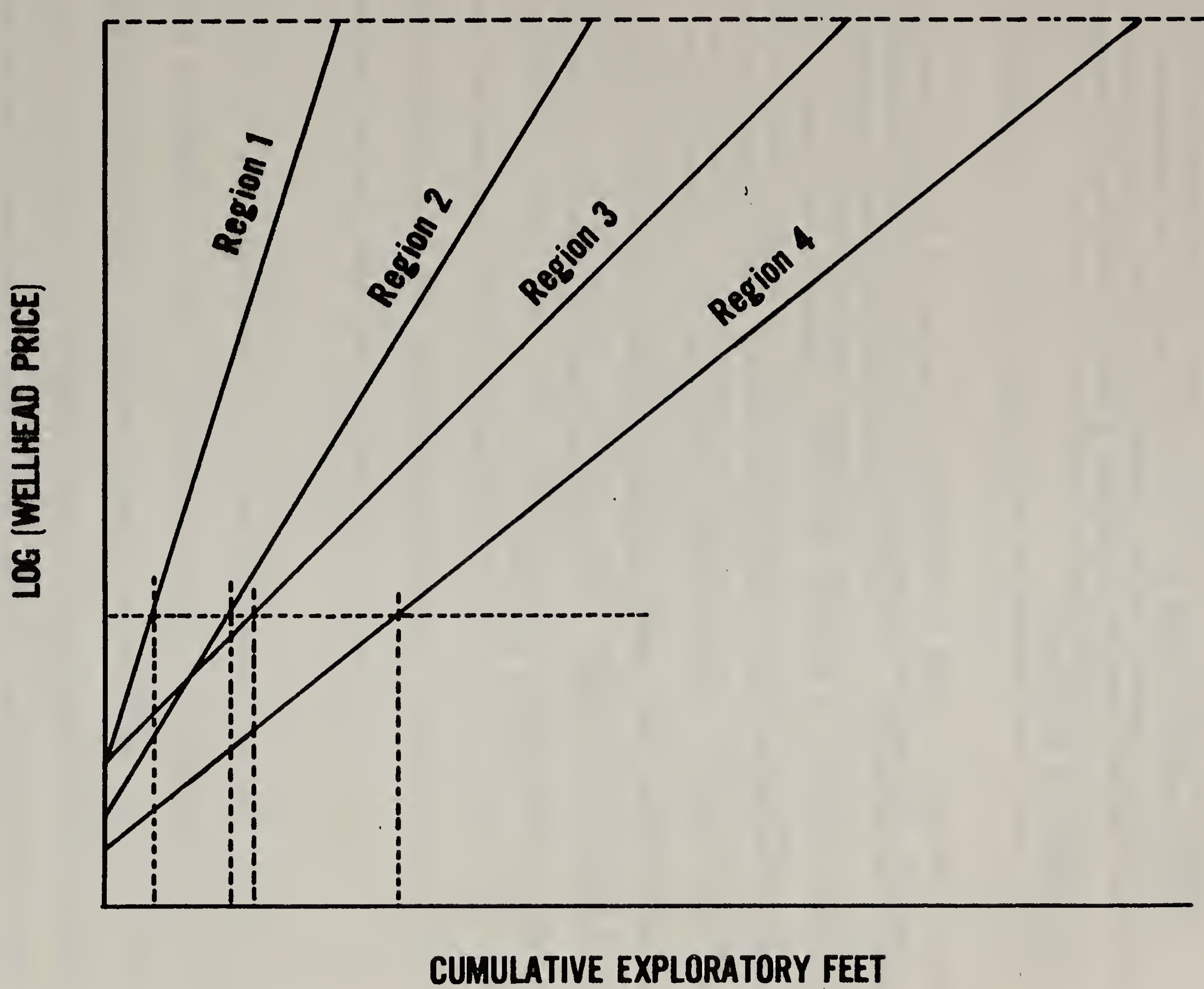
Thus drilling information for the offshore regions is input into the model as well as output from running the model. The amount of drilling done in the offshore regions is constrained by lease agreements and therefore less sensitive to price trajectories than is true for onshore regions. Only when the constraints are not binding (i.e., the minimum acceptable price dictates that less drilling take place in the offshore regions than that agreed to in the lease schedules), will the outputs of the model be different from the inputs discussed above.

VI.2 Calculating a Cumulative Exploratory Drilling to Minimum Acceptable Price Curve

The expected market price for crude oil and its coproducts defines the segment of the undiscovered resource base which is economical to pursue. To determine this quantity of economical resource in each region, a special run of the engineering and minimum acceptable price sections of the model are executed with a hypothetical, ambitious exploratory drilling program in all geographical regions.

The process is as follows. For a given region, determine how much exploratory drilling has been done to date (cumulative exploratory drilling), and calculate a minimum acceptable price for the oil obtained for that amount of drilling. This is the first (x,y) point on the cumulative exploratory drilling vs. minimum acceptable price curve. Then increase drilling in 10 percent increments and calculate the MAP associated with each new quantity of drilling. If the log of wellhead price is plotted against cumulative exploratory drilling, the curve obtained is approximately linear (Figure 11). A curve of this type is produced for each region.

Figure 11. ULTIMATE EXPLORATORY DRILLING AS A FUNCTION OF PRICE



These curves represent an estimate of the time-independent "latent" demand for drilling at alternative future oil prices. Due primarily to decreasing finding rates and increasing drilling costs (since one must drill deeper), as cumulative exploratory drilling increases linearly, the corresponding increase in the minimum acceptable price for the oil found will be approximately exponential. Each region, however, evidences a unique relationship between price and latent demand for drilling.

These curves will be used to determine the amount of drilling required for any given price trajectory. If additional drilling equipment is needed in order to produce this oil, a capacity expansion program is instituted. The model includes constraints which regulate the maximum rate of expansion for both onshore and offshore regions and limit production for offshore regions. These constraints, therefore, have significant effects on the total production of oil predicted by the model. The next section will present the methodology for calculating the drilling profiles.

VI.3 Calculating the Regional Drilling Profiles

In general, the total amount of exploratory drilling indicated by a given level of expected market prices for oil cannot be accomplished in a single year or even the usable lifetime of a current inventory of drilling equipment. Therefore, the exploratory drilling process involves estimation of future capacity requirements. We find it convenient to describe the model process in terms of a hypothetical regionally-aggregated representative planner/driller.

Thus the model simulates the activity of 12 regional drillers (one for each model region), who transform latent demand into exploratory footage by use of in situ (oil drilling) rigs with fixed annual drilling rates and usable lifetimes and similar equipment from exisiting rig plants with fixed production lifetimes. If total estimated lifetime capacities from these "old rigs" and "new rigs from old plants" are less than the latent (cumulative) demand at the expected (national) price,[13] new plant construction is commissioned to provide equal annual increments of drilling capacity, totaling over a fixed period to the calculated shortfall. This planning calculation is repeated each model year. (One year is the basic time interval in the model.)

Drilling capacity, once installed, is not retired (except through aging), nor are existing rig plants, except in off-shore regions. This means that all of the cumulative lifetime total drilling footage from existing rigs, from rigs produced, and from rigs to be produced from existing plants will be realized, even if prices should decline. Planned plant capacity additions (those commissioned but not yet built), however, will be curtailed in this event.

[13] Price is the only variable in this part of the model which is not regionally differentiated.

Aside from the incremental character of plant additions (the purpose of which is to avoid unrealistic increases in a single year), there are no explicit constraints on the availability of drilling capacity. In other words, while there is a rate restriction on capacity addition, there are no restrictions on total magnitude except what may be incorporated into the tables of the cumulative drilling versus minimum acceptable prices (MAPs). Thus no question of rig allocation arises in the model and the regions operate independently of each other.

In regions 1, 2a, 6a, and 11a exploratory footage realizable from drilling capacity (which is calculated as in the on-shore regions), is restricted by the leasing agreements described in section VI.1.

Both the thumbnail description of exploratory drilling above and the more detailed elaboration of the model equations below, are based almost entirely on interpretation of the computer program labeled OILDRL 78. In consequence, this "realized" model, deduced from FORTRAN statements, may differ from the model conceived by the developers.[14] We have included some discussion of the possible effects of such discrepancies on the outputs of the model. A more penetrating investigation would be desirable. It should consist of experimental runs of the model, and analysis of the properties of the solutions to the differential equations induced by reduction of the recursions underlying the stepwise simulated relationships.

[14]For more on the difference between a "realized" and a conceptual model, see [15]. A draft of this report was transmitted to the authors of the source documents accompanied by a request for comments. Ensuing discussions with one of those authors disclosed the fact that the program listing which had been furnished to us is not the current version. Since we have not been able to obtain a "correct" listing, note that some comments herein are subject to change.

VI.3.1 The Equations of the Drilling Submodel

In what follows, as in previous sections, we have compromised conciseness for intelligibility by using mnemonic labels, largely from the FORTRAN code, for parameters and variables, wherever practicable. The symbol t denotes a discrete "time-step", i.e. a year, (thus COR_t and COR_{t+1} denote Capacity of Old Rigs in year t and year t+1, and so forth). Because the simulation is repeated for each region, all or the variables should carry an additional index, say j, to distinguish the region. This index has been omitted from the text to improve legibility, but the reader is requested to bear in mind that each equation has 11 equivalent counterparts, one for each model region.

We begin the mathematical presentation of the drilling model with the equations for calculation of expected price for estimating capacity requirements. Equation (1) shows a three-year extrapolation of prices from the input "price trajectory vector" of oil prices, to obtain a price argument for the latent drilling demand function. This equation represents the regional developer's "foresight" in planning for future development based on past trends. The developer uses the past year's and current year's price and extrapolates to a "future" price of oil. He makes decisions based on that price. Equation (1a) refers to the first simulation year, in which the model allows the driller to "foresee" next year's price to establish a price trend for extrapolation. (An alternative would have been to set the expected price in year 1 equal to the current price, i.e. $PRICE_1 = P_1$. This is an example of a well-known unsolved problem in the theory of modeling: how to treat "start ups" in discrete event simulations.)

$$PRICE_t = P_t + IFS*(P_t - P_{t-1}) = P_t + 3(P_t - P_{t-1}) = P_t + 3\Delta P_t$$

$$PRICE_t \leq PMAX \text{ , } t = 2, 3, \ldots, IEND \text{ ;} \tag{1}$$

$$PRICE_1 = P_t + IFS*(P_2 - P_1) = P_1 + 3(P_2 - P_1) = P_1 + 3\Delta P_2$$

$$PRICE_1 \leq PMAX \text{ , } t = 1 \text{ ;} \tag{1a}$$

where

$PRICE_t$	is the projected expected price for year t ;
P_t	is the (input) prevailing national price in year t ;
ΔP_t	is $P_t - P_{t-1}$, the annual change in market price ;
PMAX	is an upper limit price (input) ;
IFS	is an input parameter of the computer model representing the extrapolation interval. (In this model version, 3 years.); and
IEND	is an input denoting the final year of the simulation, i.e. the duration of the simulation, in model time.

The model's "backstop price" PMAX serves as a ceiling for expected prices in periods of rapid market price increases. Note that according to the equations, declining prices could theoretically result in a negative extrapolated price. The input price string is tested upon input and a warning message printed if a price decline is detected but no other action is taken in the computer program. See [16] for a discussion of some effects of this action.

For any given price the developer estimates the corresponding demand for oil by examining the cumulative exploratory drilling versus minimum acceptable price curve (see Section VI.2). Equation (2) describes a <u>linear</u> interpolation to determine latent demand when the price for year t ($PRICE_t$) lies between the smallest (MAP_1) and largest (MAP_{15}) price values of the function table. Equation (2a) describes a log linear extrapolation for values of $PRICE_t$ exceeding the largest table entry. Equation (2b) is required for values of $PRICE_t$ below the smallest value which is considered economic.

The equations for drilling capacity requirements (Latent Demand):

$$LD_t = L_{i-1} + \Delta L_i * \frac{PRICE_t - MAP_{i-1}}{MAP_i - MAP_{i-1}} : MAP_{i-1} \leq PRICE_t < MAP_i \tag{2}$$

$$LD_t = L_{15} + \Delta L_{15} * \frac{\log PRICE_t - \log MAP_{15}}{\log MAP_{15} - \log MAP_{11}} : PRICE_t > MAP_{15} \tag{2a}$$

$$LD_t = 0 : PRICE_t < MAP_1 \tag{2b}$$

where

LD_t	is the latent demand for exploratory drilling in year t corresponding to $PRICE_t$;
$PRICE_t$	is the expected or planning price of oil for year t from equations (1) ;
L_i	is the i-th table value of cumulative drilling ;
ΔL_i	is $L_i - L_{i-1}$; and
MAP_i	is a "minimum acceptable price" in $/bbl corresponding to a cumulative total of exploratory drilling of L_i feet (in units of 10^6 ft). (The drilling versus price function described in section IV.2 is represented as a table of 15 pairs of values in the computer program for the exploratory drilling submodel. Thus the minimum acceptable price for cumulative drilling of L_i feet is MAP_i.)

The rationale for equations (2) and (2a) is apparently that the tabular intervals are small enough for linear interpolation of the approximately logarithmic function not to cause serious error, but that for some prices outside the range of the table, linear extrapolation could substantially overestimate total exploratory drilling (see Section VI.2). We note that an expected price <u>equal</u> to MAP_1, the smallest entry in any regional function table, will lead to a meaningless value for latent demand because of the way the extrapolation is "indexed."

Once the latent demand for drilling has been determined, one needs to determine if current drilling capacities will satisfy that demand. If not, a capacity expansion program is implemented. The following five quantities (Eq. 3-7) are components of the equations for drilling and capacity planning.

The factor for residual rig capacity is:

$$a_1 = 1 - \frac{1}{RL} = \frac{RL-1}{RL} = \frac{10-1}{10} = .9 \ . \qquad (3)$$

Rig life (RL) is an input parameter of the computer program. In this model version, rig life is assumed to be ten years. Thus a rig's output is assumed to decline by 1/10 each year.

The estimated lifetime capacity factor for old rigs is:

$$a_2 = \sum_{i=1}^{RL} \frac{i-1}{RL} = \frac{1}{2}(RL-1) = 4.5 \ . \qquad (4)$$

That is, a rig's lifetime output is estimated to be 4.5 times its initial capacty (in 10^6 ft. per annum).

The factor for residual capacity of rig building plants is:

$$a_3 = 1 - \frac{1}{PL} = \frac{10-1}{10} = .9 \ . \tag{5}$$

Plant life (PL) is an input parameter of the computer program (ten years in this model version). Thus a plant's output is assumed to decline by 1/10 each year.

The estimated lifetime capacity factor for new rigs built by old plants is:

$$a_4 = a_2 * \sum_{j=1}^{PL} \frac{j}{PL} = \frac{1}{2}(RL-1) * \frac{1}{2}(PL+1) = 24.75 \ . \tag{6}$$

Thus a_4 is the expected total output over the lifetimes of the rigs built in the lifetime of the rig plant, as a multiple of the initial capacities.

Since new plants are not added in the year needed, but spread over a number of years, one must determine the Capacity Additions from a Program Lasting (CAPL) years. The total cumulative drilling factor from a capacity addition program lasting CAPL years is calculated as:

$$a_5 = CAPL * a_4 = 10a_4 = 247.5 \ , \tag{7}$$

where CAPL is an input parameter to the computer model (set at ten years in this version).

The above equations (Eq. 3-7) provide components of the equations for drilling capacity planning. One must, however, begin with the current capacity of old rigs and rig-plants. The current capacity of existing rigs ("Capacity of Old Rigs") in any year is the amount of actual drilling in the previous year (D_{t-1}). The initial capacity COR_1 is an input to the program. Thus, the equation for annual update of capacity of rigs in place:

$$COR_t = D_{t-1} . \tag{8}$$

The current capacity of existing plants (Capacity of Old Plants) is the sum of the previous year's capacity (reduced by a decline factor) and any capacity addition (CAP) in the previous year. Initial capacity of the plants (COP_1) is an input to the program. The equation for annual update of drilling capacity of existing rig plants:

$$COP_t = \frac{PL-1}{PL} * COP_{t-1} + CAP = .9\ COP_{t-1} + CAP \tag{9}$$

Notice that the "outputs" of rigs and rig producing plants, as well as plant capacity additions, are expressed in common units: millions of feet drilled per year.

The equation for exploratory drilling in the current year is then composed of "old rigs," COR_t (reduced by a decline factor), and of new rigs old plants, COT_t.

$$D_t = \frac{RL-1}{RL} * COR_t + COP_t = .9\ COR_t + COP_t\ . \tag{10}$$

In the off-shore regions, drilling is limited by the lease constraints, equation 10c. Notice that lease-curtailed drilling at time t can be carried over to the succeeding period because the limitation is defined by time-cumulative constraints and prior drilling.

$$D_t \leq CUMOC_t - CUMD_{t-1}\ . \tag{10a}$$

Cumulated drilling to date is:

$$CUMD_t = \sum_{i-1}^{i=t} D_t\ . \tag{10b}$$

Cumulated lease constraints in an off-shore region:

$$CUMOC_t = \sum_{i=1}^{i=t} OSL_t\ , \tag{10c}$$

where

OSL_t is the off-shore lease constraint for year t .

Once the total drilling footage from existing plants and rigs is known, the total additional drilling capacity needed to satisfy latent demand (these are the main equations of the planning process), can be calculated.

New Plant to satisfy Latent Demand in year t ($NPLD_t$) (Eq. 11) is the difference between indicated latent demand (Eqs. 2, 2a, 2b) and the sum of three components of estimated available capacity: the capacity of existing rigs over their lifetime, the capacity of existing plants over their estimated lifetime, and the aggregate footage from all previous (plant) capacity additions over their estimated lifetime. Since a capacity expansion program is planned for installation over a fixed period (CAPL = 10 years), additions are scheduled to furnish 1/10 of the extra capacity required in each year of the program (Eqs. 9 and 12).

$$NPLD_t = LD_t - a_4 * COP_t - a_2 * COR_t - a_4 * \sum_{k=1}^{t-1} CAP_K$$

$$= LD_t - \frac{1}{2}(RL-1) * COR_t - \frac{1}{2}(RL-1)\frac{1}{2}(PL+1)[COP_t + \sum_{k=1}^{t-1} CAP_K] \tag{11}$$

$$= LD_t - 4.5\ COR_t - 24.75[COP_t + \sum_{k=1}^{t-1} CAP_K]\ ;\ NPLD_t \geq 0\ .$$

Portion of capacity addition to be installed in year t:

$$CAP_t = NPLD_t/a_5 = NPLD_t/CAPL * a_4 = NPLD_t/247.5\ . \tag{12}$$

If the model is reinterpreted to represent in each year a <u>fraction</u> of the regionally aggregated population of developer-drillers who plan production of their "share" of exploration so that the capacity addition in any year corresponds to this fraction, the incongruous notion of unrecorded or forgotten capacity expansion plans does not have to be rationalized.

The model output consists of a time indexed vector of the quantities D_t , i.e. a drilling trajectory for each region and the total annual drilling for all regions for year t ($USDRL_t$):

$$USDRL_t = \sum_{j=1}^{j=14} D_{tj} , \tag{13}$$

where D_{tj} is the volume of drilling, in 10^6 ft., in region j, in year t. (In this final equation we see the "phantom" index j which has been omitted from equations 1-12 as described in the introductory paragraph on page 64 for the equations. From the variable D_{tj} one can determine the total amount of oil produced in each region in each year of the forecast. That quantity is a final output of the model.

VI.3.2 Discrepancies Between Code and Documentation in the Drilling Submodel

The particulars, uncovered by study of the program, of the disparities between the computer model of the drilling submodel and descriptions in the existing documentation or verbal statements by the developers follow.

Calculation of physical depreciation of model rigs and rig-building plants, i.e. annual decline in capacity of existing equipment is inconsistent with the calculation of projected depreciation used in the determination of capacity requirements to satisfy latent demand. Model output from existing rigs, COR, is subject in each year to a decline of .1 of its current value. Thus the residual output after a year (Eq. 3) is $(1-.1) * COR = .9 * COR$ (not counting any additions); after two years, $.9 * .9 * COR = (.9)^2 * COR$; and after ten years, $(.9)^{10} * COR$. A similar relationship obtains for rig plants, COP. In models of physical or biological systems, this process is conventionally called exponential decay. (For reasons which will become clear almost immediately, we will call it also exponential depreciation.) In the calculation of capacity requirements, i.e. the planning phase of the model drilling process, the decline of in-place rig (and rig plant) capacity is treated as though it were linear decay or straight line (physical) depreciation so that existing rig output COR would be reduced in each year .1 of its initial value (again, not counting additions). At the end of one year, we would have $(1-.1) * COP = .9 * COP$ (Eq. 3); but after two years, $(1-.2) * COP = .8 * COP$; and after ten years the original capacity would be exhausted, $1-10 * .1 = 0$ with, as before, a similar decline for rig plants. (Thus the labels RL and PL for Rig Life and Plant Life.)

Equations 4 and 6 expose these assumptions. Equation 4 gives the factor by which to multiply first year production by rigs to determine remaining total output if rigs age linearly over a ten-year lifetime. Lifetime total for a rig would be initial capacity * (1 + .9 + .8 + .7 ... + .1) or 5.5 * initial capacity. The factor 4.5 thus yields residual total capacity after one year. Note that the actual exponentially depreciated model output from a "new" rig over ten years would require the factor 1 + .9 + .81 + .729 + ... + .387 = 6.513 and a nine-year residual factor of 5.513 which is substantially (22.5%) larger than 4.5. Notice also that after ten years the rig capacity is not exhausted, but has a theoretical total-remaining-capacity factor equal to $\sum_{i=10}^{i=\infty} (q)^i$ or approximately 9.0 - 6.513 = 2.487. Thus, the "true" residual lifetime factor after one year is 9.

Equation 6 yields an analogous factor for rig plants. The value of this factor after ten years is 35.906 for exponential depreciation, rather than 24.75. Its true lifetime value after one year is 90. Within the context of the planning assumption of linearity, which <u>could</u> be interpreted as representing a uniformly biased planning methodology by drillers, i.e. a deliberate discrepancy in the model between what the planners (drillers) expect and what actually occurs, there is another apparent error.

In equation 6, the component concerning plants should be a sum from the second year through the ten-year plant life, and the factor concerning rigs should be a sum from year one of rig life, because according to the timing of introduction in the model, that is the simulated updating of capacity in equation (9). In other words, equation 10 shows drilling from "discounted" or "old" rigs plus drilling from plants as output from the "new" rigs produced in the current year. Notice that the depreciation of old plant capacity is recorded in the update equation for this variable, equation (9), but that the equation for updating old rig capacity, equation (8), does not show the depreciation explicitly. This is because the rig capacity depreciation has been applied in calculating drilling from existing rigs in the first element of equation (10). It happens that in the model as now constituted conceptually, with specific numerical values for constants, the erroneous permutation of the factors has no effect on the values of the outputs, because PL, plant life, and RL, rig life, are equal (4.5 * 5.5 = 5.5 * 4.5).

The interchange does, however, invalidate the programmer's attempt to provide additional flexibility in the computer model by treating a collection of model constants labeled as input quantities, because if one were to change the model by varying input values for labeled constants, the computed parameters a_4 (Eq. 6) and a_5 (Eq. 7) would be incorrect whenever PL and RL were not given equal values.

Capacity expansions do not take place according to the model driller's planned addition schedule because the model "forgets" that it is installing only the first year's increment of the planned capacity increase, i.e. no record of the expected total is retained in the model (see description of equations 11 and 12 above).

Because capacity additions feed into the stock of rig plants and rigs through equations 8, 9, and 10, there is double counting of all available capacity in equation 12, except for the most recent increment CAP_{t-1}, resulting in underestimation of additional capacity required. The term $a_4 * \Sigma CAP_K$ in the 1 equation should be replaced by $a_4 * CAP_{t-1} + CUMD_{t-1}$ to capture drilling equipment not yet carried in the inventory of existing capacity, and drilling to date (see eq. 12, 10b). In this context at least, the assumption of linear depreciation of equipment is a "compensating error."

In the function table the drilling entry corresponding to a minimum-acceptable-price relates to the initial year of the simulation. The generation of this function table is thus conceptually part of the drilling submodel. Therefore safeguards must be incorporated into the modeling system to prevent the drilling submodel from being exercised independently on the generation of the values of the drilling price function.

Finally, because "drilling" and "equipment" are equivalent entities in the model, curtailment of drilling owing to action of lease constraints can lead (through equation 8) to "retirement" of rig capacity in an off-shore region. This capacity may be subsequently replaced. Therefore, if "existing capacity," i.e. rigs and plants in place, or the components of annual drilling as labeled in equation 10, should become of interest as model outputs, the accounting procedure would have to be modified. (At present, they are printed out under the rubric "debugging dump" and do not influence final outputs of the overall model system.)

SECTION VII. THE OTHER MAJOR MODELING SYSTEMS

The Gas Supply Model

The modeling system which produces supply projections for nonassociated natural gas and its coproducts is almost identical to the Midterm Oil Supply Modeling System. The economic basis for estimating minimum acceptable prices is the same, as is the basis for estimating "latent demand" for drilling and regulating the rate of drilling over time. There are, however, two main distinctions: first, gas finding rates are estimated as a function of total drilling (exploratory and developmental) rather than just exploratory drilling; and second, the components of the oil model which represent enhanced recovery -- secondary and tertiary -- are not present.

The Financial Model

Also included in the Midterm Oil and Gas Supply Modeling System is a Financial Model which uses detailed cost and revenue information calculated in the Economic Submodels of the other two models to provide regional income statements and selected balance sheet items for the oil and gas producing industry. This model determines the capital expenditures necessary to provide production quantities. It provides the capability to translate oil and gas supply solutions into detailed schedules of oil and gas expenditures, defined in terms compatible with the national income accounts. These schedules are needed as input to the DOE integrating model MEFS.

APPENDIX A

This Appendix identifies the input data for the resource base submodel of MOGSM. In this report, by input data we mean "the set of data elements physically read in and processed by the computer programs that formally constitute the analysis system" [18, pg. 5]. The data set presented is that corresponding to the "Series C" forecasts shown in Volume III of the 1978 Annual Report to Congress [36]. Section IV of this report describes how this data is processed. The data is presented below in the order described in that Section.

Initial Oil Reserves

The model input values given below represent the proved reserves existing at the end of the last year. The reserve estimates are obtained from the American Petroleum Institute's annual publication, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and Productive Capacity as of December 31, 1977:

TABLE 1-A

Initial Oil Reserves (million barrels)

Region	Reserves
1A	316
2	2348
2A	617
3	346
4	1243
5	5660
6	5027
6A	1874
7	1486
8-10	563
11	33
11A	0

Decline Rates:

The decline rates employed by the model are estimated from the production-to-reserves ratio expected to prevail in each region. In turn, this is estimated from the last year of actual experience in each region, which can be obtained from data published by the American Petroleum Institute in its Reserves Report (cited previously).

TABLE 2-A

Decline Rates

Region	Decline Rates
1A	.158
2	.103
3	.174
4	.168
5	.130
6	.127
7	.134
8,9,10	.156
11	.180

TABLE 3-A

PRODUCTION PROFILES FOR REGIONS 1A, 2A, 6A, AND 11A

YEAR	OIL				GAS			
	1A	2A	6A	11A	1A	2A	6A	11A
1	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0
3	0	0	.042	0	0	0	0	0
4	.004	.112	.064	.151	.014	.050	.050	.005
5	.016	.100	.074	.130	.035	.099	.099	.048
6	.033	.090	.085	.112	.047	.090	.090	.045
7	.059	.080	.085	.096	.047	.080	.080	.043
8	.093	.072	.085	.083	.047	.070	.070	.041
9	.080	.064	.073	.071	.047	.070	.070	.039
10	.070	.057	.063	.061	.047	.070	.070	.037
11	.061	.051	.054	.053	.047	.067	.067	.035
12	.052	.046	.042	.045	.047	.058	.058	.034
13	.045	.041	.040	.039	.047	.050	.050	.032
14	.039	.037	.034	.033	.047	.044	.044	.030
15	.034	.033	.029	.029	.047	.038	.038	.030
16	.033	.032	.028	.028	.047	.035	.035	.029
17	.032	.031	.027	.027	.047	.030	.030	.027
18	.031	.030	.026	.026	.047	.026	.026	.026
19	.030	.029	.025	.025	.047	.026	.026	.025
20	.029	.028	.024	.024	.047	.026	.026	.024
21	.028	.027	.023	.023	.047	.026	.026	.022
22	.027	.026	.022	.022	.047	.026	.026	.021

TABLE 3-A

PRODUCTION PROFILES FOR REGIONS 1A, 2A, 6A, AND 11A
(Continued)

YEAR	OIL				GAS			
	1A	2A	6A	11A	1A	2A	6A	11A
23	.026	.025	.021	.021	.047	.026	.026	.020
24	.025	.024	.020	.020	.047	.026	.026	.019
25	.024	.023	.019	.019	.047	.026	.026	.018
26	.023	.022	.018	.018	.047	.026	.026	.017
27	.022	.021	.017	.017	.047	.026	.026	.016
28	.021	.020	.016	.016	.047	.026	.026	.015

Initial Oil-in-Place

Initial oil-in-place was calculated by adding oil-in-place additions for 1971-1977 (calculated for finding rate data) to oil-in-place estimates for 1970 as reported in the NPC *U. S. Energy Outlook: Oil and Gas Availability*. The original source for this data is API *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada*.

TABLE 4-A

Initial Oil-in-Place (million barrels)

Region	OIP
1A	2941
2	78998
2A	2263
3	7294
4	26191
5	110645
6	84613
6A	14860
7	61983
8-10	33015
11	163
11A	0

TABLE 5-A

Quinquennial Reserve Additions
(Obtained through the Use of Hubbert Equations)

	1st Stage (Yrs. 2-6)	2nd Stage (Yrs. 7-11)	3rd Stage (Yrs. 12-31)
1A	.00293	.00200	.0000
2	.00250	.00210	.0020
2A	.02250	.01008	.00640
3	.00957	.00424	.00233
4	.00501	.00220	.00124
5	.00256	.00042	.00000
6	.00783	.00357	.00211
6A	.01569	.00723	.00394
7	.00156	.00075	.00042
8-10	.00102	.00099	.00064
11	.00000	.00000	.00000
11A	.00000	.00000	.00000

TABLE 6-A

Regression Analysis Results for 1977 ARC

Region	$Q(10^6 Bl)$	b
2	33771	.935569 E-5
3	23463	.537416 E-5
4	32709	.235143 E-5
5	56399	.498198 E-5
6	30905	.359812 E-5
6a	28100	.289454 E-4
7	28895	.288161 E-5
8-10	14192	.728011 E-5

Finding rates are calculated by taking the derivative of the curve relating COIP and cumulative drilling, with the appropriate values for Q and b, and the appropriate cumulative drilling footage.

TABLE 7-A

Initial Finding Rates

Region	Finding Rate
2	.222796
3	.134861
4	.005634
5	.136446
6	.005946
6a	.549723
7	.005386
8-10	.006964

Table 6-A above represents the regression results using the 1977 ARC estimates for b. Table 8-A below represents the 1978 estimates for b. Notice that according to the definition provided in the text, Q should be the same in both years but it is not. The reason for the discrepancy is that DOE modelers requested and received a revised estimate from the U. S. Geological Survey of regional recovery factors which were applied in turn to undiscovered recovered resources to obtain a revised estimate of ultimate recovery (Q).

TABLE 8-A

Regression Analysis Results for 1978 ARC

REGION	(MMBLS) Q	b	(MET) CMFT	R^2	STD ERROR OF REGRESSION
2	32864	.853892E-5	27024	.928	.203337E-1
3	24138	.677276E-5	28415	.9629	.951448E-2
4	32436	.226398E-5	117003	.9336	.171771E-1
5	54153	.465574E-5	131877	.9743	.247101E-1
6	31026	.362541E-5	175835	.9955	.126080E-1
6A	28924	.311079E-4	15839	.9146	.469749E-1
7	19734	.451420E-5	111447	.9981	.603939E-2
8,9,10	13834	.653296E-5	39890	.9933	.563155E-2

Primary Recovery Factors:

These factors originally were based on an engineering judgment on the part of the National Petroleum Council. Absent any improved information -- and no regularly reported data is available to replace such a judgment -- these factors are left unchanged.

TABLE 9-A

Primary Recovery Factors

Region	Factor
1A	.158
2	.103
2A	.101
3	.174
4	.168
5	.130
6	.127
6A	.150
7	.134
8-10	.156
11	.180
11A	.159

Secondary Recovery Factors:

Secondary factors similar to the primary factors are used to translate additional oil-in-place to reserves after the requisite time lag. The secondary factors are based on engineering judgment on the part of the National Petroleum Council. In 1976, ICF performed an analysis to see if these factors were consistent (on a National level) with those that would have been predicted using Hubbert's factors. First, an initial amount of oil-in-place was calculated using the finding rate for some given amount of exploratory drilling. Then Hubbert's equation was used to calculate how much additional oil would be discovered in the next five years, and this was compared to the forecasted discovery based on the secondary factors. ICF's analysis showed no glaring discrepancies between the two methodologies. Therefore, DOE decided to continue using the NPC secondary recovery factors.

TABLE 10-A

Secondary Recovery Factors for New Fields

	1st Stage	2nd Stage
1A	.0115	.0115
2	.1330	.1330
2A	.0116	.0116
3	.0730	.0730
4	.0690	.0690
5	.1000	.1000
6	.0150	.0150
6A	.0162	.0162
7	.0900	.0900
8-10	.0845	.0845
11	.0330	.0330
11A	.0162	.0162

Producing Gas/Oil Ratios:

In the initial forecast year, this factor reflects the recent experience of the total gas produced in each region to the total oil produced in that region. The ratio expected to prevail at the end of the forecast period, however, is fraught with more difficult estimating problems. Basically, it represents an engineering judgment, influenced by the geology of the region (particularly the remaining undiscovered reserves of associated-dissolved gas) and the likely trends of enhanced recovery techniques and their estimated impacts on producing gas/oil ratios. The model inputs are shown below.

TABLE 11-A

Gas/Oil Ratios (in Mcf/Bbl)

Region	1978	1991
1A	265	265
2	462	462
2A	138	138
3	1242	1242
4	522	522
5	951	951
6	1493	1493
6A	814	814
7	1616	1616
8-10	536	536
11	1128	1128
11A	800	800

APPENDIX B - COST FACTORS

This Appendix identifies the input data for the economic submodel of MOGSM. In this report by input data we mean "the set of data elements physically read in and processed by the computer programs that formally constitute the analysis system" [18, pg. 5]. The data set presented is that corresponding to the "Series C" forecasts shown in Volume III of the 1978 Annual Report to Congress [36]. Section V of this report describes how this data is processed. The data is presented below in the order described in that Section.

B.1 Return on Investment

The discount rate employed by the model represents what is believed to be the rate of return that the petroleum industry must earn after tax, on the average industrywide, to attract capital. The model, however, forecasts in a constant (or real) dollar environment. Consequently, the rate used should be adjusted to represent not what the industry would expect nominally (i.e., anticipating inflation or deflation) but rather what it would expect in a constant dollar future (i.e., anticipating a zero rate of inflation or deflation).

Finally, the rate used reflects the effects of the capital structure (especially the mix of debt and equity) expected on the part of the industry on the average. Consequently, the rate reflects a capital structure-weighted expected return, again after the effects of the federal tax code on debt versus equity have been considered.

The derivation of an appropriate rate is a difficult issue. It involves analysis of the performance of companies over time, preferably during a stable period of inflation. This analysis tends to be theoretically-based and handicapped by the lack of clear-cut data, due to, among other things, the large amount of horizontally and vertically integrated nature of the petroleum industry.

Finally, it requires two kinds of judgments. The first must deal with how petroleum companies will behave in making their future investment decisions and how this behavior will reflect on the result of the aforementioned theoretical analysis. It also requires consideration of whether some major influence in this decision making behavior has changed systematically since the period from which the theoretical rate was derived. Examples include fundamental changes in the risk of the petroleum business (due to market changes, resource changes or other alterations in the business environment) or in the capital markets (due to a long term shift in the balance of demand for, and supply of, capital).

The rate of return chosen is 8 percent.

B.2 Calculating the Cost per Well Depth

A functional relationship between cost of drilling and average well depth is assumed. To obtain the functional relationship, one first chooses the range of values that well depth can possibly assume. The smallest value for average well depth is derived by examining past drilling experience. This low depth point is obtained from the most recent API Quarterly Review of Drilling Statistics. It is assumed that the largest average well depth is between 14,000 and 16,000 feet (depending on the region). At this point (the largest well depth) it is assumed that the last oil is discovered in a region (the quantity of oil discovered can be obtained from the finding rate curve).

The curve itself is then contoured to conform with the shape of the finding rate curve. The source utilized for an estimated distribution by region is the NPC Report entitled Energy Outlook: Oil and Gas Supply Availability, page 180.

The lowest value, midpoint, and highest values, respectively, for well depths for exploration wells, producing wells, and dry development used in the 1978 ARC are shown in Tables 1B, 2B, and 3B.

TABLE 1B

Well Depth and Cumulative Footage--Initial Year

Region	Expl. Dry	Producing	Dev. Dry	Initial Footage
1A	10858	10858	10858	0
2	2403	2403	2403	0
2A	5128	5128	5128	0
3	5746	5746	5746	0
4	6389	6389	6389	0
5	4222	4222	4222	0
6	5651	5651	5651	0
6A	8892	8892	8892	0
7	3799	3799	3799	0
8-10	2548	2548	2548	0
11	9000	9000	9000	0
11A	10000	10000	10000	0

TABLE 2B

Well Depth and Cumulative Footage for Midpoint of Curve

Region	Exp. Dry	Producing	Dev. Dry	Cumulative Footage
1A	12400	13000	12400	70000
2	9850	8150	9850	75000
2A	10400	10200	10400	50000
3	10000	11650	10000	200000
4	8600	8950	8600	500000
5	7900	8000	7900	500000
6	11700	10800	11700	500000
6A	12650	12750	12650	125000
7	8800	8500	8800	500000
8-10	7600	7350	7600	225000
11	13500	15500	13500	500000
11A	12500	12500	12500	70000

TABLE 3B

Well Depth and Cumulative Footage for Endpoint of Curve

Region	Exp. Dry	Producing	Dev. Dry	Cumulative Footage
1A	15000	15000	15000	140000
2	15000	15000	15000	350000
2A	15000	15000	15000	100000
3	15000	15000	15000	400000
4	14000	14000	14000	999999
5	15000	15000	15000	999999
6	14000	14000	14000	999999
6A	15000	15000	15000	250000
7	15000	15000	15000	999999
8-10	15000	15000	15000	450000
11	15000	16000	15000	999999
11A	15000	15000	15000	140000

B.3 Drilling Costs, Producing Wells and Dry Holes

The 1976 Joint Association Survey of the U. S. Oil and Gas Producing Industry: Drilling and Equipment Costs is the data base for estimating drilling costs. This survey reports the total number of wells, footage drilled, and costs for oil and gas wells and dry holes in 11 different depth classes.

The number of producing oil wells, footage drilled, and cost data were aggregated by region in each of the 11 depth ranges. Then the average depth and cost per foot for each of the depth classes were calculated and plotted on a graph. The resulting data points were connected by straight lines, to approximate a cost per foot versus depth curve.

The average cost per foot in a region, however, is not equal to the cost per foot at the average depth, due to the disproportionately high cost of deep wells. To adjust for this difference, both the average cost per foot and the cost per foot at the average depth were calculated and the difference between the two results was added to each point of the curve. The same procedure was used to develop dry hole costs.

To incorporate real cost increases since 1975, the Independent Petroleum Association of America (IPAA) Cost Study Report of May 8-10, 1977 and the October 1977 update were used. These contain cost indices for depth adjusted drilling costs for 1973 to 1976 and estimates of cost increases in 1977. They show an increase of 8.3 percent from 1975 to 1976, and a projected increase of 8.7 percent for 1976 to 1977. The GNP deflators over these time periods as obtained from the December 1977 Annual Survey of Oil and Gas (MA-1315(76)-1) are: 1.03 for the last half of 1975, 1.0495 for 1976, and 1.027 for the first half of 1977. Thus the real cost increase from 1975 to 1977 is 6.00 percent. All drilling cost values are adjusted by this factor. The cost data used for producing wells and dry holes in the model is presented in Table 4-B.

OCS Drilling Costs:

Offshore drilling cost calculations varied between regions. Region la calculations were based on cost estimates published in the Cook Inlet and Gulf of Alaska Environmental Impact Statements. The costs per foot for 6A are the same for oil and gas and were calculated by the following procedure.

1. Total exploratory and developmental footage was calculated by multiplying the numbers of wells published in the Environmental Impact Statements by average well depth.

2. Total drilling and platform costs were obtained from the Environmental Impact Statements on Offshore Leasing Sales.

3. Success ratios were used to split dry and producing wells.

4. Dry and producing costs per foot were calculated by dividing total costs by total footage.

5. These "mid-point" values for dry and producing costs per foot were scaled according to cost curves for Region 6A.

Regions 2A and 11A calculations were based on cost factors designed by the NPC and published in Ocean Petroleum Resources. These factors scale Region 6A costs to reflect various local conditions in offshore regions. These factors were applied after resources in 2A and 11A were divided into water depth categories of 200 meter and 500 meters. The cost factor for 2A is 6A x 1.25. For 11A, the cost factor is 6A x 1.8.

TABLE 4B
Drilling Costs Per Foot by Depth Bracket

Depth	Region 1A Producing Wells	Region 1A Dry Holes	Depth	Region 2 Producing Wells	Region 2 Dry Holes
10858	281.78	239.51	2403	47.85	35.76
11250	307.86	261.68	3125	49.91	37.30
13750	411.76	350.00	4375	50.22	37.53
16250	518.77	440.95	16250	236.17	176.50

Depth	Region 2A Producing Wells	Region 2A Dry Holes	Depth	Region 3 Producing Wells	Region 3 Dry Holes
5128	87.55	74.38	5746	43.20	30.61
6250	100.54	85.46	6250	45.87	32.50
8750	146.68	124.68	8750	66.91	47.41
16250	370.54	314.96	16250	169.04	119.78

Depth	Region 4 Producing Wells	Region 4 Dry Holes	Depth	Region 5 Producing Wells	Region 5 Dry Holes
6389	39.46	23.94	4222	27.81	22.65
8750	56.13	34.05	4375	27.83	22.67
11250	84.16	51.06	6250	35.51	28.92
16250	141.81	86.03	16250	130.88	106.60

Depth	Region 6 Producing Wells	Region 6 Dry Holes	Depth	Region 6A Producing Wells	Region 6A Dry Holes
5651	37.84	33.63	8892	102.57	88.92
6250	40.65	36.13	11250	175.92	149.53
8750	59.30	52.70	23750	235.29	200.00
16250	149.81	133.14	16250	296.44	251.97

Depth	Region 7 Producing Wells	Region 7 Dry Holes	Depth	Region 8-10 Producing Wells	Region 8-10 Dry Holes
3799	29.52	21.79	2548	22.95	19.28
4375	29.60	21.85	3125	23.73	19.94
6250	37.77	27.88	4375	23.88	20.06
16250	139.21	102.76	16250	112.30	94.35

Depth	Region 11 Producing Wells	Region 11 Dry Holes	Depth	Region 11A Producing Wells	Region 11A Dry Holes
9000	67.77	49.63	10000	211.17	179.49
11250	96.77	70.87	11250	263.88	224.30
13750	129.43	94.79	13750	352.93	299.99
16250	163.06	119.41	16250	444.65	377.95

B.5 Offshore Escalation Factor

Offshore drilling costs increase not only due to drilling progressively deeper wells, but also due to drilling in progressively deeper water. To account for increased costs occasioned by drilling in deeper water, the model uses a 2 percent annual escalation in offshore drilling costs, or a 34.6 percent increase over the fifteen year forecast period.

B.6 Initial Exploratory Footage

This initial data is derived from the _API Quarterly Review of Drilling Statistics_. It provides statistics on 1976 successful oil well footage, successful gas well footage, and dry hole footage. Dry hole footage was allocated to oil and gas on the basis of successful oil and gas footage. The 1976 total exploratory footage figure (including dry hole allocation) is 21,160,364 feet for oil.

B.7 Total to Exploratory Drilling Ratio

The total to exploratory drilling ratio is a measure of the development program which is occasioned by a discovery. To calculate such a ratio, an initial intercept is chosen by observing actual experience over recent years. Since pools found will be increasingly smaller and have deteriorating reservoir structure, reserves per developmental well will not remain constant, but must decrease over time. A lognormal relationship was assumed and the different intercepts were calculated based on more recent data. Table 5B presents the total to exploratory drilling at a variety of cumulative footage points.

The data source for the initial total to exploratory drilling ratio is the latest API Quarterly Review of Drilling Statistics for the United States. Total exploratory and total developmental drilling footage is calculated by allocating dry footage according to the ratio of successful oil to gas footage drilled.

TABLE 5B

Total to Exploratory Drilling Ratio

Region 1A		Region 2		Region 2A	
T/E	Cumulative Footage	T/E	Cumulative Footage	T/E	Cumulative Footage
3.15	0	6.30	0	2.98	0
3.15	240	6.26	2800	2.96	1000
3.14	650	6.18	7700	2.93	2700
3.12	1700	5.98	21000	2.83	7400
3.08	4700	5.44	57000	2.58	20200
2.90	16000	3.63	175000	1.89	55000
1.00	140000	1.00	350000	1.00	100000

Region 3		Region 4		Region 5	
T/E	Cumulative Footage	T/E	Cumulative Footage	T/E	Cumulative Footage
3.76	0	2.89	0	5.68	0
3.75	1900	2.86	13700	5.65	6400
3.72	5200	2.82	37300	5.60	17400
3.66	14200	2.70	101500	5.46	47400
3.49	38600	2.37	275900	5.08	128800
3.04	105000	1.47	750000	4.04	350000
1.00	400000	1.00	999999	1.00	999999

Region 6		Region 6A		Region 7	
T/E	Cumulative Footage	T/E	Cumulative Footage	T/E	Cumulative Footage
3.08	0	4.98	0	5.99	0
3.05	12800	4.96	1200	5.96	6900
3.01	34900	4.93	3200	5.90	18700
2.88	94700	4.84	8800	5.74	50800
2.54	257500	4.60	23900	5.30	138000
1.62	270000	3.95	650000	4.12	379000
1.00	999999	1.00	250000	1.00	999999

Region 8-10		Region 11		Region 11A	
T/E	Cumulative Footage	T/E	Cumulative Footage	T/E	Cumulative Footage
4.99	0	2.29	0	8.47	0
4.96	3500	2.29	1100	8.43	700
4.91	9500	2.28	3000	8.38	1700
4.76	25700	2.27	8100	8.22	4700
4.37	69900	2.23	22100	7.78	12900
3.31	190000	2.12	60000	6.60	35000
1.00	450000	1.00	450000	1.00	140000

B.8 Exploratory and Developmental Dry Hole Fraction

The data source is the API drilling statistics previously cited. Dry hole footage is allocated to oil or gas drilling according to the ratio of successful oil or gas drilling to total successful gas drilling. The dry hole fraction is the proportion of total, developmental, or exploratory drilling represented by the allocated amount of dry hole drilling, or allocated dry holes divided by total exploratory or total developmental drilling. These are shown in Table 6B.

TABLE 6B

Exploratory and Developmental Dry Hole Fraction

Region	Exploratory D/H Fraction	Developmental
1A	.891	.048
2	.648	.055
2A	.733	.074
3	.784	.120
4	.748	.253
5	.695	.151
6	.767	.263
6A	.942	.443
7	.702	.289
8-10	.731	.127
11	.908	.357
11A	.785	.244

B.9 Intangible Drilling Write-Off

Similar to the factor for accelerating depreciation, the intangible drilling write-off factor represents industry experience regarding the shares of successful well expenditures which are expensed rather than capitalized. The original National Petroleum Council factor was derived from the experience of companies, Chase Manhanntan Bank data, and expert counsel. Altering their factor would have required a comparable analysis.

TABLE 7B

Intangible Drilling Factors

Oil	.70
Gas	.73

B.10 Plant Investment

The National Petroleum Council originally estimated initial gas plant investment regionally, among other things from Chase Manhattan Bank data. Since the model is not particularly sensitive to these inputs, these original estimates are left unchanged.

With respect to new gas plant investment, the National Petroleum Council developed an engineering estimate of the processing capacity required per thousand cubic foot-increment of gas plant production and the cost per unit of additional capacity. It was based on a judgment that gas plant investment would be \$30 for each incremental MCF per day of nonassociated gas, and \$175 for each incremental MCF per day of associated-disolved gas; and that 93.5 percent of marketed gas is processed (except in Region 6 where only 75 percent of marketed gas is processed).

B.11 Tax Rate

Tax rate on corporate income (including 2 percent state tax) is 50 percent. Thus, the tax rate factor is .50.

B.12 Ad-Valorem and Production Taxes

These rates are derived from the actual tax rates prevailing in the states included in each region. The nominal rates of each state are weighted by the fraction of total regional production expected from each. This weighted-average, then, is the regional ad-valorem and production tax factor.

TABLE 8B

Region	Oil	Gas
1A	.000	.000
2	.080	.080
2A	.000	.000
3	.0714	.0704
4	.0828	.0791
5	.0818	.1055
6	.0965	.1377
6A	.000	.000
7	.0710	.0825
8-10	.0403	.0729
11	.0700	.0700
11A	.0000	.0000

B.13 Royalty Rates

Royalty rates are derived in a fashion similar to ad-valorem and production taxes. The basis, however, is confined mainly to rates charged for new properties on state lands. The model uses royalty rates of 12.5 percent onshore and 16.7 percent offshore.

TABLE 9B
Royalty Rates

Onshore	12.5
Offshore	16.7

B.14 Initial Oil Wells

Initial oil wells describe the number of oil wells operating at the beginning of the forecast period. The source for this data is World Oil Well Count published in the 2/15/78 issue.

TABLE 10B

Initial Oil Wells - 1977

Region	Wells
1A	291
2	37910
2A	6089
3	3873
4	17477
5	114315
6	83938
6A	4183
7	128343
8-10	111800
11	23
11A	0

B.15 Operating Costs Per Well

Operating costs per well come from Oil and Gas Replacement Cost: Development and Production report prepared by Gruy Federal, Inc. This report gives operating costs as a function of depth for 24 different regions. The depths used were the average depths of producing oil wells (Table 3B, discussed earlier) derived from the 1976 API Drilling Statistics. Gruy regions were collapsed into NPC regions by averaging the operating costs weighted by the number of producing wells in each Gruy Region. The resultant operating costs are shown below in Table 11B.

TABLE 11B

Oil Well Operating Costs

Region	Yearly Cost/Well	Secondary Operating Costs (Cents/Barrel)
1A	526062	189
2	4900	127
2A	92588	127
3	7604	55
4	9736	55
5	5833	55
6	7232	55
6A	67310	127
7	4508	55
8-10	4985	55
11	15434	55
11A	143641	127

B.16 Overhead Expenses

Exploration and production overhead costs are derived from the Joint Association Survey as a function of drilling and producing costs, as follows: G&A overhead allocated to exploration, development, and production was summed, and divided by the sum of drilling, equipping, and production direct costs.

$$\text{Overhead factor} = \frac{\text{Annual Overhead Costs}}{\text{Annual Drilling and Producing Costs}} = .175$$

B.17 Geological and Geophysical Expenses

These costs are estimated as a function of drilling and producing costs. The derivation is based upon data from the Joint Association Survey of the U. S. Oil and Gas Producing Industry (JAS). Geological and Geophysical Expenditure; Contributions Toward Test Wells; Land Department, Leasing, and Scouting Expenditures; and Other Exploratory Expenditures from the 1975 JAS were summed, and divided by the sum of drilling, equipping, and production direct costs. The Geological and Geophysical Cost Factor (GGCF) used in the 1978 ARC report = .102.

Since the model computes minimum acceptable prices for new wells, and to avoid overburdening the new fields with the total geological and geophysical expense, (since producing and new fields both are responsible for these costs), the costs reported are allocated between existing wells and new wells as follows:

D = Annual Drilling Costs + Producing Costs

<u>New Wells</u> -- New Field G&G factor = $\frac{\text{G\&G expense}}{D}$ x .75 = .0765

<u>Existing Wells</u> -- Old Field G&G factor = $\frac{\text{G\&G expense}}{D}$ x .25 = .0255

B.18 Lease Equipment Expense

This cost factor is derived from the Joint Association Survey, as a function of drilling and equipment costs, as follows.

$$\text{Lease equipment factor} = \frac{\text{Annual Lease Equipment Costs}}{\text{Annual Drilling and Equipment Producing Costs}} = .310$$

Consistent with geological and geophysical expense, lease equipment costs must be adjusted to avoid overburdening new wells with total lease equipment expenditures. Costs typically are allocated between existing fields and new fields as follows:

C = Annual Drilling and Equipment Producing Well Expenditures

<u>New Wells</u> -- New Well Lease Equipment = 0.75 x 0.310 x C = 0.233 x C

<u>Existing Wells</u> -- Existing Field Lease Equipment = 0.25 x 0.310 x C = 0.078 x C

B.19 Project Lives

The project lives used in the model represent the anticipated economic lives, on average industrywide, of various broad classes of projects in different geographical regions. In general, rather long lives are typical (see Table 12B). The typical combination of relatively long lives (say, at least 25 years) and relatively high discount rates (say, at least 8 percent) make the model results insensitive to changes in these project life estimates.

TABLE 12B

Project Lives

Primary Oil	30 years
Secondary Oil	25 years
Tertiary Oil	20 years
New Gas	30 years
Old Gas	30 years

B.20 Factor for Accelerating Unit of Production Depreciation

This factor originally was estimated by the National Petroleum Council based on Chase Manhattan Bank data and tax counsel. Alteration of these factors would have required a similar analysis: first, of the tax code; second, of the impact on illustrative projects with regard to depreciation; and, lastly, a review of company data.

TABLE 13B

Factors for Accelerating Depreciation on UPO Basis

	1977	1980	1988	1991
Oil	1.171	1.121	1.072	1.070
Gas	1.171	1.121	1.072	1.070

B.21 Tax Credit Rate

A tax credit rate of .10 was used for the period 1977 through 1980. From 1981 on, .07 was used.

B.22 Secondary Investment Factors

Secondary investment factors are derived from the National Petroleum Council's Oil and Gas Availability, which based its figures on extensive operator polling. They set the investment at 25¢ per barrel for onshore regions and 50¢ per barrel offshore. Onshore costs were expected to triple to 75¢/barrel and offshore to double to $1.00/barrel over the 15-year time span of the original NPC model. These factors have been inflated by the GNP deflator and are shown in Table 14B.

TABLE 14B

Secondary Investment Cost Factors

	1977	2006
1A	1.06	2.11
2	.35	1.06
2A	.70	1.41
3	.35	1.06
4	.35	1.06
5	.35	1.06
6	.35	1.06
6A	.35	1.06
7	.35	1.06
8-10	.35	1.06
11	.35	1.06
11A	.70	1.41

B.23 Secondary/Tertiary Operating Costs

These data are incremental to the normal well operating cost and are applied to secondary and tertiary projects in each of the regions.

The model inputs for secondary operating costs are based on estimated averages prepared by LaRue, Moore, and Schafer. Their research concluded that incremental operating costs of secondary recovery in uncomplicated onshore areas was estimated to be about $ .55 per barrel. In offshore areas and onshore California the estimated operating cost per secondary barrel was $1.27 and in Alaska $1.89.

TABLE 15B

Secondary Operating Costs

Region	Secondary Operating Cost
1A	1.89
2	1.27
2A	1.27
3	.55
4	.55
5	.55
6	.55
6A	1.27
7	.55
8-10	.55
11	.55
11A	1.27

APPENDIX C
DISCOUNTED CASH FLOW CALCULATIONS

o Assume production in any period is proportional to reservoir pressure (P_t):

$$q_t = K_1 * P_t.$$

o Assume reservoir pressure declines with cumulative production (Q_t):

$$P_t = P_o - (K_2 * Q_t).$$

o Then $$q_t = K_1(P_o - K_2 Q_t)$$

o Differentiating with respect to time we get

$$\frac{dq_t}{dt} = -(K_1 * K_2)\frac{dQt}{dt}$$

o Now, since by definition of cumulative production

$$\frac{dQ_t}{dt} = q_t$$

o We set $a = K_1 * K_2$ (discussed in the text as the decline rate), to get

$$-aq_t = \frac{dq_t}{dt} \quad \text{or} \quad q_t = \frac{-1}{a}\,\frac{dq_t}{dt}$$

Solving this differential equation yields

$$q = q_o e^{-at}$$

o The present-value-equivalent factor for a continuous stream of payments (discount rate = r)[15]:

$$PVE = \int_0^t e^{-rt} dt$$

[15] In the text, the discount rate is denoted DR.

o The present value equivalent production (Q_E):

$$Q_E = q_o \int_0^T e^{-(a+r)t} dt = q_o * \frac{1-e^{-(a+r)T}}{a+r}$$

o Minimum acceptable price (p_t) makes net present value -- revenues less operating costs -- equal the investment (I_E) necessary to prove reserves (R) and establish initial production (q_o) and decline rate (a).

o Revenues:

-- annual revenues = $p_t * q_t$

-- present value equivalent: $p * Q_E$ (p constant)

o Two classes of operating costs:

-- Approximately constant per year (e.g., producing well expense)

- annual costs: K_t

- present value equivalent: $K_E = K * \frac{1-e^{-rt}}{r}$ (K-constant)

-- Approximately proportional to production (e.g., royalties)

- annual costs: $C_t = b * q_t$ (b = unit cost per unit production)

- present value equivalent: $C_E = b * Q_E$

o Minimum acceptable price (MAP):

$$I_E = \text{PVE (Revenues - Costs)} = (\text{MAP} * Q_E) - K_E - C_E$$

Where:

$$\text{MAP} = \frac{I_E}{Q_E} + \frac{K_E + C_E}{Q_E} = \begin{array}{c}\text{investment portion} \\ + \\ \text{annual cost portion}\end{array}$$

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15. SUPPLEMENTARY NOTES

☐ Document describes a computer program; SF-185, FIPS Software Summary, is attached.

16. ABSTRACT *(A 200-word or less factual summary of most significant information. If document includes a significant bibliography or literature survey, mention it here.)*

The Midterm Oil and Gas Supply Modeling System (MOGSM) is a computer model based on economic and engineering factors, that projects yearly domestic oil and natural gas production over a 30-year period. This document describes the methodology used to produce those curves.

The Oil Supply Model consists primarily of three interconnected submodels: a Drilling Submodel that projects regional exploratory drilling on the basis of information about the economic gradations of the resource base, the level of future expected prices, and various constraints to exploratory drilling activity; a Resource Submodel that derives annual regional production quantities based on exploratory drilling, the prospects for finding oil, the intensity of development, the fraction of oil-in-place (OIP) which can be recovered by either primary or secondary methods, and the fraction of proved reserves which can be produced each year; and an Economic Submodel that calculates a minimum acceptable price for each year's quantity of reserves proved.

The Gas Supply Model produces supply projections for non-associated natural gas and its coproducts and is identical to the Oil Supply Modeling System with two exceptions: gas finding rates are estimated as a function of total drilling (exploratory and developmental); and the Gas Supply Model has disaggregated the Eastern states into two regions.

17. KEY WORDS *(six to twelve entries; alphabetical order; capitalize only the first letter of the first key word unless a proper name; separated by semicolons)*

Assessment; energy modeling; oil and gas modeling; reservoir analysis; supply modeling; validation.

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