U.S. OIL AND GAS SUPPLY

EMF 5 SUMMARY REPORT

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I. EXECUTIVE SUMMARY

Future rates of U.S. oil and natural gas supply are among the most important concerns of this nation's domestic and foreign policymakers. The high priority placed on oil and gas supply issues has sparked politicized debates on price controls, windfall profits taxes, federal lease rates, and similar legislation. Those debates have been dominated by efficiency, equity, and environmental considerations, highlighting the need for credible projections of domestic production under alternative policy assumptions. Projections from formal mathematical models have often enlightened, but sometimes confused, the debates on U.S. oil and gas supply issues. The present study tries to put the contribution formal models can make to the debates on U.S. oil and gas issues in perspective by: (1) analyzing comparative results from a number of models under common input assumptions; and (2) using that comparison and ancillary analyses to help assess how such models can and should be used in the future.

Several key messages can be derived from analysis of the model results, given the scenario assumptions. These insights concern: (1) the general outlook for U.S. oil and gas production over the next two decades, and (2) the effects of key uncertainties affecting the future oil and gas supply environment--e.g., the amount of as-yet undiscovered oil and gas resources, the future price of world oil, etc.--on oil and gas production rates over that period; (3) the effects of uncertainties about the performance of the oil and gas industry in response to those environmental factors, and (4) the effects of various government policies on the performance of the oil and gas industry given the environment. As is typical of EMF working groups these summary conclusions were obtained through a confluence of interscenario comparisons, intermodel comparisons and model assessments.

OUTLOOK FOR U.S. OIL AND GAS SUPPLY

Domestically produced oil and natural gas will remain a significant source of energy in the U.S. for the rest of this century. Under every scenario almost all of the models utilized project conventional oil and natural gas production of at least 13 million barrels of oil equivalent per day through 2000 (as compared to about 18 million barrels per day in 1981). In fact, under certain conditions some models, particularly those that include projections of oil produced via enhanced oil recovery techniques and gas from unconventional sources, actually project increases in total U.S. liquid and gas production over this period.

Despite the existence of a contrary view--one that holds that there will be a precipitous decline in U.S. oil and gas supply before the end of the present century--several factors explain the working group's conclusion that supply will decline gradually at worst and may even increase. A simple extrapolation of the downward trend in oil and gas production during the 1970s might lead one to conclude that U.S. hydrocarbon production will drop off sharply over the coming years. Trend extrapolations of that sort, however, ignore several underlying physical relationships that have typified the hydrocarbon extraction industry over the past several decades, and perhaps more importantly, the new economic environment for domestic oil and gas supply created by: (1) the rapid increases in world oil prices over the past decade, and (2) the oil price decontrol of the last several years.

First, over the past two decades the fraction of known oil and gas reserves that have been produced in any given year has been relatively stable. If anything, during the present decade one would expect an increase in this historical relationship in response to the increase in financial incentives to produce oil and gas. Historical production to reserves ratios from these already known reserves will support production levels over the 1980s that average about 50-60% of present levels. Of course, by the mid-1990s almost all of these reserves will be depleted; new discoveries or new technology will be required to avoid a precipitous decline in U.S. oil and gas production beyond that point.

The second source of oil supply during the 1980s and 1990s will be production from newly discovered reserves. Given current estimates of undiscovered U.S. oil and gas, the fraction of the undiscovered reserves that has been discovered in any one year has not varied very much when averaged over the decades of the 1950s, 1960s, or 1970s. And, again, higher financial rewards would be expected to increase exploratory effort and improve technology so that any change in the discovery rate during the present decade would be expected to be upwards. But even the historical rate, coupled with the known reserves and expected undiscovered resources would be sufficient to hold U.S. oil and gas production above 60-70% of current levels throughout the remainder of this century. Besides the likely price responsiveness of discovery rates to higher prices, though, there is another reason to suspect the current rate of oil and gas production to be sustained for at least the next two decades.

In the future, oil and gas extracted via enhanced oil and unconventional gas recovery techniques will increasingly supplement supplies obtained through conventional energy technology. Historically only about 30% of the oil in known reservoirs has been produced--this limit reflecting both geological and economic factors. Well structure and pressurization characteristics generally dictate that about 30% of the oil in place can be extracted over a period of years with very little investment compared with what any additional recovery would cost. Higher oil prices today than during the historical period could well lead to higher recovery rates over the next two decades. In fact, the one model included in the study that attempts to project enhanced oil production anticipates over one million barrels a day from that source by 1990. Although natural gas recovery rates are generally much higher than for oil (about 80%), the new technological development in the gas area has been the discovery of large quantities of gas at great depth or in tight sands. These resources are expensive to tap, but profitable to develop at the prices expected to prevail during the 1980s and 1990s.

KEY ENVIRONMENTAL FACTORS

The working group assumed that the key factors in the environment within which the oil and gas industry will have to produce over the next two decades are the world price of oil and the amount of oil and gas that await discovery. Higher oil prices will spur greater exploratory activity for any assumption about undiscovered resources, and more undiscovered resources will lead to greater returns to exploration at any price level.

The 1990 projections of oil production (which was 9 mmb/d in 1981) from the alternative models in the high price case range from 5 to 11 mmb/d. However, enhanced oil recovery is excluded from the projections. The models included in the study that attempt to project enhanced oil production anticipate over one million barrels a day from that source by 1990. Under conditions of more favorable geology, the production estimates increase by about 2 mmb/d. At the lower extreme, in a case with lower prices and less favorable geological assumptions, the 1990 production estimates range from 3 to 9 mmb/d.

The 1990 projections of conventional natural gas production (which was 19 TCF in 1981) from the alternative models range from 15 to 25 TCF in 1990 under the high price case. However, unconventional gas supplies are excluded from the results presented here; the one model included in the study that attempts to project unconventional gas production anticipates one to two TCF a year from that source by 1990. Even under the most favorable cases, depending on the model and the resource assumption, production of natural gas is still unlikely to ever reach its historic peak of 22 TCF except according to one model that includes extreme behavioral assumptions. On the other hand, even in the most unfavorable cases, annual production levels are projected to be at least 13-14 TCF during this period.

KEY INDUSTRY PERFORMANCE FACTORS

Despite standardization of resource base and future world oil price assumptions the models produce a wide range of oil and gas production projections. Why do these differences occur and which forecasts seem most plausible in view of historical trends and current market conditions? A critical element affecting these forecasts is the rate of discovery of the undiscovered resource base. Cumulative production projected during the next 10-15 years will nearly exhaust current proved reserves. Therefore, not only the ultimate availability of currently undiscovered resources, but the rate at which those resources will be found are fundamental to longer term production projections.

One convenient way to summarize the performance of the oil and gas industry in this regard is to compute the average fraction of the undiscovered resource base discovered each year over some convenient time horizon--say a decade. Interestingly, given the study's assumption about the amount of oil yet to be discovered in the U.S., this fraction was about 2% when averaged over the 1950s, 1960s, or 1970s. A continuation of discoveries at this rate would imply a gradual decline in the production of conventional oil by the U.S. over the next decade.

Surprisingly, the results from some of the models imply a much lower discovery rate during the 1980s, even when much higher prices are assumed. Not surprisingly, those are the models that project the most rapid declines in conventional U.S. oil supply over the next two decades. On the other hand, the models that project steady increases in production over that period imply discovery rates of 3-4% or more. The projections from the bulk of the models imply discovery rates between 2% and 3 1/2% and, thus, neither a rapid increase nor a rapid decrease in conventional U.S. oil supply. Finally, it is somewhat comforting to note that the discovery rate during 1980 was about 2.5% and, although only preliminary data are available, it should be about 3.0% during 1981. As a result, U.S. oil production has started to <u>increase</u> again for the first time in nearly a decade.

In the case of natural gas there is a great deal more uniformity in the model projections, and a plausible relationship between those projections and the historical performance of the industry. Again, average decade discovery rates seem to be a useful aggregate statistic, with the 1950s, 1960s, and 1970s, implying a natural gas discovery rate slightly under 2%. This time almost all the models project a roughly 50% increase in that rate during the 1980s during which much higher prices are projected despite the continuation of natural gas price regulations during 1985. Natural gas discoveries at this rate result in a very gentle decline in natural gas production for the duration of this century. Encouragingly, a look at the record of the past two years shows discoveries at about a 3% per year rate, resulting in an almost imperceptible drop in production. What effect might government policies have on these oil and gas production levels?

POLICY PERSPECTIVES

Policy actions taken today can have a significant impact on future oil and gas production levels. Key policy levers include the extent and duration of controls on oil and gas prices, tax laws and limits on federal leasing rates. However, lead times tend to be long: Five to ten years must typically pass before a significant share of the ultimate impact of a policy action taken today is felt.

Several federal policies have been examined. Prominent in past, present, and probably future congressional debates are federal price controls on natural gas and oil. Although price controls on oil were phased out by 1981, a scenario included in the study explores the effects of a continuation of those controls and finds that they reduce conventional lower-48 crude oil supply from between 0% to 15% in 1990; in 1995 the effect is even greater, ranging from 0% to 35%.

Similarly, the impacts of oil price controls on conventional lower-48 natural gas production range from 0% to 6% in 1985, growing to from 0% to 12% by 1995. Furthermore, price controls which create expectations of future discontinuous price jumps create incentives for even perfectly competitive firms or land owners to not explore for, develop, and produce practice, can greatly enhance their usefulness in the planning process. For example, oil production projections and models are often formulated without specifying which categories of oil-e.g., just crude oil or crude oil plus natural gas liquids-and types of recovery techniques e.g., just conventional methods or enhanced recovery techniques as well, are considered. Since natural gas liquids currently constitute about 15 percent of U.S. liquids production, and many feel that about that much oil can be produced via enhanced recovery techniques during the 1990's these definitional differences are important. Thus, a 7 MMBD projection of conventional crude oil production in 1995 may, in fact be consistent with a 10MMBD project in of total liquids production, with 3MMBD of natural gas liquids and oil recovered via enhanced oil recovery techniques.
The present study was but a first step in the difficult, but potentially rewarding, process of standardization and comparison of methods and forecasts.

II. THE STUDY

ISSUES

Many crucial industry and government decisions hinge on assessments of the magnitude of U.S. oil and gas resources and the rate at which they can be produced. The present study focuses on the problem of projecting the rate at which these vital domestic resources will be discovered, developed, and produced, given alternative assumptions about the amount of resources that await discovery. Public and private R&D, investment and pricing decisions can depend on these projections and what they imply. The task of making oil and gas production estimates is difficult, depending on assumptions about the economic environment--e.g., world oil price--and policy environment--e.g., government pricing and tax laws--within which oil and gas producers will operate over the next two decades. These assumptions and their implications for oil and gas production are controversial, but perhaps by making them explicit formal modeling can help frame the debate.

Among the most prominent oil and gas policy issues are the extent to which the prices of the domestic supply of these two vital resources should be controlled below the equivalent world oil price. The post-1973 runup in the world oil price provided the motivation for the creation of price controls on crude oil to avoid the adverse macroeconomic impacts that could result from a sudden jump in the price of all oil. On the other hand, natural gas prices have been controlled since the Natural Gas Act of 1936, but the Natural Gas Policy Act of 1978 put into effect a complicated scheme that will deregulate the price of all natural gas discovered after 1978 by 1986.

Besides the oil and gas pricing issues, other important U.S. oil and gas supply issues are: (1) the rate at which federal lands are leased for the purpose of exploring, developing and ultimately producing oil and natural gas; (2) the nature of the tax laws applicable to oil and gas producers, including the level of the depletion allowance, the investment tax credit, and the expending of intangibles; (3) the impact of import quotas on domestic oil and gas production; and (4) the impact of a windfall profits tax on oil production.

Many factors that are uncertain today could have a large effect on the impacts of the various policy options. The most important of these seem to be the extent of the domestic oil and gas resource base and the world price of oil.

The study provides information about many of the impacts of the several policies under alternative assumptions about the resolution of the key uncertainties. It does not, however, provide all the information that is likely to be of interest to the policy maker. For example, the response of oil supply to higher prices with and without domestic price controls is projected under several alternative world oil price and domestic resource base assumptions. This is undoubtedly important information required in assessing the efficacy of the controls, but information on the demand response to the higher prices, resulting U.S import posture, inflationary impacts and distributional effects would also be of great interest during an administration/Congressional debate on oil pricing policy. These latter subjects were <u>not</u> addressed in the present study.

ASSUMPTIONS AND SCENARIOS

The study is built around an examination of a set of alternative scenarios, each designed to explore some important facet of the U.S. oil and gas supply system. The processing of the scenarios by the models provides a set of conditional projections for analysis and interpretation.

The scenarios do not represent forecasts. No attempt was made to develop a consensus in the working group about the likely outcomes in the future. Instead, the scenarios are designed to provide a common basis for comparing the results from the alternative scenarios, with an emphasis on the response of U.S. oil and gas supply to higher prices. The details of these scenarios are explained elsewhere, but the broad thrust of each case is outlined here to establish the context for the comparison of the results.

There are 15 scenarios in all. The Reference Scenario provides a basis for comparison. It assumes undiscovered oil and gas in place at mean values from USGS circular 725, and a 2.5% real rate of increase in the price of world oil (from $14.50/bbl in 1978 dollars on 7/1/78) trhough the end of the century. Wellhead pricing for natural gas is assumed to be as per the Natural Gas Policy Act, with deregulation in 1986, while wellhead pricing for crude oil is assumed to be as per the Energy Policy and Conservation Act, with price controls phased out by October of 1981. In the absence of price controls the price of natural gas is assumed to equal the Btu equivalent price of crude oil. Thus, in the high price scenario the price of new natural gas increases by about $1 per MCF in 1986. Leasing rates, tax structures, and the Alaskan export ban mimic the existing federal policies.

Some of the most important information that the models can provide as inputs to policy analysis are projections of the response of U.S. oil and gas supply to price. The intermodel price responsiveness comparisons are driven by three alternative assumptions (Reference, High, and Low) about the world price of oil (with corresponding increases in the price of natural gas). Additionally, the price response was investigated under Continued crude oil price Controls (with a maximum composite price increase of 4.5% per year) and High Geology (twice the reference level assumption about the resources in plac) assumptions. This defines 8 of the study's 15 scenarios[1].

Seven additional scenarios represent additional variations from the Reference scenario. In the No Tax Break scenario the investment tax credit is decreased from 10% to 0%, the percentage depletion allowance is abolished and expensing of intangibles is not allowed. In the Surprise scenario prices are initially expected to follow the reference trajectory, but then jump to the high level of 1990. This scenario highlights the differences among the models with differing degrees of foresight. In the Retarded Leasing Scenario the offshore average leased in each year drops to half the reference level. This should slow exploration, development, and production from the Outer Continental Shelf (OCS). In the Price Shear scenario gas prices are calibrated to the high world oil price level, but the world oil price is, in fact, set at its reference level. This scenario isolates how the models differ in representing "directionality" in drilling

[1]The Low Price Scenarios includes prices that are less than the continued controls level so a scenario combining the two conditions was not considered.

for gas instead of oil. Another scenario (High Geology/Controls) combines the high geology assumption with continued price controls. This combination of assumptions should lead to a slow rate of domestic depletion (measured in terms of cumulative production as a fraction of ultimate recovery).

The final two scenarios balance the scenarios that include high geology assumptions by including more pessimistic geology assumptions than in the Reference scenario. The Low Geology scenario assumes undiscovered oil and gas in place at half their reference levels. The final scenario--Resource Shear--reflects the recent pessimism about oil relative to gas resource estimates by combining the low geology assumption for oil with the reference assumption for natural gas. Table 1 summarizes the study's 15 scenarios.

THE MODELS

Table 2 lists each of our 10 models, the working group member(s) representing that model, and the organization with which the model or the modeler is closely associated. The models were run by or under the direction of the individuals listed in Table 2. All computer runs were made by people having intimate knowledge of the specific models. Most models were run for nearly all scenarios.

In this section we outline the key assumptions incorporated into these models as used in this study. There are essentially three sets of differences across the models. First, the models may be based upon different assumptions as to which real world relationships are important to include in the model and which ones can be safely ignored. Second,

TABLE 1 EMF SCENARIOS

			Reference Leasing, Taxes, Expectations				Reduced Leasing	No Tax Break	Unanticipated Price Increase
			Low Oil Geology		Medium Oil Geology	High Oil Geology	Medium Oil Geology		
			Low Gas Geology	Medium Gas Geology		High Gas Geology	Medium Gas Geology		
Continued Controls	High Oil Price	High Gas Price			D				
	Medium Oil Price	Medium Gas Price			E	N			
Controls Expire	High Oil Price	High Gas Price			B	G			K*
	Medium Oil Price				M				
		Medium Gas Price	P	Q	A	H	L	J	K*
	Low Oil Price	Low Gas Price			C	I			

*In scenario K prices unexpectedly change from medium to high

TABLE 2

MODELS USED IN U.S. OIL AND GAS SUPPLY STUDY

MODEL	REPRESENTATIVE	ORGANIZATION
Epple-Hansen	Dennes Epple Lars Hansen	Carnegie-Mellon University Carnegie-Mellon University
E-M-S (Erickson-Milsaps-Spann)	Edward Erickson Stephen Millsaps Robert Spann	North Carolina State Unive. Appalachia State University Virginia Polytechnic Insti.
FOSSIL2	Roger Nuill	U.S. Department of Energy
GEMS (Generalized Equilibrium Modeling System)	Robert Marsalla Dale Nesbitt	Decision Focus, Inc. Decision Focus, Inc.
Kim-Thompson	Y. Kim Russel Thompson	University of Houston University of Houston
LORENDAS (Long-Range Energy Development and Supplies)	Leo Rapoport	Virginia Polytechnic Insti.
MIT-WUP (Massachusetts Institute of Technology-World Oil Project)	Maurice Adelman James Paddock	Mass. Insti. of Tech. (MIT) Mass. Institute of Tech.
EIA/ICF	William Stitt	ICF, Incorporated
MGMS (Mid-Range Oil and Gas Modeling System)	Charles Fverett	Energy Information Adminis.
AHM (Alaskan Hydrocarbon Model)		
EOR (Enhanced Oil Recovery)		
RICE	Patricia Rice	Oakridge National Lab.
TERA (Total Energy Resource Analysis)	Leon Tucker	American Gas Association

modelers may disagree about the proper form for modeling the same real-world relationships. Finally, differences in the numerical parameters used within a given modeling form are possible. In what follows we will discuss only the structural differences, i.e., the differences in the features included and in the fundamental ways these features are represented.

Table 3 contains a catalog of the 10 oil and gas supply models included in this study. Although the meaning of most of the columns is clear, some further explanation may be necessary. The third column gives the dates over which the model was developed. A date of 1979 indicates that current work may be in progress. The fourth column identifies the models which formed a basis for the development of the model in question. Column 8 classifies model methodology into two types: econometric or engineering-process.

An econometric model of production is a model which relies extensively on statistical analysis of historical data pertaining to the oil and gas industry. Models of this type are usually formulated in two stages. First, an economic theory is developed as to what variables (e.g., prices resources, etc.) are thought to have primary impact on the various aspects (e.g., drilling activity, reserve additions, etc.) of oil and gas supply. Second, historical data is collected and statistical methods are employed to estimate the linkages between the dependent and independent variables in the model.

Engineering-process models differ in a fundamental way from the econometric models in terms of their methodology. In econometric models the important economic relationship in a process are of primary concern, while in engineering-process models the focus is on the process of exploring, developing, and producing oil and gas itself. This does not mean that engineering-process models do not include any econometrically estimated relationships; they often do. It is just that in econometric models the focus is on the important economic relationships which govern a process, while engineering-process models the focus is on simulating the process itself.

The ninth column in Table 1 indicates the calculational procedure used to generate the forecasts with the model. Three of these procedures or "modes of operations" are distinguished.

(1) Simulation: In this case, the model solves the set of equations that form the model, for the endogenous variables (e.g., reserve additions, production levels), given a set of values for the exogenous variables (e.g., prices, resource availabilities). When this system of equations is recursive (i.e., the equations can be ordered in such a way that every equation only depends on exogenous variables and endogenous variables determined in previous equations), then the solution is trivial. If the model is not recursive, then iterative procedures are used to find the solution (e.g., for DFI/GEMS and FOSSIL2).

(2) One-period optimization: For each time period of the model, at least one variable is determined in order to optimize an objective function.

(3) Intertemporal optimization: The model solves simultaneously for an optimal set of values for all endogenous variables for all time periods in order to optimize one objective function. Therefore, the

TABLE 3

A CATALOG OF OIL AND GAS SUPPLY MODELS

Name	Builders	Users (Funders)	Dates	Ancestors	Resources	Geography	Methodology	Mode of Operation	Integrated
Epple/Hansen	Epple, D. (Carnegie-Mellon)	--	75-79	--	oil & gas	lower 48 on & offshore	econometric	simulation	no
E-M-S	Erickson, E. (NCSU) Spann, R. (UPI) Millsaps, S. (ASU)	Brookings Institution	74	--	oil	lower 48 on & offshore	econometric	simulation	no
FOSSIL2	Naill, R. (Dartmouth-DOE)	DOE	76-79	--	oil, gas & others	all U.S.	engineering process	simulation	yes
GEMS	Marshalla, R. (DFI) Nesbitt, D. (DFI)	EIA/DFI	77-78	SRI/Gulf	oil, gas & others	all U.S.	engineering process	intertemporal optimization	yes
K-T	Kim, Y. (U. of Houston) Thompson, R. (U. of Houston)	TEAC	77-78	NPC	oil & gas	lower 48 onshore	engineering process	optimization	no
LORENDAS	Rapoport, L. (VPI)	VPI/NSF	75-79	--	oil, gas & others	all U.S.	engineering process	intertemporal optimization	yes
MIT-WOP	Adelman, M.A. (MIT) Paddock, J. (MIT) Jacoby, H.D. (MIT)	MIT/NSF	76-79	--	oil	world	engineering process	simulation	no
EIA/ICF						lower 48	engineering process		
- MOGSMS	Stitt, W. (ICF)			NPC/FEA	oil & gas	on & offshore		simulation	
- AHM	Everett, C. (EIA)				oil & gas	Alaska		intertemporal optimization	
- EOR					oil only	lower 48 on & offshore		simulation	yes
Rice	Rice, P. (ORNL)		75-79	--	oil & gas	lower 48 on & offshore	econometric	simulation	yes
TERA						lower 48			
- onshore	Tucker, L. (AGA)	AGA	71-79	--	oil & gas	onshore	econemetric	simulation	no
- offshore						lower 48 offshore	engineering process	optimization	no

model determines the values of the endogenous variables for all periods all at once, so that exogenous variables (e.g., prices) of future periods directly affect endogenous variables in the current period.

THE WORKING GROUP

In this study we have used mathematical models as tools for projecting and explaining what might happen in the world oil market under a specified set of conditions. These models require as inputs many assumptions about real world relationships. In addition to the specific numerical assumptions needed, the projections are shaped by decisions about what to omit from a model. Such specific features as an endogenous determination of OPEC production capacity and capacity utilization or broad considerations such as the international political forces and potential changes in consumer lifestyle may often by omitted. The extent to which the results accurately predict the future behavior of the world oil market depends critically upon the accuracy and completeness of the assumptions included and the significance of these phenomena that are excluded. Therefore, no model results can be considered perfect forecasts of the future. A detailed analysis of the underlying assumptions as attempted here is necessary to sort out the often contradictory projections from different models.

Dependence upon assumptions and consequent uncertainty in projections are characteristics not only of the mathematical models but also of the mental models used by experts or groups of experts to assess future oil market conditions. There is no alternative in energy analysis to some form of rational evaluation involving many explicit or implicit assumptions. Mathematical modeling is often a convenient, explicit, and powerful vehicle for such thinking.

This document summarizes conclusions reached by an EMF working group studying the possible future evolution of U.S. oil and gas supply. A complete report will be published separately. Many of the conclusions result from insights gained through the use of models but they do not represent an uncritical acceptance of the numerical outputs from models.

The 43 working group members, drawn from government agencies, private-sector firms, consulting and research institutions, international organizations, and universities, include both modelers and nonmodelers. The group met four times between early 1979 and early 1980; the EMF staff assisted the working group throughout the study.

The goals of the working group were threefold: (1) to compare and contrast the results obtained from the several participating models in order to understand the general behavior, strengths, and limitations of the models both as a class and as individual models, (2) to provide information that might be useful in national and international energy decision and policy making, and (3) to provide a guide to the models for potential users. The insights obtained from the models and their use may be in the context of a particular policy option or may focus on the implications of alternative model structures.

III. PROJECTING OIL AND GAS SUPPLY

ELEMENTS OF THE SUPPLY PROCESS

The domestic petroleum supply industry engages in three activities: exploration, development, and production (Figure 1). Exploration leads to discoveries from the stock of undiscovered resources--with each discovery, this stock is depleted. Development converts these discoveries into reserves which are ready for production--i.e., it turns discoveries into productive capacity. During production these developed reserves are extracted--with each increment of production the stock of unproduced reserves is depleted.

Exploration

Exploration is the search for deposits of petroleum. This search is undertaken in many different areas concurrently. Typically the search begins with preliminary geological analysis. This involves studying the surface geology, information from previously drilled wells, and seismic records. As exploration continues, discoveries are made and the geology of the area is better understood. This understanding aids in locating other deposits. However, as these discoveries are made, the collection of undiscovered deposits is depleted. In a particular area, exploration generates discoveries in a reasonably systematic fashion; larger deposits, because they are most obvious from the seismic record, because they represent larger targets, and because they are the most desirable, are found fairly early in the exploitation of an area. Typically there are very few of these large deposits and many, many small deposits.

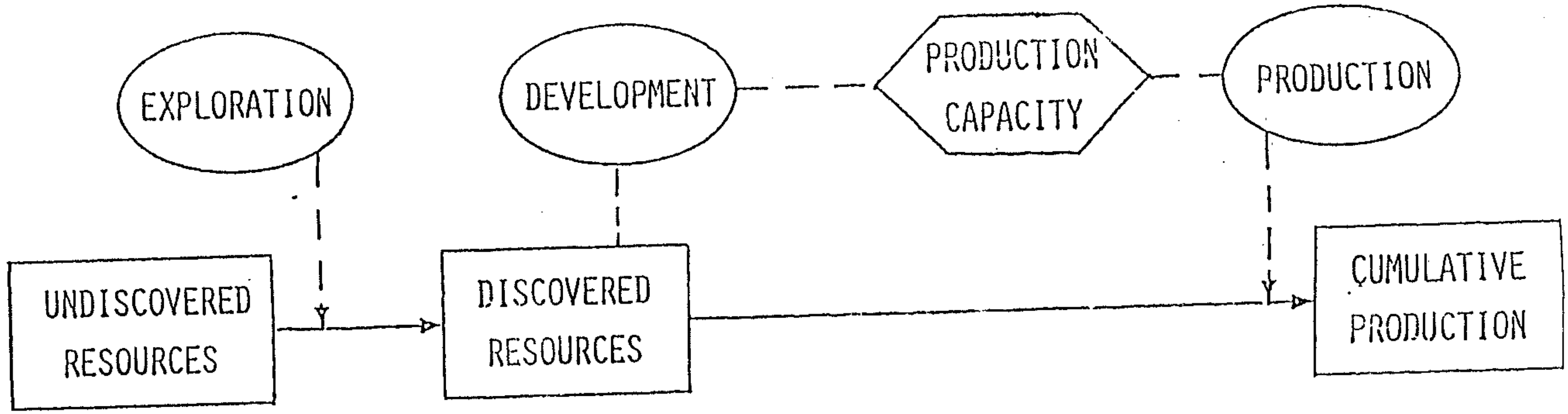


Figure 1 Oil and Gas Supply Process

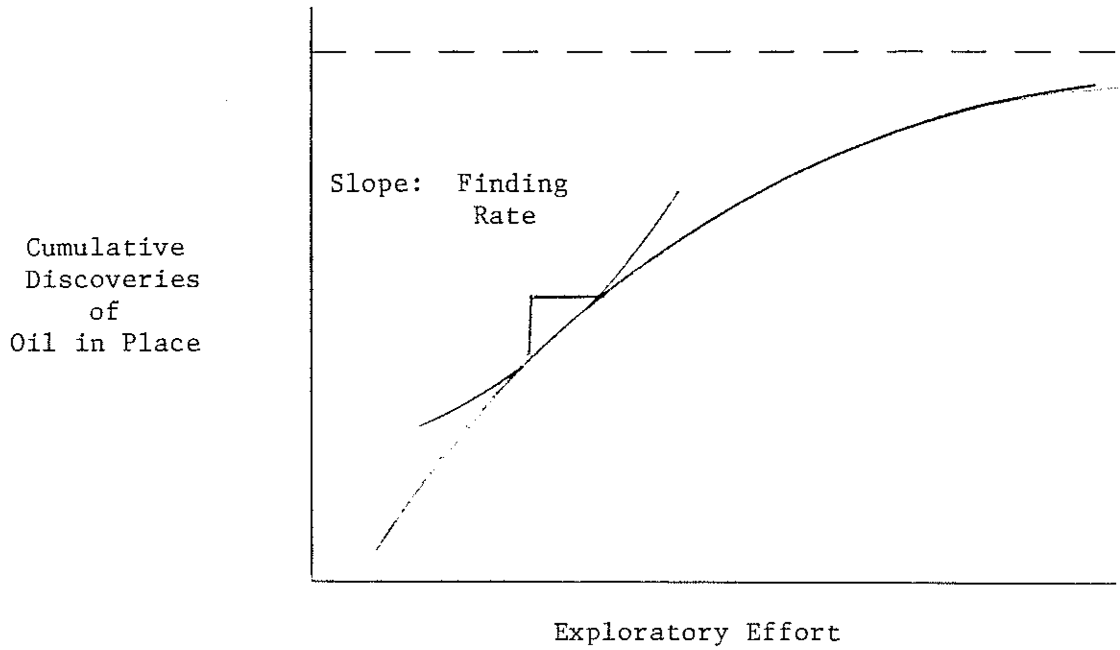
Several conceptual relationships are useful in discussing the results of exploration within a particular area. The first relationship (Figure 2a) links cumulative discoveries to cumulative exploratory effort. Cumulative discoveries begin at zero--with no effort nothing can be found. Cumulative discoveries proceed, perhaps only asymptotically, to the ultimate potential of the area as cumulative exploratory effort increases--no more than what exists can be found.[2] That the cumulative discoveries curve is steep at first and then less so is substantiated by observation. This relationship is the essence of resource depletion.

Now, if each additional unit of exploration costs the same amount one can plot the marginal cost of discovering the next barrel of oil versus cumulative discoveries (Figure 1b). Since each incremental barrel requires more exploratory effort and each unit of exploratory effort has the same price, the marginal cost curve increases with cumulative discoveries.

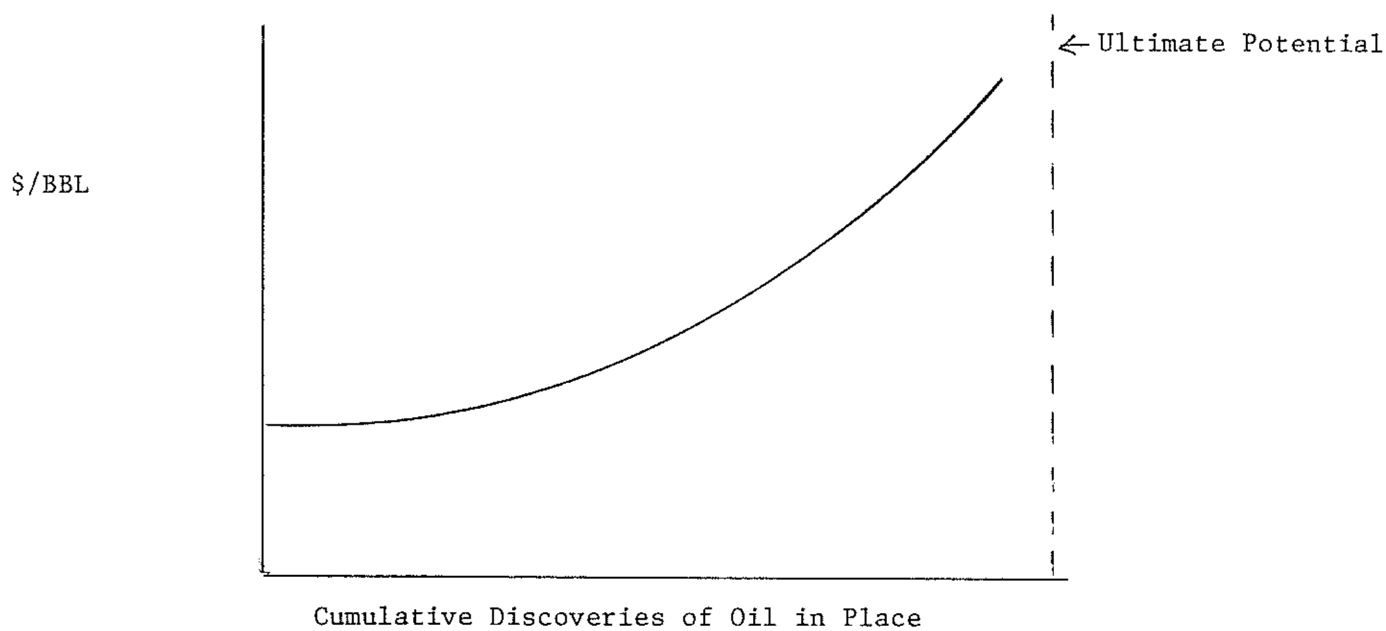
Development

Development is the second major activity undertaken by the petroleum supply industry. The role of development is to prepare newly discovered deposits of petroleum for production. For small pools this involves the installation of a pump and the connecting of the well to a pipeline or storage tank. For large discoveries the process is much more involved. In addition to installing pipelines, gas plants, and pumps, ancillary wells must be drilled. Development wells delineate the pool and provide

[2]The finding rate is defined as the additional discoveries per increment of exploratory effort (it is the slope of the curve shown in Figure 2a).



(a) Cumulative Discovery Curve



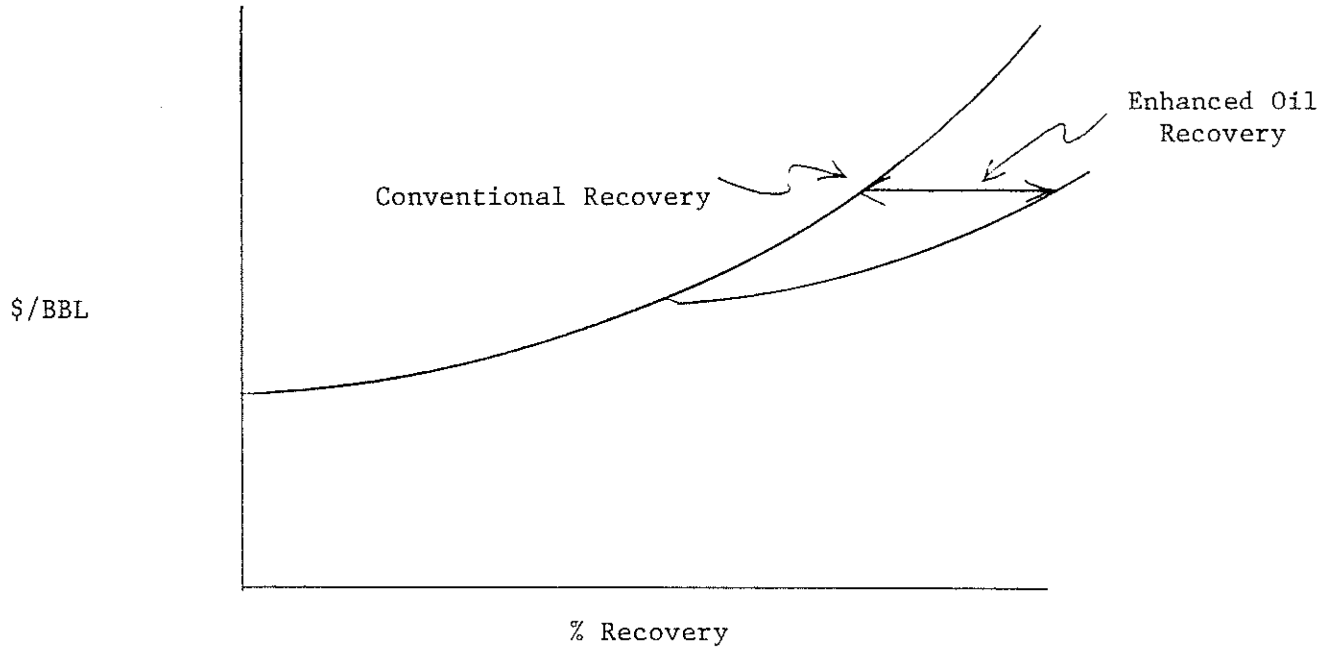
(b) Long-Run Marginal Discovery Cost Curve

Figure 2. Linking Exploration and Discovery

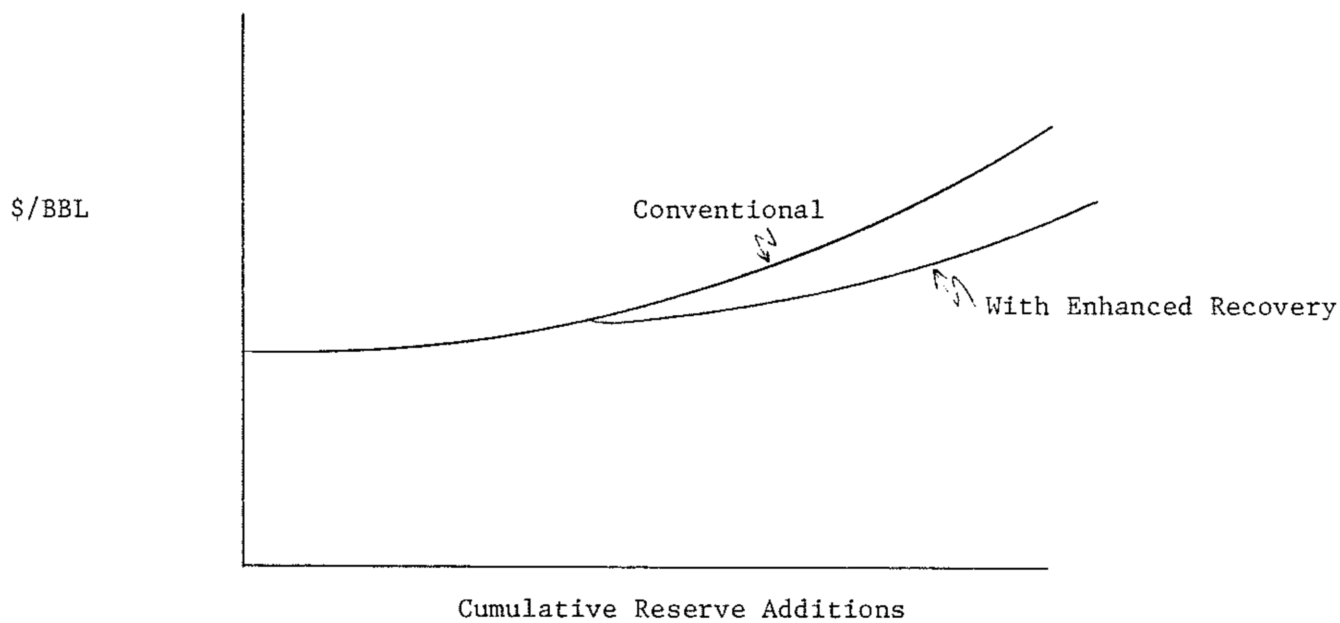
additional points of extraction. To a limited extent, the more wells within a pool, the greater the ultimate recovery from that pool. However, since wells are expensive, there is a tradeoff to be made. Today, about 30% of the oil discovered can be recovered through so-called conventional recovery techniques.

Apart from installing more development wells, though, enhanced oil recovery techniques, such as chemical injection, allow more oil to be recovered from a pool of discovered "oil-in-place". These techniques generally require sizable investments, though, and can only be justified with higher oil prices. Figure 3(a) shows how marginal development costs increase with increases in the desired recovery percentages by conventional and enhanced oil recovery techniques.

The economics of exploration and development can be summarized by a resource (marginal finding and development cost) curve like that shown in Figure 3b. In that graph the cost of converting another unit of resources to produce reserves is plotted against cumulative reserves added. The costs include all exploration and development expenses other than those associated with premiums paid for scarcity. Land leases and bonuses are included at a rate sufficient to pay for foregone uses of the land (exploration may hamper farming or devalue building sites). Drilling costs are included at a rate consistent with no extra ordinary scarcity of rigs and drilling materials. Geologist time is included at a rate representing the long-run opportunity cost for their services. These costs are interpreted as those which are inescapable if another unit of reserves is to be added from an area.



(a) Long-Run Marginal Recovery Cost Curve



(b) Long-Run Marginal Reserve Addition Cost Curve

Figure 3. Resource Development

In the stylized Figure 3b, the costs increase steadily as the area is depleted. No expense can bring forth more reserves than the ultimate potential of the area (the cost tends to infinity as cumulative reserves added approach the ultimate potential). To see how the resource curve can be useful and how the additional costs associated with premiums paid to owners of scarce resources come into play, we must first discuss production, the ultimate object and payoff of the oil and gas supply industry.

PRODUCTION

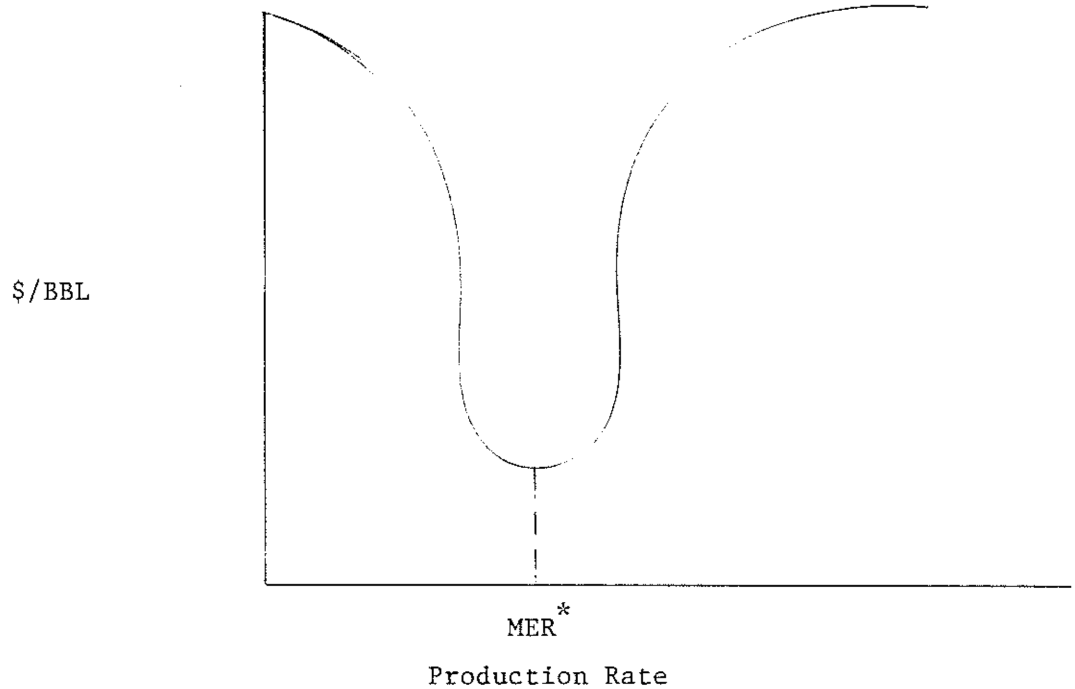
Production is the extraction of petroleum from the deposits provided by exploration and development. The extraction process is complicated and time consuming. It may take 20 years to deplete a small oil deposit and even longer for a large one. The petroleum of a deposit, because it is not actually found in pools but rather in the open spaces between grains of rock, must be given time to migrate to the well. Attempting to hasten this process can "damage" the deposit and the migration will stop prematurely. Similarly, trying to slow down this process can result in damage also. In either case this damage implies reduced recovery from the deposit. There exists an optimal rate of extraction which, by definition, generates the greatest recovery from a deposit. Substantial deviations from the optimal rate do not occur; they are uneconomic and in most states illegal. However, some flexibility in the rate of extraction exists--especially for gas. And to the extent that deviations from the optimal rate do not incur substantial decreases in the ultimate recovery, producers are free to regulate their production in response to changing economic considerations.

The economics of oil production can be summarized with a production rate cost curve like that shown in Figure 4a. Moreover, if oil is always produced at a rate that minimizes production costs, a composite long-run marginal cost curve, representing the costs of discovering, developing, and producing oil as a function of cumulative production, can be drawn as shown in Figure 4b.

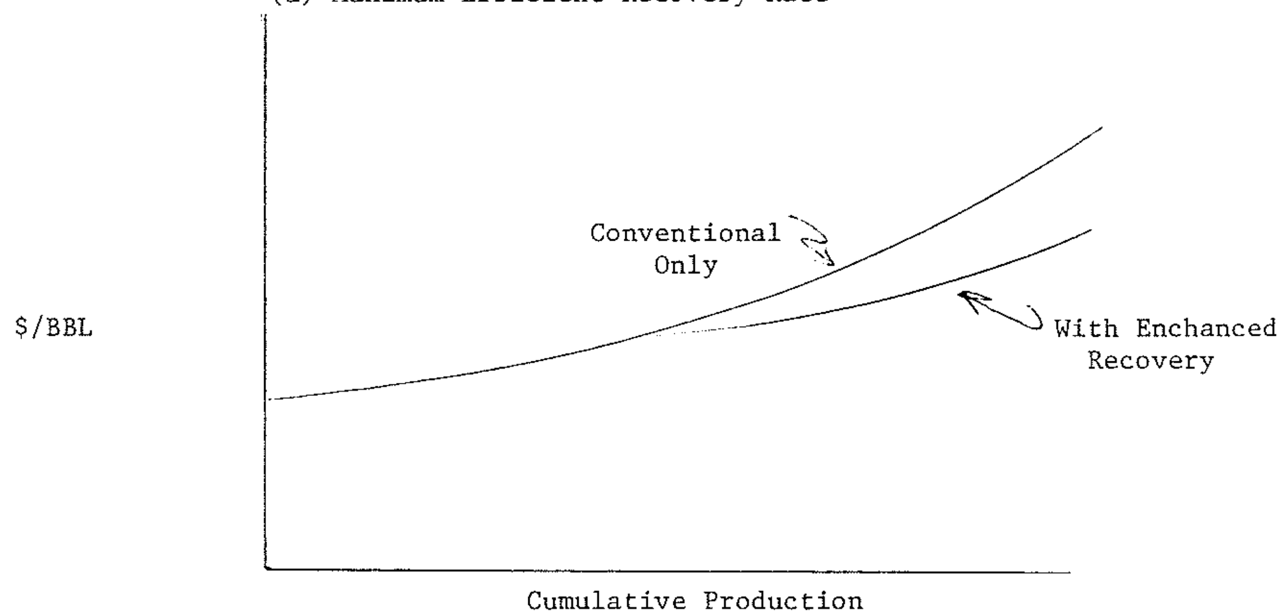
If there was a limitless supply of low cost oil available to be produced, and sudden fluctuations in international oil prices did not occur, relationships like that shown in Figure 4b could be used to project the amount of oil supplied each year. The price of oil in any year would determine the level of additional production during that year beyond what had been produced through the previous year. In such a world, gradual increases in prices are all that would be required to bring forth the required oil supplies. These were approximately the conditions that prevailed in the U.S. oil and gas industry during the 1950s and most of the 1960s. By the late 1960s, though, domestic oil and gas was getting increasingly difficult to find, and in the early 1970s international oil prices shot up rapidly. These events reflected primarily long and short-run resource scarcity, respectively; phenomenon that need to be considered in any serious attempt to project future oil and gas supplies.

Long-Run Resource Scarcity

If resource owners expect oil prices to be higher in the future than the current long run marginal cost of supply they may decide to ask for a higher price or withhold production in anticipation of future profits. The difference between the price actually charged and the long-run marginal



(a) Maximum Efficient Recovery Rate



(b) Long-Run Marginal Production Costs (Discovery, Development & Recovery)

Figure 4. Resource Depletion

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*Maximum Efficient Recovery Rate

cost is referred to as an economic rent, reflecting its interpretation as a measure of scarcity. Economic theory predicts that the size of the rent on a depletable resource will increase at the rate of interest until the price of a widely available substitute (like synthetic fuels) is achieved. Figure 5 shows the relationship between resource cost, selling price and economic rent.

Short-Run Resource Scarcity

During the late 1960s finding rates had started to decline, so some long-run scarcity value was probably included in the selling price of domestic oil and gas. However, during the late 1960s and early 1970s a greatly expanded supply of low-cost oil imports helped moderate the realization of long-run scarcity rents by domestic oil and gas resource owners.

The Arab oil embargo of 1973-74 meant that (1) a significant amount of the low-cost oil imports suddenly vanished, and (2) by the end of the embargo OPEC had unilaterally increased their oil prices by a factor of four; rather than being cheaper than domestically produced oil, oil imports were now quite a bit more costly. Since domestic resources were suddenly much cheaper to produce than the cost of oil imports, there was a dramatic increase in the incentive to produce more domestic oil and gas. In the U.S. the effect of the increased incentive to produce was blunted by price controls that kept the price domestic producers could receive below the new world oil price level. Nonetheless, the domestic price did increase significantly, spawning a domestic drilling boom. This drilling boom did increase domestic discovery, development and production beyond what it

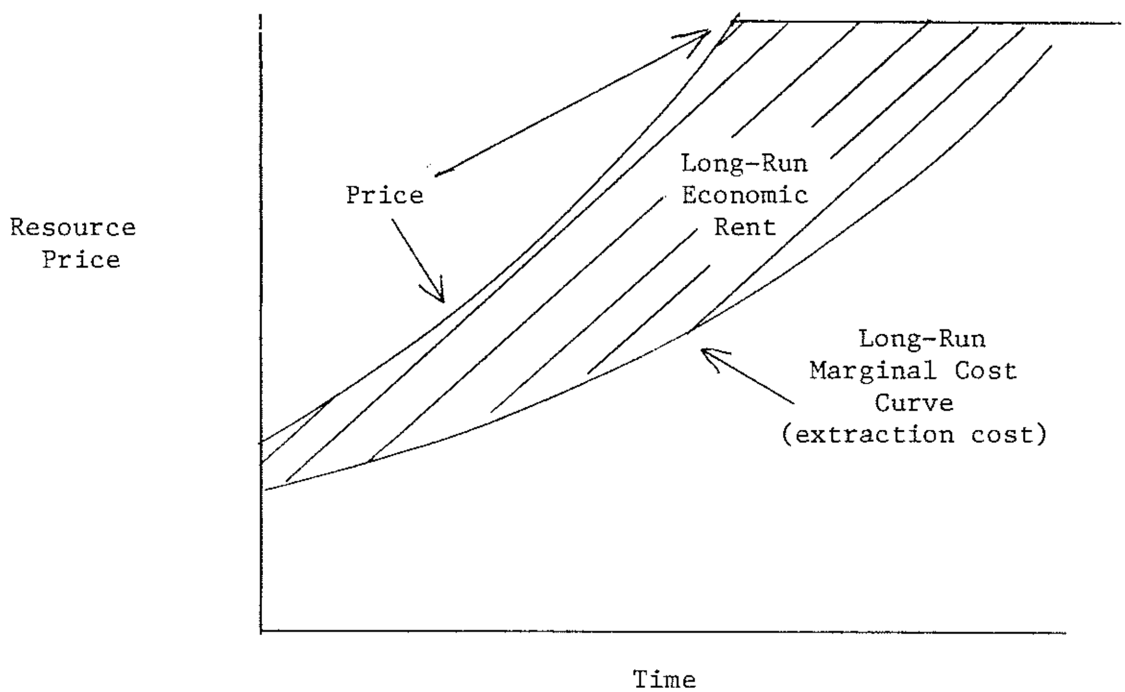
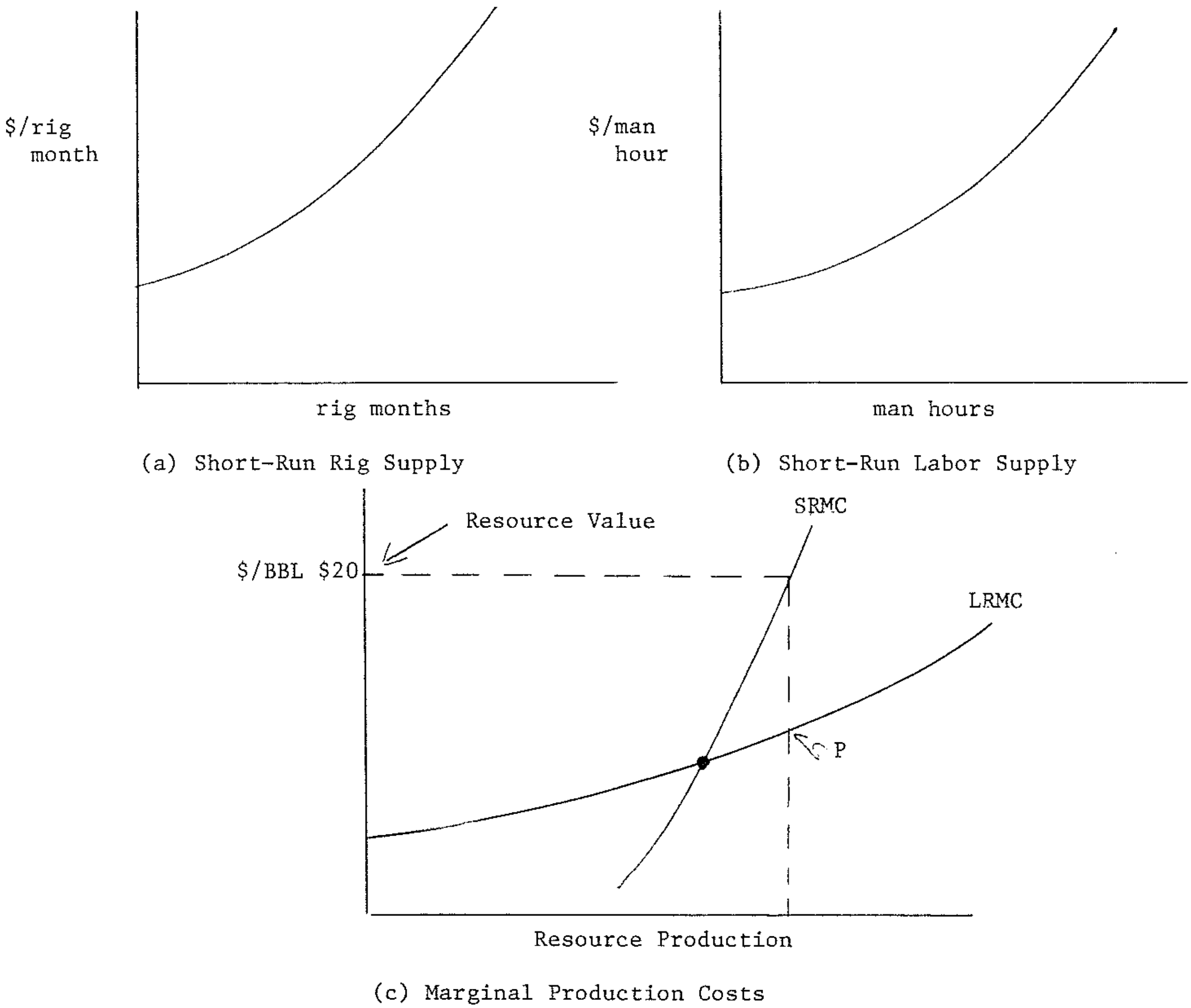


Figure 5. Long-Run Resource Scarcity and Economic Rent

would have otherwise been. Unfortunately, the resulting increase in domestic production was not nearly enough to displace the oil imports. In fact, production barely increased at all.

Besides the disincentive produced by the price controls there were two other reasons that domestic supply did not respond more dramatically: (1) depletion effects as evidenced by a decline in the finding rate per foot drilled, and (2) shortages of drilling rigs and oil company technical experts (e.g., geologists) to handle the increased level of activities. In the short-run the supply of drilling rigs and technical experts can only be increased rapidly at great expense as the requisite resources must be drawn away from other productive activities.

The short-run factor supply curves are shown in Figures 6(a) and (b). The long-run marginal cost curve shown in Figure 4b assumed that the factor markets were in long-run equilibrium (at the extreme left of the factor supply curves shown in Figure 6(a) and (b). Thus, in situations where there is a sudden external increase in oil prices (such as occurred in 1973-74 and 1979-80), the cost of increasing domestic supply in the short-run can be much greater than can be derived from the long-run marginal cost curve. Figure 6(c) shows the relationship between long-run and short-run marginal costs. During most of the period since the 1973-74 oil embargo the domestic oil industry has probably been operating at cost levels above long-run marginal costs, and during 1973-75 and 1979-81 the industry was probably well up the factor supply and short-run marginal cost curves.



(a) Short-Run Rig Supply

(b) Short-Run Labor Supply

(c) Marginal Production Costs

Figure 6. Short-Run Versus Long-Run Equilibrium

An Integrated View of Oil and Gas Supply

We are now able to complete our discussion of petroleum supply economics. We begin with a discussion of exploring, developing and producing in a single area and a single point in time, and end with a discussion of the actual industry practice of exploring, developing, and producing in many areas simultaneously and over a period of many years.

The decision to explore within an area depends upon the actual costs of exploration and development, and the expectations of the operator as to the geological and depositional characteristics of the area, and as to future prices. An explorer must acquire land and drill without knowing what size deposit will be found nor what price its production will bring. The merits of a project must be decided on the basis of expectations. These expectations of discovery characteristics and of future prices may or may not conform with reality as it is eventually revealed. How accurate are the expectations? Can we assume that the people making the exploration decisions have perfect foresight? If not, what are the appropriate assumptions?

The oil and gas industry explores, develops, and produces from many areas at once. In so doing, the costs of the various activities are determined. A complete description of the supply industry includes, the current and expected future costs of the factor services, principally drilling and geological analyses, and for each area, the cost of leasing land, the amount of exploration and development effort, and the quality of discoveries and production. All of these things are determined by the petroleum supply and related markets.

To be more concrete about this view of the oil and gas supply process, consider the state of the oil and gas industry in 1980. People had expectations about the worth of petroleum discovered in that year. Discounting future revenues, allowing for taxes and royalties, and assuming gains in the world oil price, that value might be about $20. Thus, operators, according to their expectations, could have afforded to spend up to $20 to locate and develop a barrel of oil. (In comparison, based on 1970 costs and taxes and assuming 1970 prices had prevailed, the maximum tolerable supply cost was about $2) This $20 was distributed as profit and deferment of costs to exploration companies, resource owners, rig owners, geologists and others.

In 1980, we were operating at the extreme right hand side of the factor supply curves. (See Figure 6a) No reasonable amount of money could bring forth a significant quantity of additional drilling services or of geological analyses. Owning a drilling rig or being a petroleum geologist was lucrative in 1980. Thus we might expect the cost of buying rigs to be bid up and therefore rig manufacturers to increase production (as did, in fact, occur in 1981). And as we might expect, petroleum geology is became a more popular profession. Again expectations play a key role. Nobody will buy a rig this year if he expects to be unable to employ it in the next year. Neither will anybody enter the petroleum geology profession, regardless of how lucrative it is this year, if next year he expects to be unable to obtain a job. In the short run, costs depend upon the current stock of rigs and geologists. In the long run, costs depend upon both the current stock and expectations about future demand.

The cost of leasing land, the amount of exploration and development activity, and the quantity of discoveries and production for each area is determined simultaneously with the costs of drilling and of geological analyses. The cost of leasing land, even more than the other factors, depends upon expectations about future demand. Potentially petroliferous land is a depletable resource; once leased, be it confirmed as productive or condemned as barren, it cannot be leased again. Owners must weigh current offers against what they expect to be offered in the years to come.

Explorers for petroleum, facing the costs of drilling and geological analyses, and having the opportunity to lease prospective land in several different areas, decide upon the basis of their expectations about the geology of the areas and about future prices, which areas offer an opportunity for profit. Among those areas, they select ones that they can afford. They explore in these selected areas. If a deposit of sufficient size is found, it is developed and later produced. Depending upon the outcome of having explored in these areas, their expectation about the geology changes and they are more or less able to afford to continue exploring.

Let us return to the resource curve (Figure 6c). Remember, it was defined such that the cost to convert one more unit of resource to production capacity is the absolute minimum possible; the costs used come from the left side of the factor supply curves and land is valued at its opportunity cost. An extra line labeled resource value is added to the figure. The resource value is the worth to operators of producing the petroleum, as determined from the considerations discussed above. This line, here drawn at $20/barrel, in concert with the resource curve, tells us how much of the resource can be converted to reserves. At the point where the two curves cross, exploration stops (assuming expectations conform with reality). Beyond that point the reserves cost more than they are worth. If we increase the value of reserves, we can move further out on the curve. How much further depends upon the steepness of the resource curve.

This graph also conveys another useful bit of information. Consider the point of depletion marked as P. At P there is some absolute minimum cost at which an additional unit of production can be added, say $6. The remainder of the value of the resources, in this example $14, can go to the exploration company as profit or to the factor owners or land owners. But if the cost of the factors has been bid up above the $14 mark, production will not take place. Only when scarcity in the factor markets is reduced and prices of the factors fall or the value of the oil increases can exploration continue.

An aggregate supply curve for the whole U.S. can be constructed from the various area specific supply curves. The aggregate supply curve is simply the horizontal sum of all of the area component curves. Using the curve, we can answer the question: How many reserves can be economically found and developed in the whole of the United States for a given value of petroleum? A quick re⁻iew of the performance of the oil and gas supply industry over the past two decades helps bring the implications of these concepts to life.

IV. HISTORICAL EXPERIENCE

HISTORICAL EXPERIENCE

During the 1960's when oil and gas prices were very stable, reserve additions were more than sufficient to offset the reserves that were produced (Figure 7 and 8). Thus, proved reserves in 1970 were greater than those in 1960 despite a decrease in the level of exploratory drilling. Evidently, during that period technical advances in oil and gas exploration were significant enough to counterbalance the effects of the depletion of the undiscovered resource base. During the 1970s, however, quite a different pattern was observed. During the 1970-73 period exploratory drilling continued to decline and for the first time production exceeded reserve additions, leading to a decrease in proved reserves. This trend was not then viewed with much concern as a cheap and seemingly endless supply of foreign crude promised to satisfy America's growing thirst for petroleum.

In late 1973 and early 1974, however, the industrialized world was taken by surprise by the Arab oil embargo and subsequent four-fold increase in the price of oil on the world market. These events set off a boom in domestic exploration activity, reversing the 15-year decline in drilling activity. Then, for another surprise: despite a doubling in drilling activity, production <u>continued</u> to outstrip reserve additions which--coupled with relatively constant real oil prices during the mid-seventies--led to an increase rather than a decrease in dependence upon imported crude. Technology was unable to overcome natural forces at a very inopportune moment in history. These turned out to be costly trends as the Iranian

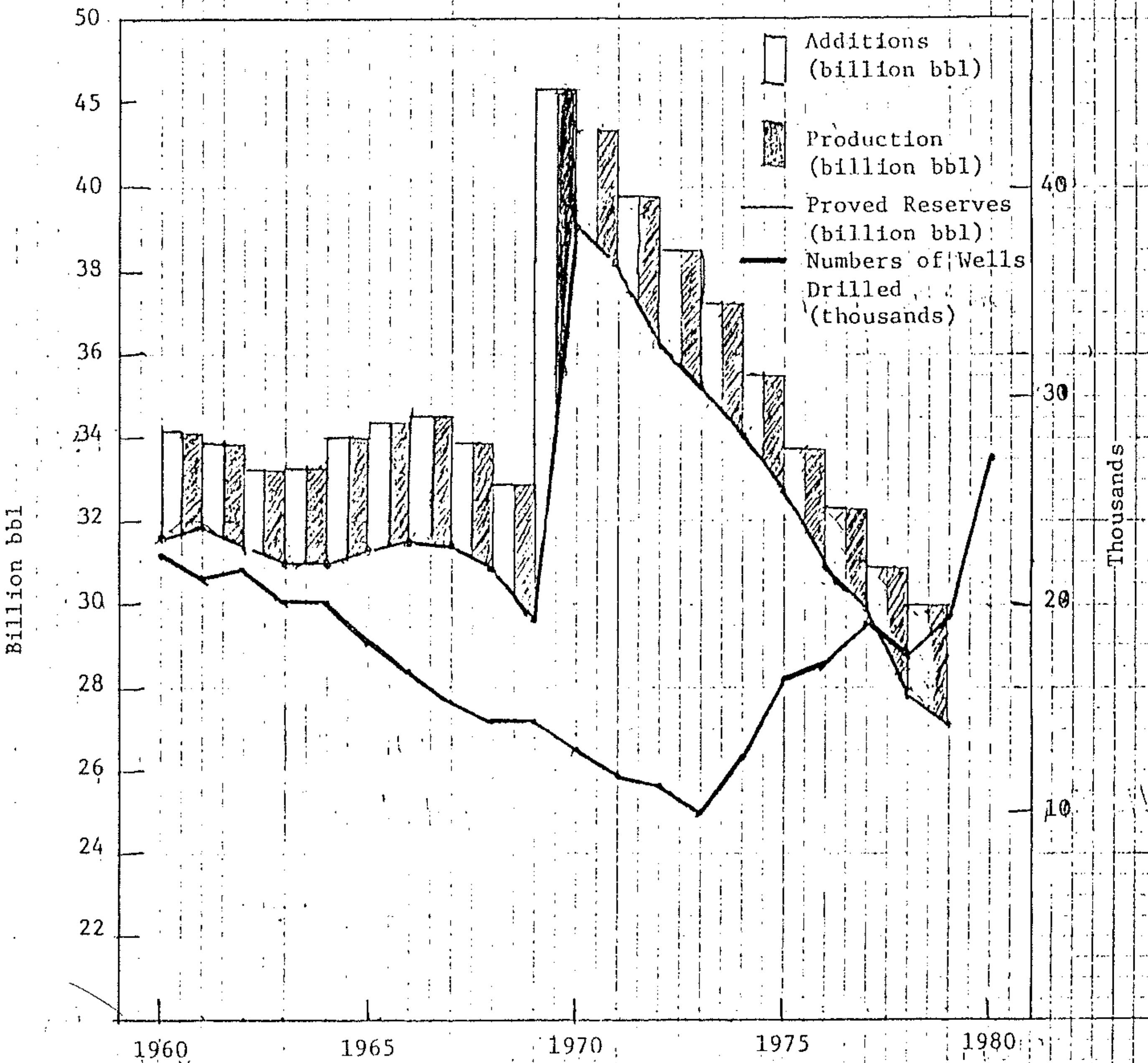


Figure 7. U.S. Crude Oil Historical Summary

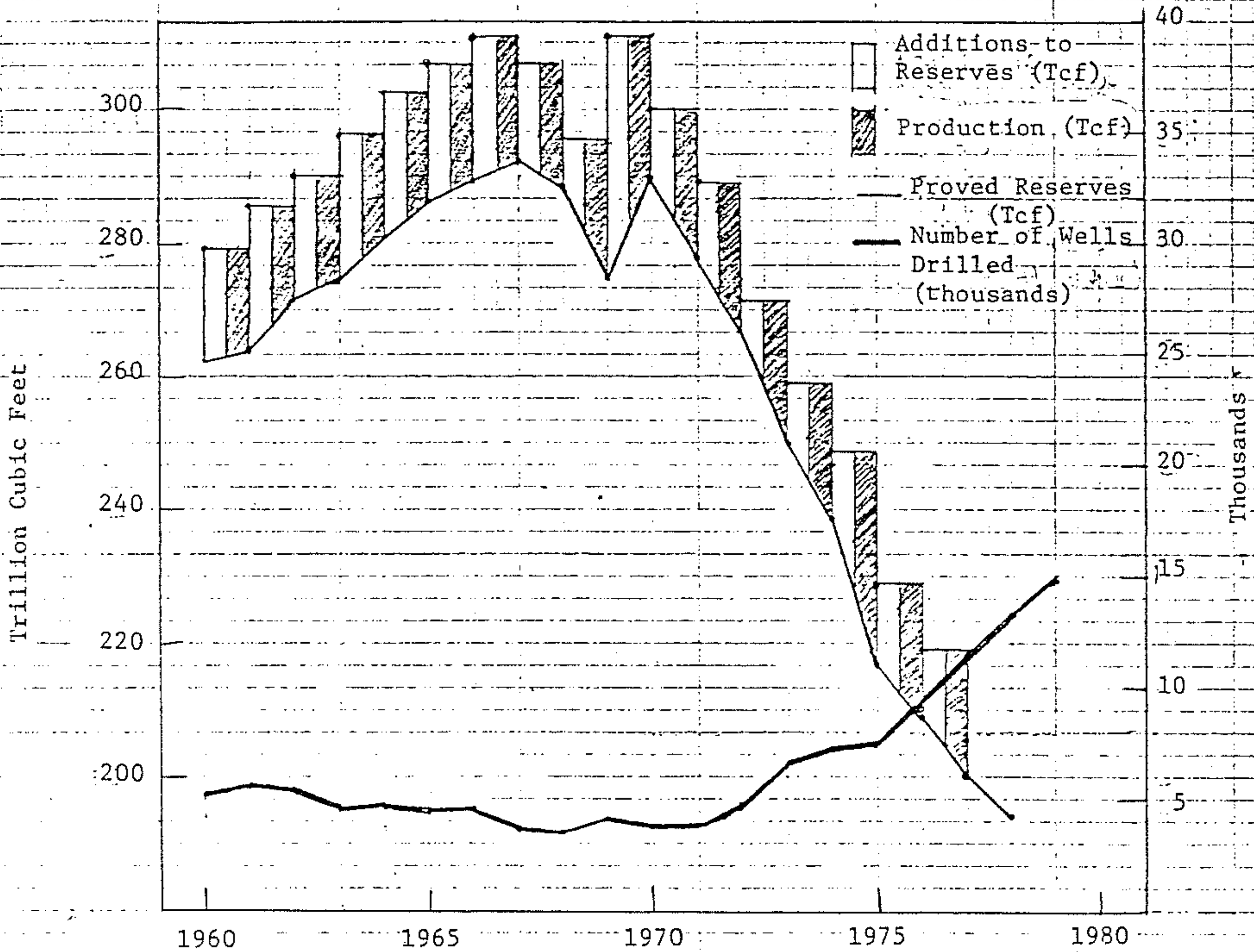


Figure 8. U.S. Natural Gas Historical Summary

revolution led to another doubling in the price of oil between late 1978 and early 1979. By now the combined incentive of the 1973-74 price increase and the 1978-79 Iranian revolution have increased drilling activity by a factor of three over its 1973 level and this year (1982) reserve additions may finally once again exceed production for both oil and natural gas.

V. PROJECTIONS WITH REAL MODELS

BROAD FINDINGS

The quantity of oil and natural gas that will be produced in the next 20 years depends significantly upon a number of factors that currently are uncertain. Uncertainty about the environment within which the oil and gas industry will operate--geological uncertainty, price uncertainty, and policy uncertainty--add to the uncertainty about the performance of the industry stemming from model data and structure. The range of projections from the models (Table 4) reflects the degree of our uncertainty about these factors (as well as the differences in the coverage of the several models). But, several key messages can be derived from analysis of the model results, given the scenario assumptions.

Qualitative Trends

Domestically produced oil and natural gas will remain a significant source of energy in the U.S. for the rest of the century. Under almost every scenario most of the models utilized project conventional oil and natural gas production of at least 25 quadrillion Btus per year through the

TABLE 4

RANGES OF CONVENTIONAL OIL AND GAS PRODUCTION PROJECTIONS FOR 1990

	Oil (MMBD)					Natural Gas (TCF)				
	Onshore	Offshore	Lower 48	Alaska	Total	Onshore	Offshore	Lower 48	Alaska	Total
AGA/TERA						6.10-10.00	4.67-6.38	11.24-16.38		
Epple/Hansen			2.98-3.49					12.57-15.75		
E/M/S			4.10-6.29							
FOSSIL2			5.90-7.10	2.00-2.60	8.00-9.70			14.10-15.70	1.70	15.80-17.40
Kim/Thompson*	0.88-1.45									
DFI/GEMS			3.71-11.03	1.20-2.40	5.10-12.22			18.93-25.06	0.91-1.34	19.91-25.97
LORENDAS	4.40-8.99	0.40-0.75	4.81-9.38	0.60-1.66	5.98-9.99	9.59-30.34	0.98-2.62	10.57-31.03	0.52-2.08	11.08-33.45
MIT/WOP			5.22-5.98	0.95	6.17-6.93					
MOGMS/AHS	5.84-9.79	1.21-2.00	7.55-11.80	1.69-2.70	8.74-14.50	10.71-16.15	2.20-3.97	13.88-20.13	1.17-1.46	15.08-21.57
Rice/Smith			7.65-10.70					14.53-33.82		
1977	6.74	1.04	7.78	0.46	8.24	14.70	4.27	18.97	0.19	19.16

*New-new oil only

1990's (compared with approximately 35 quadrillion Btus today).

Despite the uncertainty in expected production levels, no dramatic changes in total U.S. production of conventional oil and gas are expected during this period, the changes tend to be gradual rather than sudden. For example, observe the slow rate of change of the projections of conventional oil and gas production shown for the high price scenario in Figure 9 and 10, respectively.

The dramatic market changes that occurred during 1979 have already resulted in an effective world oil price (including the effect of the windfall profits tax) exceeding that implied for 1990 in the Reference scenario, making the High Price Scenario a better benchmark. Until about 1986 the oil price domestic producers see in the high price scenario after application of the windfall profits tax is less than the post-windfall profits tax they actually faced in 1981. By 1990 the oil price assumed in the high price scenario is about 15% higher than today's after windfall profits tax price, implying an average price increase rate over the decade of about 1.5%. Many feel that is a reasonable forecast, given current conditions in the world oil market.

To construct Figures 9 and 10, Alaskan production projections from the MOGSMS/AHS system are added to the projections of the several models that project lower-48 production only (Epple/Hansen, Erickson, AGA/TERA, Kim/Thompson, Rice/Smith); these composite projections are represented with dashed lines in the Figures. This seems reasonable because the pipeline capacity on Alaskan oil transport leads to similar results from the models that project Alaskan production (MOGSMS, DFI/GEMS, LORENDAS, and FOSSIL2).

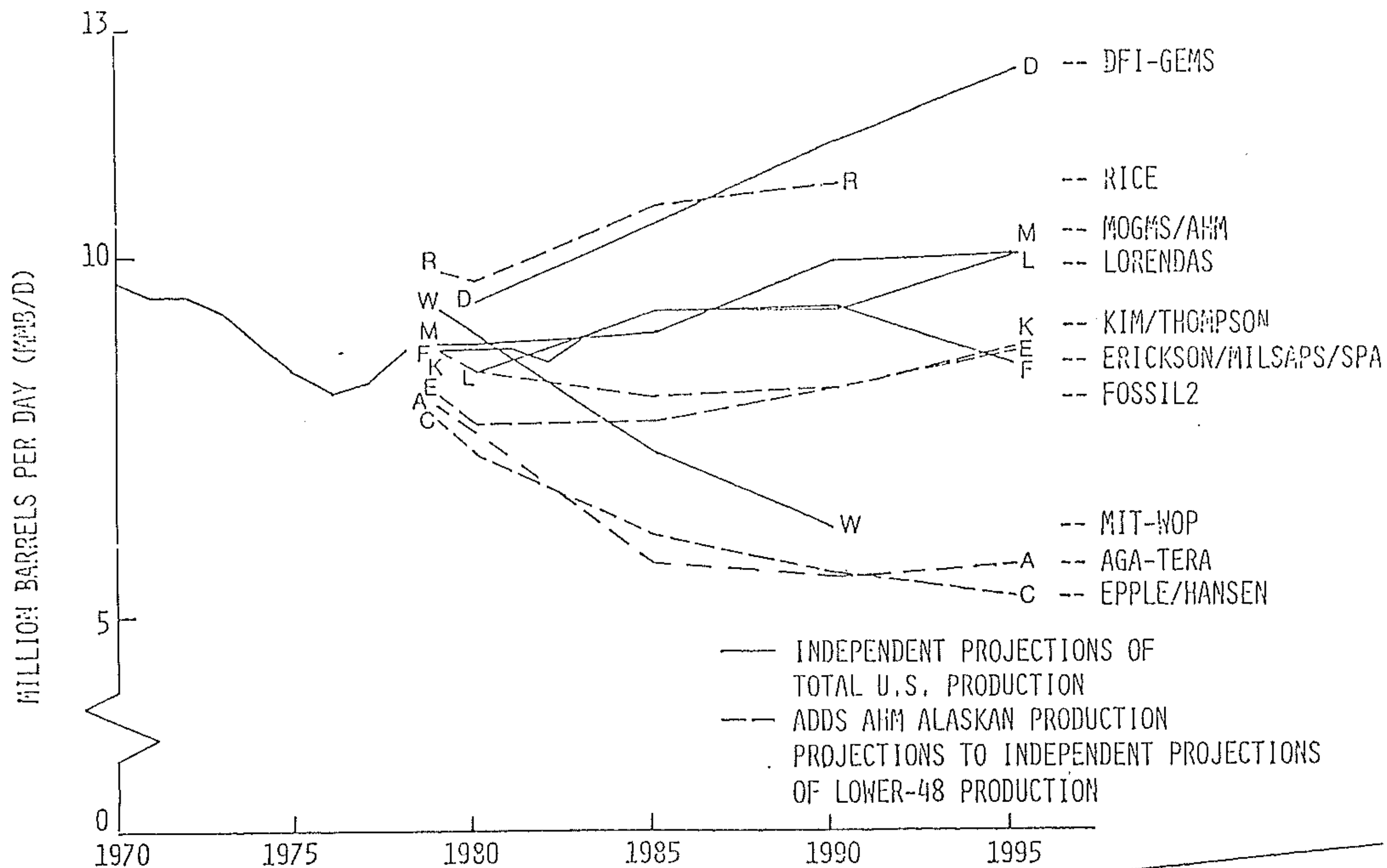


Figure 9. U.S. Total Crude Oil Production,* High Price Scenario

*Excludes NGL

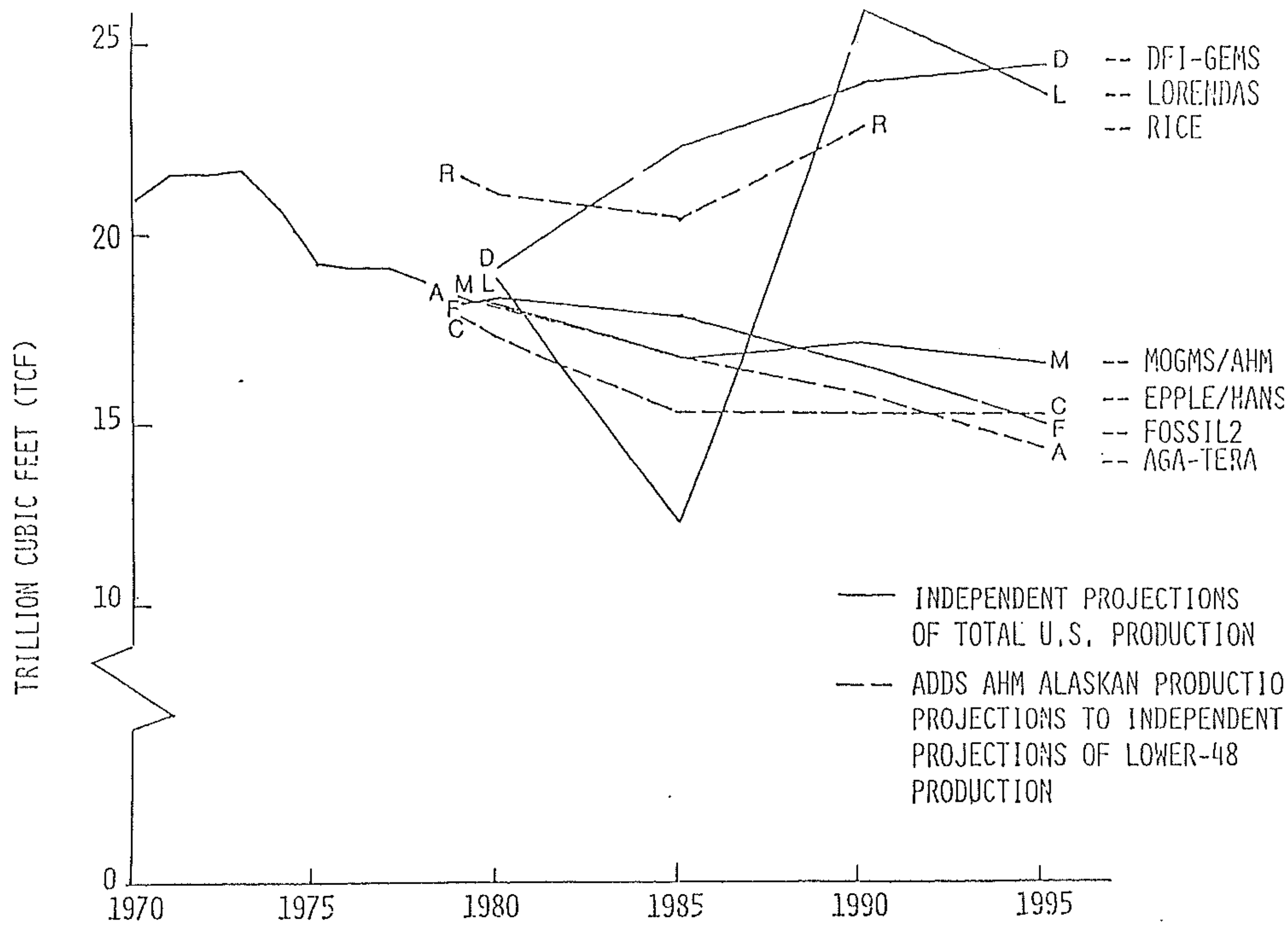


Figure 10: U.S. Total Natural Gas Production, High Price Scenario

Quantitative Estimates

The 1990 projections of oil production (which was 9 mmbd in 1978) from the alternative models in the high price case range from 5 to 11 mmbd, as illustrated in Figure 9, which also shows the corresponding oil price assumptions. However, enhanced oil recovery is excluded from the projections presented here and not included in most of the models. Oil production via enhanced oil recovery techniques might be sufficient to reverse any downward trend in production. In fact, the models that project enhanced oil recovery production (MOGMS and FOSSIL2) project 1-2 mmbd from that source by 1990 (Figure 11a). Under conditions of more favorable geology, the estimates of conventional production increase by about 2 mmbd. At the lower extreme, in a case with lower prices and less favorable geological assumptions, the 1990 conventional production estimates range from 3 to 9 mmbd.

The 1990 projections of conventional natural gas production (which was 19 tcf in 1979) from the alternative models range from 15 to 25 tcf in 1990 under the high price case, which also shows the corresponding gas price assumptions (see Figure 10). However, unconventional gas supplies which are excluded from the results presented here and not represented in most of the models might be sufficient to reverse any downward trend. In fact, the one model that considers unconventional sources of natural gas--FOSSIL2--projects an increase in total natural gas supply despite a significant decrease in supplies from conventional sources (Figure 11b). Even under the most favorable assumptions, the models generally still project that production of natural gas is unlikely to ever again reach its historic peak of 22.6 tcf. On the other hand, even under the most

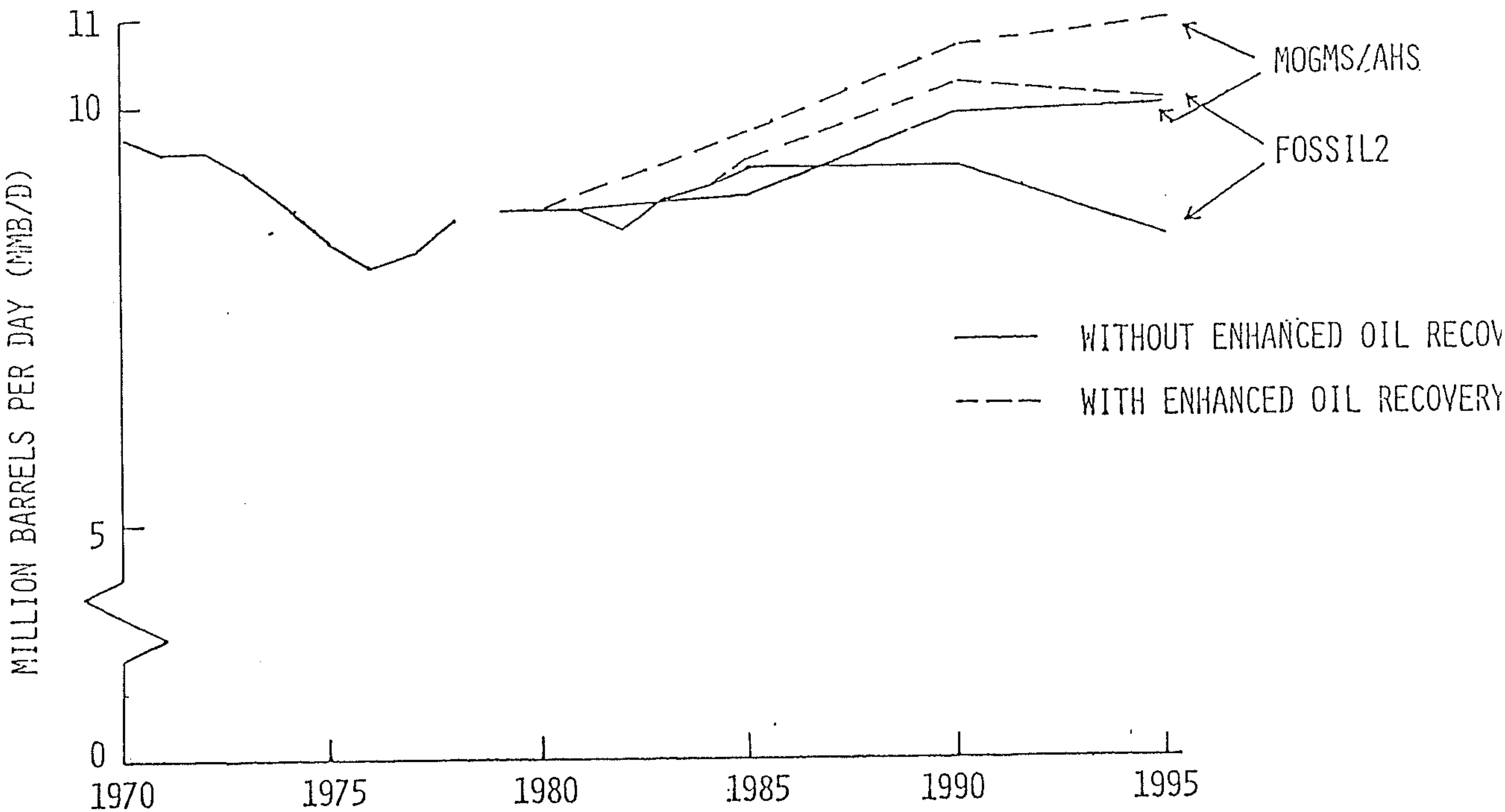


Figure 11(a). FOSSIL2 and MOGMS/AHM Enhanced Oil Recovery

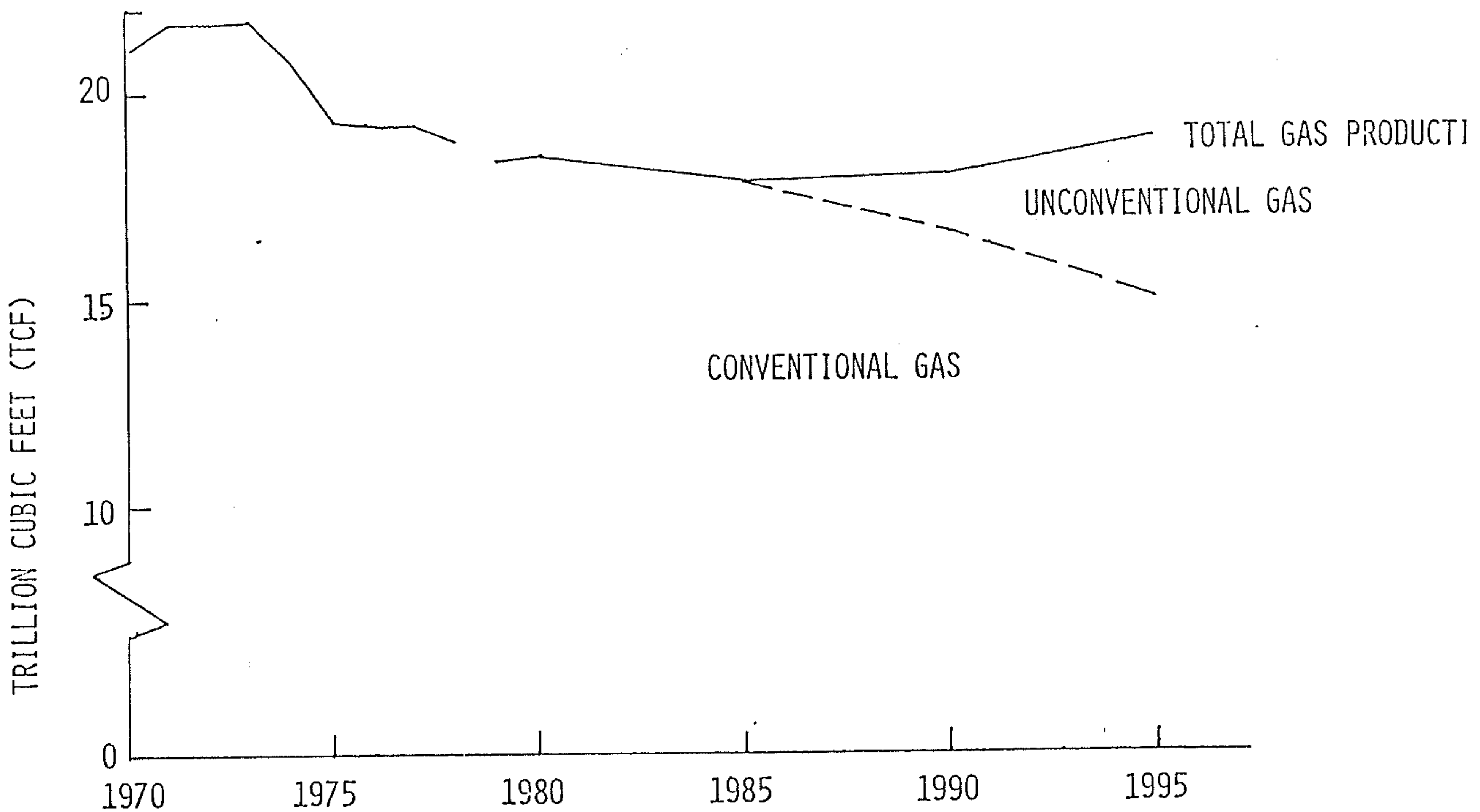


Figure 11(b). FOSSIL2 U.S. Total Gas Production High Price Scenario unfavorable cases, annual production of conventional gas is projected to be at least 13-14 tcf during this period. These broad findings indicate the direction and magnitude of the results, but several key factors must be examined in greater detail to understand the variations in projections between models and scenarios.

Examining Intermodel Differences

Despite the relative agreement about the broadest trends in the model results. Figures 9 and 10 show a wide disparity of projections of U.S. oil and gas supply through 1995. A wide variance is seen even in the first projection year (1979). especially in the case of oil, with the difference between the highest and lowest projections growing steadily over time. Why do such differences in projections of the aggregate behavior of the domestic oil and gas industry in response to common input assumptions about prices, resources and government policies occur?

Calibration Differences

Leaving aside the question of differing projections of long-run production for the moment, why are the projections for 1980 so disparate? A major reason seems to be that several credible sources of information about historical production and reserve additions differ substantially. What's more it is not possible to validate any one of the sources. For example, there is a .4 mmbl/day difference in 1977 crude oil production reported by two prominent sources of data, the Energy Information Administration and the American Petroleum Institute. Although of great interest, a review of current statistical series and their quality is not within the scope of the present study. The differing sources of data can explain some of the variation in the early years projections but it seems insufficient to explain all. Other potential explanations include: (1) differing opinions as to the flexibility in production from existing reserves; and (2) differing or misinterpretations of the several conceptual definitions used to describe the quantity of reserves available for production. Given these differences in initial conditions, why do the projections of oil and gas supply continue to diverge over the next 15 years.

Differences in Assumptions About Industry Responsiveness

In order to analyze the models and the issues we now restrict ourselves to comparing the cumulative production and reserves added projections from the various models for the next two decades. The variance in the forecasts among the several models for individual scenarios and among the several scenarios for the individual models is too great to make comparison of year by year figures a meaningful enterprise. Cumulative production and cumulative reserves represent the largest common denominator for the reports provided by the models. (Unfortunately, one model--DFI/GEMS--is already excluded from the discussion; it does not calculate reserve additions.)

We also limit ourselves to conventional oil and gas production and reserves for the lower 48 states. Several of the models do not include Alaska. In order to increase the richness of the comparison, we restrict our attention to projections for the lower 48 states. Since the Kim/Thompson model is only for onshore production from newly discovered reserves, it too is eliminated at this stage. Like the DFI/GEMS model, it is discussed only briefly near the end of this summary. We focus first on oil production because the models are more consistent in gas supply forecasting; lower 48 gas supply is discussed subsequently.

A simple model of the supply process proposed by James Sweeney, is useful in analyzing the forecasts of the models. In this models it is assumed that a constant fraction of the undiscovered resource base is discovered each year, G%, and that a constant fraction, R%, of currently held reserves are produced each year.[3] These assumptions are reasonably consistent with historical experience.

Conventional Lower-48 Crude Oil Production

Figure 12 shows the relationship between cumulative production and cumulative reserve additions of conventional lower-48 crude oil for several alternative values of R and G, given the study's reference resource base assumptions. The structure of the simple model is such that a unique implicit value of G and R can be fit to the actual cumulative production and reserve additional projections produced by the models. While such simplistic curve fitting ignores the structural inadequacies of the simple

[3] Under these assumptions:

(1) production at time t from proved reserves at time 0, $P_E(t)$ is;

$$P_E(t) = S_0 R e^{-Rt},$$

Where S_0 is the initial level of proved reserves, and

(2) production at time t from new reserve additions between time 0 and time t is;

$$P_N(t) = \int_{s=0}^{t} U_0 G e^{-Gs} R e^{-R(t-s)} ds.$$

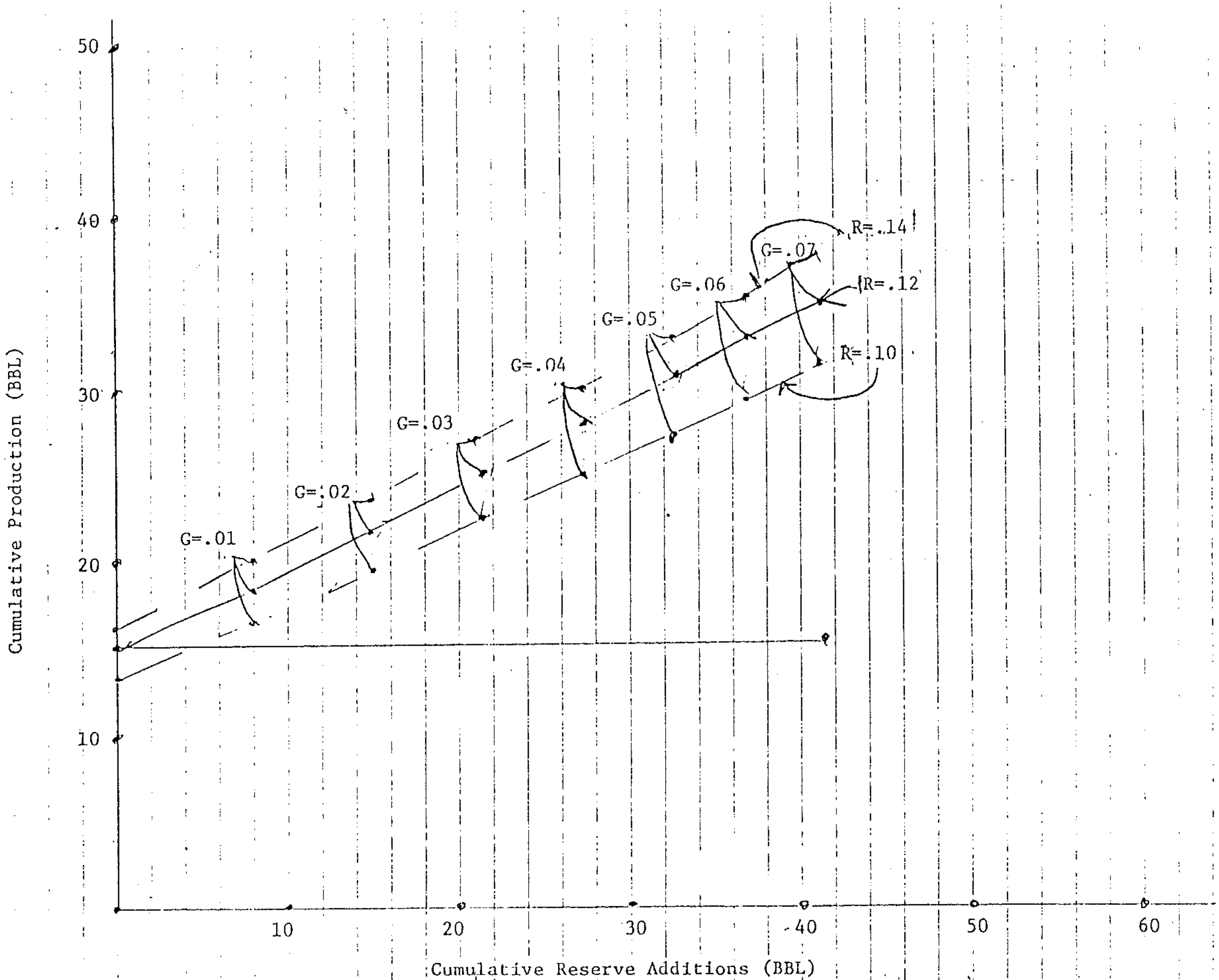


Figure 12. Illustrative Results from the Simple Model for Conventional Lower-48 Oil

model, when combined with information on the actual time profiles of G and R projected by the models, they provide an illuminating perspective on the differences in model results. Figure 13 is a plot of cumulative production versus cumulative reserve additions of conventional lower 48 crude oil during the 1980s. Also shown are results from the simple model, assuming the production to reserves ratio (R) remains at its historically observed average value of 13%, and the ultimate remaining resource potential is the USGS 725 mean value of 77 billion barrels. Successively higher assumptions about the value of the ratio of discoveries to undiscovered resources, G, trace out the diagonal line shown in the Figure. Cumulative production of at least 15.2 billion barrels averaging 3.8 mmbd for the period, will result from currently held reserves (approximately 20 billion barrels recoverable). Beyond this point additional conventional production results from new discoveries (cumulative reserve additions).

Under the "high price" assumption the results from the models are reasonably consistent with those from the simple model. EPPLE/HANSON and AGA-TERA are consistent with a G of about 1%; MIT-WOP and ERICKSON/MILSAPS/SPANN (E/M/S) with 2 to 3%; FOSSIL2 and LORENDAS with 3 to 4%, and EIA-OGM and RICE with a discovery rate, G, of 4 to 5%. The 1950s were consistent with a G of 2.3%, the 1960s with a G of 2.4%, and the 1970s with a G of 2.0%. The average of these is 2.2%. The point marked M on Figure 13 is the cumulative reserve additions (16.8 BB) and cumulative production (19.9 BB) consistent with that value of G. If we instead assume that the remaining resource potential is 139 bbl, the high resource assumption, the 50's were consistent with a G of 1.6%, the 60's with a G of 1.5%, and the 70's with a G of 1.2%. The average of these

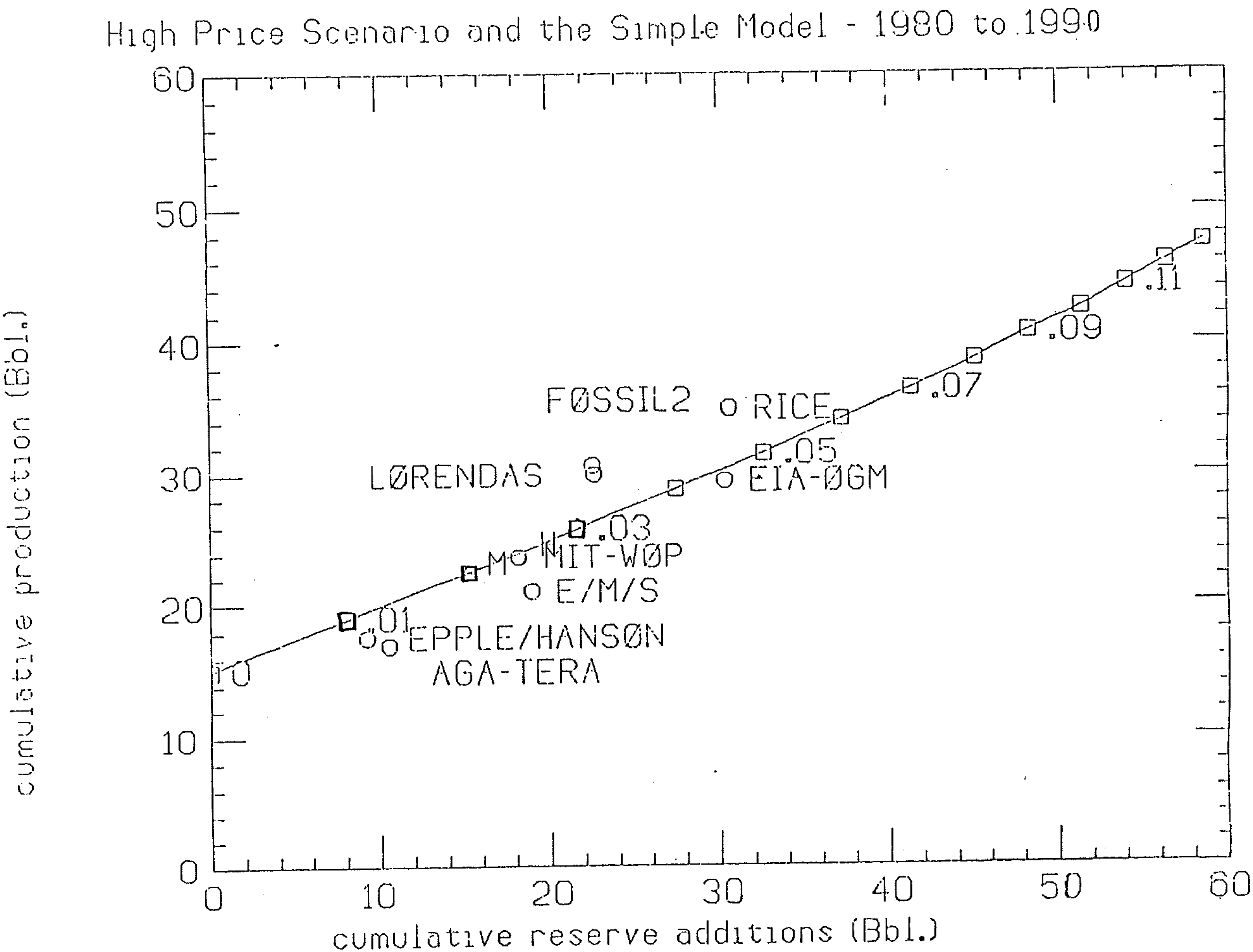

High Price Scenario and the Simple Model - 1980 to 1990
cumulative production (Bbl.)
cumulative reserve additions (Bbl.)
0
10
20
30
40
50
60
FØSSIL2
RICE
LØRENDAS
EIA-ØGM
MIT-WØP
E/M/S
EPPLE/HANSØN
AGA-TERA
.01
.03
.05
.07
.09
.11
0

Figure 13

is 1.4%. There is another diagonal line (not shown) with different G's for the assumption of high resources. Along this line, the point of cumulative reserves and production for G equal to 1.4% is shown marked as H (20 bbl reserves and 24.7 bbl production).

The projections from the simple model provide a benchmark against which the results of the models can be compared. These cumulative reserve addition and production estimates should be thought of as something like extrapolations of the status quo. Deviations from these forecasts represent deviations from the status quo--not necessarily unreasonable deviations but at variance with historical experience all the same. Thus AGA-TERA and EPPLE/HANSON forecast, assuming prices are as in the high price scenario and that the undiscovered resource base is as in USGS 725, that we will fall considerably short in reserve additions and production of what might be naively projected. MIT-WOP and E/M/S forecast, under the same assumptions, about what might be expected. FOSSIL2, LORENDAS and especially EIA-OGM and RICE anticipate larger reserves and production than what a simplistic trend extrapolation analysis might suggest.

Conventional Lower-48 Natural Gas Production

Cumulative production and cumulative reserve additions of natural gas in the lower-48 states over the next decade can also be plotted and compared with results from the simple model. Results from only six models are included in the comparison shown in Figure 14; WOP and E/M/S only consider oil; DFI/GEMS doesn't track reserve additions and KIM/THOMPSON only considers new onshore discoveries.

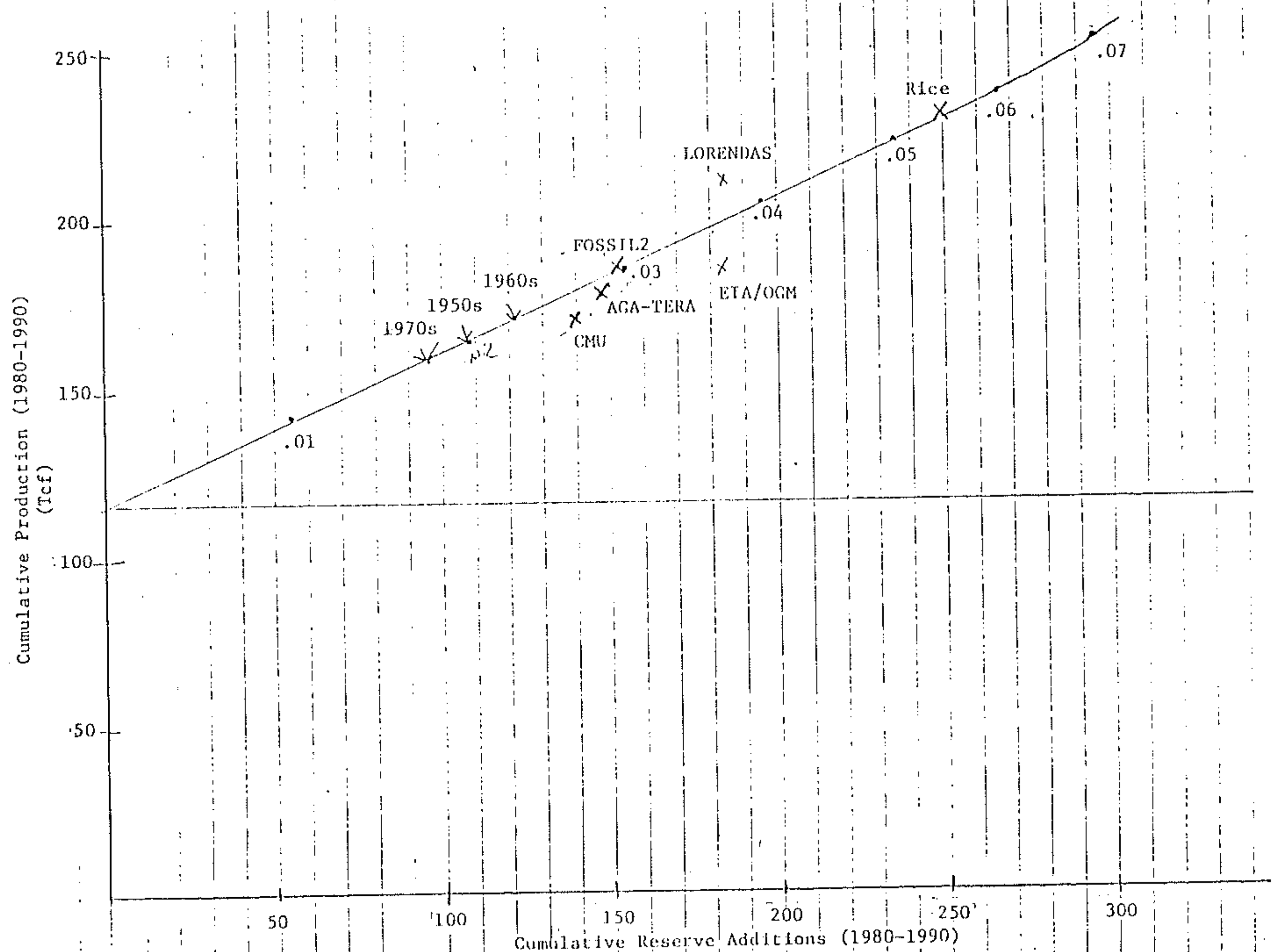


Figure 14. Relationship Between Cumulative Reserve Additions and Cumulative Production of Natural Gas During the 1980s

A much narrower range of values for the implicit discovery rate (G) characterize the models' results for gas than for oil, reflecting the greater consensus of views about the rate of natural gas production over the next 10 years. Again the RICE model, which employs much higher production and reserve figures for 1978 implies a G of .055 which is much higher than the .027 to .037 range implied by the other five models. Interestingly, this entire range exceeds the .018 to .023 range experienced during the 50's, 60's, and 70's although in some cases not by much. On the average, though, the projected discovery rates are about 50% higher than those experienced during the past three decades. In the pages that follow we investigate how these results depend on the assumptions made about major uncertainties concerning the environment within which the domestic oil and gas supply industry will operate and policies employed by the federal government.

VI. SOME KEY FACTORS INFLUENCING OIL AND GAS SUPPLY

Many factors influence oil and gas supply; some such as the size of the undiscovered resource base cannot be influenced by policy actions; others, however, are subject to direct control (price controls, tax laws, lease offer rates) or are indirectly influenced by policy actions (world oil price, natural gas market prices, discount rates). In the present study, all three classes of factors were studied.

An investigation of the effects of variations in some of the key factors influencing oil and gas production and reserve additions serves two interrelated purposes. First, since our ability to forecast values for these parameters is limited, an investigation of the effects of plausible variations in them helps provide some appreciation for the robustness of our general conclusions. Second, comparisons of the responses of the individual models to variations in key input parameters can help explain the intermodel differences observed previously. For example, a model that displays little response to price changes might be expected to project lower production levels at any price than one that displays a large response to price changes simply because of the large price increases that have occurred since the data used to estimate the model parameters was generated.

The study design includes many parameter variations. However, since a large number of these variations involve changes in world oil price or resource base assumptions, most of the comparisons considered here are grouped accordingly.

WORLD OIL PRICE VARIATIONS

Extreme uncertainty characterizes future world oil prices and the role of U.S. policies in moderating price increases is not well understood. Figure 15 shows the changes in conventional lower-48 oil and gas production as the price of world oil is increased from its reference to its high level. Recall that the dramatic increase in world oil prices since the inception of the study prompted us to use results from the high price scenario to draw the broad conclusions discussed previously.

The models generally project that price increases will increase production. The effect of the higher prices shows up quite gradually though, increasing from a few percent in the early 1980s to 20 or more

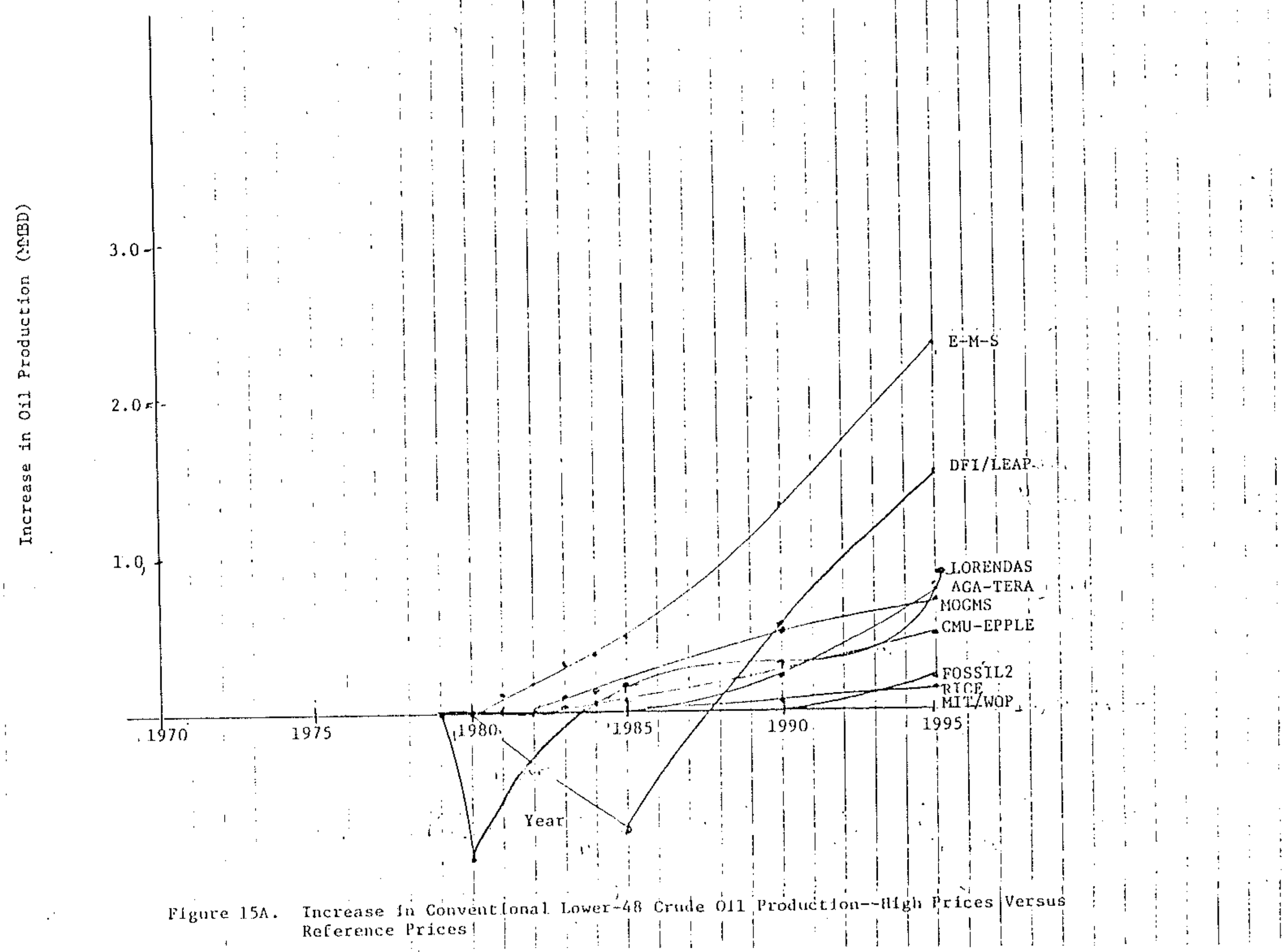


Figure 15A. Increase in Conventional Lower-48 Crude Oil Production--High Prices Versus Reference Prices percent by the end of the century. There are two explanations for this result. First, because the price assumptions are specified in percentage terms, the difference in price levels grows over time. Second, and more importantly, there are significant lags between the realization of the higher prices, increases in drilling, increases in reserve additions resulting from the increased drilling, and then, finally, increases in production resulting from those reserve addition increases.

Although the models generally indicate that price increases will increase production, increases in the expected rate of future price increase leads to ambiguous results depending on the nature of the economic incentives incorporated in the model. Some models project increases in mid-range supply, to take immediate advantage of the higher prices. In the models that assume perfect foresight and that perfectly competitive firms can shift production over time to maximize profits (DFI/GEMS and LORENDAS), however, increases in the price growth rate may lead to mid-range production decreases, so that reserves can be held in anticipation of future price increases. For example, in the reference scenario the price of natural gas increases only gradually to the Btu equivalent oil price in 1986, but in the high price scenario, the jump is about $1.00/MCF. In the LORENDAS model this creates an incentive to produce less before 1986 in the high price scenario than in the reference scenario in anticipation of even higher prices after 1986. Other models project production decreases in oil or in gas in response to increasing prices of both due to greater profitability and, hence, production of the other resource (e.g., FOSSIL2 and EPPLE/HANSEN in Figure 15b).

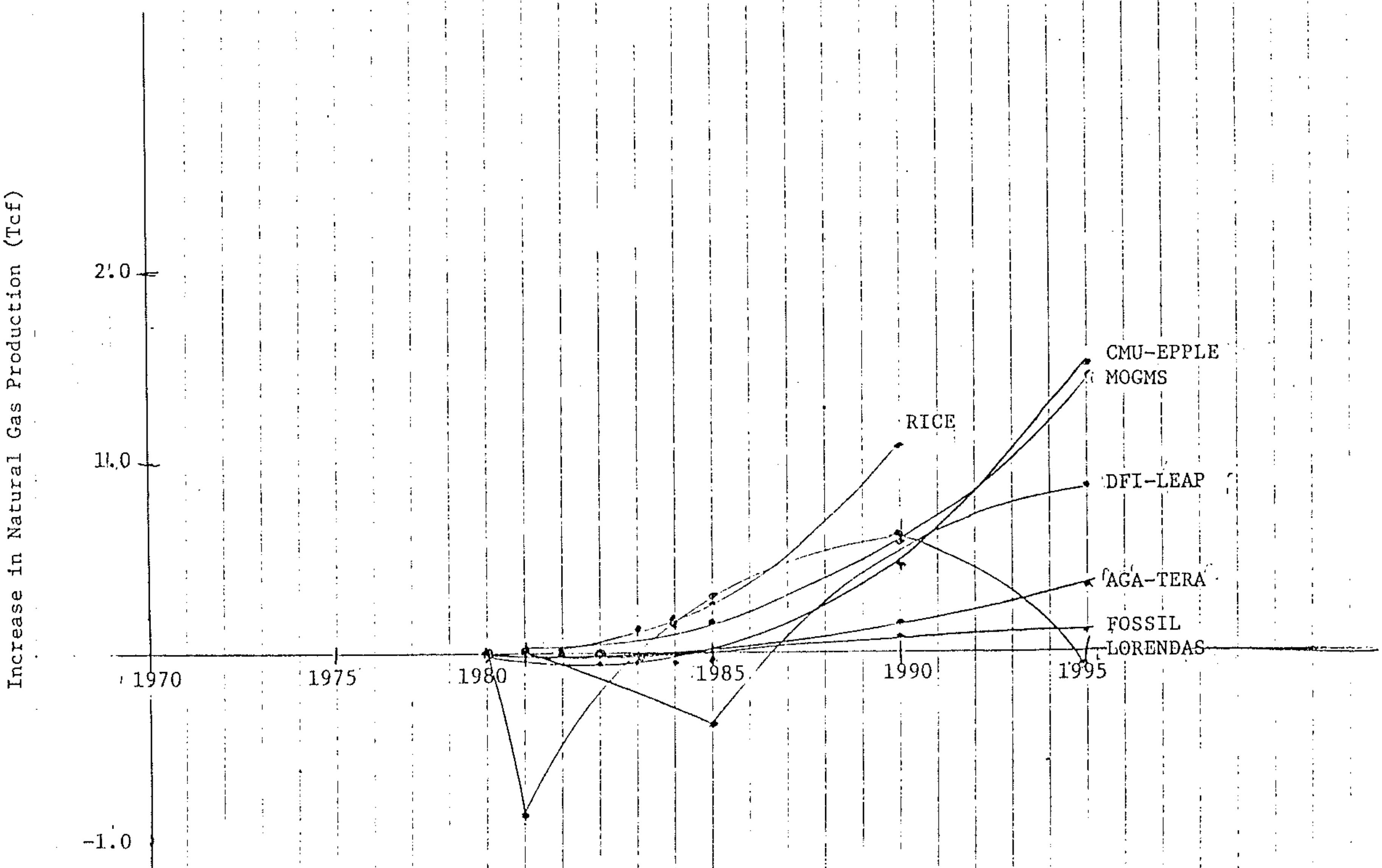


Figure 15B. Increase in Conventional Lower-48 Natural Gas Production--High Prices Versus Reference Prices

The sensitivity of the models' cumulative reserve addition and discovery rates to changes in price are illustrated in Table 4. Interestingly, the variation among the models' forecasts is more substantial than the variations due to price variations. For oil the AGA-TERA, EPPLE/HANSEN, E/M/S, and MIT/WOP's forecasts at the highest prices are lower than FOSSIL2, EIA-OGM, and RICE's at their lowest in the short term, 1980-1990. In the longer term, 1990-2000, FOSSIL2's lowest forecast is still higher than AGA-TERA and EPPLE/HANSEN's highest. Similar behavior is observed for the natural gas results, although the dispersion in projections from the models is considerably less than for the oil results.

In general, increased prices evoke increased reserves and production. (Remember that the high price forecast is actually the closest to the last three years' experience; so perhaps the most interesting price response is the one to prices above and beyond the high price scenario).

Oil Projection Comparison

As shown in the left-hand-side of Table 4, E/M/S, RICE and EIA-OGM maintain that the increases in supply are substantial and fairly uniform in the range of prices investigated. This suggests that the industry is not substantially limited by its ability to grow in response to increased incentives. AGA-TERA's forecast suggests that the lower price path spells the end to the oil industry, but that higher prices have a large, positive impact. Both FOSSIL2 and MIT-WOP maintain that the amount of oil found and produced is virtually independent of the price of oil. In fact, MIT-WOP does this by assumption; exploration, reserve additions, and production are independent of price in this model. LORENDAS projects that between current prices and those assumed in the high price scenario, the industry is constrained by its ability to grow (that is, in that price range the industry is operating far up the short-run marginal cost curve shown in Figure 6).

The EPPLE/HANSEN model estimates that as prices are increased, oil reserves and production decrease slightly, a counterintuitive result. This happens because: (1) in the EPPLE/HANSEN model, the costs of exploration and development are dependent upon the price of oil and, (2) because in this model the higher prices provide more incentive to explore for gas than for oil. These disincentives increase so rapidly that the net effect of higher prices is to decrease the incentive to explore for oil. Although quite likely overstated here, the dampening effects of increased costs with increased prices as recognized by the EPPLE/HANSEN model certainly do play a major role in the determination of exploration activity and therefore reserve additions and production.

Gas Projection Comparison

The right-hand side of Table 5 shows the comparison of cumulative reserve additions and discovery rates for natural gas. Again there is a wide range of price sensitivities. The price responses are generally less for gas than for oil, but this may be due in part to the fact that price regulations limit the wellhead price of natural gas to identical maximum permissible levels in the reference and high price scenarios through 1986. Thus, even the most price responsive models show only 2 or 3 tcf of additional cumulative gas production through 1990. But, in many of the

TABLE 5

PRICE SENSITIVITIES

MODEL	OIL: RESERVE ADDITIONS-BILLION BARRELS DISCOVERY RATE - (%)						NATURAL GAS: RESERVE ADDITIONS-TRILLION CUBIC FEET DISCOVERY RATE - (%)					
	1980-1990 PRICE LEVEL			1900-2000 PRICE LEVEL			1980-1990 PRICE LEVEL			1990-2000 PRICE LEVEL		
	LOW	REFERENCE	HIGH	LOW	REFERENCE	HIGH	LOW	REFERENCE	HIGH	LOW	REFERENCE	HIGH
AGA-TERA	6 (.7)	6 (.7)	11 (1.3)	3 (.4)	4 (.6)	15 (2.5)	144 (2.8)	143 (2.7)	149 (3.2)	78 (1.9)	88 (2.2)	86 (2.2)
EPPLE/HANSEN	9 (1.2)	9 (1.2)	9 (1.2)	9 (1.5)	8 (1.3)	6 (1.0)	131 (2.5)	134 (2.5)	140 (2.7)	105 (2.6)	125 (3.3)	165 (4.7)
E/M/S	15 (1.9)	17 (2.2)	19 (2.6)	12 (2.1)	16 (3.1)	22 (4.7)	-	-	-	-	-	-
FOSSIL2	22 (3.0)	22 (3.0)	23 (3.1)	15 (3.2)	17 (3.7)	18 (4.0)	148 (2.9)	148 (2.9)	149 (3.0)	113 (3.0)	112 (3.0)	112 (3.0)
LORENDAS	13 (1.7)	22 (3.1)	23 (3.2)	2 (.3)	17 (3.8)	26 (6.5)	147 (2.8)	163 (3.2)	176 (3.5)	18 (.4)	146 (4.1)	196 (6.7)
MIT-WOP	18 (2.4)	18 (2.4)	18 (2.4)	-	-	-	-	-	-	-	-	-
EIA-MOGMS	24 (3.5)	27 (3.9)	30 (4.5)	-	-	-	153 (3.0)	185 (3.7)	188 (3.7)			
RICE	27 (4.0)	29 (4.3)	31 (4.6)	-	-	-	202 (4.2)	229 (4.9)	247 (5.4)	-	-	-

models the higher prices do eventually result in more gas supply. From 1991-1995 average lower-48 conventional gas production projections from the Epple-Hansen, LORENDAS, and EIA/OGM models are up 1-2 tcf per year (see Figure 15b). Additionally, although projections from the RICE model only go out through 1990, the significant increase in gas reserves by then in response to higher prices is consistent with greater production during the 1990s as well. On the other hand, the FOSSIL2 and AGA-TERA systems show very little response of gas discoveries or production to the higher prices.

RESOURCE BASE VARIATIONS

Central to the supply projections are estimates of the undiscovered resource base. The impacts of doubling the assumed size of the undiscovered resource base on crude oil production projections vary from 2% to 20% in 1985 but grow to a 10% to 40% range in 1995 (Figure 16). Similarly, the impact on natural gas projections range from 0% to 35% in 1985 but grow to 15% to 50% in 1995. The slow response is explained by the quantitative dominance of presently existing reserves in early years and of new reserves in later years. To facilitate the model comparison and comparison of the models' projections with the historical experience it is again useful to compare cumulative reserve addition projections by decade.

Oil Projections Comparison

The left-hand side of Table 6 shows the cumulative reserve addition and discovery rate comparisons for conventional lower-48 crude oil as the resource base assumption is increased. Again, the variations among the models is greater than the variation among the scenarios. As a general

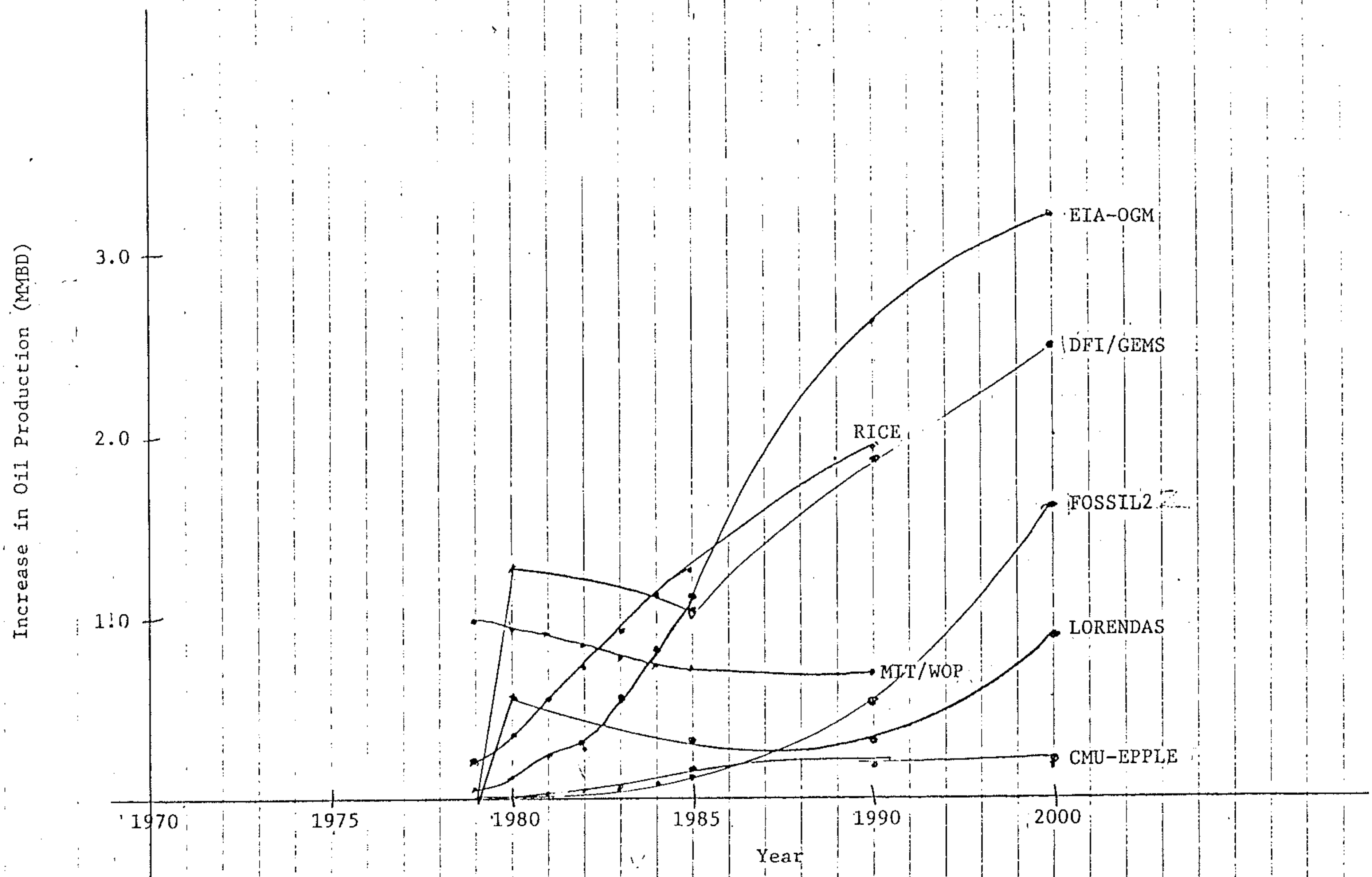


Figure 16A. Increase in Conventional Lower-48 Crude Oil Production--High Versus Reference Resources

TABLE 6

RESOURCE SENSITIVITIES

	OIL RESERVE ADDITIONS-BILLION BARRELS DISCOVERY RATE - (%)						NATURAL GAS RESERVE ADDITIONS-TRILLION CUBIC FEET DISCOVERY RATE - (%)					
	1980-1990			1990-2000			1980-1990			1990-2000		
	RESOURCE LEVEL			RESOURCE LEVEL			RESOURCE LEVEL			RESOURCE LEVEL		
MODEL	LOW	REFERENCE	HIGH	LOW	REFERENCE	HIGH	LOW	REFERENCE	HIGH	LOW	REFERENCE	HIGH
AGA-TERA	-	11 (1.3)	12 (.8)	-	4 (.6)	9 (.7)	-	143 (2.7)	147 (1.3)	-	88 (2.2)	98 (1.0)
EPPLE/HANSEN	-	9 (1.2)	10 (.7)	-	8 (1.3)	7 (.6)	-	134 (2.5)	156 (1.4)	-	125 (3.3)	193 (2.1)
E/M/S	-	19 (2.6)	-	-	16 (3.1)	-	-	-	-	-	-	-
FOSSIL2	-	23 (3.1)	24 (1.7)	-	17 (3.7)	23 (2.3)	-	148 (2.9)	156 (1.4)	-	112 (3.0)	178 (1.9)
LORENDAS	-	23 (3.2)	26 (1.9)	-	17 (3.8)	41 (4.6)	-	163 (3.2)	223 (2.1)	-	146 (4.1)	278 (3.5)
MIT-WOP	-	18 (2.4)	21 (1.5)	-	-	-	-	-	-	-	-	-
EIA-MOGMS	-	30 (4.5)	43 (3.4)	-	-	-	-	185 (3.7)	254 (2.4)	-	-	-
RICE	-	31 (4.6)	43 (3.4)	-	-	-	-	229 (4.9)	468 (5.0)	-	-	-

rule, however. the greater the remaining resources, the greater the reserve additions (and production).

Projections from the AGA-TERA, Epple/Hansen, and FOSSIL2 models show little response to the factor of two increase in undiscovered resources included in the High Resources scenario. Alternatively, MIT-WOP, LORENDAS, RICE and EIA-OGM project considerable sensitivity with 1-2 MMBD more production during the 1980s and 3-4 MMBD during the 1990s (see Figure 16a).

Of course, with more resources ultimately to be found, the discovery rates (G) for the simple analysis must be recalculated. As shown in Table 5 the implied historical value is once again higher than the value projected for the next decades by the AGA-TERA and EPPLE-HANSEN models; about the same as that projected by the LORENDAS and FOSSIL2 models; and much lower than the rate projected by the RICE and EIA-OGM systems.

Natural Gas Projection Comparisons

The cumulative reserve addition and discovery rate projections for natural gas are compared in the right-hand portion of Table 6. Here again there are a wide diversity of projections of the responsiveness of production and reserve additions to alternative assumptions about the size of the undiscovered resource base. In this case, however, even the least responsive models, Epple-Hansen, FOSSIL2, and AGA-TERA project an extra 1 to 2 tcf of production per year through the end of the decade in response to a doubling of the undiscovered resource base (see Figure 16b). The projected increases from the LORENDAS (6 tcf), EIA-OGM (4 tcf), RICE (8 tcf) models on the other hand show a substantially greater increase in average annual production in response to the higher resource base assumption.

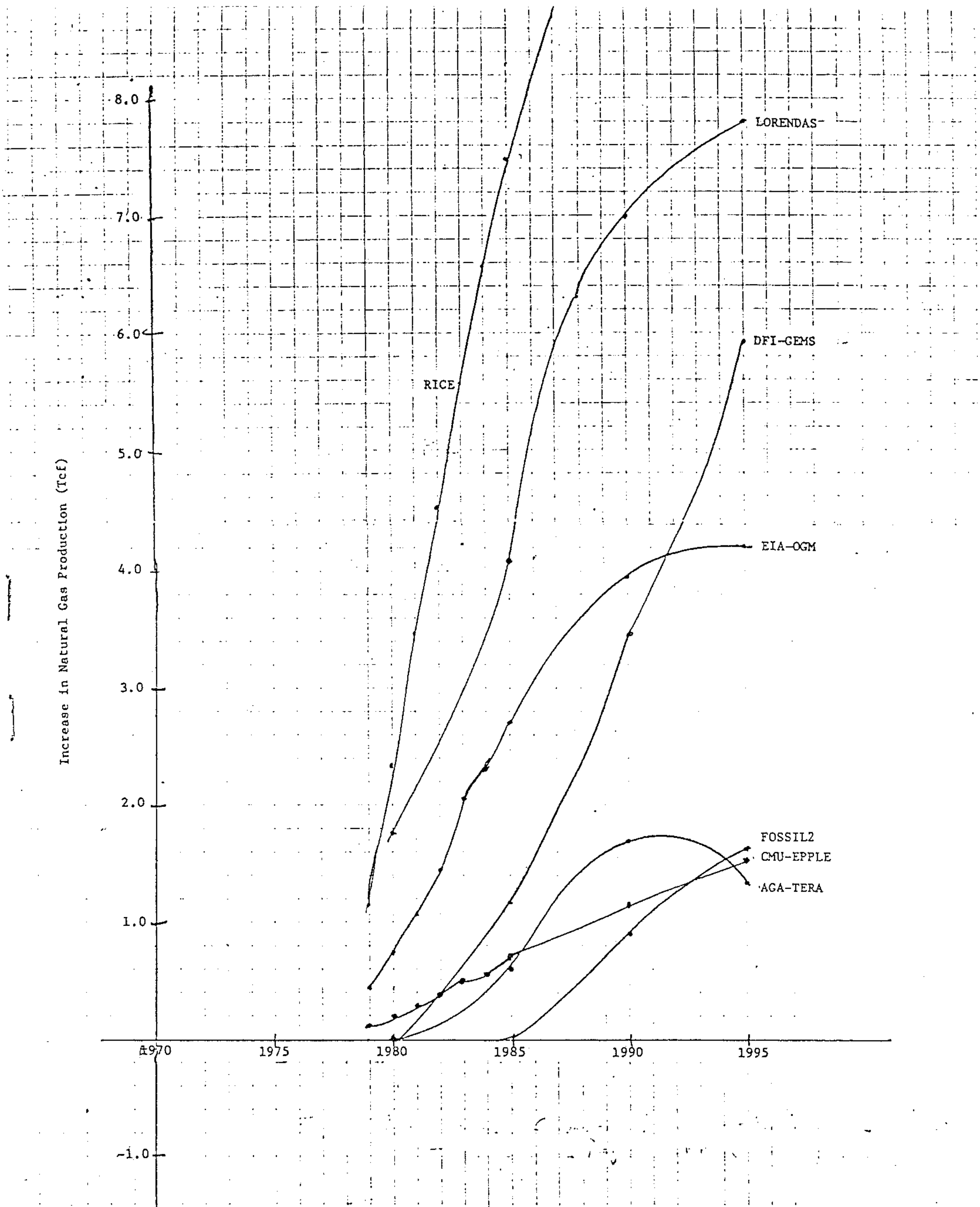


Figure 16B. Increase in Conventional Lower-48 Natural Gas Production--High Versus Reference Resources

Price controls by reducing the production of oil imply that additional resources will be available to be produced at a later date, Figure 17. To some extent, the issue to be examined is _when_ oil and gas will be produced rather than _how much_ in the aggregate will be produced. For example, price controls which create expectations of future discontinuous price jumps create incentives for even perfectly competitive firms or land owners to not explore for, develop, and produce reserves until after the price discontinuity. Whether these incentives lead to corresponding actions is open to debate.

Offshore Leasing Rates

Under direct control of the U.S. government is the rate at which federal lands are made available for lease. Current decisions on leasing rates significantly influence future production quantities through influencing reserve additions. For example, halving the federal offshore leasing rate reduces natural gas production by .2 to 1.2 TCF in 1985 and .3 to 1.0 TCF in 1995 (Figure 18). Corresponding reductions for oil production are .1 to .3 MMBD in 1985 and .1 to .7 MMBD in 1995.

Tax Regulations

While it is impossible to use the aggregate models to examine fine issues in tax treatment of oil production, broader issues can be addressed. Elimination of (1) the percentage depletion allowance, (2) provisions for expressing of intangible drilling expenses, and (3) the investment tax credit leads to reductions in oil and gas supply by 0% to 15% and 5% to 30% in 1985 and 1995, respectively (Figure 19).

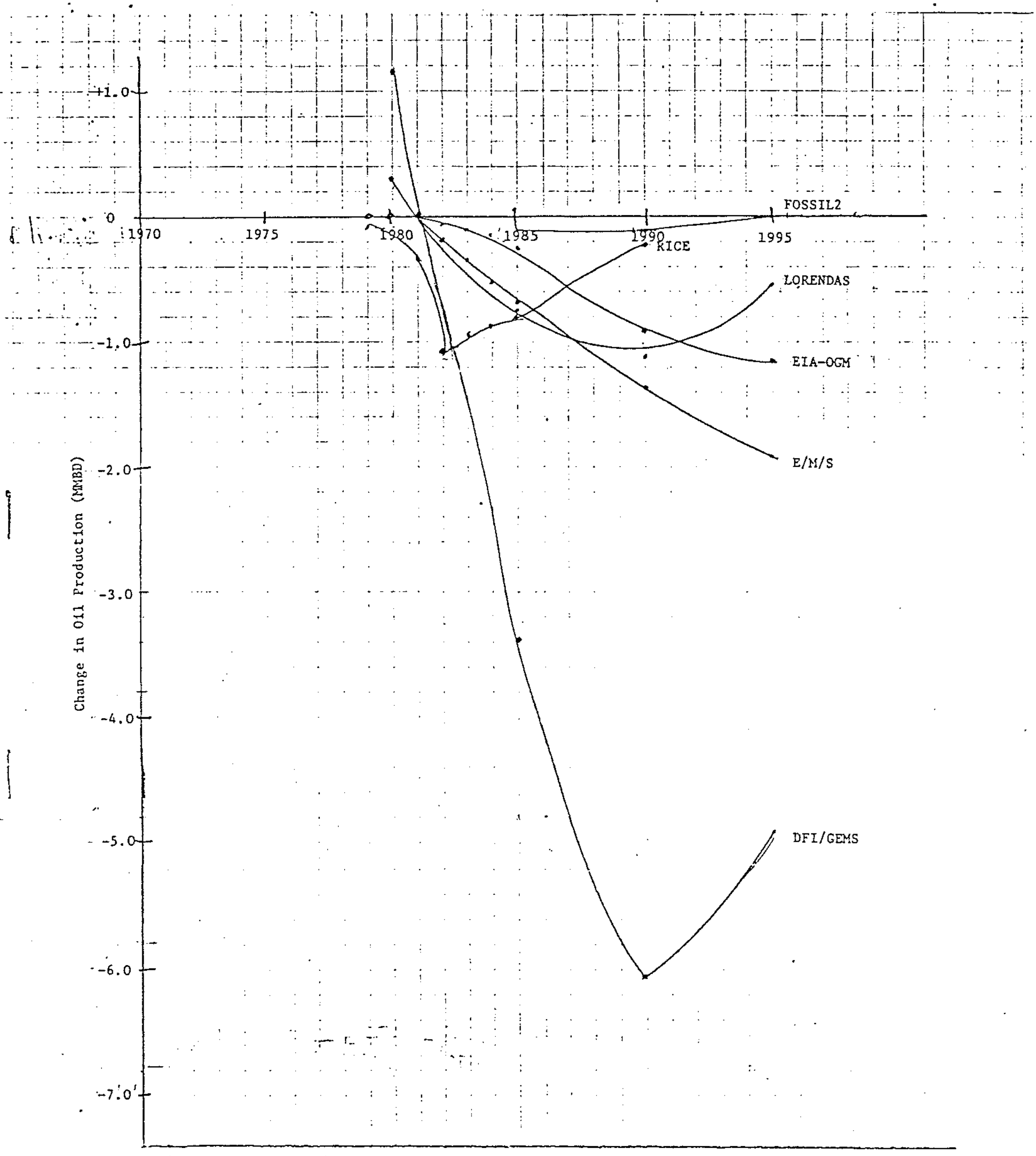


Figure 17A. Decrease in Conventional Lower-48 Crude Oil Production Due to Oil Price Controls.

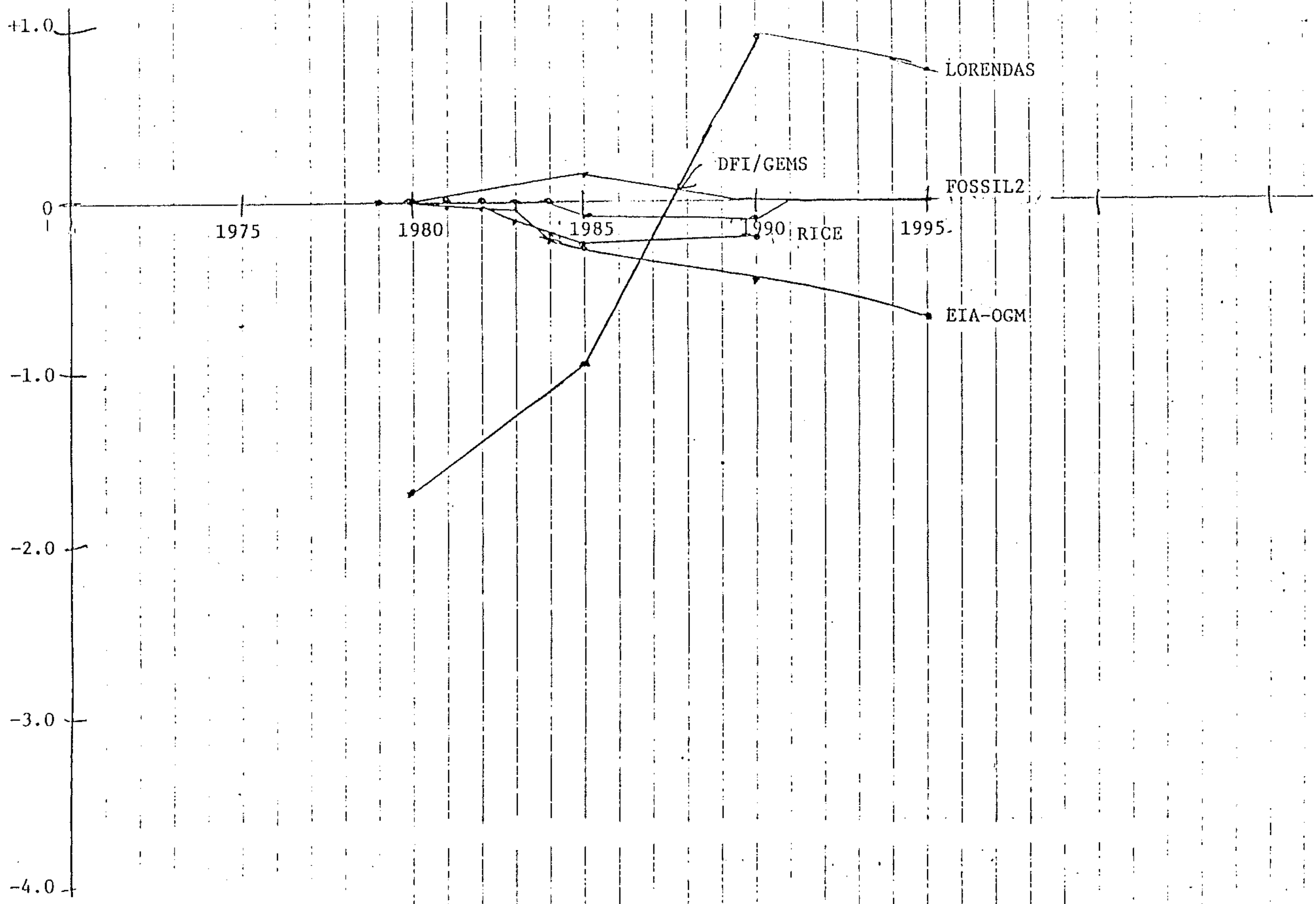


Figure 17B. Decrease in Conventional Lower-48 Natural Gas Production Due to Oil Price Controls

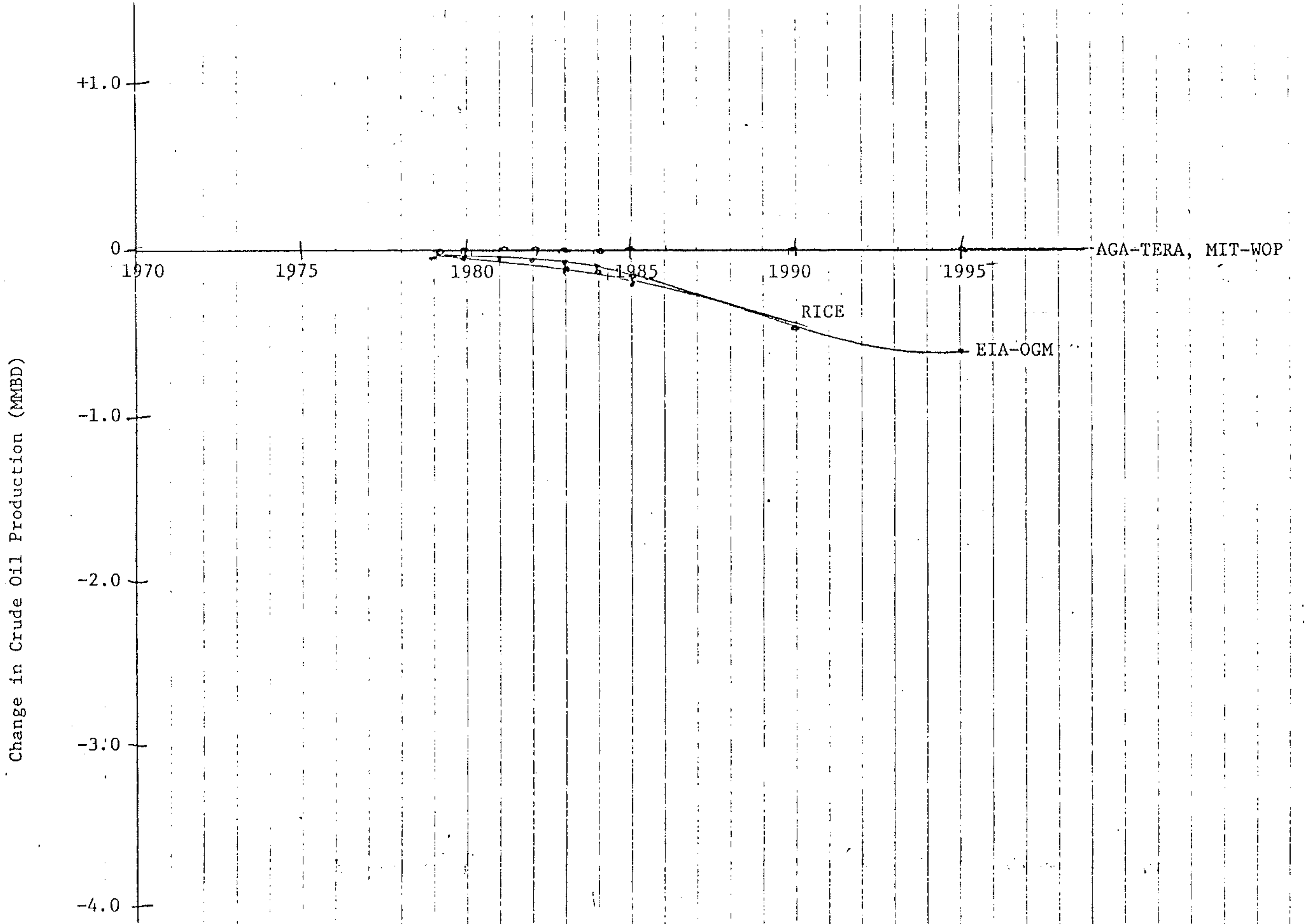


Figure 18A Decrease in Conventional Lower-48 Crude Oil Production Due to Retarded Leasing

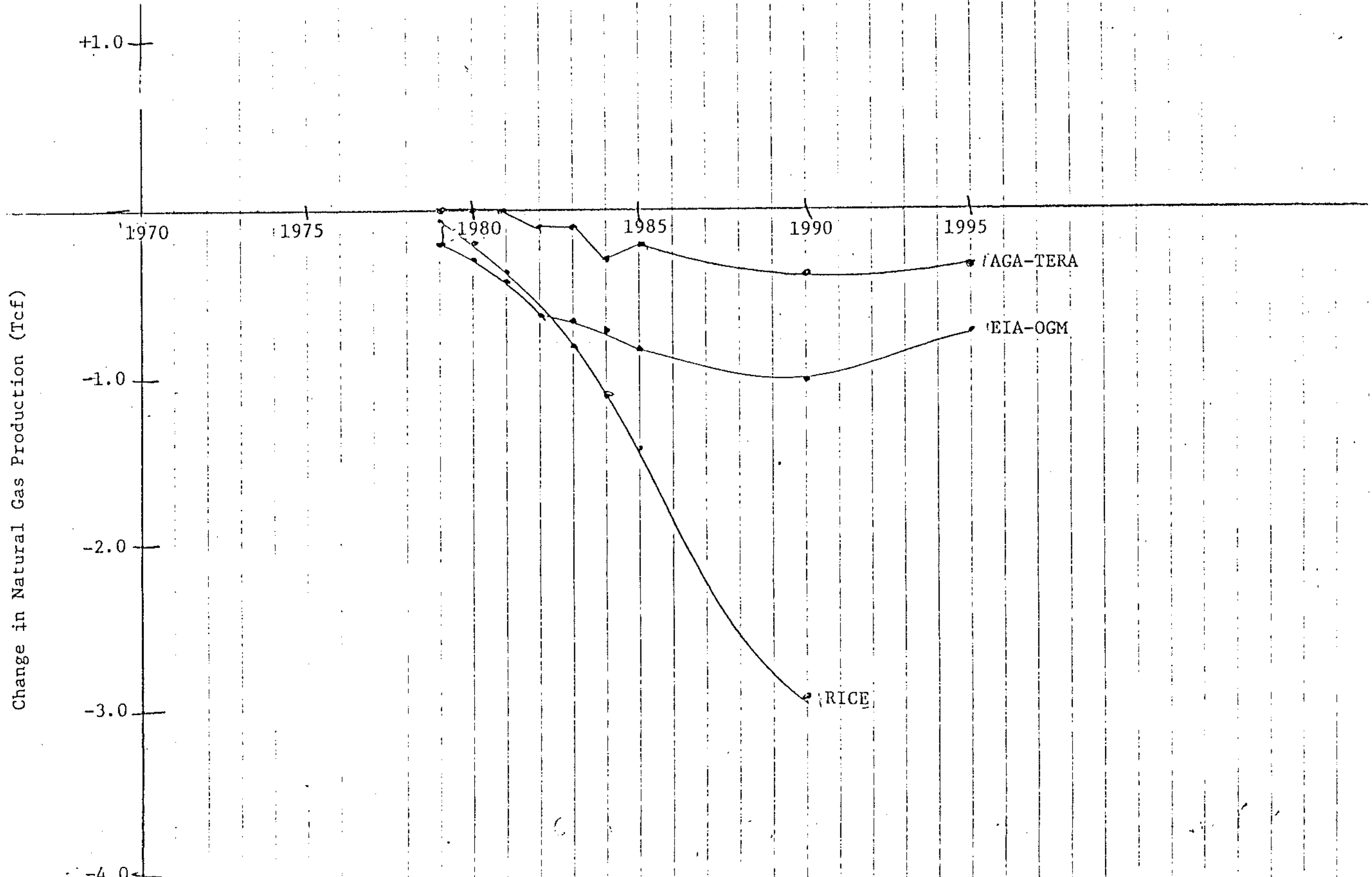


Figure 18B. Decrease in Conventional Lower-48 Natural Gas Production Due to Retarded Leasing

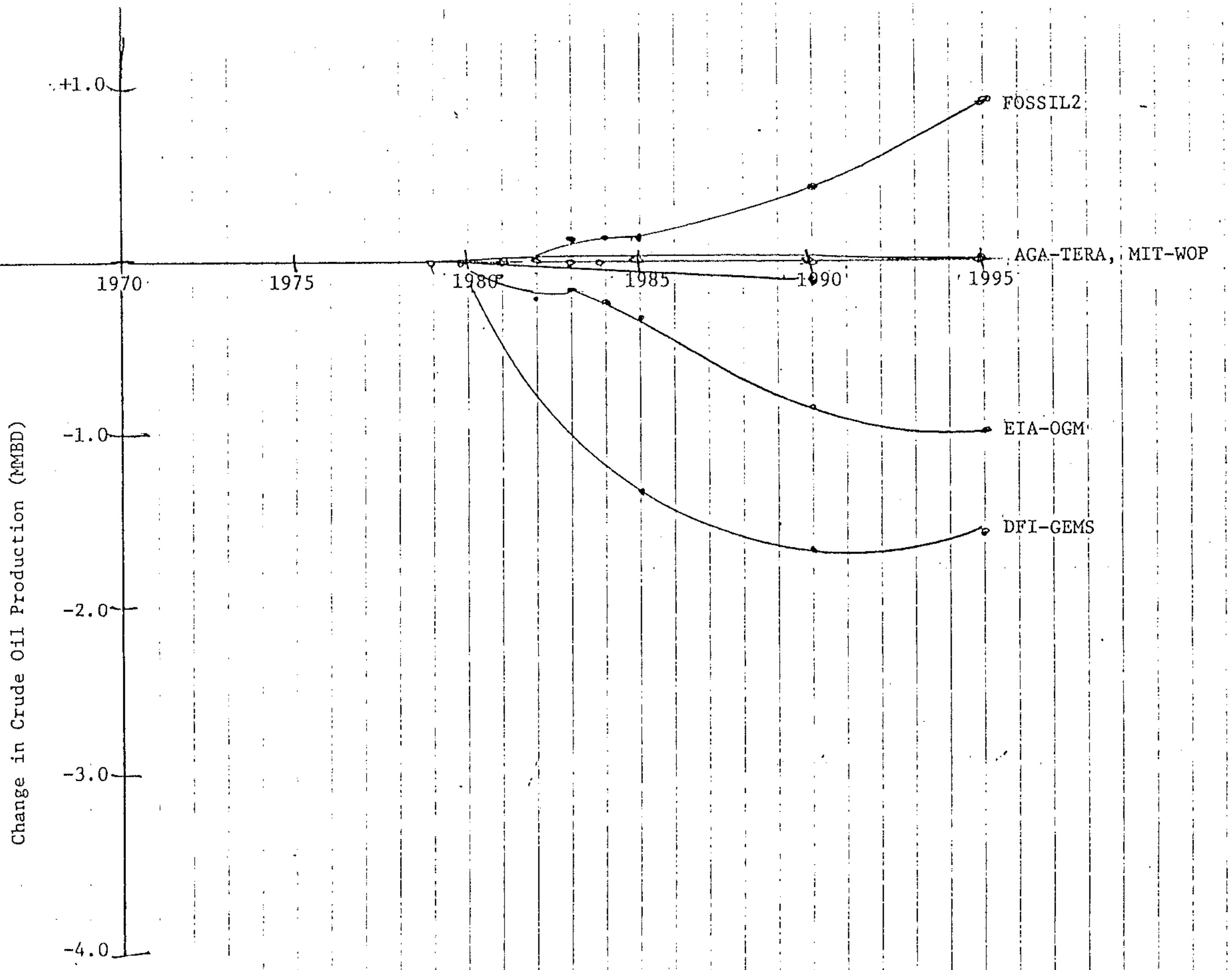


Figure 19A. Decrease in Conventional Lower-48 Crude Oil Production Due to Removal of Tax Breaks

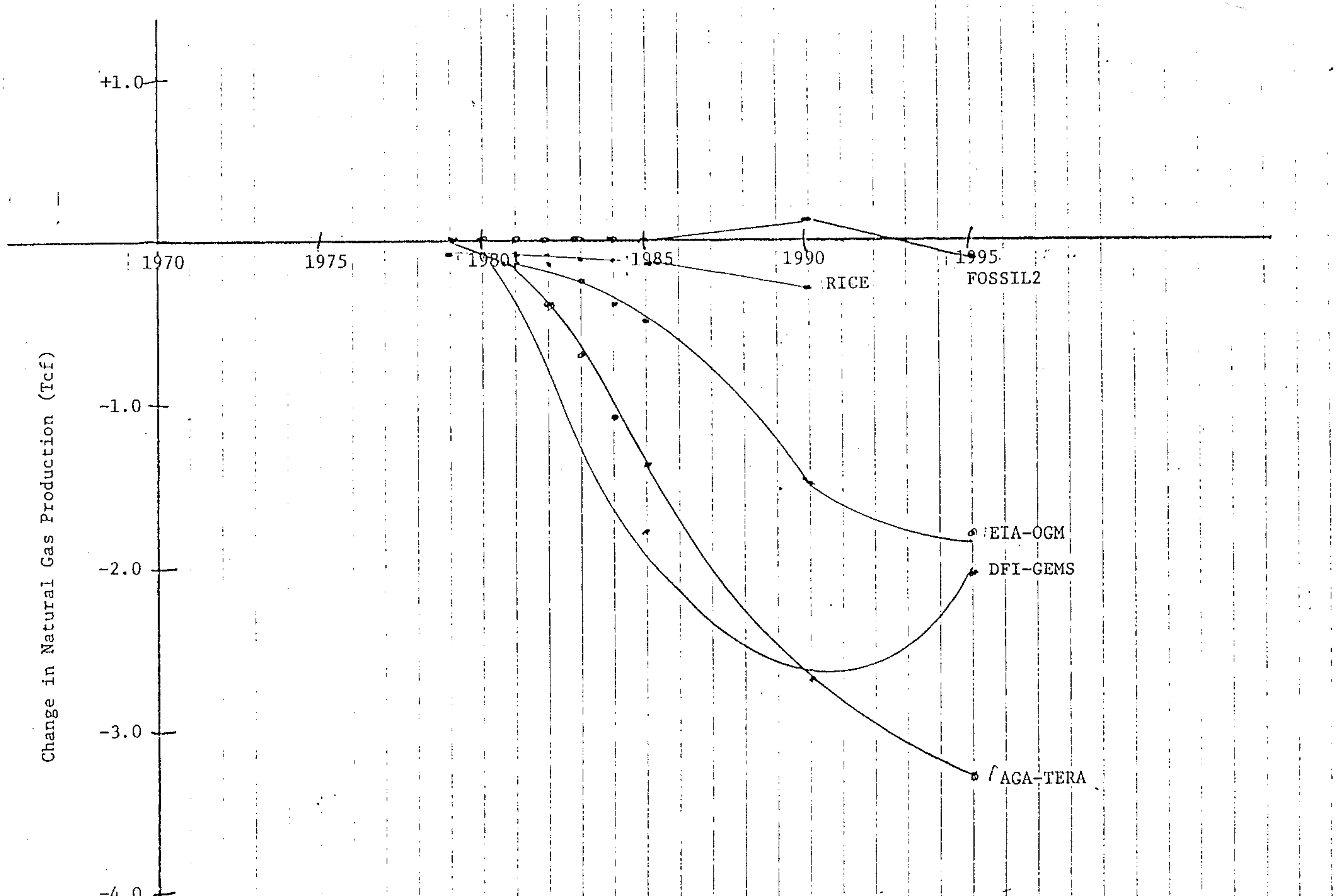


Figure 19B. Decrease in Conventional Lower-48 Natural Gas Production Due to Removal of Tax Breaks