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OAK RIDGE NATIONAL LABORATORY

MARTIN MARIETTA

Replacement Cost Integration Program Model Overview

David B. Reister

Fossil Energy Program

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Engineering Physics and Mathematics Division

REPLACEMENT COST INTEGRATION PROGRAM

MODEL OVERVIEW

David B. Reister

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TABLE OF CONTENTS

		Page
	ABSTRACT	ix
1.	INTRODUCTION	1
2.	MODEL OVERVIEW	3
3.	RESULTS	9
4.	FUTURE RESEARCH	13
	4.1. Conceptual Model	13
	4.2. Summary of Future Research	14
	REFERENCES	29

LIST OF FIGURES

Figure		Page
1	Domestic oil price (dollars per barrel)	15
2	Oil production in the United States (millions of barrels per year)	16
3	Additions to proved reserves for the United States (millions of barrels per year)	17
4	Oil production in the onshore region (million of barrels per year)	18
5	Additions to proved reserves for the onshore region (millions of barrels per year)	19
6	Oil production in the offshore region (millions of barrels per year)	20
7	Additions to proved reserves for the offshore region (millions of barrels per year)	21
8	Oil production in Alaska (millions of barrels per year)	22
9	Additions to proved reserves for Alaska (millions of barrels per year)	23
10	Oil production from EOR and other (millions of barrels per year)	24
11	Oil production in the United States forecast by RCIP and AEO (millions of barrels per year)	25
12	Oil production in Alaska forecast by RCIP and AEO (millions of barrels per year)	26
13	Oil production in the lower 48 states forecast by RCIP and AEO (millions of barrels per year)	27
14	Oil production in the lower 48 states forecast by RCIP and AEO (millions of barrels per year)	28

LIST OF TABLES

Table **Page**

1 Regions in the RCIP model 5

ABSTRACT

The Oak Ridge National Laboratory and subcontractor ICF-Lewin Energy have developed a set of computer models to forecast the replacement cost of crude oil. The REPCO model forecasts the replacement cost in the lower 48 states. The Arctic Economics Model forecasts the replacement cost in Alaska. The two models of the replacement cost system forecast domestic oil supply curves (schedules of the amount of oil available at various costs). The Replacement Cost Integration Program (RCIP) integrates the output from the two models to forecast the annual discoveries and production of domestic crude oil.

RCIP is a user-friendly menu-driven program that is designed to run on an IBM-PC. RCIP allows the user to conveniently edit the input parameters, to calculate the results, and to display the output. In addition, the user can easily store a scenario on a disk and retrieve a scenario from the disk. The built-in output editor allows the user to choose an aggregation scheme for the regional results and retrieve a scenario for comparison. The output can be directed to a file or to the screen.

This Model Overview provides an introduction to the models and presents some typical results.

1. INTRODUCTION

The U.S. Department of Energy's Fossil Energy (DOE-FE) program manages a program of long-term, high-risk R&D to develop advanced energy technologies that produce or consume fossil energy. The management of the program continually faces the question: when will an advanced technology be competitive with any alternative technologies? The standard method for comparing a set of alternative technologies is to perform a discounted cash flow analysis. There are many types of discounted cash analyses; one of the standard methods is to calculate a life-cycle cost for each alternative technology. The life-cycle cost is the constant or levelized cost that will recover all of the costs necessary to produce the product over the life cycle of the project. The technology with the lowest life-cycle cost will tend to capture the largest share of the market. DOE-FE supports research to produce liquid and gaseous fuels. The conventional technology to produce these fuels is to drill wells to extract liquid or gaseous fuels. Because the advanced technologies must compete with the conventional technology, the life-cycle cost of conventional oil and natural gas is of interest to the management of the program.

Conventional oil and gas are finite resources. As the resources are consumed, the life-cycle cost of the next barrel, the replacement cost, will tend to increase. As the replacement cost increases and R&D lowers the cost of advanced energy technologies, eventually the advanced technologies will penetrate the market.

The program has sponsored research by the Oak Ridge National Laboratory and subcontractor ICF-Lewin Energy to develop a set of computer models to forecast the replacement cost of domestic crude oil and natural gas and to forecast the contribution to the U.S. oil supply from domestic crude oil and enhanced oil recovery (EOR). The REPlacement COst (REPCO) model forecasts the replacement cost of domestic crude oil for 6 onshore regions and 14 offshore regions. The Arctic Economics Model (AEM) forecasts the replacement cost for 15 regions in Alaska. The Replacement Cost Integration Program (RCIP) uses the output from REPCO and the AEM to forecast the discovery and production of crude oil in 31 regions (16 regions in the lower 48 states and 15 regions in Alaska).

The research on REPCO, AEM, and RCIP has been supported by the Office of Planning and Environment (OPE). OPE has lead responsibility within DOE for coordination with the Minerals Management Service (MMS) on the Outer Continental Shelf (OCS) oil and gas leasing program. OPE is the designated technical representative of DOE on the various National Petroleum Council (NPC) study committees.

Every 5 years, the MMS proposes an OCS leasing program. The most recent program was adopted in 1986 and covers the period from January 1987 to December 1991. As part of the leasing program, the MMS must estimate the amount of undiscovered crude oil for each region of the OCS. OPE would like to be able to estimate the impact of the leasing program on domestic oil production. RCIP is designed to be a tool that can estimate the impact on oil production of removing a certain parcel of land from the leasing program. The inputs to RCIP include regional estimates of undiscovered oil and estimates of regional leasing schedules.

The drop in world oil prices in 1986 resulted in an interest in the impacts of low oil prices on domestic production. OPE was actively involved in the recent study by the NPC (1987) on the impacts of low oil prices on the domestic petroleum industry. RCIP is designed to estimate the impact of world oil prices on domestic oil production.

Periodically, the U.S. Geological Survey (USGS) and the MMS publish an assessment of undiscovered crude oil. The USGS published Circular 860 in 1981 (Dolton et al. 1981), and the MMS published MMS 85-0012 in 1985 (Cooke 1985). USGS and MMS are now working on a new assessment, the preliminary results of which were published in 88-373 Open-File Report in 1988. RCIP is designed to estimate the impact of revised estimates of undiscovered crude oil on domestic oil production. The data base for RCIP is based on the values in Report 88-373.

The documentation of RCIP consists of three volumes: Model Overview, User's Guide, and Model Description. The next section of this volume will provide an overview of the model. The third section will present some results for two price scenarios and compare the results to the most recent projections by Energy Information Administration (AEO) in its Annual Energy Outlook 1987. The final section will discuss potential areas for future research.

2. MODEL OVERVIEW

Crude oil is a finite resource. Over time, oil is discovered and produced. We will subdivide the domestic crude oil resource into four categories:

1. undiscovered recoverable resources,
2. discovered reserves,
3. proved reserves, and
4. cumulative production.

The sum of the four categories is a constant. Over time, oil resources move from one category to the next. Successful exploratory wells cause some shift from category 1 to category 3 and a greater shift from category 1 to category 2. Successful developmental wells create movement from category 2 to category 3. Production shifts domestic crude oil resources from category 3 to category 4. Ultimately, all economically recoverable oil will be produced.

In 1988, the USGS and the MMS published Open-File Report 88-373. The report estimates the amount of oil in each of the four categories on January 1, 1987. The values are: 142.9 billion barrels (BB) for cumulative production, 29.5 BB for proved reserves, and 21.7 BB for discovered reserves, (we define discovered reserves to be the sum of indicated reserves plus inferred reserves). The report provides six estimates of undiscovered recoverable oil (high, mean, and low vs economically recoverable and total recoverable). The three estimates of the total undiscovered recoverable oil are: 19.4 BB, 51.3 BB, and 109.5 BB. Thus, the three estimates of the ultimate production of crude oil are: 213.5 BB, 245.4 BB, and 303.6 BB. If we use the mean estimate of undiscovered oil, 79% of the ultimately recoverable oil has been discovered.

Every year, the EIA publishes an assessment of the proved reserves and production (see EIA 1987). The EIA lists five categories of additions to proved reserves: revisions, adjustments, extensions, new field discoveries, and new reservoir discoveries in old fields. We have assumed that revisions, adjustments, and extensions are the result of developmental drilling, and that new field and new reservoir discoveries are the result of exploratory drilling.

The EIA definition of proved reserves is five paragraphs long. A key part of the definition is that the area of an oil reservoir considered to be proved includes (1) that portion delineated by drilling and (2) the immediately adjoining portions not yet drilled but which can be reasonably judged as economically productive on the basis of available geological and engineering data.

When an exploratory well discovers a new field (or reservoir), a small fraction of the total oil in the field is added to the proved reserves. As the field is developed and more wells are drilled, the proved reserves expand. We shall call the ratio of the average ultimate recovery from an oil field and the initial estimate of proved reserves the Hubbert Field Growth Factor (see p. A-6 of Lewin and Associates 1985). In Circular 860, the estimate of the growth factor is 7.58. Thus, for every barrel added to proved reserves by exploratory activity, 6.58 bl are added to discovered reserves (inferred plus indicated reserves). The 6.58 bl of discovered reserves are later added to proved reserves through developmental activity.

The introduction of new technology can result in an increase in proved reserves. Consider the heavy oil in California. The application of thermal methods to recover heavy oil has increased from about zero in 1963 to 3.7×10^5 bbl/d in 1982. Most of the thermal energy is supplied using steam injection. As methods to recover heavy oil have become more cost effective, the proved reserves have increased sharply. From 1983 to 1986, the proved reserves in the heavy oil region of California increased by 1.2 BB; the heavy oil region provided 64% of the additions to proved reserves for the whole state.

The heavy oil in California provides a great strain on the accounting structure of RCIP. RCIP simulates the production of conventional oil. Oil production from EOR, heavy oil, and tar sands are an exogenous input to the model. In the 1984 NPC study on EOR, thermal recovery is defined to be EOR and provides 45% of the potential total. Thus, heavy oil is included in the historical data on oil production and reserve additions. Future production from heavy oil could be called either EOR or heavy oil. In a future version of RCIP, we hope to clarify this definition.

RCIP forecasts oil production and discoveries (additions to proved reserves) for the 31 regions displayed in Table 1. The RCIP input data editor allows the user to easily alter the estimate of undiscovered oil, discovered oil, and the lease schedule for each of the 31 regions.

Table 1. Regions in the RCIP model

Onshore - Lower 48 States

1. West Coast
2. Rocky Mountains
3. Mid Continent
4. West Texas
5. Gulf Coast
6. Appalachia

Offshore - Lower 48 States

7. West Coast Shelf - South
8. West Coast Shelf - North
9. West Coast Slope - South
10. West Coast Slope - North
11. Gulf of Mexico Shelf
12. Gulf of Mexico Slope
13. North & Central Atlantic Shelf
14. South Atlantic Shelf
15. North & Central Atlantic Slope
16. South Atlantic Slope

Alaska

17. Beaufort Shelf
18. Chukchi and Hope Shelf
19. Bristol Basin Shelf
20. Navarin Basin Shelf
21. Norton Basin Shelf
22. Other Bering Sea Shelf
23. South Offshore Shelf
24. South Offshore Slope
25. Beaufort Slope
26. Chukchi and Hope Slope
27. Other Bering Sea Slope
28. Gulf of Alaska - Onshore
29. Artic National Wildlife Refuge (ANWR)
30. National Petroleum Reserve in Alaska (NPRA)
31. North Slope (Other)

The life cycle of an oil field has several stages. The discovery and development of oil fields are simulated in the process models: REPCO and AEM. In the onshore section of REPCO, the stages are exploration, development, and production. In the first year, preexploration activities are conducted. In the second year, a lease agreement is signed with the landowner. In the third year, exploratory drilling discovers the field. In the fourth year, production from the successful exploratory well begins, and the drilling of development wells begins. The development stage can last 3 to 9 years, depending on the size of the field. The production stage lasts 15 years for small fields and 20 years for large fields. In the offshore section of REPCO, the development stage includes the construction of the drilling platform.

In REPCO and the AEM, engineering process models forecast the capital costs, operating costs, and production level of oil and gas for each year for each field class in each region. In REPCO and the AEM, the subroutine ANETPV calculates the replacement cost of domestic oil for each field class in each region (the replacement cost is the constant or levelized cost that will recover all of the costs necessary to produce crude oil over the life cycle of the oil field). The inputs to ANETPV are the outputs of the process models (time series of capital costs, operating costs, and production) and parameters (the discount rate, the royalty rate, the tax rate, the overhead rate, and the transportation cost).

In the sensitivity analysis of REPCO (Reister and Wright 1987), the parameter with the largest sensitivity coefficient was the discount rate. In the previous versions of RCIP, the replacement cost was an input that depended on the parameters required by ANETPV. Each change in a key parameter required a new run of REPCO and the AEM. In the current version of RCIP, the ANETPV calculation is performed in RCIP. Thus, the inputs to RCIP are the outputs of the process models and the parameters. The input data editor allows the user to easily change the values of key parameters.

The net present-value calculation can be performed for either a constant price track or a variable price track. Given expected domestic oil prices, ANETPV can calculate the discounted present value of the profits from the development of an oil field that commenced in a certain year. For the historical period (1960 to 1987), expected domestic oil prices were not the same as actual domestic oil prices. If oil companies had known about the increases in oil price in 1974 and 1979, they would have increased the level of drilling from 1968 to 1974. In 1981, the domestic oil price reached $41/bbl and the industry expected that the price would soon reach $100/bbl. However, in 1987, the price was $18/bbl, and the industry expected a slow increase in price. The expected prices in 1981 encouraged a much higher level of drilling than the expected prices in 1987. The input data editor allows the user to easily change the values of both the future oil price and the expected oil price.

After ANETPV calculates the expected profits from the development of each oil field in each year, the RCIP drilling module estimates the total level of drilling and reserve additions by region and field size in each year. Having forecast the regional reserve additions, RCIP uses two production profiles (one for large fields and a second for small fields) to estimate future oil production. A price elasticity parameter allows the oil production to respond immediately to price changes.

RCIP simulates the discovery, development, and production of oil. The input editor can be used to change the key variables: estimates of undiscovered and discovered oil, leasing schedules, future oil prices, discount rate, price elasticity parameter, and tax rate.

3. RESULTS

To illustrate the features of RCIP, we have created two scenarios by choosing two sets of values for the domestic oil price: high and low. The price scenarios are displayed in Fig. 1. We have created four aggregate regions: lower 48 onshore, lower 48 offshore, Alaska, and EOR. Figures 2 through 10 display the RCIP forecasts of oil discoveries and production for the United States and for the four regions for the two price scenarios.

The two price scenarios are the same until 1990 (see Fig. 1). After 1990, the low-price scenario remains at $20/bbl (in 1985 dollars), while the high-price scenario reaches $70/bbl by 2020.

For the United States total, oil production and additions to proved reserves are substantially higher for the high price case than for the low-price case (see Figs. 2 and 3). For the period from 1987 to 2020, the cumulative production increases by 64% from 57.1 BB to 93.8 BB, whereas the cumulative additions to proved reserves increase by more than a factor of three from 16.3 BB to 54.8 BB. The sharp increase in reserve additions after 2000 is the result of the leasing schedule, which increases the available undiscovered oil after 2000.

What fraction of the potential additions to proved reserves have been developed? The potential additions are the sum of the mean value of the undiscovered resources (51.3 BB) and the discovered reserves (21.7 BB) or 73.0 BB. For the low price case, 22% of the potential additions are added to the proved reserves, while 75% are added for the high price case.

Is the cumulative production more than the proved reserves? The initial value for the proved reserves was 29.4 BB. For the period from 1987 to 2020, the production from EOR was 11.9 BB. The maximum production for the low-price case is the sum of proved reserves, reserve additions, and EOR or 57.7 BB (the price elasticity term will allow the cumulative production to be larger than this estimate of maximum production). Thus, the cumulative production was 99% of the potential production. For the high-price case, the cumulative production was 97% of the potential production (96.1 BB).

For the three regions, the onshore region has the smallest response to the price change, while Alaska has the largest response. The increase in cumulative oil production from the low price case to the high-price case is

32% for onshore, 91% for offshore, and 260% for Alaska. The increase in cumulative additions to proved reserves is 65% for onshore, 330% for offshore, and a factor of 45 for Alaska.

The fractions of the potential additions to proved reserves that have been developed for the two price scenarios are 39% and 64% for onshore, 18% and 76% for offshore, and 2% and 91% for Alaska. The level of reserve additions is determined by the RCIP drilling module. The parameters in the drilling module were determined by two different methods. For the onshore region, the parameters were estimated by approximating historical data (see Reister and Christiansen 1988). For the offshore region and Alaska, the parameters were determined by judgment. Both methods have drawbacks.

For the high-price scenario, the fraction of potential reserve additions that are developed is less than 60% for four of the six onshore regions. The lowest development fraction is in the West Coast region. Previously, we discussed the large developmental reserve additions associated with heavy oil. The low reserve additions are the result of low exploratory reserve additions [72 million barrels (MB)] in the period from 1970 to 1986. The mean estimate of undiscovered oil in the West Coast region is 3490 MB. If we assume that the Hubbert Reserve Growth Factor is 7.58, then 460 MB of exploratory reserve additions would be required to discover 3490 MB of oil. For the two price scenarios, the exploratory reserve additions increase from 33 MB to 76 MB or from 7% to 17% of 460 MB. Thus, even for the high price scenario, RCIP is discovering only a small fraction of the potential exploratory reserve additions.

The model behavior is consistent with the historical data. In the historical high-price period, the exploratory reserve additions were 72 MB. In the future high-price scenario, the model forecasts exploratory reserve additions of 76 MB. An increase to 460 MB is not consistent with the historical data. (An alternative explanation for the difference is that the USGS estimate of undiscovered oil is too high. From Circular 860 to Open-File Report 88-373, the estimate of undiscovered oil in the Rocky Mountain region decreased from 23.6 BB to 6.0 BB.) However, we are not comfortable with the conclusion that 17% of the undiscovered oil will be discovered by 2020 for the high-price case. We believe the discovery rate will be more than 90%.

Although our judgment suggests that we modify the parameters (or the resource estimates) for four of the six onshore regions, we have not modified the parameters because they illustrate the difficulties with making forecasts. Futher research is required to improve the forecasts by the model.

For the offshore region and Alaska, the parameters were determined by judgment. The key uncertainty is how high the profits need to be to encourage exploration and development in unexplored regions.

The RCIP forecasts are compared with forecasts from the EIA Annual Energy Outlook (AEO) (EIA 1988) in Figs. 11 through 14. In Fig. 11, the RCIP forecasts of U.S. oil production for the high- and low-price cases are compared with AEO forecasts for a different set of high- and low-price cases. The RCIP results are higher than the AEO results, but the differences become smaller near 2000. The difference between the high and low case is larger for RCIP than for the AEO.

Because the RCIP forecast in the early years is dominated by production from proved reserves, we will discuss our method for estimating production from proved reserves. We used three spreadsheets to create values for the three models: onshore, offshore, and Alaska. For the 24 years from 1987 to 2010, each spreadsheet had three series of values: model, history, and total. The model values were obtained from the model when the production from proved reserves was zero. The historical values were the difference between the total and the model values. We adjusted the total values so that the sum of the historical values was equal to the sum of the proved reserves. The total values were piecewise linear; the values decreased (or increased) at a constant rate for three 8-year periods: 1987 to 1994, 1995 to 2002, and 2003 to 2010. In 1987, the total was equal to the historical value. By 2010, the total was nearly equal to zero. We adjusted the three decline rates until the total historical production was equal to the initial proved reserves. Because the exogenous values for production from proved reserves are multiplied by a price elasticity factor, the input values are divided by the price elasticity factor.

In Fig. 12, the RCIP forecasts of Alaskan oil production are compared with AEO forecasts. Initially the RCIP results are lower than the AEO results, but the differences become smaller near 2000. Although the

Alaskan production has been increasing in recent years, we were forced to reduce the production values to match the estimate of proved reserves (an increase in the early years would cause a sharp decrease in later years). The difference between the high and low case is larger for RCIP than for the AEO.

In Fig. 13, the RCIP forecasts of oil production in the lower 48 states are compared with AEO forecasts. Initially the RCIP results are higher than the AEO results, but the differences become smaller near 2000. Although the lower 48 production has been decreasing since the price drop in 1986, we were forced to increase the production values to match the estimate of proved reserves. The difference between the high and low case is larger for RCIP than for the AEO.

To investigate the role of EOR, we kept the oil production from EOR constant from 1987 to 2000. The results are displayed in Fig. 14. By 2000, the differences between the two sets of forecasts are significantly reduced.

To summarize the four figures, we can compare levels of oil production and changes in the levels in response to price changes. The biggest differences in levels occur near 1987. The differences occur because the AEO matches historical data, and RCIP matches the total proved reserves. The differences in level are smaller in 2000. Although the exogenous price changes are not identical, they are similar and the price responses of the two models are similar.

4. FUTURE RESEARCH

As the United States matures as an oil producing country the R&D emphasis will shift from undiscovered oil (deep water and Arctic) to recovering more oil from discovered fields (EOR, infill drilling, and heavy oil). Future research on RCIP should focus on recovering more oil from discovered fields. This section will review our conceptual model of the oil discovery process and suggest directions for future research.

4.1 CONCEPTUAL MODEL

A useful starting point for our conceptual model of the oil discovery process is the model of Arps and Roberts (1958). In their model, an unexplored basin contains a distribution of oil fields. As the basin is explored, the larger fields will tend to be found first because they have a larger surface area. When exploration for oil stops, undiscovered oil will remain in the basin. However, the undiscovered oil will be in small fields that are not profitable to discover and develop.

In previous versions of RCIP (and REPCO), we have assumed that the finding rate is proportional to the undiscovered oil as estimated by the USGS. In the current version of RCIP, we assume that the finding rate is proportional to an econometrically estimated amount of undiscovered oil, which should be larger than the largest estimate by the USGS (see Christiansen and Reister 1988).

In previous versions of RCIP, we assumed the existence of a fixed production profile. However, oil production depends on oil price. Oil fields offer many opportunities to invest money and increase production. Examples include infill drilling, reworking wells, completion of wells in multiple zones, and EOR. At a high oil price, investment and production will increase. All wells reach an economic limit where production costs become greater than revenues. At low oil prices, more wells are at their economic limits. To simulate the response of production to price, we have added a price elasticity factor to RCIP.

An oil field is a porous geological formation that contains both oil and gas. On the average, conventional recovery techniques recover about 34% of the original oil in place (OOIP). However, the recovery can range from 15% to 90%. Advanced techniques can be used to recover more of the OOIP.

In his 1987 paper in Science, Fisher estimates that about 60% of the mobile oil originally in place will be recovered by conventional primary and secondary techniques. He argues that geologically targeted infill drilling (GTID) can recover more of the unswept mobile oil. Fisher estimates that implemented EOR will recover 3% of the OOIP and that unswept mobile oil is 16% of the OOIP. We will assume that half of the unswept mobile oil can be recovered by GTID.

If we accept the USGS-MMS mean estimate for undiscovered oil, the ultimate recovery of oil will be 245 BB. If 34% of the OOIP will be recovered, then the OOIP is 722 BB. If EOR can recover 3% of the OOIP, then implemented EOR can recover 22 BB. If GTID can recover 8% of the OOIP, then GTID can recover 58 BB of the unswept mobile oil. Because the mean estimate of undiscovered oil is 51 BB, the amount of crude oil that might be recovered by EOR and GTID appears to be larger than the amount of undiscovered oil.

Our previous discussion of the heavy oil resource in California illustrates that heavy oil is a significant resource that has entered the market.

RCIP does not simulate the economics of EOR, GTID, or heavy oil. The process models (REPCO and AEM) focus on the replacement cost of undiscovered oil and do not estimate the replacement cost of discovered oil (inferred and indicated reserves), EOR, GTID, or heavy oil. The current version of RCIP attempts to separate the exploration activity from the developmental activity for the onshore region.

4.2 SUMMARY OF FUTURE RESEARCH

The process models need to be improved. The onshore model does not have a description of resource by field class. Field class data are required to improve the simulation of the economics of exploration and development including EOR, GTID, and heavy oil. The offshore and Alaskan models have a field class description but do not have an Arps-Roberts finding rate model. All of the models should be based on the Arps-Roberts model. All of the models should have a better description of recovering more oil from discovered fields.

ORNL DWG-88-14587

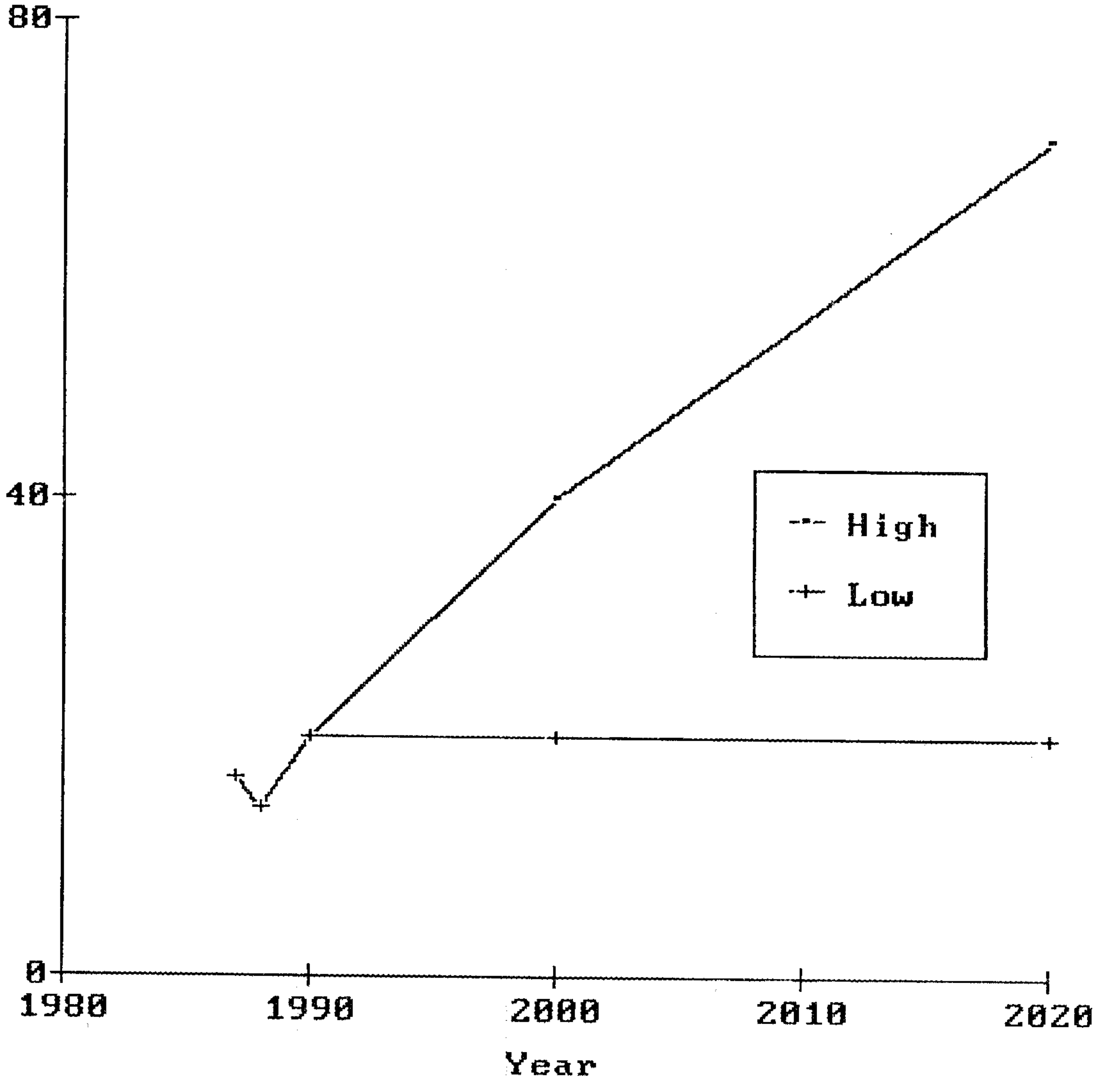

Fig. 1. Domestic oil price (dollars per barrel).

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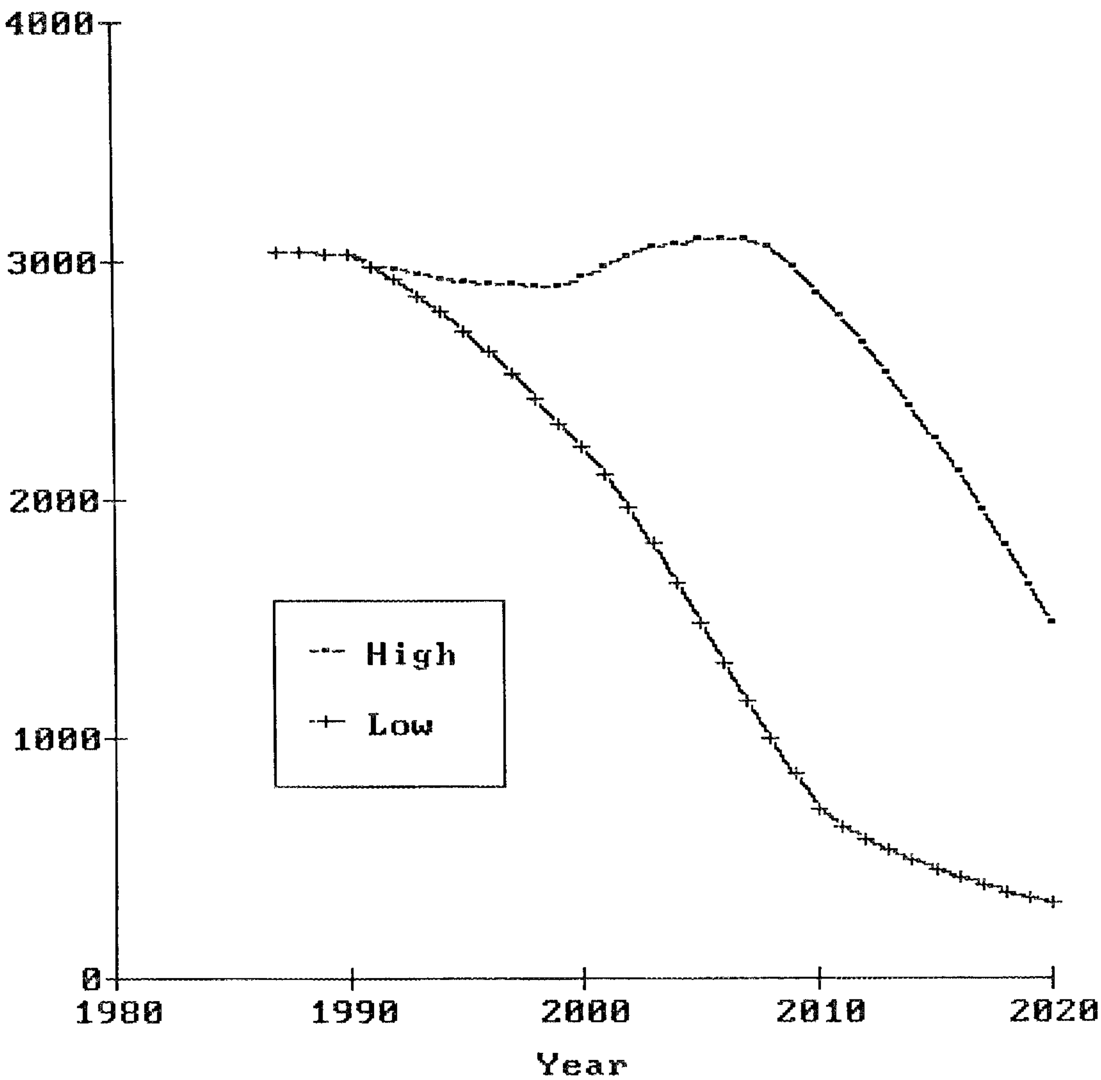

Fig. 2. Oil production in the United States (millions of barrels per year).

ORNL DWG-88-14589

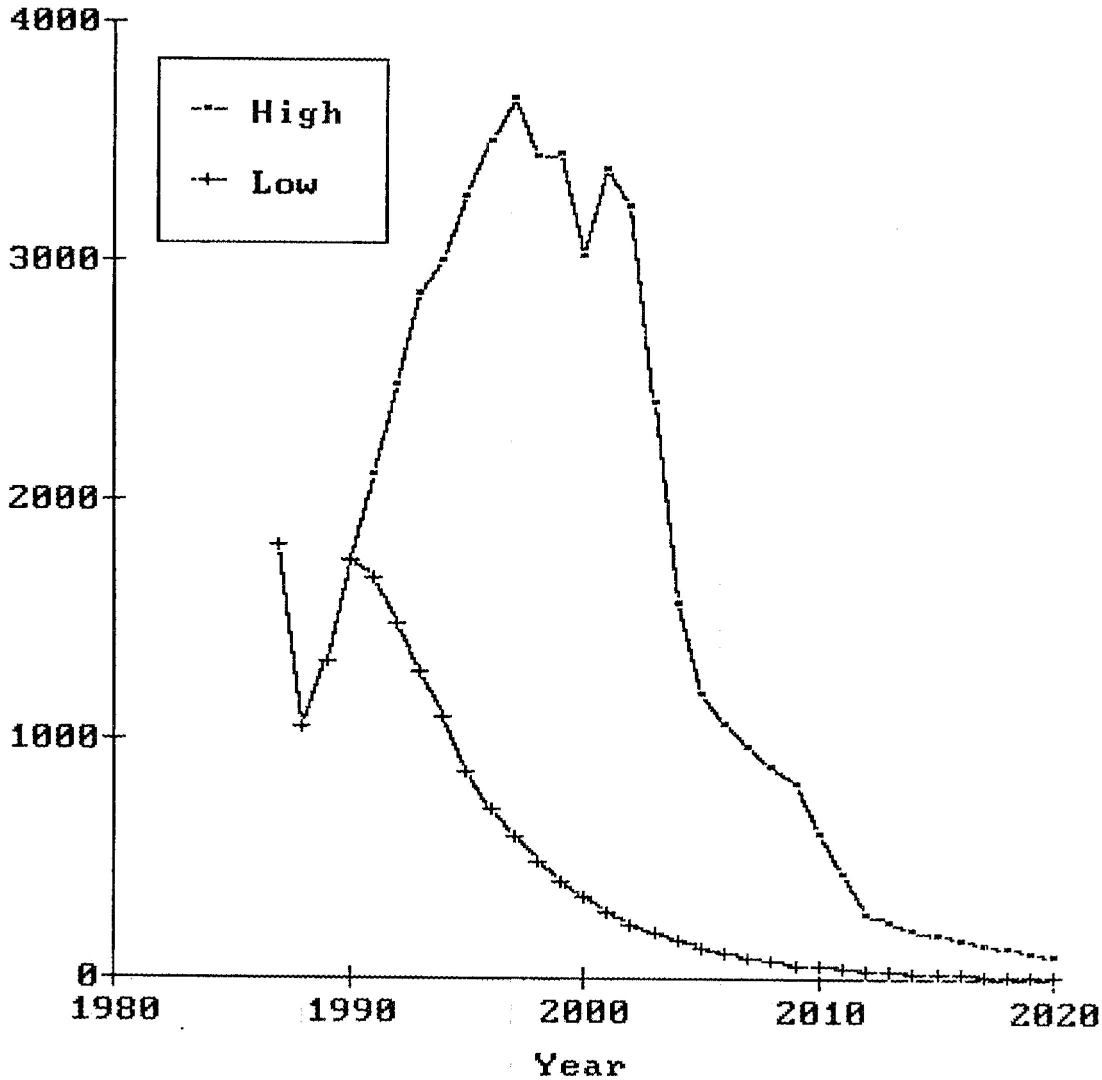

Fig. 3. Additions to proved reserves for the United States (millions of barrels per year).

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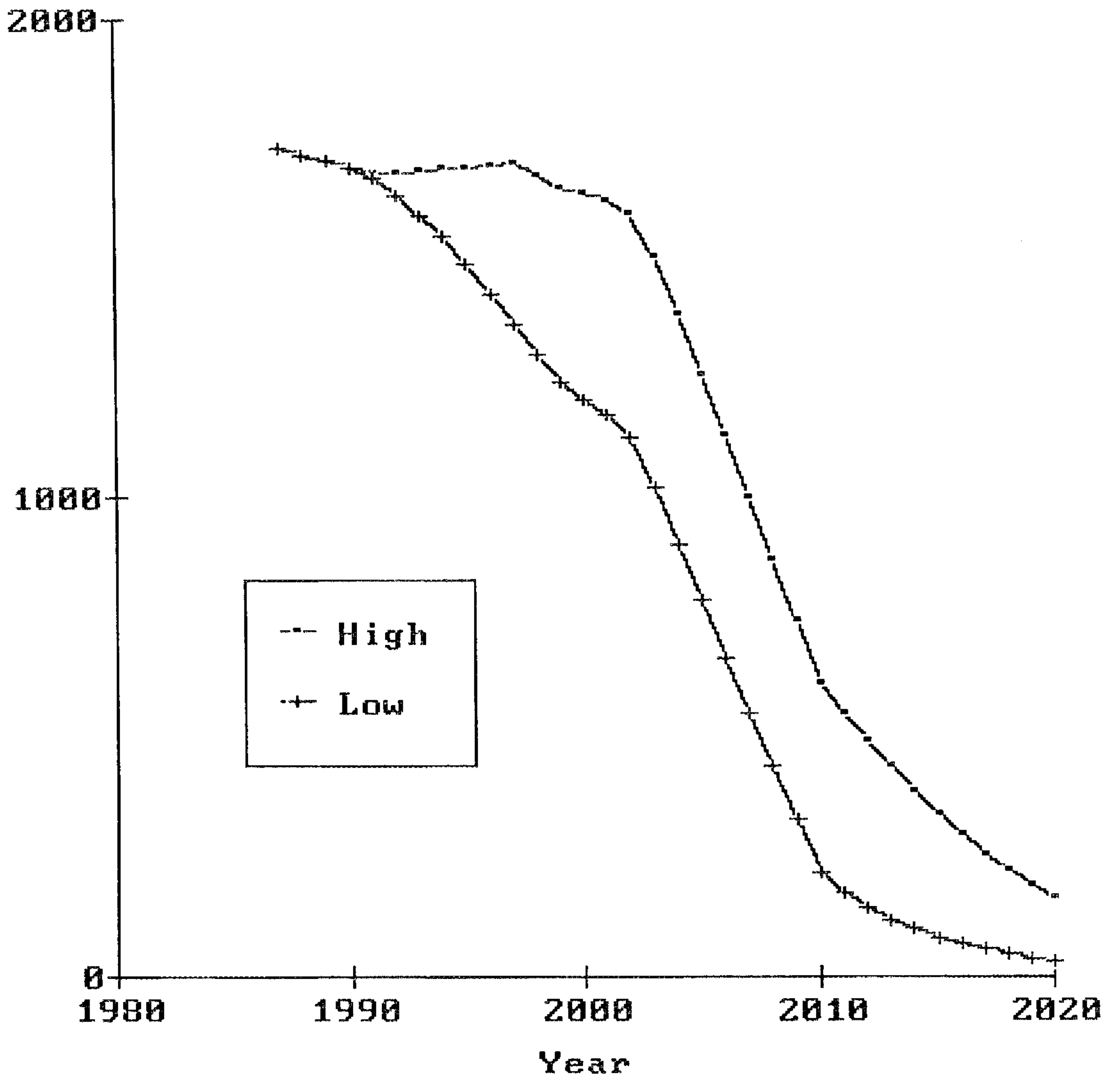

Fig. 4. Oil production in the onshore region (millions of barrels per year).

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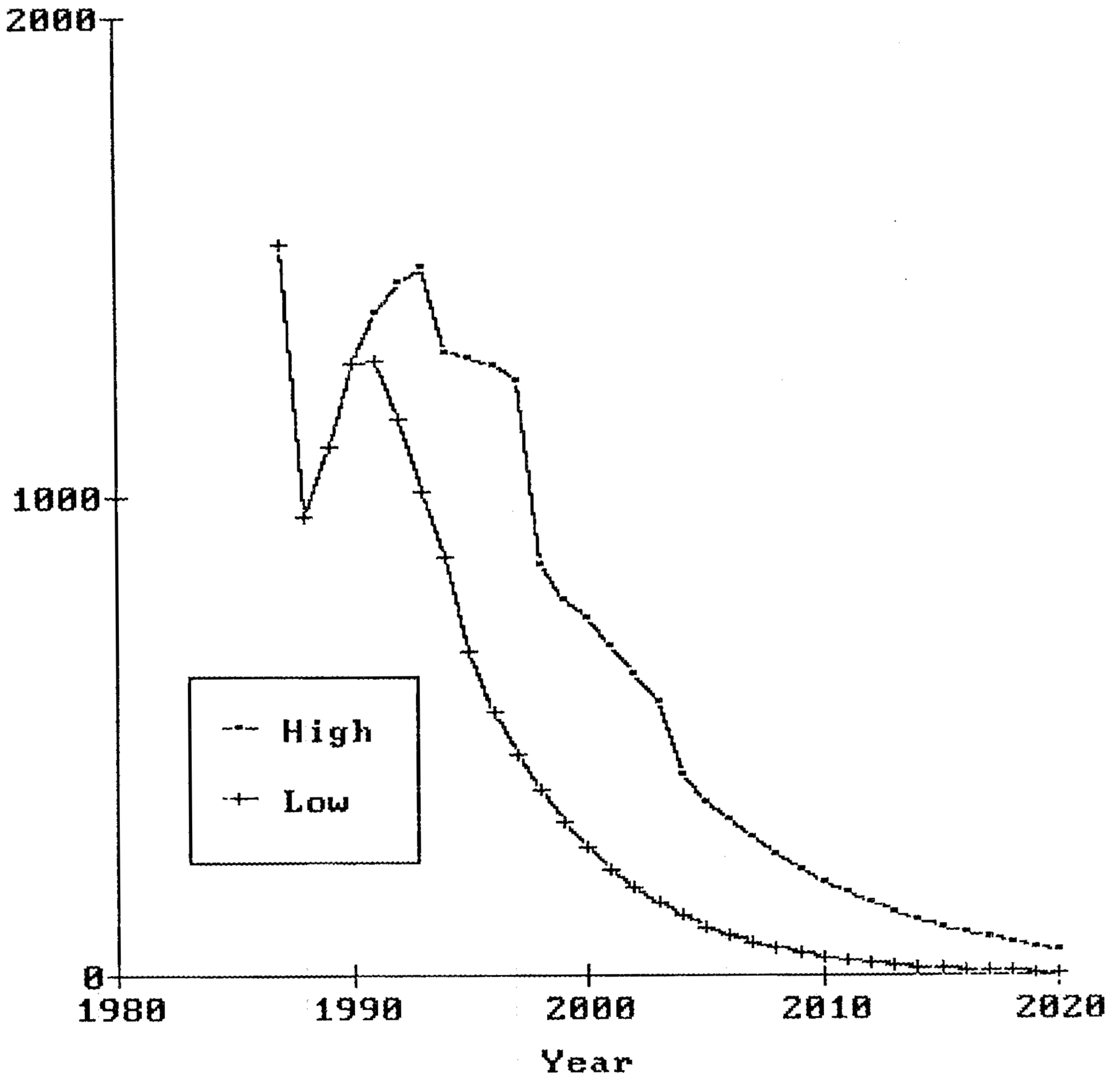

Fig. 5. Additions to proved reserves for the onshore region (millions of barrels per year).

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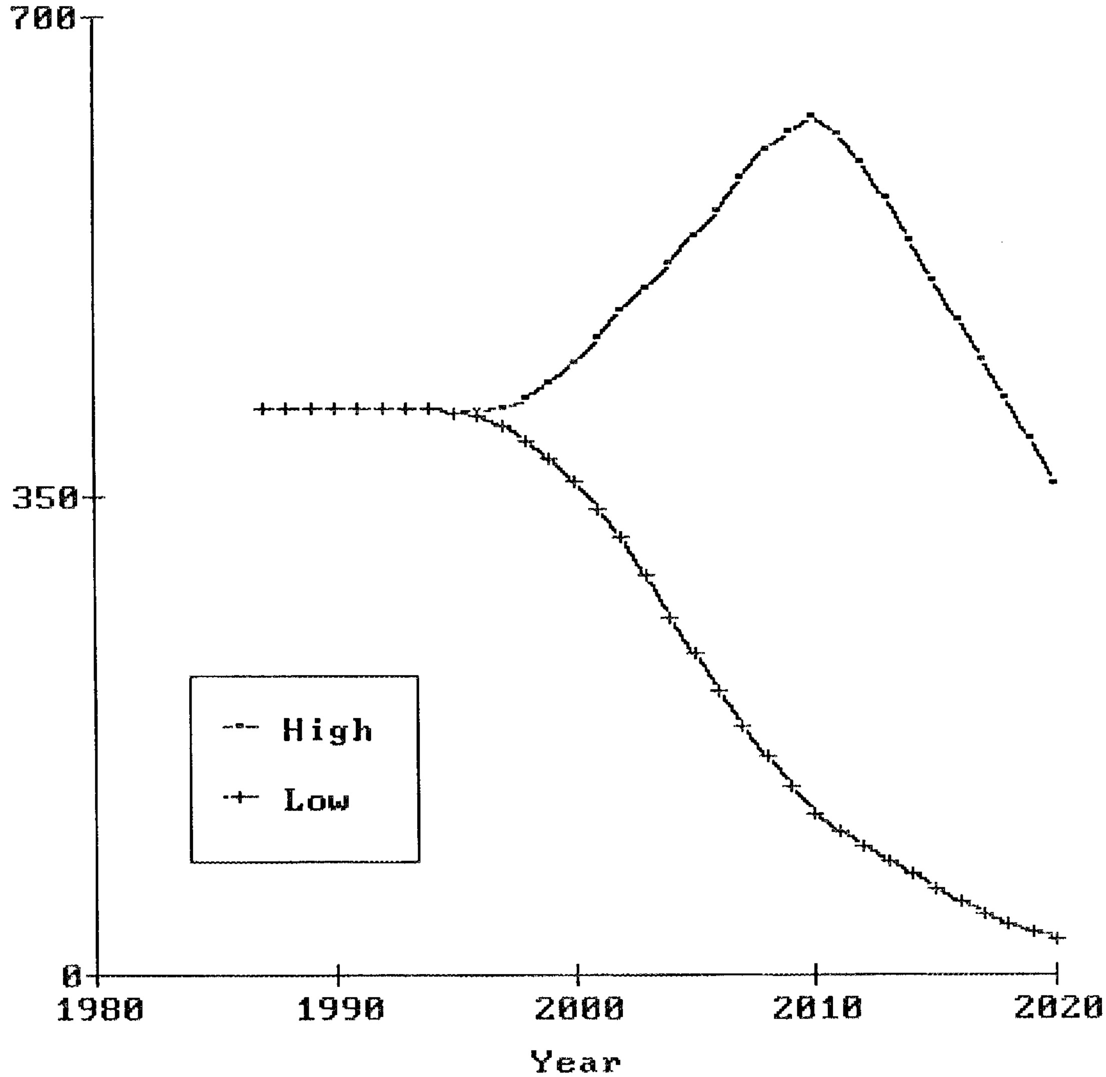

Fig. 6. Oil production in the offshore region (millions of barrels per year).

ORNL DWG-88-14593

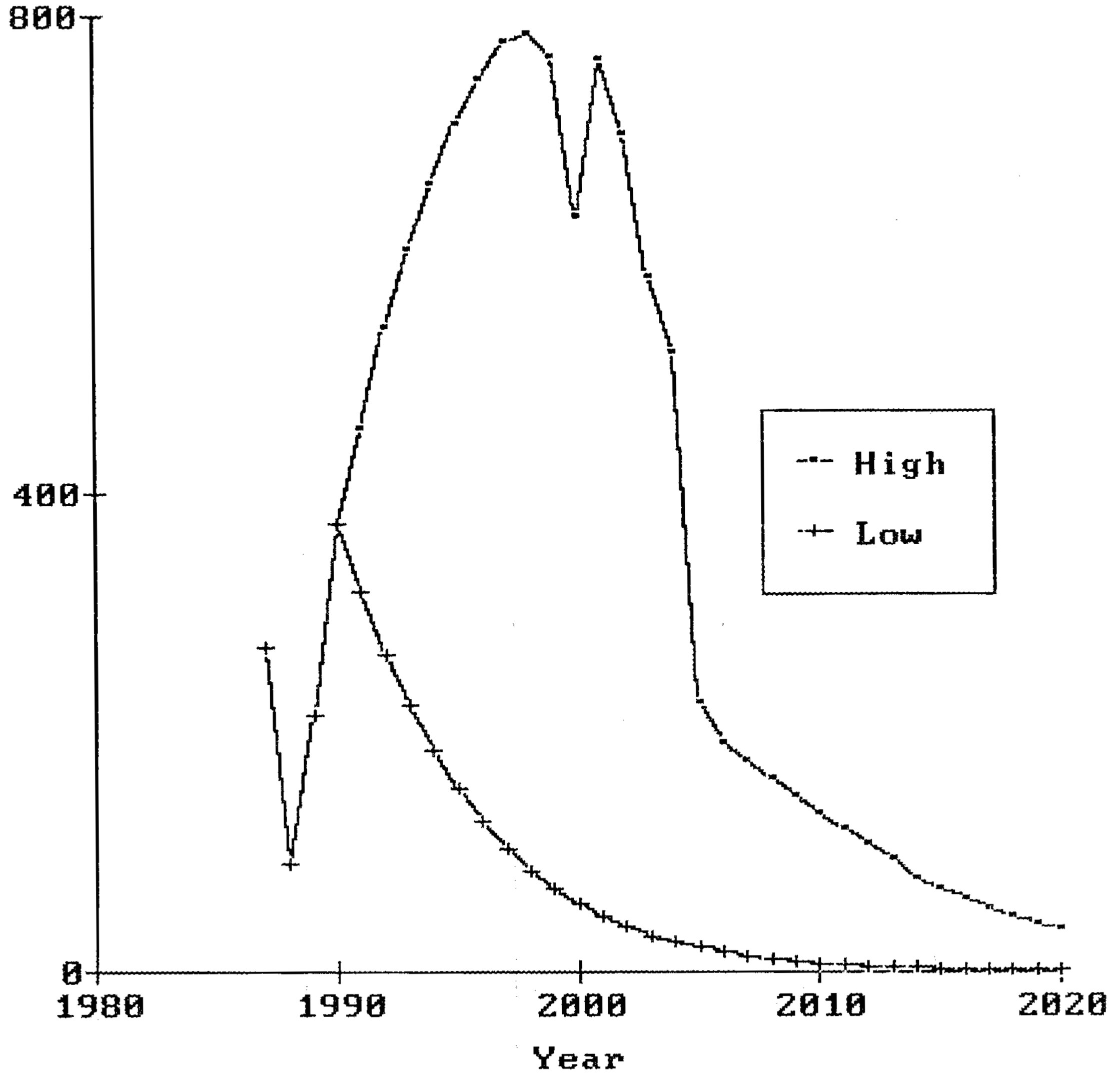

Fig. 7. Additions to proved reserves for the offshore region (millions of barrels per year).

ORNL DWG-88-14594

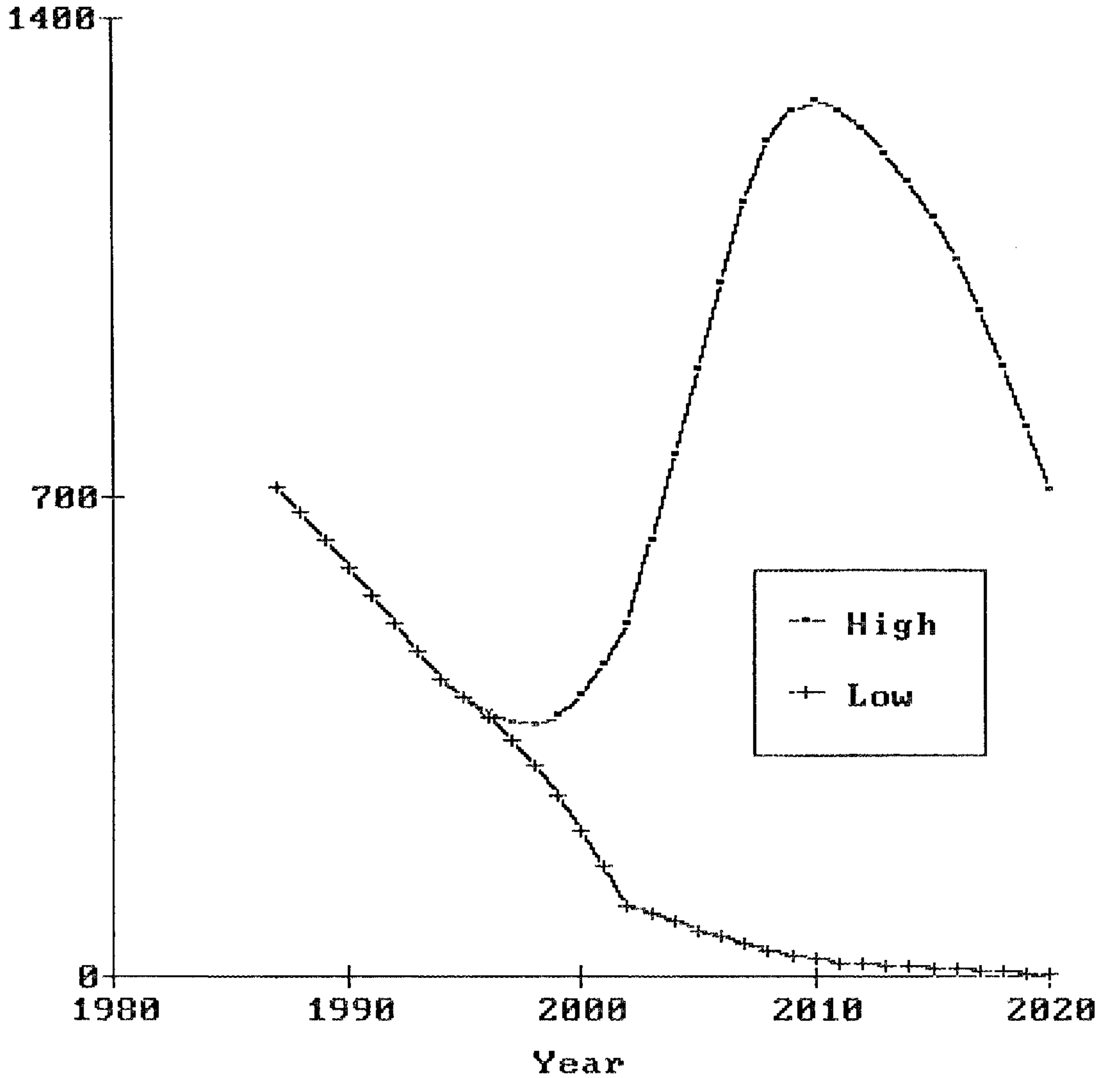

Fig. 8. Oil production in Alaska (millions of barrels per year).

ORNL DWG-88-14595

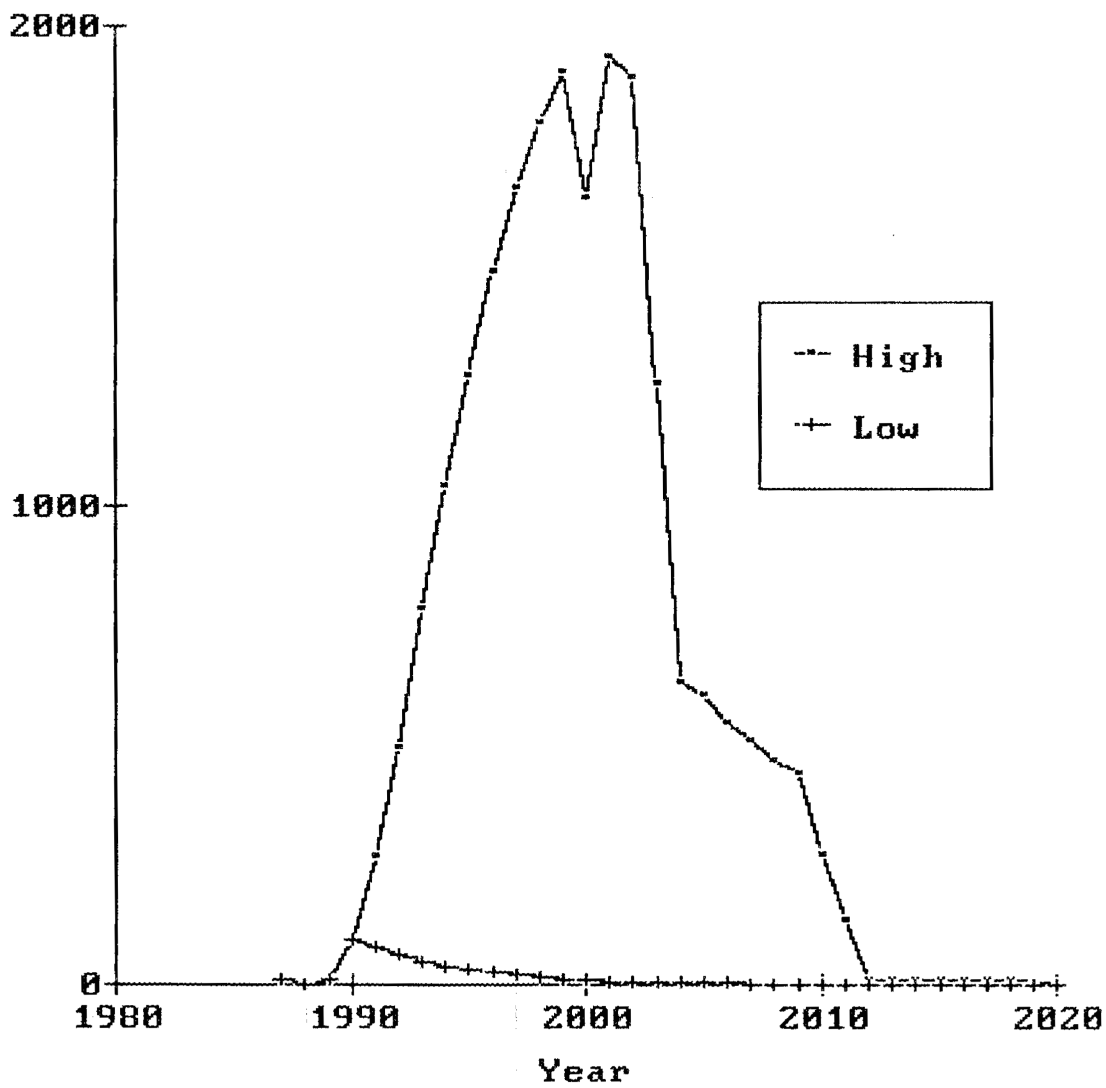

Fig. 9. Additions to proved reserves for Alaska (millions of barrels per year).

ORNL DWG-88-14596

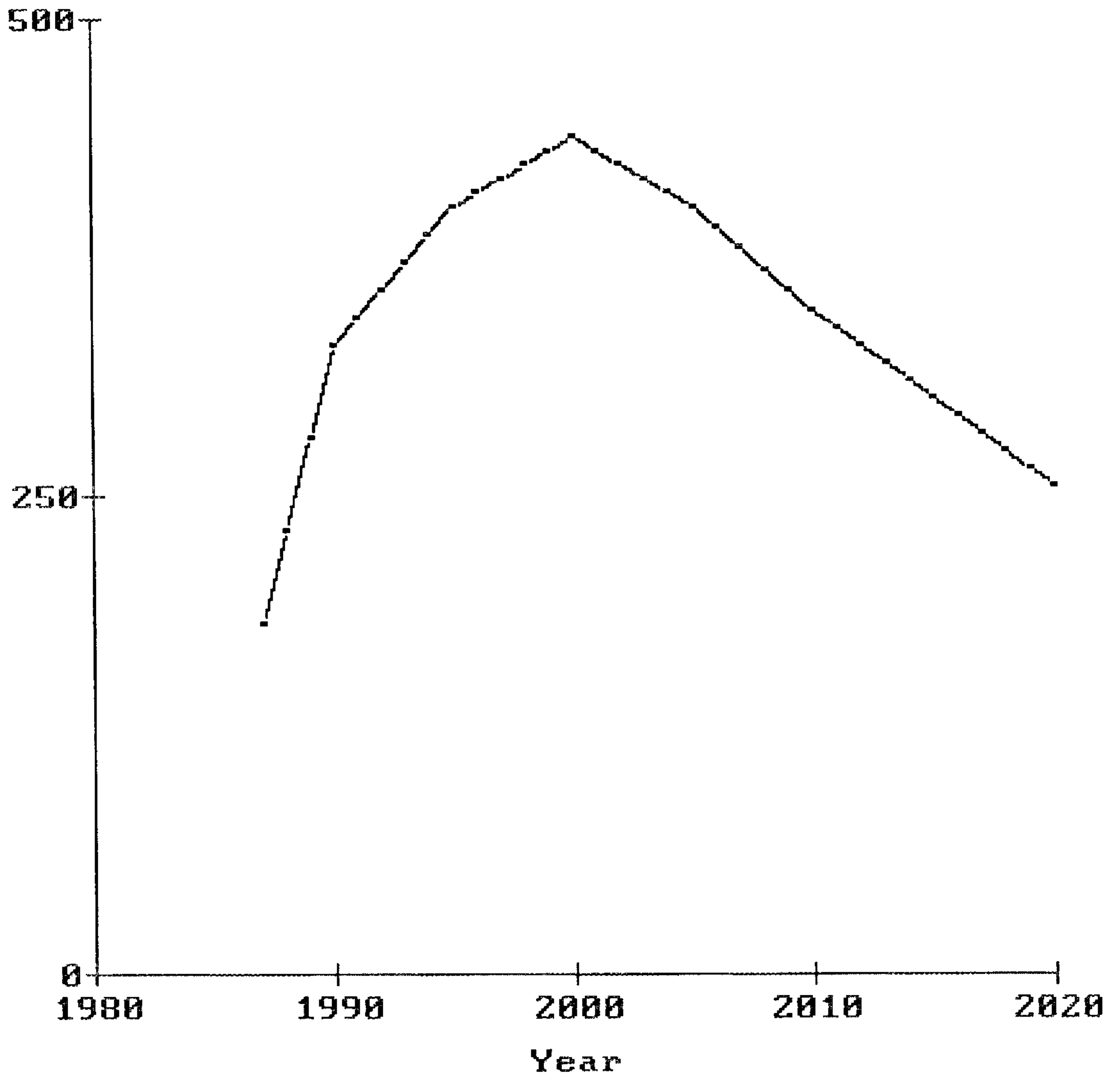

Fig. 10. Oil production from EOR and other (millions of barrels per year).

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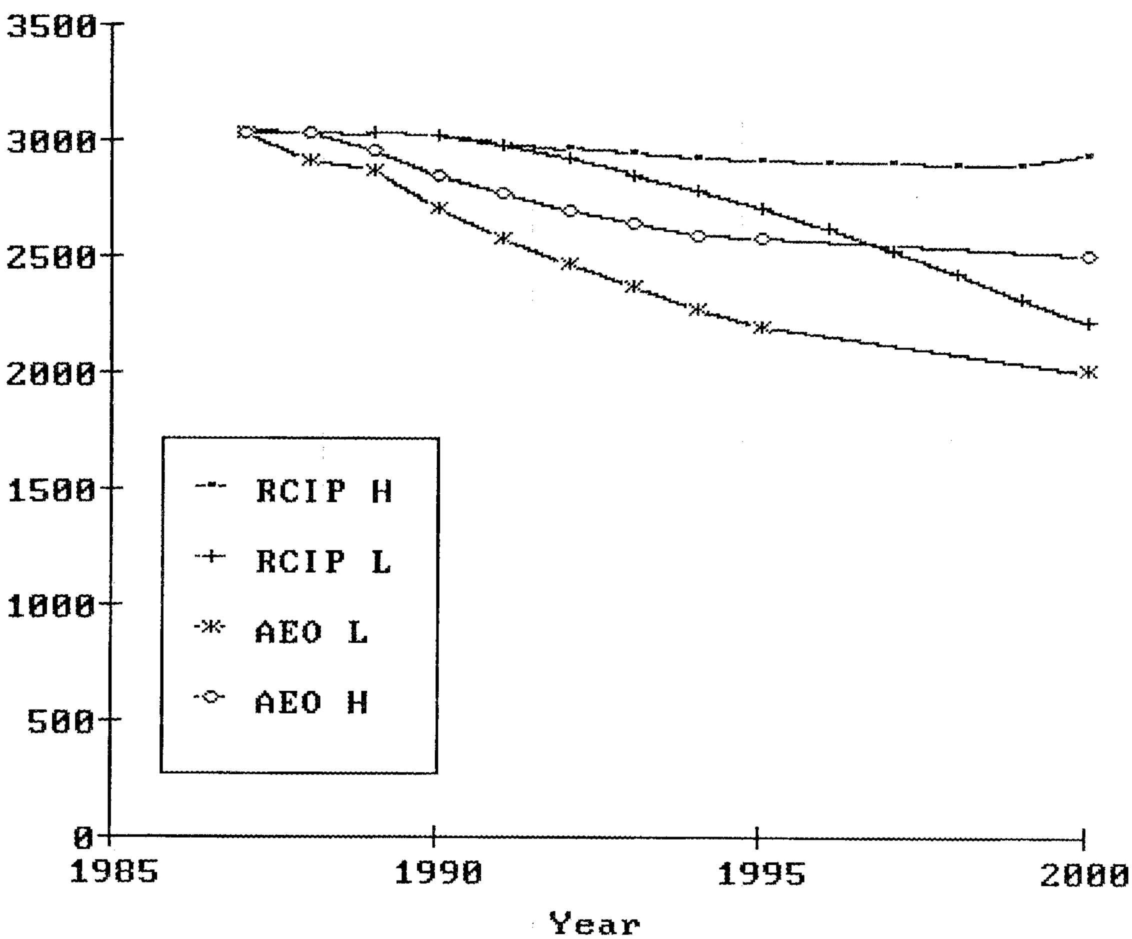

Fig. 11. Oil production in the United States forecast by RCIP and AEO (millions of barrels per year).

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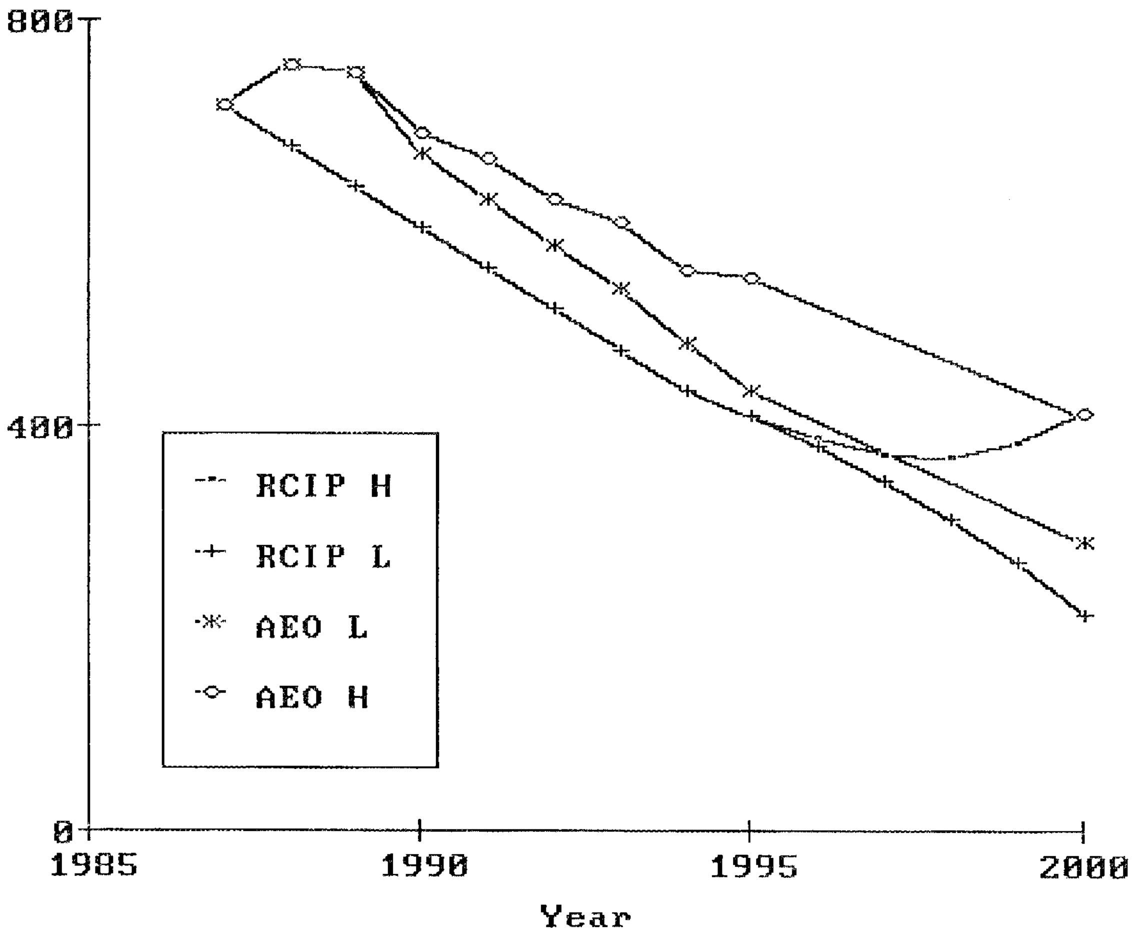

Fig. 12. Oil production in Alaska forecast by RCIP and AEO (millions of barrels per year).

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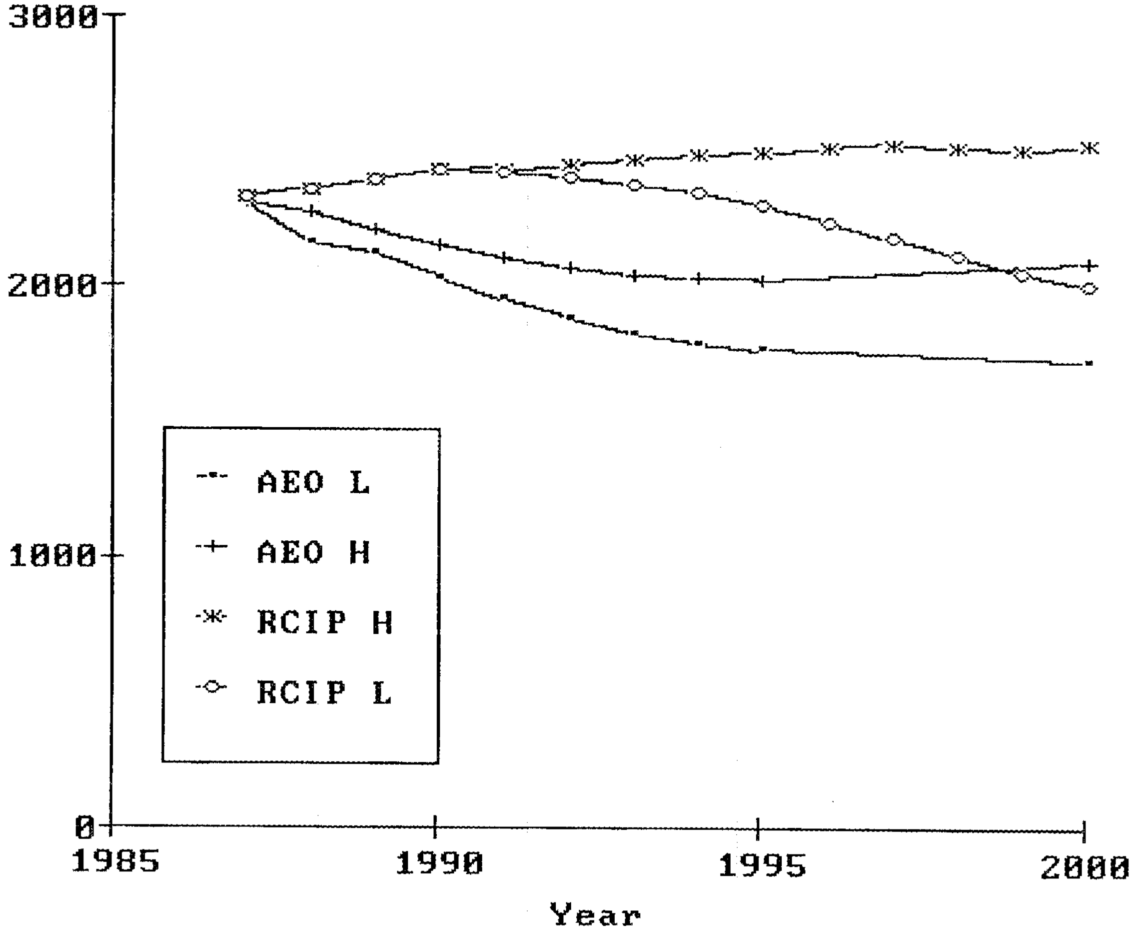

Fig. 13. Oil production in the lower 48 states forecast by RCIP and AEO (millions of barrels per year).

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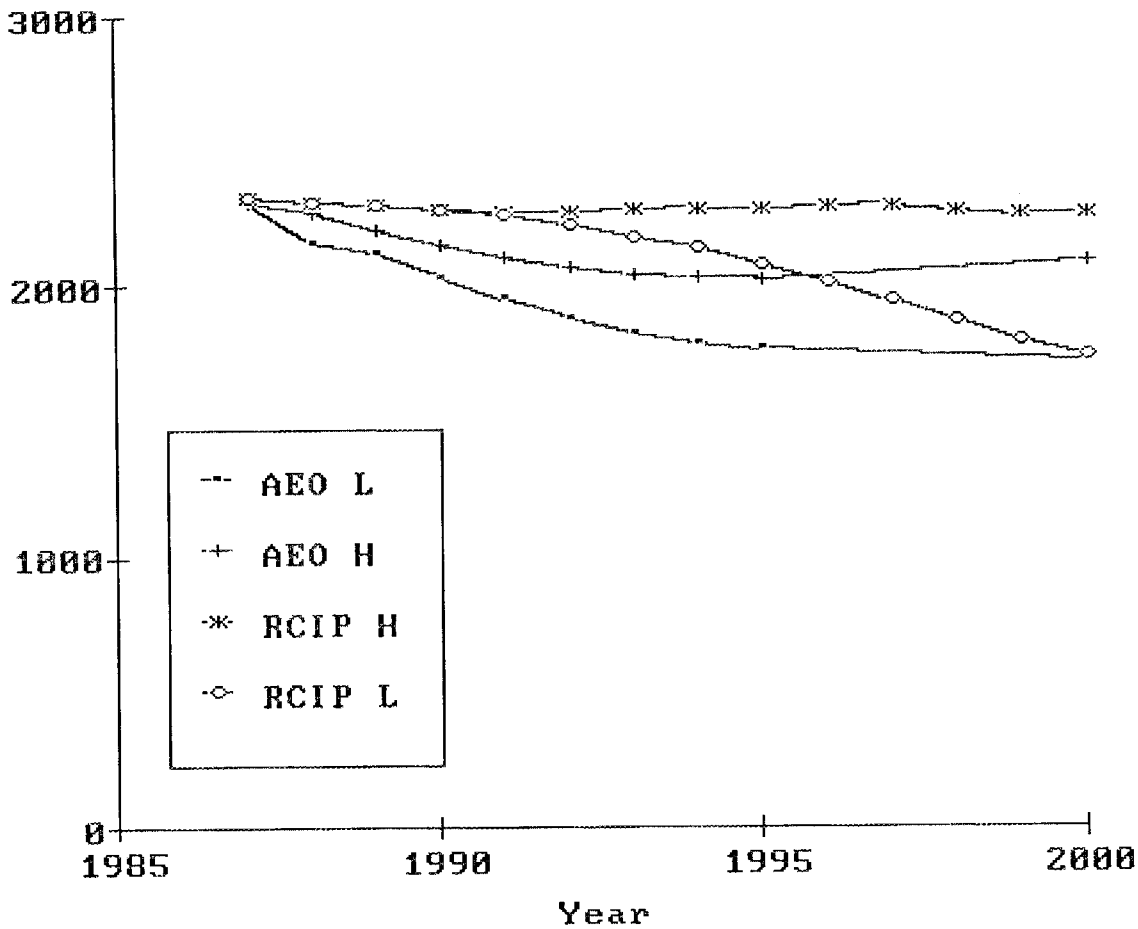

Fig. 14. Oil production in the lower 48 states forecast by RCIP and AEO (millions of barrels per year).

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