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Validation of the Replacement Cost Integration Program

David B. Reister
Daniel S. Christiansen

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Fossil
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ORNL/TM-11046

Engineering Physics and Mathematics Division

VALIDATION OF THE REPLACEMENT COST INTEGRATION PROGRAM

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TABLE OF CONTENTS

		Page
	ABSTRACT	ix
1.	INTRODUCTION	1
2.	DRILLING MODEL	3
	2.1. Finding Rate Module	3
	2.2. Profit Module	4
	2.3. Drilling Module	4
3.	VALIDATION METHODOLOGY	7
4.	RESULTS	13
5.	CONCLUSIONS	15
	REFERENCES	45
	APPENDIX - DRILLING MODEL	A-1
	Finding Rate Module	A-1
	Drilling Module	A-2

LIST OF FIGURES

Figure		Page
1	Domestic oil price (1985 dollars per barrel)	17
2	Expected growth rate for the oil price (percent per year)	18
3	Oil production cost index (1985 = 1.0)	19
4	Expected profits from exploratory drilling in the Rocky Mountain region (1985 dollars per barrel)	20
5	Exploratory drilling footage for the West Coast region (1000 feet)	21
6	Developmental drilling footage for the West Coast region (1000 feet)	22
7	Exploratory drilling footage for the Rocky Mountain region (1000 feet)	23
8	Developmental drilling footage for the Rocky Mountain region (1000 feet)	24
9	Exploratory drilling footage for the Midcontinent region (1000 feet)	25
10	Developmental drilling footage for the Midcontinent region (1000 feet)	26
11	Exploratroy drilling footage for the West Texas region (1000 feet)	27
12	Developmental drilling footage for the West Texas region (1000 feet)	28
13	Exploratory drilling footage for the Gulf Coast region (1000 feet)	29
14	Developmental drilling footage for the Gulf Coast region (1000 feet)	30
15	Exploratory drilling footage for the Appalachian region (1000 feet)	31
16	Developmental drilling footage for the Appalachian region (1000 feet)	32
17	Exploratory reserve additions for the West Coast region (million barrels)	33

LIST OF TABLES

Table		Page
1	The finding rate adjustment factor	7
2	Finding rate module parameters	9
3	Estimates of undiscovered oil - billions of barrels	10
4	Average errors for drilling footage and reserve additions (%)	13

ABSTRACT

The Oak Ridge National Laboratory and its subcontractor ICF-Lewin Energy have developed a set of computer models to forecast the replacement cost of domestic crude oil. The model REPCO forecasts the replacement cost in the lower 48 states. The Arctic Economics Model (AEM) 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 prices). 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 has been developed over several years. The most recent version was completed and delivered to DOE in January 1988. In the summer of 1987, a project was begun to validate RCIP. To validate RCIP, a historical data base was developed for the period 1970-1986, and the data base was used to estimate the parameters in the drilling model and to estimate regional finding rates. The data base includes regional data on drilling footage for exploratory and developmental wells, on additions to proved reserves from exploratory and developmental activities, and on production.

1. INTRODUCTION

The Oak Ridge National Laboratory and its subcontractor ICF-Lewin Energy have developed a set of computer models to forecast the replacement cost of domestic crude oil and natural gas and to forecast the contribution to U.S. oil supply from domestic crude oil and enhanced oil recovery. The model REPCO (REPlacement COst) forecasts the replacement cost of domestic crude oil for 6 onshore regions and 14 offshore regions.[1] 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 for the lower 48 states and 15 regions in Alaska).

The oil production process consists of three stages: drilling, reserve additions, and production. The amount of drilling is the basic investment decision. Drilling and advances in technology result in additions to proved reserves. The ratio of reserve additions and drilling (barrels/foot) is the finding rate. Since reserve additions represent uncertain process, the finding rate can exhibit wide variations from year to year. The link between oil reserve additions and production makes up the production profile.

RCIP has been developed over several years. The most recent version was completed and delivered to the Department of Energy (DOE) in January 1988. In the summer of 1987, a project was begun to validate RCIP. To validate RCIP, a historical data base was developed for the period 1970-1986, and the data base was used to estimate the parameters in the drilling model and to estimate regional finding rates. The data base includes regional data on drilling footage for exploratory and developmental wells, on additions to proved reserves from exploratory and developmental activities, and on production.

RCIP has 6 onshore regions and 10 offshore regions in the lower 48 states and 15 regions in Alaska. The available data did not include enough regional detail to develop the data base for the offshore regions and Alaska. Thus, we have developed the data base for the 6 onshore regions.

We were unable to estimate regional production profiles. Since oil wells can produce for 20 to 30 years, backcasting production for the period 1970-1986 requires a data base on additions to proved reserves for the period 1940-1986. Developing such a large regional data base was outside the scope of this project. We developed a lower-48-state data base on additions to proved reserves for the period 1931-1985 and on production for the period 1961-1985.

The project has been completed and the results are presented in three reports. This report discusses the validation of the drilling model. The second report, "Estimating Finding Rates for U.S. Crude Oil," discusses the regional data base and the regional estimates of finding rates. The third report, "The Aggregate Production Profile for U.S. Crude Oil," discusses the estimation of the aggregate production profile.

The next section provides an introduction to the principal features of the drilling model (a mathematical description of the model is in the appendix). The third section presents the methodology for the validation of the drilling model. The fourth section discusses the results of the validation. The final section presents the conclusions of the validation of RCIP.

2. DRILLING MODEL

The drilling model has three components: a finding rate module, a profit module, and a drilling module. Given the amount of undiscovered oil, the finding rate module forecasts the finding rate (barrels per foot). Given the finding rate, and a time series of values for the domestic oil price and for the expected growth rate for the domestic oil price, the profit module forecasts a time series of expected profits. Given expected profits, the drilling module forecasts the level of drilling.

2.1. Finding Rate Module

Our data base has time series of feet drilled (exploratory and developmental) and additions to proved reserves (exploratory and developmental) for the six onshore regions for the period 1970-1986. In the model, exploratory drilling is independent of developmental drilling in each of the six regions. Thus, the model forecasts 12 sets of finding rates, drilling footage, and additions to proved reserves.

The finding rate is the ratio of additions to proved reserves and drilling footage. We will use a finding rate model that was first proposed by M. King Hubbert in 1967 and subsequently used in Energy Information Administration (EIA) oil supply models and in REPCO. Our finding rate model is that the finding rate is proportional to the amount of undiscovered oil.

Although REPCO uses the same model, the definitions of the amount of undiscovered oil differ. In REPCO, the amount of undiscovered oil is equal to the U.S. Geological Survey (USGS) estimate of undiscovered recoverable resources. However, the USGS estimate is for economically recoverable resources. The finding rate will not be zero when the last economically recoverable barrel is found. Thus, the amount of undiscovered oil in RCIP should be larger than the USGS estimate of undiscovered recoverable resources.

In REPCO, the amount of oil that is discovered is calculated by multiplying the additions to proved reserves from exploratory drilling by the Hubbert Field Growth Factor (7.5811) (see p. A-6 of Ref. 1).

In RCIP, we have two sets of values for the amount of undiscovered oil --- one for exploratory drilling and a second for developmental drilling.

We have determined the values of the finding rate parameter and the amount of undiscovered oil from the historical data and we do not use the Hubbert Field Growth Factor in the finding rate equations.

2.2. Profit Module

REPCO calculates the replacement cost of domestic crude oil. The replacement cost is the constant or levelized selling price that will recover the full expenses of exploration, development, and production with a reasonable return on capital. In REPCO, the replacement cost contains the full cost of adding new reserves, including the following:

- initial investment costs for geological work, lease costs, dry holes, and the discovery well;
- subsequent investment costs for developing the oil field;
- normal operating costs, plus any special costs for conducting secondary and enhanced oil recovery;
- price adjustments for crude oil gravity and transportation;
- royalties, severance taxes, windfall profits taxes, and federal and state income taxes; and
- return on capital, based on a discount rate that reflects the long term return on invested capital within the petroleum industry.

The replacement cost is calculated using a discounted cash flow (DCF) method.[1] Given an arbitrary track for the domestic oil price and production costs, the DCF calculation produces the net present value of the profits (or losses) from an oil production project.

In RCIP, the price track is defined by the current oil price and by the value of the expected growth rate for the oil price. The values for the oil price, growth rate for the oil price, and production cost index that were used in the validation of RCIP are displayed in Figs. 1-3. The expected profits from exploratory drilling in the Rocky Mountain region are displayed in Fig. 4.

2.3. Drilling Module

Given the finding rate, a time series of values for the oil price, and for the expected growth rate for the oil price, the profit module forecasts

a time series of expected profits. The profits depend on the amount of undiscovered oil through the finding rate and on time through the price and the growth rate for price. The profits are discounted back to a common date.

The objective of the drilling module is to forecast drilling footage. However, since the finding rate relates footage and reserve additions, we can forecast reserve additions and then compute footage. As our initial model, we assume that total profits are maximized. To maximize profits, reserve additions should occur when the profits are high. In Ref. 2, we assumed that there was a constraint on the level of reserve additions and the optimum solution depended on the parameter K. When the profits are more than K, oil is discovered at the maximum rate. When the profits are less than K, no oil is discovered. In the jargon of optimal control theory, the optimal solution is bang-bang.

To avoid an exogenous constraint on reserve additions, we assume that the profits have diminishing returns to scale. At high rates of drilling, the profits are lower than at low rates of drilling. To simulate diminishing returns, we introduce a function that depends on two parameters (δ and γ). The parameter δ is dimensionless and greater than 1.0; for all 12 cases considered in the validation, the value of δ was 1.5. The value of γ determines the magnitude of the discovery rate and is measured in units of 1/Barrels; each of the 12 cases had a unique value for γ.

The optimal discovery rate depends on δ, γ, and a third parameter (K). The optimal discovery rate is zero until the profits are greater than K/δ. As the profits increase, the rate increases but never exceeds an asymptotic limit ($\delta/2*\gamma$).

In each region, we assume that there are many independent oil producers and each producer assigns different values for the expected profits and for the value of K. To simulate independent producers, we assume that there is a distribution of values for K. Given a distribution function, we can calculate the regional discovery rate.

We have chosen to use the Weibull distribution function because it is relatively easy to integrate. The Weibull distribution function depends on two parameters (ρ and σ). The parameter σ controls the mean value of the distribution, while the parameter ρ controls the width of the distribution. As ρ increases, the distribution becomes narrower and the average value of

K approaches σ. For the 12 cases, the value of ρ was $\rho = 2.0$, while the values of σ ranged from 2.0 to 4.0.

Given the expected value for the profits (P) and values for the four parameters (δ, γ, σ, and ρ), we can calculate the average discovery rate in the region. Given the discovery rate, the finding rate determines the drilling footage.

3. VALIDATION METHODOLOGY

To validate the drilling model, we created a special version of RCIP that backcasts drilling footage and additions to proved reserves for the onshore regions of the lower 48 states for the period 1970-1986. For each of the 12 cases (6 regions and exploratory or developmental), the model produces an output file with the values of the model backcast, the historical data, and the error. The file displays average values for the error.

When we began to run the special version of RCIP, we found that the profits were negative for most years. Since the profits are calculated by REPCO, the proper way to correct the problem would have been to validate the parameters in REPCO. However, the validation of REPCO was outside the scope of this project. The objective of this project is to validate the drilling model in RCIP.

To create positive profits, we introduced an adjustment factor that multiplies the finding rate in RCIP to create the finding rate used by REPCO. The 12 values for the adjustment factor are displayed in Table 1. The values range from 0.89 to 4.21. The values were chosen to make the profits positive in most years. The goal was accomplished by making the profits in 1970 approximately equal to $2.00 per barrel. (The base year for the discounted values is 1988. Thus, if the profits were $2.00 when discounted to 1988, they were $0.36 in 1970.)

Table 1. The finding rate adjustment factor

Region	Exploratory	Developmental
West Coast	4.00	0.89
Rocky Mountains	3.70	1.25
Midcontinent	2.36	2.60
West Texas	2.88	1.16
Gulf Coast	1.53	2.08
Appalachia	1.46	4.21

We would expect exploratory drilling to be less profitable than developmental drilling. Since we have chosen the values of the adjustment factors to make the exploratory profits approximately equal to the developmental profits in 1970, we would expect the exploratory adjustment factors to be larger than the developmental factors. In Table 1, the average value for the exploratory factors (2.66) is larger than the average value for the developmental factors (2.03). However, the largest and smallest factors are both for developmental drilling.

The large magnitudes for the adjustment factors are undesirable. Further work is required to integrate REPCO and RCIP.

Our finding rate model is that the finding rate is proportional to the amount of undiscovered oil. The parameter that relates the finding rate to the amount of undiscovered oil is β. If β is too large, the finding rate decreases rapidly and the profits become negative. We began with the values for β and the amount of undiscovered oil that were determined econometrically [Christiansen (1988)].

In the cases where the profits became negative, we reduced the value of β and adjusted the values of the amount of undiscovered oil to preserve the average values for the finding rate. To be more precise, we adjusted the amount of undiscovered oil such that if the model backcast was adjusted to match the 17-year total for drilling footage, then the model would backcast the correct 17-year total for additions to proved reserves.

The final set of values for β and for the amount of undiscovered oil in 1970 are displayed in Table 2. For these values, the profits were positive in all years from 1970-1990 except for one value (exploratory drilling on the Gulf Coast in 1986).

All the values of β used for the validation of RCIP are smaller than the econometric estimates. Generally, the final values are about a factor of 2 smaller than the econometric values. If the initial finding rate is constant, a reduction in β requires a corresponding increase in the estimate of undiscovered oil. However, if the rate of decrease is slower and the average is constant, the initial finding rate will also be reduced. For undiscovered oil in 1970, all the estimates from the validation of RCIP increase in comparison to the economical estimates, but the increases are all less than a factor of 2.

Table 2. Finding rate module parameters

Region	RCIP Validation Explore	RCIP Validation Develop	Econometric Explore	Econometric Develop
Parameter β - 1/Billions of Feet				
West Coast	10.0	1.0	-	-
Rocky Mountains	2.5	2.0	-	2.6
Mid Continent	5.0	1.4	8.9	3.8
West Texas	7.0	1.0	13.8	2.3
Gulf Coast	5.0	2.5	9.2	5.1
Appalachia	20.0	3.7	51.2	7.5
Undiscovered Oil in 1970 - Billions of Barrels				
West Coast	0.46	61.32	-	-
Rocky Mountains	1.71	11.51	-	9.01
Midcontinent	0.94	6.06	0.60	3.10
West Texas	0.65	22.63	0.42	11.34
Gulf Coast	2.14	5.27	1.36	2.90
Appalachia	0.51	2.17	0.28	1.48

As RCIP backcasts additions to proved reserves, the amount of undiscovered oil decreases. The amount of undiscovered oil backcast by RCIP is compared to estimates by the USGS in Table 3. For 1980, the USGS estimates are from Circular 860. For 1987, the preliminary USGS estimates are from Open-File Report 88-373.

In RCIP, undiscovered oil includes all future additions to proved reserves from exploratory or developmental drilling. To estimate a comparable number from the USGS reports, we add the mean estimate of undiscovered recoverable resources to the sum of indicated reserves and inferred reserves.

We expect that the RCIP estimate of undiscovered oil should be somewhat larger than the USGS estimate. The USGS estimates are based on economically recoverable resources. When the last economically recoverable barrel is added to proved reserves, the finding rate should be greater than zero.

For the West Coast, the RCIP estimate is much larger than both of the USGS estimates. We assume that the high values on the West Coast are due to additions to proved reserves from heavy oil in California. For the Rocky Mountain region, the RCIP estimate is much smaller than the 1980 USGS

estimate, but it is slightly larger than the 1987 estimate. The 1987 estimate is consistent with our expectations, while the 1980 estimate by USGS appears to be too large.

Table 3. Estimates of undiscovered oil - billions of barrels

1980

Region	RCIP Validation Explore	Develop	Total	Circular 860
West Coast	0.4	59.3	59.7	7.2
Rocky Mountains	1.5	9.9	11.4	27.7
Midcontinent	0.8	4.7	5.5	6.0
West Texas	0.5	18.2	18.6	10.7
Gulf Coast	1.7	3.5	5.2	12.6
Appalachia	0.4	1.6	2.0	4.0

1987

Region	RCIP Validation Explore	Develop	Total	Report 88-373
West Coast	0.4	57.1	57.5	4.0
Rocky Mountains	1.2	8.1	9.3	7.5
Midcontinent	0.6	3.1	3.7	3.2
West Texas	0.3	13.7	14.0	5.4
Gulf Coast	1.3	2.0	3.3	8.5
Appalachia	0.2	1.1	1.3	2.8

For the Midcontinent region, the RCIP estimate is smaller than the 1980 estimate and larger than the 1987 estimate. The 1987 estimate is consistent with our expectations. For the West Texas region, the RCIP estimates appear to be too high. We do not have a hypothesis to explain why the RCIP results are high.

For both the Gulf Coast and Appalachian regions, the RCIP estimates appear to be too small and we do not have an explanation for the results.

In summary, the RCIP results are roughly consistent with the 1987 USGS results except for the West Coast.

The expected growth rates for future oil prices are displayed in Fig. 2. Our initial choice for the growth rates was 0% from 1970 to 1973, 2% in 1974, 1% from 1975 to 1978, and 2% from 1979 to 1981. Since the drilling

behavior backcast by RCIP was much more volatile than the historical data, we reduced the growth rates in the period before 1981 (the rates grow linearly from 0% in 1970 to 1% in 1978 and 2% in 1981). Despite our reductions of the growth rates, the RCIP results remain too volatile in the period before 1979. To encourage drilling in the period of low prices after 1985, we raised the growth rates to 2% from 1986 to 1990.

We did not use a nonlinear search procedure to determine the parameters in the drilling model. For all 12 cases, the value of δ was 1.5 and the value of ρ was 2.0. The parameter σ was used to match the drilling peak in 1981. The values of σ ranged from 2.0 to 4.0. The parameter γ was used to match the historical data on total feet drilled during the validation period. For the 12 cases, the largest error for total feet in the 17-year period was less than 0.2%, while the largest error for total additions to proved reserves was less than 0.5% (recall that we chose the parameters for the finding rate to match total barrels with total feet).

4. RESULTS

The model backcasts of drilling footage are compared to historical data in Figs. 5-16, while Figs. 17-28 display the results for additions to proved reserves. The average errors for both drilling footage and reserve additions are presented in Table 4. The average error is the sum of the absolute values of the differences between the model backcast and the historical data divided by the sum of the absolute values of the historical data.

For drilling footage, we distinguish three periods: 1970-1978, 1979-1985, and 1986. A typical example of the period 1970-1978 is Fig. 7 (exploratory drilling in the Rocky Mountains region). In Fig. 7, the historical data on drilling footage is flat from 1970-1978, while the model shows a sharp response to the price increase in 1974. In general, the model is more volatile than the data in the period 1970-1978.

The period 1979-1985 is the boom period for drilling. A good correspondence between the model and the data is provided by Fig. 10 (developmental drilling in the Midcontinent region). In general, the model fits the data in the drilling boom period.

Table 4. Average errors for drilling footage and reserve additions (%)

	Drilling Footage		Reserve Additions	
Region	Explore	Develop	Explore	Develop
West Coast	39	27	38	53
Rocky Mountains	36	24	35	42
Midcontinent	37	24	56	59
West Texas	27	26	38	60
Gulf Coast	29	38	45	77
Appalachia	18	20	46	36

In all cases, the drilling footage backcast by the model is less than the data in 1986.

The average errors for drilling footage range from 18 to 39%. When the error is less than 30%, the model backcast appears to be close to the historical data in the figures.

The model responds to changes in profits and prices without a lag. In 9 of the 12 cases, the data exhibits a 1-year lag in responding to the price explosion from 1978-1981. The exceptions are West Coast exploratory (where the drilling boom precedes the price explosion), Midcontinent developmental, and Appalachian developmental.

The historical data on additions to proved reserves are more volatile than the data on drilling footage. Developmental reserve additions can have large negative values (see Fig. 26). Although the average errors are large (ranging from 35 to 77%), the model backcasts of reserve additions appear to track the highly variable data in most cases.

5. CONCLUSIONS

The Oak Ridge National Laboratory and its subcontractor ICF-Lewin Energy have developed a set of computer models to forecast the replacement cost of domestic crude oil and natural gas and to forecast the contribution to U.S. oil supply from domestic crude oil and enhanced oil recovery. The model REPCO (REPlacement COst) 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 for the lower 48 states and 15 regions in Alaska).

The oil production process consists of three stages: drilling, reserve additions, and production. The amount of drilling is the basic investment decision. Drilling and advances in technology result in additions to proved reserves. The ratio of reserve additions and drilling (barrels/foot) is the finding rate. Since reserve additions represent an uncertain process, the finding rate can exhibit wide variations from year to year. The link between oil reserve additions and production makes up the production profile.

RCIP has been developed over several years. The most recent version was completed and delivered to DOE in January 1988. In the summer of 1987, a project was begun to validate RCIP. To validate RCIP, a historical data base was developed for the period 1970-1986, and the data base was used to estimate the parameters in the drilling model and to estimate regional finding rates. The data base includes regional data on drilling footage for exploratory and developmental wells, on additions to proved reserves from exploratory and developmental activities, and on production.

The drilling model is described in Section 2 and the appendix. To validate the drilling model, we created a special version of RCIP that backcasts drilling footage and additions to proved reserves for the onshore regions of the lower 48 states for the period 1970-1986.

When we began to run the special version of RCIP, we found that the profits were negative for most years. To create positive profits, we

introduced an adjustment factor that multiplies the finding rate in RCIP to create the finding rate used by REPCO. The large magnitudes for the adjustment factors are undesirable. Further work is required to integrate REPCO and RCIP.

We adjusted the values of the two parameters in our finding rate model (β and undiscovered oil) to prevent negative profits and match the average values for the finding rate. For two regions (Gulf Coast and Appalachia), we should increase our estimates of undiscovered oil to make them larger than the preliminary values in Open-File Report 88-373. For the West Coast region, our estimates of undiscovered oil are too high. We need to correct our data base to exclude the reserve additions from heavy oil. Ultimately, we need to develop a heavy oil module in RCIP.

For drilling footage, we distinguish three periods: 1970-1978, 1979-1985, and 1986. The model is more volatile than the data in the period from 1970-1978. The model fits the data in the drilling boom period (1979-1985). In all cases, the drilling footage backcast by the model is less than the data in 1986. In 9 of the 12 cases, the data exhibits a 1-year lag in responding to the oil price explosion from 1978-1981.

The historical data on additions to proved reserves are more volatile than the data on drilling footage. Developmental reserve additions can have large negative values. Although the average errors are large (ranging from 35 to 77%), the model backcasts of reserve additions appear to track the highly variable data in most cases.

We have specified a model of drilling of exploratory and developmental oil wells. The model has a firm foundation of economic theory. We have developed a data base and have determined parameter values that provide a satisfactory match with the historical data.

We have identified several opportunities for future research. The first is to improve the integration of RCIP and REPCO and eliminate the large magnitudes for the adjustment factors. The second is to develop improved models of heavy oil, enhanced oil recovery (EOR), and infill drilling.

ORNL/DWG-896051

Fig. 1. Domestic oil price (1985 dollars per barrel).

ORNL/DWG-896052

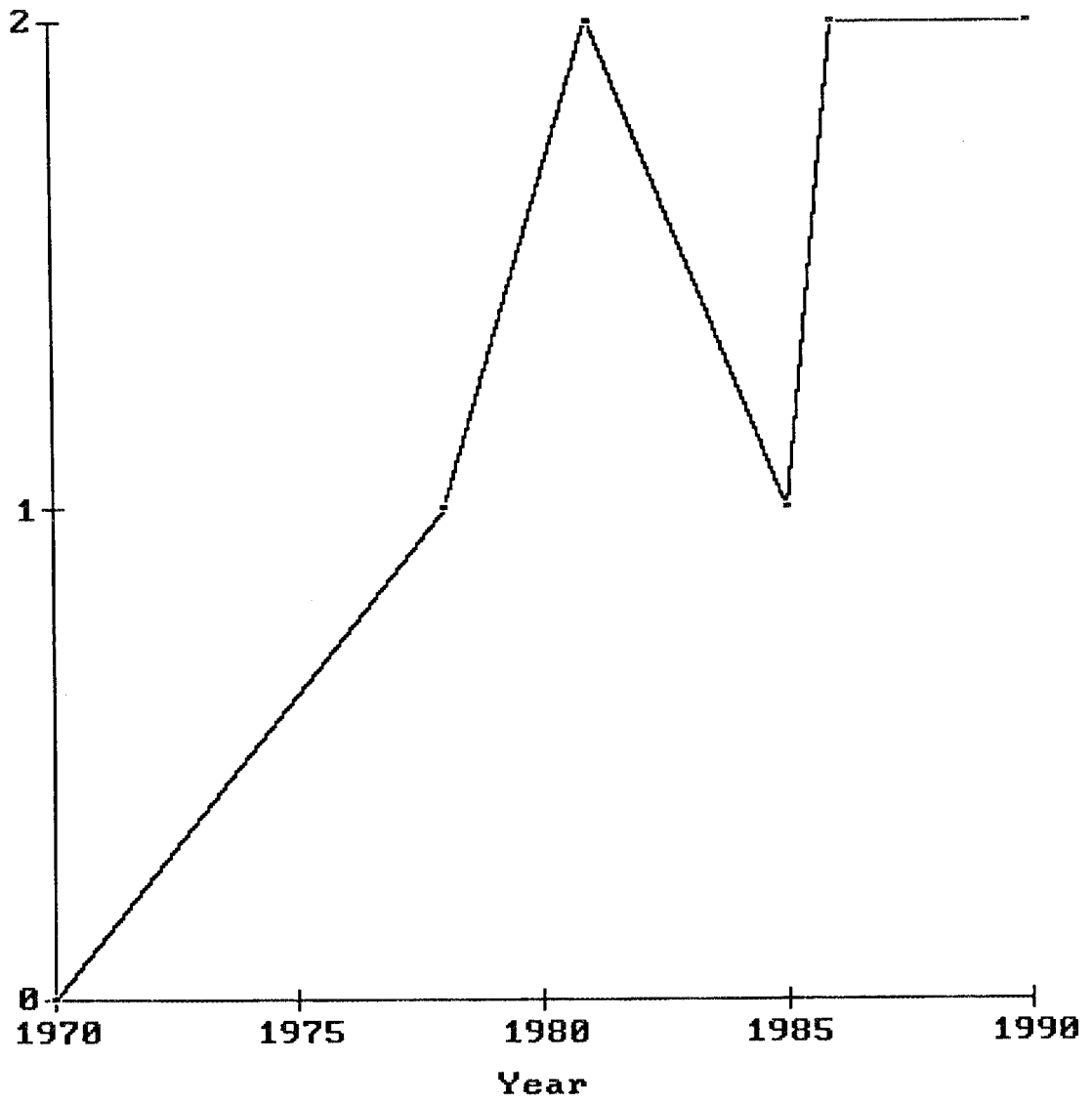

Fig. 2. Expected growth rate for the oil price (percent per year).

ORNL/DWG-896053

Fig. 3. Oil production cost index (1985 = 1.0).

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Fig. 4. Expected profits from exploratory drilling in the Rocky Mountain region (1985 dollars per barrel).

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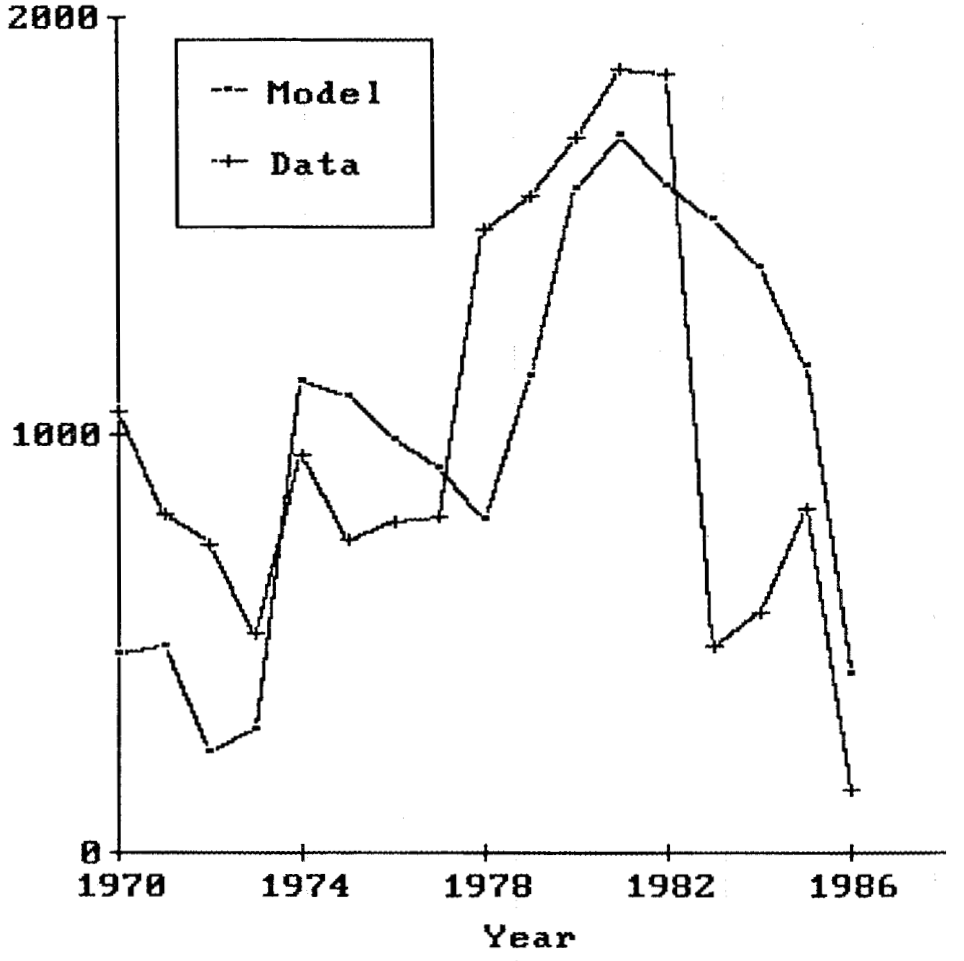

Fig. 5. Exploratory drilling footage for the West Coast region (1000 feet).

ORNL/DWG-896056

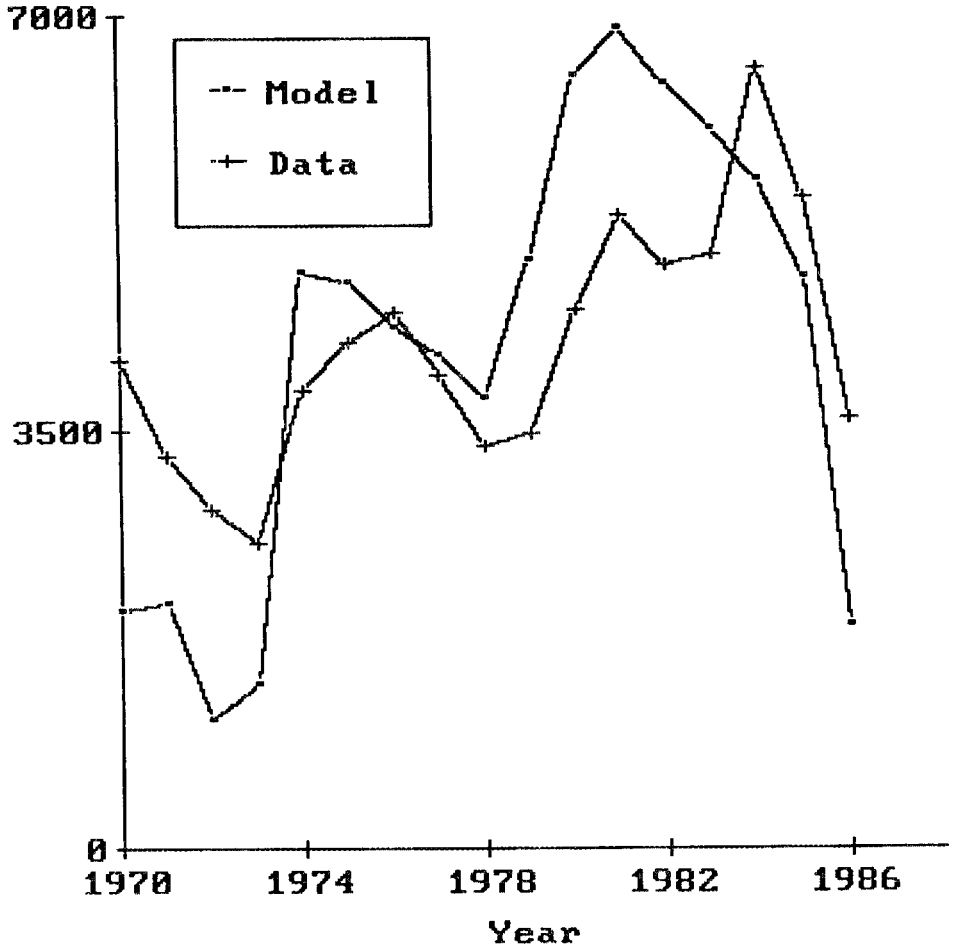

Fig. 6. Developmental drilling footage for the West Coast region (1000 feet).

ORNL/DWG-896057

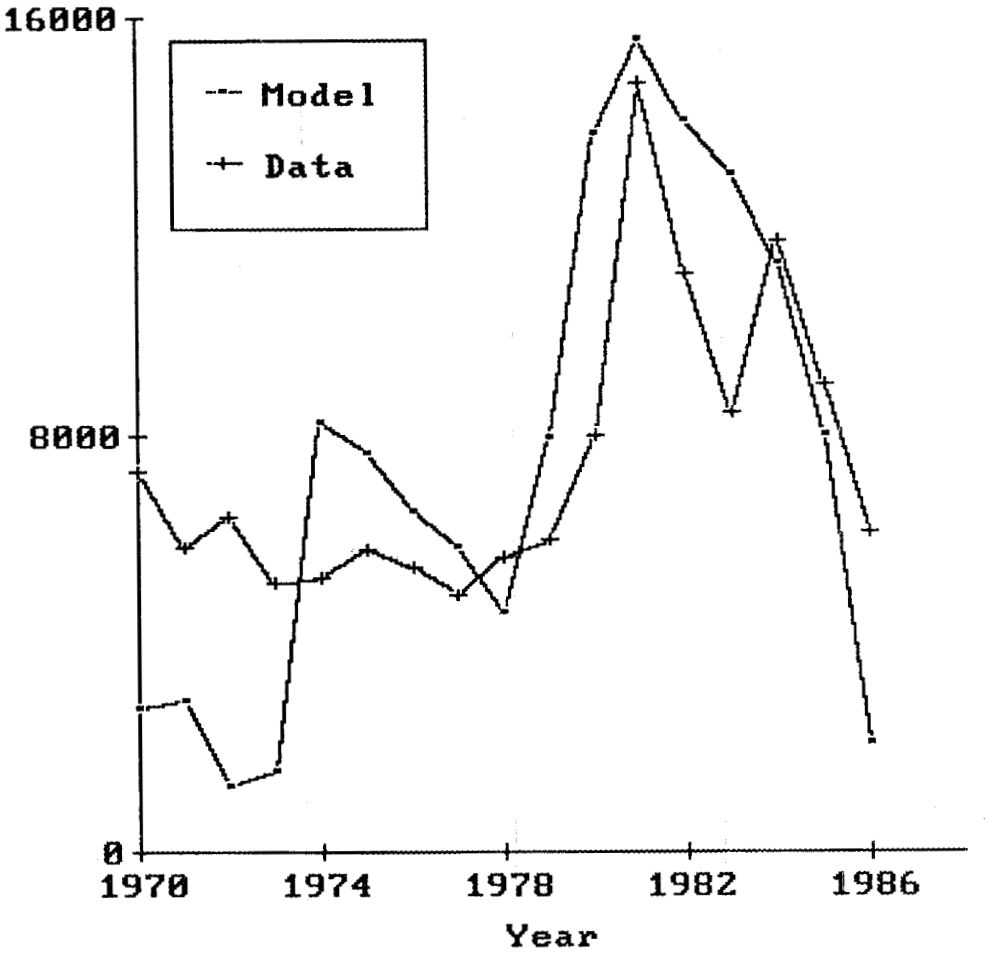

Fig. 7. Exploratory drilling footage for the Rocky Mountain region (1000 feet).

ORNL/DWG-896058

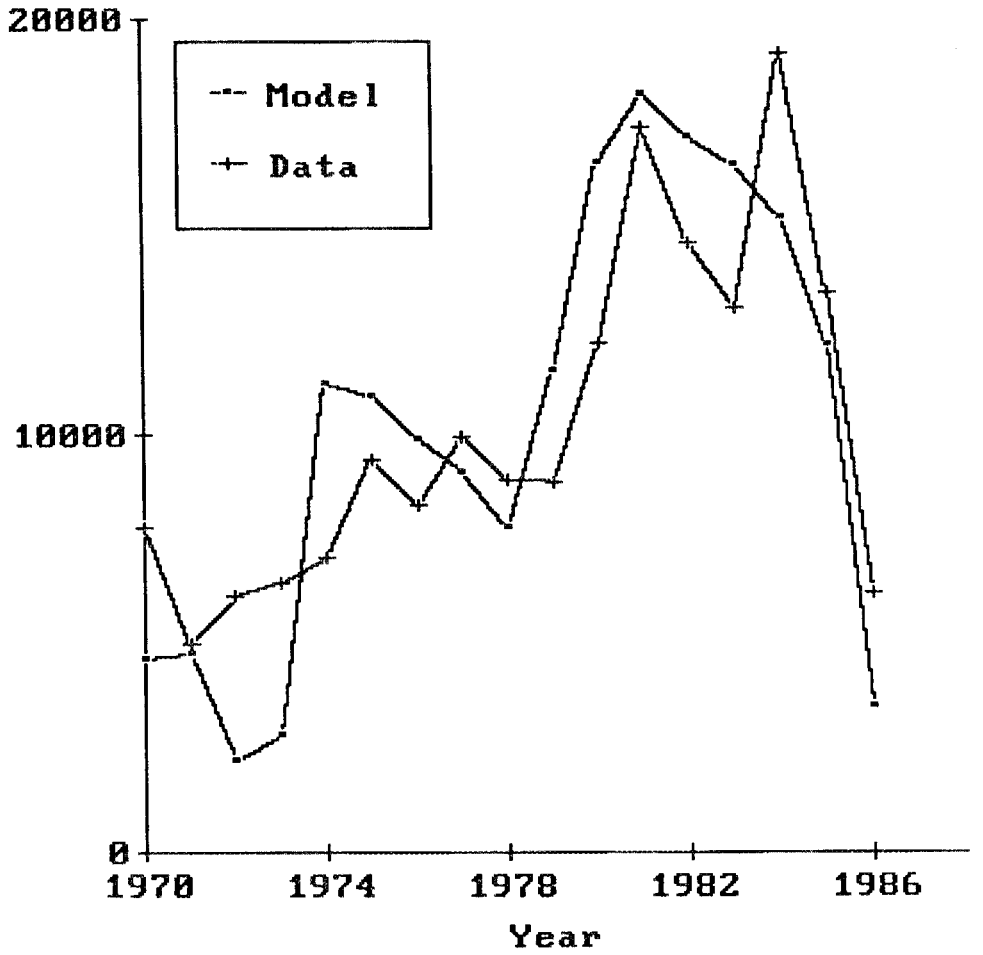

Fig. 8. Developmental drilling footage for the Rocky Mountain region (1000 feet).

ORNL/DWG-896059

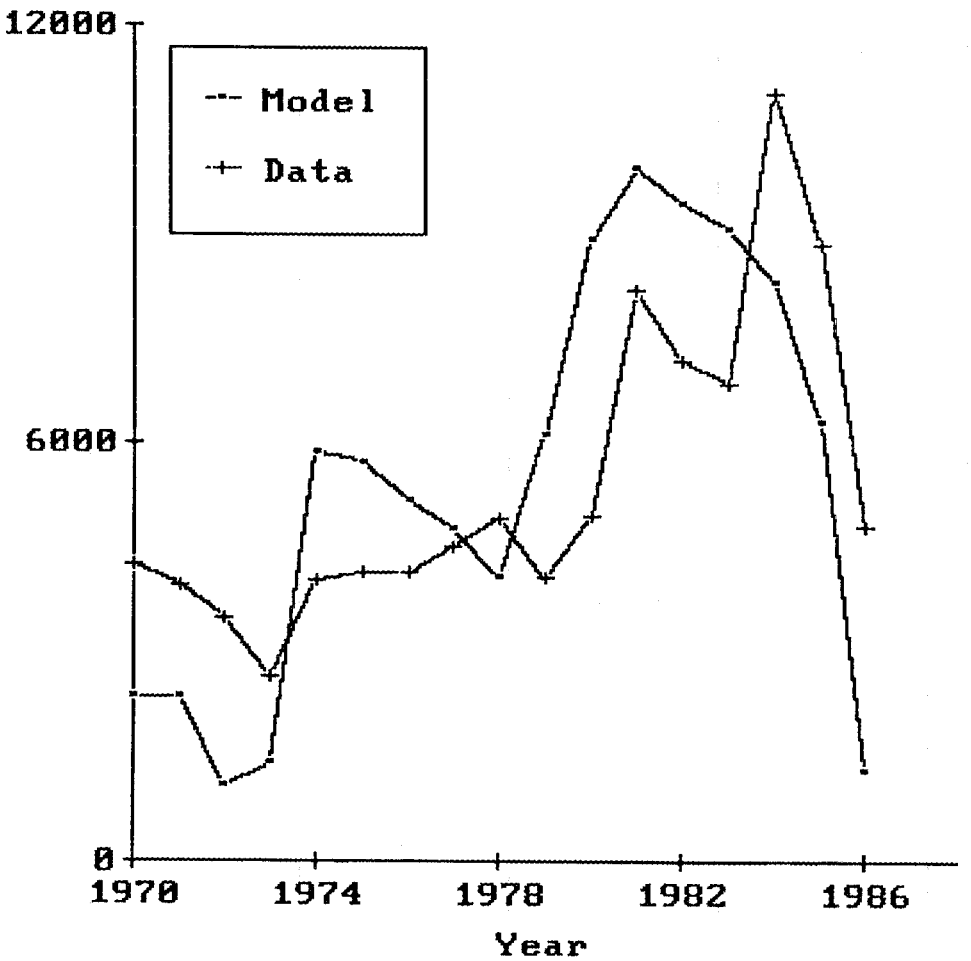

Fig. 9. Exploratory drilling footage for the Midcontinent region (1000 feet).

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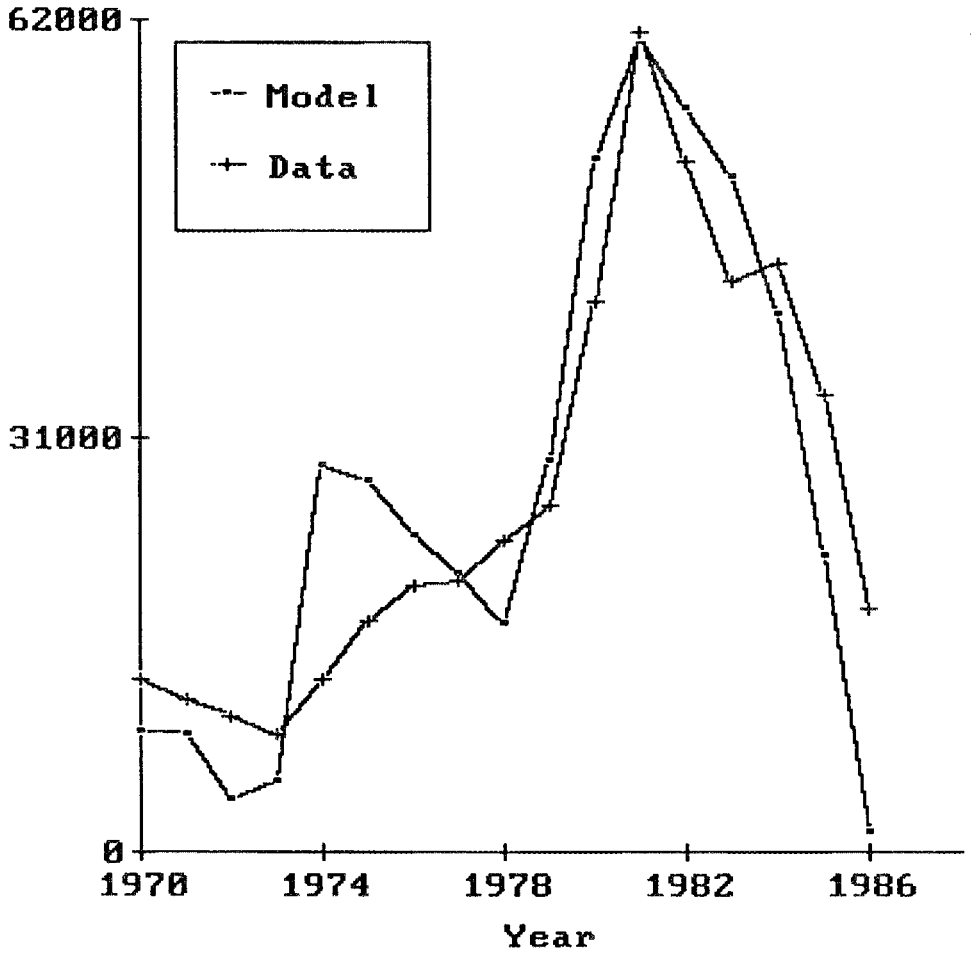

Fig. 10. Developmental drilling footage for the Midcontinent region (1000 feet).

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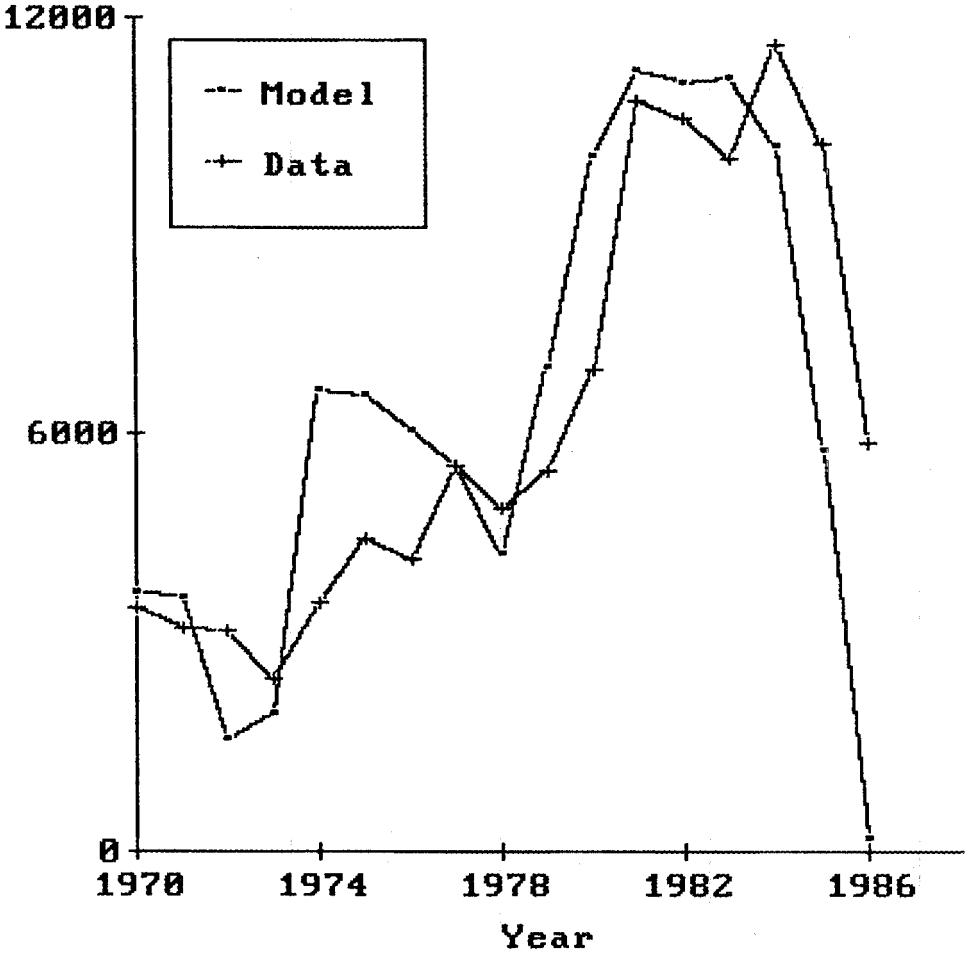

Fig. 11. Exploratory drilling footage for the West Texas region (1000 feet).

ORNL/DWG-896062

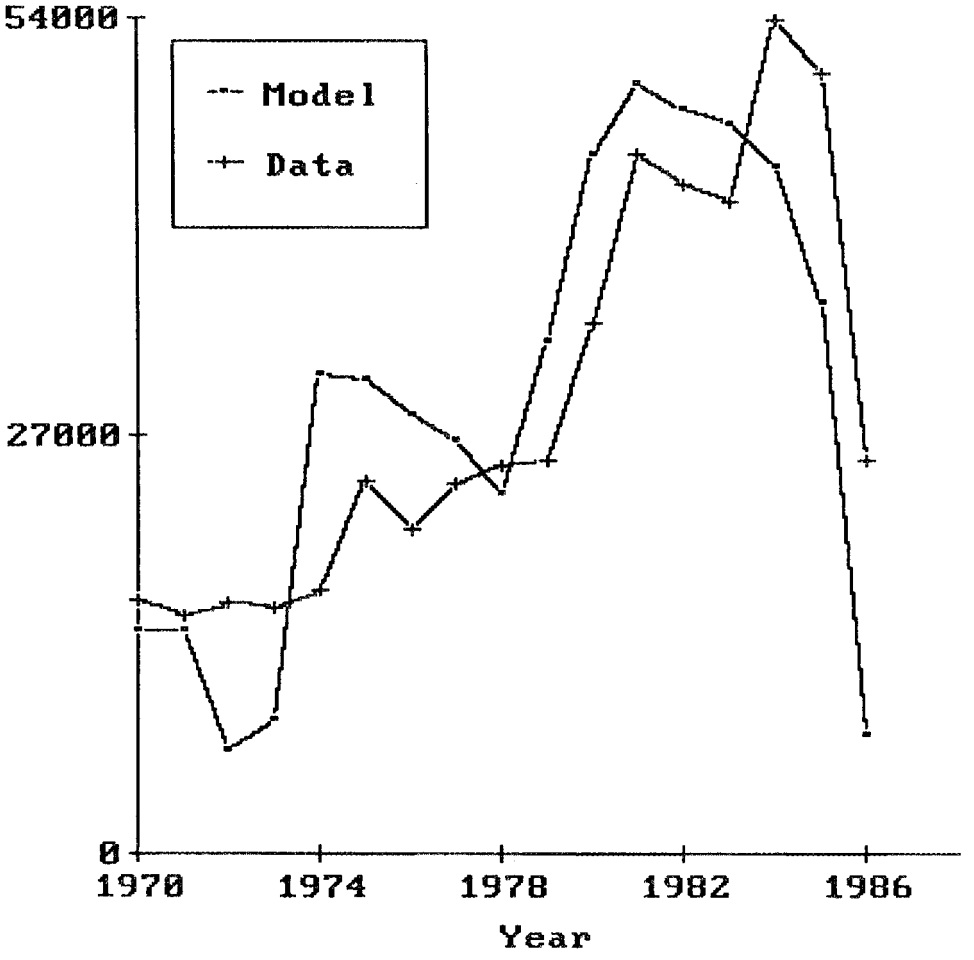

Fig. 12. Developmental drilling footage for the West Texas region (1000 feet).

ORNL/DWG-896063

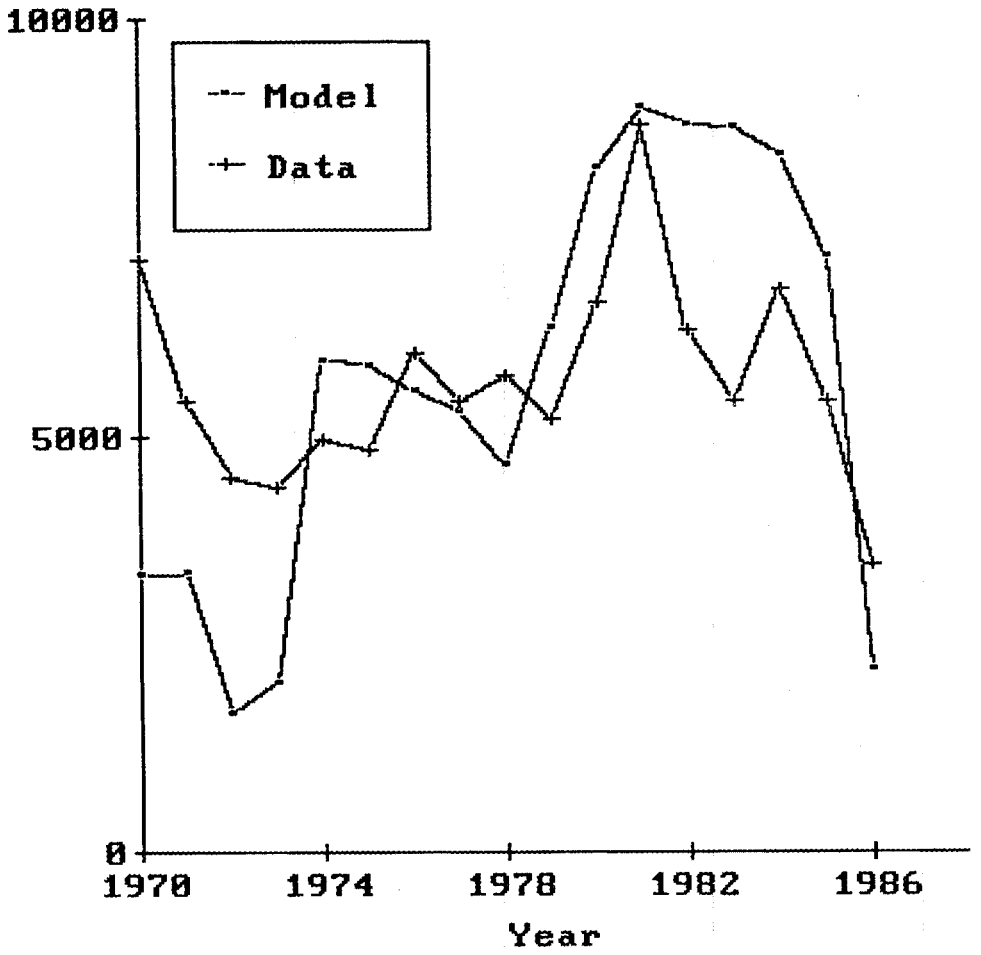

Fig. 13. Exploratory drilling footage for the Gulf Coast region (1000 feet).

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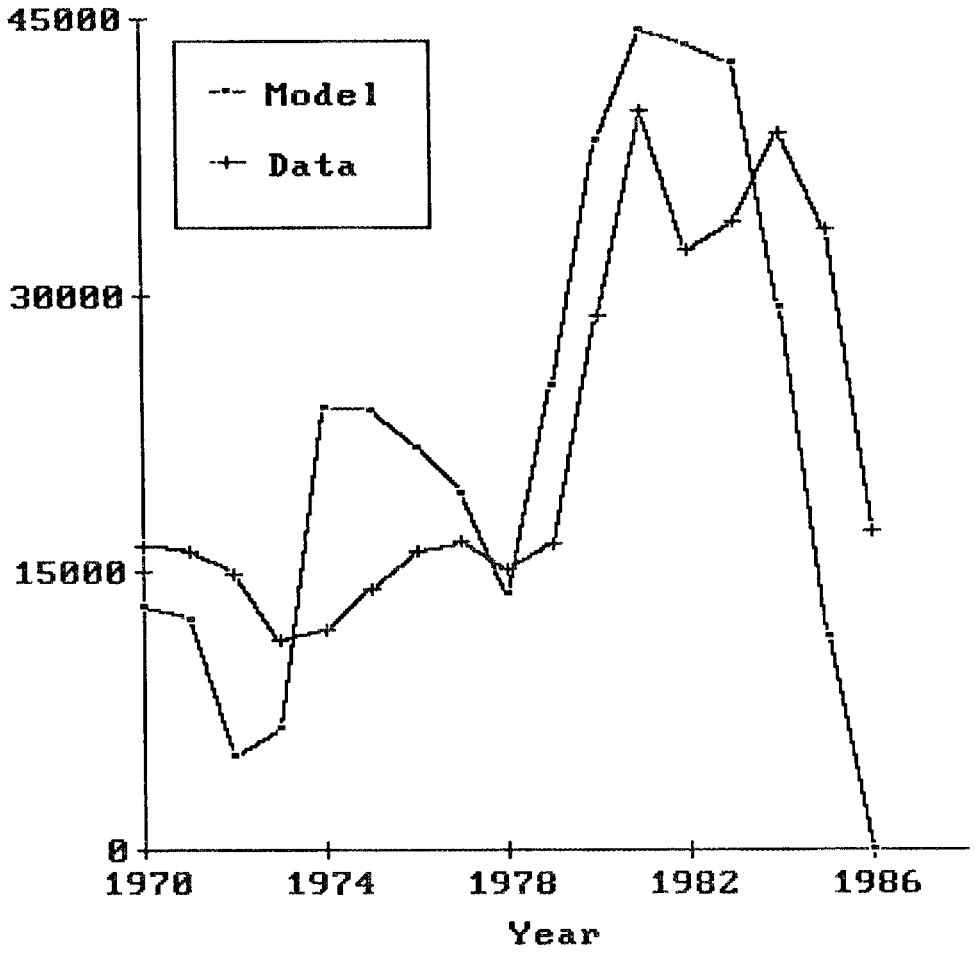

Fig. 14. Developmental drilling footage for the Gulf Coast region (1000 feet).

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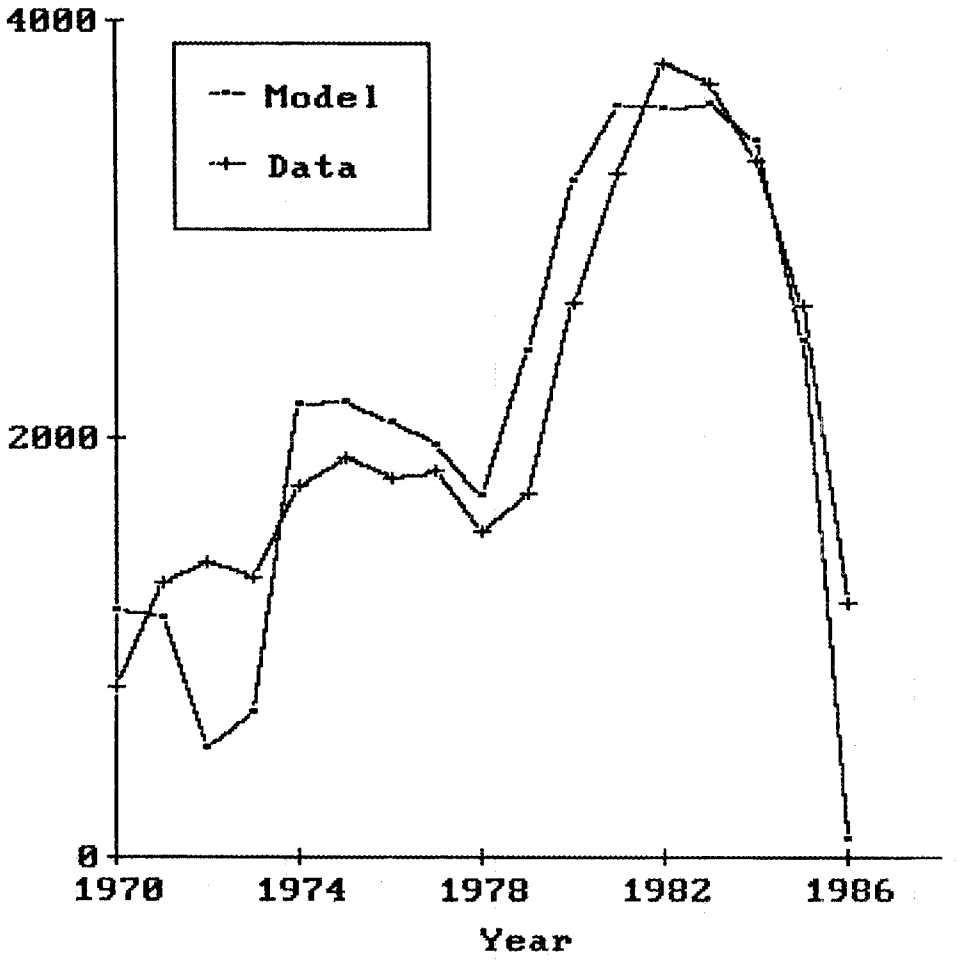

Fig. 15. Exploratory drilling footage for the Appalachian region (1000 feet).

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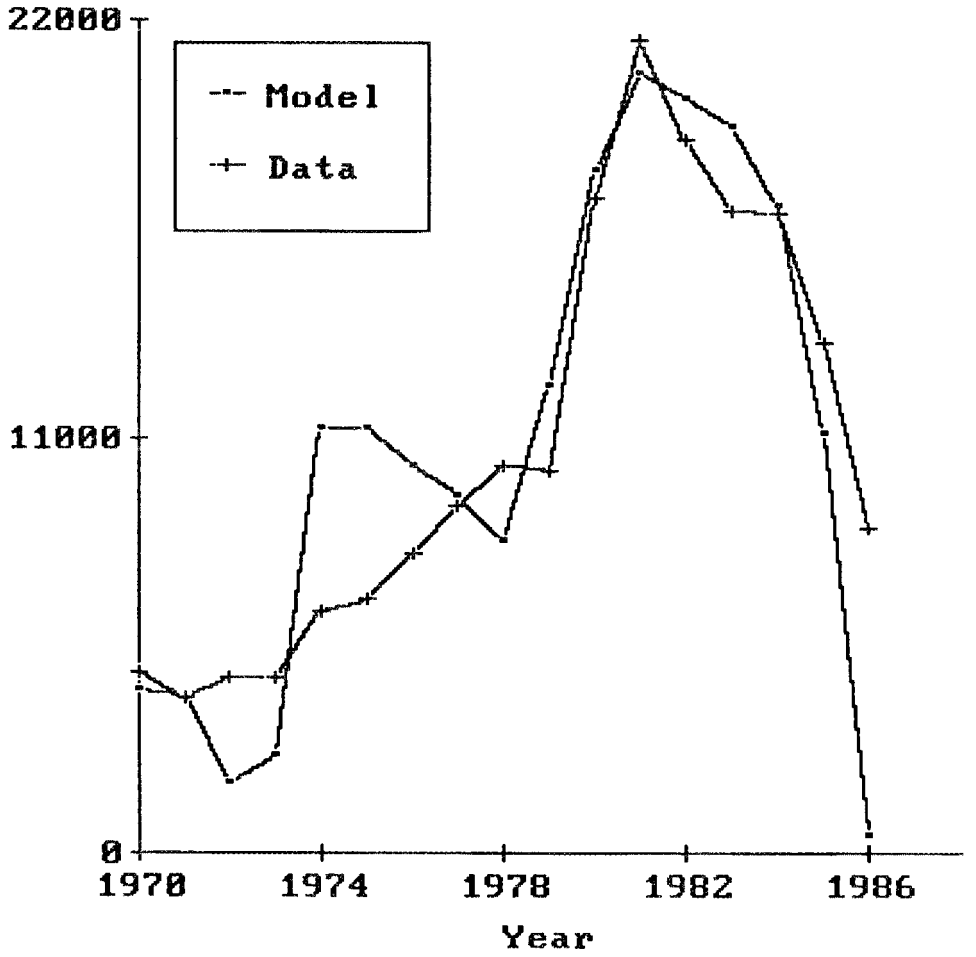

Fig. 16. Developmental drilling footage for the Appalachian region (1000 feet).

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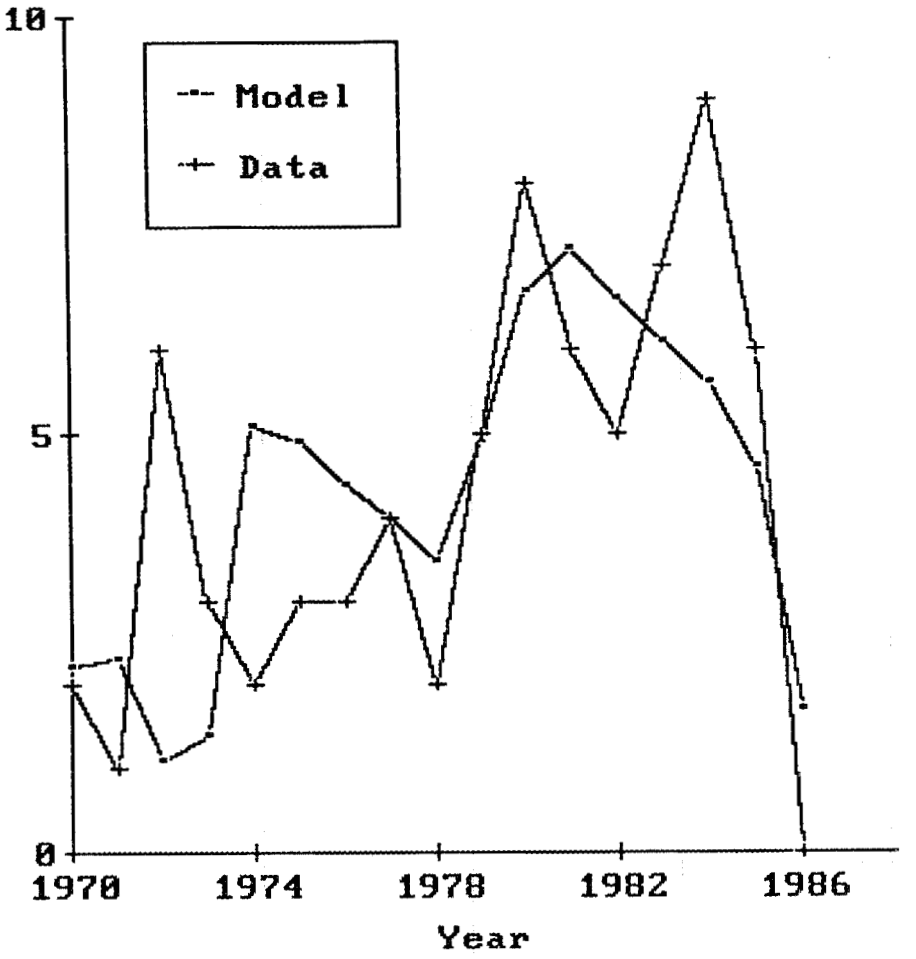

Fig. 17. Exploratory reserve additions for the West Coast region (million barrels).

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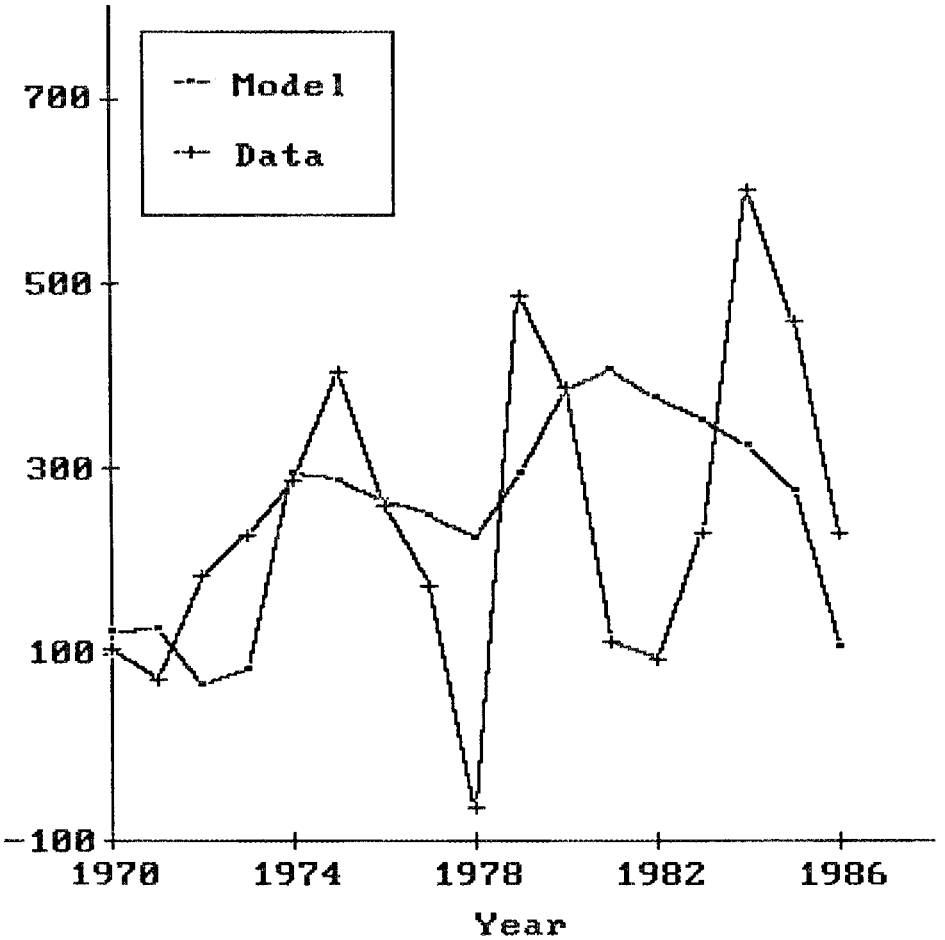

Fig. 18. Developmental reserve additions for the West Coast region (million barrels).

ORNL/DWG-896069

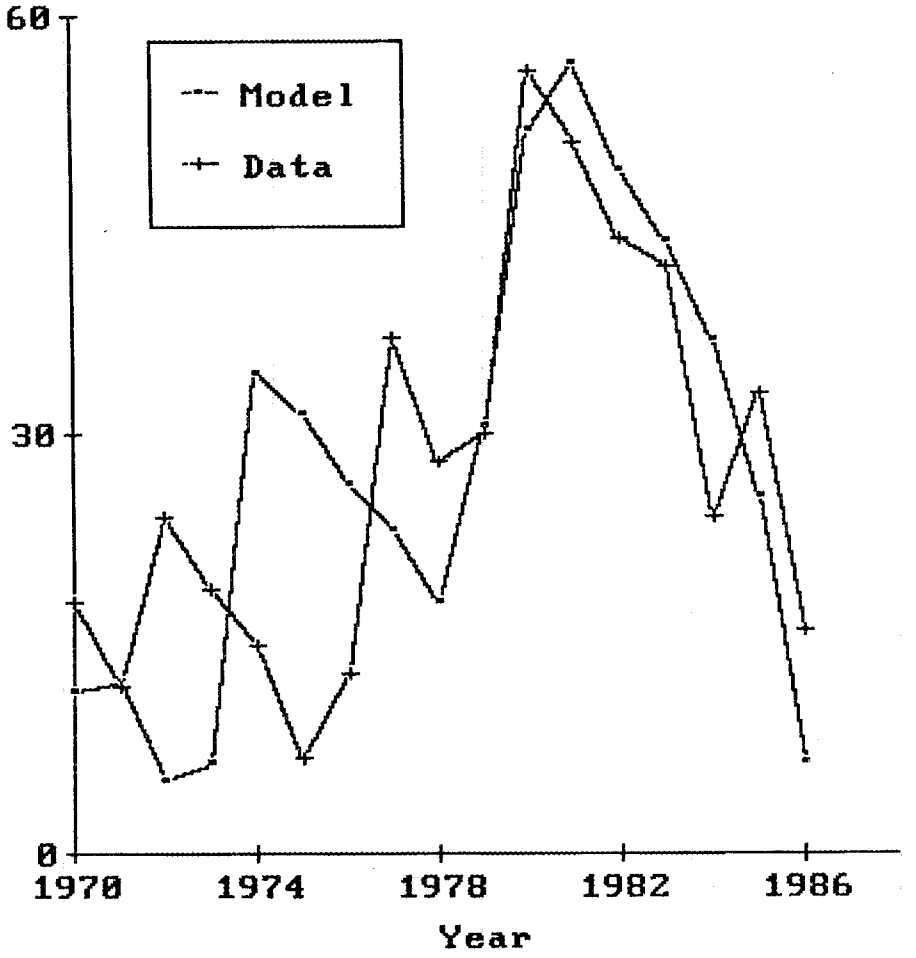

Fig. 19. Exploratory reserve additions for the Rocky Mountain region (million barrels).

ORNL/DWG-896070

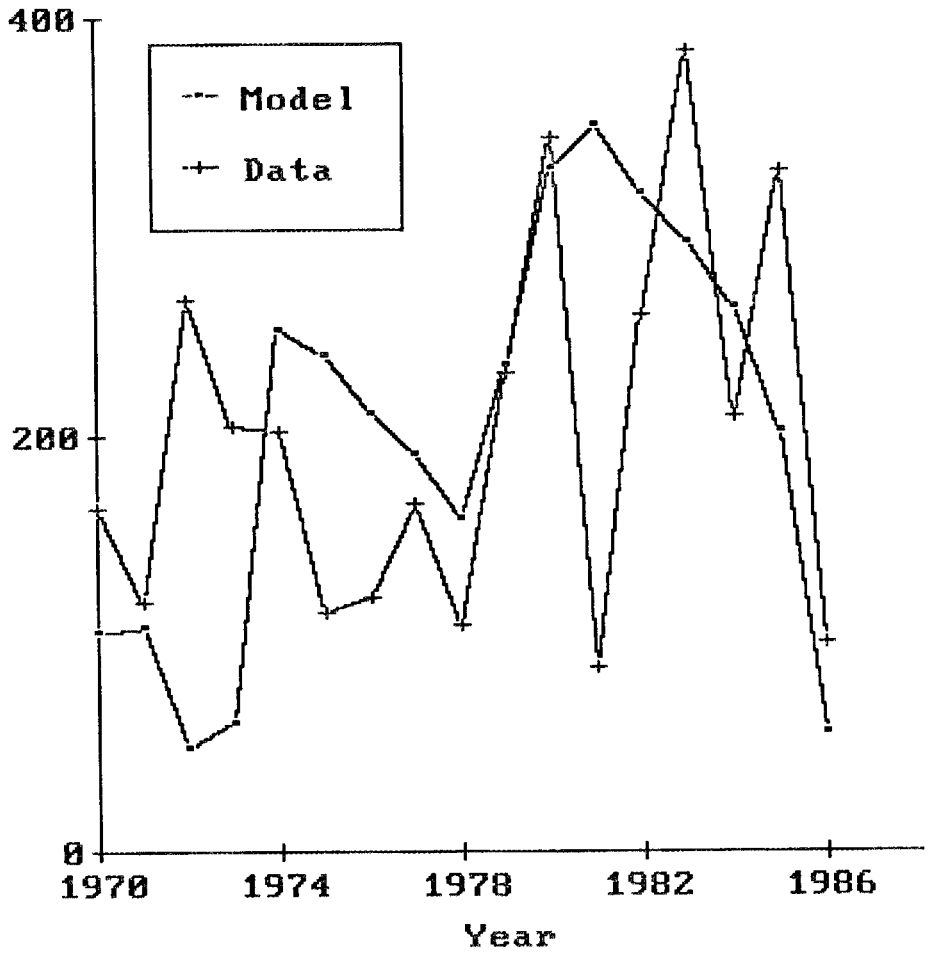

Fig. 20. Developmental reserve additions for the Rocky Mountain region (million barrels).

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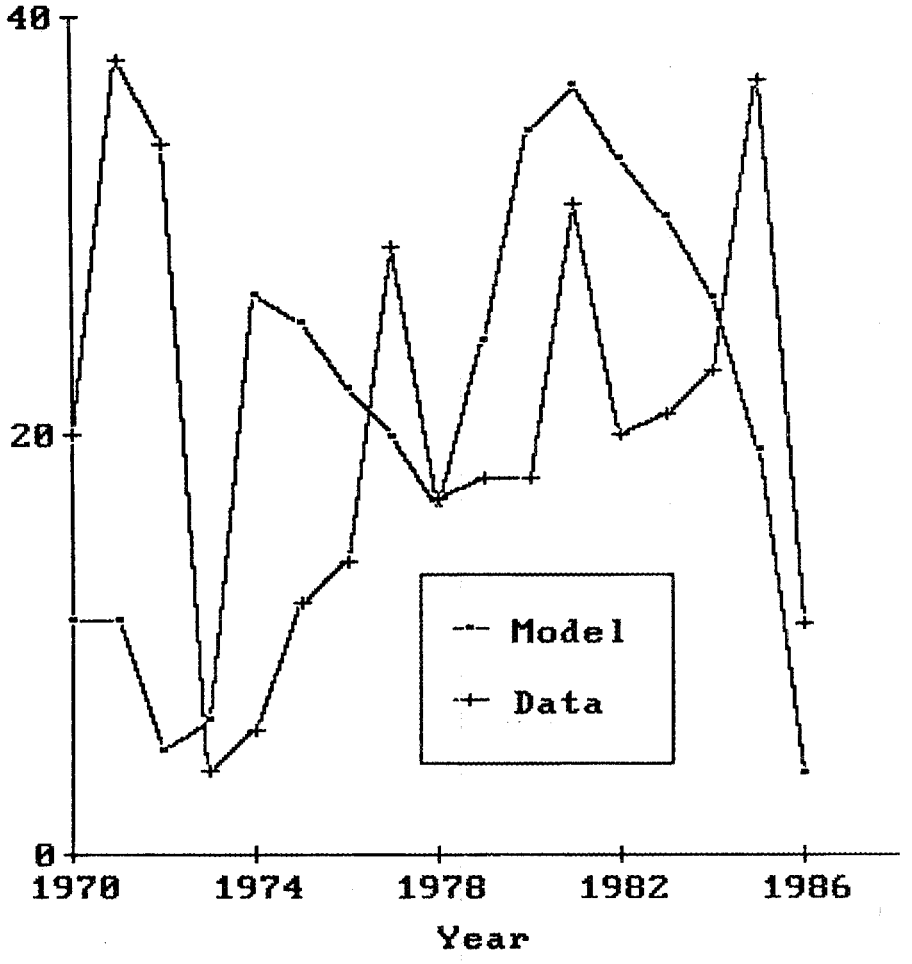

Fig. 21. Exploratory reserve additions for the Midcontinent region (million barrels).

ORNL/DWG-896072

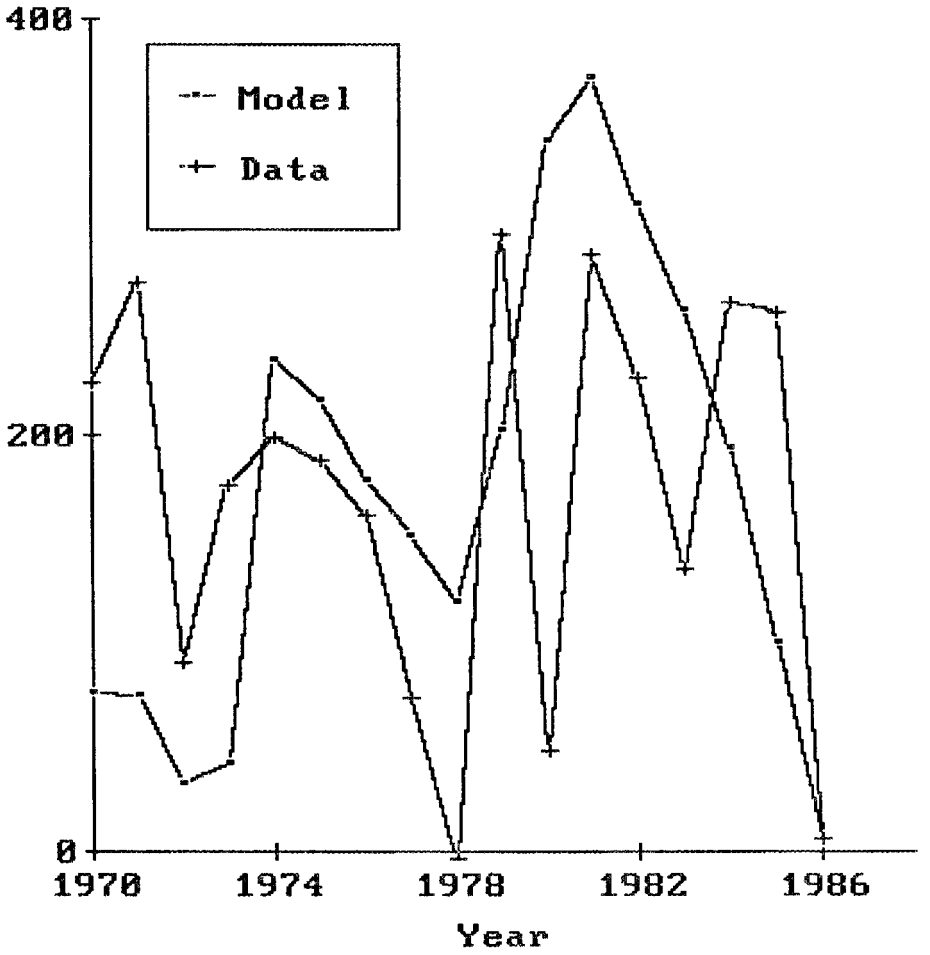

Fig. 22. Developmental reserve additions for the Midcontinent region (million barrels).

ORNL/DWG-896073

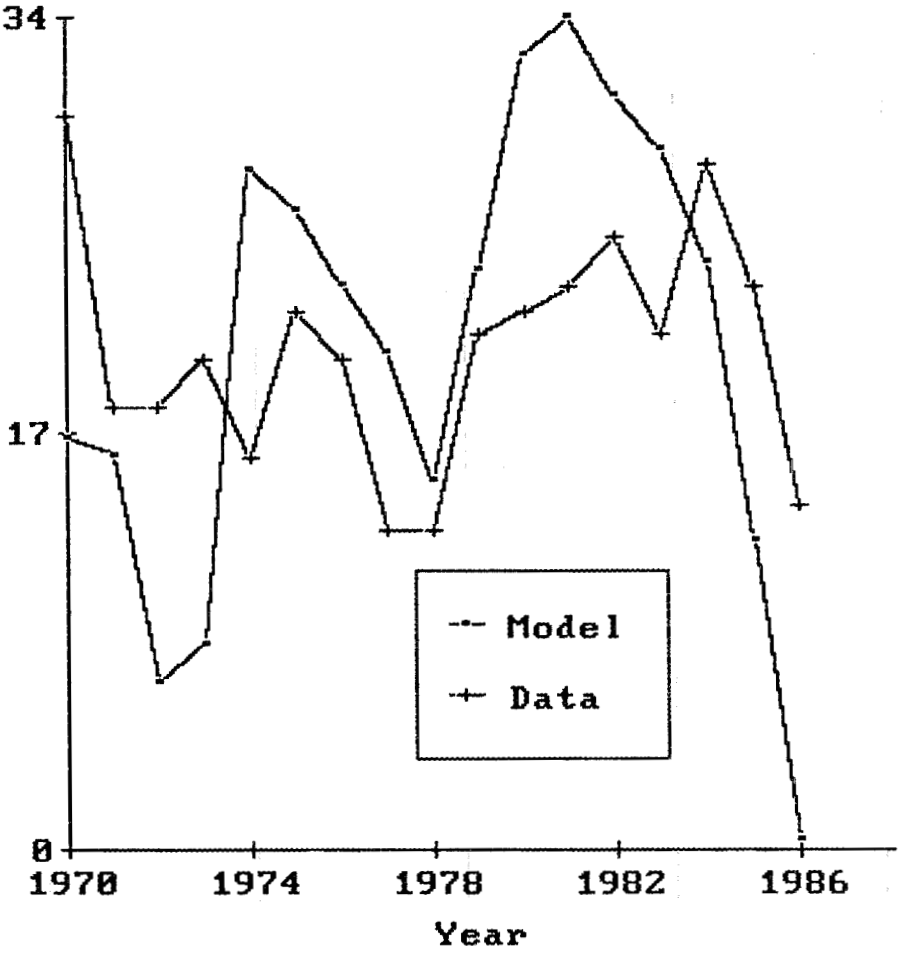

Fig. 23. Exploratory reserve additions for the West Texas region (million barrels).

ORNL/DWG-896074

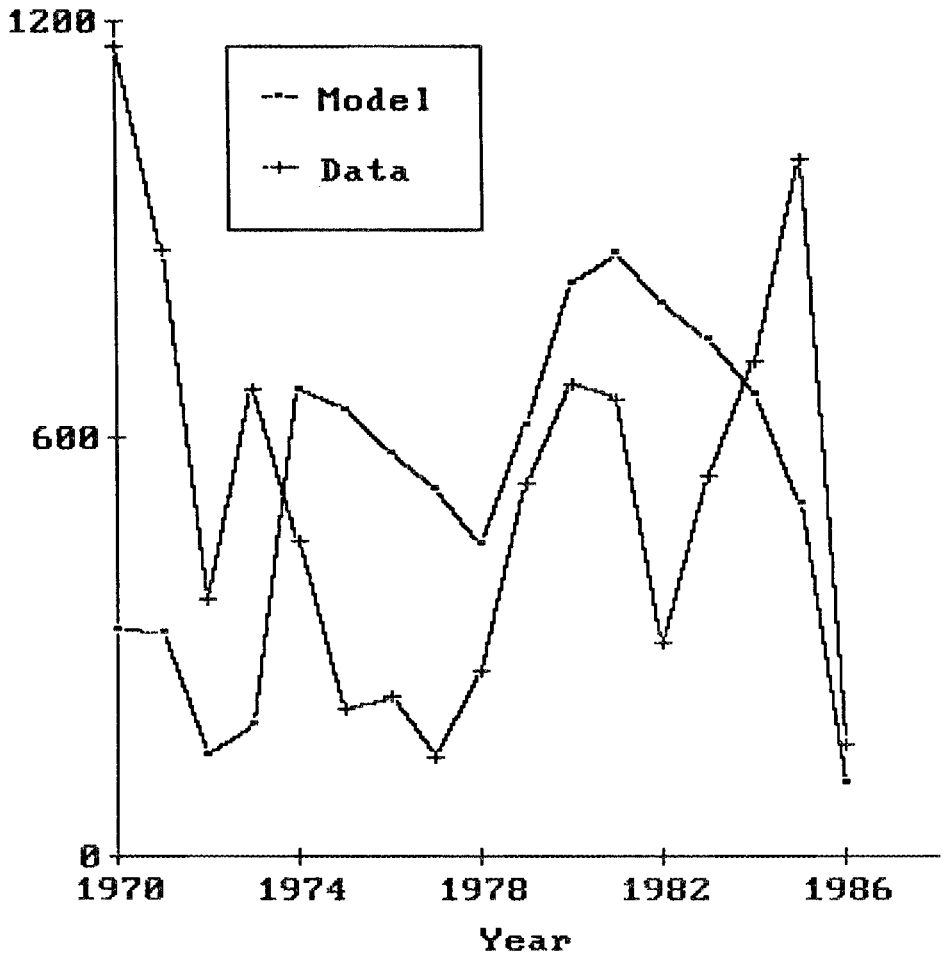

Fig. 24. Developmental reserve additions for the West Texas region (million barrels).

ORNL/DWG-896075

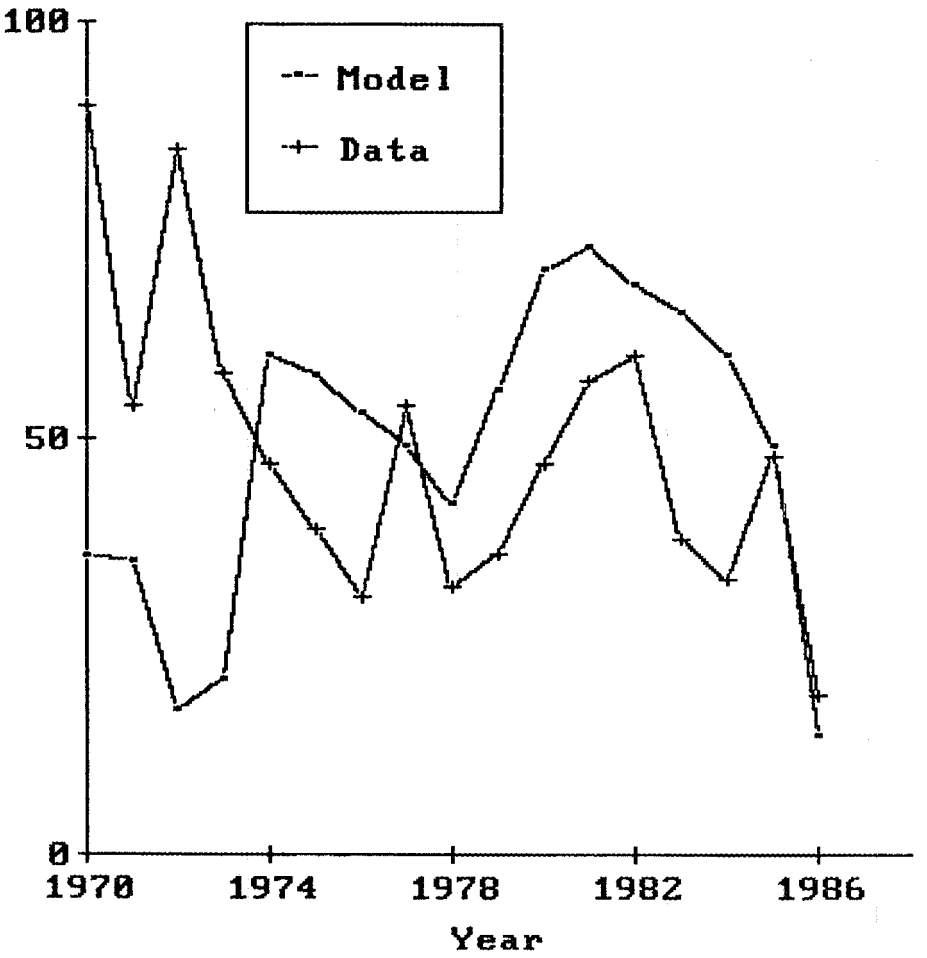

Fig. 25. Exploratory reserve additions for the Gulf Coast region (million barrels).

ORNL/DWG-896076

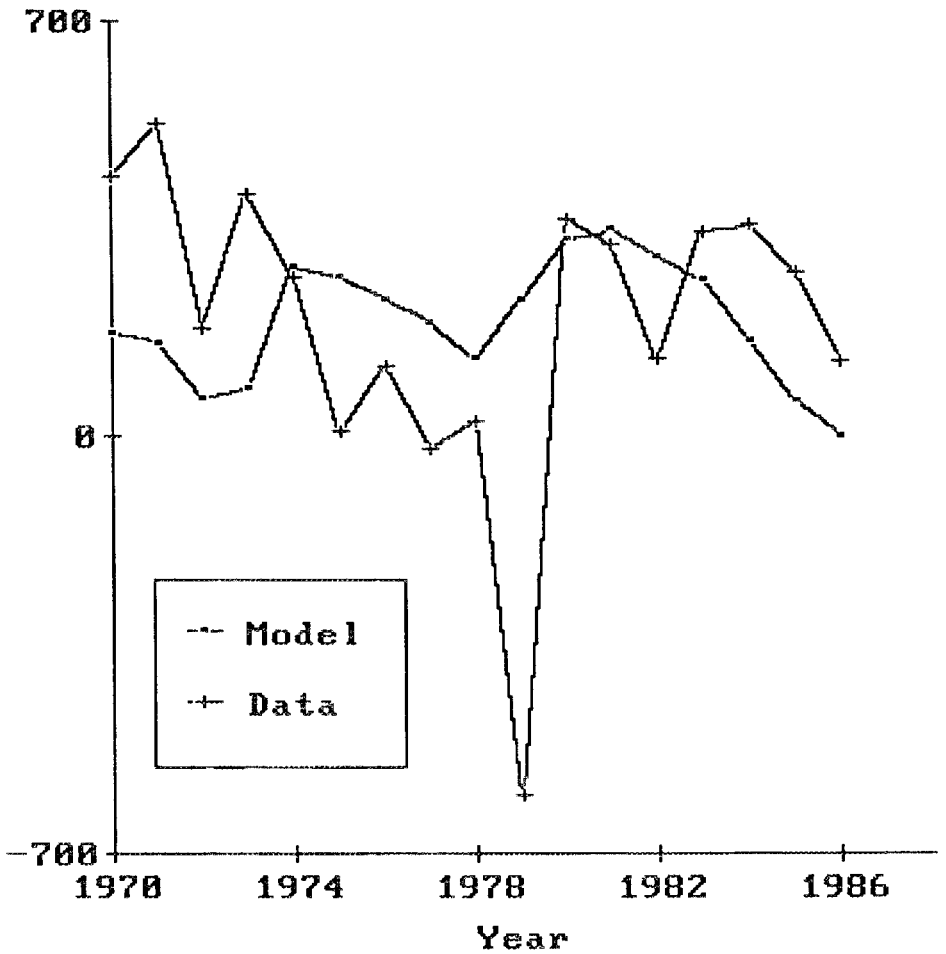

Fig. 26. Developmental reserve additions for the Gulf Coast region (million barrels).

ORNL/DWG-896077

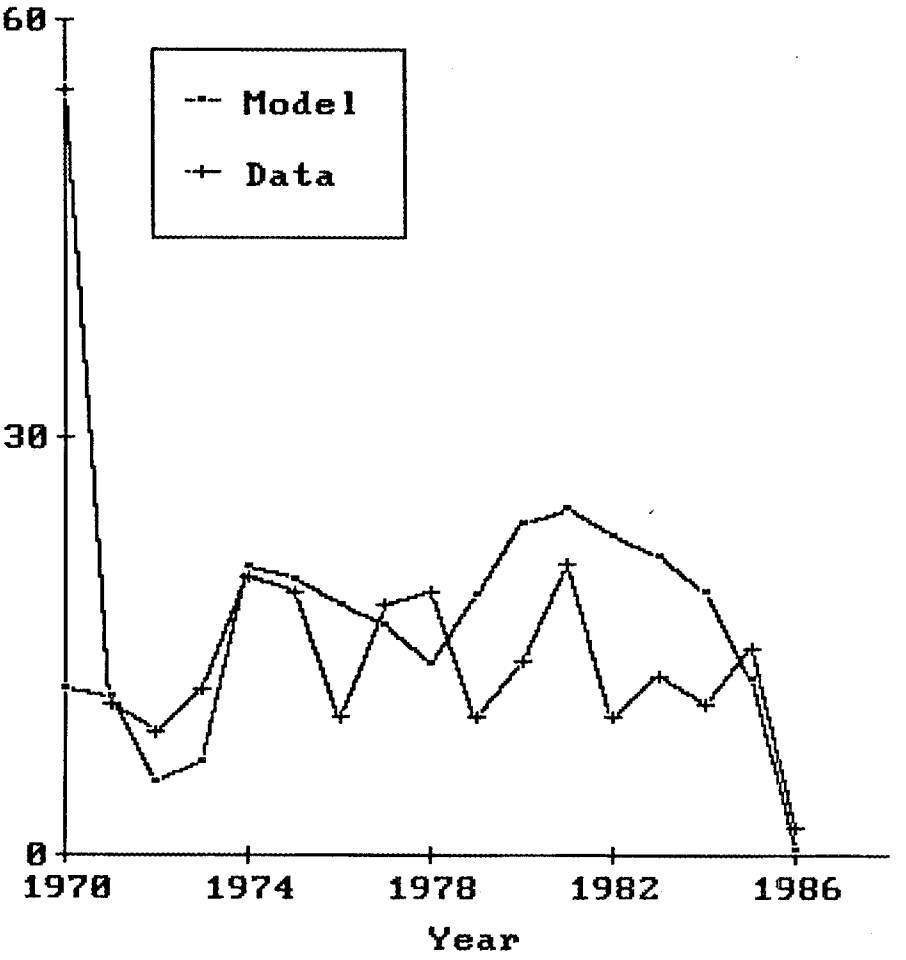

Fig. 27. Exploratory reserve additions for the Appalachian region (million barrels).

ORNL/DWG-896078

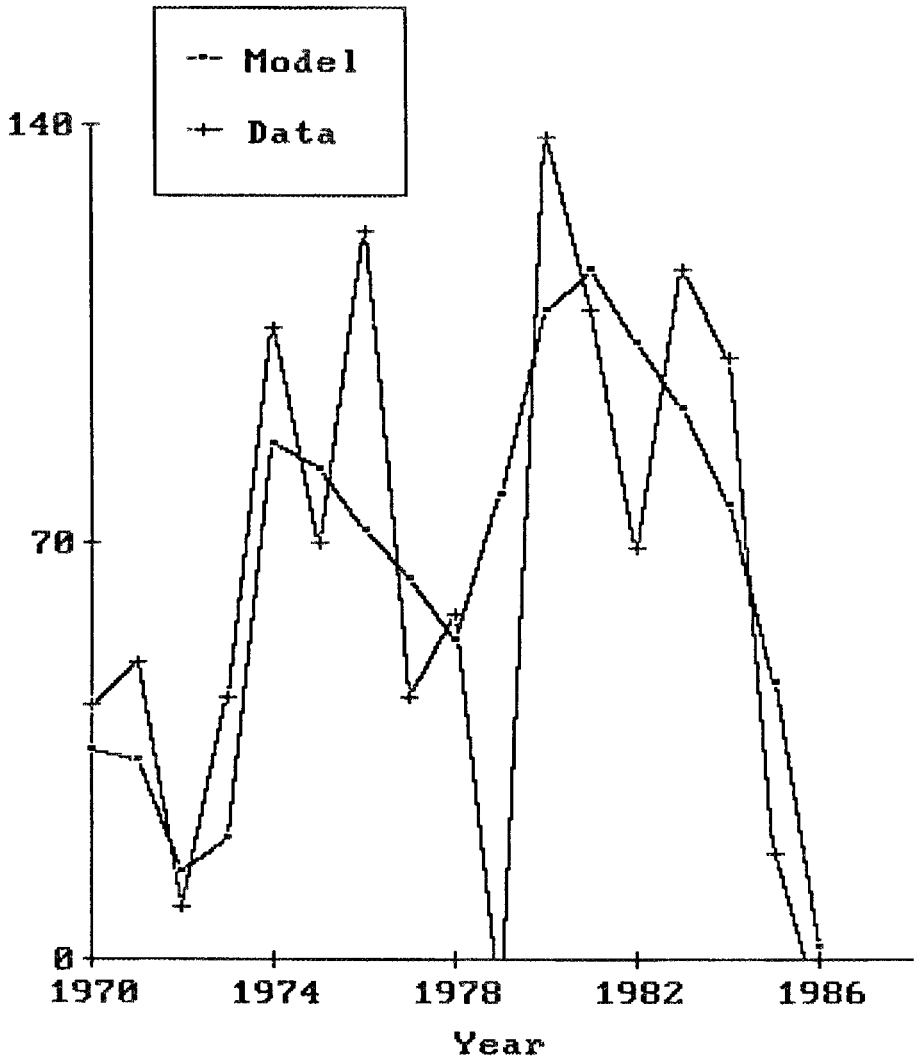

Fig. 28. Developmental reserve additions for the Appalachian region (million barrels).

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APPENDIX
DRILLING MODEL

This appendix provides a mathematical description of the drilling model for the Replacement Cost Integration Program (RCIP). RCIP forecasts the discovery and production of crude oil in 31 regions (6 onshore and 10 offshore regions for the lower 48 states and 15 regions in Alaska). This appendix will describe the drilling model for the 6 onshore regions (the model for the offshore regions and Alaska is similar).

The drilling model has three components: a finding rate module, a profit module, and a drilling module. Given the amount of undiscovered oil, the finding rate module forecasts the finding rate (barrels per foot). Given the finding rate, and a time series of values for the domestic oil price and for the expected growth rate for the domestic oil price, the profit module forecasts a time series of expected profits. Given expected profits, the drilling module forecasts the level of drilling.

The finding rate module and the drilling module will be described in this appendix. The profit module is based on REPCO and is described in Ref. 1.

Finding Rate Module

Our data base has time series of feet drilled (exploratory and developmental) and additions to proved reserves (exploratory and developmental) for the six onshore regions for the period 1970-1986. Let f(t) be the feet drilled in year t. In the model, exploratory drilling is independent of developmental drilling in each of the six regions. Thus, the model forecasts 12 sets of drilling footage. We will not use subscripts to distinguish the 12 sets.

Let b(t) be the additions to proved reserves in year t. The finding rate (R) is the ratio of additions to proved reserves and drilling footage:

$$R(t) = b(t)/f(t) \quad . \tag{1}$$

Let U(t) be the amount of undiscovered oil. Finding oil reduces the amount of undiscovered oil:

$$\dot{U} = -b \ . \tag{2}$$

Our finding rate model is that the finding rate is proportional to the amount of undiscovered oil:

$$R = \beta * U \ . \tag{3}$$

Although REPCO uses the same model, the definitions of the amount of undiscovered oil differ. In REPCO, the amount of undiscovered oil is equal to the USGS estimate of undiscovered recoverable resources. However, the USGS estimate is for economically recoverable resources. The finding rate will not be zero when the last economically recoverable barrel is found. Thus, U should be larger than the USGS estimate of undiscovered recoverable resources.

In REPCO, the amount of oil discovered is calculated by multiplying the additions to proved reserves from exploratory drilling by the Hubbert Field Growth Factor (7.5811) (see p. A-6 of Ref. 1).

In RCIP, we have two sets of U -- one for exploratory drilling and a second for developmental drilling. We have determined the values of β and U from the historical data and we do not use the Hubbert Factor in the finding rate module.

Drilling Module

Given the finding rate, and a time series of values for the oil price and for the expected growth rate for the oil price, the profit module forecasts a time series of expected profits [P(U,t)]. The profits depend on U through the finding rate and on time through the price and the growth rate for price. The profits are discounted back to a common date.

The objective of the drilling module is to forecast drilling footage (f). However, since the finding rate relates footage and discoveries, we can forecast discoveries (b) and then compute footage. As our initial model, we assume that total profits are maximized:

$$J = \int_0^T P(U,t) * b \ dt \ . \tag{4}$$

To maximize profits, discoveries should occur when the profits are high. In Ref. 2, we assumed that there was a constraint on the level of discoveries and the optimum solution depended on the parameter K. When the profits are more than K, oil is discovered at the maximum rate. When the profits are less than K, no oil is discovered. In the jargon of optimal control theory, the optimal solution is bang-bang.

To avoid an exogenous constraint on discoveries, we assume that the profits have diminishing returns:

$$J = \int_0^T P(U,t)*G(b)\ dt \quad , \tag{5}$$

where G(b) is a diminishing function of b:

$$G(b) = b*(\delta - \gamma*b) \ , \tag{6}$$

where δ and γ are parameters. We assume that the profits are calculated at a nominal rate (b_0). At the nominal rate, $G(b_0) = b_0$. Thus,

$$\delta = 1 + \gamma*b_0 \ .$$

The optimal discovery rate is given by

$$b = (\delta - K/P)/2*\gamma \ , \tag{7}$$

when b is positive, where K is a constant. The optimal discovery rate is zero until the profits are greater than K/δ. As the profits increase, the rate increases but never exceeds an asymptotic limit ($\delta/2*\gamma$).

In each region, we assume that there are many independent oil producers and each producer assigns different values for the expected profits and for the value of K. To simulate independent producers, we assume that there is a distribution of values for K and that the average value of K [<K>] is given by

$$\langle K \rangle = \int_0^\infty u*g(u)\ du\ , \tag{8}$$

where g(u) is the distribution function for K.

Using the relationship between profits and discoveries (Eq. 7), we can calculate the average value for the discoveries:

$$\langle b \rangle = \int_0^{\delta*P} [(\delta - u/P)/2*\gamma]*g(u)\ du\ . \tag{9}$$

Given a distribution function, Eq. 9 can be used to calculate the regional discovery rate. We have chosen to use the Weibull distribution function, because it is relatively easy to integrate. The Weibull distribution function is given by

$$g(u) = (\rho/\sigma)(u/\sigma)^{\rho-1} \exp[-(u/\sigma)^{\rho}]\ , \tag{10}$$

where ρ and σ are parameters.

For the Weibull distribution function, the average value of K is given by

$$\langle K \rangle = \sigma\ \Gamma(1 + 1/\rho)\ , \tag{11}$$

where $\Gamma(x)$ is the gamma function. The parameter σ controls the mean value of the distribution, while the parameter ρ controls the width of the distribution. As ρ increases, the distribution becomes narrow and $\langle K \rangle$ approaches σ.

For the Weibull distribution function, the average value of the discoveries is given by

$$\langle b \rangle = (\delta/2*\gamma)\ [1 - e^{-x} - \Lambda(a,x)/y]\ , \tag{12}$$

where $y = P*\delta/\sigma$, $x = y^{\rho}$, $a = 1 + 1/\rho$, and the incomplete gamma function $\Lambda(a,x)$ is defined by

$$\Lambda(a,x) = \int_0^x e^{-t}\, t^{a-1}\, dt \ . \tag{13}$$

Equation 12 is our drilling model. Given the expected value for the profits (P) and values for the four parameters (δ, γ, σ, and ρ), Eq. 12 determines the average discovery rate in the region. Given the discovery rate, Eq. 1 determines the drilling footage:

$$f(t) = \langle b \rangle(t)/R(t) \ . \tag{14}$$

Figure A.1 displays the discovery rate ($\langle b \rangle$) as a function of y for several values of ρ. As ρ increases, $\langle b \rangle$ approaches the asymptotic limit given by Eq. 7; the limit is $\langle b \rangle = 1 - 1/y$ when y is greater than 1 and zero when y is less than 1. The model derived using the Weibull distribution function allows the discovery rate to be positive when y is less than 1.

For the validation of RCIP, we used the following values for the parameters. For all 12 sets of data, the values of δ were 1.5 and the values of ρ were 2. The values of σ ranged from 2.0 to 4.0. The value of γ determines the magnitude of the discovery rate and had unique values for each of the 12 data sets.

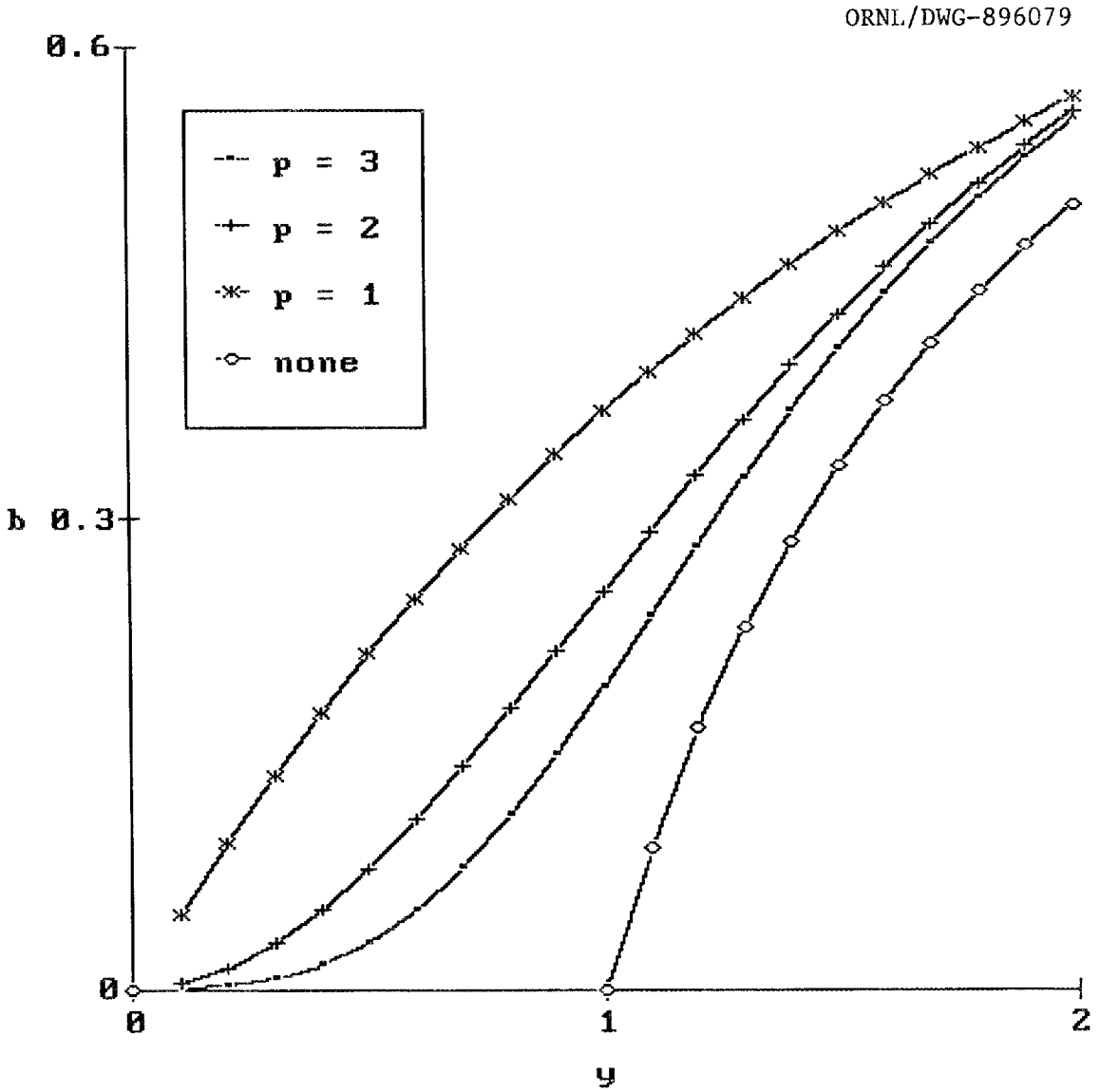

Fig. A1. The discovery rate (b) as a functon of y for several values of Rho.

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