

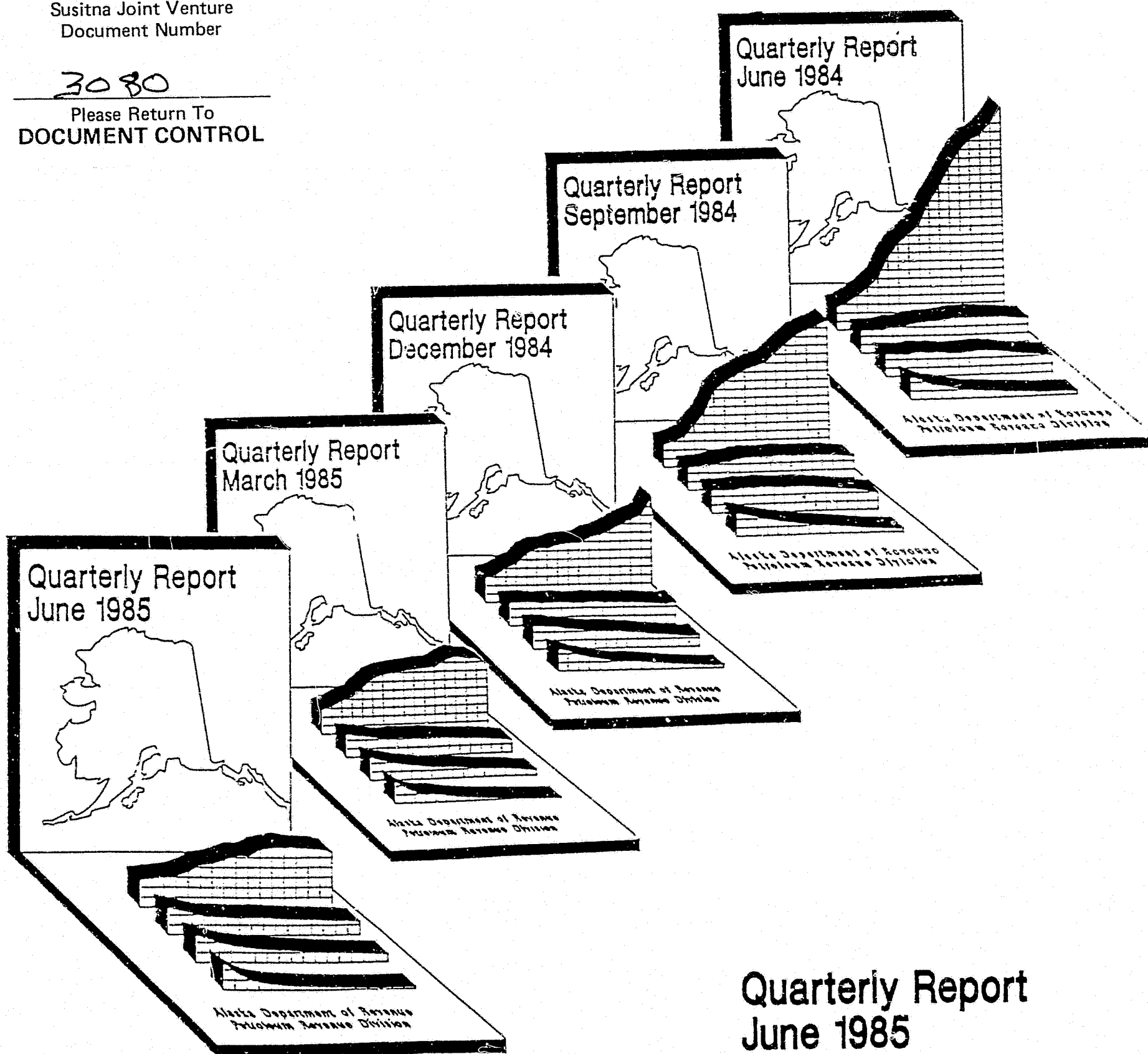
PETROLEUM PRODUCTION REVENUE FORECAST

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Quarterly Report
June 1985

STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

BILL SHEFFIELD, GOVERNOR

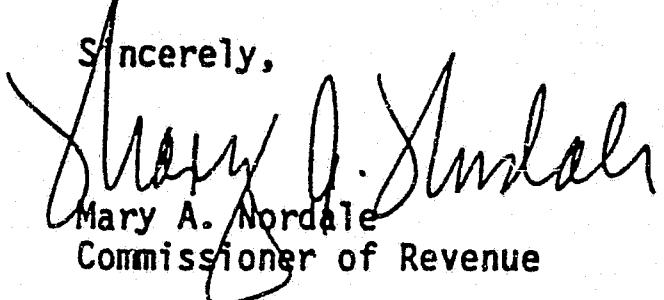
POUCH S
JUNEAU, ALASKA 99811
PHONE: (907) 465-2300

July 19, 1985

To the Reader of the Revenue Sources FY 85-87 (June 1985) and
Petroleum Production Revenue Forecast (June 1985)

The revenue forecast presented in these publications has been prepared by economists and research staff of the Department of Revenue in accordance with the highest professional standards. It has been reviewed and adopted by myself as the Department's best judgment of revenues to be received by the State of Alaska over the prescribed forecast period. The Department of Revenue has historically been and remains solely and exclusively responsible for the preparation of these quarterly forecasts. The experience of recent years involving frequent and significant revisions in estimated revenues is due to the inherent difficulty of predicting the movements in the price of crude oil--a commodity whose volatility over the last decade cannot be exaggerated. This volatility combined with the State of Alaska's almost complete dependence on oil revenues, which in recent years account for almost 85 percent of total revenues, can sometimes lead to dramatic and unavoidable changes in the forecast.

Sincerely,


Mary A. Nordale
Commissioner of Revenue

PETROLEUM PRODUCTION
REVENUE FORECAST

QUARTERLY REPORT
JUNE 1985

STATE OF ALASKA
BILL SHEFFIELD, GOVERNOR

MARY A. NORDALE
COMMISSIONER
Department of Revenue

BRUCE BOTELHO
DEPUTY COMMISSIONER
Department of Revenue

FRED BOETSCH, DIRECTOR
Department of Revenue
Petroleum Revenue Division

This Publication was Prepared by
Dr. Charles Logsdon, Petroleum Economist
Roger Marks, Petroleum Economist
Eric Hansen, Economist
Mims Jemison, Systems Analyst
J. William Moore, Operations Research Analyst

HOW THIS FORECAST WAS MADE

Many factors or variables can affect Alaska's petroleum revenues. This report takes into account over 400 dependent and independent variables, ranging from the amount of oil flow in TAPS to the amount of OPEC price changes. The number of possible combinations of all these different factors is virtually endless. A feel for the range of outcomes can be obtained from a sample of these combinations. The principles of statistics allow one to test the reliability of that sample and to find the projected revenue figure that minimizes the likely error between what is projected and what is received. To eliminate bias in the selection of the sample, a computer makes random choices of variables. If 500 combinations make up the sample, then the computer calculates the average of all of these projections as well as providing data to create many of the tables and graphs appearing in this forecast. Some of these tables and graphs depict a range of probability indicating how far the results could differ from the average and/or what the likelihood is for revenues to differ substantially from that average.

As an additional forecasting tool, the Department of Revenue has developed a model which gives explicit consideration to the economic feasibility of developing potential petroleum deposits. A full explanation of this model appears in Appendices B and C of this forecast.

Starting in March 1982, a conscious effort was made to introduce an additional measure of prudence or caution into the revenue projections by reporting, as the single point estimate of revenues, the revenue expectation corresponding to the 30 percent cumulative distribution of possible revenue outcomes. Since this estimate depicts a revenue stream which the Department of Revenue feels will have a 70 percent chance of being exceeded, it automatically builds in a safety margin. The magnitude of the safety margin will vary from forecast to forecast and from year to year, since it is based on a subjective assessment by the Department of Revenue of the array of possible outcomes for the numerous variables included in the forecast. Please see Table 8 and Graph 12, which illustrate the magnitude of the hedge or risk adjustment assumed in this forecast. By reporting the 30 percent case, the reported forecast numbers can be expected to fluctuate from forecast to forecast even if the possible outcomes remain the same because events viewed with extreme uncertainty in one time period become less uncertain in the next time period. In the short term (say FY 1985) this means that the 30 percent revenue outcome will tend to converge to the mean outcome as more data on FY 1985 revenues becomes available. (See Table 16)

It cannot be stressed enough that the forecasting of petroleum production revenues very far into the future is an extremely speculative activity. Because of the dramatic effects of compounding, small changes in assumptions about the behavior of key variables, such as oil prices and/or inflation, can produce widely different projections of oil revenues. For this reason, the reader is cautioned to examine annual revenue projections in the context of the full range of possible revenue outcomes as presented in the probability distributions of Graphs 13-15 and Tables 9-11.

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EXECUTIVE SUMMARY
(Dr. Charles Logsdon)

Results of This Forecast

Estimates of future petroleum production revenues have been revised downward due to a further reduction in the outlook for crude oil prices. Crude oil prices in this forecast are assumed to decline roughly \$2.00/bbl through FY 1986 and drop another \$1.00/bbl in FY 1987 before turning up. Real, or inflation adjusted, price increases are not expected before 1990.

Alaska North Slope production is assumed, on average, to peak in FY 1987 at 1.744 million bbls/day declining to .482 million bbls/day in FY 2000. The production assumptions remain essentially the same as in March with new assumptions about secondary and tertiary recovery from currently producing fields offsetting the negative impact of lower prices on production from undeveloped fields.

Currently 60% of the owners of the Trans Alaska Pipeline (TAPS) have agreed to an out of court settlement which would dramatically reduce future pipeline tariffs. However because of the uncertainty introduced by a recent FERC ruling on pipeline rate making viewed as favorable to the State's position in the current TAPS litigation, no attempt is made to incorporate either the settlement or other rate making method into the forecast. The average TAPS tariff is assumed to continue to be \$6.007/bbl.

Short Term (1986-1987)

World demand for crude oil continues to remain weak even as the world economy picks up steam. Predictions of demand recovery continue to be postponed by most analysts. It appears that OPEC will continue to face a shrinking market over this time period as non-OPEC production takes a larger share of a stagnant market. This situation will keep downward pressure on price throughout the period. This forecast assumes the world price of ANS quality crude will bottom out in FY 1987 at roughly \$22/bbl. These price assumptions result in a drop of petroleum production revenues in FY 1986 of \$39.81 million and in FY 1987 of \$206.50 million from the March 1985 forecast.

Intermediate Term (FY 1988 - FY 1989)

The call on OPEC oil by FY 1988 should be sufficient to cause nominal crude oil prices to begin to increase during this time period. On average though it is assumed that the increase in price will be at rates lower than inflation. North Slope crude oil production in the intermediate term will begin to decline as Prudhoe Bay production rates decline although new production is expected from the Endicott, Lisburne, and West Sak fields. Given the current tax law the effective severance tax rate will fall in FY 1988 from 13.9 percent to 11.6 percent. Risk adjusted petroleum production revenues for FY 1988 - FY 1990 are \$714 million lower than projected last March, a drop of 13.4 percent.

Long Term

The 1990's will witness the inevitable decline of the Prudhoe Bay reservoir. Although technology may increase the amount of recoverable reserves from this field, production will be at levels far below the current 1.5 million bbls/day. Other known reserves on the North Slope and in the Beaufort Sea will also come into production in the 1990's. There are literally tens of billions of barrels of oil in place on Alaska's North Slope which could be economically recovered if the price was right or the necessary technology developed. However, given the outlook for prices assumed in this forecast it is assumed that oil production in the 1990's will average only about one-third current levels. The natural gas reserves on the North Slope also could be exploited in the long run but this too will be a function of energy prices.

Lower price assumptions result in a reduction in risk adjusted petroleum production revenues for FY 1991 - FY 2001 of \$1595.88 million or 27.3 percent. (See Tables 5 and 7).

SHORT TERM MARKET ANALYSIS
(Roger Marks)

The end of the British coal strike in February reduced fuel oil demand 500,000 barrels per day. Since then spot resid prices have dropped \$5.00 per barrel. As surplus gasoline was a by-product of resid production, prices were depressed, and have recovered up to 7 cents per gallon. Gasoline prices are also up because of EPA's Lead Phasedown Program, which is described below. Resid prices appear to have bottomed out. They are now on par with natural gas and many industrial gas customers are switching back to fuel oil. Also, the hot summer has increased electricity demand for air conditioning.

Also, in Britain, the elimination of the British National Oil Company (BNOC), has disintegrated producers into many sellers, which will add to price instability.

It should be noted that Iranian production has exhibited drastic month to month fluctuation depending on its war efforts. In general, the war has suppressed production and supported price. A 500,000 barrel per day pipeline between Iraq and Saudi Arabia is about to open. This will give Iraq access for its exports to the Persian Gulf, boosting its output capacity. This may create further internal stress in OPEC if Iraq increases production accordingly.

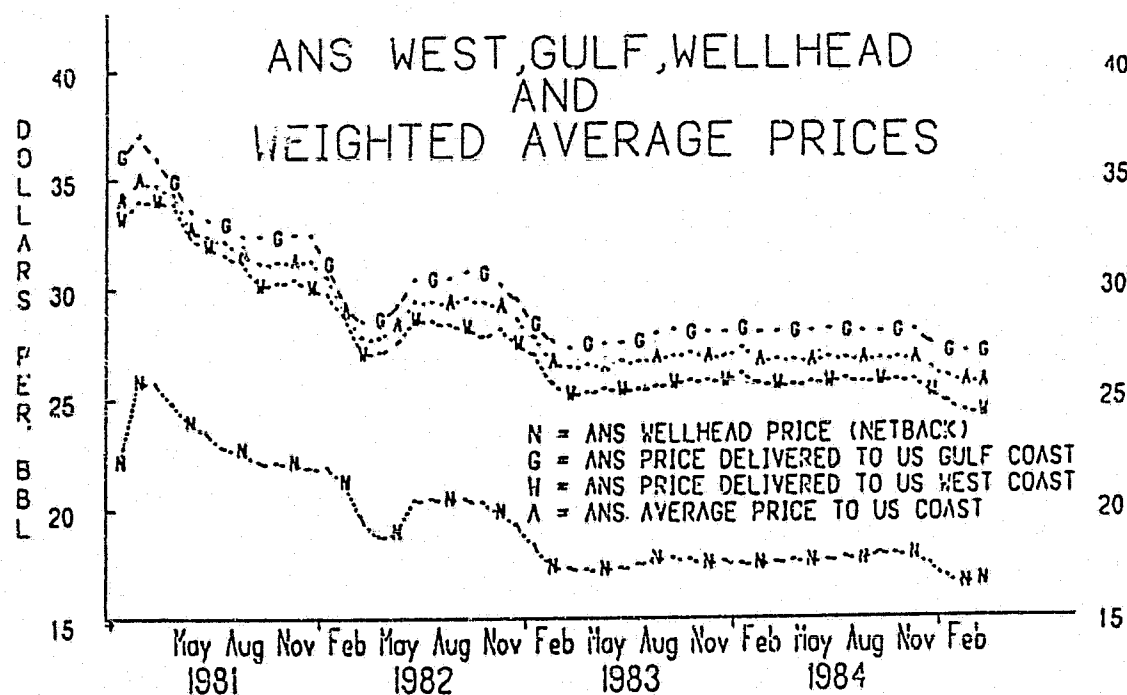
Canada has deregulated oil prices and liberalized exports. Imports to the U.S. have increased 40 percent in recent months, and are competing directly with West Texas Sour in the upper Midwest. Increased exports to the West Coast are expected to begin soon.

On July 1, as part of its Lead Phasedown Program, the EPA reduced the maximum allowable lead content in gasoline from 1.1 grams per gallon to 0.5 grams per gallon, and will reduce it further to 0.1 grams per gallon on January 1, 1986. Any less than that can be banked by the refiner and lead credits can be sold in the open market. Lead is the least expensive octane booster, and there will be a need for more octane to replace lead. The most cost effective investment approach for satisfying this need is incremental expansion of catalytic reforming (dehydrogenation) facilities. Non-investment approaches include the addition of high and low octane blendstocks the adjustment of crude slates, and the adjustment of product slates. The regulation will have two opposite effects on crude oil prices. On one hand, refining costs, and consequently, gasoline prices, will go up. It is estimated that gasoline prices should rise by the cost spread between lead credits and lead additives, which would be about 4 cents per gallon. Increased gasoline prices would depress gasoline demand, and subsequently, crude price. We have estimated the relevant elasticities and calculate this effect would depress crude prices by 17 cents per barrel. On the other hand, the overall gas yield from catalytic reforming is lower (about 5 percent) and increased crude runs will be necessary to produce the same amount of gasoline; this will increase crude demand and price. We have estimated the relevant elasticities and calculate this effect would boost crude prices 37 cents per barrel, for a net increase of 20 cents per barrel.

The combination of high gasoline and low fuel oil prices have helped the upgraded refineries. Refinery utilization rates are at 80 percent for the first time in over four years. Although gasoline stocks are fairly low now, and inventories have been building slowly, surpluses of gasoline are expected later in the summer.

Gasoline imports are at all time highs. Some refineries are running imported blending components and unfinished oil instead of processing crude. This has cut the demand for oil. Furthermore, some refineries are importing finished gasoline for their marketers because they can buy it cheaper than they can produce it. Both of these practices, as well as the importation of much unleaded gasoline, are being accomplished in order to allow the refiners to amass lead credits

Graph 1 illustrates the relationships between Gulf Coast, West Coast, and combined weighted average Alaska North Slope (ANS) crude sales prices and the weighted average wellhead (net-back) price through April, 1985.

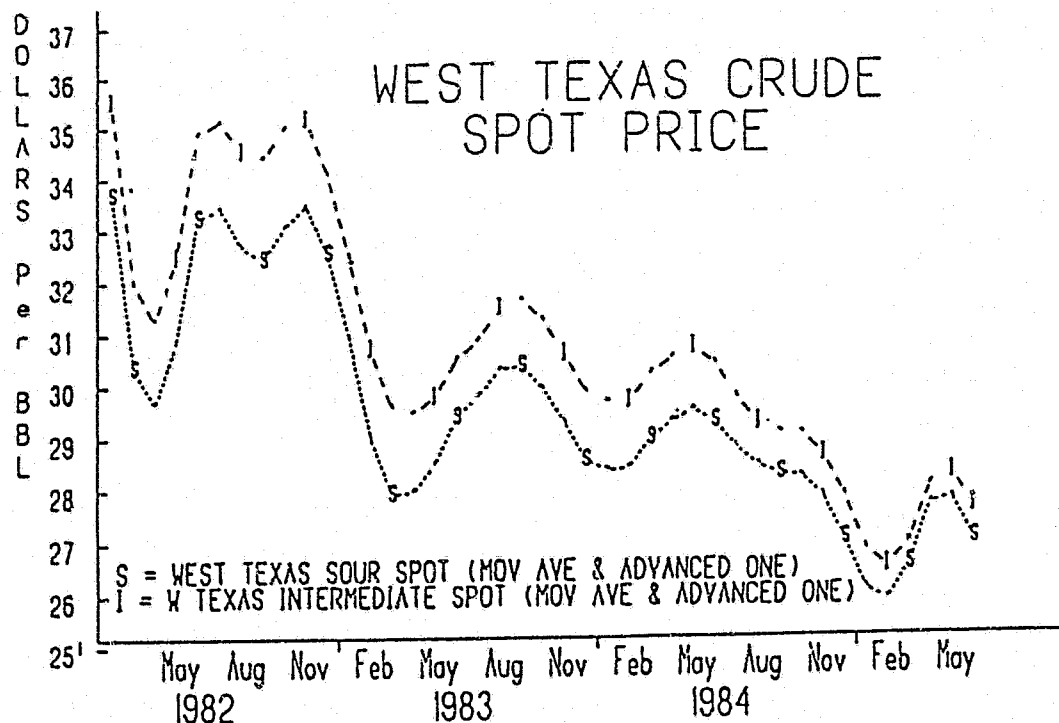


GRAPH 1

It can be seen that the difference between the sales price on the West Coast and the Gulf Coast, with modest exceptions, has remained about \$1.50 to \$2.20 per barrel. It is also apparent that the average transportation cost (primarily tanker charges and the Trans Alaska Pipeline charge) used to calculate the wellhead price has stayed relatively constant. Since the sales price trend has obviously been downward, this relatively constant cost deduction has resulted in large percentage declines in the wellhead value of ANS crude oil production.

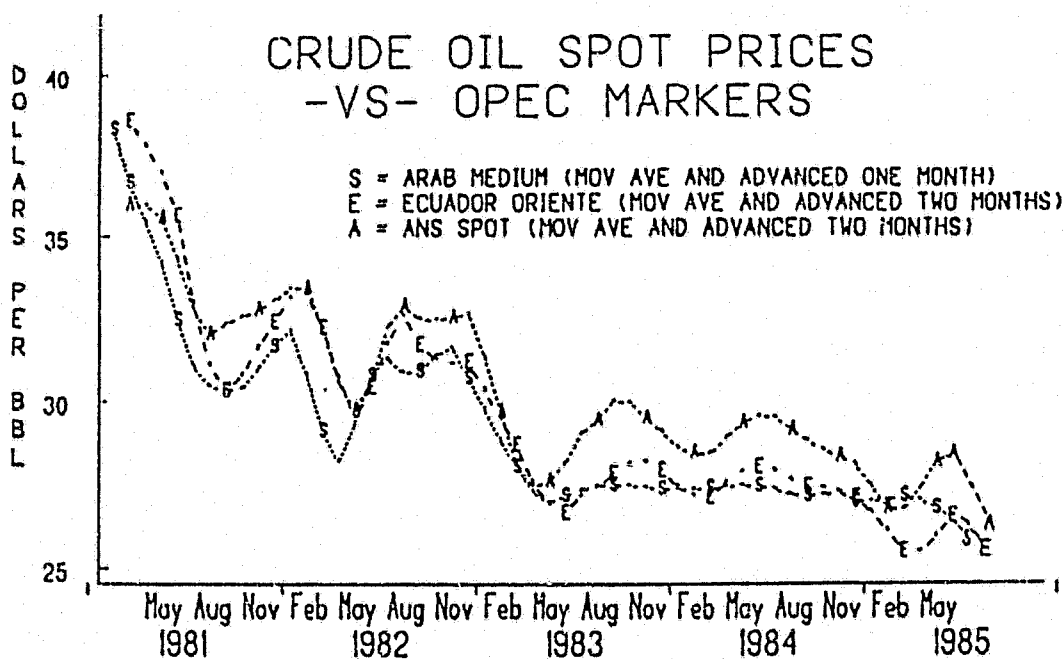
Owing to the evolving structural productive and consumptive forces mentioned above, and dwelled on at length in the March, 1985 Petroleum Production Revenue Forecast, crude prices continue to erode. Graph 2, on the following page, shows the path of two important domestic light crudes: West Texas Sour and West Texas Intermediate. ANS, although a

heavier crude oil, tracks these two oils fairly closely.



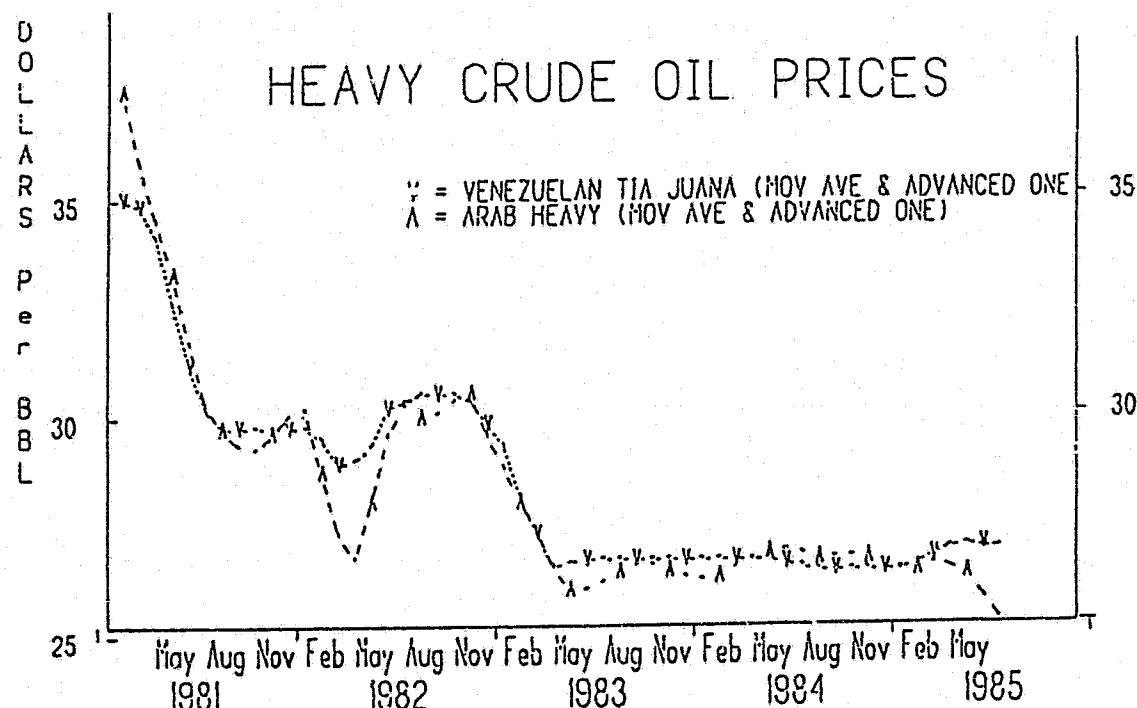
GRAPH 2

Price began to recover temporarily in February, after the OPEC Price/Quota accords. Since then, OPEC's new prices have been undermined by non-OPEC competition and some OPEC members themselves; thus quota adherence has been lax. In addition, after months of anticipating the price drop, many contracts were cut in February (though most have expired) and spot sales diminished accordingly. Similarly, in anticipation of OPEC's late July meeting, buying is now curtailed, spot sales are reduced, and spot prices appear firm. Graph 3 shows spot prices for ANS and some medium gravity crudes which track closely with ANS. Their pattern has been similar to the light crudes. ANS spot volumes are small, and the price is more volatile than contract levels.



GRAPH 3

Graph 4 shows spot prices for heavy crudes which track closely with ANS. Between the end of the coal strike and the OPEC price accords (which lowered light prices and raised heavy), any inter-gravity price differential inequities (vis-a-vis product yield differentials) seems to



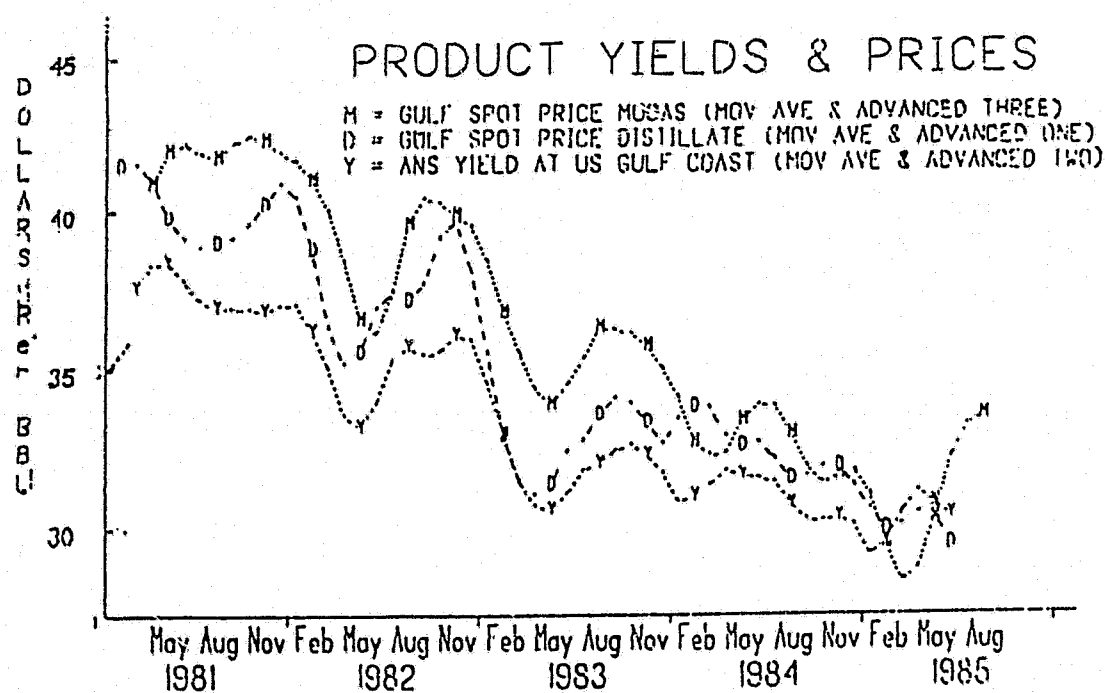
GRAPH 4

have been alleviated. In fact, Saudi Arabia has suggested that prices for heavy crudes be reduced. The heavy crudes were relatively stable prior to February. Since then, Arab Heavy has gone the way of resid prices. Venezuela has maintained its prices in loyalty to OPEC, but may drop its prices after the OPEC meeting, especially since Mexico recently dropped its heavy crude prices \$2.00 per barrel.

Graph 5, on the following page, shows spot prices of products and ANS yield (the value of products refined from a barrel) for the Gulf market. The price refineries are willing to pay for ANS crude tracks with the value of products refined from it. In general, the same factors that have depressed crude prices have carried over into product markets. Gasoline has currently upturned due somewhat to seasonal stockbuilding and increased refinery costs as well as short-term shortages of unleaded gasoline. The value of lead credits should increase as the allowable lead limit decreases. Also, leaded gas is being produced for either exchange with unleaded or for stockpiling.

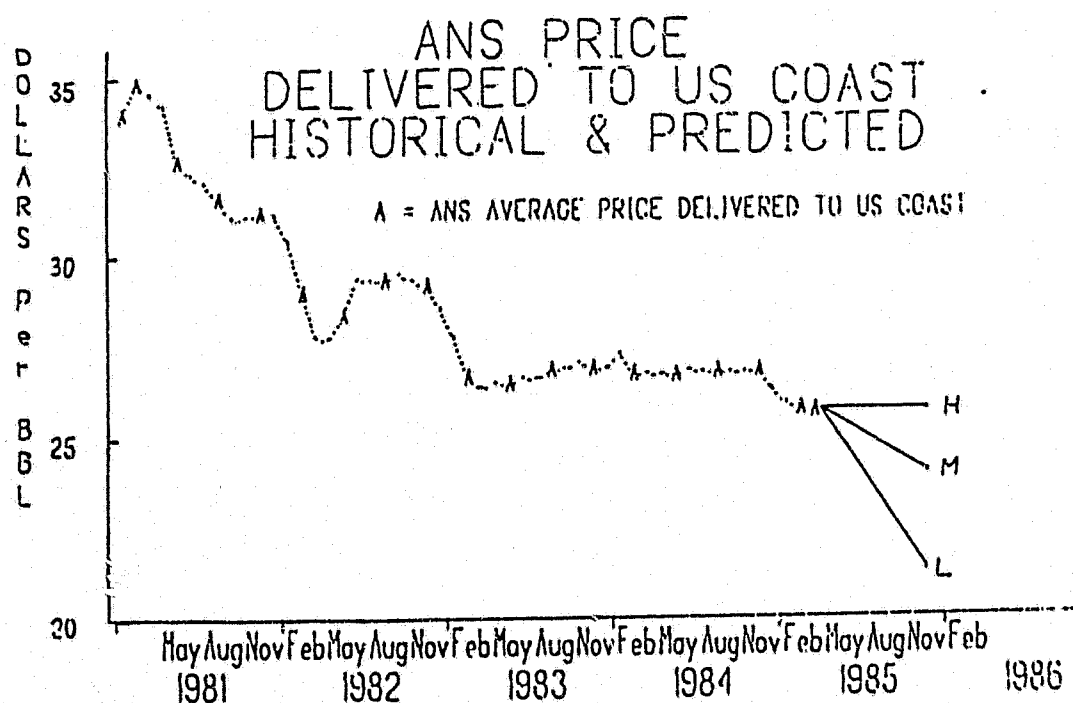
Graph 6, on the following page, shows the predicted weighted average ANS sales price for May, 1985 through November, 1985. The predicted ANS prices were developed through a combination of the economic regression modeling and the ARIMA time series modeling. Regression uses a set of independent explanatory variables to predict the movement of another dependent variable. The projected values for the independent variables associated with ANS price were predicted through the ARIMA model. In the ARIMA time series model, the future movements of a variable are determined by the past trends and cyclical behavior of the variable, as

well as past random shocks or disturbances and non-random shocks (seasonality). The predicted ARIMA values for the independent variables were then used in the regression model to arrive at the projected price paths.



GRAPH 5

Graph 6 shows a high, mean, and low projection for ANS price. The mean



GRAPH 6

projection is for a \$1.50 per barrel decline over the period. The mean is bracketed by a ninety percent confidence interval range of \$4.00 per barrel to reflect uncertainties: \$1.50 per barrel on the high side and \$2.50 per barrel on the low side. Ninety percent of the model results fell within this interval.

FORECAST ASSUMPTIONS
(Dr. Charles L. Logsdon; Eric Hansen)

Inflation

Although there is some concern over the recent rapid growth in the money supply, most analysts continue to project low rates of inflation for the foreseeable future as GNP growth has slowed and energy prices, food prices, and housing costs remain stable. As always a wide variety of inflationary scenarios are considered in the forecast and are summarized below.

<u>Fiscal Year</u>	<u>Average Rate</u>	<u>Confidence Band</u>	
		<u>Lower 95%</u>	<u>Upper 95%</u>
1986	4.42	2.41	6.87
1987-1991	4.83	.62	8.57
1992-1996	5.22	.79	9.29
1997-2001	5.68	1.09	9.92

North Slope Oil Prices

International Trends

OPEC met in early July briefly then adjourned until July 22. It is becoming evident that as world demand continues to shrink and non-OPEC production increases the cartel is finding it more difficult to make the production cuts necessary to protect their official price structure. Currently official prices are roughly \$1.00/bbl to \$2.00/bbl above market levels. Because of the revenue needs of many of the member countries they must sell oil at a discount from their official price just to sell their quotas under the current OPEC accord. It has been estimated that less than one-third of the OPEC oil being sold today is priced at official levels.

Obviously there is tremendous pressure on OPEC to lower their official price structure. The problem is that OPEC producers who currently sell at the official price, like Saudi Arabia, would have to sell more oil at the lower prices to preserve revenue which would, of course, put further downward pressure on price. In fact, Saudi Arabia has on several occasions over the last six months threatened to flood the market with crude oil unless pricing and production discipline is restored within the cartel. Because of the potential destabilizing effect of such a move on the Middle Eastern political situation, it is unlikely the Saudi's would pursue such a course of action. It does serve as a strong reminder that a breakdown of the OPEC cartel could result in a very big drop in world oil prices.

In recent days Mexico and Egypt both non-OPEC oil exporters lowered their official prices \$1.00/bbl to \$2.00/bbl. The official and spot prices of key internationally traded crude oil are as follows.

<u>Crude Oil</u>	<u>Official Price (\$/bbl)</u>	<u>Estimated Spot Price</u>	<u>Spot vs. Official</u>
Saudi Light	28.00	26.77	-1.23
Iran Light	28.05	25.05	3.00
Nigerian Bonny Light	28.65	26.66	-1.99
North Sea Brent	26.65	26.43	0.22
Ecuador Oriente	26.50	25.28	0.92
Venezuela Heavy	24.28	24.28	0
Saudi Heavy	26.50	25.07	-1.43
Mexican Maya	24.00	24.00	0

Over the longer term, the demand for crude oil is expected to grow very slowly as a result of continued loss of market to interfuel substitution and the increased use of fuel conserving technology. In fact simple extrapolation of demand growth at 2% per year and relatively constant non-OPEC production suggests the demand for OPEC oil will not reach 20 million bbls/day before 1990. This suggests that oil prices will continue low for quite a while.

In this forecast, it is assumed that the average expected price will rise from \$26.38/bbl in FY 1985 to \$43.70/bbl in FY 2001, a 3.2 percent average annual increase in nominal dollar terms.

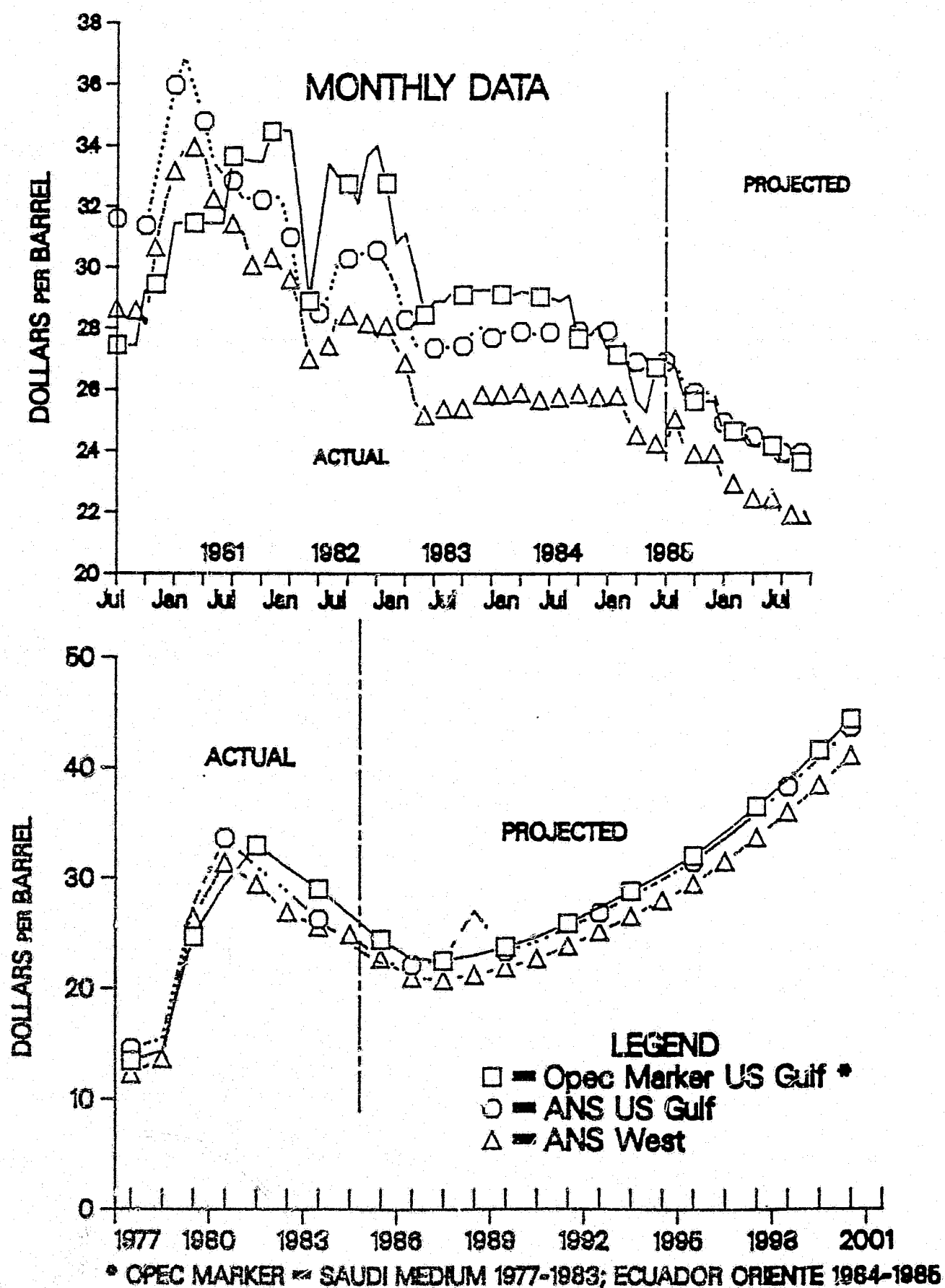
Specific average expected prices are:

<u>Fiscal Year</u>	<u>Nominal Marker Price</u>	<u>Real (1985) Marker Price</u>
1985	26.37/bbl	26.37
1986	24.09	23.18
1990	23.46	19.21
1995	29.91	19.17
2001	43.70	20.25

Domestic Price Trends

Although June and July spot prices for domestically produced crude oil have been consistently \$1.00/bbl or more below April and May levels, no significant changes in major crude oil posted prices have occurred since last January. Current market data suggest that U.S. demand is down nearly 2% from last year suggesting further price deterioration (see Short Term Market Analysis, page 3.)

ACTUAL & EXPECTED CRUDE OIL PRICES FOR ALASKA NORTH SLOPE AND OPEC MARKER AT US GULF & WEST COAST DESTINATIONS



Graph 7.

The weighted average sales price of ANS on the West Coast and Gulf Coast, and the weighted average wellhead net back price for the last twelve months were reported as follows:

<u>Month</u>	<u>Wellhead Price(\$/bbl)</u>	<u>West Coast Price (\$/bbl)</u>	<u>Gulf/East Coast Price(\$/bbl)</u>
May 1984	17.72	25.64	27.94
June	17.77	25.70	28.04
July	17.79	25.81	27.95
August	18.04	25.63	27.97
September	18.13	25.76	27.90
October	18.01	25.72	27.94
November	18.02	25.73	28.01
December	17.59	25.23	27.38
January 1985	16.99	24.72	27.00
February	16.72	24.28	26.98
March	16.79	24.31	26.97
April	16.87	24.27	26.97

In this forecast, we have assumed that, on average, the current price structure for lower 48 sales of ANS will continue. Alaska in-kind royalty sales are assumed to replace some of the sales by firms currently enjoying West Coast sales at a net-back premium. Provisions of recently approved in-kind royalty contracts also will allow the State to recover the field costs charged by the producers against State royalty oil.

The weighted average annual wellhead values for ANS crude oil, specifically for Prudhoe Bay production range from \$17.11/bbl in FY 1985 to \$36.26/bbl in FY 2001. The weighted average annual Prudhoe Bay netback values for FY 1986-1990 are \$15.48/bbl, \$13.74/bbl, \$13.56/bbl, \$14.34/bbl, and \$15.01/bbl, respectively.

Pipeline Tariffs

Assumptions about pipeline tariffs for transporting oil from the various North Slope fields to the TAPS are as follows (the tariffs include a quality adjustment).

Kuparuk	\$1.20
Milne Pt.	\$1.58
Endicott	\$1.51
Lisburne	\$0
West Sak	\$2.70
Other Onshore	\$0.75
Seal Island	\$1.53

Successful resolution of the long standing TAPS tariff litigation may be somewhat nearer as the State of Alaska has tentatively reached an out of court settlement with all but two of the pipeline owners. Essentially,

the settlement would eliminate most state claims over past tariffs in exchange for future tariffs roughly \$2.00/bbl below current levels. Complicating the situation however is the recent ruling by FERC in the long standing Williams Brothers case, which sets out a rate making method favorable to the State's position on TAPS. If the method were approved for TAPS as well as lower 48 pipelines, the State would realize a hefty settlement for tariffs charged between 1977 and the present. Continuing to pursue the case could of course involve many more years of litigation. For this reason, no specific method of TAPS rate making is used in this forecast and the average TAPS tariff is assumed to remain \$5.007/bbl.

Tanker tariffs and refinery market delivery forecasts were based on data obtained from tax returns, industry figures, journal articles, and studies done by government and private agencies. During the month of April 1985, roughly 45 percent of taxable ANS production was reported as delivered to the West Coast while 55 percent was reported as delivered to the U.S. Gulf, East Coast, and Caribbean.

It is assumed that ANS crude in surplus on the West Coast will be shipped to the Gulf and East Coast through the Panama Canal, the Trans Panama pipeline, and the Four Corners pipeline. No exports of ANS are assumed.

North Slope Gas Prices

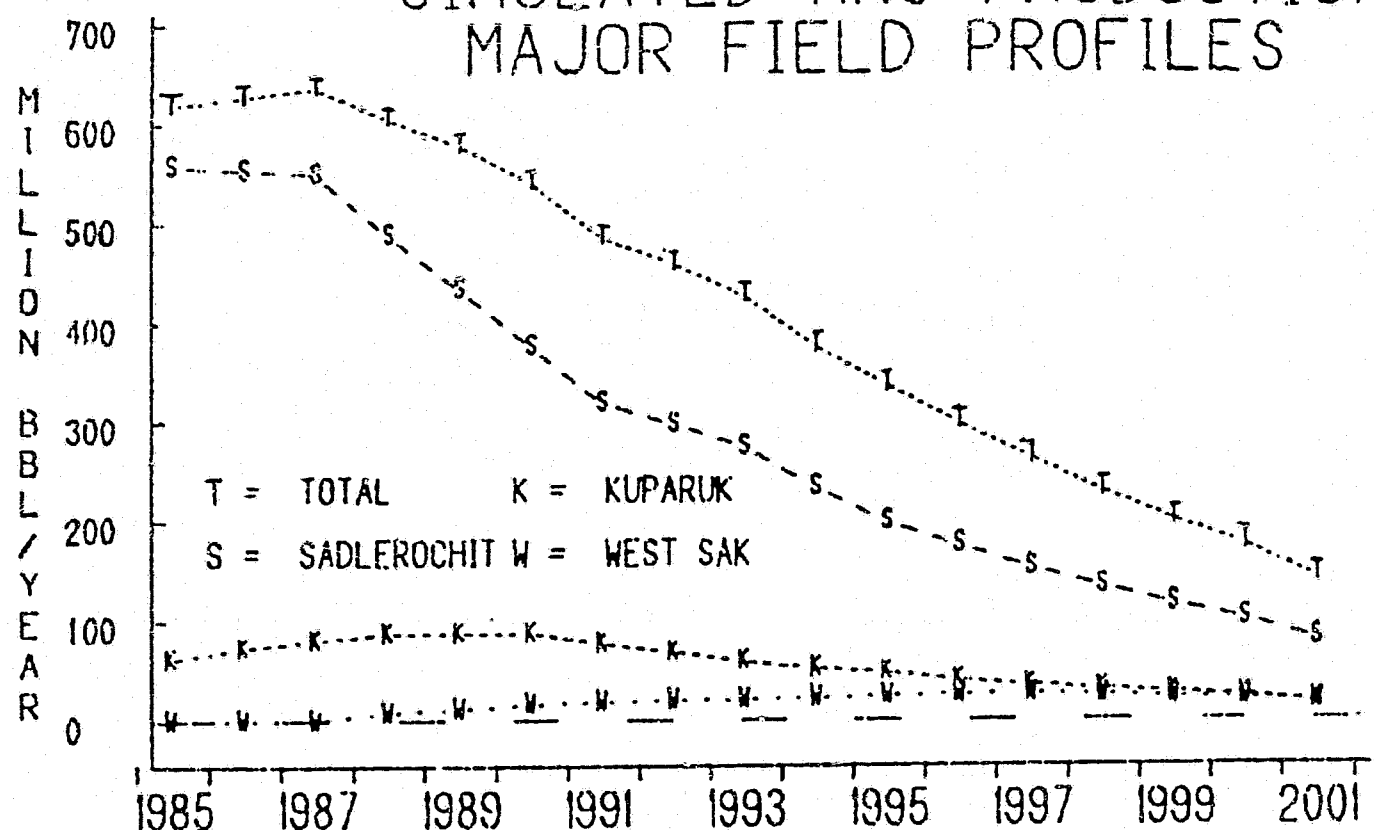
North Slope gas prices for the limited amount of gas produced and sold currently vary considerably among the producers ranging from \$0.25/Mcf to \$3.22/Mcf. This variation reflects the imperfect market structure for these limited sales since the producers sell most of the gas to TAPS which is owned by the producers and the pipeline ownership shares differ from the resource ownership shares. Future price will depend in large measure on the timing and cost of a gas transmission system built to access either international markets as in the case of the Trans Alaska Gas System (TAGS), or lower 48 markets, as in the case of the Alaska Natural Gas Transmission System (ANGTS).

Given the projected low prices for oil, the continuing apparent excess supply of less costly sources of natural gas, and the high cost of either transmission system, it is assumed that there is only a 17 percent chance that a pipeline will be built and in operation by FY 2000. The high cost of either ANGTS or TAGS implies the possibility of a zero wellhead value during the yearly years of production. Price scenarios are used which range from \$0.00/Mcf to inflation adjusted prices based on today's price. The current price averages \$1.38/Mcf. The average expected price assumed with a gas line is \$5.99/Mcf in FY 2000.

North Slope Oil Production

Multiple well and production scenarios for oil and gas were developed from many sources, including information furnished by the producing companies, the Alaska Department of Natural Resources, the Alaska Oil and Gas Conservation Commission, oil industry trade journals and news releases. Specific annual production simulation scenarios for each of the major and minor North Slope formations are depicted in Graphs 8 and 9, following.

SIMULATED ANS PRODUCTION MAJOR FIELD PROFILES



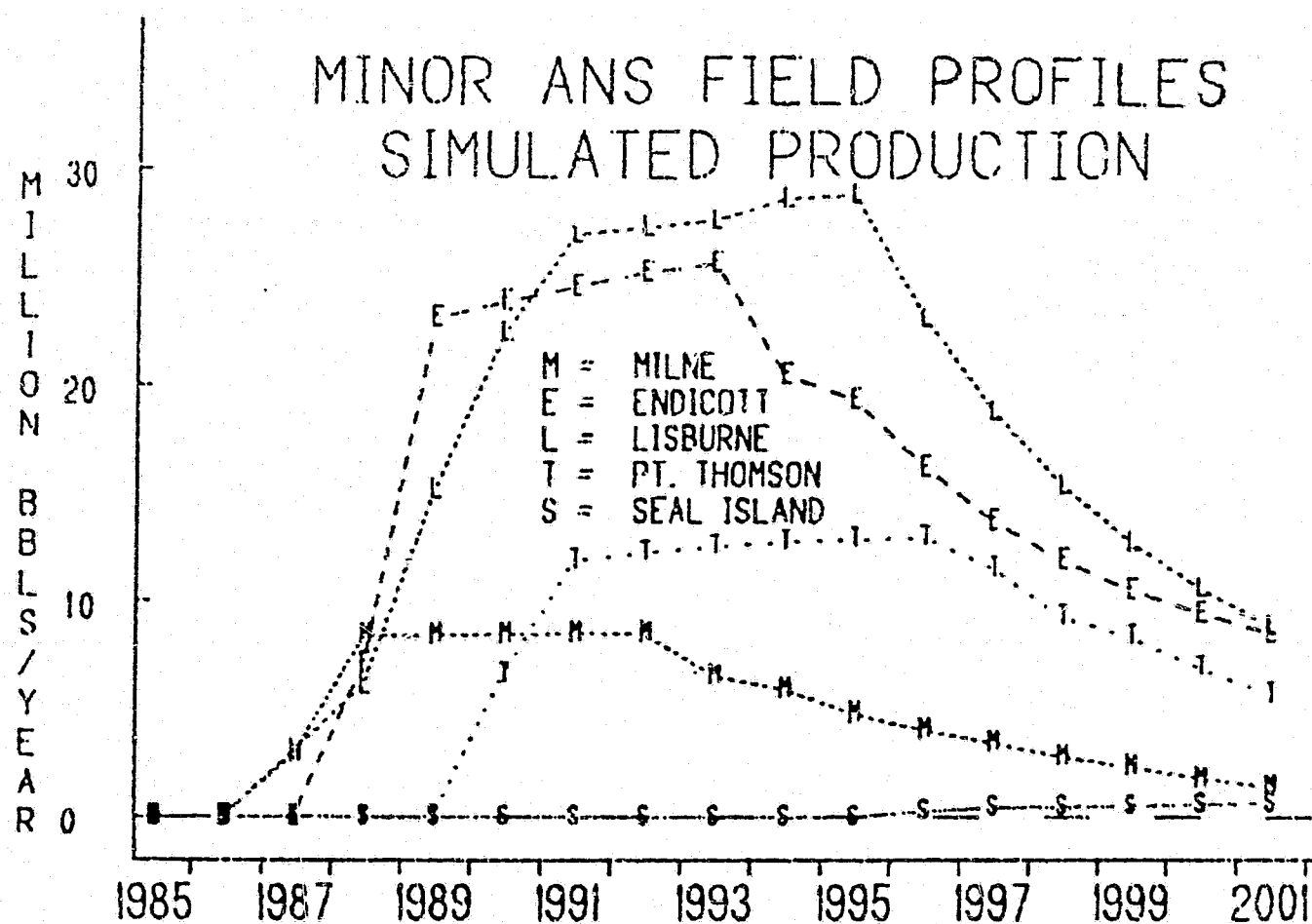
NOTE: TOTAL INCLUDES MAJOR AND MINOR FIELDS.
GRAPH 8

Table 1.

Major Field Simulated Production (Million bbls/year)

Year	Sadlerochit	Kuparuk	West Sak	Total ANS*
1985	557.73	60.97	-0-	618.71
1986	553.87	72.93	-0-	626.97
1987	550.39	80.04	-0-	636.65
1988	488.99	87.15	7.86	605.59
1989	433.79	87.15	10.98	578.50
1990	376.07	87.15	16.09	540.56
1991	318.93	76.69	18.17	485.58
1992	297.53	68.35	20.19	459.21
1993	274.71	58.99	20.96	426.94
1994	233.82	52.03	22.65	376.21
1995	198.62	48.37	24.18	336.94
1996	175.33	40.50	25.76	298.23
1997	152.72	35.62	27.62	263.48
1998	133.96	31.50	24.95	230.46
1999	116.37	27.69	22.95	201.61
2000	101.24	24.29	20.99	176.04
2001	81.14	17.79	19.10	143.28

* NOTE: Total ANS production includes minor field volumes.



GRAPH 9

Table 2.

Minor Field Simulated Production
(Million bbls/year)

Year	Milne Pt.	Endicott	Lisburne	Other Onshore	Other Offshore
1985	-0-	-0-	0.04	-0-	-0-
1986	0.06	-0-	0.05	-0-	-0-
1987	2.93	-0-	3.11	-0-	-0-
1988	8.39	7.10	6.13	-0-	-0-
1989	8.40	23.07	15.11	-0-	-0-
1990	8.43	23.85	22.41	6.60	-0-
1991	8.48	24.53	26.96	11.35	-0-
1992	8.47	25.21	27.30	12.00	-0-
1993	6.56	25.63	27.64	12.48	-0-
1994	5.94	20.46	28.63	12.72	-0-
1995	4.84	19.31	28.81	12.84	-0-
1996	4.09	16.18	23.15	12.95	0.29
1997	3.50	13.74	18.84	11.55	0.48
1998	2.85	11.84	15.43	9.32	0.51
1999	2.39	10.54	12.77	8.36	0.53
2000	1.85	9.46	10.64	6.94	0.62
2001	1.46	8.54	8.88	5.71	0.66

A full explanation of how these volumes were derived is given in Appendices B and C of this forecast. The majority of the North Slope simulation volume comes from the Sadlerochit reservoir throughout the 17-year period. Graph 8 also shows the expected total ANS production, in millions of barrels per year, given the June 1985 forecast assumptions and simulated production. Table 1 presents the volumes associated with Graph 8. Table 2 shows the volumes for Graph 9. Actual North Slope production for April 1985 averaged 1.732 million bbls/day.

Sohio is still aiming for start-up of Endicott reservoir production in December 1987. Peak production of 100,000 bbls/day is expected by late 1988, continuing through 1992, when the production will start its decline. Development costs for the field, which is exploiting the Kekiktak formation, will be about \$2 billion. The reservoir contains about one billion barrels of 23° API gravity oil, but only 350 million barrels are recoverable with current technology. Production modules are now being constructed in Louisiana and will be shipped to the Beaufort Sea site during the 1986 and 1987 sealifts.

Conoco's Milne Point field, which will be producing from the Kuparuk formation, represents the first commercially feasible small field on the North Slope. Initial production of the 100 million barrel reservoir will begin in early 1986 at about 30,000 bbl/day from 18 wells. Waterflood injection will be undertaken immediately to maintain reservoir pressure. Injection rates will average 30-40,000 bbls/day. Fabrication of the production facilities was completed recently in Everett, Washington and the modules are currently enroute to the North Slope via barge.

Evaluation of Texaco's recent discovery of oil at the Colville River Delta continues. Initial flow rates were 414 to 1,000 bbl/day for oil and 36-391 Mcf/day for natural gas from the 6,800 foot deep well. At least one more delineation well will be drilled during the winter, though no specific site has been selected. If development occurs, the field's production could be linked via pipeline to the existing Kuparuk River pipeline for shipment to the TAPS.

North Slope Gas Production

Both the Trans Alaska Gas System (TAGS) and the Alaska Natural Gas Transmission System (ANGTS) continue to have financial and political difficulties, therefore, our current projections assume only a one percent chance that either system will be built by 1990.

Cook Inlet Oil Prices

Since oil produced domestically is no longer subject to price controls, Cook Inlet oil prices are assumed to change throughout the forecast in the same manner and at the same rate assumed for the West Coast ANS crude prices, as determined in the Prudhoe Bay simulation model. The price is assumed to increase from \$24.82/bbl in FY 1985 to \$41.15/bbl in FY 2001.

Prices for FY 1985 to FY 1989 are assumed to be: \$24.82/bbl, \$22.70/bbl, \$21.07/bbl, \$20.92/bbl, and \$21.34/bbl, respectively. The average April 1985 price was \$23.87/bbl.

Cook Inlet Gas Prices

Gas prices were adjusted according to contract escalation agreements and were inflated at an annual rate approximating the rate of inflation after the termination of contracts. Gas prices not subject to contractual agreements were escalated one penny per quarter in accordance with the Federal Power Commission's Opinion 770. The severance tax floor of \$.064/Mcf was assumed to remain constant. The actual weighted average price for April 1985 was \$.67/Mcf.

Cook Inlet Oil Production

Oil and gas production forecasts made by Petroleum Revenue Division consultants and the Division of Oil and Gas Conservation were used to generate the production estimates. In Cook Inlet, oil production was assumed to decline throughout the 17-year forecast period at approximately 12 percent per annum. In all wells, a 300-barrel-a-day production at the economic limit was assumed. Those wells which produced less than this amount were assumed to shut down operations.

Oil production annually was expected to decline over the 17-year forecast period from 39,292 bbls/day in FY 1985 to 10,968 bbls/day in FY 2001. April 1985 production averaged 30,538 bbls/day.

Cook Inlet Gas Production

Gas production in Cook Inlet is anticipated to increase slightly over the 17-year forecast period from the FY 1985 level of .566 Bcf/day to a FY 2001 level of .576 Bcf/day. These figures are based on the abandonment of plans to build a Pacific Alaska LNG facility. Other uses or markets may become available for the volumes previously committed to Pacific LNG, especially as Alaska's population around Cook Inlet grows. April 1985 production averaged .563 Bcf/day.

Table 3 shows average values for FY 1985 and risk-adjusted values for FY 1986-FY 2001 for severance and conservation taxes, royalties, and total petroleum revenues.

Table 3.

Petroleum Production Revenue Forecast
(Expected Values in Millions of Dollars)

<u>Fiscal Year</u>	<u>Total Severance and Conservation Taxes</u>	<u>Total Royalties</u>	<u>Total Petroleum Revenues</u>
1985	1367.50	1359.13	2726.63
1986	1165.67	1181.66	2347.33
1987	980.92	998.64	1979.56
1988	750.87	920.02	1670.89
1989	666.38	861.25	1527.63
1990	587.25	808.60	1395.85
1991	524.89	747.62	1272.51
1992	515.54	748.00	1263.54
1993	491.26	725.47	1216.73
1994	439.90	686.18	1126.07
1995	410.83	667.30	1078.13
1996	364.22	634.07	998.30
1997	339.74	625.71	965.45
1998	310.67	594.80	905.46
1999	285.86	573.58	859.44
2000	260.13	547.73	807.87
2001	220.60	498.89	719.48

The data presented in Table 3 have been broken down into their component parts in Table 4 on the following page. In this case, revenues are shown for oil and gas from the two major producing regions in the state: Cook Inlet and the North Slope. The values shown are the mean for FY 1985 and the 30 percent cumulative distribution (risk-adjusted) values for FY 1986-FY 2001.

Table 4.

Petroleum Production Revenue Forecast
(Expected Values in Millions of Dollars)

Year	OPT	GPT	North Slope		OCT	Total	OPT	GPT	Cook Inlet		OCT	Total	Statewide Total
			O ROY	G ROY					O ROY	G ROY			
1985	1346.89	1.43	1301.99	2.14	0.67	2653.13	6.75	11.74	40.54	14.45	0.01	73.50	2726.63
1986	1144.35	1.16	1122.13	1.86	0.68	2270.18	6.68	12.78	37.53	20.15	0.01	77.15	2347.33
1987	957.89	1.21	941.00	1.93	0.68	1902.71	3.79	17.34	30.30	25.40	0.01	76.84	1979.56
1988	724.19	1.23	860.05	2.00	0.62	1588.09	2.67	22.15	26.13	31.84	0.01	82.80	1670.89
1989	639.58	1.26	802.17	2.08	0.56	1445.65	1.03	23.95	23.38	33.62	0.01	81.99	1527.63
1990	556.70	0.78	742.34	1.31	0.50	1301.63	0.07	29.20	21.17	43.77	0.01	94.22	1395.85
1991	489.83	0.96	673.71	1.64	0.44	1166.58	0.00	33.66	19.28	52.99	0.01	105.94	1272.51
1992	476.41	0.65	667.48	1.13	0.41	1146.08	0.00	38.06	17.65	61.74	0.01	117.46	1263.54
1993	448.74	0.41	641.21	0.00	0.39	1090.75	0.00	41.71	16.05	68.21	0.01	125.98	1216.73
1994	396.95	0.40	599.11	0.00	0.34	996.81	0.00	42.20	14.89	72.18	0.00	129.27	1126.07
1995	365.26	0.40	575.43	0.00	0.30	941.39	0.00	44.87	15.11	76.76	0.00	136.74	1078.13
1996	315.94	0.39	537.12	0.00	0.26	853.71	0.00	47.63	15.48	81.47	0.00	144.58	998.30
1997	284.69	3.11	515.94	5.98	0.23	809.95	0.00	51.71	16.08	87.71	0.00	155.51	965.45
1998	251.84	3.15	477.77	6.16	0.20	739.13	0.00	55.47	16.44	94.42	0.00	166.33	905.46
1998	223.01	3.16	446.31	6.37	0.18	679.03	0.00	59.51	17.10	103.80	0.00	180.41	859.44
2000	193.95	3.10	413.83	6.46	0.15	617.48	0.00	62.94	16.16	111.27	0.00	190.38	807.87
2001	152.29	3.01	358.15	6.46	0.12	520.02	0.00	65.18	15.29	118.99	0.00	199.46	719.48

OPT = Oil Production Taxes
GPT = Gas Production Taxes

O ROY = Oil Royalties
G ROY = Gas Royalties

OCT = Oil Conservation Taxes

The following table compares the Total Petroleum Revenues from Table 3 of the March 1985 and June 1985 Petroleum Production Revenue Forecasts. Again, the mean values are given for FY 1985 and the risk-adjusted values are given for FY 1986-FY 2001.

Table 5.

Comparison of March 1985 and June 1985
State of Alaska Petroleum Revenue Forecasts
for FY 1985-FY 2001
(In Millions of Current Dollars)

<u>Fiscal Year</u>	<u>March 1985 Forecast</u>	<u>June 1985 Forecast</u>	<u>Difference</u>	<u>% Change</u>
1985	2744.41	2726.63	-17.78	-0.65
1986	2387.14	2347.33	-39.81	-1.67
1987	2186.06	1979.56	-205.50	-9.45
1988	1899.22	1670.89	-228.33	-12.02
1989	1761.63	1527.63	-234.00	-13.28
1990	1647.78	1395.85	-251.93	-15.29
1991	1476.76	1272.51	-204.25	-13.83
1992	1459.04	1263.54	-195.50	-13.40
1993	1406.26	1216.53	-189.53	-13.49
1994	1298.99	1126.07	-172.92	-13.31
1995	1203.79	1078.13	-125.66	-10.44
1996	1113.13	998.30	-114.83	-10.32
1997	1070.80	965.45	-105.35	-9.84
1998	1035.53	905.45	-130.07	-12.56
1999	985.92	859.44	-126.48	-12.83
2000	926.83	807.87	-118.96	-12.84
2001	831.81	708.41	-112.33	-14.84

State of Alaska Permanent Fund Contributions are depicted in Table 6. These contributions are based on the mean royalty values for FY 1985 and the risk-adjusted royalty values for FY 1986-FY 2001. The level of contributions is substantially lower for this forecast because of lower expected royalty revenues and adjustments to the contribution percentages for several fields. The contributions are exclusive of lease rentals, bonuses, royalty sale proceeds, reinvested earnings and legislative appropriations. The contribution rate is assumed to be 25 percent of royalties earned from mineral leases issued on or before December 1, 1979, such as Kuparuk, and 50 percent of royalties earned from mineral leases issued after December 1, 1979, such as Seal Island. The balance in the Permanent Fund as of June 30, 1984 was \$4838.30 million.

Table 6.

Projected State of Alaska Permanent Fund Contributions
for FY 1985-FY 2001
(In Millions of Current Dollars)

<u>Fiscal Year</u>	<u>Annual Contribution</u>	<u>Cumulative Contribution</u>
1985	339.82	5178.12
1986	295.44	5473.56
1987	252.04	5725.60
1988	241.22	5966.81
1989	236.74	6203.55
1990	231.10	6434.65
1991	221.55	6656.20
1992	225.04	6881.25
1993	221.04	7102.25
1994	212.78	7315.03
1995	211.39	7526.42
1996	202.34	7728.76
1997	201.03	7929.79
1998	190.64	8120.43
1999	184.31	8304.74
2000	176.21	8480.94
2001	163.33	8644.27

It should be stressed that the forecast of petroleum production revenues is done in nominal or current dollars, that is, future revenues are inflated. Often it is useful to examine future revenue flows in terms of constant dollars in order to provide an estimate of "purchasing" power in a present day context. The values for FY 1985-FY 2001 as given on Table 3 are deflated by the average expected rates of inflation to obtain Table 7.

Table 7.

Constant Dollar
Petroleum Production Revenue Forecast
(Values in Millions of 1985 Dollars)

<u>Fiscal Year</u>	<u>Total Severance and Conservation Taxes</u>	<u>Total Royalties</u>	<u>Total Petroleum Revenues</u>
1985	1367.50	1359.13	2726.63
1986	1121.70	1137.08	2258.79
1987	907.50	923.90	1831.40
1988	663.14	812.52	1475.66
1989	561.78	726.06	1287.84
1990	472.48	650.58	1123.06
1991	403.05	574.08	977.13
1992	377.82	548.18	926.01
1993	342.29	505.48	847.78
1994	291.40	454.54	745.94
1995	258.73	420.24	678.97
1996	218.07	379.64	597.71
1997	192.57	354.67	547.25
1998	166.70	319.17	485.87
1999	145.21	291.36	436.57
2000	125.10	263.41	388.51
2001	100.43	227.13	327.56

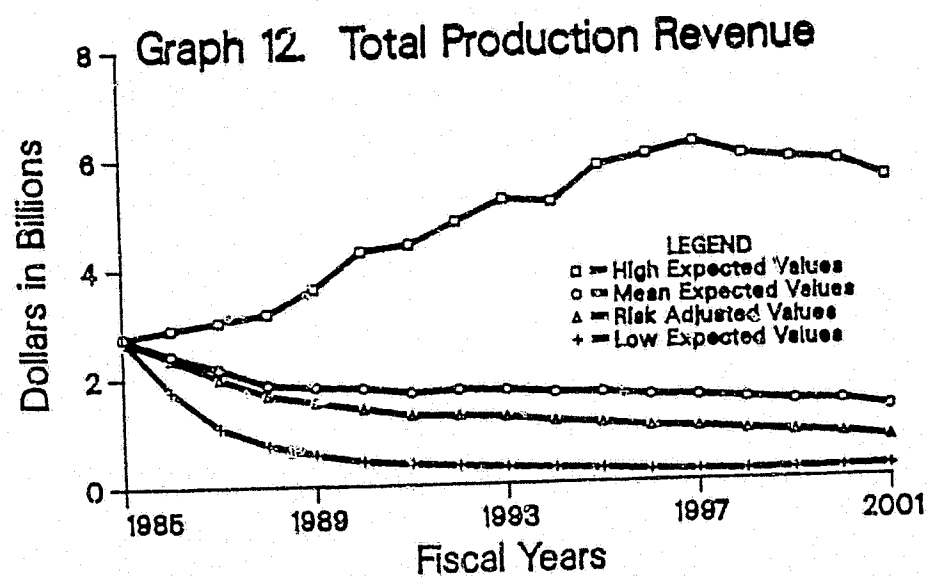
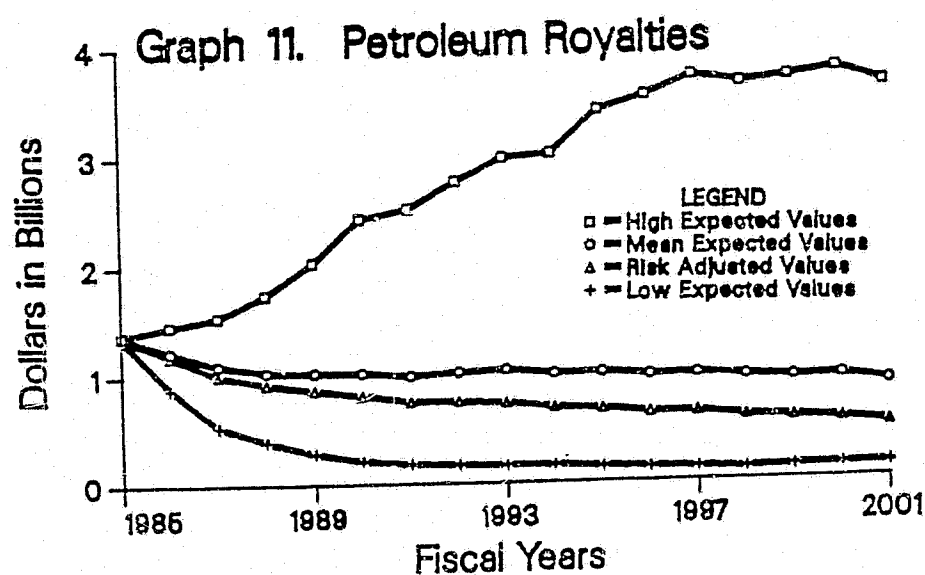
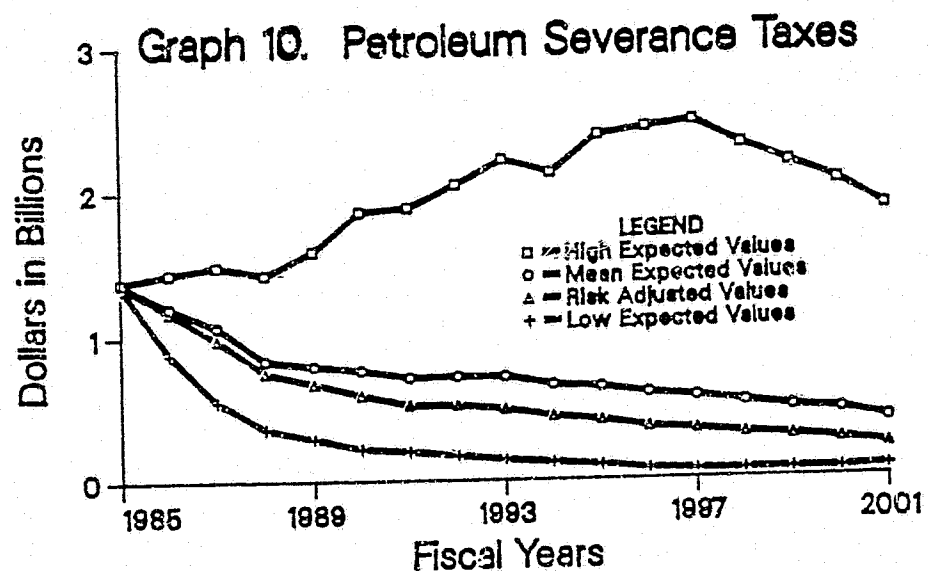
The hedge achieved by use of the risk-adjusted petroleum production revenue for the Summer 1985 forecast is illustrated in Table 8, which compares the risk-adjusted revenue forecast to the average expected revenue forecast.

Table 8.

Comparison of Projected Average Expected and
Risk-Adjusted Total Petroleum Production Revenues
(Millions of Dollars)

<u>Fiscal Year</u>	<u>Average Expected Revenue</u>	<u>Risk Adjusted Revenues</u>	<u>Difference</u>
1985	2726.63	2723.31	3.32
1986	2423.89	2347.33	76.56
1987	2163.10	1979.56	183.54
1988	1860.51	1670.89	189.62
1989	1812.10	1527.63	284.47
1990	1781.42	1395.85	385.57
1991	1697.19	1272.51	424.68
1992	1736.54	1263.54	473.00
1993	1751.93	1216.73	535.20
1994	1655.74	1126.07	529.67
1995	1642.54	1078.13	564.41
1996	1569.50	998.30	571.20
1997	1546.15	965.45	580.70
1998	1486.13	905.46	580.67
1999	1428.70	859.44	569.26
2000	1413.67	807.87	605.80
2001	1283.75	719.48	564.27

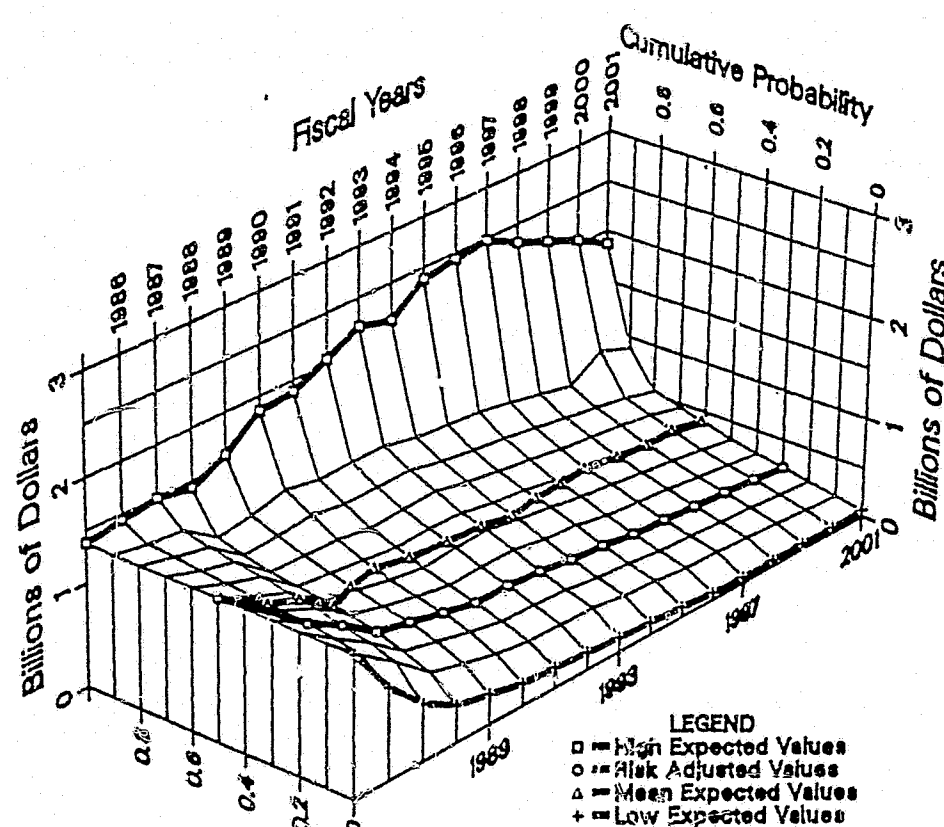
Based on the probabilistic input assumptions made in the March 1985 forecast, Graphs 10, 11, and 12 show the expected high, mean, risk-adjusted, and low ranges for severance taxes, royalties, and total production revenues, respectively, which will accrue to the state between FY 1985-FY 2001.



Revenues tend to decline throughout the forecast horizon because of deteriorating oil prices and lower expected inflation rates offsetting minor gains in production. Production declines in the Sadlerochit Reservoir, as well as the mechanics of the Economic Limit Factor (ELF), account for most of the drop in expected severance tax revenues after FY 1988.

A shortcoming of single-line graphs such as Graphs 10, 11 and 12 is that it is impossible to "see" the real shape of the total distribution of outcomes. This problem can be solved by Graph 13. It has three dimensions: (1) time on the bottom right, (2) billions of dollars on the vertical scale, and (3) cumulative probability on the bottom left. Graph 13 represents exactly what was shown on Graph 10 with one change: it shows the shape of the entire distribution of answers produced by the simulation model.

Petroleum Severance Taxes
Graph 13.



The values shown in Table 9 are used to interpret Graph 13. All of the values shown fit the intersections on the surface of Graph 13. By looking at Graph 13, an observer can see the shape of severance tax potential outcomes extending 17 years into the future. By looking at Table 9, the

observer can estimate severance tax values at particular points in time given different degrees of certainty. A couple of simple examples can illustrate how Graph 13 and Table 9 work together. Given the assumptions used in this forecast:

1. Table 9 states that 100 percent of the time FY 1986 severance tax collections will be less than \$1.44 billion. Graph 13 indicates that at a cumulative probability of 1.0 (the same as 100 percent) there are no solutions which appear higher than about \$1.5 billion. Graph 13 and Table 9 are revealing the same thing: there is a "0 percent" probability that more than about \$1.7 billion in severance taxes will be collected in FY 1986.

Table 9.
Cumulative Frequency Distribution
(Current Dollars in Billions)

Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1985	1.33	1.36	1.36	1.37	1.37	1.37	1.37	1.37	1.37	1.37	1.38
1986	0.88	1.08	1.13	1.17	1.19	1.22	1.24	1.26	1.29	1.31	1.44
1987	0.55	0.84	0.92	0.98	1.04	1.09	1.14	1.18	1.22	1.28	1.49
1988	0.36	0.57	0.67	0.75	0.81	0.85	0.88	0.92	0.98	1.05	1.43
1989	0.29	0.48	0.59	0.67	0.72	0.78	0.84	0.91	1.00	1.10	1.59
1990	0.22	0.40	0.51	0.59	0.65	0.71	0.80	0.90	1.04	1.19	1.86
1991	0.20	0.35	0.44	0.52	0.59	0.66	0.76	0.85	0.99	1.13	1.89
1992	0.17	0.34	0.43	0.52	0.60	0.69	0.78	0.87	0.99	1.14	2.05
1993	0.14	0.33	0.41	0.49	0.60	0.70	0.77	0.89	1.00	1.14	2.22
1994	0.12	0.28	0.36	0.44	0.54	0.64	0.71	0.82	0.93	1.07	2.13
1995	0.10	0.26	0.33	0.41	0.52	0.60	0.67	0.77	0.88	1.04	2.39
1996	0.07	0.22	0.29	0.36	0.45	0.54	0.61	0.72	0.84	1.01	2.44
1997	0.06	0.21	0.27	0.34	0.42	0.50	0.56	0.67	0.79	0.95	2.48
1998	0.06	0.19	0.25	0.31	0.39	0.46	0.53	0.63	0.73	0.88	2.31
1999	0.06	0.17	0.23	0.29	0.35	0.42	0.49	0.59	0.69	0.81	2.18
2000	0.06	0.14	0.20	0.26	0.31	0.37	0.45	0.54	0.62	1.01	2.05
2001	0.07	0.12	0.17	0.22	0.27	0.32	0.39	0.46	0.54	0.89	1.87

2. Graph 13 indicates that there is a 0.0 cumulative probability that FY 1986 severance tax collections will be less than \$.90 billion. From Table 9 it can be seen that in FY 1986 the absolute minimum level of expected severance taxes is \$.88 billion. In this example, both the graph and the table are indicating there is a "0 percent" probability of collecting less than about \$.90 billion from severance taxes during FY 1986.

Graph 14 and Table 10 depict State of Alaska royalty collections from FY 1985 to FY 2001. Graph 15 and Table 11 show State of Alaska total petroleum revenues during the same forecast period. The graphics and associated tables depict families of distribution functions, one function for each forecasting time period. Generally we do not expect the sum of the distributions to be equal to the distribution of the sums reported here. We refer the reader to technical note 1982 AN-1 for a discussion of the topic. Our technical notes are available upon request.

Graph 14. Petroleum Royalties

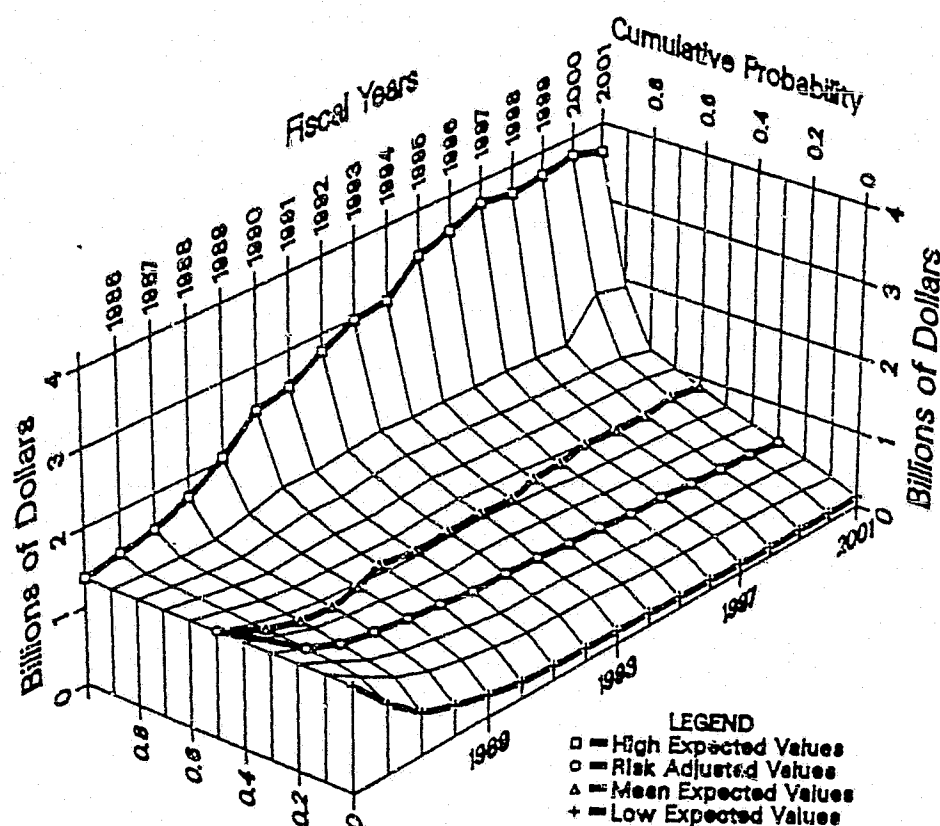


Table 10.
Cumulative Frequency Distribution
(Current Dollars in Billions)

Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1985	1.35	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.37
1986	0.88	1.09	1.15	1.18	1.21	1.23	1.26	1.28	1.30	1.33	1.46
1987	0.53	0.85	0.93	1.00	1.07	1.12	1.16	1.21	1.25	1.32	1.54
1988	0.39	0.69	0.81	0.92	1.00	1.05	1.10	1.15	1.22	1.32	1.74
1989	0.28	0.60	0.73	0.86	0.96	1.03	1.09	1.18	1.29	1.43	2.03
1990	0.21	0.53	0.66	0.81	0.90	0.99	1.08	1.20	1.36	1.56	2.43
1991	0.18	0.48	0.60	0.75	0.87	0.97	1.06	1.18	1.34	1.55	2.52
1992	0.17	0.47	0.60	0.75	0.90	1.00	1.10	1.23	1.41	1.60	2.77
1993	0.16	0.46	0.59	0.73	0.90	1.02	1.12	1.27	1.45	1.65	2.98
1994	0.16	0.42	0.55	0.69	0.86	0.98	1.08	1.23	1.41	1.61	3.02
1995	0.14	0.39	0.52	0.67	0.83	0.94	1.06	1.21	1.39	1.61	3.41
1996	0.13	0.37	0.49	0.63	0.78	0.89	1.01	1.19	1.36	1.59	3.54
1997	0.12	0.36	0.48	0.63	0.75	0.86	0.99	1.16	1.34	1.59	3.71
1998	0.11	0.35	0.47	0.59	0.73	0.84	0.98	1.15	1.31	1.56	3.64
1999	0.12	0.33	0.46	0.57	0.70	0.82	0.95	1.14	1.29	1.52	3.69
2000	0.13	0.31	0.44	0.55	0.66	0.79	0.93	1.11	1.26	2.01	3.76
2001	0.13	0.27	0.39	0.50	0.62	0.74	0.87	1.03	1.16	1.91	3.62

Graph 15. Total Production Revenue

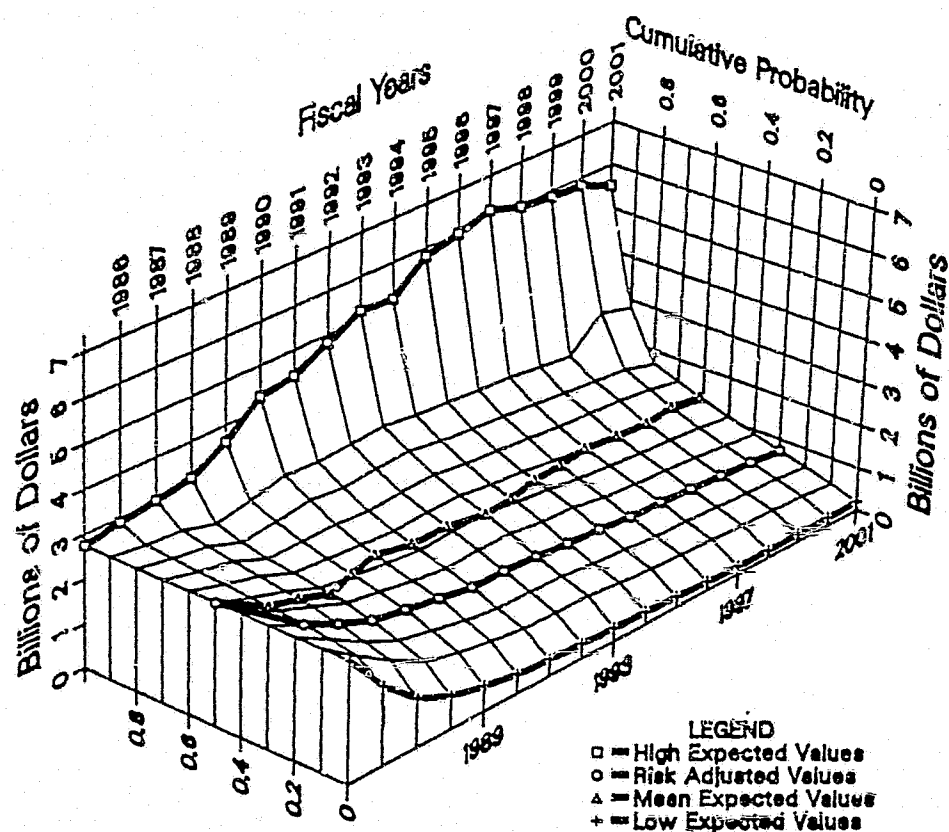


Table 11.
Cumulative Frequency Distribution
(Current Dollars in Billions)

Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1985	2.71	2.72	2.72	2.72	2.73	2.73	2.73	2.73	2.73	2.74	2.75
1986	1.76	2.17	2.28	2.35	2.41	2.45	2.50	2.54	2.59	2.64	2.90
1987	1.08	1.69	1.84	1.98	2.11	2.21	2.30	2.39	2.48	2.60	3.03
1988	0.75	1.26	1.48	1.67	1.81	1.90	1.99	2.07	2.20	2.38	3.17
1989	0.57	1.08	1.31	1.53	1.68	1.80	1.93	2.09	2.29	2.53	3.62
1990	0.44	0.93	1.16	1.40	1.55	1.70	1.88	2.10	2.41	2.74	4.29
1991	0.38	0.83	1.04	1.27	1.45	1.63	1.82	2.04	2.33	2.68	4.41
1992	0.34	0.80	1.03	1.26	1.50	1.69	1.88	2.10	2.40	2.74	4.82
1993	0.30	0.79	1.00	1.22	1.50	1.72	1.90	2.15	2.45	2.79	5.21
1994	0.28	0.71	0.91	1.13	1.40	1.62	1.79	2.05	2.34	2.69	5.15
1995	0.24	0.65	0.85	1.08	1.35	1.54	1.73	1.98	2.27	2.65	5.80
1996	0.20	0.59	0.78	1.00	1.22	1.43	1.62	1.91	2.20	2.59	5.99
1997	0.18	0.57	0.75	0.97	1.17	1.36	1.55	1.83	2.13	2.54	6.19
1998	0.17	0.53	0.72	0.91	1.12	1.30	1.50	1.78	2.04	2.44	5.95
1999	0.18	0.50	0.68	0.86	1.05	1.24	1.44	1.73	1.96	2.34	5.87
2000	0.19	0.46	0.64	0.81	0.98	1.17	1.38	1.65	1.89	3.02	5.81
2001	0.20	0.39	0.56	0.72	0.89	1.07	1.25	1.48	1.69	2.81	5.49

Table 12, following, shows cash flows on a monthly basis. The mean values used for FY 1985 and risk-adjusted values are given for FY 1986-FY 2001.

Table 12.

Petroleum Production Revenue Forecast
Monthly Cash Flow
(Expected Values in Millions of Dollars)

Month	OPT	GPT	North Slope		OCT	Total	OPT	GPT	Cook Inlet		OCT	Total	Statewide Total
			O ROY	G ROY					O ROY	G ROY			
JUL	109.96	.15	102.24	.14	.05	212.54	.75	.47	4.99	.86	0.00	7.06	219.60
AUG	116.43	.14	111.17	.22	.06	228.02	.79	1.01	4.08	1.32	0.00	7.20	235.22
SEP	110.03	.14	105.22	.22	.05	215.66	.73	1.01	3.89	1.30	0.00	5.93	221.59
OCT	118.20	.13	112.93	.20	.06	231.51	.67	.87	3.90	1.09	0.00	6.53	238.04
NOV	117.56	.13	113.46	.20	.06	231.41	.54	1.09	3.54	1.42	0.00	6.59	238.00
DEC	116.25	.13	112.68	.20	.06	229.32	.63	1.08	3.78	1.28	0.00	6.77	236.09
JAN	112.02	.13	109.47	.20	.06	221.88	.42	1.23	3.46	1.50	0.00	6.61	228.49
FEB	103.50	.10	101.08	.15	.06	204.88	.43	1.01	3.19	1.23	0.00	5.86	210.74
MAR	105.40	.09	102.59	.14	.05	208.27	.39	1.27	3.37	1.45	0.00	6.48	214.75
APR	115.93	.10	113.46	.15	.06	229.70	.48	1.15	3.42	1.36	0.00	6.40	236.11
MAY	107.28	.10	107.00	.15	.06	214.59	.42	1.03	3.28	1.19	0.00	5.92	220.51
JUN	114.38	.10	110.76	.15	.06	225.45	.78	1.01	3.77	1.32	0.00	6.88	232.33
FY85	1346.93	1.44	1302.06	2.14	0.67	2653.24	7.03	12.23	44.67	15.32	0.02	78.23	2731.48
JUL	102.45	.09	99.35	.15	.06	202.10	.77	1.04	3.72	1.71	0.00	7.24	209.34
AUG	103.96	.10	102.40	.16	.06	206.68	.57	1.09	3.30	1.78	0.00	6.74	213.42
SEP	103.95	.10	102.39	.16	.06	206.65	.55	1.05	3.20	1.72	0.00	6.52	213.17
OCT	100.59	.09	99.08	.15	.06	199.98	.57	1.09	3.30	1.78	0.00	6.74	206.72
NOV	96.40	.10	95.03	.16	.06	191.75	.53	1.05	3.06	1.66	0.00	6.30	198.05
DEC	93.49	.10	92.12	.15	.06	185.91	.54	1.09	3.16	1.72	0.00	6.51	192.42
JAN	96.60	.10	95.19	.16	.06	192.11	.52	1.09	3.02	1.66	0.00	6.29	198.40
FEB	91.90	.10	90.22	.16	.06	182.43	.48	.98	2.79	1.53	0.00	5.78	188.21
MAR	83.10	.09	81.57	.14	.05	164.96	.53	1.09	3.09	1.69	0.00	6.40	171.36
APR	92.20	.10	90.38	.16	.06	182.90	.52	1.05	2.99	1.64	0.00	6.20	189.10
MAY	85.70	.10	84.06	.16	.06	170.06	.57	1.09	3.00	1.66	0.00	6.32	176.38
JUN	88.64	.10	86.94	.16	.06	175.90	.55	1.05	2.91	1.60	0.00	6.11	182.01
FY86	1138.99	1.16	1118.73	1.86	0.68	2261.42	6.68	12.78	37.53	20.15	0.02	77.15	2338.58

OPT = Oil Production Taxes
GPT = Gas Production Taxes

O ROY = Oil Royalties
G ROY = Gas Royalties

OCT = Oil Conservation Taxes

Graph 16 depicts State of Alaska severance tax revenue monthly cash flow collections. The variations are primarily due to differing number of days in each of the production months represented. Table 13 is associated with Graph 16.

GRAPH 16. PETROLEUM SEVERANCE TAXES

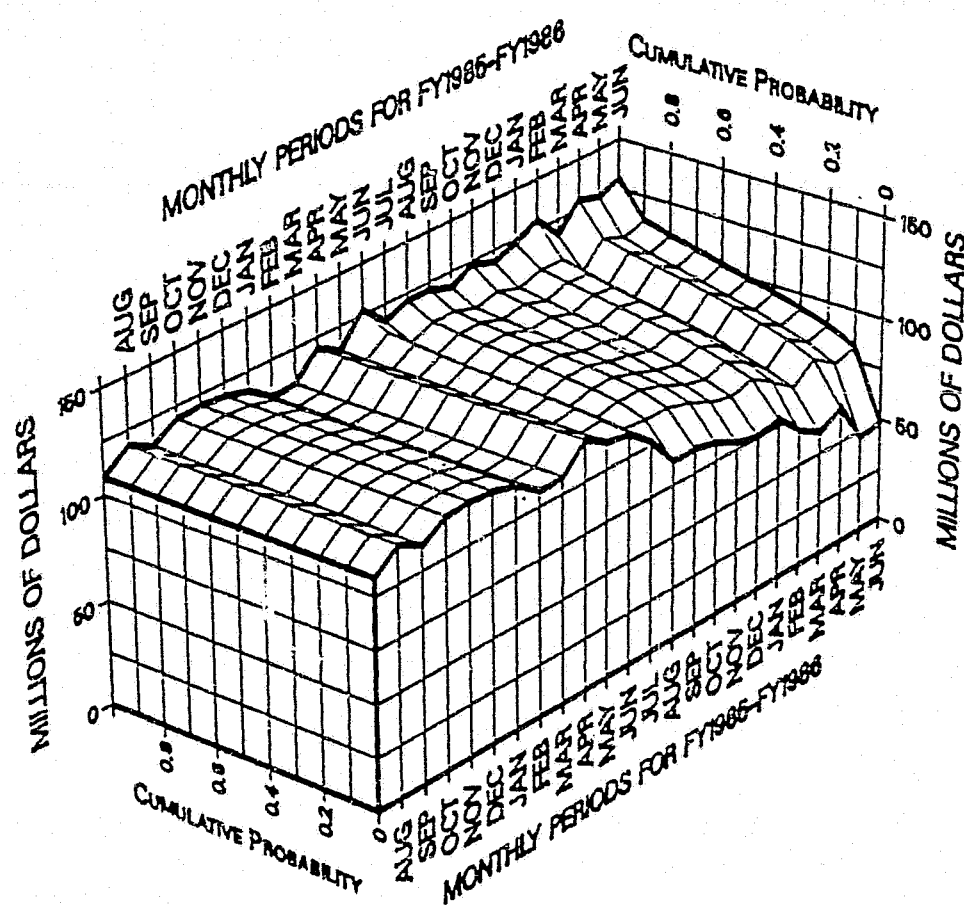


Table 13.
Total Petroleum Severance Taxes
Cumulative Frequency Distribution
(Current Dollars in Millions)

Fiscal Year-1985

Month	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Jul	111	111	111	111	111	111	111	111	111	111	111
Aug	118	118	118	118	118	118	118	118	118	118	118
Sep	112	112	112	112	112	112	112	112	112	112	112
Oct	120	120	120	120	120	120	120	120	120	120	120
Nov	119	119	119	119	119	119	119	119	119	119	119
Dec	118	118	118	118	118	118	118	118	118	118	118
Jan	114	114	114	114	114	114	114	114	114	114	114
Feb	105	105	105	105	105	105	105	105	105	105	105
Mar	107	107	107	107	107	107	107	107	107	107	107
Apr	118	118	118	118	118	118	118	118	118	118	118
May	109	109	109	109	109	109	109	109	109	109	109
Jun	108	111	113	114	115	116	117	118	120	121	128

Table 13.(Continued)
Total Petroleum Severance Taxes
Cumulative Frequency Distribution
(Current Dollars in Millions)

Fiscal Year-1986

Month	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Jul	99	101	103	104	105	106	107	108	109	111	118
Aug	86	101	104	106	107	109	110	111	112	114	120
Sep	87	101	104	106	107	108	110	111	112	114	120
Oct	84	97	101	102	104	105	106	107	109	110	116
Nov	77	91	95	98	101	103	105	107	109	111	120
Dec	75	88	92	95	97	100	102	103	105	108	116
Jan	77	91	95	98	101	103	105	107	109	111	120
Feb	66	84	90	94	97	100	103	106	108	111	126
Mar	60	76	81	85	88	91	93	95	98	100	114
Apr	66	85	90	94	97	100	103	106	108	111	126
May	46	77	83	87	91	94	97	100	103	106	122
Jun	48	80	86	90	94	97	100	103	106	110	126

Graph 17 shows monthly petroleum royalties and is associated with Table 14, on the following page.

GRAPH 17. PETROLEUM ROYALTIES

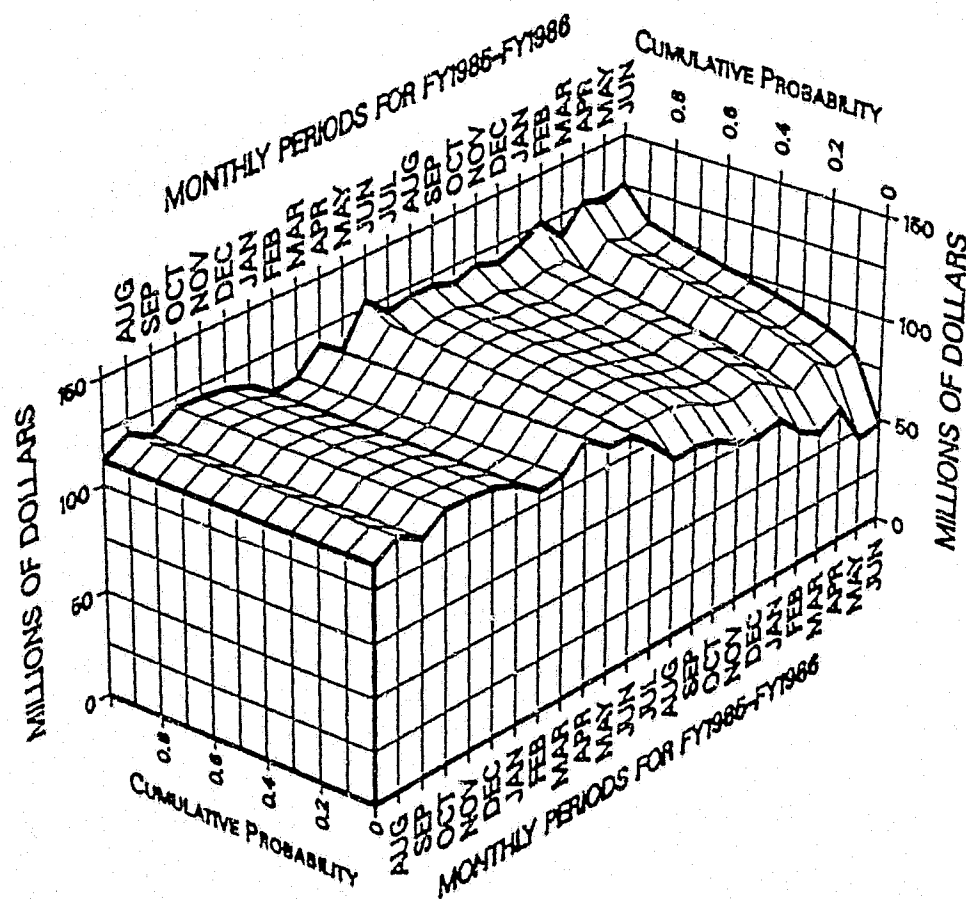


Table 14.
Total Petroleum Royalties
Cumulative Frequency Distribution
(Current Dollars in Millions)

Fiscal Year-1985

Month	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Jul	108	108	108	108	108	108	108	108	108	108	108
Aug	118	118	118	118	118	118	118	118	118	118	118
Sep	112	112	112	112	112	112	112	112	112	112	112
Oct	119	119	119	119	119	119	119	119	119	119	119
Nov	120	120	120	120	120	120	120	120	120	120	120
Dec	119	119	119	119	119	119	119	119	119	119	119
Jan	116	116	116	116	116	116	116	116	116	116	116
Feb	107	107	107	107	107	107	107	107	107	107	107
Mar	108	108	108	108	108	108	108	108	108	108	108
Apr	119	119	119	119	119	119	119	119	119	119	120
May	113	113	113	113	113	113	113	113	113	113	113
Jun	111	113	114	115	116	117	117	118	119	121	127

Fiscal Year-1986

Month	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Jul	101	103	105	105	106	107	107	108	109	110	117
Aug	87	102	106	108	109	110	111	112	114	115	121
Sep	87	102	106	108	109	110	111	112	114	115	121
Oct	84	99	103	105	106	107	108	109	110	111	117
Nov	78	94	98	101	104	106	108	110	112	114	123
Dec	76	91	95	98	100	102	104	106	108	111	119
Jan	79	94	98	101	104	106	108	110	112	114	123
Feb	67	87	92	96	100	103	106	108	111	114	130
Mar	61	78	83	87	90	93	96	98	100	103	117
Apr	67	87	93	96	100	103	106	108	111	114	130
May	47	79	86	90	93	96	99	102	105	109	126
Jun	49	82	88	93	97	99	103	106	109	113	130

Graph 18, on the following page, depicts monthly collections for total petroleum revenues. Table 15 give the values for Graph 18. Given the assumptions of this forecast, the State will collect (according to Table 15) between \$200 and \$234 million in July of 1985 (FY 1986) as a consequence of May's production. This range is also shown on Graph 18. From Table 12, it can be seen that the 30 percent revenue level for July 1985 is \$209.34 million in total petroleum revenues. Table 15 tells us that 30 percent of the time we will collect less than \$210 million and 70 percent of the time we will collect more than \$210 million.

GRAPH 18. TOTAL PETROLEUM REVENUES

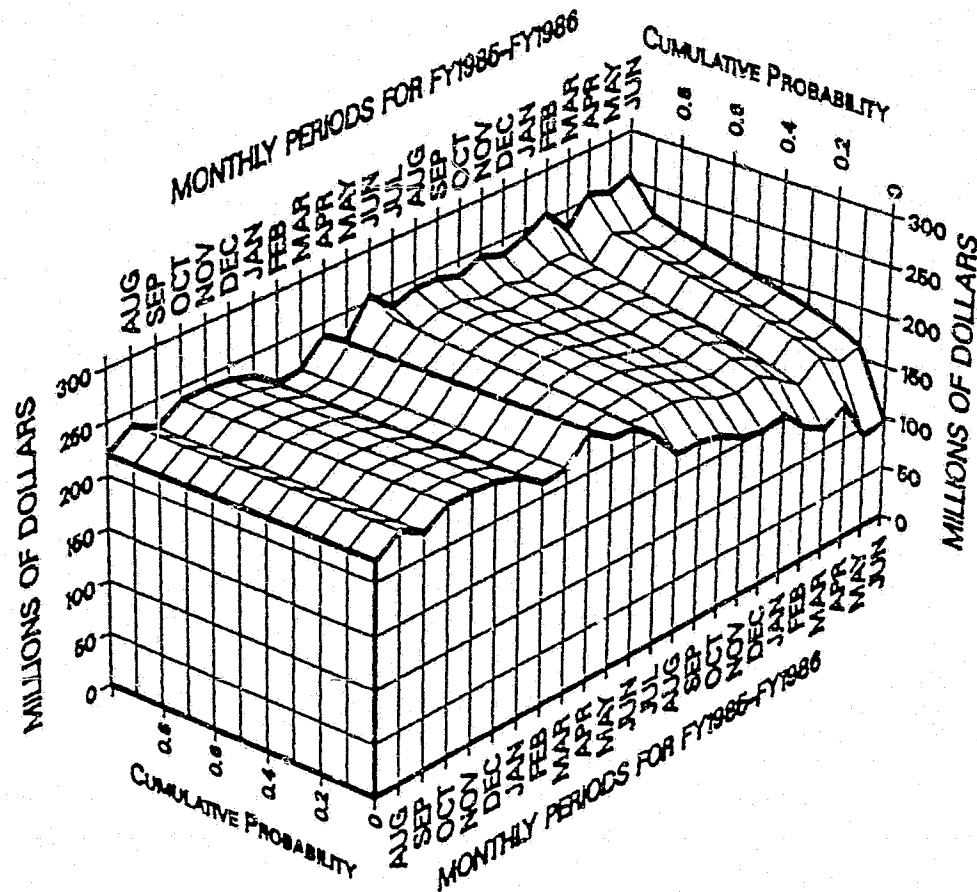


Table 15.
Total Petroleum Royalties
Cumulative Frequency Distribution
(Current Dollars in Millions)

Fiscal Year-1985

Month	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Jul	220	220	220	220	220	220	220	220	220	220	220
Aug	236	236	236	236	236	236	236	236	236	236	236
Sep	224	224	224	224	224	224	224	224	224	224	224
Oct	239	239	239	239	239	239	239	239	239	239	239
Nov	239	239	239	239	239	239	239	239	239	239	239
Dec	237	237	237	237	237	237	237	237	237	237	237
Jan	229	229	229	229	229	229	229	229	229	229	229
Feb	212	212	212	212	212	212	212	212	212	212	212
Mar	215	215	215	215	215	215	215	215	215	215	215
Apr	237	237	237	237	237	237	237	237	237	237	237
May	222	222	222	222	222	222	222	222	222	222	222
Jun	219	224	227	229	231	233	235	237	239	242	256

Table 15.(Continued)
Total Petroleum Revenues
Cumulative Frequency Distributions
(Current Dollars in Millions)

Fiscal Year-1986

Month	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Jul	200	205	208	210	211	213	215	216	218	221	234
Aug	173	203	210	214	216	219	221	223	226	229	242
Sep	174	203	210	214	216	219	221	223	226	229	242
Oct	168	196	204	207	209	212	214	216	218	221	234
Nov	156	185	193	199	204	209	213	217	221	225	243
Dec	151	179	187	193	198	202	206	210	214	218	235
Jan	156	185	193	199	204	209	213	217	221	225	243
Feb	133	171	182	190	197	203	209	214	219	225	256
Mar	120	155	165	171	178	184	189	193	198	204	231
Apr	133	171	183	190	197	203	209	214	219	225	256
May	93	156	169	177	184	190	196	202	208	216	248
Jun	97	162	175	183	191	197	203	209	215	223	256

Forecast Track Record

The PETREV forecasting model was constructed to allow for a wide range of probable events. (For a full discussion of the model, the reader is referred to Appendices B and C.) However, the distribution of potential revenue outcomes shifts through time as events or anticipated events change. Accordingly, the statistical mean may vary over time. It is possible, however, for the range of potential revenues to change through time to a lesser or greater extent than the statistical mean.

Table 16 illustrates how the range and mean for FY 1985 total revenue has varied since the March 1984 forecast. It can be seen that the range changed from \$2600 million to \$40 million, a decline of \$2560. At the same time, the mean revenues forecast decreased by \$177 million, from \$2904 million in March 1984 to \$2727 million in June 1985. This statistical narrowing of the range of outcomes reflects the fact that information becomes increasingly more reliable as the time periods being analyzed draw nearer.

Table 16.

A Comparison of Recent FY 1985 Petroleum Production Revenue Forecasts (In Millions of Dollars)

Percentage Less Than Cumulative Frequency Distribution Forecast	3/1984 Forecast	6/1984 Forecast	9/1984 Forecast	12/1984 Forecast	3/1985 Forecast	6/1985 Forecast
0%	2020	2160	2510	2620	2660	2710
10%	2430	2430	2650	2690	2700	2720
20%	2580	2540	2710	2710	2710	2720
30%	2700	2620	2740	2730	2720	2720
40%	2790	2670	2760	2740	2730	2730
50%	2880	2710	2790	2750	2740	2730
60%	2980	2760	2820	2770	2750	2730
70%	3070	2810	2850	2790	2760	2730
80%	3160	2870	2890	2810	2780	2730
90%	3340	2970	2940	2840	2790	2740
100%	4620	3310	3100	2960	2860	2750
RANGE	2600	1150	590	340	200	40
MEAN	2904	2717	2801	2757	2744	2727

PETREV Accuracy

PETREV's accuracy is illustrated in Table 17.

Table 17.

Actual and Estimated FY 1985 Cash Flows
(In Millions of Current Dollars)

<u>Month</u>	<u>Severance and Conservation Taxes</u>		<u>Royalties</u>	
	<u>Actual</u>	<u>Estimated</u>	<u>Actual</u>	<u>Estimated</u>
July 1984	111.38	111.38	108.23	108.23
August 1984	121.08	118.43	116.88	117.58
September 1984	117.88	112.02	116.81	111.61
October 1984	118.99	119.86	112.11	118.82
November 1984	118.23	119.43	113.70	119.69
December 1984	116.41	118.09	117.53	118.64
January 1985	113.55	113.85	115.06	115.52
February 1985	104.33	105.39	106.23	107.08
March 1985	106.61	107.15	106.16	108.00
April 1985	117.87	117.84	117.20	119.43
May 1985	112.39	109.13	114.19	112.77
June 1985		<u>116.28</u>		<u>116.60</u>

Estimates of FY 1985 revenues for past months compare favorably with collections actually received. PETREV estimated severance and conservation tax collections through May 1985 to be \$1,252.57 million, actual collections amounted to \$1,258.72 million. This represents an under-estimate of \$6.15 million or 0.48 percent. PETREV projected royalty receipts through May 1985 to be \$1,257.37 million while actual collections amounted to \$1,244.10 million. This is an over-estimate of \$13.27 million or 1.06 percent. In total, PETREV estimated all petroleum production revenues through May 1985 to be \$2,509.94 million while actual collections amounted to \$2,502.82, an over-estimate of \$7.12 million or 0.28 percent.

Presented in the Appendix A is a summary of Alaska's expected revenues from all sources for FY 1985 - FY 1987. Presented in Appendix B and Appendix C are discussions of the Petroleum Production Revenue economic feasibility model used in this forecast.

Revenue Summary

In Thousands of Current Dollars

	FY 1985 Estimate <u>June</u>	FY 1986 Estimate <u>June</u>	FY 1987 Estimate <u>June</u>
Total General Fund Unrestricted Revenues (p. 5)	<u>3,237,600</u>	<u>2,872,800</u>	<u>2,573,500</u>
Total General Fund Restricted Revenues (p. 8)	<u>284,500</u>	<u>312,500</u>	<u>321,400</u>
Total General Fund Revenues (p. 8)	<u>3,522,100</u>	<u>3,185,300</u>	<u>2,894,900</u>
Alaska Permanent Fund (p. 9)	<u>654,200</u>	<u>299,600</u>	<u>254,000</u>

General Fund Unrestricted Revenues

In Thousands of Current Dollars

	FY 1985 Estimate <u>June</u>	FY 1986 Estimate <u>June</u>	FY 1987 Estimate <u>June</u>
<u>Taxes</u>			
<u>Income</u>			
Corporate-General	41,000	41,000	41,000
Corporate-Petroleum	168,600	230,000	250,000
<u>Gross Receipts</u>			
Alaska Business License (1)	39,000	2,000	2,000
Fish-Canned Salmon	5,500	5,000	5,000
Fish-Shorebased	7,000	7,000	7,000
Fish-Floating	6,000	6,000	6,000
Seafood Marketing	1,000	1,000	1,000
Salmon Enhancement (2)	2,500	2,800	2,800
Insurance Companies	17,500	18,000	18,000
Electric and Telephone Co-ops	1,900	1,800	1,800
Mining License Tax	300	300	300
<u>Severance</u>			
Oil & Gas Production (3)	1,366,800	1,165,000	980,200
Oil & Gas Conservation	700	700	700
<u>Property</u>			
Oil & Gas	128,300	123,000	126,200
<u>Sale/Use</u>			
Alcoholic Beverages	14,000	14,500	14,500
Fuel Taxes-Aviation (4)	8,000	8,000	8,000
Fuel Taxes-Highway (4)	24,000	22,500	22,500
Fuel Taxes-Marine (4)	4,200	4,300	4,400
Tobacco Products (5)	2,300	5,700	7,800
<u>Other</u>			
Estate	500	600	600
Total Taxes	<u>1,839,100</u>	<u>1,659,200</u>	<u>1,499,800</u>
<u>Licenses & Permits</u>			
Business (6)	12,000	12,800	15,600
Non-Business	<u>16,000</u>	<u>16,500</u>	<u>17,000</u>
Total Licenses & Permits	<u>28,000</u>	<u>29,300</u>	<u>32,600</u>
<u>Intergovernmental Receipts</u>			
Federal Shared Revenues (7)(8)(9)	<u>11,500</u>	<u>11,500</u>	<u>11,500</u>
<u>State Resource Revenue</u>			
<u>Sale/Use</u>			
Bonus Sales (7)(10)(11)	10,200	-0-	-0-
Investment Earnings	247,000	200,000	195,000
Rents (7)(10)(11)	5,500	5,500	6,000
Royalties (3)(7)	1,019,400	886,300	749,000
Sale of State Property	7,500	8,000	8,500
Gravel, Timber, etc. (12)	3,000	10,000	5,800
<u>Facilities Related Charges</u>			
Airports	1,600	1,600	1,700
Ferry System-Southeast	30,000	32,500	34,000
Ferry System-Southwest	3,700	4,000	4,400
Other	5,000	5,000	5,000

General Fund Unrestricted Revenues

In Thousands of Current Dollars

	FY 1985 Estimate <u>June</u>	FY 1986 Estimate <u>June</u>	FY 1987 Estimate <u>June</u>
<u>Taxes</u>			
<u>Income</u>			
Corporate-General	41,000	41,000	41,000
Corporate-Petroleum	168,600	230,000	250,000
<u>Gross Receipts</u>			
Alaska Business License (1)	39,000	2,000	2,000
Fish-Canned Salmon	5,500	5,000	5,000
Fish-Shorebased	7,000	7,000	7,000
Fish-Floating	6,000	6,000	6,000
Seafood Marketing	1,000	1,000	1,000
Salmon Enhancement (2)	2,500	2,800	2,800
Insurance Companies	17,500	18,000	18,000
Electric and Telephone Co-ops	1,900	1,800	1,800
Mining License Tax	300	300	300
<u>Severance</u>			
Oil & Gas Production (3)	1,366,800	1,165,000	980,200
Oil & Gas Conservation	700	700	700
<u>Property</u>			
Oil & Gas	128,300	123,000	126,200
<u>Sale/Use</u>			
Alcoholic Beverages	14,000	14,500	14,500
Fuel Taxes-Aviation (4)	8,000	8,000	8,000
Fuel Taxes-Highway (4)	24,000	22,500	22,500
Fuel Taxes-Marine (4)	4,200	4,300	4,400
Tobacco Products (5)	2,300	5,700	7,800
<u>Other</u>			
Estate	500	600	600
Total Taxes	<u>1,839,100</u>	<u>1,659,200</u>	<u>1,499,800</u>
<u>Licenses & Permits</u>			
Business (6)	12,000	12,800	15,600
Non-Business	16,000	16,500	17,000
Total Licenses & Permits	<u>28,000</u>	<u>29,300</u>	<u>32,600</u>
<u>Intergovernmental Receipts</u>			
Federal Shared Revenues (7)(8)(9)	<u>11,500</u>	<u>11,500</u>	<u>11,500</u>
<u>State Resource Revenue</u>			
<u>Sale/Use</u>			
Bonus Sales (7)(10)(11)	10,200	-0-	-0-
Investment Earnings	247,000	200,000	195,000
Rents (7)(10)(11)	5,500	5,500	6,000
Royalties (3)(7)	1,019,400	886,300	749,000
Sale of State Property	7,500	8,000	8,500
Gravel, Timber, etc. (12)	3,000	10,000	5,800
<u>Facilities Related Charges</u>			
Airports	1,600	1,600	1,700
Ferry System-Southeast	30,000	32,500	34,000
Ferry System-Southwest	3,700	4,000	4,400
Other	5,000	5,000	5,000

<u>Service Related Charges</u>			
Court System	4,600	4,900	5,200
Other	<u>5,000</u>	<u>5,000</u>	<u>5,000</u>
Total State Resources			
Revenues	1,342,500	1,162,800	1,019,600
<u>Miscellaneous Revenues</u>	<u>16,500</u> (13)	<u>10,000</u>	<u>10,000</u>
<u>Total Unrestricted Revenues (14)</u>	<u>3,237,600</u>	<u>2,872,800</u>	<u>2,573,500</u>

(1) The large amounts in FY 85 are the result of litigation in favor of the State on gross receipts taxes for years prior to 1979. The amounts shown for FY 86 and FY 87 do not include any estimate of proceeds from cases which are still in litigation.

(2) The FY 86 and FY 87 estimates reflect the recent approval by the Prince William Sound Aquaculture Corporation to assess a 2% salmon enhancement tax, effective upon the first opening of the 1985 commercial salmon season.

(3) The FY 85 forecast assumes the mean case. The forecasted numbers for FY 86 and FY 87 assume the 30 percent case; however, if the mean case had been utilized for FY 86 and FY 87, the production taxes would change to \$1,203.6 million and \$1,069.4 million, respectively. The royalty figures would change to \$915.2 million and \$820.28 million, respectively.

(4) Revenues from the three main categories of fuel tax are shown separately. However, under the provisions of AS 43.40.010(h), all refunds are made from the highway fuel tax account. If gross collections of highway fuel taxes remain constant, an increase in refunds for aviation and marine fuels could lower the net revenues shown for highway fuels. Also, increasing use is being made of tax credits, which can be taken in lieu of claiming a refund on certain non-taxable use of fuel (15 AAC 40.200).

(5) SLA 85, Ch. 24 raised the general fund portion of the cigarette tax from a rate of 1-1/2 mills (\$.0015) to 5-1/2 mills (\$.0055) per cigarette. The Act takes effect October 1, 1985.

(6) The FY 86 and FY 87 estimates reflect Ch. 26 and Ch. 37, SLA 1985 which increase the revenue collected for insurance and occupational licensing fees.

(7) Net Permanent Fund contribution by Ch. 18 SLA 1980.

(8) Ch. 94, SLA 1984 establishes the National Petroleum Reserve, Alaska, Special Revenue Fund, and provides for federal mineral receipts to be divided equally between the Alaska Permanent Fund and the National Petroleum Reserve Fund. FY 85 and subsequent year estimates have been lowered to reflect this change in allocation.

(9) The FY 85 estimate does not include any revenues shared (50/50 basis) with the federal government from the NPR-A lease sale held July 20, 1983. Although high bids totaled \$16.7 million, leases will not be awarded until challenges of the sale by the State of Alaska are resolved. The State's share, assuming the case is resolved, will be equally divided between the General Fund and the Permanent Fund.

(10) Reflects state lease sales of \$33.8 million held May 22, 1984 (Sale 43 and 43A—Beaufort Sea), \$0.8 million held September 19, 1984 (Sale 41—Bristol Bay), and \$2.5 million held February 26, 1985 (Sale 46A—Upper Cook Inlet). Due to the timing of collections, some receipts from the May 1984 lease sale are shown as FY 85 revenue. The FY 85 figure represents the General Fund's 50 percent share with the remaining 50 percent deposited in the Permanent Fund.

(11) The Department of Natural Resources projects the following FY 86 and FY 87 state lease sales: FY 86 (Sale 45A—North Slope onshore, Sale 47—Kuparuk Uplands, Sale 48—Kuparuk Uplands, Sale 49—Cook Inlet); and FY 87 (Sale 52—Beaufort Sea, Sale 51—Prudhoe Bay Uplands, Sale 50—Camden Bay). However, bonus bids are impossible to anticipate prior to sales and, therefore, no estimates are provided.

(12) Estimates reflect increased construction of roads and drilling pads as projected by the Department of Natural Resources, however, some of these projects may be delayed or changed due to permit denials or environmental impact statement requests.

(13) The FY 85 estimate reflects the termination of the Alaska Resources Corporation. Corporate assets (\$6.2 million) were deposited in the General Fund per Ch. 161, SLA 1984.

(14) The state, per AS 38.05.180, will be granting incentive credits against royalties, severance taxes, and rentals to the oil companies for drilling exploratory wells. The anticipated deduction is approximately \$15.3 million which has not been subtracted from the aforementioned FY 85 figure of \$3,237.6 million. Additional credits are anticipated in subsequent years.

Revenue Breakdown

The total General Fund unrestricted revenues for Fiscal Years 1985, 1986, and 1987 are projected to be \$3,237.6 million, \$2,872.8 million, and \$2,573.5 million, respectively.

The following table depicts a breakdown of General Fund unrestricted revenues in terms of petroleum versus non-petroleum revenues based on the June estimates:

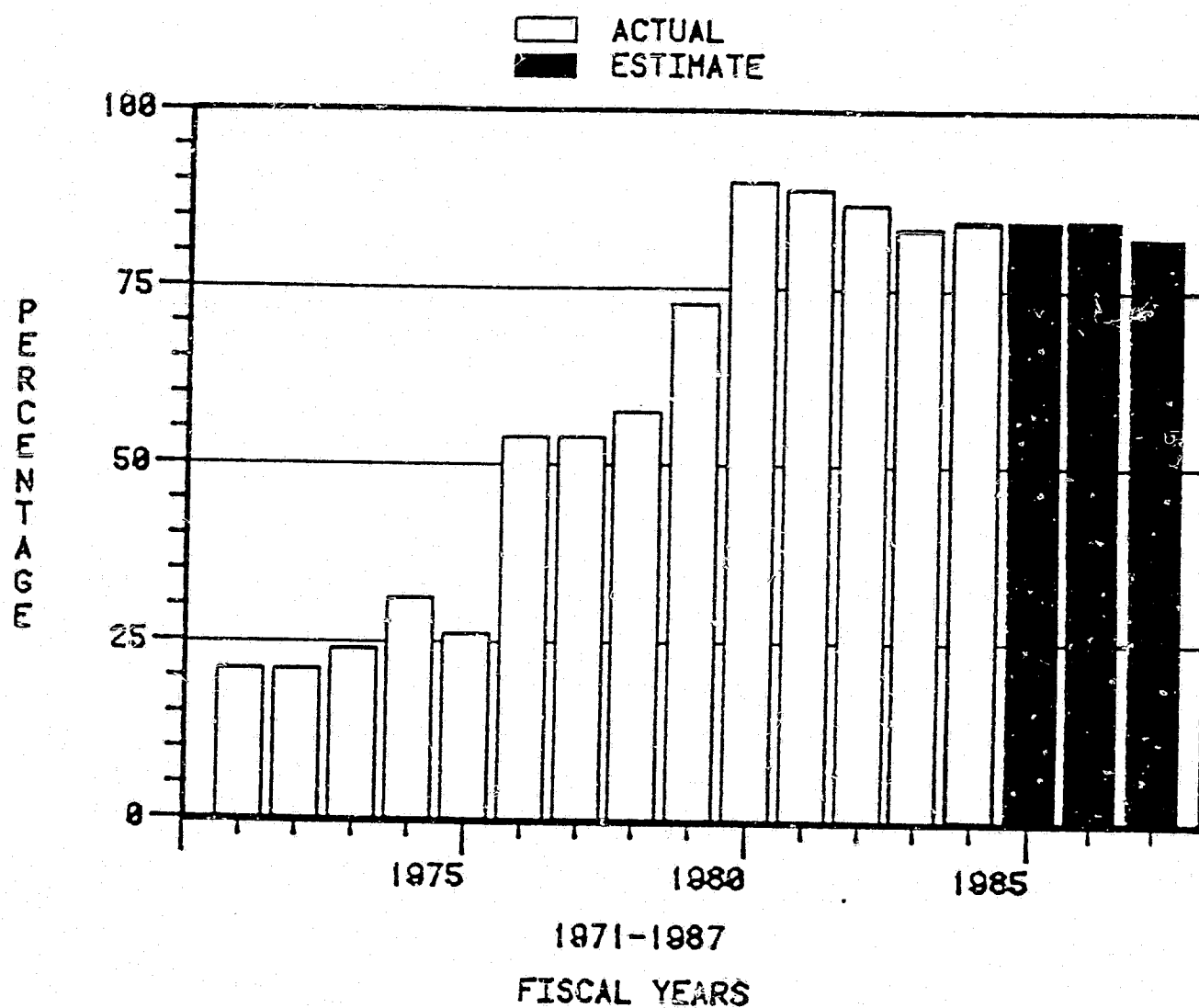
Petroleum vs. Non-Petroleum Revenues

(In Millions of Current Dollars)

	<u>Petroleum Revenues</u>		
	<u>FY 85</u>	<u>FY 86</u>	<u>FY 87</u>
Corporate Petroleum	168.6	230.0	250.0
Severance Tax	1,367.5	1,165.7	980.9
Royalties	1,019.4	886.3	749.0
Property Tax	128.3	123.0	126.2
Bonus Sale	10.2	-0-	-0-
Rents	2.5	3.5	3.8
Intergovernmental Receipts	2.3	9.3	9.3
	<u>2,668.3</u>	<u>2,417.8</u>	<u>2,119.2</u>
	<u>Non-Petroleum Revenues</u>		
	<u>FY 85</u>	<u>FY 86</u>	<u>FY 87</u>
Taxes	174.7	140.5	142.7
Licenses & Permits	28.0	29.3	32.6
Intergovernmental Receipts	2.2	2.2	2.2
State Resources Revenues	309.4	273.0	266.8
Miscellaneous Revenues	16.5	10.0	10.0
	<u>530.8</u>	<u>455.0</u>	<u>454.3</u>
Total	<u>3,237.6</u>	<u>2,872.8</u>	<u>2,573.5</u>

Petroleum Revenues

Historical Comparison of General Fund
Unrestricted Petroleum Revenues as Percentages
of General Fund Unrestricted Revenues
(in Millions of Current Dollars)



<u>Fiscal Year</u>	<u>Total General Fund Unrestricted Revenues</u>	<u>Total General Fund Unrestricted Petroleum Revenues</u>	<u>Percent</u>
1971	220.4	47.0	21
1972	219.2	48.4	22
1973	208.2	50.3	24
1974	254.9	80.2	31
1975	333.4	90.4	27
1976	709.8	391.5	55
1977	874.3	477.6	55
1978	764.9	441.5	58
1979	1,133.0	821.6	73
1980	2,501.2	2,256.5	90
1981	3,718.2	3,304.3	89
1982	4,108.4	3,574.6	87
1983	3,631.0	3,026.6	83
1984	3,390.1	2,861.6	84
1985*	3,237.6	2,706.8	84
1986*	2,872.8	2,417.8	84
1987*	2,573.5	2,119.2	82

* Estimate

Restricted Revenues

In Thousands of Current Dollars

	FY 1985 Estimate <u>June</u>	FY 1986 Estimate <u>June</u>	FY 1987 Estimate <u>June</u>
<u>Federal Grants-in-Aid</u>			
I. Education	47,500	54,300	55,400
II. Social Services	103,600	114,400	115,900
III. Health	6,000	6,000	6,000
IV. Natural Resources	14,700	20,300	23,300
V. Public Protection	9,300	9,700	9,700
VI. Administration of Justice	600	600	600
VII. Development	4,000	3,700	3,200
VIII. Transportation	70,000	73,500	77,000
IX. General Government	<u>100</u>	<u>100</u>	<u>100</u>
Total Federal Grants-in-Aid	<u>255,800</u>	<u>282,600</u>	<u>291,200</u>
<u>Other Grants-in-Aid</u>			
I. Education	1,500	1,400	1,400
II. Social Services	5,400	3,100	3,300
III. Health	100	100	100
IV. Natural Resources	500	700	500
V. Public Protection	1,500	2,200	2,000
VI. Administration of Justice	100	200	200
VII. Development	6,200	8,300	8,700
VIII. Transportation	700	900	900
IX. General Government	<u>2,700</u>	<u>3,000</u>	<u>3,100</u>
Total Other Grants-in-Aid	<u>18,700</u>	<u>19,900</u>	<u>20,200</u>
Miscellaneous Restricted Revenue-All Categories	<u>10,000</u>	<u>10,000</u>	<u>10,000</u>
Total Restricted Revenue 1/	<u>284,500</u>	<u>312,500</u>	<u>321,400</u>
Total Unrestricted Revenue	<u>3,237,600</u>	<u>2,872,800</u>	<u>2,573,500</u>
Total General Fund Revenue	<u>3,522,100</u>	<u>3,185,300</u>	<u>2,894,900</u>

1/ Restricted Revenue figures may not agree with those shown in the Governor's budget due to categorical differences between the budget and accounting system.

APPENDIX B

Economic Feasibility of Potential Fields (Roger Marks; J. William Moore)

I. Overview

Beginning with the March 1985 Petroleum Production Revenue Forecast, the Department of Revenue will explicitly consider the economic feasibility of potential fields¹ in its revenue forecasts. Prior to this these fields were assumed to produce without explicit recognition of price/production volume/cost relationships.

Recall that a forecast "run" of the petroleum revenue model is generated from the aggregation of 500 or more simulated realizations of the future. Associated with each realization are wellhead price and production vectors for the six non-producing oil fields with proven recoverable reserves. Hereinafter we refer to these price and production vectors as "sampled" prices and volumes. This adjunct to the revenue forecasting model works as follows:

1. A base case cost scenario is developed for the most likely production volumes and the earliest practical development for each field, ignoring any sunk costs. Cost inputs for the feasibility analysis were derived from a variety of sources including industry, journal articles, the State Department of Natural Resources (Divisions of Oil and Gas and Geological and Geophysical Survey), Alaska Oil and Gas Conservation Commission, U.S. Department of Interior, and U.S. Army Corps of Engineers.
2. The main model independently samples for price and field production volume.
3. Costs for the sampled production volume are generated based on cost functions which relate to sampled production volume to the base case costs.²

¹ Discoveries where production has not commenced. Currently this includes Endicott, Lisburne, Milne Pt., Seal Island, West Sak, and "other" onshore North Slope.

2 Cost Functions A. Capital Costs

$$C_s = aC_B + bC_B \sqrt{\frac{V_s}{V_b}}$$

where

- C_s = Total capital cost for selected production volume
- C_B = Total capital cost for base case
- a = Proportion of fixed capital costs
- b = Proportion of variable capital costs
- V_s = Peak production volume in selected scenario
- V_b = Peak production volume in base case

C_s is distributed proportionally over time as C_B is in base case.

4. The economic rent for a given sample production volume and price vectors is computed on a per barrel basis for the field. (This is described in detail in Part II below.)
5. For each realization the model examines the feasibility of production for the six prospective fields. For instance, if field #3 has negative rent for a 1985 go-ahead then a 1986 go-ahead is examined. The model continues to search for a go-ahead with positive economic rent looking farther into the future in the price vector. Suppose that for a specific realization field #3 has negative rents for 1985, 1986, ..., 1992 and positive rent for 1993. The sample volume vector for field #3 is then advanced to correspond to a 1993 go-ahead. "Go-ahead" times are found for all six fields and the volume vectors are shifted accordingly. Next³ the model calculates revenues for the realization based upon sampled wellhead price and shifted sample volume vectors. Finally a new outcome or realization is generated and the process all begins again.

II. Economic Rent

The Department of Revenue has developed an economic feasibility model which computes economic rent for a field's given price/cost/production volume scenario, on an equivalent amortized per barrel basis.

Inputs to the model are:

- Year (by year) ($F1_i$)
- Production volume (by year) ($F2_i$)
- Capital Costs (by year) ($F3_i$)
- Operating costs (by year) ($F4_i$)
- Transportation capital costs (by year) ($F5_i$)
- Producing wells (by year) ($F6_i$)
- Oil price ($PS1$) (by year) ($F7_i$)
- After tax discount rate (I)
- Royalty rate (ROY)
- Severance tax rate (SEV)
- State corporate income tax rate (CIT)
- Federal corporate income tax rate (TAX)

2(Continued)

B. Operating Costs

$$O = aCP + bCV$$

where

- O = Total operating costs for year
- a = Proportion of operating costs fixed
- b = Proportion of operating costs variable
- C = Per barrel operating costs (based on base case)
- P = Base case peak yearly production volume
- V = Yearly production volume for selected scenario

³ Roughly speaking. Actually there is a small price adjustment due to volume change.

- Investment tax credit rate (ITC)
- Bonus (BONUS)
- Fixed transportation costs (FTC)
- Capital recovery factor (CRF)
- Intangible portion of capital investment (INTANG)
- Field costs (FLD)

All prices and costs are real dollars of current year.

The model functions as follows:

$$\text{Year}(C1) = F1_i$$

$$\text{PS1 Price } (C2) = F7_i$$

$$\text{Production Volume } (C3) = F2_i$$

$$\text{Discounted Production Volume } (C4) = C3 \times \frac{1}{(1+I)} C1$$

$$\text{Gross Revenue } (C5) = C2 \times C3$$

$$\text{Royalties } (C6) = C3 \times [\text{Roy} \times (C2 - T - \text{FLD})]$$

Where T is transportation costs to bring the PS1 price back to the wellhead for a specific field (see below).

$$\text{Discounted royalties } (C7) = C6 \times \frac{1}{(1+I)} C1$$

$$\text{Severance tax } (C8) = C3 \times (1 - \text{ROY}) \times [\text{ELF} \times \text{SEV} \times (C2 - T)]$$

Where ELF is the economic limit factor to reduce the severance tax rate as well productivity declines.

$$= \left(\frac{((F2_i \times 1,000,000) / (365 \times F6_i)) - 300}{((F2_i \times 1,000,000) / (365 \times F6_i))} \right) 1.5333$$

If ELF greater than .7, ELF = 1.0 (for first 10 years)

If ELF less than 0, ELF = 0

SEV is adjusted to remove royalty portion of production. SEV is reduced 22% for first 5 years of production.

$$\text{Discounted Severance Tax } (C9) = C8 \times \frac{1}{(1+I)} C1$$

$$\text{State Net Revenue (before tax) } (C14') =$$

$$C5 - [(6 + C8 + C12 + (T \times C3))]$$

$$\text{State Tax Depreciation (C 20')} = C15 \times \left(\frac{C3}{\sum C3} \right)$$

$$\text{State Total Deductions (C22')} = C17 + C20' + C21$$

$$\text{State Taxable Income (C23')} = C14' - C22'$$

$$\text{State Corporate Income Tax (C10)} = CIT \times C23'$$

$$\text{Discounted State Corporate Income Tax (C11)} = C10 \times \frac{1}{(1+I)} C1$$

$$\text{Property Tax (C12)} = \sum_{i=1}^n [C15 \times (1-INTANG)] \times (.02) \times \left(\frac{z-t}{z-1} \right)$$

where i = year expenditure incurred
 n = number of years over which expenditures occurred
 z = final year of production
 t = subject year

$$\text{Discounted Property Tax (C13)} = C12 \times \frac{1}{(1+I)} C1$$

$$\text{Net Revenue (before tax) (C14)} = C5 - [C6 + C8 + C10 + C12 + (T \times C3)]$$

$$\text{Capital Costs (C15)} = F3_i$$

$$\text{Discounted Capital Costs (C16)} = C15 \times \frac{1}{(1+I)} C1$$

$$\text{Operating Costs (C17)} = F4_i$$

$$\text{Discounted Operating Costs (C18)} = C17 \times \frac{1}{(1+I)} C1$$

$$\text{Intangible Drilling Costs (C19)} = INTANG \times C15$$

$$\text{Federal Tax Depreciation (C20)} = \sum_{i=1}^n [C15 \times (1-INTANG)]_i \times D$$

where i = year expenditure incurred
 n = number of years over which expenditures occurred
 t = subject year
 $D = .20$ if $t - i = 0$
 $.32$ if $t - i = 1$
 $.24$ if $t - i = 2$
 $.16$ if $t - i = 3$
 $.08$ if $t - i = 4$
 0 if $t - i$ greater than 4

$$\text{Bonus Depletion (C21)} = [\text{BONUS} \times (\frac{C3}{\sum C3})]$$

$$\text{Total Deductions (C22)} = (C17 + C19 + C20 + C21)$$

$$\text{Taxable Income (C23)} = (C14 - C22)$$

$$\text{Federal Income Tax (C24)} = (\text{TAX} \times C23) - [\text{ITC} \times ((1 - \text{INTANG}) \times C15)]$$

$$\text{Discounted Federal Income Tax (C25)} = C24 \times \frac{1}{(1+I)} C1$$

$$T (\text{Transportation}) = [(\sum (F5_i \times \frac{1}{(1+I)} C1)) / (\sum C4)] \times \text{CRF} = \text{FIXT}$$

CRF accounts for taxes, operating costs, rate of return, and depreciation, to a third party operator. FIXT accounts for known tariff portions between the field and PSI, and can be adjusted to account for gravity differentials between the subject field and Sadlerochit.

The equivalent amortized per barrel cost (EAC) =

$$((\sum C7 + \sum C9 + \sum C11 + \sum C13 + \sum C16 + \sum C18 + \sum C25) / \sum C4) + T$$

The equivalent amortized per barrel price (EAP) = $\sum (C2 \times C4) / \sum C4$

The equivalent amortized per barrel economic rent (ER) = EAP - EAC

Note: The model also compares the total economic rent of development ($\sum C4 \times \text{ER}$) against the value in decreased Federal income taxes of writing off lease bonuses ($.46 \times \text{BONUS}$), as an additional feasibility check. Also, once decline sets in the model cuts off production when Federal taxable income becomes negative (also for Sadlerochit and Kuparuk).

Appendix C

The Relationship of Production Volume to Price (Roger Marks; J. William Moore)

As described in Appendix B, the revenue forecasting model tests economic feasibility of potential fields given the price/production volume/cost relationships of simulated realizations of the future. This attempts to assure that no projected revenues will accrue to the State for production which has de facto negative economic rent.

Volume produced is not sensitive to price in the feasibility algorithm. That algorithm makes a binary decision to either produce or not produce a given volume, depending on positive or negative economic rent, and solves for the first startup year which generates a positive economic rent.

When startup does not occur in the earliest practical timeframe, economic rents when startup does occur are small, and there is little incentive to expand production at increasing marginal costs. In addition, as the input volume scenarios represent primary production, there is little incentive to reduce production at decreasing marginal costs.

However, when startup occurs at the earliest practical time, economic rents are generally large, and marginal revenues exceed marginal costs. Microeconomic theory suggests that production should increase to where marginal costs equal marginal revenues. This would represent some kind of enhanced recovery.

Beginning with the March 1985 Petroleum Production Forecast, projected volumes have been made sensitive to projected price within the feasibility framework.

To find the optimal amount of incremental production given the primary price/cost/volume vectors, volume is increased in increments and the marginal revenue and marginal cost are compared. This is called an "increment cycle". If marginal revenue exceeds marginal cost, volume is increased again and marginal revenue and cost compared again (another increment cycle). This continues until marginal revenue equals marginal cost, at which point there is optimal production volume. (An upper limit on enhanced recovery is set as an empirically estimated percentage of primary production. Limits are differentiated between secondary and tertiary recovery.)

As incremental production represents enhanced recovery, capital outlay begins after 5 years of primary production and extends over 2 years, after which incremental production begins and continues until the same final year as primary production. (After 5 increment cycles another year is added.) Volume is incremented by adding one million barrels a year. (Although in a strict sense only one barrel at a time should be added, this does not sacrifice accuracy here.)

For example, if production in the base case begins in year 5, capital costs for enhanced recovery occur in years 10 and 11, and incremental production begins in year 12. If the last year of primary production was year 21, there are 1 million barrels per year added for years 12 through 21 (10 years), for an increment of 10 million barrels. Similarly, each increment cycle adds 10 millions barrels.

$$\text{Marginal revenue}_{1/} = \sum_{i=Y_F}^{Y_L} \left[\left(\frac{1}{(1+I)^{C1_i}} \right) \times C2_i \right]$$

Where Y_F = First year of incremental production
 Y_L = Last year of incremental production

Since volume is increased by the same amount each increment cycle, and since price does not change when volume is added, the marginal revenue is the same for each increment cycle.

An increasing marginal cost function has been posited using an exponential relationship between incremental volume and incremental cost:

$$K_N = K_B \times \left[\left(\frac{V_N + V_B}{V_B} \right)^X - 1 \right]$$

Where K_N = Incremental capital cost
 K_B = Base case capital cost
 V_N = Incremental volume
 V_B = Base case volume

Similarly with operating costs:

$$O_{N_i} = O_{B_i} \times \left[\left(\frac{V_N + V_B}{V_B} \right)^Y - 1 \right]$$

Where O_{N_i} = Incremental operating costs for year i
 O_{B_i} = Base case operating costs for year i

Empirical estimates have been made for X and Y for both secondary and tertiary recovery.

Marginal cost_{1/} =

$$\left[\left(\sum C7 + \sum C9 + \sum C11 + \sum C13 + \sum C16 + \sum C18 + \sum C25 \right) t - \left(\sum C7 + \sum C9 + \sum C11 + \sum C13 + \sum C16 + \sum C18 + \sum C25 \right) (t-1) \right]$$

Where t = Subject increment cycle
 $t-1$ = Previous subject increment cycle

1/ Nomenclature is described in Appendix B.