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ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

INTRODUCTION TO THE AMENDMENT TO THE LICENSE APPLICATION BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

NOVEMBER 1985

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This document provides an overview of the history and present status of the Alaska Power Authority's application for a license to construct and operate the Susitna Hydroelectric Project. In addition, the principal economic and environmental issues relating to the licensing of the Project are addressed. The reader should refer to the Draft Amendment for more detailed discussion of these and other aspects of the Project, including engineering design, construction and operation issues.

I. THE HISTORY AND PRESENT STATUS OF THE SUSITNA PROJECT

In February, 1983, the Alaska Power Authority (Power Authority) filed an application with the Federal Energy Regulatory Commission (FERC) seeking a license to construct and operate a two-dam hydroelectric project on the Susitna River in south central Alaska. The Susitna Project is the centerpiece of a long-term plan for meeting demand for electricity in the "Railbelt" region of the State, relying primarily on hydroelectric development, supplemented as necessary by additional thermal-fired generation.

The Power Authority's decision to seek a license for the Susitna Project was the product of over three decades of State and Federally-sponsored studies of the potential for hydropower development in the Susitna River basin. In 1980, the Power Authority commissioned Acres American, Inc. (Acres) to undertake a complete review and reassessment of the economic, engineering, environmental and financial feasibility of a number of potential Susitna River development schemes. The Acres feasibility study, completed in 1982, reaffirmed prior conclusions of the United States Army Corps of Engineers (COE) that a two-dam project at the Watana and Devil Canyon sites represents the preferred plan for the productive, economic and environmentally sound development of the Susitna River's hydroelectric potential.

To further test the feasibility of the Susitna Project, the Governor, pursuant to legislative direction, secured an independent, comparative evaluation of the Susitna Project and various alternative means of meeting future demand for electricity in the Railbelt. The resulting series of reports prepared by Battelle Pacific Northwest Laboratories concluded that the Susitna Project, over the long term, is the preferred means for providing power to the Railbelt. Based on this consistent history of analytic support for the Susitna Project, the Power Authority, acting on express legislative authorization, filed its application with the FERC seeking a license for the two-dam Project.

In May 1985, the Power Authority concluded that a number of substantial benefits would derive from modification of the plan for construction of the Project to provide for completion of construction in three stages, rather than the two proposed in the February 1983 license application. While "staging" will not alter the character of the fully completed Project, it will reduce labor and material requirements for the initial Watana development, thereby reducing the "upfront" costs of construction. Moreover, staging will permit the development of generation capacity from the Project to match more closely the Railbelt's load growth and need for replacement of existing capacity.

The modification of the Project to incorporate the 3-stage development plan requires the filing of a formal license application amendment (Amendment). To ensure that the views of State and Federal resource agencies and other interested persons are meaningfully addressed in the Amendment, the Power Authority is now circulating a draft Amendment for a 60-day comment period.

After reviewing these comments, the Power Authority will revise the draft Amendment as appropriate, and submit the formal Amendment to the FERC in February or March 1986.

II. THE DRAFT AMENDMENT

Although the Amendment process has been undertaken primarily to reflect the 3-stage development plan, the Power Authority has substantially revised the application in a number of other respects to reflect the wealth of information that has evolved over the last 2-1/2 years. Both the economic and environmental analyses have been re-examined and modified since the initial filing in February 1983.

The economic re-evaluation has again produced the conclusion that the Susitna Project is, over the long term, the least expensive means for meeting future Railbelt electricity requirements. The analysis presented in the Amendment demonstrates that the "least cost" thermal alternative can be expected to cost Railbelt ratepayers about 1.5 times as much as the "with Susitna" alternative over the first 50 years of the project's life. In terms of "present value", this would mean that, should Susitna not be built, electricity costs associated with the construction and operation of the "least cost" alternatives to Susitna would absorb an additional $2 billion over this period, reducing disposable income and inhibiting economic activity.

These conclusions are the product of a more conservative set of economic assumptions than were set out in the February application. It is recognized that analysis of the Project necessarily depends upon the ability to forecast events into the next century. This means that any analysis of the Project, whether favorable or unfavorable, is burdened with uncertainty. To ensure that the Susitna Project is evaluated by reference to reasonable forecasts, previous assumptions have been scrutinized and tested against the mainstream of current opinion and in many instances have been revised. For example, the present analysis presumes a lower rate of oil price increase than previously contemplated and does not assume any real price increase after the year 2023. Similarly, the Power Authority has assumed that Cook Inlet natural gas supplies will substantially exceed the levels of proven reserves currently estimated by the Alaska Department of Natural Resources. In addition, the forecasts of economic, population and electricity demand growths have been reconsidered and reduced. Finally, a number of "sensitivity analyses" have been undertaken to test the Project's viability against a range of more conservative alternative assumptions.

On the basis of the revised economic analysis, the Power Authority remains persuaded that the FERC license should be pursued. Since the filing of the application, the data and analysis underlying the project have substantially matured. This has occurred, in part, as a response to the FERC environmental impact analyses and also as a result of extensive ongoing consultations in Alaska with State and Federal resource agencies. Through this process the Power Authority has identified appropriate studies and a comprehensive list of environmental issues to be addressed in the FERC proceeding and over the course of the Project's development. The Power Authority's guiding policy objective has been, and continues to be, to develop the hydropower potential of the Susitna River with no net loss of beneficial habitat for fish and wildlife. Toward this end, the Power Authority has developed plans for mitigation of possible adverse environmental effects of project development. Recognizing the State's commitment to prudent and environmentally sound use of its natural resources, the mitigation measures outlined in the draft Amendment contemplate an investment of over $300,000,000 over the life of the Project. These include special design features in the project to accommodate water quality concerns, habitat modification to facilitate fish migration and spawning, as well as ongoing monitoring over the life of the Project to ensure environmentally sound construction and operation.

The Power Authority has also used the ongoing consultation process to re-examine its proposed flow regime against the rigors of the "no-net-loss" standard. On the basis of comments and modeling studies suggested by resource agencies, the Power Authority has altered the originally proposed flow regime to constrain the flow released from the Project within limits designed to maintain river conditions necessary to support productive fish habitat. In sum, the ongoing consultation process has significantly improved the project and confirmed the Power Authority's earlier conclusion that the Susitna Project is the environmentally preferred means for meeting Railbelt power needs.

The following sections provide a more detailed examination of the essential aspects of the analysis contained in the Draft Amendment including:

- A brief Project Description
- Economic and Financial Analysis; and
- Environmental Analysis.

III. PROJECT DESCRIPTION

The Susitna Hydroelectric Project, as presented in the draft License Amendment, is a two-dam hydroelectric development to be located on the Susitna River some 116 air miles north-northeast of Anchorage and approximately 144 air miles south of Fairbanks (See Exhibit 1).

The two dam sites are the Watana site, planned for a rockfill dam to be located at river mile (RM) 184, and the Devil Canyon site, planned for a concrete arch dam at RM 152, some 32 miles downstream from the Watana site. The project development is proposed to be constructed in three stages as described below.

Stage I of the development, planned for completion in 1999, would consist of a 700 foot high rockfill dam at the Watana site shown on Exhibit 2. This structure, with a crest at el. 2,025 ft., would impound 4.3 million acre-feet of water in a reservoir some 39 miles long with a surface area of 19,900 acres. Four turbine/generator units with a combined nominal capacity of 440 Megawatts (MW) would generate an average annual energy of 2,400

Gigawatt Hours (GWh). The dependable capacity of this installation would be 300 MW during the critical months of December and January when the electrical demand of the Railbelt system is highest.

Stage II, to be completed in 2005, would be a 646 foot high double curvature concrete arch dam at the Devil Canyon site shown on Exhibit 3. Devil Canyon Dam, with a crest at el. 1,463 ft., would impound 1.1 million acre-feet of water (0.35 million acre feet of live storage) in a 26-mile long reservoir having a surface area of 7,800 acres. Four turbine/generator units at Devil Canyon with a combined nominal capacity of 680 MW would generate an average annual energy of 2,350 GWh; the December-January dependable capacity would be 388 MW. The addition of the Devil Canyon facility will permit greater flexibility in the operation of the Watana facility, thereby increasing its dependable capacity to 417 MW.

Stage III of the project, to be completed in 2012, would consist of raising the Watana Dam crest to el. 2,205 ft. (resulting in an 885 foot high dam) shown on Exhibit 2. This raise would inc[illegible] the storage to 9.5 million acre-feet of water in a 48-mile lo[illegible]voir having a surface area of 38,000 acres. Two additional turbine/generator units would be installed and this addition, in combination with the increase in turbine operating head would raise the nominal capacity at Watana to 1,110 MW. The increased water storage would raise the average annual energy of Watana to 3,500 GWh and that of Devil Canyon to 3,400 GWh.

Completion of this final stage would bring the Susitna Hydroelectric Project development to its final nominal capacity and energy levels of 1,790 MW and 6,900 GWh respectively. The 1,790 MW capacity is the average capacity under average head of the two plants; during the critical months of December and January, the project would have a dependable capacity of 1,620 MW.

Access for construction of all three stages would be via a 44-mile road running south from about mile 23 of the Denali Highway (Milepost 112) to the Watana site and, as Stage II begins, continuing for 39 miles west along the uplands north of the Susitna River to the Devil Canyon site. In addition, a 12-mile long extension of the railroad from Gold Creek (river mile 137 on the Susitna River) east to Devil Canyon would be constructed to complete the project access facilities.

Power from the two dams would be transmitted via power lines to a substation to be built at Gold Creek, about 37 air miles east-southeast of the Watana site. At that point the existing Anchorage-Fairbanks Intertie would carry power to the two major Railbelt population centers with appropriate upgrading of the system as the three stages come on-line.

IV. ECONOMIC AND FINANCIAL ANALYSIS

The following discussion provides an overview of the economic analysis that has been performed by the Alaska Power Authority (Power Authority) concerning the Susitna Hydroelectric Project. The starting point is the forecast of new electric generating capacity that will be required in the Railbelt over the course of the planning period. This is followed by review of the primary alternatives identified in meeting those requirements. A comparison of the costs of Susitna and those of the least cost alternatives to Susitna is then presented, followed by consideration of State contribution levels that would facilitate Susitna project financing.

Future Electric Generating Capacity Requirements

In order to estimate the amount of new plant capacity that will have to be provided in the future, two elements must be examined:

1. future electricity demand; and

2. the expected retirement schedule for existing plants. Even in the absence of demand growth, new plant capacity will be required to replace existing plants as they reach the end of their useful lives.

Electricity Demand Forecast. There are many factors that exert significant influence on the forecast of electricity demand, including consumer income, the price of electricity and competing forms of energy, industrial development, commercial use and the number of residential households. Of these, commercial demand and the number of households are the most influential determinants of total demand in the Railbelt. The number of households is related to the level of population, and both commercial use and population are determined primarily by the level of employment. Therefore, the employment forecast that underlies the Power Authority electricity demand forecast is presented below. Statewide employment figures are shown. Since about 70% of the state population lives in the Railbelt, the statewide trends are closely indicative of Railbelt trends.

Exhibit 4 displays total employment from 1962 to 1984 and the Power Authority forecast of employment from 1985 to 2010. Three categories are shown: basic sector, support sector, and state and local government. Wages and salaries in the basic sector are supported by payments from sources outside the state; e.g., export revenues, tourist expenditures, federal government outlays. The support sector is driven by the circulation of funds in the local economy that were initially drawn through the basic sector. State and local government has elements of both and is broken out separately as a result. Of the three categories shown, the major contributor to employment growth since statehood has been the support sector followed by state and local government. Support sector growth has been traceable primarily to a substantial increase in the ratio of support employment to basic employment. The Power Authority forecast implies a continued long-run increase in this ratio, though at a much reduced rate, along with a moderate long-run decline in state and local government employment. Basic sector employment in the aggregate is expected to increase gradually.

Exhibit 5 displays the components of basic employment. Federal government employment is expected to remain nearly constant during the planning period, following years of gradual decline that occurred in the military segment.

For the forecast of employment growth in mining and petroleum, it is assumed that additional development of marginal North Slope fields such as Kuparuk, Endicott, and Lisburne will take place, as well as additional exploration and development of the Outer Continental Shelf. However, development of heavy oil fields such as West Sak and construction of a North Slope natural gas pipeline are assumed not to occur prior to 2010.

Though the figures for hard rock mining are small in comparison with oil and gas, it is also assumed that Beluga coal will be developed for export during the 1990s, and that the Red Dog and Quartz Hill mining prospects will also be developed.

In the Fisheries, Forest Products, and Agriculture category, the forecast implies a very low rate of growth. The figures for Fisheries and Forest Products dominate the category, and exhibit such low growth rates due primarily to the assumption that biological resource constraints severely limit any significant increase in the harvesting effort. It is assumed that U.S. fishermen will successfully penetrate the bottomfish segment of the industry. Finally, it is assumed that Tourism employment will continue to grow at a fairly steady pace over the planning period.

State and local government employment is shown in Exhibit 6. It is assumed that various revenue enhancement measures will allow current employment levels to be maintained for several years. In addition, employment is predicated on use of the Power Authority oil price forecast, which is higher than the forecast developed by the Alaska Department of Revenue. However, it is anticipated that declining North Slope oil production will eventually force a reduction in employment. The Power Authority forecast anticipates that state and local government employment in 2010 will be about the same as it was in 1980.

The forecast for support sector employment is shown in Exhibit 7. As stated earlier, it is anticipated that the ratio of support to basic employment will continue to grow in the long run, though at a lower rate than experienced over the last 25 years. This is consistent with the assumption that real per capita income will grow in the long run, and that real income growth will generate a corresponding increase in domestic purchases of goods and services. It is also consistent with national trends and expectations for an economy that exhibits faster support sector growth than basic sector growth.

The product of all these assumptions is a long run employment forecast that is intended to provide a reasonable base case for planning. It is recognized that there are plausible variations that would produce higher or lower results.

The employment forecast leads to the statewide population forecast shown in Exhibit 8. Regional allocation produces the forecast of Railbelt population shown in Exhibit 9. As noted earlier, population (expressed as the number of households) and employment are the most significant inputs to the load forecasting model that produces the forecasts of electric energy demand and peak demand shown in Exhibits 10 and 11. For comparison, the most recent combined forecast of demand growth obtained from the Railbelt utilities is also displayed.

Retirement Schedules and Need for New Capacity. Retirement schedules for existing plants were obtained from the Railbelt utilities in summer 1985, and are displayed in Exhibit 12. At present there are 1147 MW of generating capacity installed in the Railbelt. It is expected that 510 MW of existing plant capacity will be retired between now and 1999, and that approximately 1100 MW of existing capacity will be retired between now and 2010.

Given the Power Authority load forecast for the Railbelt combined with the utilities' plans for retiring existing capacity, an estimate of requirements for new plant capacity can be constructed.

Total required capacity for any year equals peak demand plus an allowance for adequate reserves. Reserves are considered adequate if capacity is sufficient to preclude a loss of load in excess of one day in any 10-year period. Exhibit 13 shows peak demand, estimated reserve requirements, and existing resources net of retirements. The cumulative requirement for capacity additions is the difference between "peak demand plus reserve" and "existing resources net of retirements." Thus, the cumulative requirement for capacity additions is approximately 650 MW by the year 2000, 1500 MW by 2010, and 1800 MW by 2020.

The question that remains for long-range planning is how best to meet the requirements for new generating capacity. Prior studies have led to the conclusion that the best alternatives to Susitna are natural gas-fired generation and coal-fired generation. The expected costs of these alternatives are therefore essential to the determination of an optimal, long-range plan to meet the specified requirements.

Cost Assumptions for the Primary Alternatives

Natural Gas-Fired Generation: Cook Inlet. Electricity generation in the southern portion of the Railbelt is presently based primarily on the combustion of Cook Inlet natural gas. The single component that dominates the total production cost for natural gas-fired generation is the price of the fuel itself. Therefore, an important element of the analysis is the price forecast for Cook Inlet natural gas.

The assumption that drives the Power Authority forecast of Cook Inlet natural gas prices is that the price of natural gas and the price of oil are tied together in the long run. That assumption is supported by two considerations:

1. Natural gas and fuel oil are close substitutes for each other in large-scale utility applications and industrial boilers. Therefore, if the price of fuel oil goes up, natural gas should be able to command a comparable price increase to the extent that comparable markets are served.

2. Three major contracts for the purchase of Cook Inlet gas presently contain provisions that explicitly tie the price of natural gas to the price of oil. In the Phillips contract for sale of Liquefied Natural Gas (LNG) to Japan, the delivered price of the gas is established as the British Thermal Unit (Btu) equivalent price of crude oil delivered to Japan. In the 1982 Enstar contracts for purchase of gas from Marathon and Shell, the price of gas is adjusted annually based on changes in the posted price of fuel oil at a local refinery.

Though relative prices of oil and natural gas may move independently in the short run in response to particular market conditions, it is reasonable to expect that relative prices of these two fuels will move in the same direction at comparable long-run rates of change. Given this assumption, the long run forecast of oil prices is a critical determinant of the long run forecast of natural gas prices.

There is of course a wide spectrum of opinion regarding the long-term outlook for world oil prices, as illustrated by the six price forecasts displayed in Exhibit 14. In the past, the Power Authority has grounded its analysis on a single forecast opinion of the future course of world oil prices, namely that provided by Sherman H. Clark Associates (SHCA). The Draft License Amendment puts forward two companion analyses: one based on SHCA's 1985 forecast; the other based on a composite forecast of world oil prices determined by averaging the six forecasts shown in Exhibit 14. In devising this composite, the Power Authority's objective is to approximate the mainstream of expert opinion for use as an alternative basis for analysis.

The analysis in this discussion will center on the "composite" forecast, shown in Exhibit 15. Also shown in this Exhibit for comparison is the 1985 Sherman H. Clark forecast and the forecast from Wharton Econometrics. The composite forecast is extrapolated from 2010 until 2023, the year in which it reaches a level of $75/barrel (in $1985). It is capped at that level based on the assumption that it will be possible to manufacture synthetic oil at approximately that price, and that therefore it will not be possible to sell crude oil at a higher price.

Given an oil price forecast, the next step in the analysis is to define the nature of the assumed price relationship between oil and natural gas. Two methods have been examined for the present analysis: one based on netback pricing of LNG delivered to Japan and the other based on extrapolation of current Enstar contracts with Marathon and Shell.

The established practice of Japanese LNG buyers has been to pay a price that is the Btu equivalent of the price of crude oil delivered in Japan. Given an oil price forecast, it is therefore possible to construct a forecast of the price of LNG delivered in Japan, assuming that the established pricing mechanism is maintained. Further assuming that Cook Inlet gas producers will, in the long run, have the opportunity to sell their gas as LNG to Japan, it can be concluded that the gas will not be offered for sale on the domestic market at a price that yields a lower wellhead value than could be realized from export as LNG. The wellhead value that would be realized from LNG export to Japan can therefore be used to construct an estimate of prices the producers would require for sales in the domestic market in the long run. The Power Authority forecast of Cook Inlet natural gas prices delivered to the domestic market, based on the composite oil price forecast and the netback methodology, is shown in Exhibit 16. While the price forecast implies a substantial long-run rate of growth, it might also be observed that the price estimated in the year 2000 is about $3.50/MMBtu (in $1985), a price that is well within the range of prices commonly paid today in the rest of the U.S.

The other method examined for defining the relationship between natural gas and oil is the extrapolation of recent Enstar contracts that tie the price of gas to the price of locally refined fuel oil. The result of that extrapolation, again assuming the composite crude oil price forecast, is also shown in Exhibit 16.

The netback pricing methodology has been selected for the Power Authority base case analysis, although a sensitivity test has been performed using the Enstar contract extrapolation prices as well. The primary basis for that selection is that the netback methodology rests on the established pricing practice of the dominant LNG consumer on the Pacific Rim, and is built on a base price that can be analytically understood and supported; i.e. a price that is equivalent to the crude oil price on a Btu basis. The Enstar contracts, on the other hand, represent the product of negotiations in a much smaller market at a particular point in time, and are not built on a base price that can be analytically derived. Future negotiations might well result in particular contracts that are above or below the Enstar line. Consequently, given a long run LNG export opportunity, the netback methodology appears to provide a more reliable methodology for developing a long run price forecast.

Given the Cook Inlet natural gas prices that are used in the base case in concert with other base case assumptions discussed later in this overview, Power Authority economic studies indicate that, on a life cycle cost basis, coal-fired generation becomes the preferred choice over natural gas for new plant capacity in the Railbelt by the year 2000, except for peaking operation. Because of this shift to coal-fired generation, a Cook Inlet natural gas supply limitation is not encountered in the present base case analysis.

However, in sensitivity cases that assume lower gas prices (or higher interest rates that penalize the coal alternative), natural gas-based generation is selected on an economic basis for a longer period of time, and in some instances it is selected indefinitely. The question raised by these cases is whether the amount of natural gas in Cook Inlet is sufficient to allow its continued use for electric generation over these longer time spans.

The most recent estimates of Cook Inlet natural gas supplies from the Alaska Department of Natural Resources are included in Exhibits 17 and 18. Proven reserves are estimated at 4.5 trillion cubic feet (TCF). The estimate of the amount of undiscovered natural gas is presented in the form of a probability distribution, ranging from an extreme low end of .5 TCF to an extreme high end of 9 TCF. The mean estimate within this range is approximately 3.5 TCF.

Current annual demand is approximately .2 TCF as shown in Exhibit 17. Assuming continuation of the current pattern of use, with gradual growth in retail sales and electric generation but no new commitments such as additional LNG export, approximately 3.5 of the 4.5 TCF of proven reserves will be consumed by the year 2000. What this means is that a long-range plan that anticipates the use of Cook Inlet natural gas for base-load operation well beyond the year 2000 depends on the future discovery of substantially more gas. As the time frame for assumed reliance on Cook Inlet natural gas is increased, the risk increases that the needed supplies will not be discovered.

In view of the probability that a Cook Inlet natural gas supply constraint will at some point be encountered, the primary assumption adopted by the Power Authority is that base load plants fueled by Cook Inlet gas can be installed until the year 2000. All such plants are assumed to burn Cook Inlet gas for the duration of their useful lives, i.e. 25 years for combustion turbines and 30 years for combined cycle plants. Only peaking units (limited to 1,500 hours of operation per year) are assumed to be installed after 2000. For sensitivity analysis, however, this supply limitation is relaxed in some cases and eliminated in others.

<u>Natural Gas-Fired Generation: North Slope</u>. There are two ways in which North Slope natural gas could be used as a primary fuel for Railbelt electric power generation:

1. The gas could be burned in Railbelt power plants if made available by pipeline, or

2. The gas could be burned in power plants on the North Slope if tied into the Railbelt via long distance transmission lines.

Previous studies have determined that a small diameter natural gas pipeline from the North Slope to the Railbelt is not economically feasible. The domestic market is too small to justify the expense. However, if a North Slope natural gas pipeline such as the proposed Trans Alaska Gas System (TAGS) were constructed in order to serve an export market, a portion of that gas could become available in the Railbelt. In that event, the appropriate method for estimating the price to Railbelt consumers would be a netback calculation. In the case of the TAGS proposal for delivering gas for export as LNG to Japan, the price of the gas in Anchorage would be equal to the delivered price in Japan minus the costs of liquefaction, transportation by tanker, and regasification. This would yield essentially the same price estimate developed for Cook Inlet gas using a netback methodology. As a result, the Power Authority assumption is that the delivered price of North Slope natural gas would not be less than the price forecast developed for Cook Inlet gas. To assume construction of a North Slope natural gas pipeline would eliminate any assumed supply constraints but would not reduce the estimated price of those supplies.

Previous studies have also indicated that the cost of installing a North Slope generation and transmission system of sufficient reliability renders that option uncompetitive, even if the gas is assumed to be available at a zero wellhead price. Questions have been raised about the level of confidence that can be placed in these cost estimates. However, based on currently available information, the feasibility of the North Slope generation alternative has not been demonstrated, and for that reason the Power Authority has not accounted for this in its evaluation of alternative means for meeting the Railbelt's future needs.

Coal-Fired Generation. The capital cost and operation and maintenance cost (O&M) of coal plants are among the most influential factors that determine the price of electric energy produced by coal-fired generation. These costs have been estimated at a feasibility level for hypothetical, site-specific 200 MW plants that would be constructed either at Nenana or Beluga. The sites are in close proximity to the two major sources of coal in the Railbelt, either of which is sufficiently large to support all Railbelt needs throughout the period of analysis and beyond.

The detailed derivation of these cost estimates is available in a technical document recently published by the Power Authority. A rough comparison of the Power Authority capital and O&M costs with those estimated by sponsors of the Matanuska Power Project and by Diamond Alaska is presented in Exhibit 19. Although there are undoubtedly a number of differences that distinguish these plants, and although the Power Authority estimate is marginally higher than the other two, the similarity of magnitude demonstrates that the Power Authority cost assumptions are generally in line with estimates currently produced for similar plants by private sector sponsors.

The other significant cost component is the price of coal itself. The Power Authority has developed two distinct price forecasts: one for Nenana coal delivered to a Nenana plant some distance away and one for Beluga coal to be consumed at a minemouth plant. It is assumed that air quality considerations stemming from proximity to Denali National Park would prevent construction of a 200 MW coal plant directly adjacent to the Nenana coal fields.

For Nenana coal, studies were performed to estimate the cost of production that would be experienced for a mine extension dedicated to supplying a new major coal-fired generating plant. As shown in Exhibit 20, a 1985 cost of $1.45/MMBtu was estimated. This is within the range of current minemouth prices in effect under existing contracts for Nenana coal, which vary from $1.30/MMBtu for Golden Valley Electric Association to an estimated $2.40/MMBtu for the U.S. Military. Adding an estimated transportation charge to deliver the coal to the assumed plant site yields a delivered, 1985 cost of $1.84/MMBtu.

A long-run real escalation factor of 1.5% per year is then applied to the 1985 price, an assumption that is consistent with historical trends and with expectations for future costs and productivity. As shown in Exhibit 21, the average U.S. coal price increased in real terms at an average rate of .8% per year between 1900 and 1973, and by 1.2% per year between 1900 and 1980. Principal causes of this trend included: (1) rising wages, (2) regulations governing coal production, and (3) rising operating costs (including taxes). coal costs rose despite increases in productivity associated with continuous mining machines, large surface mines, and the introduction of other technologies.

In addition, both Golden Valley Electric Association (GVEA) and the Fairbanks Municipal Utilities System (FMUS) have experienced average real escalation of coal prices in excess of 2% per year under existing contracts during the last 10 years. GVEA has experienced an average real rate of increase of 2.0% per year over the last 20 years.

The forecast that emerges from the Power Authority studies anticipates that wages of mine employees will continue to climb in real terms over the long run, but that productivity gains will level off due to a variety of technological barriers. These expectations translate into the forecast of rising real prices for Nenana coal displayed in Exhibit 22.

While Nenana coal is assumed to be available at its cost of production, the forecast for Beluga coal is based on a different pricing theory. Assuming Beluga coal is produced primarily for export in the Pacific Rim market, the minemouth price for domestic sale is likely to equal the price that can be obtained in the export market minus the costs of transportation from the mine. The price forecast for Beluga coal is therefore driven by the assumed market price of imported coal on the Pacific Rim, adjusted to yield a minemouth value by use of a netback methodology.

It is anticipated that the Pacific Rim market for imported coal will grow at a substantial rate throughout the period of analysis, and that increasingly costly mines will be brought into operation in order to satisfy the growing demand. Assuming that the market price equals the cost of production from the marginal source of coal, the real price of coal on the Pacific Rim market is expected to grow. That is the primary phenomenon that drives the Power Authority forecast of Beluga coal prices, shown in Exhibits 20 and 22. Although the pricing methodology is different for Beluga than for Nenana, the average real rate of escalation estimated for Beluga coal prices over the entire analysis period is again 1.5% per year.

It was assumed earlier that oil price escalation would be capped at $75/barrel (in 1985 dollars). According to the composite oil price forecast, this price level is reached in 2023. Since the price forecast for natural gas is driven by the price of oil, it too is assumed to remain level in real terms in the years beyond 2023. However, real price escalation for coal escalation is assumed to occur throughout the analysis period (i.e. until 2054). As shown in Exhibit 23, coal price escalation can be extended well beyond 2023 without encountering the ceiling imposed by oil and gas prices.

Finally, it should be noted that a sensitivity analysis has been performed with the assumption that coal prices will remain constant in real terms throughout the analysis period.

<u>The Susitna Project</u>. The costs of generation from Susitna are almost entirely the result of the project's capital cost. The estimated construction cost is $5.4 billion in 1985 dollars, and is displayed for each of the three stages in Exhibit 24. Average annual energy generation is estimated at 2400 GWh (millions of kilowatt-hours) from the first stage, 4750 GWh from both the first and the second stage, and 6900 GWh from the completed project. Current annual electric energy demand served by Railbelt utilities is approximately 3400 GWh.

The total estimated financing requirements for the project, including interest during construction and other financing costs, are shown in Exhibit

25, based on an average annual inflation rate of 5.5% and a nominal interest rate on the bonds of 9%. Total estimated financing requirements (in nominal dollars) are approximately $7.4 billion for stage one, $5.8 billion for stage two, and 7.3 billion for stage three. An annual bond issue summary is displayed in Exhibit 26.

Economic Evaluation

Based on the specified set of assumptions, two long-range plans are developed for meeting the estimated electric generation requirements:

1. The "optimal" (i.e. lowest long-run cost) plan that can be devised without Susitna; and

2. The "optimal" plan that can be devised that includes Susitna.

These plans are labeled the "thermal alternative" and the "Susitna alternative". The annual costs (including fuel, O&M, and capital cost) of each plan are calculated during the optimization process. The capital costs for all new facilities, both Susitna and thermal plants, are equal to the complete construction costs of each facility including an allowance for interest during construction that is consistent with 100% debt financing. The present value of each annual cost stream is then computed and compared. The plan that entails the lower present value of future costs is deemed the preferred alternative.

It is necessary to select a discount rate in order to calculate the present value of future cost streams. The Power Authority policy is to set the real discount rate equal to the real interest rate anticipated for market financing. It is presently assumed that tax-exempt financing will be available at a nominal 9% rate and that the inflation rate will average 5.5% in the long run. This in concert with the historical record of real interest rates supports the selection of a 3.5% real discount rate for the Power Authority analysis.

The least cost thermal alternative is characterized by the plant capacity additions displayed in Exhibit 27. Note that a 90 MW hydroelectric project at Bradley Lake is assumed to be on-line in 1990 in both the "thermal" alternative and the Susitna alternative. Of particular interest is that the thermal expansion plan with the lowest long-run cost, given all of the Power Authority base case assumptions, provides for the installation of a 400 MW coal plant in 1999 followed by additional 200 MW coal plants in 2005, 2007, 2010, and 2025. (The gas-fired combustion turbines installed after the year 2000 are for peaking operation).

Coal-fired generation is highly capital intensive, and the impact of initial debt service on consumer rates can be substantial. A sharp increase in rates would be experienced by Railbelt consumers in 1999 if the plan displayed in Exhibit 27 were implemented. In actual practice, it is likely that Railbelt utilities would explore alternatives that would be easier for their consumers to face in the short run. However, such alternatives would be more costly than the "optimal" thermal plan identified over the long run.

Exhibit 28 displays total installed capacity under the thermal alternative in relation to the forecast of peak demand. Note that there is little indication of 400 MW of coal capacity coming on-line in 1999. This is because approximately 300 MW of existing capacity is scheduled for retirement in the same year according to the Railbelt utility retirement schedules presented in Exhibit 12.

The capacity additions that characterize the Susitna alternative are displayed in Exhibit 29. The first stage of the Susitna Project (lower height Watana) is brought on-line in 1999, the second stage (Devil Canyon) is on-line in 2005, and the third stage (raising Watana to full height) is on-line in 2012. The December-January dependable capacity of stage one is estimated at 300 MW, well below the full "installed capacity" of the project at that time. Additional power can be generated at other times of the year when the reservoir level is higher. In addition, Watana's range of operation is constrained within certain limits until Devil Canyon is built downstream, at which time the flow through Watana, and therefore power output can be varied to a much greater extent.

The 505 MW of additional capacity identified in 2005 in Exhibit 29 represents not only the December-January increment from the Devil Canyon power plant but also the relaxation of constraints on the operation of Watana. Exhibit 30 displays total dependable capacity in December-January for the Susitna alternative in relation to the forecast of peak demand. Note again that the addition of the first stage of the project in 1999 is not discernible in this display due to the simultaneous retirement of approximately 300 MW of existing capacity.

The annual production costs calculated for these two alternatives are displayed in the first two columns of Exhibit 35 in nominal dollars for the years 1985-2020. The two streams are identical through 1998 and begin to diverge in 1999. For purposes of economic evaluation, the cost streams are extended through 2054 assuming all cost factors are held constant beyond 2020 except for fuel costs as described earlier. The present value of each cost stream from 1996-2054 was then computed with the following results:

	Present Value of Costs For Period 1996-2054 ($ Millions)
Thermal Alternative	7,158
Susitna Alternative	4,823
Net Benefit	2,335
Benefit/Cost Ratio	1.5

The "Benefit/Cost Ratio" is actually a "Cost/Cost Ratio", determined by dividing the thermal alternative cost by the Susitna alternative cost. The cost savings of proceeding with the Susitna alternative is defined as a net benefit.

he comparative cost of electric energy on a cents/KWh basis is presented in Exhibits 31-34, in both 1985 dollars and nominal dollars for the years 1985-2020 (assuming 5.5% inflation and 9% nominal interest). As shown in Exhibit 31, it is expected that average Railbelt production costs will increase in real terms between 1985 and 1998, with a noticeable jump occurring in 1994 due to the expiration of contracts that provide natural gas from the Beluga field to Chugach Electric Association at very low prices. The jump in 1999 under the thermal alternative represents the rate increase that would be experienced if 400 MW of coal plant capacity were brought on-line at that time. Average Railbelt production costs would be higher yet under the Susitna alternative in 1999, assuming 100% debt financing and level nominal debt service, and would remain higher until 2007.

The real cost of energy under the Susitna alternative declines in the long run as a result of two factors:

1. The impact of continuing inflation on level nominal debt service, resulting in declining real cost;

2. The impact of demand growth on the unit cost of energy, a factor that is relevant for stages two and three due to their excess energy potential in the initial years of operation.

The shaded area in Exhibits 31 and 33 represents the excess cost of energy under the Susitna alternative relative to the defined thermal alternative until the crossover point in 2007. The financing strategy that has been under consideration for a number of years entails a State government contribution sufficient to ensure that Railbelt ratepayers will at no time pay more than they otherwise would under the thermal alternative. The shaded area therefore represents the amount that must be paid out in order to accomplish that purpose.

The amount of that "payout" from state government is calculated in Exhibit 35, and equals approximately $680 million in nominal dollars. State funds that are appropriated for this purpose are deposited in the Power Development Fund. If the Power Authority were authorized to retain the interest earnings of the Power Development Fund, it is estimated that State appropriations of approximately $220 million would be adequate to generate the necessary payout plus cover all pre-construction expenses between 1985 and 1990. It should be noted, however, that the Railbelt utilities might have different forecasts of the thermal alternative costs for the early years of project operation. To the extent that their forecasts are lower, their estimate of the necessary "payout" from the Power Development Fund would be correspondingly higher.

It should also be noted that the energy costs displayed in Exhibits 31-34 are blended costs, representing the average cost produced by all components of the system. The expected cost of energy from the Susitna project itself in both real and nominal terms is displayed in Exhibit 36.

Finally, the Power Authority has tested the validity of its base case analysis by measuring the economic and financial implications of changing a number of important variables. Exhibits 37 and 38 display these results.

V. ENVIRONMENTAL ANALYSIS

The major environmental issues of importance for the Susitna Project include:

- Project induced changes in the seasonal patterns of flow in the river below the dams and the potential for resultant impacts on fish habitat, particularly salmonid spawning and incubation habitat.

- Project induced changes in water quality and temperature below the dams and the potential for resultant impacts to fish (primarily salmonid) populations.

- Potential loss of terrestrial habitat, particularly winter browse habitat for moose, and denning and foraging habitat for bear, due to inundation of lands by the Reservoir.

- Potential loss of habitat and/or habitat degradation due to construction of project facilities including the construction camp, access road and borrow sites, particularly as it impacts moose, and bear.

- Potential interference with caribou movements due to project access road and Watana reservoir.

- Potential loss of bald and golden eagle nesting sites through construction activities and/or inundation.

- Potential loss of cultural resources (historic and prehistoric sites and artifacts) due to construction activities and/or inundation.

- Potential socioeconomic impacts to local communities due to the influx of project workers into these communities.

- Potential recreational impacts due to loss of the white water resource of Devil Canyon through inundation.

Summarized below are the results of the technical investigations and analyses which have been conducted for the purpose of resolving these issues, along with brief descriptions of proposed mitigation programs.

- Project induced changes in water quality and temperature below the dams and the potential for resultant impacts to fish (primarily salmonid) populations.

- Potential loss of terrestrial habitat, particularly winter browse habitat for moose, and denning and foraging habitat for bear, due to inundation of lands by the Reservoir.

- Potential loss of habitat and/or habitat degradation due to construction of project facilities including the construction camp, access road and borrow sites, particularly as it impacts moose, and bear.

- Potential interference with caribou movements due to project access road and Watana reservoir.

- Potential loss of bald and golden eagle nesting sites through construction activities and/or inundation.

- Potential loss of cultural resources (historic and prehistoric sites and artifacts) due to construction activities and/or inundation.

- Potential socioeconomic impacts to local communities due to the influx of project workers into these communities.

- Potential recreational impacts due to loss of the white water resource of Devil Canyon through inundation.

Summarized below are the results of the technical investigations and analyses which have been conducted for the purpose of resolving these issues, along with brief descriptions of proposed mitigation programs.

Water Use and Quality

Project effects on the seasonal pattern of flows in the Susitna River, as well as on water temperature, ice formation and turbidity/suspended sediment have been analyzed by a system of inter-linked computer simulation models including reservoir operation, temperature and sediment models, and downstream flow, temperature and ice models. Results of these models, along with other baseline data collection and field observation studies have shown that impacts to flow and water quality will be greatest in the middle Susitna River (defined as the 50 mile reach of river between Devil Canyon and the confluence of the Susitna River with the Talkeetna and the Chulitna rivers, near the town of Talkeetna). From that point, the flow from the basin above Devil Canyon constitutes only about 40 percent of the total flow in the river, so that project impacts on flow, temperature and water quality are largely masked and/or ameliorated by intervening flow from other sources in the lower river. The proportional contribution of water from tributaries of the Susitna River are depicted on Exhibit 39. Thus, lower Susitna River impacts are generally considered to be less significant and very probably not predictable given the natural range of variation in the complex lower river ecosystem.

Flow. Average summer (May-September) flows in the middle Susitna River (between Devil Canyon and Talkeetna) will be reduced as follows: for Stages I and II from about 20,000 cfs to about 13,000 cfs; for early Stage III to about 12,000 cfs; and for later Stage III to about 10,000 cfs. (All flows given herein are as measured at the Gold Creek gaging station, 14 miles downstream of Devil Canyon).

Average winter (October-April) flows for Stages I and II will be increased from the natural flow of 2,200 cfs to about 7,400 cfs. Early Stage III flows would increase to an average of around 8,000 cfs and later Stage III flows to an average of about 9,500 cfs.

In relation to natural conditions, flows would be more stable after project development. The natural range of average monthly summer flows is from 13,500 cfs to 27,800 cfs. With Stage I this range would be from 6,000 cfs to 18,000 cfs, for Stage II from 7,000 cfs to 20,000 cfs and for Stage III from 9,000 cfs to 11,000 cfs.

Monthly average winter flows presently range from 1,200 cfs to 5,800 cfs. For Stage I this range would be from 4,000 cfs to 9,000 cfs, Stage II would be from 6,000 cfs to 8,500 cfs, and Stage III would be from 8,000 cfs to 11,000 cfs.

Additionally, flood peaks would be substantially reduced by the project. The 50-year flood would be reduced from 98,000 cfs (natural) to about 46,000 cfs for Stages I and II and to about 43,000 cfs for Stage III. The mean annual flood would be reduced from 44,000 cfs (natural) to 36,000 cfs for Stages I and II and to 22,000 cfs for Stage III.

Temperature. The project reservoirs would cause river temperatures to lag behind natural conditions, although annual average temperatures will remain about the same. In Stage I, in the middle Susitna River, this lag would be approximately 2 to 3 weeks. Temperatures in May and June would be slightly less than natural and temperatures in September and October would be slightly higher than natural. Winter temperatures would be the same as natural (0°C) except in the 30-50 mile reach downstream of the Watana Dam where temperatures would be up to 3°C above natural. In the lower river temperatures would be much closer to natural than in the middle river, generally differing by less than 1°C from natural temperatures.

In Stages II and III, with-project temperatures in the middle Susitna River would lag behind natural temperatures by four to six weeks. Temperatures would generally be less than natural in May through July, similar to natural in August, and higher than natural in September through mid-November. Winter temperatures would be similar to natural except in a 15 to 35 mile reach of the river downstream of Devil Canyon Dam where the temperature would be up to 3°C higher than natural. As project energy production increases in Stage III, the differences between with-project and natural spring and summer temperatures would decrease, and the differences in winter temperatures would increase.

In the lower river, temperature differences will be greater in Stage II than in Stage I. Spring temperatures may be up to 2°C cooler than natural and fall temperatures may be up to 2.5°C warmer than natural near Talkeetna. Further downstream the differences would be less. During the summer and winter, temperatures would be the same as natural. Stage III lower river temperatures will at first be similar to Stage II but as energy production increases, differences between natural and with-project summer temperatures will decrease toward Stage I values.

Sediment. The simulations of reservoir suspended sediment behavior indicate that between 80 and 90 percent of the sediment influent to the reservoir would be trapped. This would include most of the larger sized particles, which settle out more rapidly. Thus, after project development, material with a size range of 0-3 microns would comprise the majority of sediment in the middle river below the dams. The concentration of suspended sediment would be reduced from summer natural levels which average 700 mg/l to approximately 100 mg/l in Stage I, 80 mg/l in Stage II and 60 mg/l in Stage III. Average winter concentrations would increase from near 0 mg/l naturally to approximately 70 mg/l in Stage I, 60 mg/l in Stage II and 50 mg/l in Stage III. Lower river suspended sediment concentrations would be generally unaffected in the summer because of the large sediment inflow from the Chulitna River. In the winter, lower river sediment concentrations would also increase over natural values and the increase would be about 10 - 20 mg/l less than in the middle river in all three stages, due to dilution by the Chulitna and Talkeetna Rivers.

Ice. Under natural conditions the Susitna River first becomes ice-covered near its mouth at Cook Inlet in late October or early November. The ice cover then generally progresses upstream and reaches Talkeetna between mid-November and early December. The middle river becomes ice covered at the confluence with the Chulitna River generally about the same time, and the ice cover progresses upstream to Gold Creek by mid-December. The river remains ice covered until late April to mid-May.

Under with-project conditions the lower river is expected to become ice covered in generally the same manner as in natural conditions. However, progression of the ice cover to Talkeetna is expected to be delayed by 2-4 weeks in Stage I, and 4-7 weeks in Stages II and III because of reduced frazil ice production in the middle river. Progression of the ice front in the middle river is expected to be delayed by comparable amounts. Additionally, because of the warmer (3°C) reservoir releases, a section of the middle river below the dams is not expected to become ice covered. In Stage I, the ice cover is expected to reach near RM 140 and the area upstream to Watana Dam would be open water. In Stage II, the ice cover is expected reach near RM 135. In early Stage III the ice cover would extend to near RM 125 and, as energy production increases, the ice cover would extend only up to near RM 115.

The higher than natural winter releases would cause winter water levels to be higher than natural within ice covered areas. In areas where an ice cover existed under natural conditions but would not exist with-project, the water level may be less than natural. The increase in water level in the middle river is expected to be 2 to 6 feet in Stage I, 1 to 4 feet in Stage II and approximately 2 feet in Stage III.

These water level increases are of concern since they may cause overtopping of natural berms at the upstream ends of peripheral habitat areas. This could introduce cold mainstem water (near 0°C) into the slough or side channel habitats (see discussion below) and could affect overwintering and incubating salmonids. Therefore, the Applicant has proposed to protect the important habitat areas by raising the berms above the expected maximum winter water levels. The increase in winter water level in ice affected areas may be beneficial by providing additional winter groundwater upwelling to the adjacent habitat areas. Upstream of the ice-affected area water levels are expected to be lower than natural but similar to average summer water levels. In all areas, upwelling, a major component of suitable spawning and incubation habitat in these peripheral habitats, is expected to be generally more stable all year than for natural conditions.

Fish and Fish Habitat

Twenty species of fish are known to inhabit the Susitna Basin. The most important are five spe. ?s of Pacific Salmon, rainbow trout, Dolly Varden char, arctic grayling and burbot.

The majority of fish production in the system occurs in tributaries outside the area of anticipated project affects. Devil Canyon acts as an effective passage barrier to upstream mitigation so no salmon have been observed above the Watana Dam site and only a few (less than 100) move past the Devil Canyon damsite. Salmon production from the middle river, the reach expected to experience the greatest project induced changes, is quite small compared to total production from the Susitna system. Only approximately six percent of the total Susitna salmon runs spawn in the middle river and less than one percent spawn in the mainstem influenced, non-tributary habitats. Resident fish populations in the middle river are relatively small and low density.

Based on the baseline fisheries studies over the past five years and consultations with various fisheries agencies, it has been determined that the most critical habitat and habitat use in the middle river vis a vis project-induced flow, temperature and water quality impacts is largely limited to chum (and sockeye) salmon spawning and incubation in side sloughs and chinook (king) salmon rearing in side channels. Mitigation measures, including flow constraints and design features have been proposed to maximize the availability of these habitats.

Flow Related Impacts. Mainstem habitat is of little value to the salmonid populations in the middle river. Upland sloughs and tributaries would be essentially unaffected by the project. Thus, the species/habitat combinations of chinook salmon rearing and chum salmon spawning and incubation in side sloughs and side channels were chosen after consultation for primary consideration in developing environmental flow requirements. Secondary consideration was given to the other evaluation species for flow allocations and all the species are treated in impact analyses and mitigation planning.

A plan for regulating river flow (Flow Case E-VI) has been selected as the preferred set of environmental flow constraints to mitigate flow related fishery impacts. Briefly, this flow regime establishes seasonal minimum and maximum flows for the project as depicted on Exhibit 40, as well as limits on the rate of change in flow. As noted above, the primary focus of this case is maintenance of rearing habitat for chinook salmon juveniles by maintenance of high summer minimum flows. Project operation under Case E-VI requirements would result in maintenance of or an increase in chinook rearing habitat. The mean total available area for chinook rearing under natural flows is approximately 6.1 million square feet. This is the estimated area in all habitat categories that meet the derived suitability criteria derived in consultation with interested agencies. Estimated available habitat under Case E-VI flows, using the same suitability criteria and all habitat categories, is approximately 6.0 million square feet. This estimated slight decrease in rearing habitat would have no affect on chinook juvenile survival and production. The area estimates include habitat categories that rearing chinook do not use under natural conditions and may not use under with-project conditions.

Chinook rearing habitat estimates in habitat types used extensively by juvenile chinook under natural conditions show an increase in area available under with-project flows. The mean total area available under natural conditions is approximately 4.2 million square feet as compared to approximately 4.3 - 4.6 million square feet under with-project conditions.

Chum salmon spawning habitat and egg incubation success would be reduced by Case E-VI flows without further mitigation. Since chum spawning in the middle river is largely limited to a few side sloughs, however, this potential loss can be easily rectified by structural habitat modifications in appropriate side sloughs.

Evaluation of the distribution and timing of habitat utilization by the other evaluation species produced no other expected negative impacts due to altered flows. Most of the habitat use by other species is outside the area that would be affected by changes in mainstem flow and use within the affected area is similar to that of the primary evaluation species. Hence, the mitigation measures to protect the habitat for the primary species would also provide the secondary species sufficient protection.

<u>Water Quality Impacts</u>. Factors affecting habitat quality are less predictable than habitat quantity. The major anticipated changes in quality-related factors are increased flow stability and altered temperature and suspended sediment regimes. Increased flow stability would have a beneficial affect on habitat use by all the evaluation species. With-project water temperatures are expected to be slightly cooler in the early summer and warmer in the fall. Although the expected temperature changes would alter timing of some annual cycles and behaviors, they are well within documented ranges of tolerance for each species and are within the range of temperatures that Susitna populations experience under natural conditions. Thus, no significant impact is anticipated.

As dicussed above, project operation would reduce the total suspended sediments in downstream habitats. Concentrations would be much less during the summer and slightly greater during the winter. Most of the sediments that would be transported downstream would be in the category of glacial flour i.e. particles less than 3 microns in diameter. These small fines are the major contributor to with-project turbidity. The annual pattern of turbidity would follow the same trend as for suspended sediments. That is, turbidity would be less in the summer and greater in the winter than natural conditions. The summer reduction in suspended sediment and turbidity would improve habitat quality for juvenile chinook salmon and other species that presently use turbid water habitats for rearing. The winter increase would reduce mainstem habitat quality; however, winter sampling indicates limited use of mainstem areas during the winter and most of the documented use is by species known to be tolerant to turbidity, e.g., rainbow trout and burbot. The effect that increased turbidity would have on observed periphyton blooms during the spring and fall and, in turn, how that affect would influence fish production from the system is not quantitatively predictable. However, a decrease in the short spring and fall blooms would be offset, at least partially, by lower rates of productivity over the entire summer season given reduced summer turbidity levels.

The proposed monitoring plan includes components to measure these habitat quality parameters and would detect unanticipated changes during project operation. Monitoring would also detect any loss of fish production occuring in the event proposed mitigation measures are not as effective as expected.

In summary, the proposed mitigation plan would avoid, minimize or rectify the anticipated impacts on aquatic habitats and species that would be caused by operation of the project. The result would be maintenance of existing levels of productivity from naturally reproducing populations. The proposed monitoring plan would measure this productivity to show if refinement or alteration of mitigation is needed.

Botanical and Wildlife Resources

Botanical. Stage I would result in the permanent removal, through construction or inundation, of 15,762 acres of vegetation, 84 percent of which would consist of forest (mostly spruce and spruce-birch) and almost 16 percent of which would consist mainly of dwarf tree scrub and low shrub vegetation.

Stage II (Devil Canyon) would result in 6,020 acres of vegetation permanently lost through inundation and construction. Almost all of this, some 94 percent, is forest (spruce, spruce-birch, and spruce-poplar).

Construction of Stage III would result in the permanent loss of 16,370 acres of vegetation. Some 82 percent of this would consist of spruce and spruce-birch forests and white spruce woodland. The remainder would consist mostly of dwarf tree scrub and low shrub.

Much of the area to be affected by the project is classified as wetlands, as in the case for most of Alaska. The areas of palustrine or lacustrine wetlands permanently lost due to construction or inundation are 3,430 acres for Stage I, 950 acres for Stage II, and 4,090 acres for Stage III. However, only about 18 percent of these areas consist of emergent, pond, or lake wetland types which are considered to be of relatively high value for waterfowl and other wildlife. The remainder consists of forested and scrub-shrub wetlands which are usually of equal or lower value to wildlife than are adjacent uplands.

Mitigation plans for botanical resources were developed primarily to minimize vegetation losses and support the wildlife mitigation program. Specific measures include the minimization and consolidation of project facilities and the siting of these facilities in areas with low habitat values and the prompt rehabilitation of disturbed areas when no longer needed for project construction.

Moose. From 2,000 to 3,000 moose inhabit the 1,400 square mile area which includes and surrounds the project area. This represents about 10 percent of the Alaska Game Management Unit 13 moose population and approximately 1-2 percent of the population in the State of Alaska. Winter habitat is the critical habitat for these animals. The 38,152 acres of vegetation lost for Stages I, II and III, would result in loss of winter habitat for some 300 moose (about 0.1 percent of the moose population of Alaska). This loss would be mitigated by habitat enhancement on mitigation lands in both the lower and middle Susitna Basin. Burning and clearing would increase browse production and resultant carrying capacity sufficiently to over compensate for moose habitat losses and would also provide out-of-kind mitigation for other species.

Caribou. The Susitna Project lies within the northwestern portion of the range of the Nelchina caribou herd, which currently numbers about 24,000 animals or about five percent of the statewide caribou population. Given the low historic use of the impoundment zone, the habitat loss associated with inundation is not expected to detectably reduce carrying capacity for the Nelchina herd. The access road could locally affect caribou movements and range use and public use of the road for hunting could result in a redistribution of hunting pressure resulting in greater pressure on the local subherd and less pressure elsewhere. However, significant impacts to Nelchina herd numbers are not expected from these factors. The Watana impoundment could alter caribou movements and may result in an increase in the number of crossing-related mortalities over natural conditions; however, significant population changes or reductions in carrying capacity due to crossing mortalities or blockage of movements are not expected. A variety of mitigation measures, including a worker transportation plan to reduce traffic on the access road, have been incorporated into project plans to minimize these impacts.

Bears. Brown bears will lose spring foraging habitat and black bears will lose denning and foraging habitat, due to inundation. Increased human use of the area will likely result in increased bear mortality, particularly for brown bears. Mitigation measures have been incorporated into project design and operation plans to minimize these impacts and both in-kind and out-of-kind compensation through habitat preservation and through enhanced moose production would mitigate residual impacts.

Raptors. Twenty-three golden eagles and ten bald eagle nesting locations have been identified in or near the project area. Seven golden eagle and three bald eagle nest locations would be inundated or significantly disturbed and two golden eagle nest locations will be partially innundated. A mitigation program which includes placement of artificial nests and the enhancement of nesting sites is expected to fully mitigate for these impacts.

Social Sciences

Socioeconomic Resources. The major socioeconomic impact identified for the Susitna Project is project induced population influx into local impact area communities and the effect of this influx on these communities' ability to provide services' to their residents. In general, the analysis of impacts show that only two communities, Talkeetna and Cantwell, are forecast to receive a population increase of 10 percent or greater over levels expected without the project (baseline). Project-related population increases in Talkeetna are forecast to be 15 percent (71 people) above baseline in 1997 (peak employment for Watana Stage I) and 15 percent (87 people) in 2003 (Devil Canyon Stage II peak) and 5 percent (36 people) above baseline in 2009 (Watana-Stage III peak). This level of population impact would have minor impacts on the primary school in Talkeetna and would reduce housing vacancy rates in Talkeetna to almost zero in 2003.

Impacts in Cantwell would be greater, with population increases over baseline of 166 percent (375 people) in 1992 (railhead construction peak), 47 percent (118 people) in 1997, 5 percent (113 people) in 2003, and 22 percent (69 people) in 2009. The community services in Cantwell most affected by these population increases would be housing and the primary school. Housing shortages would be mitigated during the railhead construction by the provision of single-status housing. The impact on the primary school would also be mitigated during years of impacts.

Other communities receiving moderate population impacts (from 5 to 10 percent over baseline) would be Trapper Creek (8 percent or 39 people at peak in 2009) and Nenana (6 percent or 94 people percent at peak in 2009). These levels of impact, when compared to changes in baseline, would have little effect on the timing or magnitude of the communities' need to expand their facilities or services.

Socioeconomic impact levels have been minimized by the Applicant's policies to provide onsite worker housing at the project construction sites, single-status worker housing at the railhead construction site, and a worker transportation program for Watana-Stage I. These policies will help avoid large population influxes into nearby small communities by decreasing advantages that workers might perceive would come from living near the construction sites.

<u>Cultural Resources</u>. Issues relating to the project involve the extent to which construction and operation would adversely affect historic, archeological, or architectural sites, properties and objects, and the degree to which proposed measures would mitigate those adverse effects. Cultural resources sites in the project area would be affected by ground disturbance associated with construction activities, by inundation (sites within permanent reservoir pools) and erosion (sites within drawndown areas and at impoundment margins). In addition, as yet unidentified sites (believed to be qualitatively similar in nature to those identified to date) may be affected by construction of the project's linear features and the creation of recreation areas and wildlife mitigation lands. However, proposed mitigation measures should negate the majority of adverse project effects to cultural resources.

To date, studies carried out in connection with the Susitna Project have identified a total of 297 historic and prehistoric archeological sites. An additional 22 sites, within or near the project area have been previously recorded in the files of the State of Alaska Office of History and Archeology.

No sites are located at the designated construction camps and villages, permanent village, airstrips, intake structures, dams, spillways, switchyards, powerhouses or cofferdams for any stages of the project.

However, six sites are located within 500 feet of these features and are likely to be adversely affected.

A variety of mitigation measures would be implemented to address both known and undiscoved sites. The most important of these would be data recovery at archeological sites when avoidance of those sites is not feasible. The vast majority of identified and anticipated cultural resource sites in the project impact area are small-scale archeological sites important solely for the scientific data they contain. For this reason, excavation and analysis of a carefully selected representative sample of these sites would be undertaken. Controlled burial, construction of protective barriers, and restriction of access would also be employed when appropriate. A monitoring program would be implemented to ensure that increased access to the project vicinity does not result in any vandalism of cultural resource sites. A public interpretation and education program designed to make available to the public the results of cultural resources studies and to allow controlled access to selected sites in the Project area would be implemented.

Finally, a procedure would be established to insure that any as yet unidentified sites in portions of the project area where direct ground disturbance limits cannot be identified on the basis of existing engineering data would not be ignored. This would involve pre-construction field surveys of these areas designed and executed in consultation with the State Historic Preservation Officer.

Recreation Resources. To date, the project area has not been developed as a recreational resource. Total recreational use in the 3,600 square-mile encompassed in and surrounding the project area is currently estimated at less that 7,000 user days. Predominant recreational activities in the project area are fly-in hunting and fishing. The only public recreational facilities that exist near the project area are roadside facilities on the Denali Highway. In addition, three private lodges in the vicinity of the project area are used primarily to support hunting and fishing trips. The present level of use in the project area is very low because of the lack of developed road access into the area. Current access is mostly by plane. All-terrain vehicles are used in the areas near the Denali Highway. A small number of boaters put in at the Denali Highway bridge and travel downstream. Almost all boating stops above Vee Canyon rapids, however.

Construction of the proposed project would result in loss of the white-water boating associated with Devil Canyon rapids. These rapids are dangerous and only infrequently attempted by the most experienced of whitewater experts. Yet, whitewater enthusiasts regard the loss of this resource to be a significant impact of project development.

A recreation plan has been developed to accommodate increased public use of project lands and waters, and to compensate for project-related impacts to existing recreation resources and activities. In general, the plan provides for developed recreational activities near the damsites and adjacent to the access roads; beyond these areas, trails and backcountry cabins are the principle recreation facilities proposed.

EXHIBITS

SUSITNA HYDROELECTRIC PROJECT
RESOURCE USE AREA
GUIDE SURVEY

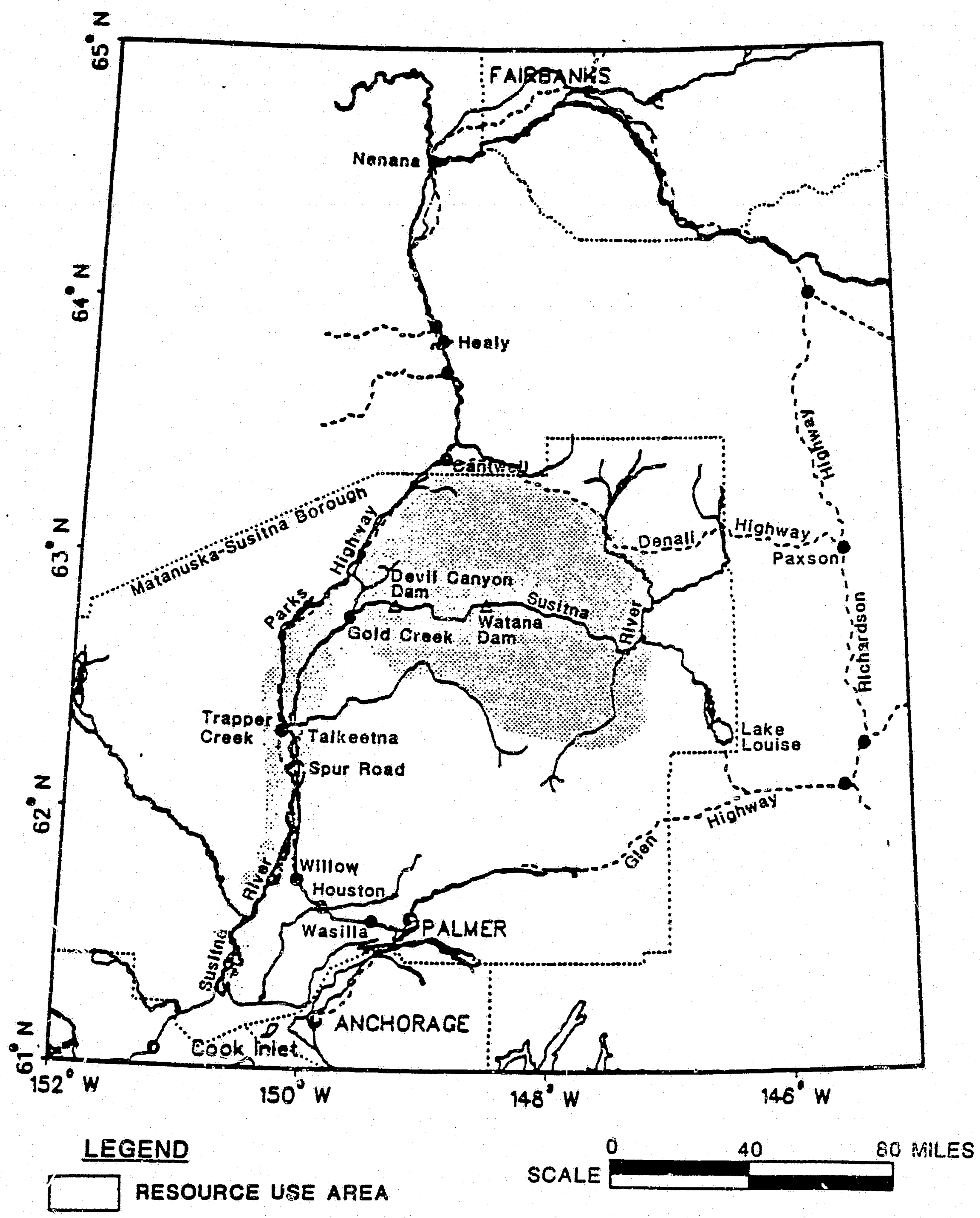


EXHIBIT 1

WATANA DAM GENERAL PLAN

(STAGES I & III)

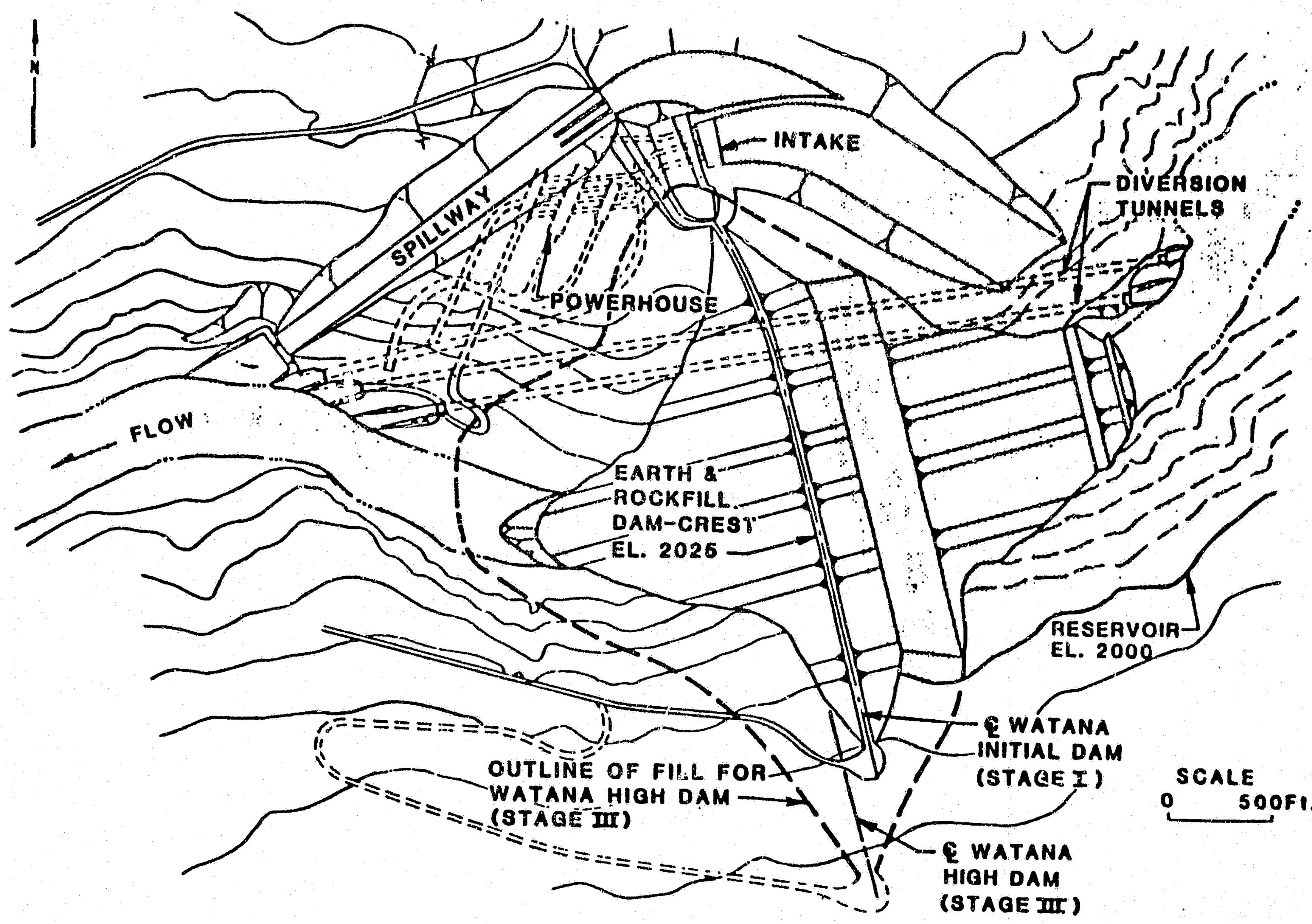


EXHIBIT 2

DEVIL CANYON DAM GENERAL PLAN

(STAGE II)

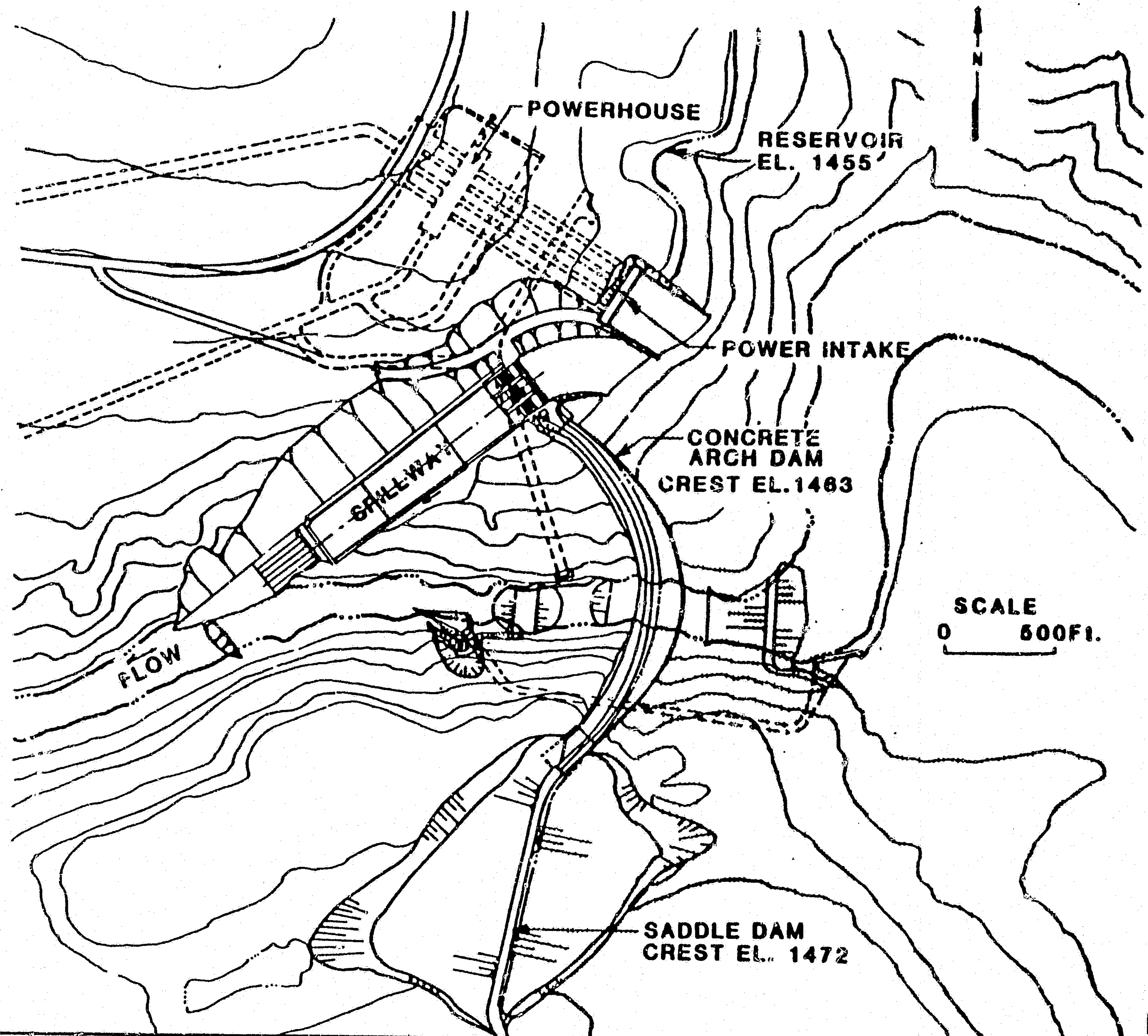


EXHIBIT 3

TOTAL EMPLOYMENT STATEWIDE

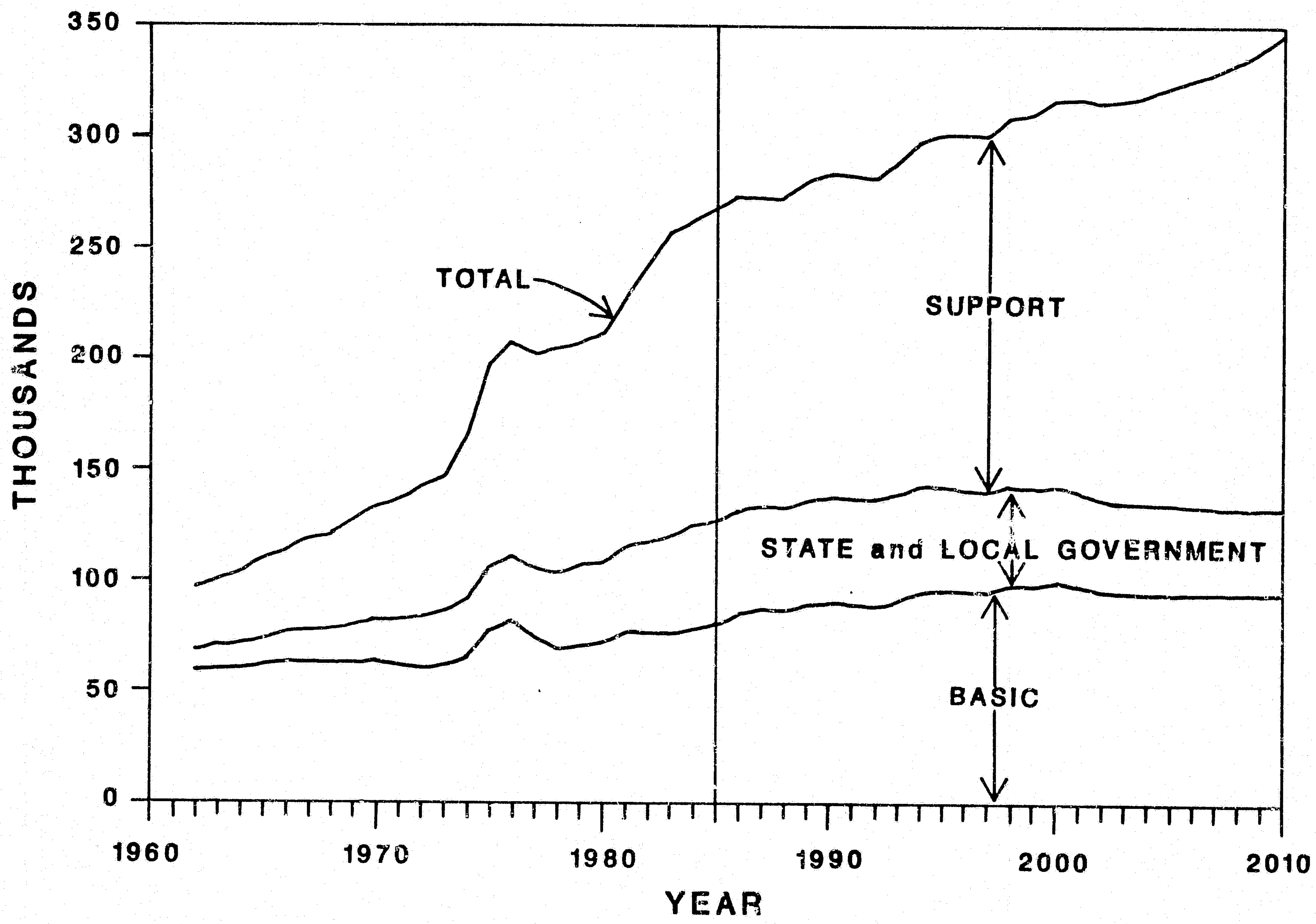
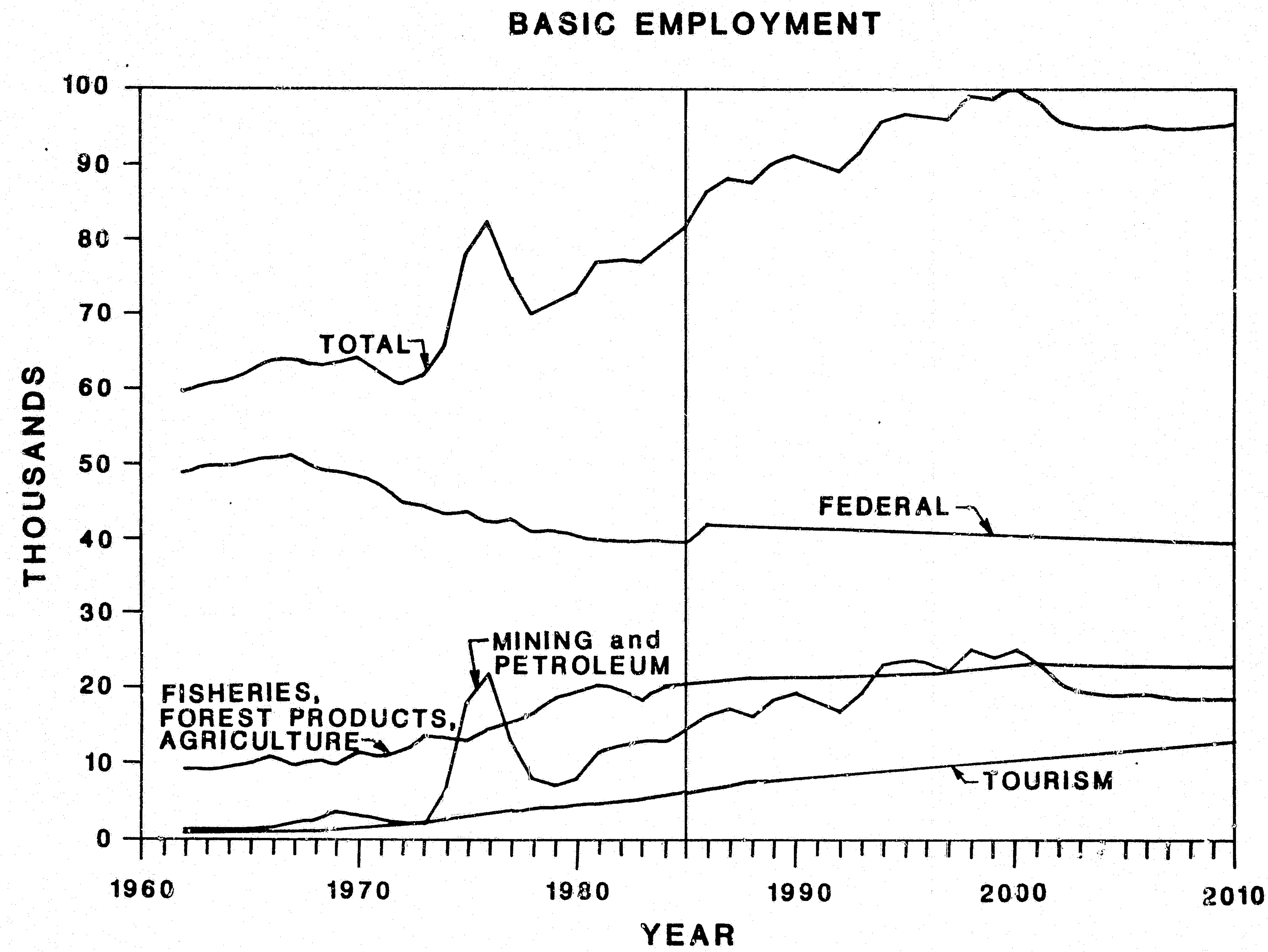
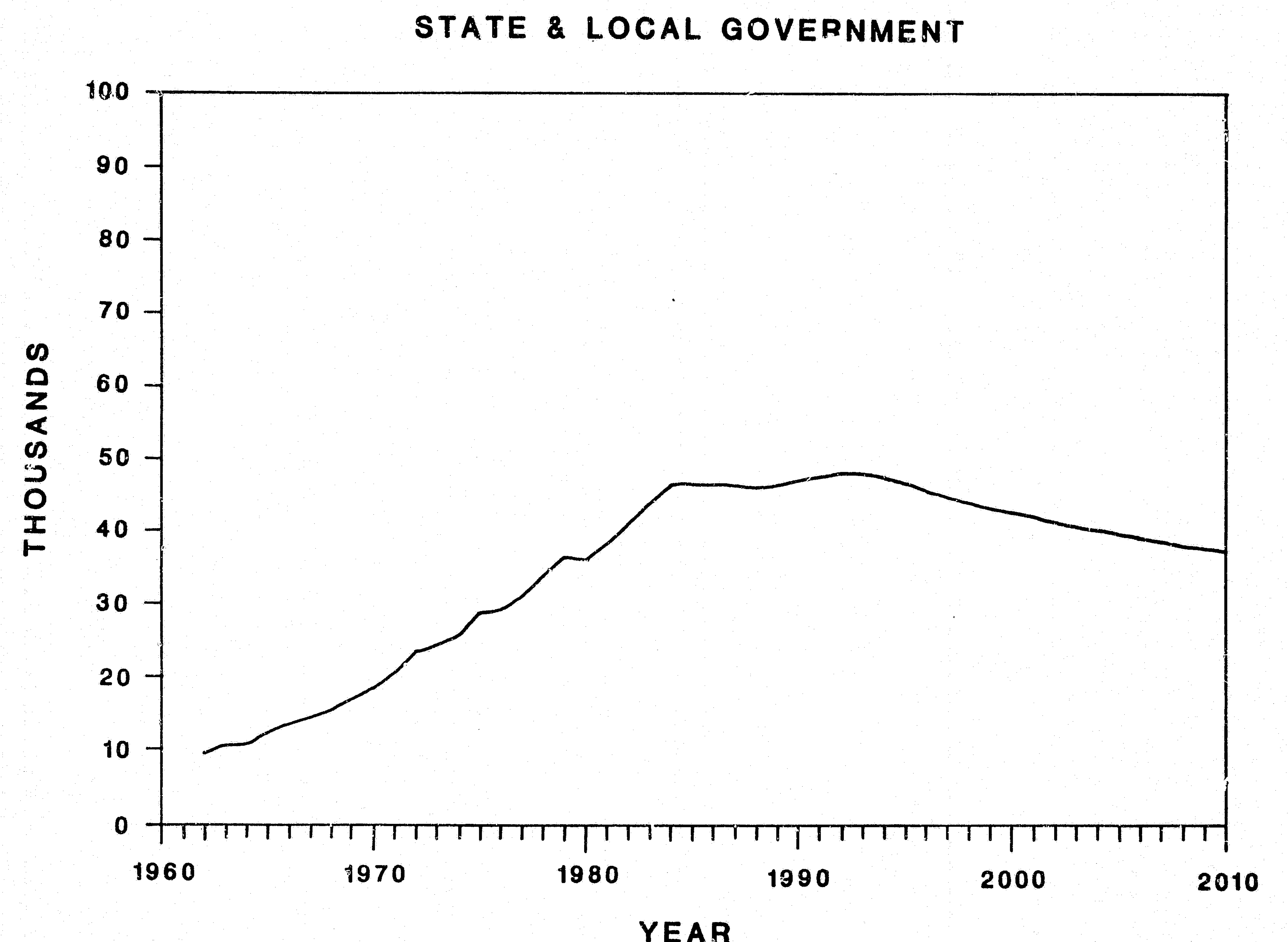


EXHIBIT 4



BASIC EMPLOYMENT
100
90
80
70
60
50
40
30
20
10
0
THOUSANDS
TOTAL
FEDERAL
MINING and PETROLEUM
FISHERIES, FOREST PRODUCTS, AGRICULTURE
TOURISM
1960
1970
1980
1990
2000
2010
YEAR

EXHIBIT 5



STATE & LOCAL GOVERNMENT
THOUSANDS
100
90
80
70
60
50
40
30
20
10
0
1960
1970
1980
1990
2000
2010
YEAR

EXHIBIT 6

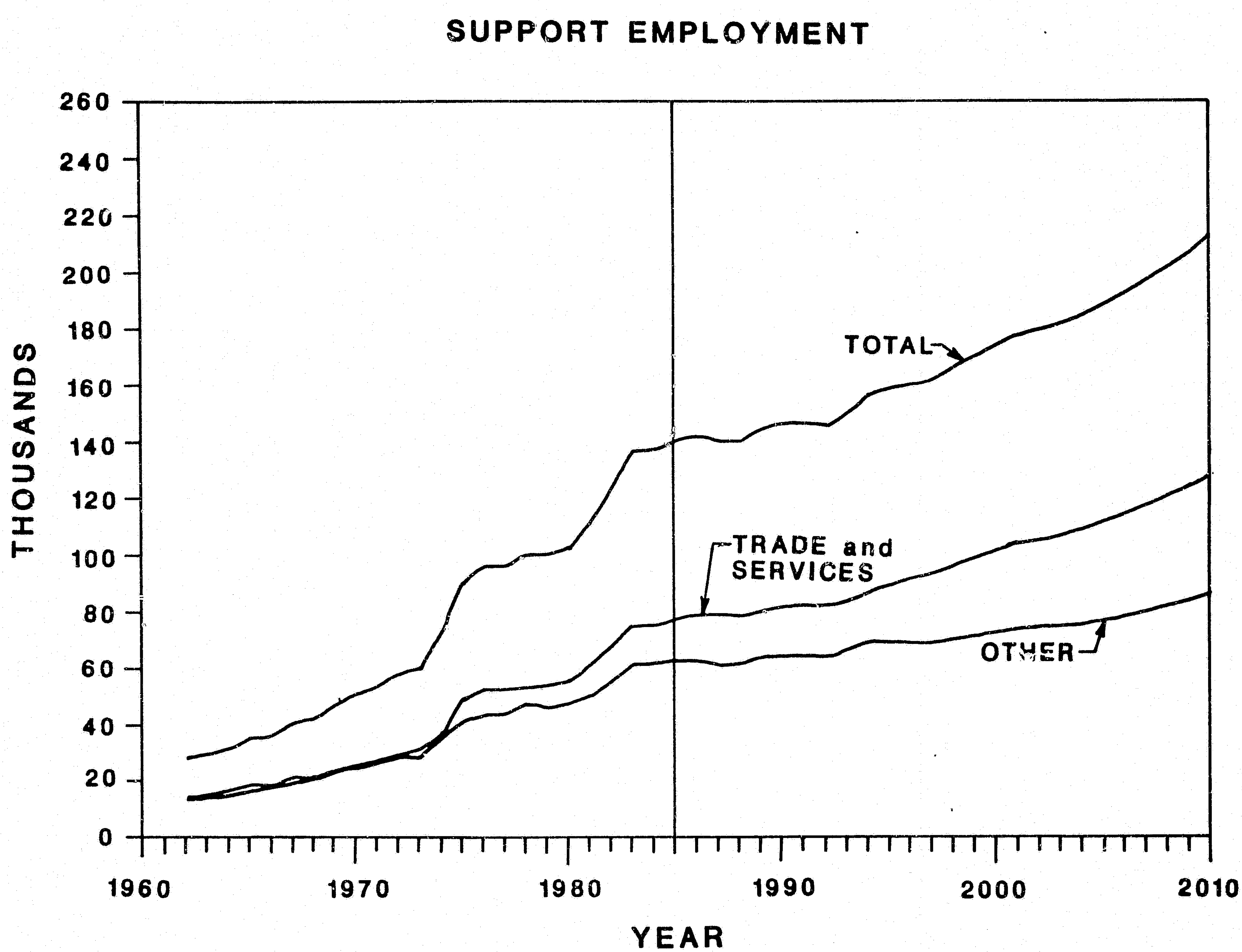
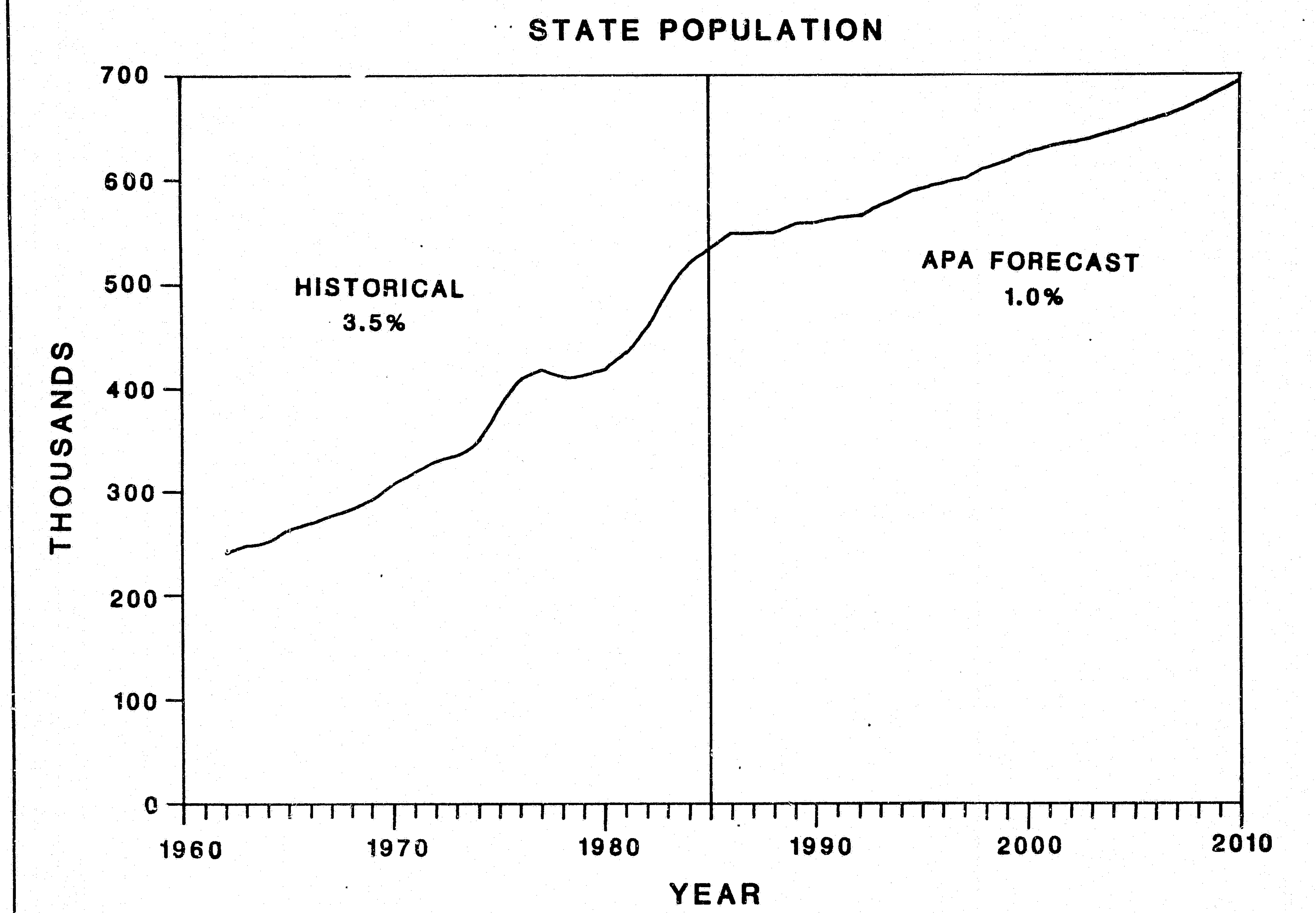

SUPPORT EMPLOYMENT
THOUSANDS
260
240
220
200
180
160
140
120
100
80
60
40
20
0
1960
1970
1980
1990
2000
2010
YEAR
TOTAL
TRADE and SERVICES
OTHER

EXHIBIT 7


STATE POPULATION
THOUSANDS
700
600
500
400
300
200
100
0
HISTORICAL
3.5%
APA FORECAST
1.0%
1960
1970
1980
1990
2000
2010
YEAR
EXHIBIT 8

RAILBELT POPULATION

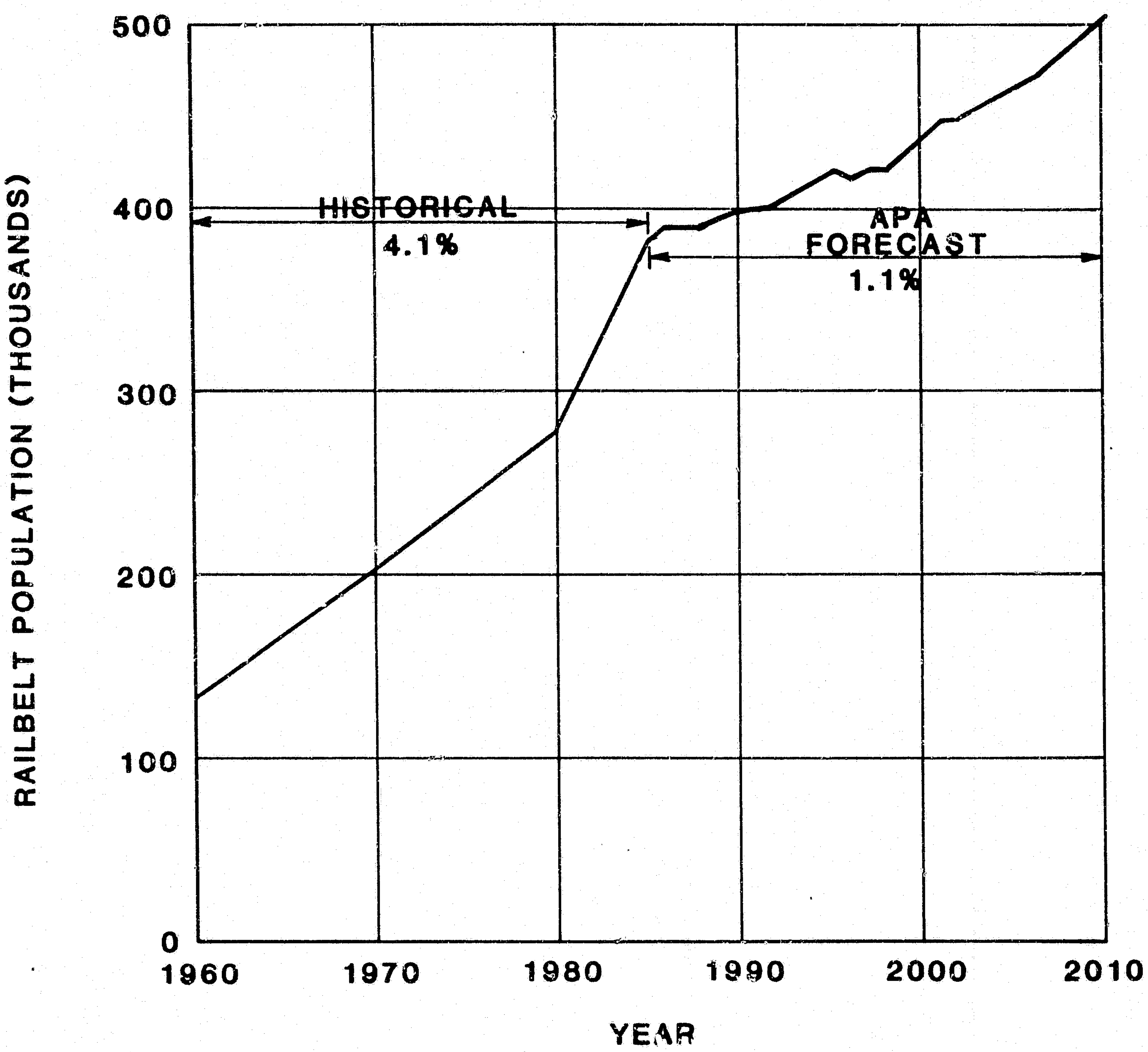


EXHIBIT 9

RAILBELT ELECTRIC ENERGY DEMAND

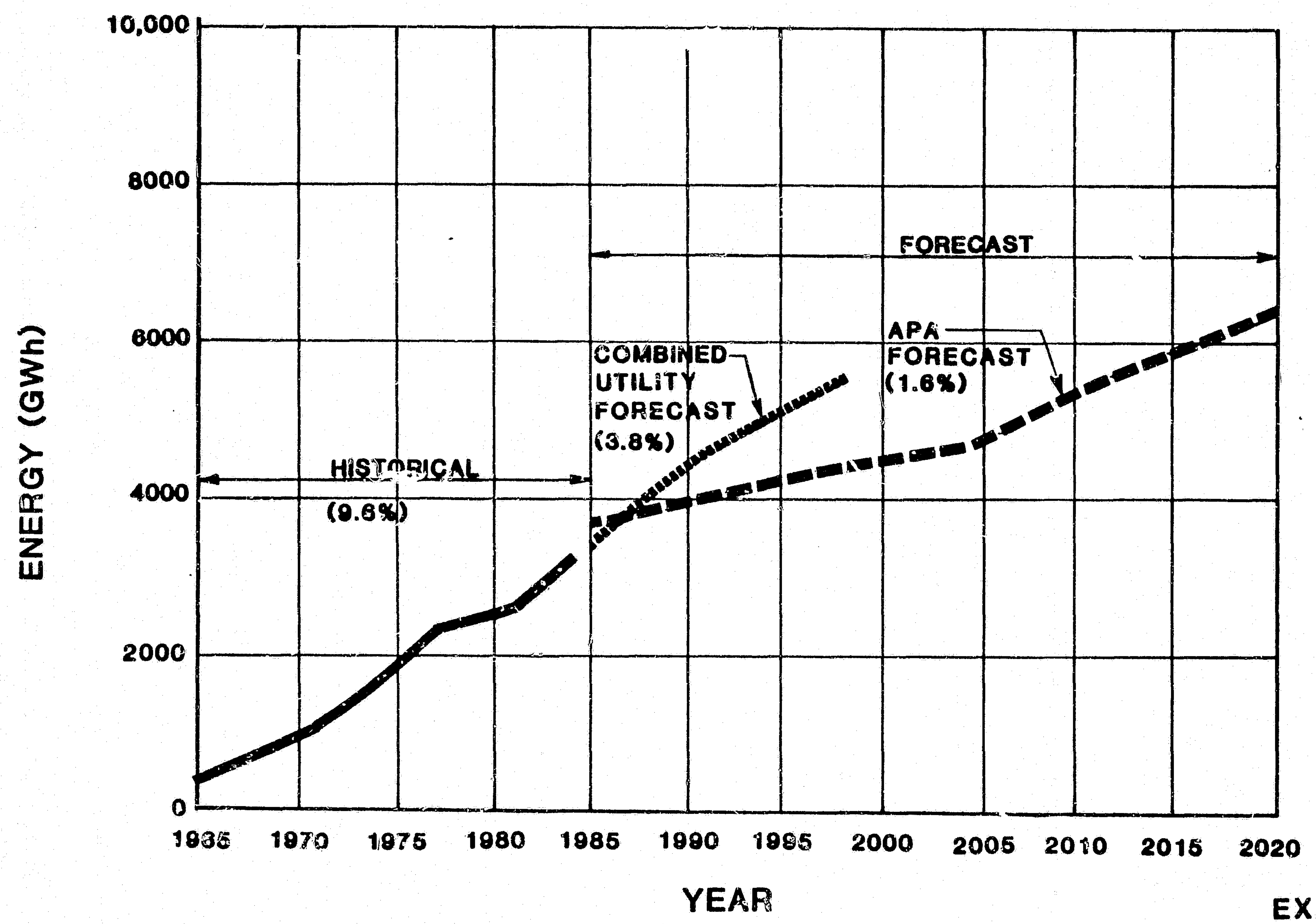


EXHIBIT 10

RAILBELT PEAK DEMAND

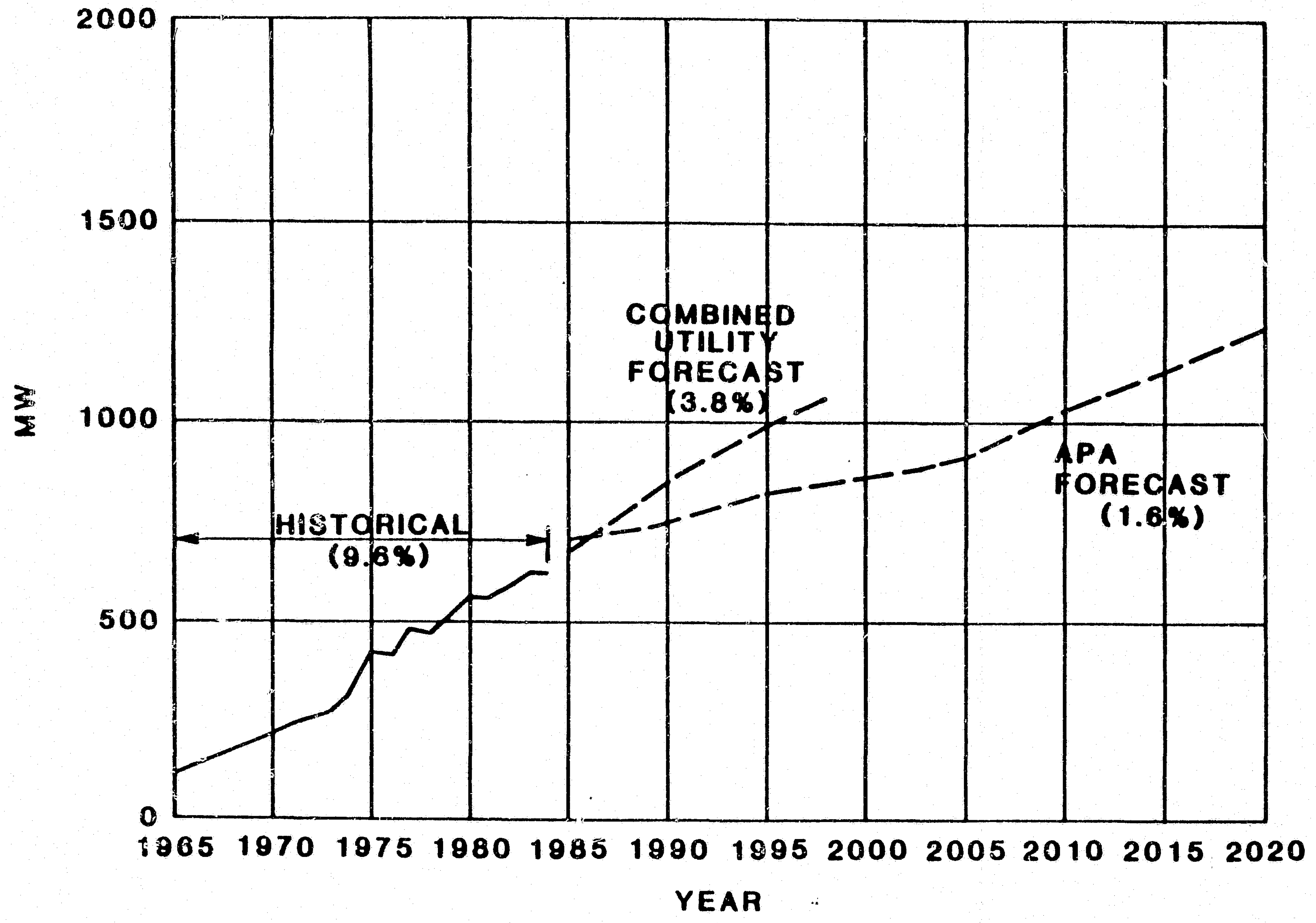


EXHIBIT 11

RAILBELT EXISTING EQUIPMENT RETIREMENT SCHEDULE

Year	AMLP Capacity Retired (MW)	AMLP Unit Name 1/	GEA Capacity Retired (MW)	GEA Unit Name	HEA Capacity Retired (MW)	HEA Unit Name	SES Capacity Retired (MW)	SES Unit Name	FMUS Capacity Retired (MW)	FMUS Unit Name	GVEA Capacity Retired (MW)	GVEA Unit Name	TOTAL RAILBELT Annual Capacity Retired (MW)	TOTAL RAILBELT Cumulative Capacity Retired (MW)	Year
1985									6.1	CHENCT #4			6.1	6.1	1985
1986														6.1	1986
1987														6.1	1987
1988			8.9	BERNCT #1									8.9	15.0	1988
1989														15.0	1989
1990	32.4	AMLPCT #1&2			0.3	SELDIC #1	3.0	SESIC #1&2					35.7	50.7	1990
1991	19.9	AMLPCT #3									5.7	DSLIC #1,2,&3	25.6	76.3	1991
1992	33.8	AMLPCT #4							8.4	FMUSIC #1,2,&3			42.2	118.5	1992
1993														118.5	1993
1994			32.2	BELCT #1&2	0.6	SELDIC #2							32.8	151.3	1994
1995							2.5	SESIC #3					2.5	153.8	1995
1996			58.5	BELCT #4, INTCT #1,2,&3							3.8	UAFIC #7&8	62.3	216.1	1996
1997			18.4	BERNCT #2							2.6	HEALIC #2	21.0	237.1	1997
1998														237.1	1998
1999	156.8	AMCC #56&76	116.8	BELCT #3&5									273.6	510.7	1999
2000					0.6	SELDIC #3			8.6	CHENST #1,2,&3	5.2	DSLIC #5&6	14.4	525.1	2000
2001											18.0	ZENCT #1	18.0	543.1	2001
2002											43.0	HEALST #1 ZENCT #2	43.0	586.1	2002
2003														586.1	2003
2004			54.4	BERNCT #3&4									54.4	640.5	2004
2005									20.0	CHENST #5			20.0	660.5	2005
2005									26.1	CHENCT #6	60.9	NOPOCT #1	87.0	747.5	2006
2007			201.2	BELCC #68&78							60.9	NOPOCT #2	262.1	1009.6	2007
2008														1009.6	2008
2009	87.0	AMLPCT #8											87.0	1096.6	2009
2010														1096.6	2010
2011														1096.6	2011
2012					0.6	SELDIC #4							0.6	1097.2	2012
Total	329.9		490.4		2.1		5.5		69.2		200.1		1097.2		
											Not Retired:	Eklutna	30.0		
												Cooper	17.4		
											Total Online:		1144.6		

1/ Key to plant types:
- CC: Gas-fired combined cycle
- CT: Combustion turbine
- H: Hydroelectric
- IC: Oil-fired internal combustion (diesel)
- ST: Coal-fired steam turbine

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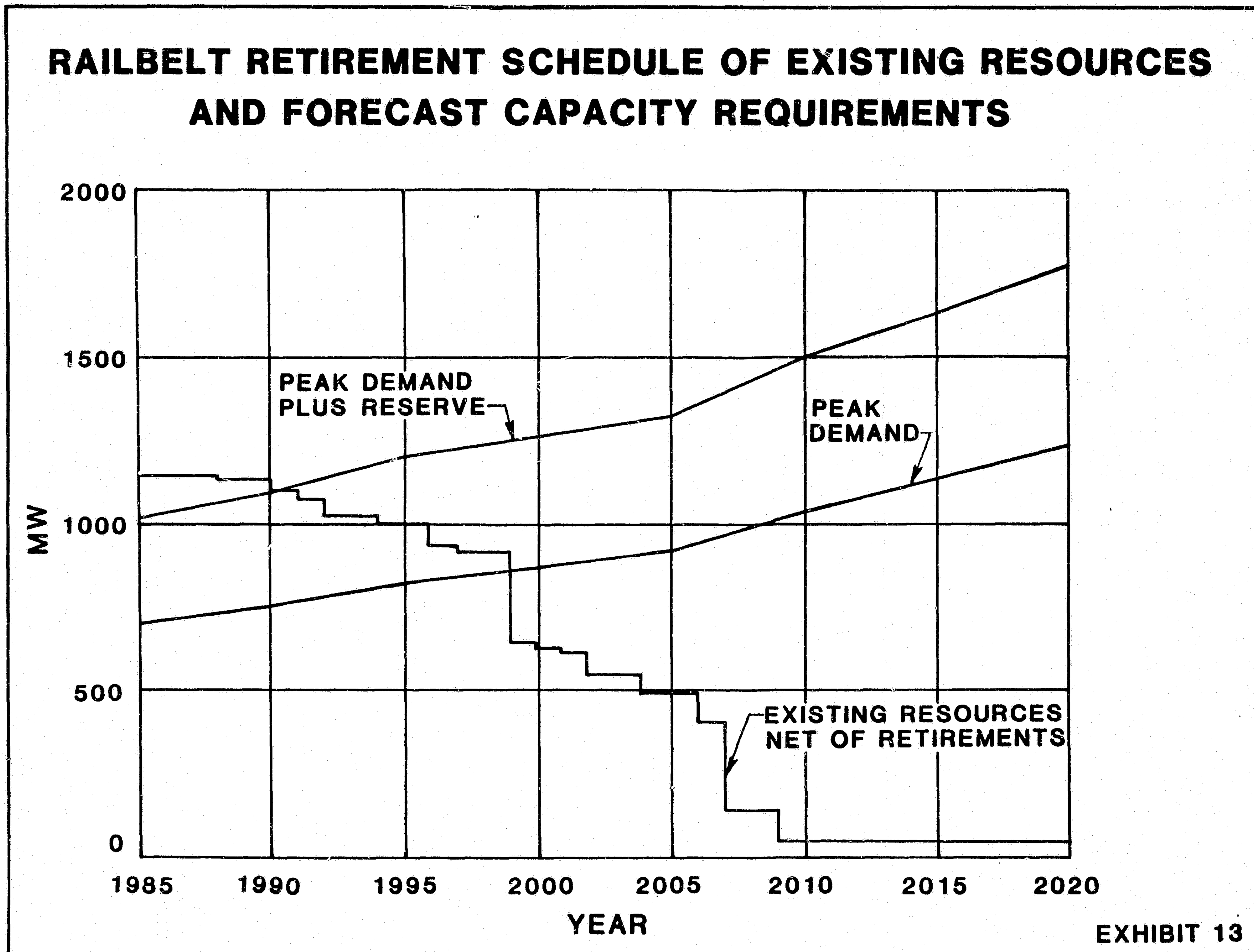
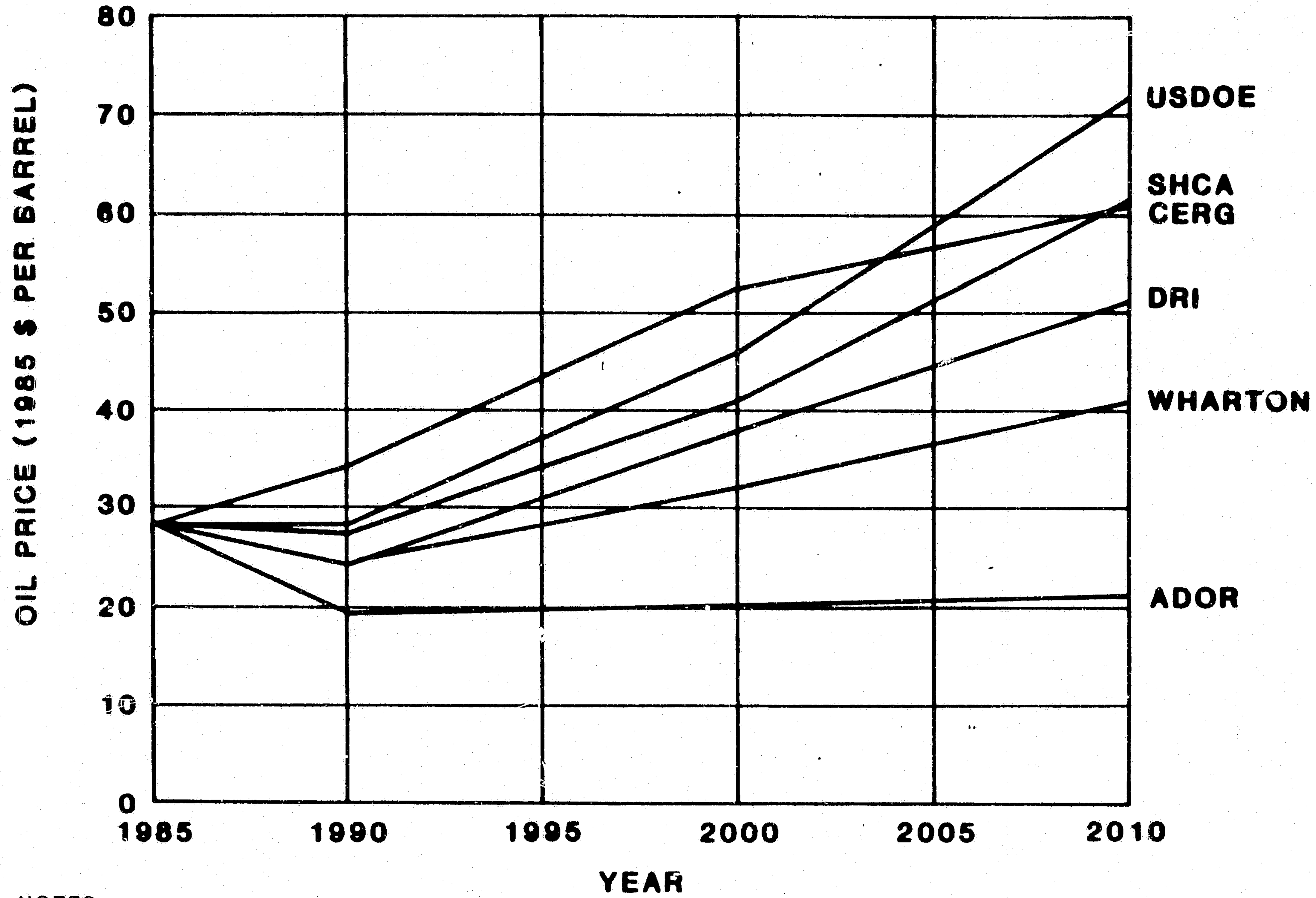


RAILBELT RETIREMENT SCHEDULE OF EXISTING RESOURCES AND FORECAST CAPACITY REQUIREMENTS
2000
1500
1000
500
0
MW
PEAK DEMAND PLUS RESERVE
PEAK DEMAND
EXISTING RESOURCES NET OF RETIREMENTS
1985
1990
1995
2000
2005
2010
2015
2020
YEAR
EXHIBIT 13

WORLD OIL PRICE FORECASTS



NOTES

USDOE:	U.S. Department of Energy (1985)
SHCA:	Sherman H. Clark Associates (1985)
CERG:	Cambridge Energy Research Group (1985)
DRI:	Data Resources Inc. (1985)
WHARTON:	Wharton Econometrics (1985)
ADOR:	Alaska Department of Revenue (1985)
	ADOR extrapolated from 2002.

EXHIBIT 14

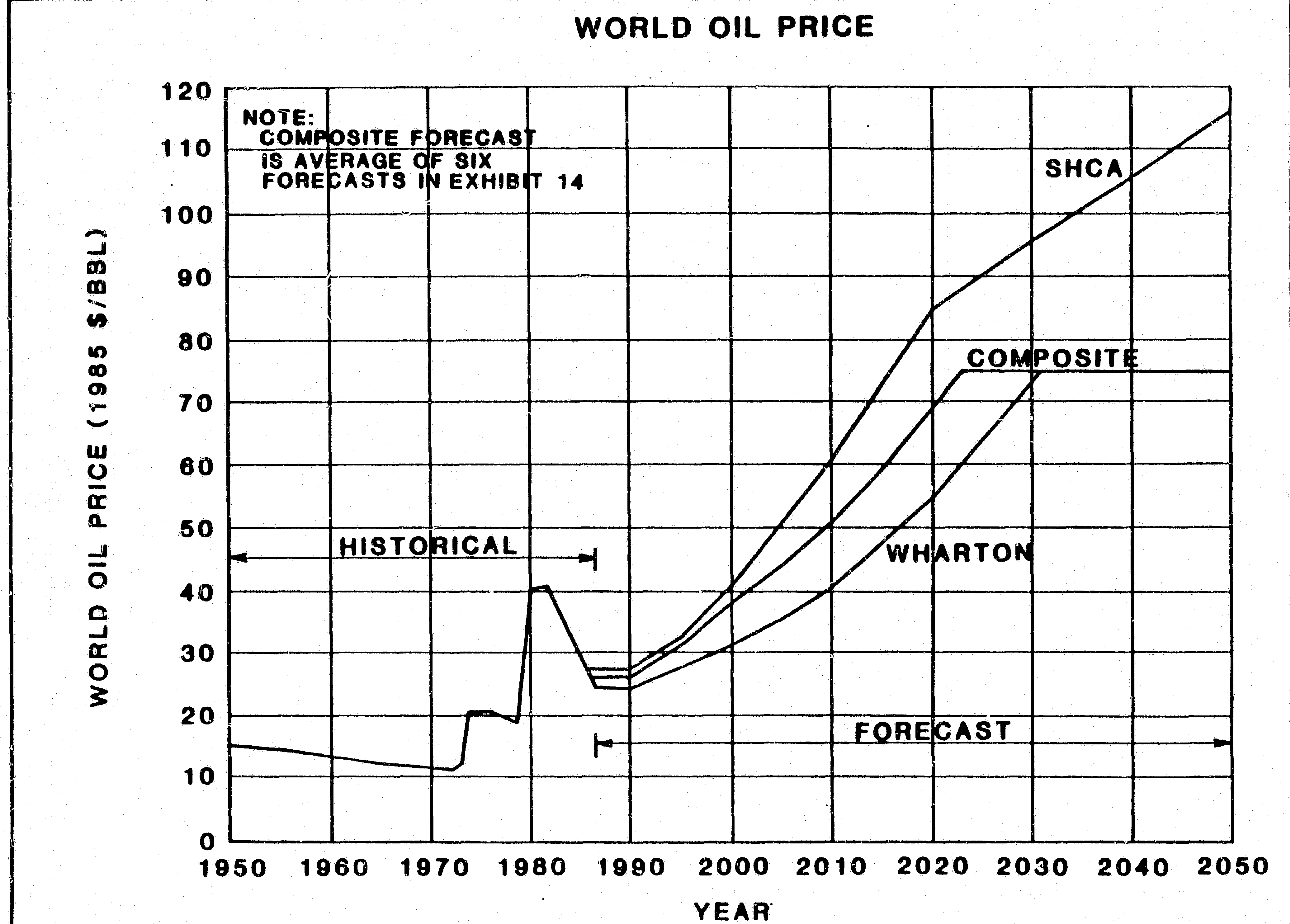

WORLD OIL PRICE
NOTE:
COMPOSITE FORECAST
IS AVERAGE OF SIX
FORECASTS IN EXHIBIT 14
SHCA
COMPOSITE
WHARTON
HISTORICAL
FORECAST
WORLD OIL PRICE (1985 $/BBL)
0
10
20
30
40
50
60
70
80
90
100
110
120
1950
1960
1970
1980
1990
2000
2010
2020
2030
2040
2050
YEAR

EXHIBIT 15

COOK INLET NATURAL GAS PRICE FORECAST
(COMPOSITE OIL PRICE)

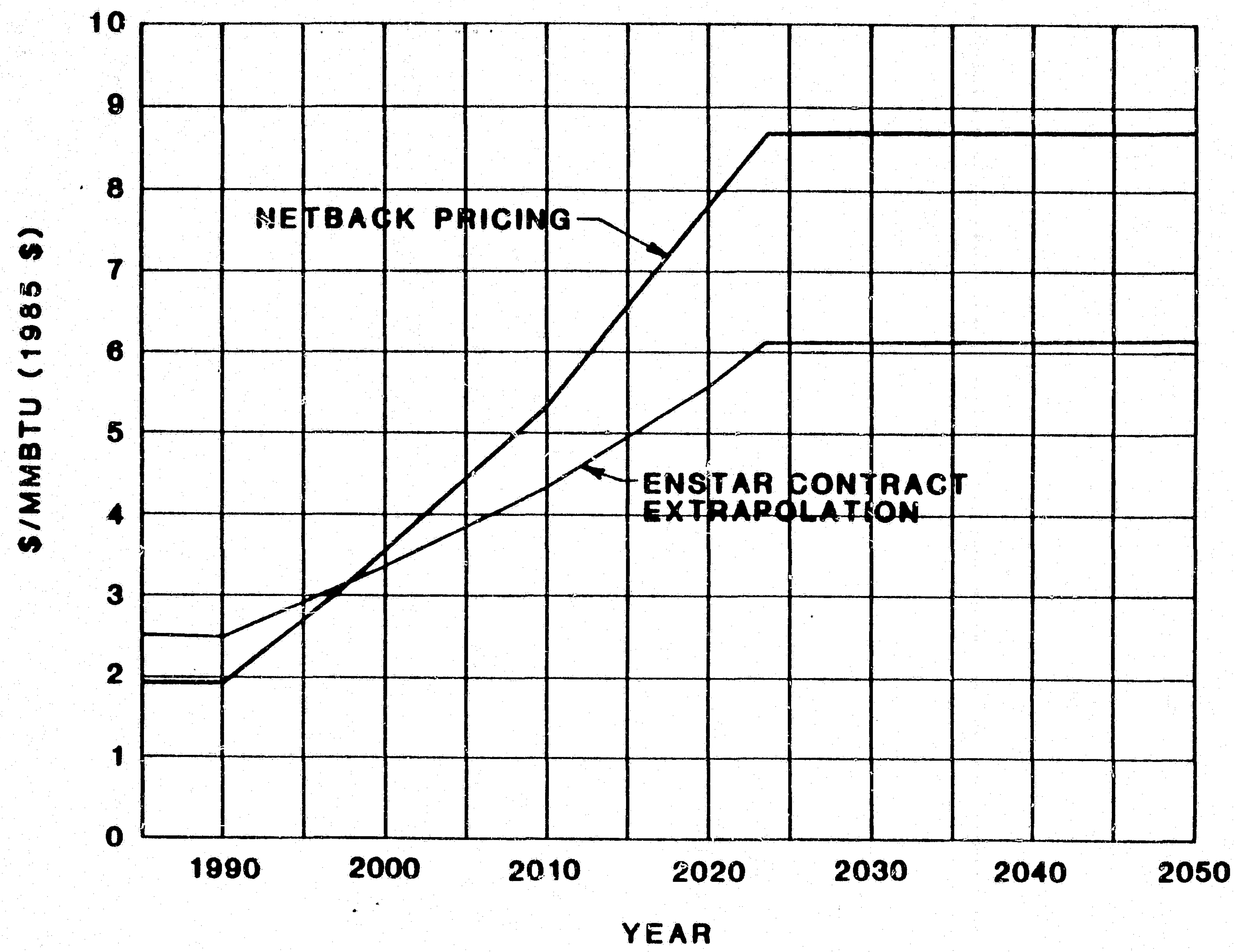


EXHIBIT 16

ASSUMPTIONS FOR COOK INLET NATURAL GAS AVAILABILITY

TOTAL SUPPLY		**8.0 TCF**
PROVEN RESERVES	4.5 TCF	
MEAN ESTIMATE OF UNDISCOVERED RESOURCES	3.5 TCF	
CURRENT ANNUAL DEMAND		**.2 TCF**
LNG EXPORT	60 BCF	
AMMONIA/UREA	55 BCF	
FIELD OPERATIONS, ENSTAR RETAIL, MILITARY, MISC.	50 BCF	
ELECTRIC GENERATION	35 BCF	

EXHIBIT 17

ESTIMATE OF UNDISCOVERED GAS RESOURCES IN PLACE FOR THE COOK INLET BASIN

PROBABILITY THAT QUANTITY IS AT LEAST THE GIVEN VALUE (%)	TRILLIONS OF CUBIC FEET
99	.47
95	.93
90	1.24
75	1.98
50	3.07
25	4.38
10	5.84
5	6.93
1	9.06
MEAN	3.36

SOURCE DIVISION OF GEOLOGICAL AND GEOPHYSICAL SURVEYS
DEPARTMENT OF NATURAL RESOURCES
STATE OF ALASKA, 1983

EXHIBIT 18

COAL PLANT COST ESTIMATES
(1985 $)

	APA (BELUGA)	MPP [1]	DIAMOND ALASKA
CAPACITY OF PLANT (NET-MW)	2X200	1X153	1X141
CAPITAL COST ($/kW) [2]	$2593	$2451	$2266
O & M COST (¢/kWh) [3]	1.3	0.7	1.8

[1] MATANUSKA POWER PROJECT

[2] COST BASED ON NET CAPACITY AND EXCLUDES FINANCING COSTS

[3] ASSUMES 80% CAPACITY FACTOR

<u>NOTE:</u> CAPITAL COST ESTIMATES FOR MPP PLANT AND DIAMOND ALASKA PLANT DO NOT INCLUDE TRANSMISSION LINE COSTS.

EXHIBIT 19

COAL COSTS
(1985 DOLLARS)

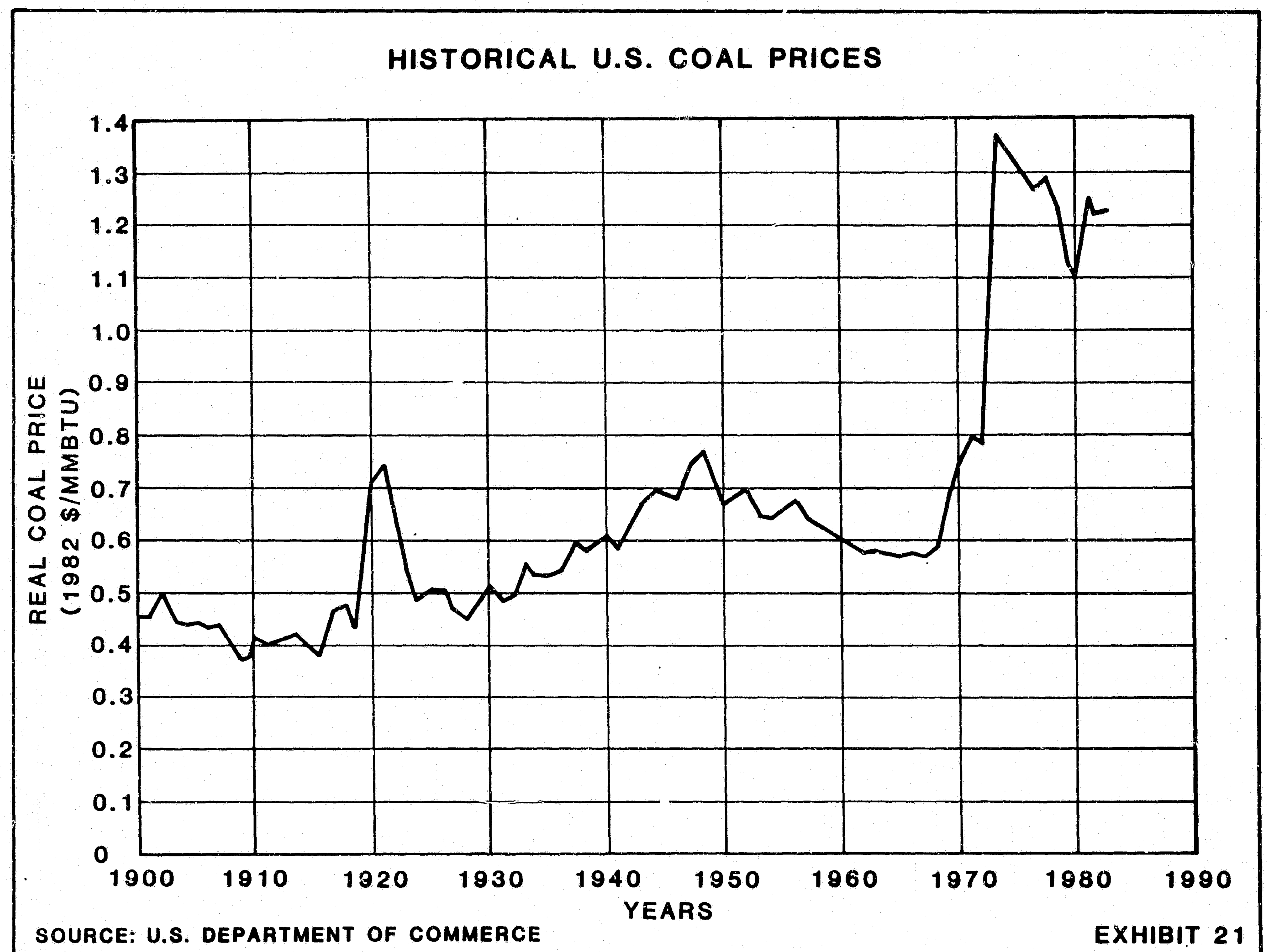
	COAL FIELD	
	BELUGA	NENANA
CURRENT COST		
MINE MOUTH		$1.45/MMBTU [1]
DELIVERED		$1.84/MMBTU
YEAR 2000 COST		
MINE MOUTH	$1.78/MMBTU	
DELIVERED		$2.31/MMBTU
AVERAGE REAL ESCALATION RATE BEYOND 2000	1.5%	1.5%
HISTORICAL RATES OF REAL COAL ESCALATION		
10YR. [2]		2.2–2.6%
20YR. [3]		2.0%

[1] ESTIMATED PRODUCTION COST FOR MINE EXTENSION

[2] GVEA AND FMUS EXPERIENCE

[3] GVEA EXPERIENCE

EXHIBIT 20

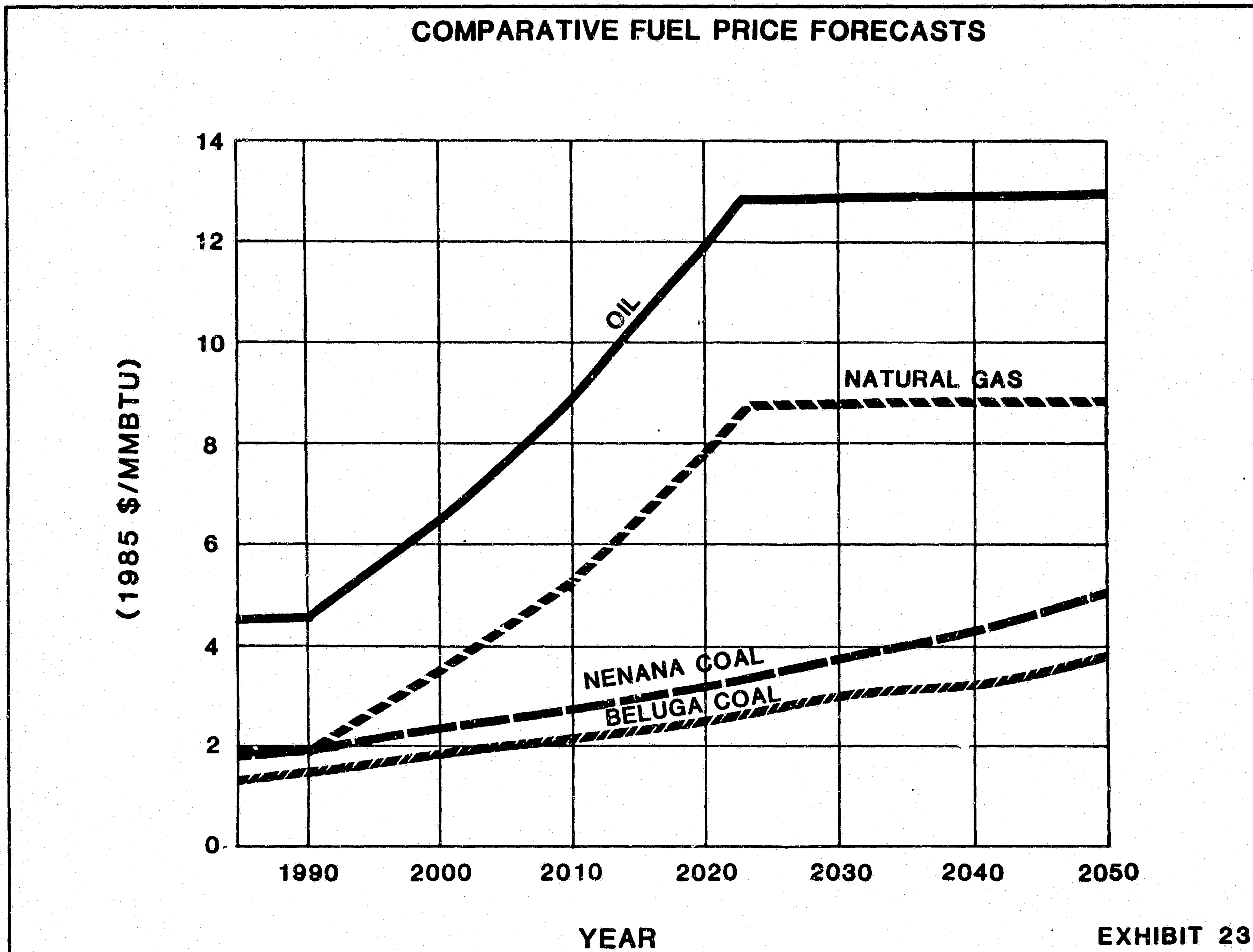

HISTORICAL U.S. COAL PRICES
REAL COAL PRICE (1982 $/MMBTU)
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
1900
1910
1920
1930
1940
1950
1960
1970
1980
1990
YEARS
SOURCE: U.S. DEPARTMENT OF COMMERCE
EXHIBIT 21

COAL PRICE FORECAST

(1985 DOLLARS)

YEAR	NENANA (DELIVERED) ($/MMBTU)	BELUGA (MINEMOUTH) ($/MMBTU)
1985	1.84	
1990	1.99	
1995	2.14	
2000	2.31	1.78
2010	2.69	2.19
2020	3.13	2.57
2030	3.64	3.08
2040	4.24	3.22
2050	4.94	3.74

EXHIBIT 22



COMPARATIVE FUEL PRICE FORECASTS
(1985 $/MMBTU)
14
12
10
8
6
4
2
0
OIL
NATURAL GAS
NENANA COAL
BELUGA COAL
1990
2000
2010
2020
2030
2040
2050
YEAR
EXHIBIT 23

SUSITNA CAPITAL COST
(JANUARY 1985 $ x 10^6)

ITEM	WATANA STAGE I	DEVIL CANYON STAGE II	WATANA STAGE III	TOTAL
CONSTRUCTION COSTS	1961	1081	1025	4067
CONTINGENCY	275	159	147	581
SUBTOTAL	2236	1240	1172	4648
LICENSING, ENGINEERING AND ADMINISTRATION	446	154	147	747
TOTAL PROJECT COST	2682	1394	1319	5395

EXHIBIT 24

FINANCING REQUIREMENTS
SUSITNA HYDROELECTRIC PROJECT
(MILLIONS OF DOLLARS)

	WATANA I	DEVIL CANYON	WATANA II	TOTAL
January 1985 Costs...............	2,561 (1)	1,394	1,321	5,276
Inflation (2)...................	1,866	1,935	3,542	7,343
Subtotal......................	4,427	3,329	4,863	12,619
Debt Service Reserve Fund........	698	546	686	1,930
Working Capital Fund.............	180	180	160	520
Discount and Financing Expenses..	222	174	219	615
Interest During Construction (3).	2,525	2,240	1,988	6,753
Subtotal......................	8,052	6,469	7,916	22,437
Less Interest Earnings (4).......	(648)	(669)	(616)	(1,933)
Total Bond Issue.................	7,404	5,800	7,300	20,504

1_/ Includes licensing and other development costs for both Watana and Devil Canyon. Does not include costs incurred prior to Fiscal Year 1986.
2_/ Based on an assumed average annual inflation rate of 5.5 percent.
3_/ Interest costs based on an assumed 9.0 percent interest rate.
4_/ Assumes a reinvestment rate of 10.0 percent.

BOND ISSUE SUMMARY
SUSITNA HYDROELECTRIC PROJECT
(MILLIONS OF DOLLARS)

YEAR	WATANA I NOMINAL DOLLARS	WATANA I 1985 DOLLARS 1/	DEVIL CANYON II NOMINAL DOLLARS	DEVIL CANYON II 1985 DOLLARS 1/	WATANA III NOMINAL DOLLARS	WATANA III 1985 DOLLARS 1/	TOTAL NOMINAL DOLLARS	TOTAL 1985 DOLLARS
1991 2/	1,000	725	---	---	---	---	1,000	725
1992	1,000	687	---	---	---	---	1,000	687
1993	---	---	---	---	---	---	---	---
1994	1,000	618	---	---	---	---	1,000	618
1995	1,200	703(3)	500	293	---	---	1,700	996
1996	1,104	613(3)	500	277	---	---	1,604	890
1997	1,500	789	---	---	---	---	1,500	789
1998	800	299	500	249	---	---	1,100	548
1999	---	---	---	---	---	---	---	---
2000	---	---	1,000	448	---	---	1,000	448
2001	---	---	1,000	425	---	---	1,000	425
2002	---	---	1,000	402	---	---	1,000	402
2003	---	---	1,300	496	---	---	1,300	496
2004	---	---	---	---	---	---	---	---
2005	---	---	---	---	---	---	---	---
2006	---	---	---	---	1,000	325	1,000	325
2007	---	---	---	---	1,000	308	1,000	308
2008	---	---	---	---	1,500	438	1,500	438
2009	---	---	---	---	1,500	415	1,500	415
2010	---	---	---	---	1,500	393	1,500	393
2011	---	---	---	---	500	124	500	124
2012	---	---	---	---	300	71	300	71
	7,404	4,434	5,800	2,590	7,300	2,074	20,504	9,098
Average Annual Issue (1991-2012)							932	413

1_/ Based on an assumed average annual inflation rate of 5.5 percent.

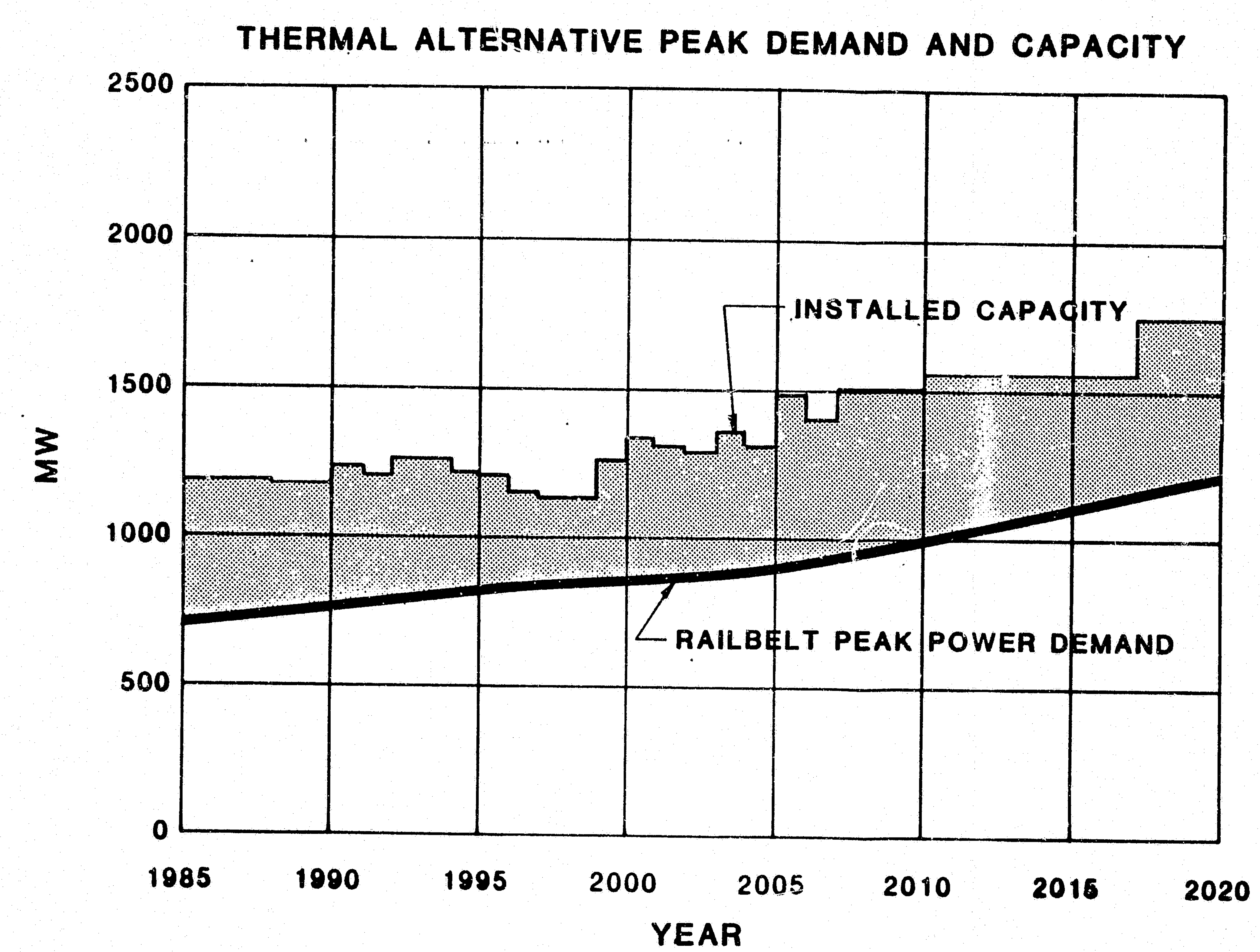
2_/ Expenditures incurred prior to 1991 are assumed to be funded through continuing State appropriations.

3_/ Includes issues of $200,000,000 and $104,000,000 for 1995 and 1996, respectively for 345 kV transmission upgrade.

THERMAL EXPANSION PLAN

YEAR	CAPACITY ADDITIONS (MW)				
	HYDRO-ELECTRIC	COAL FIRED STEAM TURBINE	GAS FIRED COMBUSTION TURBINE	GAS FIRED COMBINED CYCLE	OIL FIRED INTERNAL COMBUSTION
1985			45		2.5
1986					2.5
1987					
1988					
1989					
1990	90				2.5
1991					
1992			87		
1993					
1994					
1995					
1996					
1997					
1998					
1999		400			
2000			87		
2001					
2002					
2003			87		
2004					
2005		200			
2006					
2007		200	174		
2008					
2009			87		
2010		200			
2011					
2012					
2013					
2014					
2015					
2016					
2017			174		
2018					
2019					
2020					
2021			87		
2022					
2023					
2024					
2025		200			
	90	1200	828	0	7.5

Note: Gas-fired turbines installed after 1999 are for peaking operation.



THERMAL ALTERNATIVE PEAK DEMAND AND CAPACITY
2500
2000
1500
1000
500
0
MW
INSTALLED CAPACITY
RAILBELT PEAK POWER DEMAND
1985
1990
1995
2000
2005
2010
2015
2020
YEAR

EXHIBIT 28

SUSITNA EXPANSION PLAN

YEAR	CAPACITY ADDITIONS (MW)				
	HYDRO-ELECTRIC	COAL FIRED STEAM TURBINE	GAS FIRED COMBUSTION TURBINE	GAS FIRED COMBINED CYCLE	OIL FIRED INTERNAL COMBUSTION
1985			45		
1986					2.5
1987					2.5
1988					
1989					
1990	90				
1991					2.5
1992			87		
1993					
1994					
1995					
1996					
1997					
1998					
1999	300 1/				
2000					
2001					
2002			87		
2003					
2004			87		
2005	505 1/				
2006					
2007					
2008					
2009					
2010			87		
2011					
2012	726 1/				
2013					
2014					
2015					
2016					
2017			87		
2018					
2019			87		
2020					
2021					
2022					
2023			87		
2024					
2025					
	1,621	0	654	0	7.5

Note: Gas-fired turbines installed after 1999 are for peaking operation.

1_/ December/January Dependable Capacity

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EXHIBIT 29

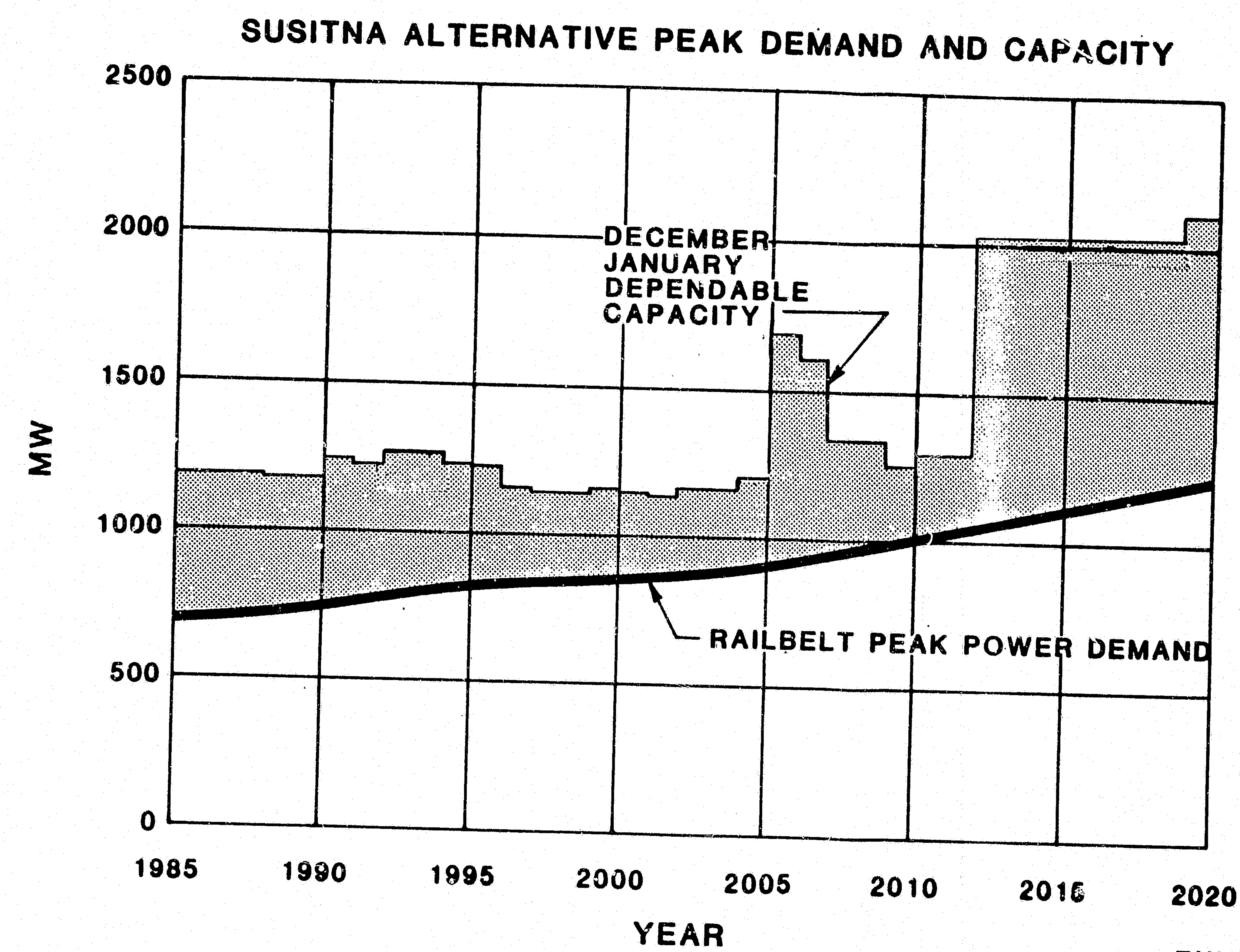
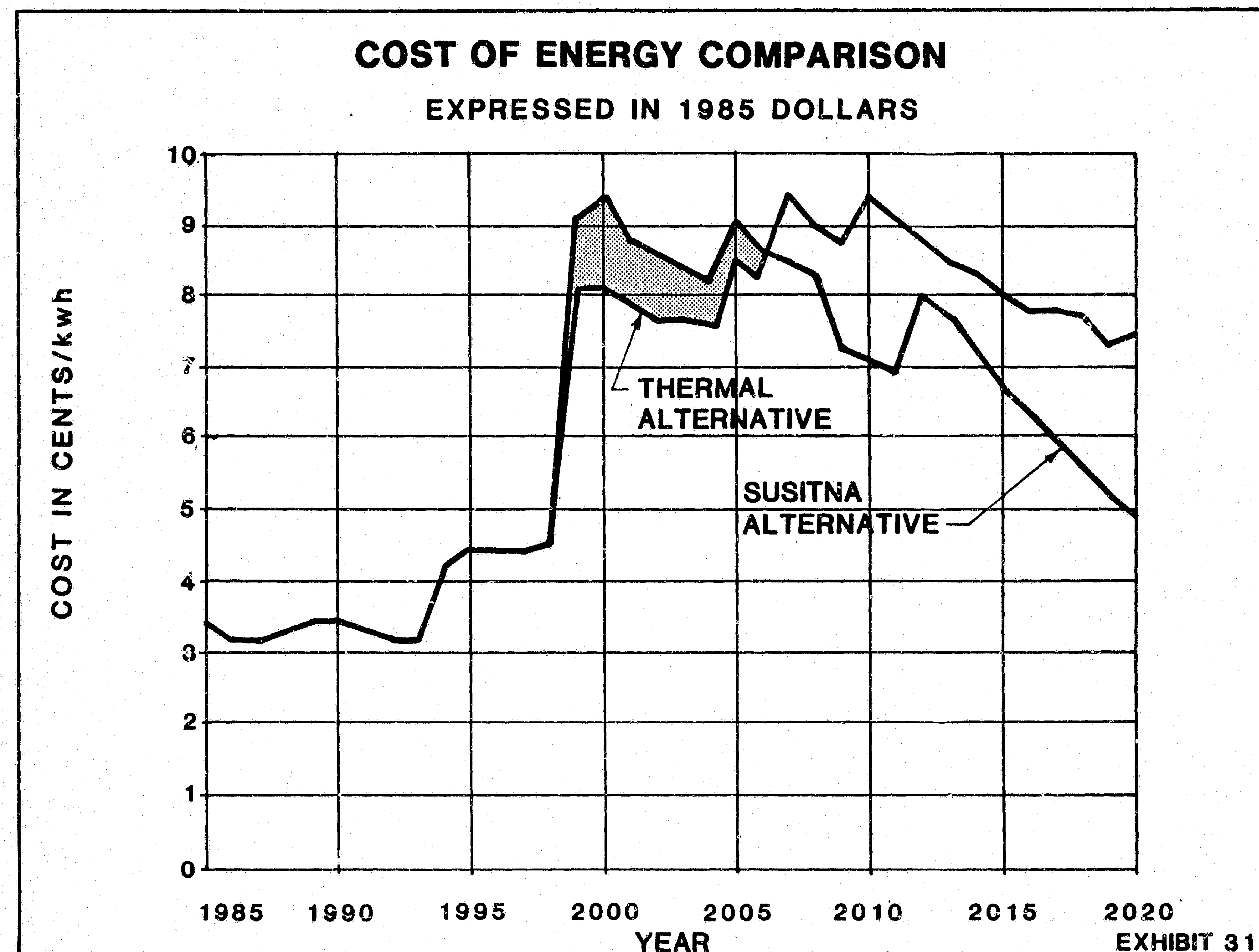

SUSITNA ALTERNATIVE PEAK DEMAND AND CAPACITY
2500
2000
1500
1000
500
0
MW
DECEMBER
JANUARY
DEPENDABLE
CAPACITY
RAILBELT PEAK POWER DEMAND
1985
1990
1995
2000
2005
2010
2015
2020
YEAR

EXHIBIT 30


COST OF ENERGY COMPARISON
EXPRESSED IN 1985 DOLLARS
COST IN CENTS/kwh
10
9
8
7
6
5
4
3
2
1
0
1985
1990
1995
2000
2005
2010
2015
2020
YEAR
THERMAL ALTERNATIVE
SUSITNA ALTERNATIVE
EXHIBIT 31

REAL COST OF ENERGY COMPARISON
(1985 DOLLARS)

YEAR	THERMAL ALTERNATIVE ¢/KWH	SUSITNA ALTERNATIVE ¢/KWH
1985	3.4	3.4
1986	3.2	3.2
1987	3.2	3.2
1988	3.3	3.3
1989	3.4	3.4
1990	3.4	3.4
1991	3.3	3.3
1992	3.2	3.2
1993	3.2	3.2
1994	4.2	4.2
1995	4.4	4.4
1996	4.4	4.4
1997	4.4	4.4
1998	4.5	4.5
1999	8.1	9.1
2000	8.1	9.4
2001	7.9	8.8
2002	7.7	8.6
2003	7.7	8.4
2004	7.6	8.2
2005	8.5	9.1
2006	8.3	8.7
2007	9.4	8.5
2008	9.0	8.2
2009	8.8	7.3
2010	9.4	7.1
2011	9.1	6.9
2012	8.8	8.0
2013	8.5	7.7
2014	8.3	7.2
2015	8.0	6.7
2016	7.8	6.3
2017	7.8	5.9
2018	7.7	5.6
2019	7.3	5.2
2020	7.4	4.9

NOTE - COST IS PRODUCTION COST, AND EXCLUDES DISTRIBUTION AND ADMINISTRATION COSTS.

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EXHIBIT 32

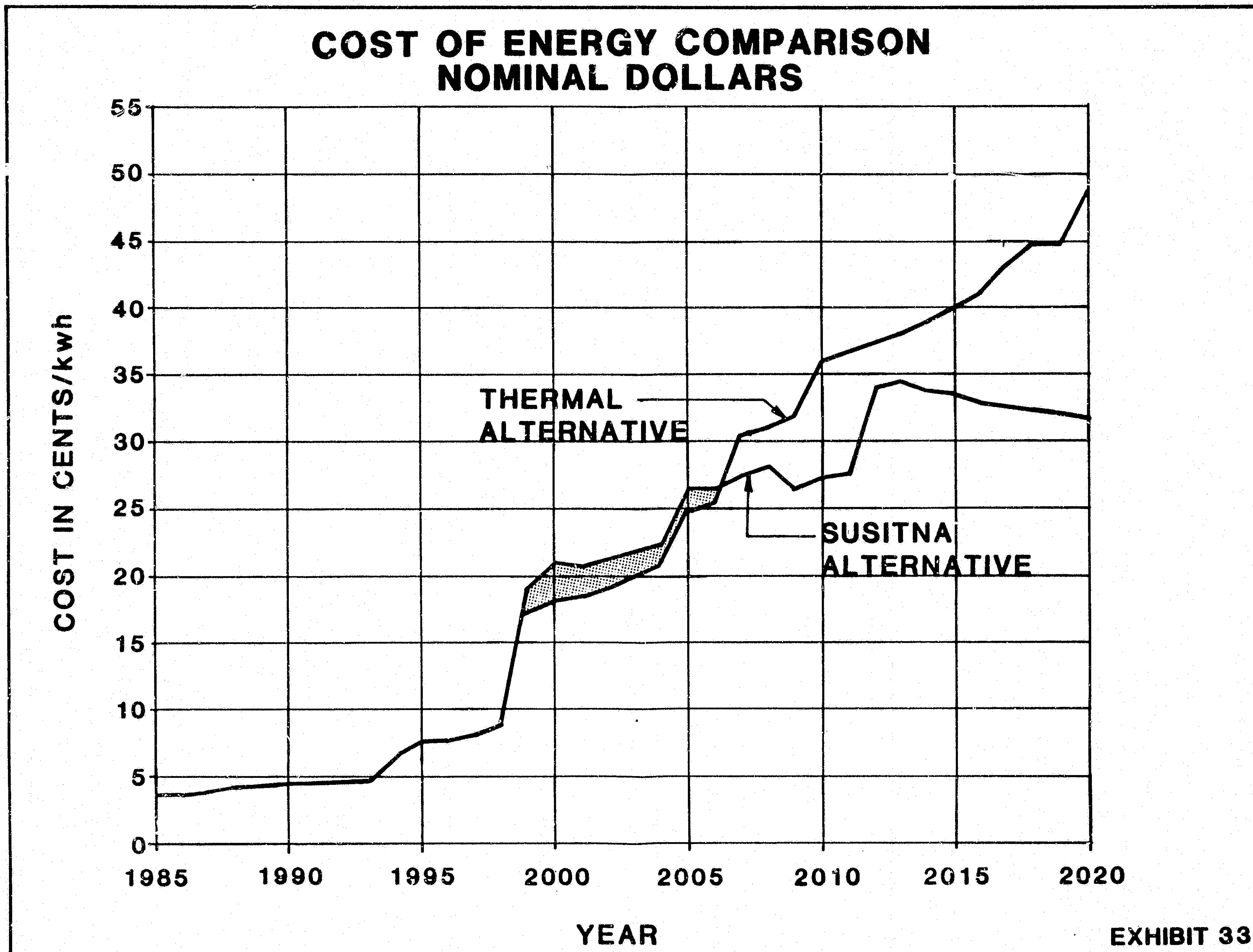
COST OF ENERGY COMPARISON
NOMINAL DOLLARS
COST IN CENTS/kwh
YEAR
THERMAL ALTERNATIVE
SUSITNA ALTERNATIVE
0
5
10
15
20
25
30
35
40
45
50
55
1985
1990
1995
2000
2005
2010
2015
2020

EXHIBIT 33

COST OF ENERGY COMPARISON
(NOMINAL DOLLARS)

YEAR	THERMAL ALTERNATIVE ¢/KWH	SUSITNA ALTERNATIVE ¢/KWH
1985	3.4	3.4
1986	3.4	3.4
1987	3.6	3.6
1988	3.9	3.9
1989	4.2	4.2
1990	4.4	4.4
1991	4.5	4.5
1992	4.7	4.7
1993	4.9	4.9
1994	6.8	6.8
1995	7.6	7.6
1996	7.9	7.9
1997	8.4	8.4
1998	9.0	9.0
1999	17.2	19.3
2000	18.1	20.3
2001	18.7	20.7
2002	19.2	21.4
2003	20.2	21.9
2004	20.9	22.6
2005	24.9	26.6
2006	25.4	26.7
2007	30.4	27.6
2008	31.0	28.2
2009	31.9	26.5
2010	36.0	27.2
2011	36.7	27.7
2012	37.4	34.0
2013	38.1	34.4
2014	39.0	33.9
2015	40.0	33.4
2016	41.2	32.9
2017	43.3	32.6
2018	44.9	32.9
2019	44.9	32.1
2020	48.5	31.6

NOTE - COST IS PRODUCTION COST, AND EXCLUDES DISTRIBUTION AND ADMINISTRATION COSTS.

POWER DEVELOPMENT FUND
(NOMINAL DOLLARS)

Year	ANNUAL COST: THERMAL ALTERNATIVE ($Mil)	ANNUAL COST: SUSITNA ($Mil)	CONTRIBUTIONS TO POWER DEVELOPMENT FUND: STATE APPROPRIATION ($Mil)	CONTRIBUTIONS TO POWER DEVELOPMENT FUND: BOND PROCEEDS ($Mil)	POWER DEVELOPMENT FUND PAYOUT ($Mil)	POWER DEVELOPMENT FUND BALANCE 1/ ($Mil)
1985	121	121	100		16.8	83.2
1986	124	124	118.7		28.0	181.9
1987	131	131			32.6	165.9
1988	145	145			39.3	141.3
1989	159	159			85.5	86.8
1990	167	167			91.0	0
1991	176	176		239.6		251.3
1992	187	187				276.4
1993	200	200				304.1
1994	286	286				334.5
1995	321	321				367.9
1996	336	336				404.7
1997	361	361				445.2
1998	390	390				489.7
1999	755	846			91	443.3
2000	802	900			98	384.8
2001	834	926			92	326.8
2002	868	969			101	253.5
2003	923	1,001			78	197.1
2004	962	1,043			81	131.8
2005	1,159	1,239			81	60.1
2006	1,212	1,275			63	0
2007	1,489	1,353				
2008	1,555	1,415				
2009	1,642	1,364				
2010	1,899	1,431				
2011	1,967	1,487				
2012	2,042	1,857				
2013	2,117	1,911				
2014	2,205	1,914				
2015	2,302	1,919				
2016	2,409	1,925				
2017	2,577	1,941				
2018	2,722	1,996				
2019	2,769	1,978				
2020	3,044	1,985				
			218.7	239.6	685 2/	

1/ At end of year. Assumes interest retention at 10 percent.
2/ Excludes costs incurred prior to 1991.

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EXHIBIT 35

SUSITNA HYDROELECTRIC PROJECT ENERGY COSTS

YEAR	ENERGY COST[1/] (Nominal) ¢/KWH	(1985 Dollars) ¢/KWH
1999	28.3	13.4
2000	29.8	13.4
2001	29.7	12.6
2002	29.6	11.9
2003	29.5	11.2
2004	29.4	10.6
2005	27.6	9.5
2006	28.1	9.1
2007	28.0	8.6
2008	27.8	8.1
2009	26.9	7.4
2010	26.2	6.9
2011	25.7	6.4
2012	35.5	8.4
2013	35.9	8.0
2014	35.3	7.5
2015	34.7	7.0
2016	34.1	6.5
2017	33.4	6.0
2018	32.8	5.6
2019	32.2	5.2
2020	31.7	4.9

1/ Includes all associated transmission line costs. Energy cost is delivered cost to Railbelt utilities. Inflation is assumed at 5.5 percent.

ECONOMIC SENSITIVITY ANALYSES

Case	Load Forecast	Gas Availability	Gas Price	Other	Present Worth of System Costs (million $)			Benefit/Cost Ratio
					Without Susitna	With Susitna	Net Benefits	
Base	Composite	limit 2000	Composite - net back	--	7,158	4,823	2,335	1.48
A	Composite	limit 2000	Composite - net back	Construction[1]	7,158	5,137	2,021	1.39
B	Composite	limit 2000	Composite - net back	Discount Rate[2]	5,329	4,168	1,161	1.28
C	Composite	limit 2000	Composite - net back	Zero Coal[3]	6,164	4,820	1,344	1.28
D	Composite	unlimited	Composite - net back	--	7,105	4,813	2,292	1.48
E	SHCA	limit 2000	SHCA - net back	--	7,720	5,527	2,193	1.40
F	SHCA	limit 2000	SHCA - net back	Construction[1]	7,720	5,841	1,879	1.32
G	SHCA	limit 2000	SHCA - net back	Discount Rate[2]	5,812	4,611	1,201	1.26
H	SHCA	limit 2000	SHCA - net back	Zero Coal[3]	6,393	5,524	869	1.16
I	SHCA	unlimited	SHCA - net back	--	7,632	5,400	2,232	1.41
J	Wharton	limit 2000	Wharton - net back	--	6,884	5,148	1,736	1.34
K	Wharton	unlimited	Wharton - Enstar	Zero Coal[3]	5,754	4,984	770	1.15
L	Wharton	limit 2010	DOR - Enstar	--	3,905	4,712	(807)	0.83

1/ Construction cost overrun for Watana Stage I of 15%.

2/ Discount Rate of 4.5%.

3/ Coal prices with no real escalation.

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EXHIBIT 37

FINANCIAL SENSITIVITY ANALYSES

Case	Load Forecast	Gas Availability	Gas Price	Other	Power Development Fund[2] State Contribution (Million Nominal $)	Power Development Fund[2] Payout (Million Nominal $)
Base	Composite	limit 2000	Composite - net back	---	218.7	685
E	SHCA	limit 2000	SHCA - net back	---	218.7	596
J	Wharton	limit 2000	SHCA - net back	---	707.3	2,208
K	Wharton	unlimited	Wharton - Enstar	Zero Coal[1]	850.5	4,147
L	Wharton	limit 2010	DOR - Enstar	---	2,160.0	12,570

1/ Coal price with no real escalation.

2/ Assumes interest retention in Power Development Fund.

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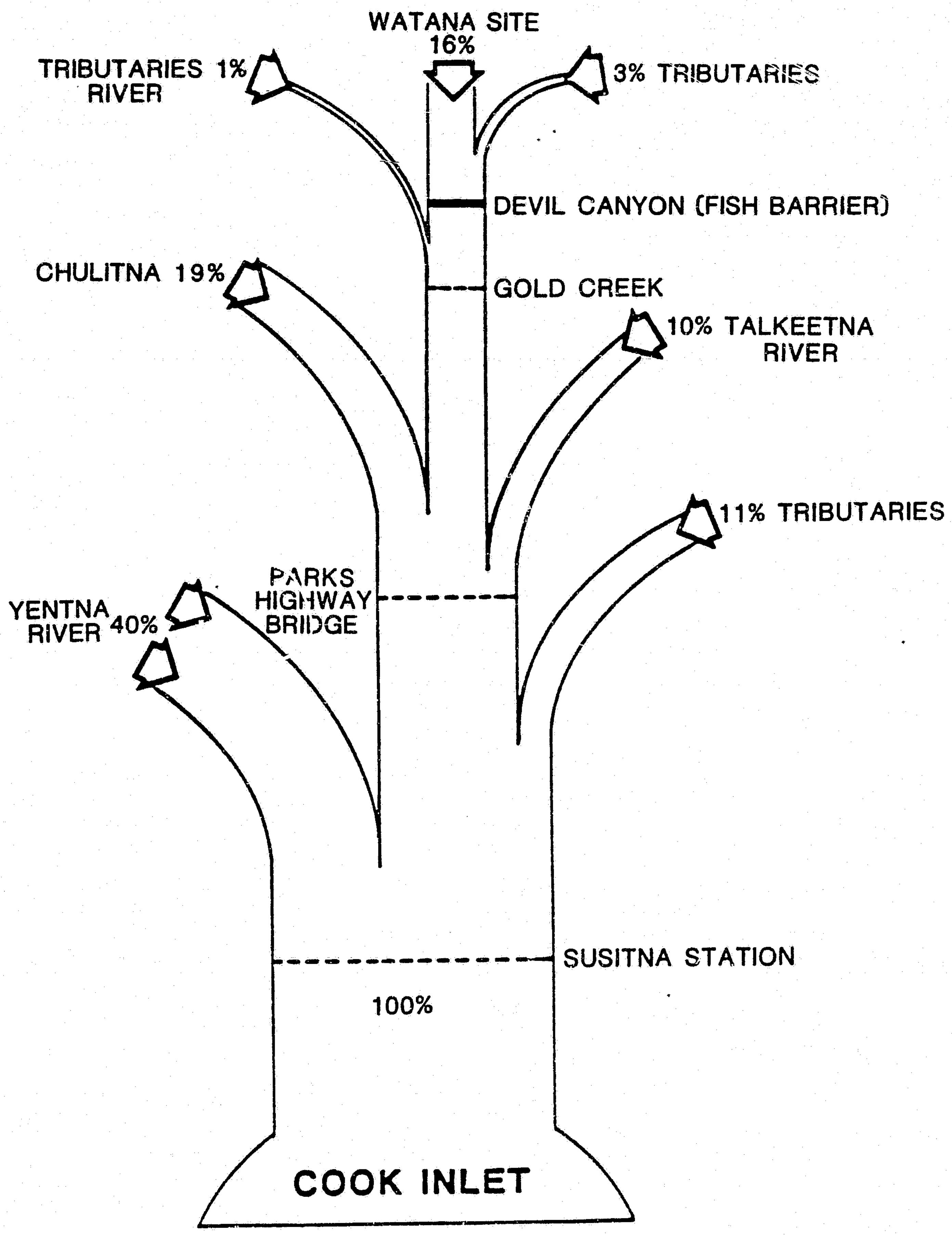
EXHIBIT 38

SUSITNA RIVER FLOW



Percentages indicate streams' contribution to total Susitna River flow from Watana Dam Site to Cook Inlet.

EXHIBIT 39

ENVIRONMENTAL FLOW REQUIREMENT CASE E-VI

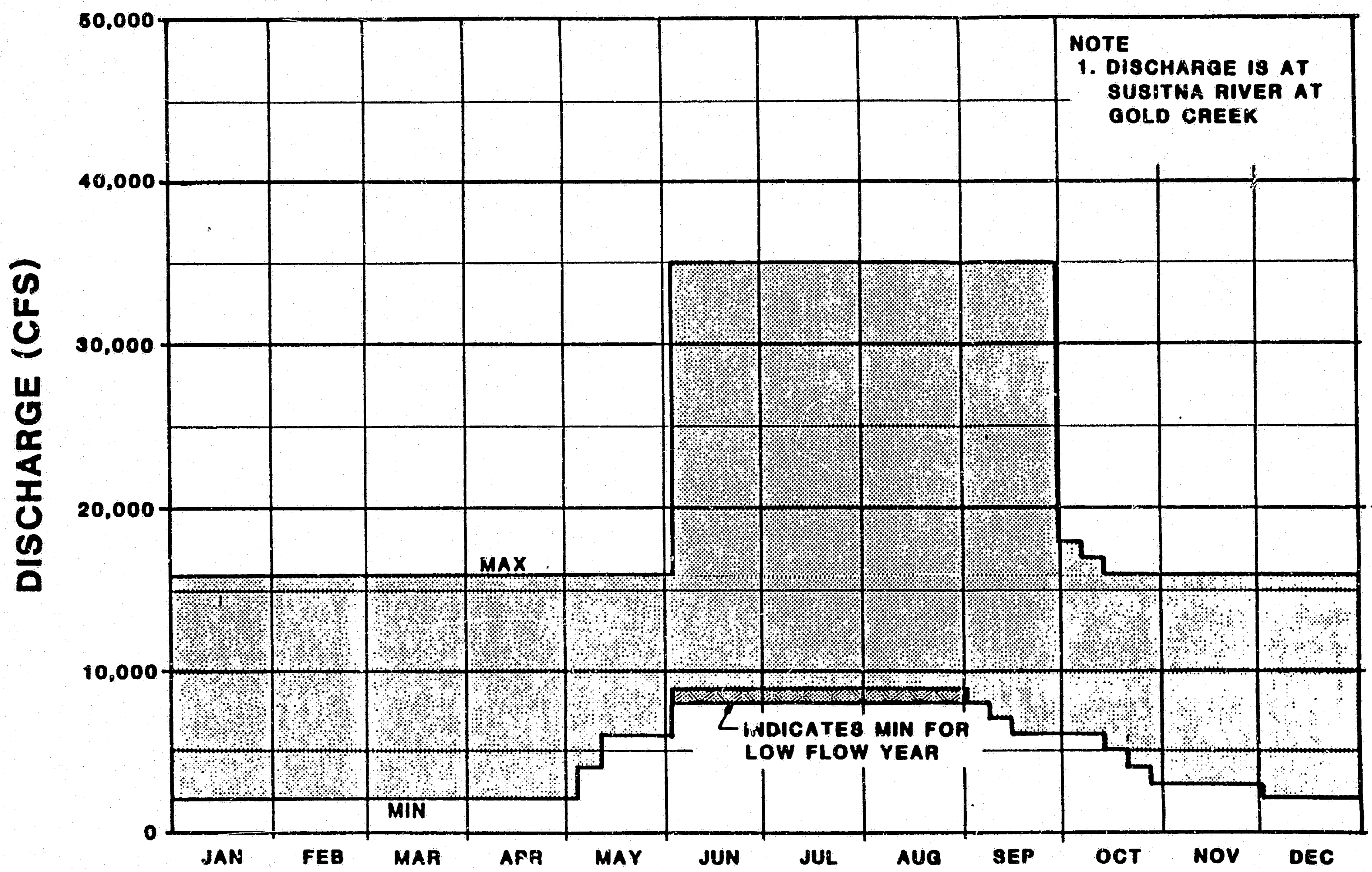


EXHIBIT 40