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SUSITNA HYDROELECTRIC PROJECT

ECONOMIC AND FINANCIAL UPDATE

SEPTEMBER 1983

HARZA-EBASCO
SUSITNA JOINT VENTURE

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

ECONOMIC
AND
FINANCIAL UPDATE

SEPTEMBER 1983

SUBMITTED BY

HARZA-EBASCO
SUSITNA JOINT VENTURE

TO THE

ALASKA POWER AUTHORITY

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1.0 INTRODUCTION

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1.1 INTRODUCTION

An update of the Susitna Project has been accomplished. The study was conducted to assess the effect of oil prices and the corresponding outlook on the State's economy on the feasibility of the Susitna Project. The primary purposes of the update have been:

a. To provide an in-depth assessment c the economics of the project and the cost of power therefrom, and

b. To determine if the currently proposed project should be modified to suit the current economic and financial conditions.

In this Chapter, a brief review of the history of the Susitna Project is given. Then, the current status of the Project is described including the scope and methodology for this update; and, a short discussion of the oil price projections is provided. Finally, a synopsis of the contents of the report is given.

1.2 HISTORY AND CURRENT STATUS

The Susitna Project as presented in the FERC License Application consists of a two-dam development on the Susitna River at the Watana and Devil Canyon sites. The first development would be at Watana with 1020 MW of installed capacity and 3500 million kWh average annual energy production to be placed in service in 1993. The second development would be at Devil Canyon with 600 MW of installed capacity and 3500 million kWh average annual energy production to be placed in service in 2002.

The studies leading to the present concept began in 1948 by the U.S. Bureau of Reclamation. The Susitna Project was identified as a very attractive project because of its location midway between Anchorage and Fairbanks. Subsequently, the Department of the Interior and the U.S. Corps of Engineers performed numerous studies which resulted in the selection of the Watana and Devil Canyon dam sites as favorable for the development of the Upper Susitna River.

The Power Authority took over the studies of the Susitna Project, and completed a comprehensive feasibility study during the period 1980-1982. Based on that study, the Legislature directed the Power Authority to file a Federal Energy Regulatory Commission (FERC) License Application for the entire project and to begin design of the initial phase of the project (Watana).

The License Application was filed February 28, 1983, and was subsequently revised, as requested by the FERC. The revised License Application, which updated the future power demand forecast and the economic analysis, was accepted by the FERC for processing on July 29, 1983.

After filing the FERC License Application, the Power Authority Board expressed concerns regarding the State's ability to pay for the Susitna Project. Also, questions were raised at the Alaska Senate State Affairs Committee Hearing in February 1983 regarding project economics and financial viability. Suggestions were made that a smaller-scale project might better suit current conditions. Governor Sheffield through the Power Authority directed that an assessment of crucial assumptions affecting project feasibility be conducted.

This September 1983 update is designed to respond to the concerns expressed in the State. Key variables affecting project economics and financing have been reviewed and revised where appropriate. Exhibit 1.1 provides the basic data, assumptions, and results developed from this update. The exhibit has been prepared in the form and detail directed by the Power Authority.

Apart from the economic and financial update, parallel engineering and environmental studies have been in progress providing further refinements and improvements in project design and mitigation of adverse impacts. Specific results of these refinements have been incorporated in the updated studies.

1.3 SCOPE AND METHODOLOGY AND OIL PRICE SCENARIOS

The update has been accomplished starting with oil price projections because the State's economy and the electric power demand are linked to oil prices. Oil prices directly affect State revenues and the State's ability to finance the project.

In April 1983 when the License Application revision began, a methodology was developed which permitted tracing the price of oil through all pertinent variables and parameters including the electric power demand, alternative costs of fuel, and financing capability of the State. This methodology is briefly described in Chapter 2 of this report.

While the economic and financial forecast has been specifically tied to the future price of oil, the oil price projection itself is subject to a great deal of uncertainty since there is a wide variation among experts in forecasting the trajectory of oil prices. Because of the implications on the feasibility of the Susitna Project, several oil price forecasts have been considered and economic and cost of power analyses have been performed for two forecasts in this update.

The Alaska Department of Revenue (DOR) makes petroleum revenue projections to produce a probability distribution of future revenue. Estimates of future revenues are made on a quarterly basis and are used by the State Office of Management and Budget in developing budgets. Because the revenue projections are used in the State budgeting process, the Board of Directors of the Alaska Power Authority designated the DOR Mean oil price forecast for use in the evaluation of the project in this update. The DOR Mean forecast is from the DOR June 1983 Quarterly Report.

In the July 1983 FERC License Application, the Sherman H. Clark Associates - No Supply Disruption (SHCA-NSD) forecast, developed by an energy consultant, was adopted as the Reference Case. To permit establishing a link between the License Application and this September 1983 Update, an analysis based on the SHCA-NSD oil price forecast is also included. The DOR Mean and SHCA-NSD oil price projections are summarized in Table 1.1.

Table 1.1

OIL PRICE SCENARIOS USED IN THE UPDATE
(in 1983 $ per barrel)

	DOR Mean	SHCA-NSD
1983	28.95	28.95
1993	25.13	30.49
1999	27.45	36.40
2010	32.42	50.39
Annual Growth 1983-1999 - %	-0.3	1.4
Annual Growth 1983-2010 - %	0.4	2.0

The published DOR forecasts extend to 1999. Beyond 1999, the DOR Mean oil prices have been extended at a growth rate of 1.5 percent annually. The annual growth rates shown in Table 1.1 are lower than the fiscal year 1983 Power Authority planning guideline of 2.5 percent per year growth in oil prices.

1.4 CONTENTS OF THIS REPORT

This report is organized into seven chapters. Chapter 2 provides a description of the electric power demand forecast. This Chapter has drawn largely from the work performed in connection with the July 1983 revision of the License Application. It introduces June 1983 DOR forecast of oil prices. Chapter 2 also provides a description of the computer models and the methodology used in tying the oil price forecasts to electric power demand forecasts, economic analysis and financial analysis.

Chapter 3 provides a description of the project contained in the FERC License Application. It summarizes the proposed refinements in design and cost estimates of the current Watana 2185 project which is the subject of another Harza-Ebasco Report "Susitna Hydroelectric Project, Review and Update of Conceptual Design" November 1983. The chapter describes the physical characteristics, cost estimates, and power and energy production of the Watana Project. This chapter also provides a review of the status of the environmental issues. LBB

Chapter 4 reviews and updates the non-Susitna generation alternatives which are attractive and could be competitive sources of generation. The costs and performance characteristics of these generation alternatives are updated and revised from previous studies to reflect the latest available information. The chapter also contains a summary description of the availability and cost of natural gas and coal for use in the fossil-fuel power plants.

Chapter 5 describes the various ways that the demands of the future electric power system can be met, cost effectively, with and without the Susitna Project. The sizes, types and number of powerplants and the installation schedules are developed. The annual costs of constructing, operating and maintaining each supply alternative are presented.

In Chapter 6, the economic and cost of power analyses are described. The economic analysis compares the alternative system expansion programs using a life cycle approach. A threshold analysis and sensitivity analysis of the key variables are also included in the analysis. The cost of power analysis identifies the wholesale cost of power with various levels of State equity contributions. In addition, the affordability of the Susitna Project is assessed by comparing the availability of capital for Susitna under various State operating budget levels with construction cash flow requirements.

Chapter 7 presents the alternative concepts of the Watana and Devil Canyon developments. The Chapter describes the Watana project with the reservoir lowered to elevations 2100, 2000, and 1900. The chapter then describes an improved mode of operation for the Susitna project that would provide greater reliability of service to the electric system and attendant economic benefits. Also, environmental implications related to the above changes are discussed. The economics of the Watana Development constructed to the various reservoir elevations and with different generation capacities are also discussed. The effect that lowering the Watana Dam has on the upfront State appropriation of part of the construction cost is illustrated by comparing the required State equity contribution for the Watana 2185 project with a lower Watana 2000 project.

1.5 ACKNOWLEDGEMENTS

The preparation of this report has been guided by the Power Authority staff, special assistants to the Power Authority Board of Directors, and by the Office of Management and Budget.

R.W. Beck & Associates, Inc. assisted Harza-Ebasco in the performance of the cost of power analysis.

GOVERNOR'S CHECKLIST
September 1983 Update
(January 1983 price level)

	1982 FEASIBILITY STUDY	REVISED FERC LICENSE APPLICATION (REFERENCE CASE)	SHCA-NSD UPDATE	SHCA-NSD THRESHOLD[a] (change)	DOR Mean UPDATE	DOR Mean THRESHOLD[a] (change)
Oil Price Forecast (b) - $/bbl						
1983	38 (c)	28.95	28.95	0	28.95	0.0
1993	46 (c)	30.49	30.49	-	25.13	-
1999	52 (c)	36.40	36.40	-	27.45	-
2010	65 (c)	50.39	50.39	-	33.35	-
2020	65 (c)	64.48	64.48	-26.86	37.62	0.0
Long Term Oil Price Growth - %/yr						
1983-1993	2.0	0.5	0.5	-	-1.4	-
1983-1999	2.0	1.4	1.4	-	-0.3	-
1983-2010	2.0	2.0	2.0	-	0.5	-
1983-2020	1.5	2.2	2.2	-1.5	0.7	0.0
Projection of Energy Generation - GWh/yr						
1983	3,402	3,027	3,088	-	3,088	-
1993	5,126	4,321	4,397	-	4,167	-
2010	8,414(d)	6,280	6,444	-	5,945	-
2020	---	8,039(d)	8,312(d)	(e)	7,505(d)	0.0
Long Term Load Growth Rate - %/yr						
1983-1993	4.2	3.6	3.6	-	3.0	-
1983-1999	2.4	2.7	2.7	-	2.5	-
1983-2020	--	2.7	2.7	(e)	2.4	0.0
Cook Inlet Gas Price Forecast (b) - $/MMBtu						
1993	3.2	3.02	3.02	-	2.45	-
1999	4.7	3.61	3.61	-	2.68	-
2010	6.2	5.00	4.43(f)	-1.46(g)	2.97(f)	0.0
2020	6.2	6.39	-	-	-	-
2050	6.2	9.05	-	-	-	-
Cook Inlet Gas Price Growth - %		Linked with oil price growth				
Cook Inlet Gas Availability Forecast	Assumed unlimited	Assumed unlimited	Available through 2006	(h)	Available through 2006	(h)
North Slope Gas Price Forecast (i) - $/MMBtu						
1993	NA	4.22	4.22	-	4.00	-
1999	NA	5.04	5.04	-	4.00	-
2010	NA	6.97	6.97	-	4.18	-
2020	NA	8.92	8.92	-	4.85	-
2050	NA	12.62	12.62	-5.04(g)	7.58	0.0
North Slope Gas Availability Forecast (f)	NA	Assumed unlimited	Available in 2007	(j)	Available in 2007	(j)

GOVERNOR'S CHECKLIST
September 1983 Update
(January 1983 price level)

	1982 FEASIBILITY STUDY	REVISED FERC LICENSE APPLICATION (REFERENCE CASE)	SHCA-NSD UPDATE	SHCA-NSD THRESHOLD (change)	DOR Mean UPDATE	DOR Mean THRESHOLD (change)
Nenana Coal Price Forecast (b) - $/MMBtu						
1983	1.9	1.72	1.72	-	1.80	-
1993	2.4	2.17	2.17	-	1.80	-
2010	3.1	2.57	2.57	-	1.80	-
2020	---	2.84	2.84	(h)	1.80	0.0
Nenana Coal Price Growth - %/yr						
1983-1993	2.4	2.3	2.3	-	0.0	-
1983-2010	1.8	1.3	1.3	-	0.0	-
1983-2020	---	1.2	1.2	(h)	0.0	0.0
Nenana Coal Availability Forecast	(k)	(k)	(k)	(h)	(k)	(h)
Beluga Coal Price Forecast (b) (l)-$/MMBtu						
1983	1.5	1.86	1.86	-	1.80	-
1993	2.0	2.17	2.17	-	1.80	-
2010	2.7	2.57	2.57	-	1.80	-
2020	---	2.84	2.84	(h)	1.80	0.0
Beluga Coal Price Growth - %/yr						
1983-1993	2.9	1.6	1.6	-	0.0	-
1983-2010	2.2	1.3	1.3	-	0.0	-
1983-2020	---	1.2	1.2	(h)	0.0	0.0
Beluga Coal Availability Forecast	Assumed	Unlimited	Unlimited	(m)	Unlimited	(m)
Real Discount Rate (%)	3.0	3.0	3.5	+1.9	3.5	+0.2
Real Interest Rate (%)	3.0	3.0	3.5	+12.0	3.5	+1.4
General Inflation Rate (%)	7.0	7.0	6.5	NA	6.5	0.0
Susitna Construction Cost - $ x 10^6						
Watana	3,805 (o)	3,750 (o)	3,338(p)	+50%	3,338(p)	+5%
Devil Canyon	1,535 (o)	1,620 (o)	1,554	(n)	1,554	0.0
Capital Cost Escalation Rate - % 1982 to 1985	: 1.1	0.0	0.0	(m)	0.0	0.0
1986 to 1992	: 1.0	0.0	0.0	(m)	0.0	0.0
1993 on	: 2.0	0.0	0.0	(m)	0.0	0.0

GOVERNOR'S CHECKLIST
September 1983 Update
(January 1983 price level)

	1982 FEASIBILITY STUDY	REVISED FERC LICENSE APPLICATION (REFERENCE CASE)	SHCA-NSD		DOR Mean	
			UPDATE	THRESHOLD (change)	UPDATE	THRESHOLD (change)
Project Timing						
Watana	1993	1993	1993	NA	1993	NA
Devil Canyon	2002	2002	2002	NA	2006	NA
Benefit/Cost Ratio	1.17	1.33	1.28	NA	1.03	NA
State Equity Contribution (1983 $ billions)	1.9 (q)(r)	1.9 (q)(r)	1.7/2.1 (s)	NA	1.5/2.3 (s)	NA
Wholesale Cost of Power (cents per kWh)	14.7 (r)	13.6 (r)	10.2/8.4 (s)	NA	11.6/7.6 (s)	NA
IRS Tax Exemption	Probably yes since interest rate is assumed to be 10%					

NA: Not Applicable

(a) The threshold point is that point for each variable at which the Susitna Project has a benefit/cost ratio equal to 1:00, holding all other variables constant. The column shows the amount of change which must occur in each variable before the threshold point is reached.

In determining the threshold points for prices of oil and natural gas, the values under the DOR Mean scenario are used, since the benefit-cost ratio for that scenario is 1.03 or very nearly 1.00.

(b) 1982 Feasibility Study fuel costs were inflated to January 1983 price level using the U.S. GNP index of 6.0%.

(c) Based on 2.0% average annual growth rate until 2010, and 0% thereafter as reported in February 1983 Exhibit D p. D-4-22.

(d) Last year of generation expansion planning studies.

(e) A large decrease of that variable would be required to arrive at the threshold value.

(f) Gas price in 2006, which was assumed to be the last year of Cook Inlet gas availability.

(g) Approximate. The threshold value would be greater.

(h) No threshold value, because of substitution possibilities.

(i) Forecast also represents prices of gas from some other source such as Cook Inlet, and reflect increased prices due to higher exploration and development costs and associated risks.

GOVERNOR'S CHECKLIST
September 1983 Update
(January 1983 price level)

(j) Unavailability of North Slope gas, when Cook Inlet gas is depleted, could cause major supply problems to the thermal alternatives. No threshold value is available.

(k) 1982 Feasibility Study up to 200 MW of coal-fired steam plant. Revised FERC License and 1983 Update up to 400 MW of coal-fired steam plant.

(l) Assume Beluga field developed for export market, but prices sold for local needs independent of opportunity price.

(m) Unavailability of Beluga coal could cause major supply disruption to the thermal alternatives.

(n) A large increase would be required to arrive at the threshold value.

(o) January 1982 costs escalated to January 1983 using a 4.3 percent factor.

(p) Construction cost for initial four-unit installation. Construction cost for six-unit installation is estimated at $3,432 million, or 2.8% higher.

(q) Inflated from 1982 to 1983 using U.S. GNP index of 6.0%.

(r) Coal expansion plan.

(s) Coal expansion plan/Gas and Coal expansion plan.

2.0 POWER MARKET FORECAST

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2.1 INTRODUCTION

This chapter presents an update of the power market forecasts which were described in Exhibit B of the FERC License Application. Electric power demand forecasts have been developed for the Railbelt market that will be served by the Susitna Project. The forecasts begin from the year 1983 and extend to 2010, a period during which resources of the Susitna Project will be developed.

The magnitude of the future power demand depends on a number of factors, the primary one being the price of oil which affects the revenue to the State and the State's economic activity. To account for a range of world oil price projections, demand forecasts are developed for the DOR-Mean and SHCA-NSD oil price scenarios. The SHCA-NSD scenario was used as the Reference Case for the License Application.

In addition to world oil price, the influence of energy conservation and the relative costs of alternative forms of energy are also important and have been factored into the forecasts.

The following sections describe the interconnected Railbelt market, the basic approach used to develop the forecasts, the variables and assumptions in the forecasts, and finally the results of the forecasts and their significance. A summary of the power market forecasts is given at the end of this Chapter. The resulting forecasts are then utilized in the development of the system expansion programs described in Chapter 5.

2.2 THE INTERCONNECTED RAILBELT MARKET

The Railbelt region contains two principal electrical load centers: the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area. These two load centers will comprise the interconnected Railbelt market when the Intertie currently under construction by the Alaska Power Authority is completed. The Glennallen Valdez load center is not planned to be interconnected nor to be served by the Susitna Project.

The existing transmission system of the Anchorage-Cook Inlet area extends north to Willow and consists of a network of 115-kV and 138-kV lines with interconnection to Palmer. The Fairbanks-Tanana system extends south to Healy over a 138-kV line. The Intertie which is being built by the Alaska Power Authority to connect Willow and Healy will operate initially at 138-kV. The existing transmission system in the Railbelt region is illustrated on Exhibit 2.1.

2.2.1 Anchorage-Cook Inlet Area

The Anchorage-Cook Inlet area has two municipal utilities, three rural electric cooperative associations (REAs), the Federal Power Administration, and two military installations, as follows:

- Municipality of Anchorage-Municipal Light & Power Department (AMLP)
- Seward Electric System (SES)
- Chugach Electric Association, Inc. (CEA)
- Homer Electric Association, Inc. (HEA)
- Matanuska Electric Association, Inc. (MEA)
- Alaska Power Administration (APAd)
- Elmendorf Air Force Base - Military
- Fort Richardson - Military

AMLP and CEA are the two principal utilities serving the Anchorage-Cook Inlet Area. All of these organizations, with the exception of MEA, have electrical generating facilities. MEA buys its power from CEA. HEA and SES have relatively small generating facilities that are used for standby operation. They also purchase power from CEA. The existing generation system is described in Chapter 5. The total installed capacity was 873 MW in 1982. The Anchorage-Cook Inlet area is almost entirely dependent on natural gas to generate electricity. About 92 percent of the total capacity is provided by gas-fired units. The remaining are hydroelectric units and oil-fired diesel units.

In 1982, the electricity generation by the Anchorage-Cook Inlet utilities was 2,446 GWh, with a peak demand of about 472 MW. Between 1976 and 1982, the demand has increased at an average annual growth rate of 7.1 percent.

2.2.2 Fairbanks-Tanana Valley Area

The Fairbanks-Tanana Valley area is currently served by an REA cooperative, a municipal utility, a university, and three military installations as follows:

- o Fairbanks Municipal Utilities System (FMUS)
- o Golden Valley Electric Association, Inc. (GVEA)
- o University of Alaska, Fairbanks
- o Eielson Air Force Base - Military
- o Fort Greeley - Military
- o Fort Wainwright - Military

Golden Valley Electric Association, Inc. and Fairbanks Municipal Utilities System own and operate generation, transmission, and distribution facilities. The University and military bases maintain their own generation and distribution facilities. Fort Wainwright is interconnected with GVEA and FMUS and is providing both utilities with secondary energy. The existing generation system is described in Chapter 5. The total installed capacity was 351 MW in 1982. A large portion of the total installed capacity consists of oil-fired combustion turbines (57 percent) and coal steam turbines (30 percent). The remaining capacity is provided by diesel units.

In 1982, the total energy generation, including purchases, of the utilities was 491 GWh, with a peak demand of 94 MW. The growth in the past six years has averaged less than one percent.

2.3 METHODOLOGY FOR POWER MARKET FORECAST

The power market forecast is based on broad econometric and end-use approaches rather than individual utility forecasts which were developed for their own generation planning. As in the FERC License Application, four computer models provided the methodology for developing the updated power market forecast and the subsequent assessment of alternatives. These models are the petroleum revenue model operated by the Alaskan Department of Revenue (DOR), the Man-in-the-Arctic Program (MAP) operated by the Institute of Social and Economic Research (ISER), the Railbelt Electric Demand (RED) model of Battelle Pacific Northwest, and the Optimized Generation Planning (OGP) model of General Electric Co. (GE). The relationship between the models and their principal input and output data are shown on Exhibit 2.2 which also shows the role of financial analysis in the selection of generation expansion plans.

In general, the petroleum revenue forecasting model produces alternative State revenue forecasts based upon petroleum price forecasts. MAP converts these revenue projections plus additional data into projections of economic conditions including population, housing, and employment. The RED model then uses the MAP model output plus additional data to produce an electricity load and peak demand forecast for the Railbelt Region. Results of the RED model plus investment, fuel, and operating cost data then are input to OGP to produce optimized generation expansion plans and cost of power estimates. A complete description of these models is presented in Exhibit B of the FERC License Application. A summary description is presented in the following paragraphs.

2.3.1 The Petroleum Revenue Forecasting Model

Petroleum revenues constitute approximately 85 percent of the incoming cash flows of the State of Alaska. For this reason, projections of the most important sources of State revenues are generated by a specialized model. The PETREV model generates 17-year State revenue forecasts based upon alternative world oil price forecasts.

PETREV is an economic accounting model that utilizes a probability distribution of possible values for each of the factors that affect State petroleum revenues to produce a range of possible State royalties and production taxes. The principal factors influencing the level of petroleum revenues are petroleum production rates, mainly on the North Slope, the market price of petroleum, and tax and royalty rates applicable to the wellhead value of petroleum.

Due to the many uncertainties involved in forecasting revenues, the forecasting model projects a range, or frequency distribution, of State petroleum revenues by year, so that for each year a forecasted petroleum revenue figure may be selected based on a given cumulative frequency of occurrence. The model accomplishes this by iteratively selecting a set of input variable values from among alternative values and computing a petroleum revenue figure for each time period. Each projection is computed using a set of accounting equations that estimate royalties and production taxes from each State oil and gas lease for each time period. By selecting the average value of all input data the model produces an average petroleum revenue forecast.

Because of uncertainties in projecting petroleum prices and their importance in developing alternative generation plans and load forecasts, it is necessary to examine the implications of several different world oil price projections in addition to the price projections developed by the DOR. This need is accommodated by DOR through a petroleum revenue sensitivity accounting model referred to by DOR as MJSENSO. This sensitivity accounting model, which is in effect a sub-model of the PETREV model, utilizes the accounting equations and average values for all input variables other than world oil prices from PETREV, to compute an adjustment to PETREV's average petroleum revenue forecasts based on different assumed world oil price forecasts. By executing the sensitivity model with the alternative petroleum price projections, alternative petroleum revenue projections are developed for use in projecting State economic activity in the MAP model.

2.3.2 The Man-in-the-Arctic Program (MAP) Economic Model

The MAP model is a computer-based economic modeling system that simulates the behavior of the economy and the population of the State of Alaska and each of twenty regions of the State corresponding closely to the Bureau of Census divisions. The Railbelt consists of six of these regions. The MAP model develops Railbelt socio-economic activity forecasts to the year 2010. Input from the MJSENSO model are extrapolated from 1999 to 2010, using the average annual rate of change of the period 1996-1999.

The MAP model functions as three separate but linked sub-models: the scenario generator sub-model, the economic sub-model, and the regionalization sub-model, as illustrated on Exhibit 2.3. The scenario generator sub-model enables the user to quantitatively define scenarios of development in exogenous industrial sectors; i.e., sectors whose development is basic to the economy rather than supportive. Examples of such sectors are petroleum production and other mining, the federal government, and tourism. The scenario generator sub-model also enables the user to implement assumptions concerning State revenues from the MJSENSO model. The economic sub-model produces statewide projections of numerous economic and demographic factors based on quantitative relationships between elements of the Alaskan economy such as employment in basic industries, employment in non-basic industries, state revenues and spending, wages and salaries, gross product, the consumer price index, and population. The regionalization sub-model enables the user to disaggregate the statewide projections of population, employment, and households to each of the 20 separate regions of the state, using data on historical and current economic conditions and assumptions concerning basic industrial development.

2.3.3 The Railbelt Electricity Demand (RED) Model

The Railbelt Electricity Demand (RED) Model is a partial end-use - econometric model that projects both electric energy and peak load demand in the Anchorage-Cook Inlet and Fairbanks-Tanana Valley load centers of the Railbelt for the period 1983-2010. The RED model is designed to forecast annual electricity consumption for the residential, commercial, small industrial, government, large industrial, and miscellaneous end-use sectors of the two load centers of the Railbelt region. The model is made up of seven separate but interrelated modules, each of which has a discrete computing function within the model. They are the uncertainty, housing, residential consumption, business consumption, program-induced conservation, miscellaneous consumption, and peak demand modules. Exhibit 2.4 shows the basic relationship among the seven modules.

The model may be operated probabilistically, whereby the model produces a frequency distribution of projections where each projection is based on a different, randomly selected set of input parameters. The model may also be operated on a deterministic basis whereby only one set of forecasts is produced based on a single set of input variables. When operated probabilistically, the RED model begins with the Uncertainty Module, which selects a trial set of model parameters to be used by other modules. These parameters include price elasticities, appliance saturations, end-use consumption, and regional load factors.

Exogenous forecasts of population, economic activity, and retail prices for fuel oil, gas and electricity are used with the trial parameters by the Residential Consumption and Business Consumption Modules to produce forecasts of electricity consumption. These forecasts, along with additional trial parameters, are used in the Program-Induced Conservation Module to simulate the effects of government programs that subsidize or mandate the market penetration of certain technologies that reduce the need for power. This program-induced component of conservation is in addition to those savings that would be achieved through normal consumer reaction to energy prices.

The consumption forecasts of residential and business (commercial, small industrial, and government) sectors are then adjusted to reflect these additional savings. The revised forecasts are used to estimate future miscellaneous consumption and total sales of electricity. These forecasts and separate assumptions regarding future major industrial loads are used along with a trial system load factor to estimate peak demand.

After a complete set of projections is prepared, the model begins preparing another set by returning to the Uncertainty Module to select a new set of trial parameters. After several sets of projections have been prepared, they are formed into a frequency distribution to allow the user to determine the probability of occurrence of any given load forecast. When only a single set of projections is needed, the model is run in Certainty-Equivalent Mode whereby a specific default set of parameters is used and only one trial is run.

The RED model produces projections of electricity consumption by load centers and sectors at 5-year intervals. A linear interpolation is performed to obtain yearly data. The outputs from the RED model runs are used by the Optimized Generation Planning (OGP) model to plan and dispatch electric generating capacity for each year.

2.3.4 The Optimized Generation Planning (OGP) Model

The OGP model uses the output from the RED model plus data characterizing the units in the existing electricity generating system. It also uses investment and operating cost data plus operating characteristics (e.g., heat rate, forced and scheduled outage rates) for new power plants to forecast the most cost-effective electricity generation system. In addition to these variables, it requires the user to make a specific assumption concerning the required reliability of the system, taken as the loss-of-load probability (LOLP) of 1 day in 5 years for the Susitna studies.

The first calculation in selecting the generating capacity to install in a future year is the reliability evaluation using LOLP criteria. This answers the questions of "how much" capacity to add and "when" it should be installed. A production costing simulation is also done to determine the operating costs for the generating system with the given unit additions. Finally, an investment cost analysis of the capital costs of the unit additions is performed. The operating and investment costs help to answer the question of "what kind" of generation to add to the system.

2.4 FUTURE OIL PRICES AND STATE REVENUES

Forecasting future oil prices is a difficult and controversial task. However, oil price projections are required in the methodology used in this economic and financial update. Since the Alaska Department of Revenue oil price forecast represents the State view of oil prices, it has been relied upon in this update as directed by the Power Authority. In addition, other oil price forecasts have also been considered since oil price forecasts have a profound influence on the economic and financial viability of the Susitna Project.

There is generally a wide range of strong positions regarding the long-term trends in the supply and demand of oil and its prices. At this time, the general consensus is that oil prices will remain flat or trend downward in real terms for the next few years due to an excess of production capacity. The degree and duration of this situation will depend upon the vigor of the world economic recovery, the longer term world economic growth, the success of conservation efforts, and the influence of OPEC setting oil prices. Most forecasters predict that oil production will peak at about year 2000, give or take 10 years; and free world oil demand will surpass the peak that was reached in 1979. By that time, the cost of synthetic fuel oil would be the basis for marginal pricing of oil, and the world price can be expected to rise over time to the cost of alternative fuel oil. This type of price trajectory should prevail under normal free market conditions.

Because of the influence of OPEC, with most oil reserves in the industrial countries being depleted, it is likely that the upward move in price could precede the transition period long before the petroleum reserve is exhausted, and in fact would enter into a "what the market will bear" situation. Ultimately, the world oil price should reach the cost of its substitute synthetic fuel.

2.5 OIL PRICE FORECASTS

A detailed review of oil price forecasts was presented in Volume 2A of the License Application. In this section, the current update of some of these forecasts is presented. The June 1983 Alaska Department of Revenue (DOR) forecast is first presented. For comparison purposes, the Summer 1983 Data Resources Incorporated (DRI) forecasts, the U.S. Department of Energy (DOE) forecasts, and the May 1983 Sherman H. Clark Associates - No Supply Disruption Case (SHCA-NSD), which was used as the Reference Case in the FERC License Application, are also presented. In addition, oil price forecasts by several other nationally known organizations are presented. These forecasts are summarized on Exhibit 2.5, and displayed on Exhibit 2.6.

2.5.1 Alaska Department of Revenue (DOR) Forecast (June 1983)

DOR forecasts future petroleum revenues over a 17-year period to assist in the preparation of state budgets. These forecasts are updated on a quarterly basis. In developing the revenue forecast, a number of State employees of the Office of Management and Budget, Department of Natural Resources, and DOR each develop one to ten scenarios of futur world oil prices, and assign a subjective probability to each scenario. Using the Delphi method, DOR aggregates these individuals' forecasts and develops a probability density function using a computer model. The individual probability density functions are then aggregated by the model to produce a composite probability distribution of future world oil prices.

DOR's forecasts of oil prices are on a monthly basis for the first two years and by quarters for the next three years. Beyond the first five years, DOR forecasts a fixed escalation rate in oil prices for each probability point. The mean or average oil price for each period is determined from the composite frequency distribution.

The 17-year projections of the mean oil price (June 1983) developed by DOR are presented on Exhibit 2.5. Under the Mean scenario, the crude oil real price is expected to decrease until 1987 to $23.90 per barrel (bbl); then, the real price would increase to $27.45/bbl in 1999. After 1999, the last year of the DOR projections, the price of oil is assumed to escalate at 1.5 percent, the average annual growth rate of the period 1994-1999. Hence, with a 1999 price of $27.45/bbl, the 2010 oil price would be $32.42/bbl. The October 1983 DOR Mean oil price estimate for 1999 is $29.25/bbl which is about 6.5 percent greater than the June 1983 forecast.

2.5.2 Data Resource Incorporated (DRI) Forecast (Summer 1983)

The 1983-2005 projections of crude oil price developed by DRI are presented on Exhibit 2.5. Crude oil prices are expected to remain low in the near term, before beginning rapid escalation in the latter half of the 1980's. Then, real price increase averages about 3.0 percent in the 1990's, and 1.6 percent for the period 2000-2005. The 2005 real price is expected to be $49.47 per barrel.

2.5.3 U.S. Department of Energy (DOE) Forecast (First Quarter 1983)

The Policy group of the U.S. Department of Energy has developed, during the first quarter of 1983, projections of crude oil price which will be presented in the National Energy Plan report. These projections are presented on Exhibit 2.5. Real prices are expected to decrease until the mid 1980's, and increase rapidly after 1990. The 2010 real price would vary between $65.60 and $102.40 per barrel.

2.5.4 Sherman H. Clark Associates - No Supply Disruption (May 1983)

The 1983-2010 projections of crude oil price developed by SHCA are presented on Exhibit 2.5. The real price of oil is expected to decrease to $26.30 in 1983, and remain at that level until 1988. From 1988 to 2010, price increases at a 3.0 percent annual rate. A special analysis was done by SHCA to project crude oil price to 2040. After 2010, the rate of price escalation is projected to taper off as the oil price approaches the price that will bring forth supplies of alternative fuels.

2.5.5 Other Oil Price Forecasts

In addition to the oil price forecasts discussed above, the Power Authority solicited forecasts from a total of seventeen other sources. These sources comprise research organizations, universities, and oil companies who have the expertise to perform oil price forecasts. Ten of the seventeen sources contacted had no forecast available or did not supply oil price data. The forecasts obtained from the remaining seven sources are presented on Exhibit 2.5 and summarized below:

- Stanford Research Institute
  Prices down until 1985, then constant at $25/bbl (1983), until 1990, then 1 percent increase to present level in 2000. Done without models.

- Standard Oil of California
  Prices flat through 1980's, rise slowly in 1990's. Price anywhere between $35 and $50/bbl (1983). Done without models.

- Rand Corporation
  No big increases before the end of the century. Prices will stay the same or decline in the next few years, then slowly increase after that. No models are used.

- State of Alaska, DCED Forecast of Alaska's Development Delphi Panel

  79 percent of the Delphi Panel believe that prices will be at or above their present level by 2000; 51 percent believe they will be higher. Only 8 percent believe they will be lower.

- Booz-Allen & Hamilton (for DNR)

  Three different forecasts are used. The strong economy scenario leads to a price of $37/bbl (1983) in 1990, $50.9/bbl in 2000, and $73.1/bbl in 2001. The weaker economy scenario has prices at $29.7/bbl in 1990, $36.0/bbl in 2000, and $48.8/bbl in 2010. The third scenario comes from the Governor's Office, and assumes prices will stay constant at $29.7/bbl throughout the period.

- World Bank

  1985 price is at $34.94/bbl (1983), 1995 it is at $46.07/bbl. Done partially with models.

- Chase Econometrics

  Prices fall until 1985 and then rise slowly, reaching $34.98/bbl in 2000. Done partially with models.

- Contacted but no forecast available:
  - Phillips
  - Exxon
  - Gulf
  - Congressional Budget Office
  - Council of Economic Advisors
  - Petroleum Industry Research Foundation
  - National Petroleum Council
  - American Petroleum Institute
  - Brookings
  - Wharton Econometrics

Although most forecasters predict that oil prices will fall or remain constant in real terms until around 1985, modest real price increases are predicted by each expert.

The assumptions about world conditions in most of the forecasts are quite similar. Economic growth rates are in the 3 percent range, with inflation around 6 percent. Most assume that the majority of changes in consumption brought about by conservation are permanent, and that the amount of energy required per unit of Gross National Product (GNP) is going to continue to decrease. Supply is assumed by most to be greater than demand through 2000; even though consumption will rise somewhat, oil's share of the energy market is seen as decreasing by all the experts, with coal picking up most of this market. Most see OPEC oil as the marginal supply, and also as a major determinant of oil price. Given the disparity in function and concerns among the forecasters, the similarities in the underlying assumptions and general forecast trends are remarkable.

2.6 SELECTION OF OIL PRICE FORECASTS

The estimates of future world oil prices presented above illustrate the different views and outlooks on the world economy by various fore-

- Contacted but no forecast available:
  - Phillips
  - Exxon
  - Gulf
  - Congressional Budget Office
  - Council of Economic Advisors
  - Petroleum Industry Research Foundation
  - National Petroleum Council
  - American Petroleum Institute
  - Brookings
  - Wharton Econometrics

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2.6 SELECTION OF OIL PRICE FORECASTS

The estimates of future world oil prices presented above illustrate the different views and outlooks on the world economy by various forecasters. The range of forecasts is graphically displayed on Exhibit 2.6.

To assess the impact of future oil prices on the demand for electric energy in the Railbelt, the broad range of forecasts has been analyzed and evaluated. Although it is possible that any one of the scenarios could occur in the future, some presently seem to be more probable than others. OPEC seems to be holding the line on their new benchmark price of $29.90/bbl and the United States economy is recovering from the 1981-82 recession at a stronger real rate of growth than recently predicted by many economists.

In this update study, the DOR Mean as well as the SHCA-NSD oil price forecasts are tested. The DOR Mean forecast is used because it relates Susitna feasibility to State revenue projections.

The SHCA-NSD case has also been studied to provide a link between this Update and the FERC License Application. Inspection of Exhibit 2.6 shows that for 1990 two forecasts are lower than the SHCA-NSD and ten are higher; in 1995 six forecasts are lower and six forecasts higher; and for the year 2000, seven forecasts are lower with five higher. In the early years (1983-1990) of the projections, the SHCA-NSD forecast is in the low range, and in the later years (1995-2010) the SHCA-NSD forecast is in the middle of the range of forecasts illustrated.

The use of the DOR Mean and SHCA-NSD forecasts provides a good basis for assessing the State's economy, the Railbelt electricity demand, and the economic and financial viability of the Susitna Project.

2.7 POWER MARKET FORECAST

Exhibits 2.7 and 2.8 summarize the input and output data for the DOR Mean and SHCA-NSD forecasts over the period from 1983 to 2010. Historical data and projections of general fund expenditures, population, household, energy demand, and peak demand are displayed on Exhibits 2.9 through 2.13.

In 2010, the State General Fund Expenditures, in current dollars, are expected to be $11.8 billion under the DOR Mean forecast and $18.0 billion under SHCA-NSD. The Railbelt population is expected to increase from 319,767 in 1983 to 506,548 under DOR Mean and to 533,218 under SHCA-NSD for the year 2010. The corresponding number of households would increase from 111,549 in 1983 to 185,477 and 195,652, for the DOR and SHCA-NSD forecasts, respectively. As shown on Exhibit 2.12, the 2010 electric energy consumption would be 5,404 GWh for DOR Mean and 5,858 GWh for SHCA-NSD. The corresponding average annual growth rate over the period 1983-2010 would vary between 2.4 and 2.8 percent. The peak demand is expected to increase from 580 MW in 1983 to 1,122 MW under DOR Mean and 1,217 MW under SHCA-NSD for the year 2010.

Similar projections for the SHCA-NSD forecast are presented in Exhibit B of the FERC License Application. Detailed projections of State revenues, economic conditions, and electric energy demand are presented on Exhibits 2.14 through 2.21 for the DOR Mean scenario.

Exhibit 2.14 presents the DOR Mean projections of State petroleum revenues from each of the primary revenue sources through the year 2010. The first two columns of this exhibit contain projected royalties and severance, or production taxes, respectively. These projections are in nominal dollars, reflecting an annual change in the consumer price index of 6.5 percent. The projections of royalties and severance taxes through the year 1999 were produced by the Department of Revenue's petroleum revenue forecasting model system, adjusted for minor differences in the future assumed rate of inflation. Projections for the year 2000 through 2010 were extrapolated using the average annual rate of change between the years 1996 through 1999.

Exhibit 2.14 also presents projections of State petroleum revenues derived from corporate income taxes, property taxes, lease bonuses, and federal shared royalties. Future revenues from these sources, estimated by the Institute of Social and Economic Research, were used along with the projections of royalties and severance taxes as input to the MAP economic sub-model.

Exhibit 2.15 presents projections of several important components of the State's fiscal structure. These components include unrestricted general fund expenditures, the balance in the general fund, permanent fund dividends, State personal income tax revenues, level of outlays for subsidies, and the percentage of Permanent Fund earnings that are reinvested. The exhibit shows that dividends from the Permanent Fund continue to be disbursed through the year 1987, at which time the program is halted. A State personal income tax is reinstituted in the year 1989 in order to augment revenues. State subsidy programs are terminated after the year 1987, and reinvestment of Permanent Fund dividends ends after 1989. The subsidy programs that may be affected include, for example, mortgage subsidies, student loans and AIDA industrial development loans.

Each of these measures is assumed to occur in order to permit State expenditures to grow as closely as possible in proportion to the rate of population growth, taking into account the effects of inflation. However, while these fiscal measures are assumed to be implemented, petroleum revenues are projected to continue to provide the largest share of State expenditures. In the year 2010, they will account for approximately half of the total unrestricted general fund expenditures, i.e., those expenditures not funded by revenues dedicated to specific functions.

Exhibit 2.16 presents the DOR Mean population projections for the State, Railbelt, Anchorage-Cook Inlet area, and Fairbanks-Tanana Valley area. Railbelt population is projected to grow by approximately 58 percent between 1983 and 2010, from 319,767 to 506,548. In the Railbelt, the Anchorage area is projected to grow by 61 percent, compared to the projected growth in Fairbanks of 49 percent.

The growth of employment, shown on Exhibit 2.17 is uniformly lower than that of population. While statewide non-agricultural wage and salary employment is projected to grow by 53 percent during the next 27 years, total State employment is forecasted to increase by only 47 percent. Again, the Railbelt is projected to experience a higher employment increase, rising by 52 percent, with the Anchorage area growing by 55 percent compared to 43 percent growth in the Fairbanks area.

Exhibit 2.18 presents projections of households for the State, the Railbelt, the Anchorage area and Fairbanks area. In contrast to projected employment, households are projected to increase faster than population. Statewide households are projected to increase by 63 percent by the year 2010, compared to a 62 percent increase in the Railbelt, a 66 percent rise in the Anchorage area, and a 58 percent increase in the Fairbanks area.

The effects of demand elasticity are computed by adjusting the average consumption per household for conservation and fuel substitution, as shown on Exhibit 2.19. In the Anchorage area, the average consumption per household is expected to decrease from about 13,699 kWh in 1980 to 12,582 kWh in 2000, due mainly to the real increase of electricity price which will continue to cause some conversion from electric space heating to substitute fuels. After 2000, the consumption is expected to increase to about 12,760 kWh by 2010. In the Fairbanks area, the average household consumption is expected to increase from 11,519 kWh in 1980 to 14,526 kWh in 2010, or about an average annual growth rate of 0.8 percent. This increase is due to the stabilization of electricity prices, while the prices of substitute fuels are increasing. The projected consumption in year 2000 is similar to the 1975 average consumption.

The employment forecasts obtained from MAP are used in the RED Business Consumption module to derive the electric demand in the commercial-government-small industry sector. Exhibit 2.20 summarizes the "business use" per employee projections. The consumption projections were obtained from a forecast of predicted floor space per employee, and an econometrically derived electricity consumption per square foot, which is then adjusted for price impacts. The floor space per employee is expected to increase by 10 percent in Anchorage and 15 percent in Fairbanks to approach the current national average by the year 2010. As a result, in the Anchorage area, the average consumption per employee is expected to increase from about 8,407 kWh in 1980 to 11,170 kWh in 2010, at an average annual rate of 1.0 percent. In the Fairbanks area, the consumption per employee is expected to increase from 7,496 kWh in 1980 to 9,670 kWh in 2010, at an average annual growth rate of 0.8 percent.

A breakdown of electric energy demand projections by customer categories, based on the underlying projections of average consumption per household and per employee presented in the previous paragraphs, is presented on Exhibit 2.21. Exhibit 2.21 also shows miscellaneous sector which includes street lighting, second (recreation) homes, and vacant houses. It corresponds to about one percent of the total energy demand. The exogenous industrial loads include the large industrial customers which are located in the Homer Electric Association, Inc. (HEA) service area, and an estimate of the amount of electricity that could be provided by the utilities to the military installations. These exogenous loads would increase from about 108 GWh in 1983 to 315

GWh in 2010 for the Anchorage-Cook Inlet area, and from 0 to 50 GWh in the Fairbanks-Tanana Valley area. A detailed discussion of the industrial and military loads are presented in the following paragraph.

The large industrial projections were based on work by Burns & McDonnell in their preparation of the 1983 Power Requirements Study for HEA. Those projections indicate that electrical demand is expected to increase from 100 GWh in 1982 to 142 GWh in 1990 and 158 GWh in 1995. An annual growth rate of 3.5 percent was assumed after 1995.

Discussions were held with representatives of the two military installations (Fort Richardson and Elmendorf) of the Anchorage-Cook Inlet Area, and the three military installations (Fort Wainwright, Fort Greely, and Eielson) of the Fairbanks-Tanana Valley Area to obtain information on historical and projected electricity consumption. A continuation of the annual military electricity demand of 150 GWh is expected in each area. Existing power contracts and exchanges with the utilities were reviewed and estimates of the amount of electricity that could be provided by the utilities were discussed, recognizing that continued operation of military generating facilities for heating purposes is expected. For the purpose of load forecasting, it was assumed that one-third of the total military electrical demand in each area, or 50 GWh, would be provided by the utilities. The load demand would increase linearly from 0 GWh in 1985 to 50 GWh in 1990 in each area, and remain at 50 GWh thereafter.

Finally, Exhibit 2.22 summarizes the annual peak and energy sales projections for each load center and for the total system. The average annual growth rate of electricity demand is expected to slowly decrease from about 5.6 percent during the period 1980-1985 to 1.8 percent during the period 1995-2000. After 2000, the demand is expected to increase at an average annual rate of 2.1 percent until 2005, and 2.6 percent for the period 2005-2010.

2.8 COMPARISON WITH PREVIOUS FORECASTS AND UTILITY FORECASTS

Two sets of previous forecasts have been used in the early stages of the Susitna Hydroelectric Project studies in addition to the power market forecasts presented in detail in this section. In 1980, the Institute for Social and Economic Research (ISER) prepared economic and accompanying end-use electric energy demand projections for the Railbelt. These forecasts were used in several portions of the Susitna Feasibility Study, including the Development Selection Study.

In 1981 and 1982, Battelle Pacific Northwest Laboratories produced a series of load forecasts for the Railbelt, as shown on Exhibit 2.23. These forecasts were developed as a part of the Railbelt Alternatives Study completed by Battelle under contract to the State of Alaska. Battelle's forecasts were based on updated economic projections prepared by ISER and some revised end-use models developed by Battelle which took into account price sensitivity and several other factors not included in the 1980 projections. The December 1981 Battelle forecasts were used in the optimization studies for the Watana and Devil Canyon developments which were completed early in 1982. The 1981 forecast reflected a projection of world oil nominal prices of $27.45/bbl in July 1981 to $31.45/bbl in July 1982, with first quarter prices increasing from $36.35/bbl to $44.65/bbl over the next three fiscal years, and then from $53.22/bbl in the sixth fiscal year to $157.60/bbl in the subsequent seventeenth fiscal year.

These previous forecasts were made for three electric load centers: the Anchorage-Cook Inlet area; the Fairbanks-Tanana Valley area; and the Glennallen-Valdez area. When these studies were undertaken, it was not decided whether the Glennallen-Valdez area would be included in the intertied Railbelt electrical system. The decision was subsequently made, based on economics, that the Glennallen-Valdez area would not be initially included in the interconnected area. Therefore, the updated electric load forecasts presented herein do not consider the power requirements of this load center.

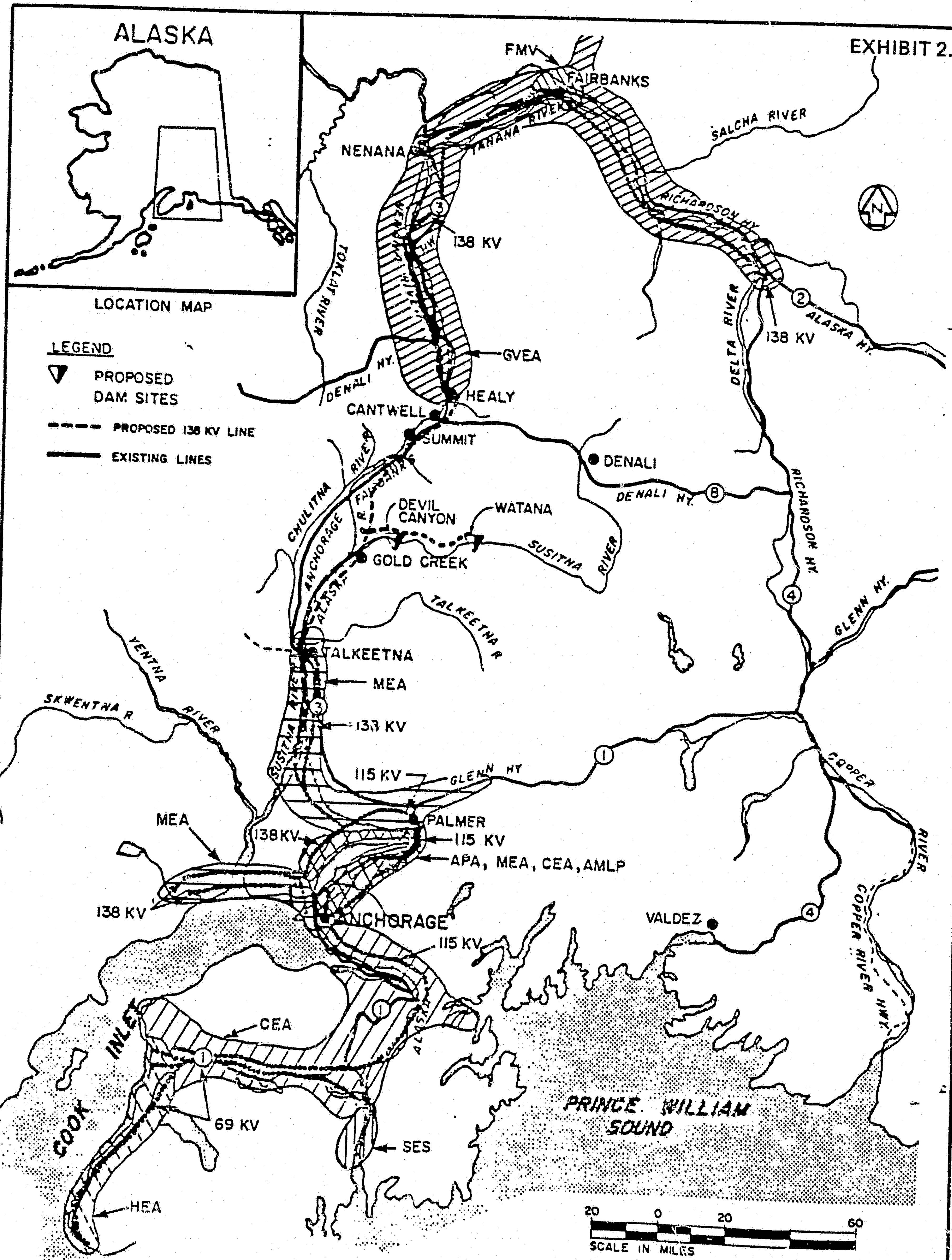
Exhibit 2.23 provides a summary comparison of these power market forecasts used in earlier studies. While these forecasts are not precisely consistent in the definitions of the market area or in the assumptions relating to the current load forecasts, the comparison does provide insight to the change in perception of future growth rates during the time that the various sets of forecasts were developed. The ISER forecast projected an average annual growth rate of about 4.0 percent for the period 1980 to 2010. The Battelle 1981 forecast projected an average annual growth rate of about 3.5 percent over the same period. The DOR Mean shows a 2.4 percent average annual growth rate.

In addition to the ISER and Battelle forecasts performed for the purpose of planning the Susitna Hydroelectric Project, the Railbelt utilities annually produce forecasts for their own respective markets. Exhibit 2.24 summarizes the projections made by the utilities in early 1983, for the period 1983-2001. The average annual growth rate is expected to decrease slowly from about 6.0 percent for the period 1983-1990 to 4.5 percent for the period 1991-2001. The total energy generation is expected to be 7,662 GWh in year 2001, which is about 75 percent greater than the DOR Mean projections.

A power requirements study was recently performed by Burns & McDonnell for Chugach Electric Association, Inc. The results are summarized in Exhibit 2.25. Three forecasts were developed: low, moderate, and high for the period 1983-1997. The Burns & McDonnell projections confirm the forecast made previously by the utility. Under the moderate forecast, energy demand for the year 1997 is 3,467 GWh, while the utility projection was 3,428 GWh. The average annual growth rate of electricity demand is expected to vary between 3.9 and 6.2 percent for the period 1983-1997. The average annual growth rate of the moderate forecast is about twice the growth rate of the DOR Mean projection for the Anchorage-Cook Inlet area.

2.9 SUMMARY

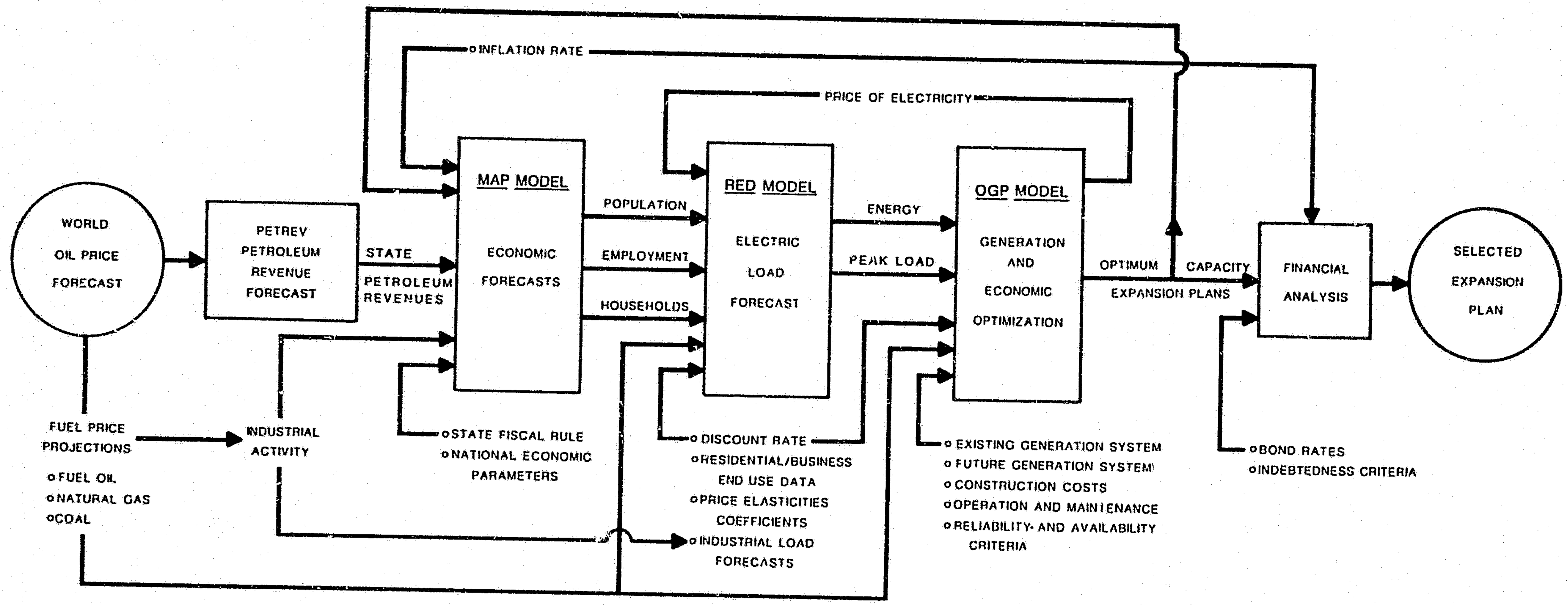
Exhibit 2.26 provides a summary of the DOR Mean and SHCA-NSD power demand forecasts. A comparison with the current forecasts of the Railbelt utilities indicates that the update forecasts are substantially lower. For instance, under the SHCA-NSD scenario, the forecasted 1990 energy demand is 3,737 GWh, compared with 4,678 GWh forecast by the Railbelt utilities. It is not possible at this point to establish the reasons for the difference, since the forecasting techniques are likely to be different. In any case, the utilities' forecasts are likely to be more accurate on a near-term basis, since their forecasts are heavily influenced by recent trends. On the other hand, the forecasts using the MAP and RED Models take a fundamental approach with the primary objective of developing a reliable forecast on a long-term basis. In any case, the use of these lower forecasts is a conservative approach in analyzing the economic feasibility of the Susitna Project.



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

LOCATION MAP SHOWING TRANSMISSION SYSTEMS

SEPTEMBER 1983



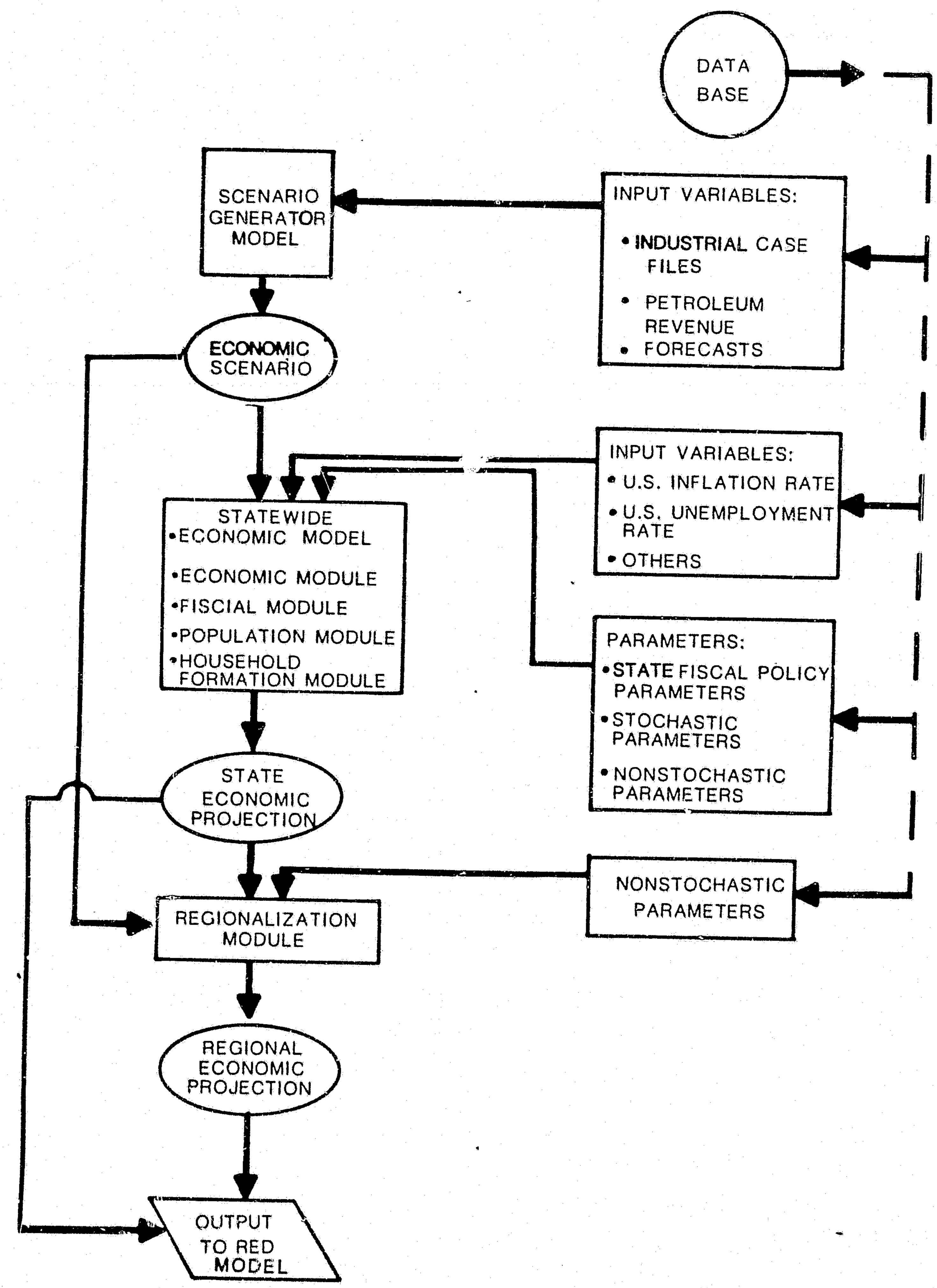
SUSITNA HYDROELECTRIC PROJECT UPDATE
ALASKA POWER AUTHORITY

RELATIONSHIP OF PLANNING MODELS AND INPUT DATA

SEPTEMBER 1983

EXHIBIT 2.2

EXHIBIT 2.3

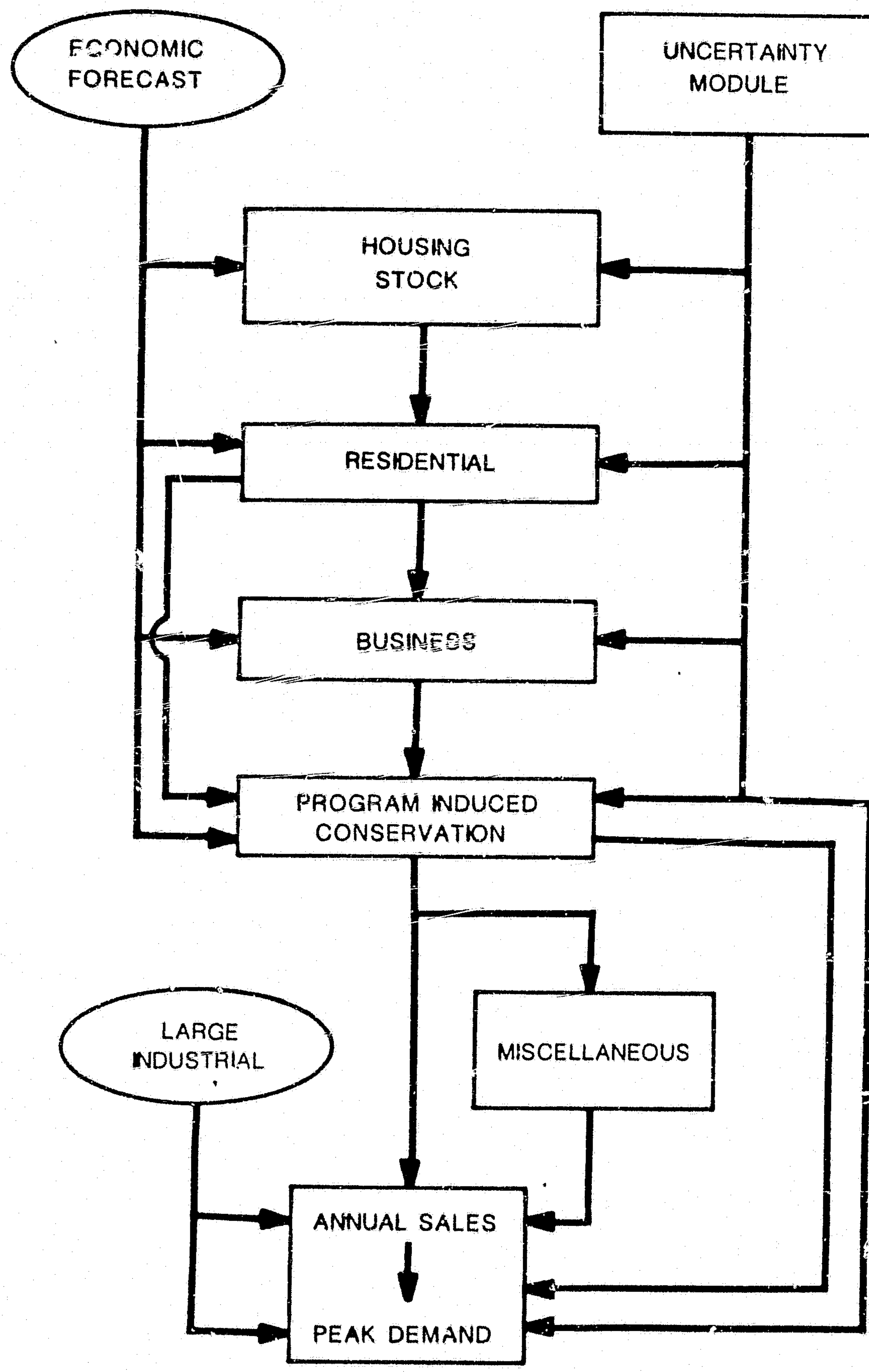


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

MAP MODEL SYSTEM

SEPTEMBER 1983

EXHIBIT 2.4



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

RED INFORMATION FLOWS

SEPTEMBER 1983

OIL PRICE FORECASTS
(1983 $/bbl except as noted)

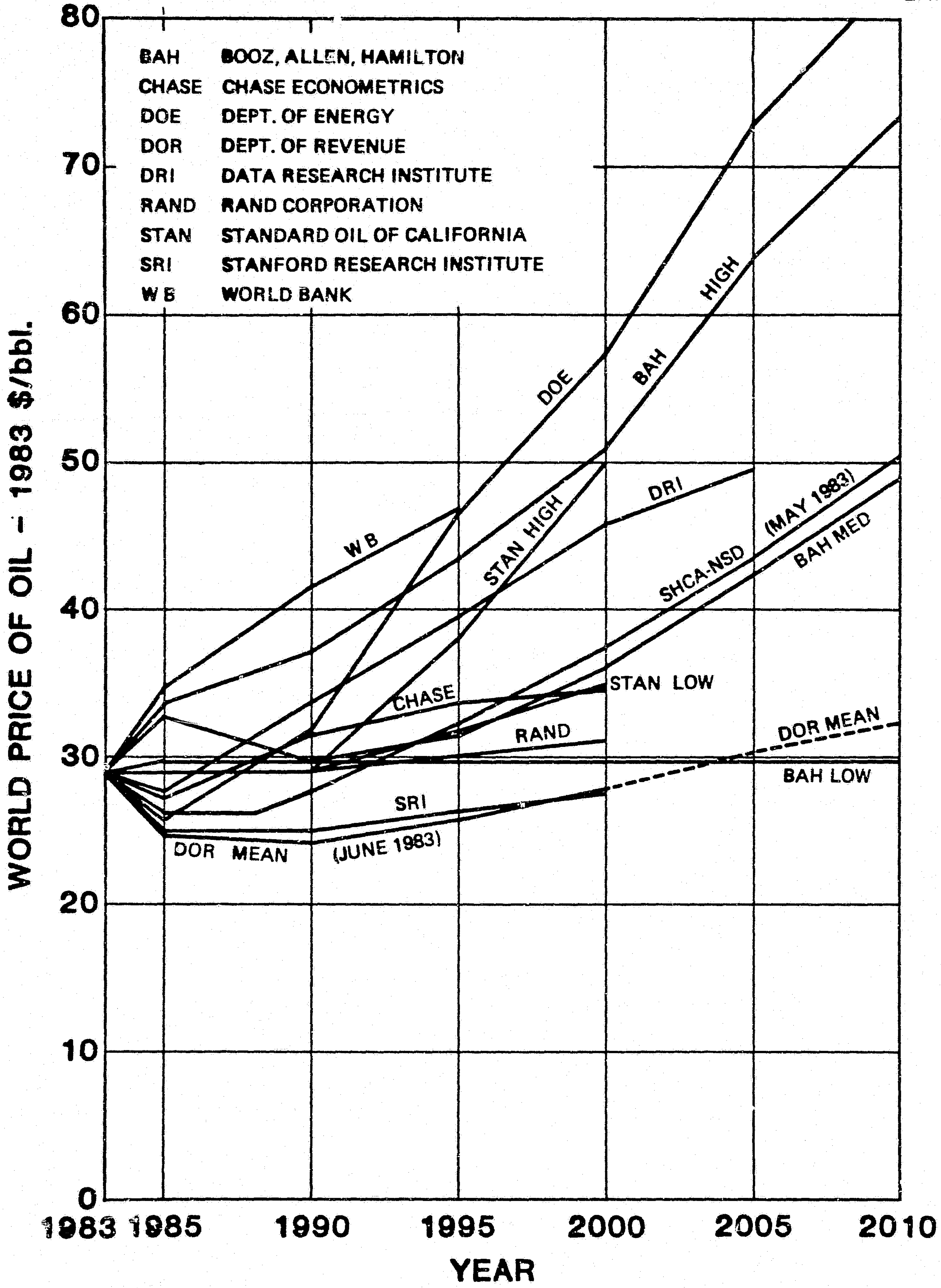
	Year 1985	Average Rate of Change Per Year (%)	Year 1990	Average Rate of Change Per Year (%)	Year 1995	Average Rate of Change Per Year (%)	Year 2000	Average Rate of Change Per Year (%)	Year 2005	Average Rate of Change Per Year (%)	Year 2010
DOR Mean	24.83	-0.4	24.39	1.1	25.79	1.5	27.87	1.5	30.06	1.5	32.42
SHCA-NSD	26.30	1.2	27.90	3.0	32.34	3.0	37.50	3.0	43.47	3.0	50.39
DRI*	27.77	4.0	33.85	3.2	39.58	2.9	45.71	1.6	49.47	NA	NA
DOE Low*	23.80	3.2	27.80	7.4	39.70	3.9	48.20	3.7	57.70	2.6	65.60
DOE Mid-Range*	25.90	4.3	31.90	7.8	46.50	4.3	57.40	6.4	72.20	1.3	83.60
DOE High*	26.80	6.2	36.20	8.0	53.10	5.3	68.80	5.9	91.50	2.3	102.40
SRI*	25.00	0.0	25.00	1.0	26.27	1.0	27.61	-	-	-	-
Standard Low**	29.00	0.0	29.00	1.9	31.86	1.9	35.00	-	-	-	-
Standard High**	29.00	0.0	29.00	5.6	38.00	5.6	50.00	-	-	-	-
Rand**	29.00	0.0	29.00	0.7	30.00	0.7	31.00	-	-	-	-
BAH High**	33.92	1.8	37.10	3.2	43.50	3.2	50.90	4.5	63.60	2.8	73.10
BAH Medium**	29.70	0.0	29.70	1.4	31.80	2.5	36.00	3.3	42.40	2.8	48.80
BAH Low**	32.90	-2.0	29.70	0.0	29.70	0.0	29.70	0.0	29.70	0.0	29.70
World Bank**	34.94	3.5	41.57	2.0	46.07	-	-	-	-	-	-
Chase Econometrics**	27.41	3.0	31.86	1.1	33.69	0.8	34.98	-	-	-	-

*1982 $/bbl

**Solicited Forecasts by the Alaska Power Authority

EXHIBIT 2.5

EXHIBIT 2.6



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ALTERNATIVE OIL PRICE PROJECTIONS

SEPTEMBER 1983

DOR-MEAN SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	24.83	24.39	25.79	27.87	30.06	32.42
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	6.54	6.43	6.80	7.34	7.92	8.54
Natural Gas - Anchorage ($/MMBtu)	1.73	2.00	2.81	3.40	3.58	3.76	3.96
State Petroleum Revenues 1/ (Nom. $\$x10^6$)							
Production Taxes	1,512	1,451	1,723	1,444	1,394	1,472	1,555
Royalty Fees	1,451	1,450	2,092	2,048	2,238	2,588	2,993
State General Fund Expenditures (Nom. $\$x10^6$)	3,288	3,700	5,390	6,106	7,306	9,214	11,830
State Population	457,836	490,373	543,901	581,710	614,105	653,359	706,582
State Employment	243,067	258,634	284,232	296,942	310,315	329,544	357,253
Railbelt Population	319,767	341,839	380,344	404,351	430,823	463,623	506,548
Railbelt Employment	159,147	169,392	183,738	192,881	204,424	220,479	214,809
Railbelt Total Number of Households	111,549	120,219	135,554	145,532	156,234	169,098	185,477
Railbelt Electricity Consumption (GWh)							
Anchorage	2,325	2,567	2,930	3,159	3,459	3,844	4,387
Fairbanks	481	536	670	751	825	914	1,029
Total	2,806	3,102	3,600	3,910	4,284	4,757	5,417
Railbelt Peak Demand (MW)	580	641	749	814	891	988	1,125

1/ Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

EXHIBIT 2.7

SHCA-NSD SCENARIO

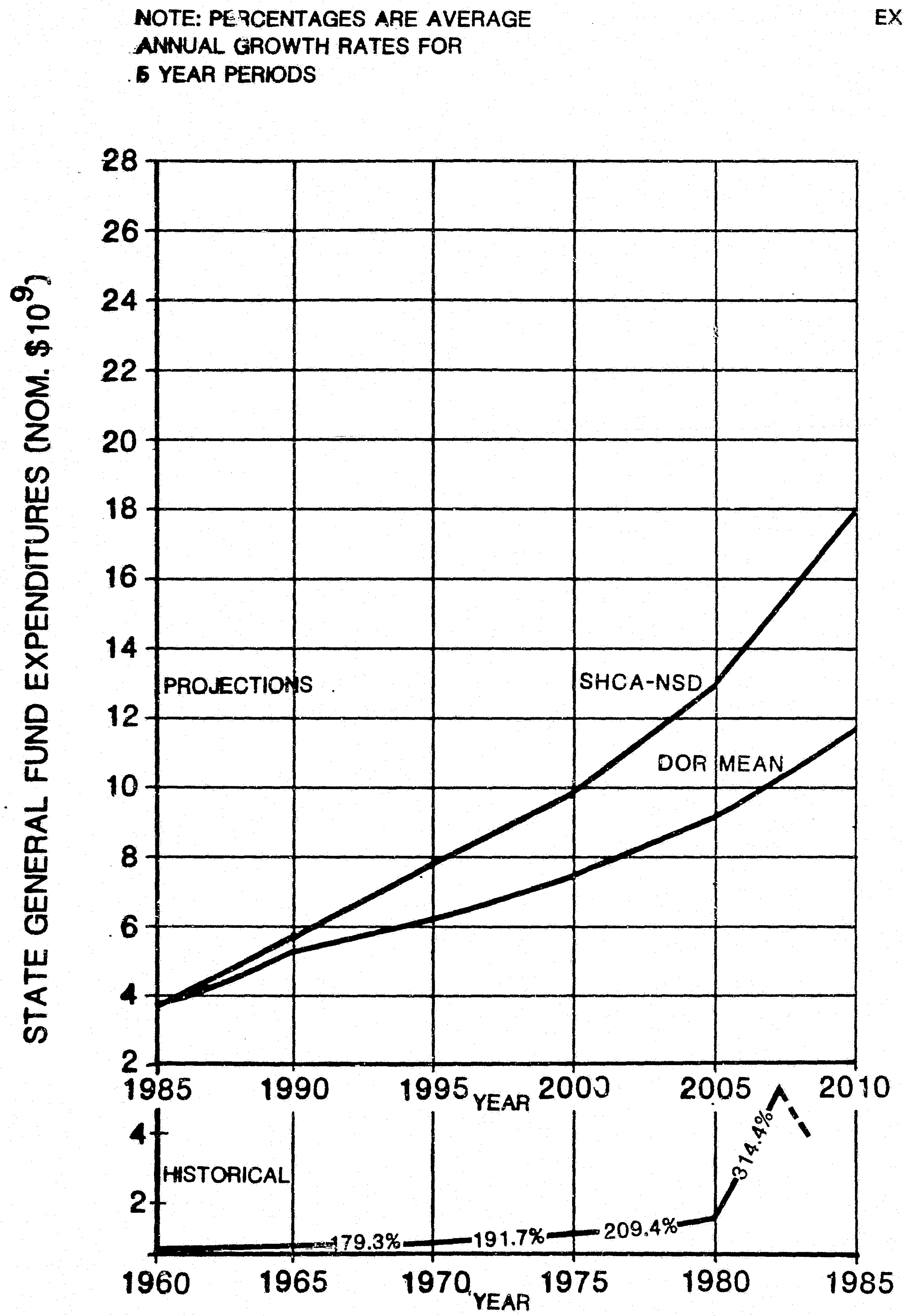
SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1983	1985	1990	1995	2000	2005	2010
World Oil Price (1983$/bbl)	28.95	26.30	27.90	32.34	37.50	43.47	50.39
Energy Price Used by RED (1980$)							
Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	6.45	6.84	7.93	9.19	10.65	12.35
Natural Gas - Anchorage ($/MMBtu)	1.73	1.95	2.88	4.05	4.29	4.96	5.38
State Petroleum Revenues 1/ (Nom. $x10^6$)							
Production Taxes	1,474	1,561	2,032	1,868	1,910	2,150	2,421
Royalty Fees	1,457	1,555	2,480	2,651	3,078	3,799	4,689
State General Fund Expenditures (Nom. $x10^6$)	3,288	3,700	5,577	7,729	9,714	13,035	17,975
State Population	457,836	490,146	554,634	608,810	644,111	686,663	744,418
State Employment	243,067	258,396	293,689	313,954	325,186	345,701	376,169
Railbelt Population	319,767	341,613	389,026	423,460	451,561	486,851	533,218
Railbelt Employment	159,147	169,197	190,883	204,668	214,542	231,584	255,974
Railbelt Total Number of Households	111,549	120,140	138,640	152,463	163,913	177,849	195,652
Railbelt Electricity Consumption (GWh)							
Anchorage	2,326	2,561	3,045	3,371	3,662	4,107	4,735
Fairbanks	482	535	691	800	880	986	1,123
Total	2,808	3,096	3,737	4,171	4,542	5,093	5,858
Railbelt Peak Demand (MW)	579	639	777	868	945	1,059	1,217

1/ Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

EXHIBIT 2.8

EXHIBIT 2.9

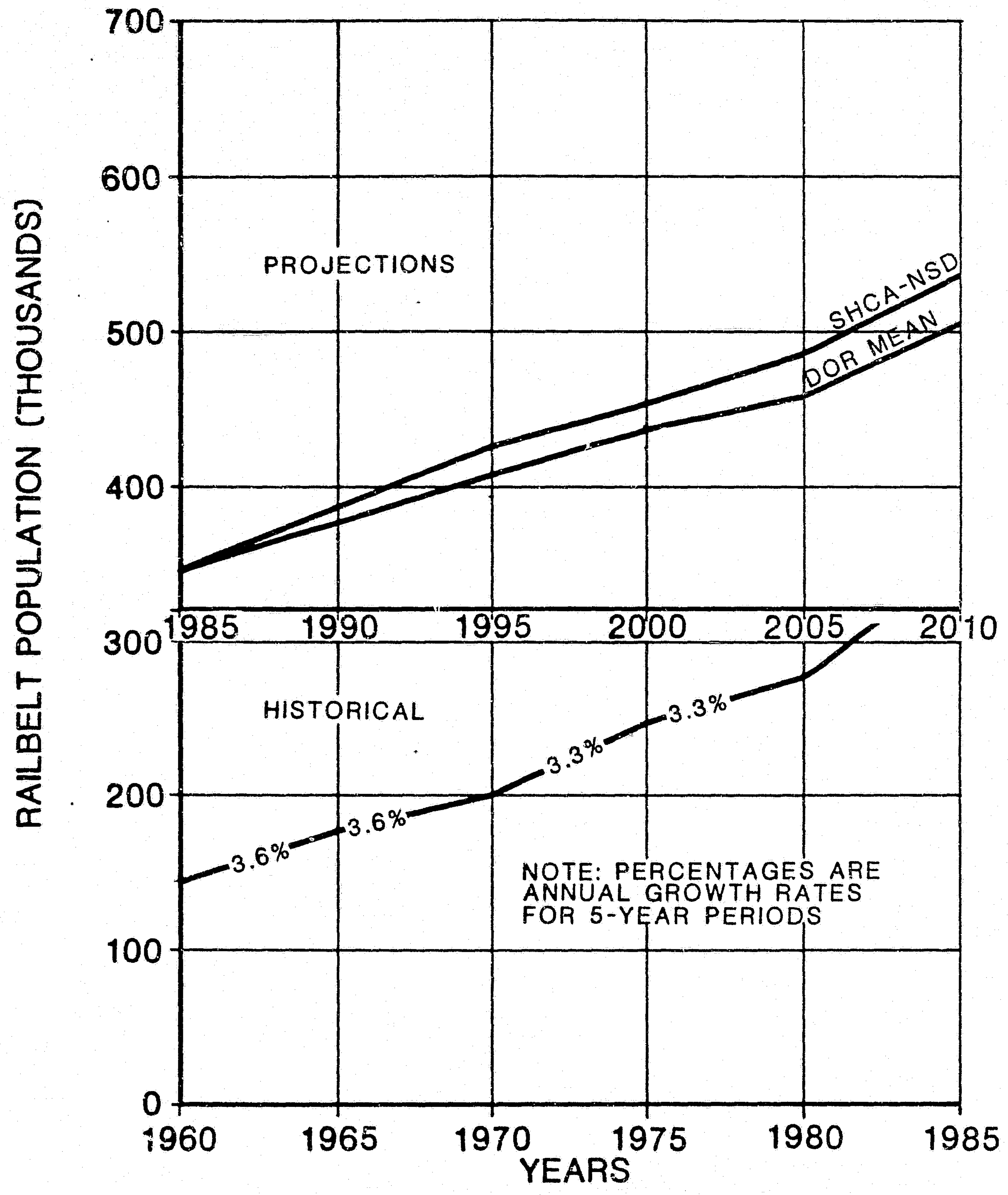


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

ALTERNATIVE STATE GENERAL FUND EXPENDITURE FORECASTS

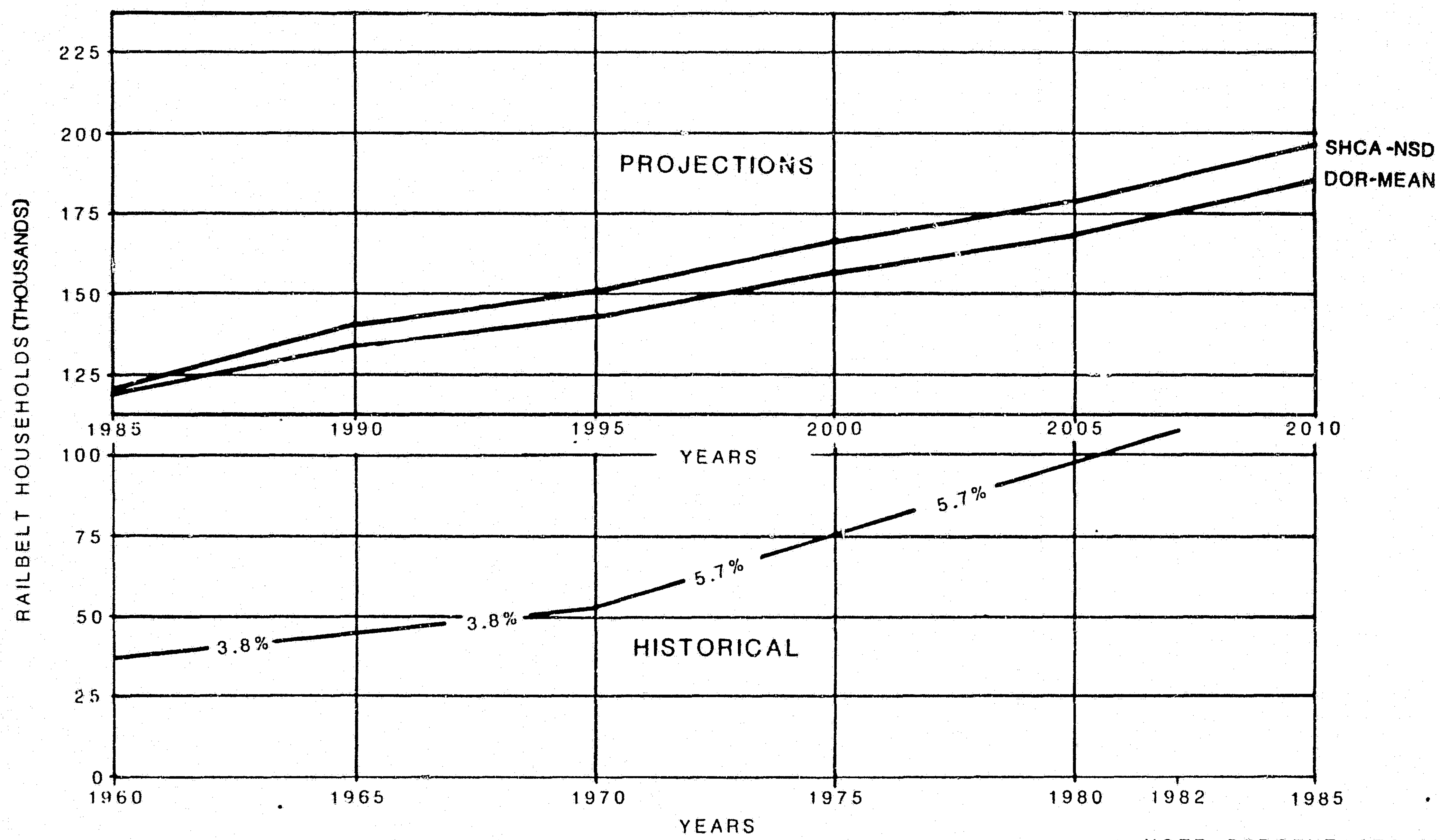
SEPTEMBER 1983



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ALTERNATIVE RAILBELT POPULATION FORECASTS

SEPTEMBER 1983



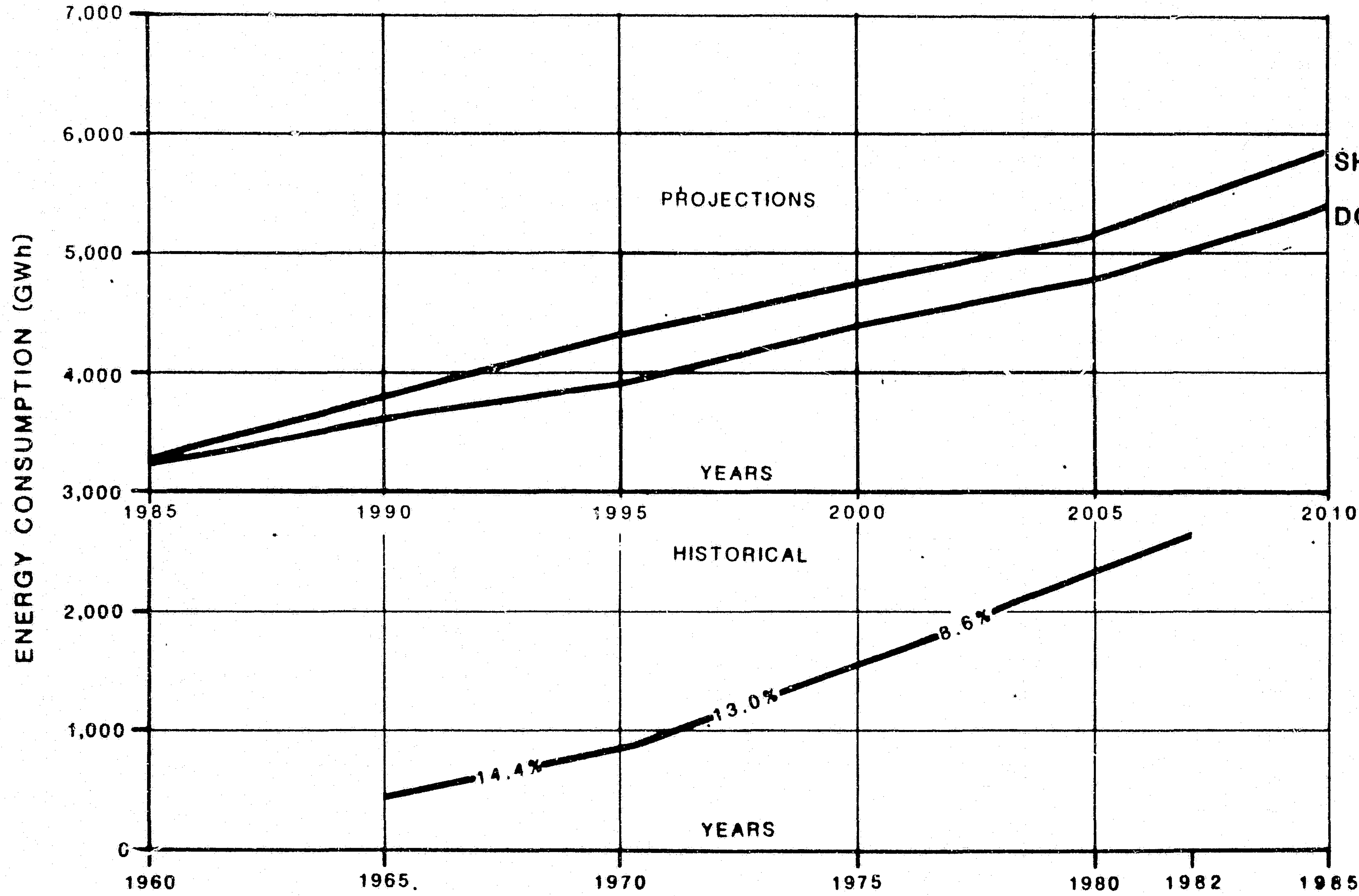
NOTE: PERCENTAGES ARE AVERAGE ANNUAL GROWTH RATES FOR 5-YEAR PERIODS

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ALTERNATIVE RAILBELT HOUSEHOLDS FORECASTS

SEPTEMBER 1983

EXHIBIT 2.11



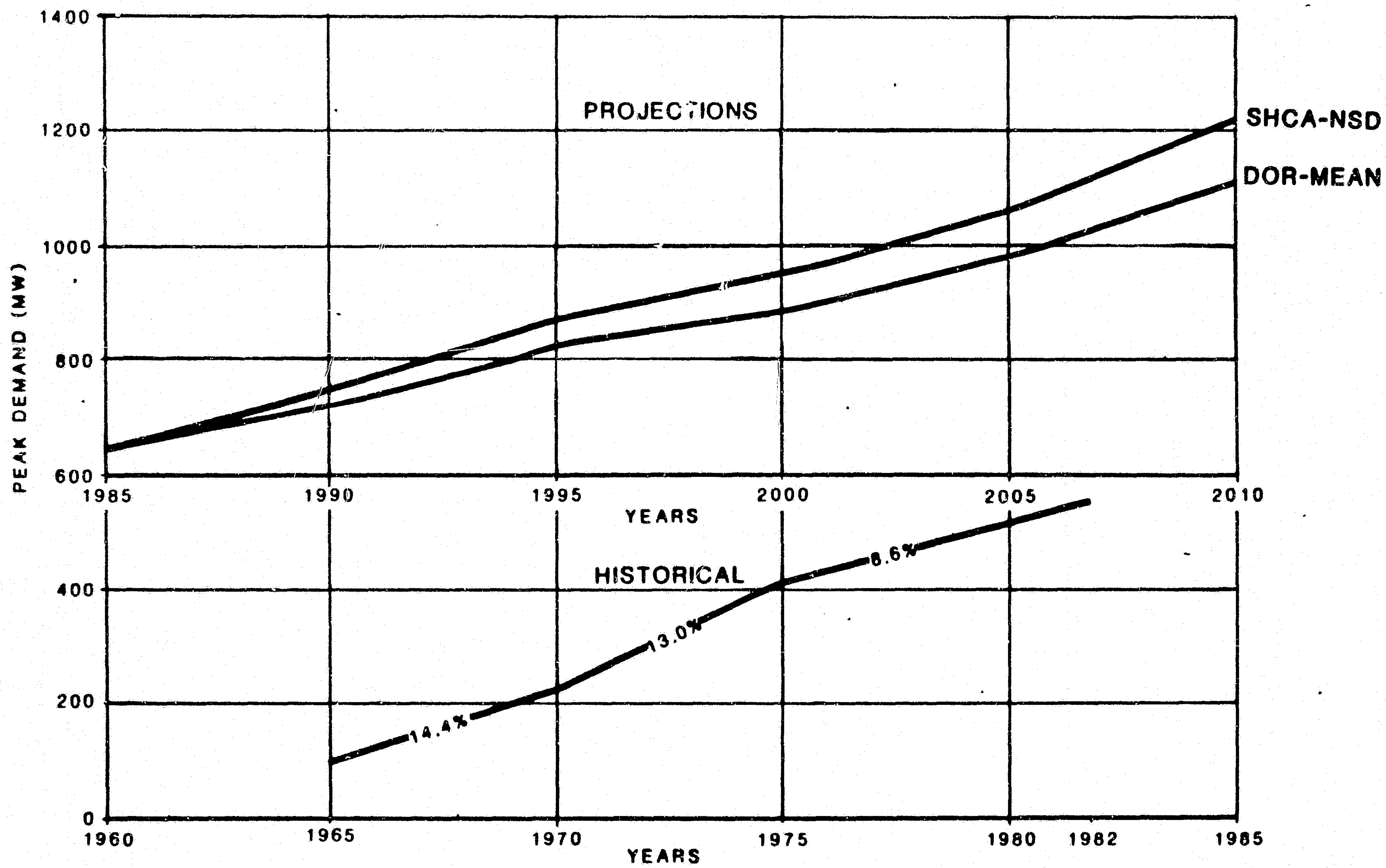
NOTE: PERCENTAGES ARE AVERAGE ANNUAL GROWTH RATES FOR 5-YEAR PERIODS

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ALTERNATIVE ELECTRIC ENERGY DEMAND FORECASTS

SEPTEMBER 1983

EXHIBIT 2.12



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ALTERNATIVE ELECTRIC PEAK DEMAND FORECASTS

SEPTEMBER 1983

NOTE: PERCENTAGES ARE AVERAGE ANNUAL GROWTH RATES FOR 5-YEAR PERIODS

EXHIBIT 2.13

EXHIBIT 2.14

SIMULATION CASE: AK DEPARTMENT OF REVENUE, JUNE 1983 MEAN

STATE PETROLEUM REVENUES
****
(MILLION $)
****

	ROYALTIES	SEVERANCE TAXES	CORPORATE INCOME TAXES	PROPERTY TAXES	TOTAL INCLUDING BONUSES AND FEDERAL SHARED ROYALTIES	TOTAL TO GENERAL FUND (NET OF PERMANENT FUND CONTRI- BUTION)
1982	1530.000	1590.000	668.900	142.700	3960.200	3570.350
1983	1450.820	1511.729	235.622	148.600	3395.871	3020.891
1984	1356.917	1371.872	246.073	153.200	3163.128	2815.132
1985	1449.808	1450.802	270.000	158.000	3358.302	2988.427
1986	1574.577	1554.771	288.900	163.456	3609.693	3209.052
1987	1689.480	1654.900	311.916	169.101	3853.240	3423.909
1988	1799.450	1484.916	336.572	174.940	3824.235	3367.283
1989	1974.123	1631.482	364.246	180.981	4179.980	3679.162
1990	2092.330	1723.442	399.675	187.231	4432.742	3902.144
1991	2032.379	1615.883	459.687	193.697	4332.672	3816.821
1992	2041.312	1559.445	506.563	200.385	4339.715	3821.384
1993	2116.684	1582.365	562.968	207.305	4502.324	3964.902
1994	2159.577	1584.669	622.593	214.464	4615.305	4066.910
1995	2048.210	1444.414	693.756	221.870	4443.250	3922.448
1996	1990.307	1333.398	751.489	229.532	4340.723	3834.146
1997	2084.163	1414.253	813.035	237.458	4585.906	4055.615
1998	2144.563	1420.565	898.521	245.658	4747.305	4201.664
1999	2173.862	1379.000	960.344	254.141	4806.348	4253.129
2000	2237.762	1394.027	1041.998	262.917	4976.703	4407.262
2001	2303.776	1409.361	1130.593	271.996	5156.723	4570.527
2002	2371.737	1424.863	1226.721	281.389	5346.707	4743.270
2003	2441.703	1440.536	1331.022	291.106	5547.363	4926.188
2004	2513.734	1456.381	1444.191	301.158	5759.457	5120.023
2005	2587.889	1472.401	1566.983	311.558	5983.824	5325.602
2006	2664.231	1488.596	1700.214	322.317	6221.355	5543.797
2007	2742.826	1504.970	1844.773	333.447	6473.016	5775.559
2008	2823.739	1521.524	2001.625	344.962	6739.848	6021.910
2009	2907.040	1538.260	2171.812	356.874	7022.980	6283.969
2010	2992.797	1555.181	2356.468	369.198	7323.641	6562.941

SOURCE: MAP MODEL OUTPUT FILES HE.23 AND HER.23
VARIABLES: RPRY, RPTS, RTCSPX, RPPS, RP9S, AND RP9SGF

EXHIBIT 2.15

SIMULATION CASE: AK DEPARTMENT OF REVENUE, JUNE 1983 MEAN

STATE GOVERNMENT EXPENDITURES
****
(MILLION $)
****

	UNRESTRICTED GENERAL FUND EXPENDITURES	GENERAL FUND BALANCE	PERMANENT FUND DIVIDENDS	STATE PERSONAL INCOME TAX	STATE SUBSIDY PROGRAMS	PERCENT OF PERMANENT FUND EARNINGS REINVESTED
1982	4601.891	399.200	425.000	0.000	634.000	0.000
1983	3287.977	521.801	152.608	0.000	500.000	0.500
1984	3389.657	409.699	196.668	0.000	350.000	0.500
1985	3699.574	190.332	222.540	0.000	300.000	0.500
1986	3733.185	190.320	250.679	0.000	200.000	0.500
1987	3999.295	190.316	281.617	0.000	100.000	0.500
1988	3994.070	190.313	0.000	0.000	0.000	0.500
1989	4746.605	22.027	0.000	217.174	0.000	0.500
1990	5390.395	108.285	0.000	444.067	0.000	0.500
1991	5527.559	108.305	0.000	489.953	0.000	0.000
1992	5643.840	108.320	0.000	541.554	0.000	0.000
1993	5938.184	108.340	0.000	594.960	0.000	0.000
1994	6141.148	108.355	0.000	631.101	0.000	0.000
1995	6106.457	108.379	0.000	672.065	0.000	0.000
1996	6141.340	108.402	0.000	722.809	0.000	0.000
1997	6498.758	108.426	0.000	781.378	0.000	0.000
1998	6789.934	108.449	0.000	844.131	0.000	0.000
1999	6991.496	108.465	0.000	910.612	0.000	0.000
2000	7305.895	108.477	0.000	983.385	0.000	0.000
2001	7640.316	108.500	0.000	1062.438	0.000	0.000
2002	7994.613	108.523	0.000	1148.529	0.000	0.000
2003	8373.992	108.547	0.000	1244.121	0.000	0.000
2004	8781.945	108.570	0.000	1348.620	0.000	0.000
2005	9214.430	108.594	0.000	1461.278	0.000	0.000
2006	9674.970	108.625	0.000	1583.202	0.000	0.000
2007	10164.960	108.660	0.000	1714.895	0.000	0.000
2008	10686.680	108.691	0.000	1857.048	0.000	0.000
2009	11241.370	108.727	0.000	2008.690	0.000	0.000
2010	11830.010	108.766	0.000	2172.465	0.000	0.000

SOURCE: MAP MODEL OUTPUT FILES HE.23 AND HER.23
VARIABLES: EXGFBM, BALGF, EXTRNS, RTIS, EXSUBS, AND EXPFBAK

EXHIBIT 2.16

SIMULATION CASE: AK DEPARTMENT OF REVENUE, JUNE 1983 MEAN

POPULATION
****
(THOUSANDS)
****

	STATE	RAILBELT	GREATER ANCHORAGE	GREATER FAIRBANKS
1982	437.175	307.105	239.830	67.277
1983	457.836	319.767	251.057	68.711
1984	473.752	330.201	259.678	70.523
1985	490.373	341.839	269.479	72.360
1986	505.292	351.873	277.869	74.004
1987	516.310	357.846	282.350	75.497
1988	524.023	362.552	286.345	76.206
1989	532.751	370.576	293.177	77.400
1990	543.901	380.344	301.114	79.231
1991	548.656	382.859	302.869	79.990
1992	565.792	392.937	312.070	80.868
1993	573.417	396.894	314.824	82.071
1994	577.042	401.173	317.521	83.652
1995	581.710	404.351	320.394	83.957
1996	587.896	408.841	324.160	84.681
1997	594.829	414.714	328.994	85.721
1998	601.122	419.844	333.205	86.640
1999	607.410	425.158	337.600	87.559
2000	614.105	430.823	342.207	88.616
2001	620.790	436.674	346.930	89.744
2002	627.799	442.731	351.855	90.876
2003	635.795	449.299	357.275	92.024
2004	644.315	456.259	362.995	93.264
2005	653.359	463.623	369.043	94.580
2006	662.935	471.462	375.466	95.997
2007	673.061	479.628	382.151	97.477
2008	683.805	488.280	389.233	99.048
2009	694.797	497.089	396.407	100.682
2010	706.582	506.548	404.135	102.413

SOURCE: MAP MODEL OUTPUT FILES HE.23 AND HER.23
VARIABLES: POP, P.IR, P.AG, AND P.FG

EXHIBIT 2.17

SIMULATION CASE: AK DEPARTMENT OF REVENUE, JUNE 1983 MEAN

EMPLOYMENT
****
(THOUSANDS)
****

	STATE NON-AG WAGE AND SALARY	STATE TOTAL	RAILBELT TOTAL	GREATER ANCHORAGE TOTAL	GREATER FAIRBANKS TOTAL
1982	192.903	231.984	154.033	120.533	33.500
1983	202.237	243.067	159.147	125.221	33.927
1984	205.902	246.983	162.258	127.852	34.406
1985	216.836	258.634	169.392	133.823	35.569
1986	224.846	267.182	174.385	138.003	36.383
1987	229.926	272.616	176.540	139.640	36.900
1988	232.340	275.202	177.683	140.685	36.998
1989	235.306	278.393	180.394	143.048	37.346
1990	240.777	284.232	183.738	145.921	37.818
1991	239.563	282.955	184.190	146.042	38.147
1992	252.777	297.053	190.167	151.429	38.738
1993	252.503	296.787	191.261	152.012	39.249
1994	251.478	295.727	191.327	151.853	39.475
1995	252.580	296.942	192.881	153.181	39.699
1996	254.883	299.449	194.700	154.720	39.980
1997	257.812	302.636	197.284	156.867	40.417
1998	259.885	304.927	199.564	158.733	40.831
1999	262.116	307.409	201.863	160.651	41.212
2000	264.791	310.315	204.424	162.749	41.675
2001	267.483	313.186	207.092	164.921	42.171
2002	270.447	316.348	209.949	167.256	42.693
2003	274.272	320.429	213.146	169.909	43.236
2004	278.371	324.804	216.676	172.815	43.861
2005	282.812	329.544	220.479	175.941	44.539
2006	287.521	334.571	224.548	179.276	45.272
2007	292.496	339.884	228.827	182.776	46.051
2008	297.787	345.536	233.329	186.460	46.869
2009	303.001	351.107	237.944	190.206	47.738
2010	308.751	357.253	242.809	194.183	48.626

SOURCE: MAP MODEL OUTPUT FILES HE.23 AND HER.23
VARIABLES: EM97, EM99, M.IR, M.AG, AND M.FG

SIMULATION CASE: AK DEPARTMENT OF REVENUE, JUNE 1983 MEAN

HOUSEHOLDS
****
(THOUSANDS)
****

	STATE	RAILBELT	GREATER ANCHORAGE	GREATER FAIRBANKS
1982	145.453	106.572	83.678	22.894
1983	153.141	111.549	88.038	23.511
1984	159.154	115.671	91.425	24.246
1985	165.377	120.219	95.228	24.991
1986	170.988	124.159	98.501	25.657
1987	175.232	126.633	100.369	26.265
1988	178.319	128.6[illegible]5	102.088	26.597
1989	181.739	131.783	104.705	27.078
1990	185.983	135.554	107.757	27.798
1991	188.025	136.701	108.576	28.124
1992	194.310	140.694	112.182	28.512
1993	197.343	142.364	113.368	28.996
1994	198.998	144.152	114.527	29.625
1995	201.001	145.532	115.749	29.783
1996	203.519	147.398	117.303	30.095
1997	206.291	149.766	119.242	30.524
1998	208.842	151.836	120.933	30.903
1999	211.390	153.972	122.691	31.282
2000	214.073	156.234	124.523	31.711
2001	216.749	158.559	126.393	32.166
2002	219.531	160.956	128.335	32.621
2003	222.645	163.535	130.454	33.081
2004	225.935	166.246	132.674	33.573
2005	229.400	169.098	135.007	34.091
2006	233.044	172.118	137.473	34.645
2007	236.874	175.246	140.025	35.221
2008	240.913	178.545	142.717	35.828
2009	245.036	181.894	145.435	36.458
2010	249.428	185.477	148.354	37.123

SOURCE: MAP MODEL OUTPUT FILES HE.23 AND HER.23
VARIABLES: HH, HH.IR, HH.AG, AND HH.FG

DOR MEAN SCENARIO
RESIDENTIAL USE PER HOUSEHOLD

Year	Before Conservation Adjustment and Fuel Substitution				After Adjustment
	Small Appliances (kWh)	Large Appliances (kWh)	Space Heat (kWh)	Total (kWh)	Total (kWh)
		Anchorage-Cook Inlet Area			
1980	2110	6500	5089	13699	13699
1985	2160	6151	4821	13132	12851
1990	2210	6022	4598	12830	12549
1995	2260	5958	4511	12730	12544
2000	2310	5989	4460	12759	12582
2005	2360	6060	4419	12839	12628
2010	2410	6126	4440	12976	12758
		Fairbanks-Tanana Valley Area			
1980	2466	5740	3314	11519	11519
1985	2536	6179	3607	12322	12150
1990	2606	6447	3864	12916	12688
1995	2676	6658	4043	13377	13175
2000	2746	6793	4312	13851	13722
2005	2816	6852	4507	14175	14149
2010	2886	6892	4656	14434	14526

DOR MEAN SCENARIO
BUSINESS USE PER EMPLOYEE

Year	Before Conservation Adjustment and Fuel Substitution: Anchorage-Cook Inlet Area (kWh)	Before Conservation Adjustment and Fuel Substitution: Fairbanks-Tanana Valley Area (kWh)	After Adjustments: Anchorage-Cook Inlet Area (kWh)	After Adjustments: Fairbanks-Tanana Valley Area (kWh)
1980	8,407	7,496	8,407	7,496
1985	9,585	7,974	9,225	7,907
1990	10,184	8,277	9,570	8,235
1995	10,646	8,572	9,877	8,569
2000	11,187	8,879	10,199	8,901
2005	11,842	9,225	10,592	9,263
2010	12,648	9,618	11,168	9,670

EXHIBIT 2.20

DOR MEAN SCENARIO
BREAKDOWN OF ELECTRICITY PROJECTIONS (GWH)
ANCHORAGE - COOK INLET AREA

YEAR	RESIDENTIAL PROJECTIONS	BUSINESS PROJECTIONS	MISCELLANEOUS PROJECTIONS	EXOG. INDUSTRIAL LOAD PROJECTIONS	TOTAL
1983	1101.05	1090.57	25.34	108.24	2325.20
1984	1141.55	1162.31	25.69	116.32	2445.87
1985	1182.06	1234.04	26.04	124.40	2566.54
1986	1208.06	1266.57	26.66	137.89	2639.17
1987	1234.05	1299.09	27.28	151.38	2711.81
1988	1260.05	1331.61	27.91	164.88	2784.44
1989	1286.05	1364.13	28.53	178.37	2857.08
1990	1312.05	1396.65	29.16	191.86	2929.72
1991	1331.76	1419.09	29.60	195.13	2975.57
1992	1351.46	1441.52	30.05	198.40	3021.43
1993	1371.17	1463.95	30.50	201.66	3067.29
1994	1390.88	1486.39	30.94	204.93	3113.14
1995	1410.59	1508.82	31.39	208.20	3159.00
1996	1433.98	1538.95	32.00	214.14	3219.06
1997	1457.36	1569.08	32.60	220.08	3279.13
1998	1480.75	1599.22	33.21	226.02	3339.19
1999	1504.14	1629.35	33.81	231.96	3399.26
2000	1527.52	1659.48	34.42	237.90	3459.32
2001	1555.52	1700.63	35.12	244.96	3536.23
2002	1583.53	1741.77	35.81	252.02	3613.13
2003	1611.53	1782.92	36.51	259.08	3690.04
2004	1639.53	1824.06	37.21	266.14	3766.95
2005	1667.53	1865.21	37.91	273.20	3843.85
2006	1705.45	1926.63	38.96	281.58	3952.62
2007	1743.36	1988.05	40.00	289.96	4061.38
2008	1781.28	2049.47	41.05	298.34	4170.14
2009	1819.19	2110.89	42.10	306.72	4278.90
2010	1857.11	2172.31	43.14	315.10	4387.66

DOR MEAN SCENARIO
BREAKDOWN OF ELECTRICITY PROJECTIONS (GWH)
FAIRBANKS - TANANA VALLEY AREA

YEAR	RESIDENTIAL PROJECTIONS	BUSINESS PROJECTIONS	MISCELLANEOUS PROJECTIONS	EXOG. INDUSTRIAL LOAD PROJECTIONS	TOTAL
1983	219.25	255.53	6.67	0.00	481.45
1984	233.54	268.33	6.63	0.00	508.50
1985	247.82	281.13	6.60	0.00	535.55
1986	258.62	287.22	6.60	10.00	562.45
1987	269.42	293.32	6.61	20.00	589.35
1988	280.22	299.41	6.62	30.00	616.25
1989	291.03	305.50	6.63	40.00	643.16
1990	301.83	311.60	6.64	50.00	670.06
1991	312.09	317.40	6.81	50.00	686.30
1992	322.36	323.20	6.98	50.00	702.54
1993	332.63	329.00	7.15	50.00	718.78
1994	342.90	334.80	7.32	50.00	735.02
1995	353.17	340.61	7.49	50.00	751.26
1996	361.48	346.80	7.64	50.00	765.91
1997	369.79	352.99	7.79	50.00	780.56
1998	378.10	359.18	7.94	50.00	795.22
1999	386.41	365.37	8.09	50.00	809.87
2000	394.72	371.56	8.24	50.00	824.52
2001	404.00	379.93	8.40	50.00	842.34
2002	413.28	388.31	8.56	50.00	860.15
2003	422.56	396.69	8.72	50.00	877.97
2004	431.84	405.06	8.88	50.00	895.78
2005	441.12	413.44	9.04	50.00	913.60
2006	452.38	425.03	9.31	50.00	936.72
2007	463.65	436.62	9.57	50.00	959.84
2008	474.92	448.21	9.83	50.00	982.97
2009	486.19	459.80	10.10	50.00	1006.09
2010	497.45	471.39	10.36	50.00	1029.21

DOR MEAN SCENARIO
PROJECTIONS OF PEAK AND ENERGY DEMAND

	Energy Demand (GWh)			Peak Demand (MW)			
YEAR	ANCHORAGE - COOK INLET AREA	FAIRBANKS - TANANA VALLEY AREA	TOTAL	ANCHORAGE - COOK INLET AREA	FAIRBANKS - TANANA VALLEY AREA	TOTAL	Load Factor %
1983	2325	481	2806	469	109	579	55.3
1984	2445	508	2954	494	116	610	55.3
1985	2566	535	3102	518	122	640	55.3
1986	2639	562	3201	533	128	662	55.2
1987	2711	589	3301	549	134	683	55.1
1988	2784	616	3400	564	140	705	55.0
1989	2857	643	3500	580	146	727	54.9
1990	2929	670	3599	595	152	748	54.9
1991	2975	686	3661	605	156	761	54.9
1992	3021	702	3723	614	160	774	54.9
1993	3067	718	3786	623	164	787	54.9
1994	3113	735	3848	632	167	800	54.9
1995	3159	751	3910	642	171	813	54.9
1996	3219	765	3984	654	174	829	54.9
1997	3279	780	4059	666	178	844	54.9
1998	3339	795	4134	678	181	859	54.9
1999	3399	809	4209	690	184	875	54.9
2000	3459	824	4283	702	188	890	54.9
2001	3536	842	4378	718	192	910	54.9
2002	3613	860	4473	733	196	929	54.9
2003	3690	877	4568	749	200	949	54.9
2004	3766	895	4662	764	204	969	54.9
2005	3843	913	4757	780	208	988	54.9
2006	3952	936	4889	801	213	1015	54.9
2007	4061	959	5021	823	219	1043	55.0
2008	4170	982	5153	845	224	1070	55.0
2009	4278	1006	5284	867	229	1097	55.0
2010	4388	1029	5417	890	235	1125	55.0

EXHIBIT 2.22

LIST OF PREVIOUS

RAILBELT PEAK AND ENERGY DEMAND FORECASTS

(MEDIUM SCENARIO)

	ISER 1980 Forecast[1]		Battelle 1981 Forecast[2]		Battelle 1982 Forecast Plan 1A (w/o Susitna)[3]		Battelle 1982 Forecast Plan 1B (w/ Susitna)[3]		Battelle Revised 1982 Forecast Plan 1A[4]	
YEAR	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)
1980	510	2790	----	----	521	2551	521	2551	521	2551
1981	----	----	574	2893	----	----	----	----	----	----
1985	650	3570	687	3431	643	3136	647	3160	615	3000
1990	735	4030	892	4456	880	4256	924	4482	701	3391
1995	934	5170	983	4922	993	4875	996	4894	791	3884
2000	1175	6430	1084	5469	1017	5033	995	4728	810	4010
2005	1380	7530	1270	6429	1092	5421	1073	5327	870	4319
2010	1635	8940	1537	7791	1259	6258	1347	6686	1003	4986

1/ Table 5.6 - Acres Feasibility Report - Volume 1. Includes 30% of military loads, and excludes industrial self-supplied electricity.

2/ Table 5.7 - Acres Feasibility Report - Volume 1. Excludes military and industrial self-supplied electricity.

3/ Table B.12 and B.13 of Battelle Volume 1. Excludes military and industrial self-supplied electricity.

4/ Page xv of Battelle Volume 1. Excludes military and industrial self-supplied electricity.

Note: The ISER and Battelle forecasts are for the Anchorage - Cook Inlet area, Fairbanks-Tanana Valley area, and Glennallen - Valdez area.

EXHIBIT 2.23

RAILBELT UTILITIES FORECAST

YEAR	AML&P (1) Energy (GWH)	AML&P (1) Winter Peak (MW)	CEA (1) (2) Energy (GHW)	CEA (1) (2) Winter Peak (MW)	FMU (1) Energy (GWH)	FMU (1) Winter Peak (MW)	GVEA (1) Energy (GHW)	GVEA (1) Winter Peak (MW)	RAILBELT TOTAL (3) Energy (GHW)	RAILBELT TOTAL (3) Winter Peak (MW)
1983	717	140	1854	384	147	29	387	74	3105	627
1984	786	1152	1966	408	153	30	416	81	3321	672
1985	844	162	2079	432	161	32	447	89	3531	716
1986	915	174	2192	457	165	32	480	97	3752	761
1987	1053	197	2304	48[illegible]	168	33	516	107	3974	807
1988	1126	209	2417	505	172	34	603	113	4200	850
1989	1200	221	2530	529	175	35	653	120	4443	894
1990	1270	232	2642	554	183	36	653	128	4678	940
1991	1270	232	2754	578	190	38	706	136	4920	984
1992	1322	241	2867	602	198	39	764	145	5151	1028
1993	1375	251	2979	626	206	41	826	154	5386	1073
1994	1431	261	3091	651	214	42	894	164	5630	1118
1995	1489	272	3203	675	225	45	967	174	5884	1166
1996	1549	283	3315	699	237	47	1046	185	6147	1215
1997	1621	294	3428	723	249	49	1131	197	6429	1264
1998	1697	306	3540	747	262	52	1223	209	6722	1415
1999	1775	318	3652	771	275	54	1323	222	7025	1367
2000	1858	331	3764	795	281	56	1432	236	7335	1419
2001	1944	344	3875	820	295	58	1548	251	7662	1474

NOTES:
(1) CEA forecast includes Matanuska Electric Assoc., Homer Electric Assoc., & Seward Electric requirements.
(2) Eklutna is included in AML&P & CEA.

AML&P = Anchorage Municipal Light & Power
CEA = Chugach Electric Association
FMU = Fairbanks Municipal Utilities System
GVEA = Golden Valley Electric Association, Fairbanks Area

SOURCE: ALASKA POWER ADMINISTRATION, March 1983

EXHIBIT 2.24

CHUGACH ELECTRIC ASSOCIATION, INC.

PROJECTIONS OF TOTAL SYSTEM ENERGY REQUIREMENTS[1/]

Year	Low		Moderate		High	
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
1983	1,817	412	1,868	426	1,879	429
1984	1,942	432	2,050	463	2,081	469
1985	2,059	451	2,265	501	2,299	510
1986	2,189	470	2,473	533	2,614	575
1987	2,281	491	2,642	568	2,935	654
1988	2,365	513	2,803	606	3,283	745
1989	2,445	535	2,962	646	3,664	850
1980	2,523	559	3,121	689	4,087	974
1991	2,582	575	3,167	699	4,150	978
1992	2,651	591	3,207	706	4,164	969
1993	2,725	606	3,251	713	4,187	961
1994	2,802	623	3,299	721	4,220	954
1995	2,884	639	3,350	729	4,261	946
1996	2,982	660	3,406	738	4,315	938
1997	3,103	680	3,467	747	4,381	931

1/ Includes Matanuska Electric Association, Homer Electric Association, and Seward Electric System.

Source: Power Requirements Study, 1983, by Burns & McDonnell

Exhibit 2.26

SUMMARY OF POPULATION, ENERGY AND PEAK DEMAND PROJECTIONS UNDER THE DOR MEAN AND SHCA-NSD SCENARIOS FOR SEPTEMBER 1983 UPDATE

	1990	2000	2010
DOR-MEAN Scenario (a)			
Population	380,344	430,823	506,548
Energy Demand (GWh) (b)	3,599	4,281	5,404
Peak Demand (MW)	749	890	1,122
SHCA-NSD Scenario			
Population	389,026	451,561	533,218
Energy Demand (GWh) (b)	3,737	4,542	5,858
Peak Demand (MW)	777	945	1,217

(a) DOR Mean forecast is from the June 1983 DOR quarterly report.

(b) All projections at consumption level, excluding military and self generations that cannot be supplied by Susitna or Railbelt utilities.

3.0 UPDATE OF THE SUSITNA PROJECT

3.0 UPDATE OF THE SUSITNA PROJECT

3.1 INTRODUCTION

This Chapter presents an update of the Susitna Project as proposed in the FERC License Application incorporating the design refinements and corresponding revisions in estimated project costs that resulted from recent studies. Details on the refinements to conceptual design are contained in the report "Review and Update of Conceptual Design", November 1983. / No

Using the recommended design concepts, the estimated costs and power and energy production are developed.

Improved ways the project can be operated are described. The results are incorporated in the studies of alternative system expansion programs to meet future Railbelt demand in Chapter 5. Economic analyses and cost of power are given in Chapter 6.

3.2 DESCRIPTION OF THE SUSITNA PROJECT

The Susitna Hydroelectric Project will comprise two major developments on the Susitna River some 180 miles north and east of Anchorage, Alaska. The first phase of the project will be the Watana Development which will incorporate an earth and rockfill dam together with associated diversion, spillway outlet facilities, power facilities, and a transmission system. The second phase will include the Devil Canyon concrete arch dam with associated diversion, spillway outlet facilities, power facilities, and an integrated transmission system.

3.2.1 Watana Development

The Watana Dam can provide a reservoir approximately 54 miles long, with a surface area of 38,000 acres, and a gross storage capacity of 9,600,000 acre-feet at El. 2185, the normal maximum operating level. The minimum operating level of the reservoir for the El. 2185 development would be El. 2065, providing an active storage volume during normal operation of 3,700,000 acre-feet.

The dam will be a zoned embankment structure with a central impervious core. The nominal crest elevation of the dam will be El. 2205, with a maximum height of 885 feet above the foundation and a crest length of 4,100 feet.

The power intake will be located on the north bank with an approach channel excavated in rock. From the intake structure, concrete-lined penstocks will lead to an underground powerstation housing six 170-MW generating units.

Low level outlet facilities will be provided to assure that downstream flow requirements can be met without power releases and to provide discharge capacity for frequent floods.

The main spillway, also located on the north bank, will consist of a gated ogee control structure and an inclined contrete chute and flip bucket designed to pass a maximum discharge of 118,000 cfs at the maximum normal pool level. The spillway will provide sufficient capacity to permit discharge of the Probable Maximum Flood (PMF) with the reservoir surcharged to elevation 2201.

3.2.2 Devil Canyon Development

The Devil Canyon Dam will form a reservoir approximately 26 miles long with a surface area of 7,800 acres and a gross storage capacity of 1,100,000 acre-feet at El. 1455, the normal maximum operating level. The operating level of the Devil Canyon reservoir controls the tailwater level of the upstream Watana development. The minimum operating level of the reservoir will be El. 1405, providing a live storage of 350,000 acre-feet during normal reservoir operation.

The dam will be a thin arch concrete structure with a crest level of El. 1463 and maximum height of 646 feet. It will be supported by mass concrete thrust blocks on each abutment. Adjacent to the thrust block, an earth and rockfill saddle dam will provide closure to the south bank.

The power intake on the north bank will consist of an approach channel excavated in rock leading to a reinforced concrete gate structure. Concrete-lined penstock tunnels will lead from the intake structure to an underground powerstation housing four 150-MW units.

Outlet facilities will be located in the lower part of the main dam to assure that downstream flow requirements can be met without power releases and to provide capacity for discharge of frequent floods. The spillway facilities are designed to pass the 10,000-year flood without reservoir surcharge above normal maximum elevation of 1455. The reservoir will surcharge to elevation 1463 during the Probable Maximum Flood event.

3.3 DESIGN IMPROVEMENTS

The initial engineering effort by the Harza-Ebasco Joint Venture was a detailed review of the design concept and cost estimates for the Watana

Development and the associated access and transmission facilities as presented in the FERC License Application.

The review process led to the identification of some design refinements that are clearly favorable based on cost and safety considerations. The design refinements that are being introduced reflect the more detailed geotechnical data available as a result of the 1983 Winter Geotechnical Program and a detailed study of the probable maximum flood (PMF). The recommended design refinements (Category 1) have been reviewed and accepted by the Alaska Power Authority External Review Panel and Board of Directors. The following list identifies the major (Category 1) design features that have been recommended for refinement.

Category 1 - Recommended Refinements

WATANA

- Dam Foundation Excavation and Treatment
- Dam Configuration and Composition
- Cofferdam and Diversion Tunnels
- Power Intake - Spillway Approach Channel
- Underground Cavern Orientation
- Power Conduits
- Elimination of Fuseplug Spillway
- Transmission Voltage

DEVIL CANYON

- Elimination of Fuseplug Spillway

In addition to the design refinements under Category 1, there are additional cost-saving design refinements which appear to be promising, but need further study. These include the following:

Category 2 - Potential Refinements

- Relict channel treatment
- Outlet facilities
- Emergency release facilities
- SF-6 Switchgear
- Transformer locations for underground powerstation
- Transmission circuits

At the October 14, 1983 Board Meeting the Power Authority Board of Directors directed further study on the Relict Channel treatment and other design refinements that will not delay the FERC licensing process. These studies have been initiated; however, the results are not available for inclusion in this update.

3.4 COST ESTIMATES

3.4.1 Construction Cost Estimates

Exhibit 3.1 shows the estimated costs for the Watana and Devil Canyon Developments which incorporate the Category 1 refinements only. For the Watana development, the construction cost estimate can be reduced from $3,828 million for the layout shown in the License Application to $3,432 million (1983 dollars), a saving of $396 million. For the Devil Canyon Development, the construction cost estimate can be reduced from $1,577 million to $1,552 million (1983 dollars), a saving of $25 million.

The installed capacity of the Watana Project is 1020 MW in the License Application. It is provided in six units, each rated at 170 MW. The fifth and sixth units provide no additional energy production. They are available for peaking use and spinning reserve but do not provide significant economic benefit in view of the reduced load growth. Cost reduction of the initial project amounting to $94 million (January

1983) can be achieved with the postponement of installing these two units, as shown on Exhibit 3.2. Exhibit 3.3 shows the general plan of the Watana 2185 development with Category 1 refinements.

3.4.2 Operation and Maintenance Costs

The operation and maintenance costs account for the personnel, equipment, materials, and facilities required to operate the generating plant and to maintain all of the structures and machinery. Under changing project conditions over time, the following estimated costs cover the various periods of the project life:

1. Watana (first five years), $8.5 million per year
2. Devil Canyon addition (first five years), $2.5 million per year
3. Eventual annual cost, $7.3 million per year

These costs, as all other costs presented here, are at January 1983 levels. The components of these figures appear on Exhibit 3.4.

3.5 RESERVOIR OPERATION STUDIES

In the present License Application, the initial Watana project would operate on base in order to maintain nearly uniform discharge from the powerplant. When Devil Canyon comes on line, Watana would operate in a load following mode, while Devil Canyon operates on base.

Operation studies were performed to estimate the power and energy production capability of the Susitna Project under the above operation assumptions.

3.5.1 Simulation Model

A dual-reservoir computer simulation program was developed during the 1982 Susitna Project Feasibility Study. This program was modified to incorporate some desired improvements. Major changes related to the use of a variable tailwater rating, and variable turbine capacity and efficiency as a function of head. Minor changes in data input requirements and output format were also implemented.

3.5.2 Hydrology

Thirty-two years of streamflow data, as provided in the 1982 feasibility report for the Watana, Devil Canyon, and Gold Creek sites, were reviewed and accepted for use in the analysis. These data included an adjustment to the 1969 drought. Subsequently, another year of flow data became available and was incorporated. The project operation is simulated on a monthly basis for an historical streamflow period of 33 years (Water Years 1950-1982).

The adjustment to the 1969 drought was made to reflect a 30-year recurrence interval, instead of the approximately 1000-year recurrence of the natural flow event. The effect of this adjustment on average energy production from the project for the 33-year simulation was analyzed. Use of the adjusted 1969 flows increases the annual energy production by about one percent over that computed using the 1969 natural flows.

3.5.3 Reservoir Data

Area and volume versus elevation relations for the Watana and Devil Canyon damsites are given on Exhibits 3.5 and 3.6. At the Watana normal maximum pool elevation of 2185, the reservoir surface area is about 38,000 acres, and the gross storage volume is 9.6 million acre-feet. At the Devil Canyon normal maximum pool elevation of 1455, the reservoir surface area is about 7,800 acres, with a gross storage volume of 1.1 million acre-feet. The active storage volumes are fixed by the normal maximum reservoir elevations and drawdowns as shown in Table 3.1.

Table 3.1

SUSITNA PROJECT DATA

Development	Nor. Max. W.S. Elev. (ft. msl)	Draw-down (ft)	Initial No. of Units	Rated Head (ft)	Initial Installed Capacity (December) (MW)
Watana	2185	120	4	680	680
Devil Canyon	1455	100	4	590	600

3.5.4 Turbine and Generator Data

The operating characteristics for the Watana and Devil Canyon powerplants are summarized on Exhibit 3.7 based on the rated net head. In all cases, generator and transformer efficiencies of 98 and 99 percent, respectively, were used to compute the overall plant efficiency. A head loss percentage of 1.5 percent of gross head was used for both Watana and Devil Canyon powerplants.

3.5.5 Reservoir Operation Constraints

During the early years of operation, energy generation from the Susitna Project could be limited by the system demand. Beyond some high demand level, the physical limits of the project machinery and water supply will control. Operation simulations were made for a wide range of system demand levels (4000-8000 GWh/year) to establish the relation of system demand to energy production from the project.

The project is operated to meet a minimum monthly flow requirement, at the mouth of Gold Creek, denoted as "Case C" in the License Application and shown in Table 3.2.

Table 3.2

"CASE C"

FLOW REQUIREMENTS AT GOLD CREEK, cfs (a)

Month	Flow	Month	Flow
October	5000	April	5000
November	5000	May	6000
December	5000	June	6000
January	5000	July	6480 (b)
February	5000	August	12000
March	5000	September	9300 (b)

(a) As discussed in the license application, the "Case C" flow scenario was selected as the project operation flow regime considering both project and environmental interests.

(b) Flows change by 1000 cfs per day from 6000 on July 25 to 12,000 on August 1 and from 12,000 on September 14 to 6000 on September 21.

The reservoir rule curve is the list of monthly target reservoir elevations to control the reservoir drawdown. A low rule curve maximizes drawdown and average energy production, but tends to minimize the firm energy production in the critical water period. A high rule curve would have the opposite effect. The selected Watana rule curve is developed to maximize average energy generation while at the same time maintaining a high level firm energy. The Devil Canyon operating rule is to keep the reservoir as full as possible in all cases.

3.5.6 Power and Energy Production

Energy production (GWh) and project capability (MW) are estimated from reservoir operation studies. The studies considered the energy demands for the period 1993 through 2020, for the DOR Mean and SHCA-NSD load forecasts.

Exhibit 3.8 summarizes the power and energy production for Watana 2185 and Devil Canyon under the DOR Mean load forecast for the year 2020. The power and energy estimates are based on the modes of operation and constraints discussed previously.

3.6 ENVIRONMENTAL STATUS UPDATE

This section presents an update of the status of the principal environmental issues related to the Susitna Project, and the activities being conducted to resolve them.

A full range of environmental studies has been continued since the filing of the FERC License Application in February 1983. The objectives of these studies have been to refine the assessment of impacts as identified in Exhibit E of the License Application and to assist in the licensing process by responding to FERC inquiries. As of this time, responses have been prepared and provided to FERC on 230 questions or requests for clarification and supplementary information. At this time, all inquiries from FERC have been addressed. In addition, a list of approximately 300 issues and questions has been compiled from a comprehensive review of all state and federal agency comments received by the Alaska Power Authority during the last four years. Many of these issues were addressed in Exhibit E. Work on others is continuing.

In addition to preparation of written responses, FERC personnel were conducted on a tour of the Susitna basin and related areas during the week of August 21-27 so that they could better evaluate the project based on first-hand information.

Continuing environmental activities relate to the refinement and quantification, if possible, of impacts and the development of mitigation programs tailored to specific project needs. These activities cover all aspects of potential project impacts and are briefly discussed below under the major headings of aquatic, terrestrial and social science programs.

3.6.1 Aquatic

The key environmental issue related to the aquatic resources focuses on the effects of the altered flow regime on the aquatic ecosystem in the Susitna River. The Susitna Hydroelectric Project will also alter the water temperature regimes, turbidity and other water quality parameters such as dissolved gas and suspended solids concentrations downstream from the reservoirs.

The effect of the altered flows on anadromous and resident fish populations is the major focus of present studies. The principal concerns are potential alterations to spawning habitats of salmon, access to the spawning habitats, and juvenile rearing habitats. These questions are being addressed through a series of mathematical models designed to quantify the expected changes in flow and fish habitats. Both physical and biological data are being collected to calibrate the predictive models and to relate the physical changes in habitats to the biological impacts. Five major habitat types have been identified which are important to the fish and which will be affected by the altered flows. These are the mainstem of the Susitna River, side channels, side sloughs, upland sloughs and tributary mouths.

Most of the effort to quantify the effects has been directed toward those habitat types found in the Devil Canyon to Talkeetna reach of the Susitna River. Additionally, preliminary studies are being conducted in the reach between Talkeetna and Cook Inlet. These latter studies will be used to develop a more detailed quantification, to the extent possible, of the effects of the Susitna Hydroelectric Project on the aquatic resources in the lower reach of the Susitna River.

Studies will be also conducted to address questions of navigability throughout the Susitna River and of the effects to various Susitna River user groups.

It is anticipated that the project will alter the temperature regimes of the Susitna River. To address the potential effects of the altered temperature regime, it is necessary to estimate what changes will occur. This is being accomplished through a series of mathematical models concerning water temperature in the reservoirs and in the river downstream. As a part of this analysis, a mathematical model is also being used to address questions related to ice processes in the reservoirs and river.

Questions related to changed turbidity and other water quality parameters are being answered through comparisons of the expected changes with observed changes at other comparable hydroelectric projects in Alaska and elsewhere.

3.6.2 Terrestrial

No single outstanding concern has been identified as a key terrestrial issue. Rather, continuing terrestrial studies are aimed at more detailed evaluation and refinement of project impact assessments and of proposed mitigation plans as discussed in the License Application. Many of the present studies were developed to contribute to modeling efforts designed to evaluate loss of habitat (lost moose carrying capacity and changes in moose population due to changes in carrying capacity), predator-prey ratios, hunting pressure, and other factors. Components of these modeling efforts include browse inventories, plant phenology studies, more precise mapping of forage areas, moose censuses, and studies of the importance of moose movements, and the importance of predation by wolves and bears in controlling moose numbers. Output from the studies will facilitate the development of mitigation programs commensurate with project impacts.

Other studies underway include monitoring movements and habitat use of moose in the riparian zone downstream of Devil Canyon; monitoring the movements and herd size of caribou in the project area; analysis of the use of the Jay Creek mineral lick by Dall Sheep; studies on bear and wolf movements and habitat use; and raptor studies, particularly directed at project effects on golden and bald eagles. Beaver surveys and modeling efforts for the riparian zone from Devil Canyon to Talkeetna are being conducted to determine the likely effects of altered downstream flow regimes. More stable flows following project construction may improve habitat conditions for beaver and result in increased populations and increased numbers of beaver dams and other structures. This, in turn, could decrease the value of the area as spawning habitat for salmon.

3.6.3 Social Sciences

The social science program comprises six subtasks: cultural resources, socioeconomics, recreation, aesthetics, land use, and project alternatives. The following discussion briefly outlines the status of each subtask in FY 1984 and the principal focus of each subtask for FY 1985.

3.6.3.1 Cultural Resources. The final report on the 1983 field season is currently being prepared by the University of Alaska Museum. Field work in 1983 included continued reconnaissance surveying (for the purpose of identifying historic and archeological sites) of the proposed dam sites, impoundment areas, and borrow sites. In addition, limited systematic testing of identified sites was conducted. Furthermore, sensitivity mapping showing archeological potential was completed for the proposed railroad, access road, transmission line, and Phase I Recreation Plan.

The second main activity of the cultural resources subtask FY 1984 is a reevaluation of the Susitna archeological program in light of a review of current procedures and schedule, and the rule of the Advisory Council on Historic Preservation. Part of this reevaluation will include an analysis of whether the project area should be considered individually, or whether the project area should be considered as an archeological district. Following this reevaluation, Harza-Ebasco will prepare and submit a position paper summarizing their recommendations to the Power Authority for review. Meeting(s) will then be held with the Advisory Council on Historic Preservation and other agencies, as appropriate, to develop a concensus on the continued direction of the Susitna archeological program. Following these meetings, the cultural resources mitigation program will be reevaluated and updated as required. In addition, an appropriate level-of-effort will be developed for the FY 1985 field program.

3.6.3.2 Socioeconomics. The principal thrust of the socioeconomic subtask in FT 1984 is to revise the projections of the socioeconomic baseline and "with project" conditions and to update the mitigation plans based on the revised projections. In order to more accurately describe existing socioeconomic conditions in the communities of Cantwell, Talkeetna, and Trapper Creek, surveys of households, businesses, and public sector employees are being conducted in those communities. In addition, a survey of workers on the Anchorage/ Fairbanks Intertie Project has been completed to help validate assumptions regarding worker characteristics used to forecast project-related impacts.

It is widely recognized that several additional socioeconomic-related issues must be addressed in order to more accurately forecast socioeconomic impacts and to develop a meaningful mitigation plan. These issues include further definition of: worker shift and rotation schedules; how workers will be transported to and from the project site; worker hiring program; type of housing, facilities, and amenities at the construction camp and permanent village; the project access route; and whether or not a permanent village is a viable option. Currently, these issues are scheduled to be examined in early FY 1985 prior to the next round of household, business, and public sector surveys.

The socioeconomic subtask for FY 1984 and 1985 will also be directed to address the potential impacts of the project on users of fish and wildlife resources. The household and business surveys (to be conducted in the fall of 1983 and 1984) are designed to gather baseline information with regard to the importance of fish and wildlife resources to households and businesses in Cantwell, Talkeetna, and Trapper Creek. In addition, a survey of guides and lodge operators and a survey of users of project area fish and wildlife resources will be conducted in FY 1985 in order to more accurately assess the project's potential impacts on fish and wildlife resource user groups.

3.6.3.3 Recreation. The primary objective of the recreation subtask in FY 1984 is to prepare a Recreation Plan Implementation Report. This report will outline the schedule and steps required to implement Phase I of the Recreation Plan as identified in Chapter 7, Exhibit E of the License Application. An important element of this report will be a plan of action for resolving necessary policy and management issues, such as what project areas and facilities will be open to the public; worker policies regarding access and use of recreation resources; and control by landowners and landmanagers. FY 1985 activities for the recreation subtask will focus on tasks identified in the Recreation Plan Implementation Report that will be necessary to keep the licensing process on schedule.

3.6.3.4 Aesthetics. The principal activity in the aesthetics subtask in FY 1984 is to update the Aesthetics Mitigation Plan. The thrust of the update, which will recommend steps necessary to implement the aesthetics mitigation program, will be to outline the structure and approach of the Interdisciplinary Design Team. The main aesthetics subtask activities in FY 1984 will include mobilizing the Interdisciplinary Design Team and reevaluating the location and design of the construction camps and permanent townsite.

3.6.3.5 Land Use. In FY 1984, the land use subtask will focus on the update of the License Application. As part of this work, the land use and land status information presented in Chapter 9 will be updated. In addition, land use issues will be reexamined in order to outline appropriate land use subtask work for FY 1985.

3.6.3.6 Project Alternatives. The thrust of the project alternatives subtask in FY 1984 and 1985 will be to develop and update a matrix that displays differential impacts between alternative project locations, designs, and energy sources.

EXHIBIT 3.1

SUSITNA PROJECT
LAYOUTS WITH DESIGN REFINEMENTS (Category 1)
COST ESTIMATES
(Millions of Dollars)

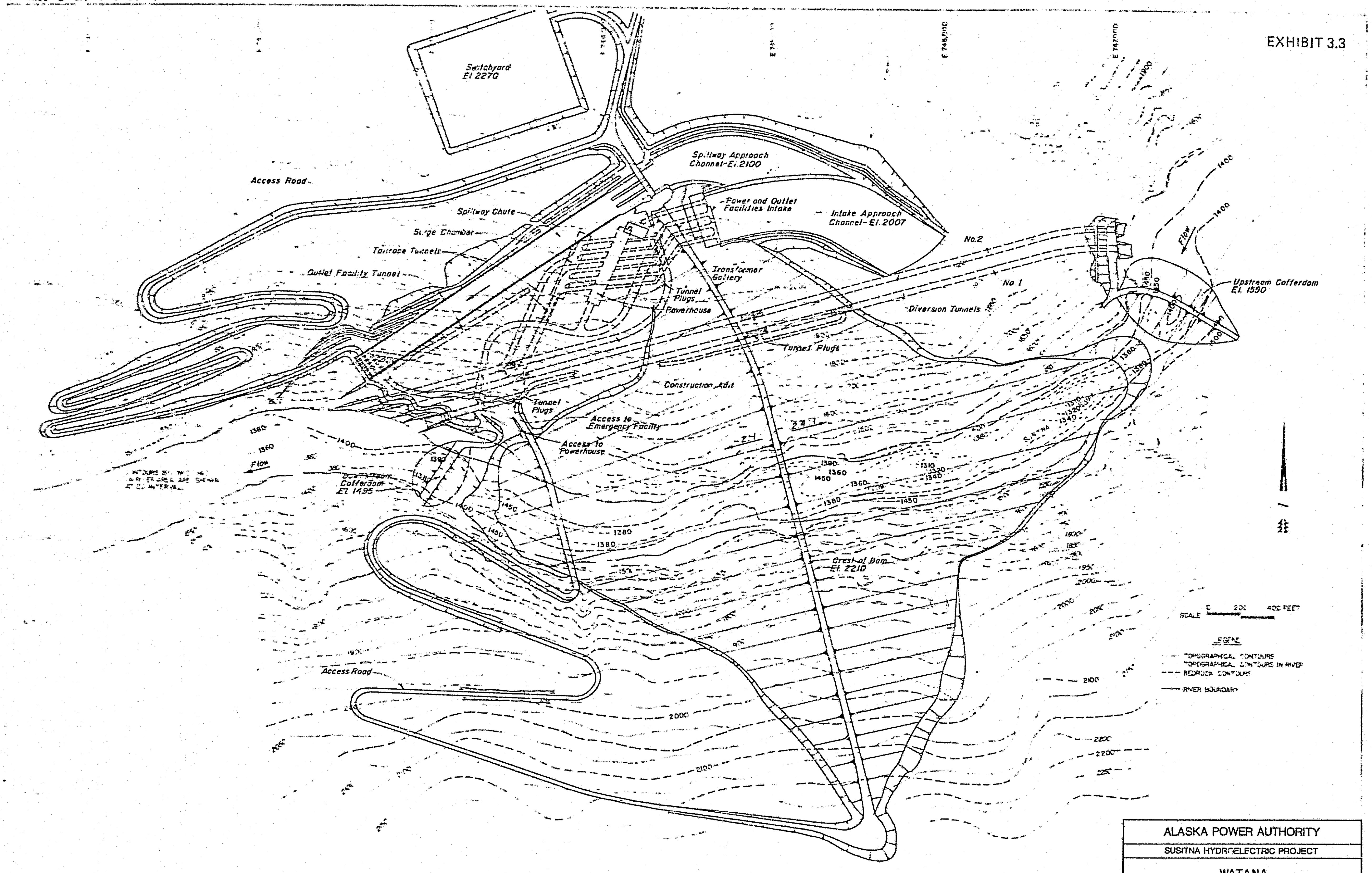
ITEM	WATANA	DEVIL CANYON
Land and Land Rights	51	22
Powerhouse	72	80
Reservoir Clearings	54	10
Diversion Tunnels	111	16
U/S Cofferdam	17	7
D/S Cofferdam	3	1
Main Dam	752	292
Relict Channel or Saddle Dam	110	34
Outlet Facilities	36	15
Main Spillway	113	63
Emergency Spillway	---	---
Power Intake	72	25
Surge Chamber	12	14
Penstocks	31	40
Tailrace	16	55
Waterwheels, Turbines & Generators	79	42
Accessory Electrical Equipment	21	14
Misc. Power Plant Equipment	14	11
Roads, Rail & Air Facilities	214	119
Transmission Plant	405	105
General Plant	5	5
Construction Facilities	325	176
Mitigation	29	4
SUBTOTAL	2543	1150
Contingency Allowance (15%)	382	173
Total Construction Cost	2925	1323
Engineering & Administration (12.5%)	366	164
Total Cost - Jan '82 Price Levels	3291	1487
Escalation to Jan '83 (4.3%)	141	65
Total Cost - Jan '83 Price Levels	3432	1552

EXHIBIT 3.2

SUSITNA PROJECT
WATANA 2185 COST ESTIMATES (Category 1)
FOUR AND SIX UNIT POWERPLANTS
(Millions of Dollars)

ITEM	4-UNIT POWERPLANT	6-UNIT POWERPLANT
Land and Land Rights	51	51
Powerhouse	57	72
Reservoir Clearings	54	54
Diversion Tunnels	111	111
U/S Cofferdam	17	17
D/S Cofferdam	3	3
Main Dam	773	752
Relict Channel or Saddle Dam	110	110
Outlet Facilities	36	36
Main Spillway	118	113
Emergency Spillway	---	---
Power Intake	55	72
Surge Chamber	8	12
Penstocks	23	31
Tailrace	14	16
Waterwheels, Turbines & Generators	53	79
Accessory Electrical Equipment	14	21
Misc. Power Plant Equipment	12	14
Roads, Rail & Air Facilities	214	214
Transmission Plant	405	405
General Plant	5	5
Construction Facilities	317	325
Mitigation	29	29
SUBTOTAL	2482	2543
Contingency Allowance (15%)	367	382
Total Construction Cost	2849	2925
Engineering & Administration (12.5%)	352	366
Total Cost - Jan '82 Price Levels	3201	3291
Escalation to Jan '83 (4.3%)	137	141
Total Cost - Jan '83 Price Levels	3338	3432

EXHIBIT 3.3



WATANA DAMSITE

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

WATANA
MAIN DAM
PLAN

HARZA-EBASCO
SUSITNA JOINT VENTURE
ANCHORAGE, ALASKA

APPROVED		
DATE	CONTRACT NUMBER	DRAWING NUMBER
		WA SKC 403601

SUSITNA HYDROELECTRIC PROJECT
OPERATION AND MAINTENANCE COST ESTIMATES
($1000/yr)

	Watana 1/			Devil Canyon 1/			Eventual Project		
	Labor	Expenses	Subtotal	Labor	Expense	Subtotal	Labor	Expenses	Subtotal
Power and Transmission	3300	990	4290	625	500	1125	2740	990	3460
Contracted Services 2/		900	900		480	480		1050	1050
Townsite Operations	625	180	805	400	55	455	285	180	465
Environmental Mitigation			1000			—			1000
Contingency (15%)			1045			310			895
Total, January 1982 dollars			8040			2370			6870
Escalation to 1983 dollars (6%)			480			140			410
Total, January 1983 dollars			8520			2510			7280

1/ For first 5 years of operation of each development; total of 10 years.

2/ Includes annual maintenance services, major maintenance overhaul, helicopter service, and road maintenance.

B3/40/1

EXHIBIT 3.4

AREA AND VOLUME VERSUS ELEVATION
WATANA RESERVOIR

Elevation (ft, msl)	Volume (acre-feet)	Area (acres)
1460.0	0.	0.
1500.0	3000.	150.
1550.0	34000.	1100.
1600.0	127000.	2620.
1650.0	292000.	3990.
1700.0	532000.	5620.
1750.0	870000.	7860.
1800.0	1318000.	10010.
1850.0	1877000.	12270.
1900.0	2546000.	14490.
1950.0	3330000.	16880.
2000.0	4248000.	19850.
2050.0	5341000.	23870.
2100.0	6645000.	28290.
2150.0	8189000.	33940.
2200.0	10017000.	39730.
2250.0	12212000.	48030.

AREA AND VOLUME VERSUS ELEVATION
DEVIL CANYON RESERVOIR

Elevation (ft, msl)	Volume (acre-feet)	Area (acres)
900.0	0.	0.
950.0	2000.	70.
1000.0	7000.	190.
1050.0	25000.	400.
1100.0	49000.	654.
1150.0	65000.	955.
1200.0	132000.	1360.
1250.0	195000.	1860.
1300.0	292000.	2490.
1350.0	456000.	3565.
1400.0	707000.	5480.
1450.0	1048000.	7600.
1500.0	1484000.	9560.

POWERPLANT DATA
WATANA

Net Head (%Rated)	Net Head (Feet)	Four Unit Plant Capacity (MW)	Four Unit Plant Capacity (%Rated)	Efficiency Turbine	Efficiency Plant
0.750	510.0	470.2	0.650	0.880	0.854
0.800	544.0	517.9	0.716	0.888	0.862
0.850	578.0	567.1	0.784	0.894	0.867
0.900	612.0	617.8	0.854	0.900	0.873
0.950	646.0	669.9	0.926	0.905	0.878
1.000	680.0	723.4	1.000	0.910	0.883
1.030	700.4	755.9	1.045	0.908	0.881
1.060	720.8	789.2	1.091	0.906	0.879
1.100	748.0	834.8	1.154	0.903	0.876
1.150	782.0	891.9	1.233	0.900	0.873

POWER AND ENERGY PRODUCTION
WATANA 2185
DOR Mean Forecast
Year 2020 Demand Level

MONTH	WATANA ALONE			DEVIL CANYON			WATANA AFTER DEVIL CANYON		
	Capability(a) (MW)	Average Energy (GWh)	Reliability Energy (GWh)	Capability(a) (MW)	Average Energy (GWh)	Reliability Energy (GWh)	Capability(b) (MW)	Average Energy (GWh)	Reliability Energy (GWh)
Jan	464	345	290	449	334	239	700	366	247
Feb	425	286	225	451	303	215	674	323	219
Mar	355	264	182	402	299	213	649	310	212
Apr	338	243	158	379	273	273	625	263	104
May	306	228	139	359	267	188	621	211	95
Jun	261	188	60	354	255	201	656	180	180
Jul	290	216	82	321	239	200	708	179	133
Aug	464	345	314	320	238	219	747	262	180
Sep	393	283	274	357	257	257	766	249	249
Oct	404	301	191	336	250	203	765	343	308
Nov	553	398	287	428	308	224	749	348	236
Dec	539	400	362	482	359	256	726	402	269

(a) Corresponds to monthly plant capacity output that produces the total estimated monthly energy available.
(b) Corresponds to four unit capability and is based on monthly net head and turbine efficiency.

EXHIBIT 3.8

4.0 NON-SUSITNA GENERATION ALTERNATIVES

4.0 NON-SUSITNA GENERATION ALTERNATIVES

4.1 INTRODUCTION

Numerous alternative technologies and systems exist that could be used to generate electricity for the Railbelt Region either as substitutes for or complements to the Susitna Project. The more attractive alternatives include natural gas-fired combustion turbines and combined cycle power plants, and coal-fired steam turbines. In addition, the Chakachamna Hydroelectric Project is an alternative to Susitna. These alternatives have been identified from previous studies and have been re-analyzed for this Update.

The application of any thermal powerplant alternative depends on electricity demand and the availability and price of fuels to meet Railbelt generation needs. These were analyzed most recently in Appendix D-1 to Exhibit D of the July 1983 revised FERC License Application for the Susitna Project. This Chapter provides a summary description of the studies contained in that document. In addition, recently completed studies by the Power Authority on the Chakachamna Hydroelectric Project and on the use of North Slope Gas for the Railbelt have been incorporated.

The generation alternatives discussed in this Chapter are used in the formulation of system expansion plans described in Chapter 5.

4.2 NATURAL GAS-FIRED OPTIONS

Natural gas is the fuel currently used for 66 percent of the electricity generating capacity in the Railbelt Region, and its use provides the region with 74 percent of the electrical energy consumed. Assessments of thermal alternatives, therefore, logically begin with gas-fired options.

4.2.1 Natural Gas Availability and Cost in Alaska

4.2.1.1 Cook Inlet Gas Availability. Estimates of natural gas resources in the Cook Inlet area have been made by the Alaska Department of Natural Resources (DNR; Early 1983), the Alaska Oil and Gas Conservation Commission (OGCC; January 1982) and the United States Geological Survey (USGS: 1980, Circular 860). The estimates are summarized under identified and undiscovered resource classifications.

Identified gas resources are those resources whose location is known from wells drilled and whose quantity is estimated by flow rates and specific geologic data. Undiscovered gas resources are resources that are located outside of known fields and whose volume is estimated using geological information.

The Alaska Oil and Gas Conservation Commission estimates identified gas resources. The OGCC makes an annual estimate by field and the results are published in their Statistical Report. Gas volume is estimated using initial well head pressure, changes in well head pressure caused by production, drill cores, and field size obtained from seismic data. The OGCC's estimate of identified Cook Inlet gas resources as of January 1982 is 3.59 TCF. Cook Inlet proven reserves as of January 1983 are taken as 3.5 TCF.

The Alaska Department of Natural Resources developed an estimate in early 1983 of undiscovered gas resources in the Cook Inlet Area. The DNR method used was a "Play Approach" which determines the amount of hydrocarbon in a "play" or prospect through use of reservoir engineering equations taking geologic risk factors into account. Inputs for variables are in the form of estimated probability distributions, and Monte Carlo methods are used to develop a probability distribution for the amount of hydrocarbons.

The DNR estimates undiscovered gas resources for: 1) total gas in place, and 2) economically recoverable gas. The estimates are in the form of a cumulative probability distribution with a quantity of gas versus the probability that the amount found will be at least that quantity. The average or expected value is also presented. The expected value of total gas in place was estimated to be 3.36 trillion cubic feet (TCF) and the average or expected value for economically recoverable gas was 2.04 TCF.

In the USGS estimates of Cook Inlet undiscovered resources, a direct subjective method was used, in which the gas resources are estimated by a team of experts. Geological information and results from other methods (e.g. volumetric-yield, play analysis, etc.) are reviewed and weighed by the experts using Delphi techniques. The mean or weighted average quantity of undiscovered gas was estimated as 5.72 TCF.

The economically recoverable expected value of 5.72 TCF from the USGS estimate is considerably larger than the comparable value of 2.04 TCF from the DNR estimate. The reasons for this difference are unknown but development of the estimates differs in at least three major areas. These are:

1) time of estimate,
2) area analyzed, and
3) estimating method employed.

The USGS estimate was made using data available in 1980. While no exploration for non-associated gas occurred during the 1980-82 period, oil exploration continued so that the DNR has information that was not available to the USGS in 1980.

The Cook Inlet area analyzed by the USGS was larger than the Cook Inlet basin analyzed in the DNR estimate. The larger amount consisted mostly of additional onshore areas on the Seward Peninsula and to the west and north of Cook Inlet.

The estimating methods used by the USGS and DNR were different. The USGS used a direct subjective method while the DNR used a play analysis approach. Both methods require a considerable amount of subjective probability input as to the existence and quantity of recoverable gas. The methods differ in that the play approach begins with each individual potential hydrocarbon prospect and builds up to a total estimate for the area while, in the direct subjective method, the total amount of hydrocarbon is estimated in aggregate after reviewing all information on the area.

The best estimate of undiscovered gas resources appears to be that developed by the DNR. The USGS 1980 estimate is out of date and the method employed is probably not as reliable as that used by the DNR. The expected value for undiscovered gas is taken as 2.0 TCF with an approximate probability of occurrence of 0.45.

4.2.1.2 Cook Inlet Gas Consumption. Cook Inlet gas is used for household heating, commercial applications, LNG and ammonia/urea production, and for electricity generation. Of the 3.5 TCF, some 1.9 TCF are committed by contract to the existing users, and about 1.6 TCF remain uncommitted. In addition to these 3.6 TCF of proven reserves, there are estimated undiscovered reserves; of which about 2.0 TCF are considered to be economically recoverable.

The future consumption of Cook Inlet gas depends on the gas needs of the major users and their ability to contract for needed supplies. Since there is a limited quantity of proven gas and estimates of undiscovered reserves in the Cook Inlet area have yet to be proven, gas reserves will be exhausted by the late 1990's. In addition, there may not be sufficient gas for electrical generation beyond some point because of higher priorities accorded other uses, either through contract or by order of regulatory agencies such as the Alaska Public Utilities Commission. To estimate the quantity of Cook Inlet gas available for electrical generation, the requirements and priorities of the major users are discussed below and summarized on Exhibit 4.1.

Phillips/Marathon LNG currently has 360 BCF of gas under contract and Collier Chemical has 377 BCF. It is highly probable that both entities will obtain enough of the uncommitted gas resources to meet their needs through 2010. The reason is that both Phillips/Marathon LNG and Collier are established, economically viable facilities. They are also owned by Cook Inlet gas producers who control part of the uncommitted reserves. Phillips/Marathon LNG and Collier are therefore estimated to consume 62 BCF and 55 BCF respectively per year from 1983 through 2010.

At present, Enstar has enough gas under contract to serve its retail customers until after the year 2000, but since Enstar also sells gas to the military, Chugach Electric Association, and Anchorage Municipal Light and Power for electric generation, it may hav. to seek additional reserves in order to meet the needs of those larger customers. It is assumed, however, that Enstar will be able to acquire sufficient gas to meet the needs of its retail customers (including new Matanuska Valley customers). Further, it is reasonable to assume that those customers' needs will have priority over the use of gas for electrical generation. Retail use is estimated to increase from about 19 BCF in 1983 to 52 BCF in 2010.

Gas used in field operations and the residual, "Other Sales" vary from year to year but together are estimated to average about 25 BCF/yr. over the period 1983 to 2010 based on historical use.

After satisfying all of the forementioned needs, there is still a considerable amount of gas remaining that could be used for electrical generation, at least for a number of years. Chugach Electric

Association has 285 BCF committed through contract and Enstar has 759 BCF contracted, some of which will be sold to Anchorage Municipal Power and Light and Chugach Electrical Association for electrical generation. Assuming that the Anchorage/Fairbanks intertie is completed in 1984-85, the electrical requirements of both cities could be met (at least in part) with generation using Cook Inlet gas.

An estimate of the quantities of Cook Inlet gas that would be required to meet all Railbelt electrical requirements was made using the estimated load and energy forecast (DOR Mean) for the Railbelt area. Estimated generation from the existing Eklutna and Cooper Lake hydroelectric units, and the proposed Grant Lake and Bradley Lake hydroelectric units, was subtracted, as well as generation from the existing Healy coal-fired unit. The estimated annual gas requirements for power generation increase from 27 BCF in 1983 to 35 BCF in 2010.

The forecast annual and cumulative use of gas for each of the major users, and the total use of gas for the Railbelt, is shown in Exhibit 4.1. The remaining proven and undiscovered (mean or expected quantity) gas resources are also shown. As can be seen, proven reserves (3.5 TCF) will be exhausted by 1998 and proven plus economically recoverable undiscovered resources will be exhausted in about 2007. Inspection of the Total Cumulative Gas Use column shows that currently committed reserves (1.9 TCF) will be exhausted in 1992.

The data indicates that relying on gas-fired electrical generation to provide the Railbelt's needs is problematic because it depends on the future availability of uncommitted proven and undiscovered reserves for electrical generation.

The uncommitted proven reserves and any undiscovered resources could be acquired by established entities or entities not shown in Exhibit 4.1, reducing the availability of Cook Inlet gas for electric generation.

Known potential purchasers for the uncommitted recoverable and undiscovered Cook Inlet gas reserves, are Pacific Alaska LNG Associates and whoever would own and operate the proposed Trans-Alaska Gas System (TAGS).

The proposed Pacific Alaska LNG (PALNG) project was initiated about ten years ago, but has been repeatedly delayed due to difficulties in obtaining final regulatory approval for a terminal in California. The project has also had difficulty in contracting for sufficient gas reserves in order to obtain Federal Energy Regulatory Commission (FERC) approval of the project. At one time, PALNG had 980 BCF of recoverable reserves under contract. The contracts expired in 1980, but producers did not give written notice of termination so the contracts have been in limbo. Recently, however, Shell Oil Company sold 220 BCF of gas that was formerly committed to PALNG to Enstar Natural Gas Company. This reduced reserves committed to the PALNG project to 760 BCF.

Implementation of the project would depend primarily on the availability and price of alternative sources of natural gas for the lower forty-eight market, and particularly for the California market. When all factors are considered, it does not appear that the PALNG project will be implemented prior to 1995. The recoverable reserves originally committed to PALNG can probably be acquired by other purchasers such as Chugach Electric Association and Enstar.

The proposed TAGS project would build a natural gas transmission line from Prudhoe Bay on the North Slope to the Kenai Peninsula (near Nikishka). The gas from the North Slope would be liquefied and sold to Japan and other Asian countries. The proposed project is an alternative method of bringing North Slope gas to market.

If the project were implemented, Cook Inlet gas producers might be able to sell their gas to Trans Alaska Gas System for liquefaction and sale to Asia. Sale will depend on the capacity of the liquefaction plant and the market for LNG. The price paid by TAGS to Cook Inlet producers might be high enough to outbid competing purchasers, since the Cook Inlet gas would not be burdened with the costs of the transmission line from Prudhoe Bay (although shorter transmission and gathering lines would probably be required).

4.2.1.3 Cook Inlet Gas Price. If current and future Railbelt electrical requirements are to be met with gas generation, new purchases of uncommitted Cook Inlet gas and future purchases of undiscovered resources will be required. The price that will have to be paid for these additional gas resources is important in the evaluation of thermal alternatives versus the Susitna hydroelectric alternative.

The actual price that would be agreed upon for uncommitted gas between producers and the utilities is difficult to predict but an indication is provided by the recent Enstar/Shell and Enstar/Marathon contracts for uncommitted gas resources. Under the agreements, the wellhead price is $2.32/MMBtu with an additional demand charge of $0.35/MMBtu beginning in 1986. Severance tax is estimated at $0.15/MMBtu. A fixed pipeline charge of about $0.30/MMBtu is additional for pipeline delivery to Anchorage. The pipeline delivery charge from Beluga of $0.30/MMBtu would not be incurred if the gas is used at Beluga to generate electricity. This price could be a reasonable basis provided there is no competition and there continues to be a plentiful gas supply that can be obtained at low costs. Although the possibility of uncommitted Cook Inlet reserves being purchased for LNG export seems to be remote at the present time, conditions may change in the future.

The price producers might be able to obtain if LNG export opportunities exist might then become important. A method that can be used to estimate wellhead prices for LNG export is to begin with the market price for delivered LNG and then subtract shipping, liquefaction, conditioning, and transmission costs to arrive at the maximum wellhead price. The estimated, netback, wellhead price of Cook Inlet gas for LNG export would vary depending on the average price of oil delivered to Japan. Based on $34/bbl and $29/bbl oil the maximum price that could be paid to producers is $3.00-$3.85/MCF. These prices are higher than the estimated prices where no LNG export opportunities exist. Therefore, if LNG opportunities did exist, the price of Cook Inlet gas for electrical generation would be higher than the price assumed since the utilities would have to outbid potential LNG exporters.

It can be seen that pricing Cook Inlet gas involves many complex issues. For this analysis, the Enstar gas price has been chosen because it is tied to the price of oil and reflects recent thinking in natural gas pricing. In spite of this, gas is priced at about 40% of heating oil price, which would make gas very competitive where the two fuels are substitutable. Further this price was negotiated last year when the oil price was softening, the development of ANGTS and TAGS were becoming less certain, and PALNG was not going forward. Furthermore, uncommitted proven reserves were still plentiful, and the producer's cost of proven reserves was negligible since such reserves were discovered in conjunction with oil exploration and production years ago.

The gas price situation could change in the future for the purchase of additional gas. Uncommitted proven reserves would be exhausted (by 1998) and economically discovered reserves must be brought into production through exploration and development that would involve risk and substantially higher cost with all the costs allocated to gas. The demand for gas would also increase resulting in greater competition. With time, it is likely that natural gas price might move closer to the oil price than the approximately 40% relationship established under the current Enstar contract.

The above considerations would seem to lead to a higher incremental gas price in future years for the remaining uncommitted reserve, and for the undiscovered reserves than the gas price under the Enstar contract. Therefore, the Enstar pricing approach used would tend to favor the thermal alternatives, resulting in a conservative approach to the analysis of the Susitna Project.

The method used to project future prices of natural gas was to correlate the gas price with the world price of oil. The method was selected since the two fuels can be substituted in many cases and because the terms of the current Enstar contract provide for escalation of gas prices based on the price of No. 2 fuel oil on the Kenai peninsula. Natural gas prices and real escalation rates for the DOR Mean and SHCA-NSD oil prices are shown on Exhibits 4.2 and 4.3, respectively.

4.2.1.4 North Slope Gas. The vast reserves of natural gas in the North Slope could be moved closer to the Railbelt if either the proposed Alaska Natural Gas Transportation System (ANGTS) or the Trans Alaska Gas System (TAGS) is built. The ANGTS project would deliver North Slope gas to the lower forty-eight states by means of a large diameter pipeline traversing Central Alaska and Canada. The line route is such that it would be possible to construct a lateral line to Fairbanks. The TAGS project proposes to deliver gas to the Kenai Peninsula for liquefaction and export as LNG principally to Japan. The development of either ANGTS or TAGS depends on favorable prices of world oil or natural gas in the lower forty-eight states. At the current prices and near-term outlook under the DOR Mean oil price projections, it is unlikely that either ANGTS or TAGS could move forward.

Even with ANGTS or TAGS, natural gas from the North Slope would not be inexpensive if transported to either Fairbanks or the Kenai peninsula. The purchase price of such natural gas must include the costs of transporting it to the point of use and of conditioning.

ANGTS prices for the Fairbanks area would be $4.03-$6.32/MMBtu in 1983 dollars in the first year of pipeline operation as estimated by Battelle. The General Accounting Office's (GAO) most recent first year estimates are $2.80-$5.10/MMBtu in 1983 dollars in Fairbanks on a delivered basis. Previous GAO estimates were $4.88-$7.18/MMBtu in 1983 dollars. These ranges are driven by the assumed wellhead price. Assuming the TAGS line, prices would be $3.03-$4.19/MMBtu in 1983 dollars; however, the $3.03 value is not realistic since it assumes a negative wellhead price.

These ranges converge to a price of about $4.00/MMBtu for North Slope gas delivered to the Railbelt and this value is assumed to be realistic provided that either TAGS or ANGTS could be built.

In the absence of ANGTS and TAGS, two energy development scenarios utilizing North Slope gas have been analyzed in a recently completed Power Authority report. These include (1) power generation at the North Slope via simple cycle combustion turbines with attendant electrical transmission from the North Slope to Fairbanks and then on to Anchorage and (2) electric power generation at Fairbanks using combined cycle plants with transmission line construction from Fairbanks to Anchorage. The first alternative would require the construction of two 450 mile 500-kV transmission lines from the North Slope to Fairbanks. The second alternative would require transportation of gas to Fairbanks from the North Slope by means of a 22 inch diameter, high pressure pipeline and a gas conditioning facility on the North Slope.

The North Slope power generation scenario is not economically attractive and is subject to many reliability uncertainties. The study determined that the capital investment requirements for the construction of 1400 MW of generating capacity and transmission lines (approximately the new capacity required to satisfy the Railbelt's electrical demand in the year 2010) would amount to $4.2 billion (1982 dollars). Total operation and maintenance costs for the system would amount to a total of $1.1 billion for the years 1993 through 2010. In addition to these high costs, the scenario is subject to some severe technical uncertainties which would require much more detailed study to determine project feasibility.

North Slope gas could also be made available at Fairbanks via a 22-inch diameter gas pipeline. The pipeline design flow is 383 million cubic feet per day (MMCFD), a volume of gas sufficient to produce approximately 1400 MW of electrical power, and satisfy the projected residential/commercial natural gas demand in the Fairbanks area to the year 2010.

Utilizing the capital investment estimates cited in the Power Authority report for the pipeline and its associated gas conditioning facilities ($5.8 billion), and assuming that capital and operation and maintenance costs would increase at the rate of inflation, a levelized price of about $9.90/MMBtu was calculated for the gas. Other assumptions utilized in this analysis include: 1) private ownership by the energy industry, 2) a well head price of $1.00/MMBtu, subject to a 12.5 percent royalty, 3) a real discount rate of 10.0 percent and a capital cost escalation rate of 3.5 percent, and 4) a pipeline and conditioning facilities life of 30 years. If ownership and financing of the pipeline by the State of Alaska is assumed, the real discount rate would be 3.5 percent and the levelized delivered price of the gas would be about $7.20/MMBtu. Neither cost is competitive, making the pipeline to Fairbanks scenario uneconomical.

For North Slope gas to enter the marketplace, then, natural gas prices will have to rise considerably. There are several alternative plans for bringing this gas to the marketplace, however, they involve substantial capital investments in pipeline and gas conditioning facilities.

4.2.2 Natural Gas-Fired Powerplants

Natural gas can be used in the following types of thermal powerplants: simple cycle combustion turbines (SCCT), combined cycle combustion turbines (CCCT), and steam turbines. The SCCT and CCCT alternatives are preferred because natural gas-fired steam turbine plants are only economical at very large unit sizes (i.e., substantially larger than 200 MW). In the sizes appropriate for the Railbelt needs, they are more costly and less efficient than the CCCT.

4.2.2.1 Simple Cycle Combustion Turbines. The simple cycle combustion turbine (SCCT) is a well proven system for electricity generation that can be used to meet both baseload and peak demand requirements. Natural gas and air under pressure are combusted with the resulting products of combustion being expanded across the turbine. The unit is characterized by rapid start-up capability with no need for cooling.

The combustion turbine is factory manufactured and supplied in components that are assembled at the site. These characteristics result in ecc omies of mass production. Technical efficiencies under standard ISO rating (sea level and 59°F air inlet conditions) are given in Table 4.1.

Table 4.1

EFFICIENCIES OF COMBUSTION TURBINE UNITS

Unit Size (MW)	Full Load Heat Rate, Btu/kWh
25	13,575
37	12,343
75	11,755

The 75-MW unit size is chosen because it can be utilized effectively in the interconnected Railbelt system and it is less costly on a per kilowatt basis than the small units.

The efficiency of the 75-MW machine has been estimated on the basis of Anchorage area conditions under full and part load. This efficiency is somewhat better than when running at ISO conditions because lower air inlet temperatures improve the performance of the machine. These efficiency values are presented in Table 4.2

Table 4.2

EFFICIENCIES OF 75-MW GAS TURBINES IN THE ANCHORAGE AREA UNDER FULL AND PART LOAD

Load (%)	Heat Rate (Btu/kWh)	Fuel Consumption as a Percent of Full Load Fuel Consumption
100	11,650	100
80	12,092	83
60	13,008	67
40	15,145	52
20	22,141	38

The maximum generating capability is estimated at 84 MW under the ambient conditions (sea level and 33°F annual average temperature). The data above demonstrate that the large combustion turbine is a reasonably efficient machine when operating at or near full load. Its efficiency suffers substantially, however, when it is operated at less than 80 percent of nameplate capacity.

Capital and operation and maintenance costs of combustion turbines are summarized on Exhibit 4.4. The capital cost is estimated using the bid-line item costs from the Power Authority's Feasibility Level Assessment - Use of North Slope Gas for Heat and Electricity in the Railbelt, dated September 1983.

4.2.2.2 Combined Cycle Combustion Turbines. The combined cycle combustion turbine (CCCT) makes use of the high-temperature (1000°F) combustion turbine exhaust. In the CCCT system, the exhaust is ducted to a waste heat boiler or heat recovery steam generator (HRSG). The steam pressure is then raised (typical conditions might be 850 psig/950°F) and the steam is expanded in a conventional steam turbine to produce additional power.

Like the SCCT, the CCCT system exhibits both technical and economic gains from scale. These gains from scale are derived, to a large extent, from the SCCT units since a typical configuration would involve two SCCT's and one HRSG plus turbine system. Typical technical gains from scale are shown in Table 4.3.

Table 4.3

HEAT RATES FOR VARIOUS SIZE
COMBINED CYCLE UNITS

System Size (MW)	Heat Rate at ISO Conditions (Btu/kWh)
49	9,720
103	9,270
220	8,350

Because of both the technical and economic gains from scale available at the 220-MW (ISO conditions, Nominal Rating) size, and because of the assumed interconnection in the Railbelt Region, this unit was chosen for analysis.

The 220-MW (ISO Rating) CCCT unit was calculated to have a capacity of 237 MW and a heat rate (HHV based) of 8,280 Btu/kWh in the Railbelt Region of Alaska, when operating at full load. When operating under part load (below 70 percent) the steam turbine would have to be shut down and the boiler kept warm for hot start-up. Under such conditions, down to a 32 percent load, the SCCT heat rate would govern. Thus the rang of maximum and minimum efficiencies are as shown in Table 4.4.

Table 4.4

EFFICIENCY CHARACTERISTICS OF
COMBINED CYCLE UNITS AT FULL
AND PART LOAD

Load (%)	Heat Rate (Btu/kWh; HHV Based)	Fuel Consumption as a Percent of Full Load Fuel Consumption
100	8,280	100
32	11,650	45

The CCCT has a thermal efficiency of 41 percent when operating at full load, compared to the SCCT efficiency of 29 percent under the same conditions. The CCCT demonstrates the classic case of trading capital costs for efficiency. Capital and operation and maintenance cost estimates for a 237-MW unit are summarized on Exhibit 4.4. The capital cost is taken from bid-line item costs of the North Slope Gas Studies.

4.3 COAL-FIRED OPTIONS

Coal-fired generation is another viable thermal alternative for the Railbelt Region of Alaska. Coal currently supports 8.3 percent of the utility power generation capacity, and it is used to generate 13.5 percent of the electrical energy supplied to consumers in the Railbelt Region.

4.3.1 Coal Availability and Cost in Alaska

There are three major deposits of coal in Alaska: the Nenana Field, the Kukpowruk Field, and the Beluga Field. There are additional smaller deposits in the vicinity of Nome, in Matanuska, and on the Kenai Peninsula. These fields contain 130 billion tons of coal resources and 6 billion tons of coal reserves. The Nenana and Beluga fields are the most important as the other deposits have problems that preclude effective exploitation on a large scale.

The Nenana Field has a total resource of 7 billion tons and a reserve base of 457 million tons. The Beluga Field has identified resources of 1.8 to 2.4 billion tons of coal. Both fields are characterized by thick seams (i.e. greater than 10 ft.), and low stripping ratios (i.e. 4-6) and have modest quality coal with 7500-7800 Btu/lb. Other characteristics of the coals include 0.1-0.2 percent sulfur, 7-8 percent ash, greater than 25 percent moisture content, and Hardgrove grindability of about 30-35.

Coal production in the Nenana field is at the Usibelli Coal Co. mine at Healy and current production is 830,000 tons/yr. Currently the coal produced at this mine is sold to the Fairbanks Municipal Utility System, the Golden Valley Electric Association, the University of Alaska at Fairbanks, and the U.S. Department of Defense. This production would increase to 1.7 million tons/yr if the Suneel exports to Korea, currently under negotiation, commence at full scale. The mine could be expanded further to about 4.0 million tons/yr in support of electric power generation.

The current Usibelli mine uses a dragline and front end loader based production system. Capacity utilization rates have sufficient room to support the increase in capacity to 1.7-2.0 million tons/yr. The system would be duplicated to achieve the second doubling in capacity.

The Beluga Field is not being mined at the present time. However, the deposits are in reasonable proximity to tidewater and therefore have access to the Pacific Rim markets. The Beluga Field represents an export opportunity, and both Diamond Alaska Coal Co. and Placer Amex have plans for development. The Diamond Alaska Coal Co. design will produce 10 million tons/yr of coal while the Placer Amex project is sized at 5 million tons/yr. These facilities are designed to serve the growing market of Japan, Korea, Taiwan, and other Asian nations. They would be on-line in 1988, and they could serve domestic as well as foreign markets.

While the Pacific Rim market is growing, the lack of infrastructure creates major risks in projecting the development of a large Beluga mine. If the export mines do not develop, a small scale coal mine could be developed for the domestic market. Such a development would involve altering the production technologies to meet the reduced capacity requirements.

Coal price is influenced not only by production costs but also by available markets, coal quality, and mining conditions. The results of investigations concerning these considerations are summarized below.

For the purposes of the expansion planning analysis, it is assumed that up to 400 MW of coal-fired steam units would be located near the community of Nenana. The plant would not be located at Healy coal field due to the mine's proximity to the Denali National Park. A mine-mouth price of $1.40/MMBtu in 1983 dollars was estimated for Nenana coal based on current contracts with Golden Valley Electric Association and Fairbanks Municipal Utility System adjusted for changes in production levels and new land reclamation regulations. Transportation costs to Nenana are estimated to be $0.32/MMBtu in 1983 dollars. Therefore, the total cost of the coal delivered in Nenana would be $1.72/MMBtu. The coal has an average heat content of about 7800 Btu/lb. Besides this 400 MW installed at Nenana, it is assumed that all other coal-fired units would be mine-mouth units installed at Beluga.

Beluga field production costs are estimated to be $1.70/MMBtu, and the market value of the coal FOB Granite Point is estimated to be

$1.86/MMBtu. Both costs include the cost of developing an infrastructure, assume 10 million tons/yr of production, and assume that an export market develops.

Agreements between coal suppliers and electric utilities for the sale/purchase of coal are usually under long-term contracts which include a base price for the coal with an escalation clause.

Several escalation rates have been estimated for utility coal in Alaska and in the lower forty-eight states, and they range from 2.0-2.7 percent per year (real). Several more generic rates have also been developed by Sherman H. Clark and Associates and by Data Resources Inc. (DRI). Because the forecasts of DRI and Sherman H. Clark are based upon supply-demand factors, they were applied to the base contract price of coal. The 2.6 percent real rate of increase used by DRI and Sherman H. Clark is applied to the mine-mouth price of Nenana Field coal as this mine is used principally to supply domestic markets. The escalation rates apply to prices before transport. Transportation costs over time are assumed to increase at 0.9 percent per year. The overall real composite rate of escalation including transportation for coal consumed in a generating plant located at Nenana is estimated at 2.3 percent per year.

An escalation rate of 1.6 percent per year of the price of Beluga coal is based on escalation rates developed by DRI and Sherman H. Clark for coal exported to Pacific Rim countries.

For the July 1983 License Application revision, both Nenana and Beluga coal prices were assumed to escalate to the date a given generating unit entered operation. At that time, the coal price for that unit was assumed to remain constant in real terms until the unit was replaced. Using this approach, the average coal price escalation rate for the

SHCA-NSD all thermal generation alternative was about one percent per year.

In the current expansion plan studies for the SHCA-NSD forecast, Beluga and Nenana coal prices were escalated at their stated rates until 1993; the first year of coal plant operation. At this date the cost from either source is equal to $2.17/MMBtu. For the remainder of the study horizon (1993-2050), a coal price escalation rate of one percent per year is used.

For the DOR Mean forecast an average 1983 coal price of $1.80/MMBtu is used and zero real price escalation is assumed. Coal prices and real escalation rates for DOR Mean and SHCA-NSD are shown on Exhibits 4.2 and 4.3.

Without export market development, the Beluga Field could be developed to serve domestic needs. Under such circumstances the costs of Beluga coal have been estimated as shown in Table 4.5.

Table 4.5

ESTIMATED BELUGA FIELD COAL COSTS WITHOUT EXPORTS

Mine Production Rate (tons/yr)	Power Plant Capacity Served (MW)	Coal Cost ($/MMBtu)
1,000,000	200	3.20
3,000,000	600	2.23

These costs include the expenditures required for infrastructure developments at the totally undeveloped Beluga Field. The cost of coal is substantially higher than the $1.70 to 1.86/MMBtu cost associated with an export market production of ten million tons per year because of the smaller size mine development.

4.3.2 Coal-Fired Powerplants

There are several technologies potentially available for converting coal into electricity including the traditional coal-fired steam turbine system, and coal gasification feeding a combined cycle combustion turbine.

The steam turbine system is the most favorable of these alternatives. The gasification - combined cycle unit is not included for three reasons: (1) the technology is not yet proven and commercially available, and the commercialization time frame is uncertain; (2) the capital costs are 60 percent higher than that of a comparable steam turbine system; and (3) despite the 60 percent increase in capital cost, the efficiency increase is less than five percent. However, the integration of a coal gasifier with combined-cycle technology would allow use of abundant Alaska coal resources when Cook Inlet gas reserves are depleted. Future studies should include review of the coal-gasification alternative.

The coal-fired steam turbine system is a well proven technology. It involves burning coal under a boiler and raising high pressure steam (e.g. 1450 - 2400 psig/950 - 1005°F). This steam is expanded in a high pressure (HP) turbine and, in larger systems, exhausted from the HP turbine at an intermediate pressure and temperature (e.g. 595°F), and reheated in the boiler to 1005°F. Reheated steam is expanded in the intermediate pressure and low pressure turbines and then condensed to water using air or water coolers whereupon the cycle is repeated.

There are substantial technical gains from scale in coal-fired units. Typical operating conditions and efficiencies as a function of unit size are shown in Table 4.6.

Table 4.6

TYPICAL OPERATING CONDITIONS OF COAL-FIRED UNITS

Unit Size - MW	100	150	200
Steam Conditions - psig	1450	1800	2400
- °F	950	950	1000
Feedwater Heaters	4	7	7
Full Load Heat Rate - Btu-kWh	10,500	10,100	9,750

There are capital cost gains from scale in coal fired power plants that parallel the technical gains from scale. These economies of scale, plus the technical gains previously discussed, indicate that the 200-MW unit is the most cost effective and appropriate for an interconnected system. Further, the 200-MW size is about the minimum size for using the most efficient subcritical 2400 psig/1000°F steam conditions.

The coal steam turbine system is reasonably efficient with a fully loaded net station heat rate of 9,750 Btu/kWh. That is a station efficiency of 35 percent. Partial load efficiencies are somewhat lower than full load efficiencies.

Coal fired units have been operated at levels considerably below 100 percent with several units being cycled down to 25 percent of load. The operating constraints associated with load cycling are shown in Table 4.7.

Table 4.7

CONSTRAINTS ON OPERATING
COAL-FIRED UNITS AT PART LOAD

Percent of Full Load Level	Limiting Constraint
50%	Pulverizers, with a 2:1 turn down ratio must be taken off line, limiting the ability of the unit to return to full load if load is reduced below 50 percent
30%	Auxiliary fuel must be used in the boiler for flame stabilization below 30 percent load

Efficiencies and fuel consumption rates to 50 percent of full load are shown in Table 4.8.

Table 4.8

EFFICIENCY CHARACTERISTICS OF
COAL-FIRED UNITS AT FULL AND PART LOADS

Load (%)	Heat Rate (Btu/kWh)	Fuel Consumption as a Percent of Fuel Consumption Under Fully Loaded Conditions
100	9,750	100
75	10,160	78
50	10,710	55

These data demonstrate that there is a significant loss in efficiency as part loads are served; however, the degradation in efficiency for a steam turbine is less than the loss of efficiency associated with a combustion turbine.

Capital and operation maintenance cost estimates are summarized on Exhibit 4.4. The capital costs are from the July 1983 revision of the FERC License Application and are updated to January 1983 price levels using the Marshall and Swift equipment cost indices and CE Construction Labor index.

4.4 CHAKACHAMNA HYDROELECTRIC DEVELOPMENT

Chakachamna Lake is located on the west side of Cook Inlet, about 85 miles west of Anchorage. The project concept includes diversion of water from Chakachamna Lake via a tunnel to a powerplant on the McArthur River. Project plans and evaluation are in a Power Authority report titled, "Chakachamna Hydroelectric Project - Interim Feasibility Assessment Report" dated March 1983.

The study evaluated the merits of developing the power potential by diversion of water southeasterly to the McArthur River via a tunnel about 10 miles long, or easterly down the Chakachatna Valley either by a tunnel about 12 miles long or by a dam and tunnel development.

The construction of a dam in the Chakachatna River canyon, approximately 6 miles downstream from the lake outlet, was found to be unattractive. While the site is topographically suitable, the foundation conditions in the river valley and left abutment are poor.

Construction of the 12 mile Chakachatna Valley tunnel alternative, running more or less parallel to the river in the right wall of the valley, would not develop equivalent power and energy capability at comparable costs to the McArthur tunnel alternative.

Two alignments were studied for the McArthur tunnel. The first considered the shortest distance that gave no opportunity for any intermediate points of access during construction. The second alignment was about a mile longer, but gave additional points of access, thus reducing the time required for construction of the tunnel. Cost comparisons nevertheless favored the shorter 10-mile, 24-foot diameter tunnel.

The recommended scheme, designated Alternative E, includes a dam and provisions for fish passage at the Chakachamna Lake outlet, an intake, 10 miles of power tunnel, and a powerplant on the McArthur River. The project would have an installed capacity of 330 MW, average annual energy generation of 1,590 GWH and is estimated to cost $1,438 million in 1983 dollars. The project costs and power and energy capabilities are shown on Exhibit 4.5.

5.18

4.5 ENVIRONMENTAL CONSIDERATIONS

The environmental and socioeconomic effects of the above-described Non-Susitna generation alternatives are substantial and extremely varied. Exhibit 4.6 presents a summary of some of the environment-related facility characteristics of these alternatives. Based upon these data, relative environmental impacts by category for given locations and technology options are summarized on Exhibit 4.7.

The ranking values within one category are unweighted with respect to another category. For example, a moderate impact to water resources may be more significant than a high impact to aesthetics. To further differentiate between alternatives from an environmental standpoint would require a subjective weighting of factors between categories, an involved process which requires input from all parties who have an interest in or who may be affected by project development.

It is apparent that there is no single superior project alternative in terms of minimizing environmental impacts in all categories. Rather, many impacts are a function of specific site selection, detailed engineering, and extent of mitigative measures. Compliance with regulatory criteria and good engineering design should minimize most impacts.

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ESTIMATED CUMULATIVE CONSUMPTION OF COOK INLET NATURAL GAS RESERVES (a)
(billion cubic feet)

Year	Phillips/ Matathon LNG/Plant	Collier Ammonia/Urea	Retail Sales	Field Operations & Other Sales	Electric Generation		Total Gas Use	Total Cumulative Gas Use	Remaining Reserves	
					Military	Expansion Planning Studies(b)			Proven	Proven Plus Undiscovered
1983	62	55	19.2	25	5	27.1	193.3	193.3	3157.6	5197.6
1984	62	55	19.8	25	5	28.8	195.6	388.9	2962.0	5002.0
1985	62	55	20.5	25	5	30.4	197.9	586.8	2764.1	4804.1
1986	62	55	22.8	25	5	29.1	198.9	785.7	2565.2	4605.2
1987	62	55	23.6	25	5	30.3	200.9	986.6	2364.3	4404.3
1988	62	55	24.4	25	5	27.5	198.9	1185.5	2165.4	4205.4
1989	62	55	25.3	25	5	28.7	201.0	1386.5	1964.4	4004.4
1990	62	55	26.1	25	5	29.8	202.9	1589.4	1761.5	3801.5
1991	62	55	27.1	25	5	30.4	204.5	1793.9	1557.0	3597.0
1992	62	55	28.0	25	5	31.2	206.2	2000.1	1350.8	3390.8
1993	62	55	29.0	25	5	31.0	207.0	2207.1	1143.8	3183.8
1994	62	55	30.1	25	5	31.7	208.8	2415.9	935.0	2975.0
1995	62	55	31.1	25	5	32.3	210.4	2626.3	724.6	2764.6
1996	62	55	32.2	25	5	33.0	212.2	2838.5	512.4	2552.4
1997	62	55	34.4	25	5	33.8	215.2	3053.7	297.2	2337.2
1998	62	55	34.6	25	5	34.4	216.0	3269.7	81.2	2121.2
1999	62	55	35.8	25	5	35.1	217.9	3487.6	(136.7)	1903.2
2000	62	55	37.0	25	5	35.9	219.9	3707.5		1683.3
2001	62	55	38.3	25	5	36.8	222.1	3929.6		1461.2
2002	62	55	39.7	25	5	38.8	225.5	4155.1		1236.0
2003	62	55	40.1	25	5	39.7	226.8	4381.9		1009.2
2004	62	55	42.6	25	5	40.7	230.2	4612.2		778.2
2005	62	55	44.1	25	5	42.6	233.7	4845.9		544.2
2006	62	55	45.6	25	5	31.6	224.2	5070.1		320.0
2007	62	55	47.2	25	5	32.9	277.1	5297.2		92.9
2008	62	55	48.9	25	5	34.2	230.1	5527.3		(137.2)
2009	62	55	50.6	25	5	34.6	232.2	5759.5		
2010	62	55	52.4	25	5	35.9	235.3	5994.8		

(a) Estimates of Natural gas consumption, with the exception of electric generation from expansion planning studies, proven and proven plus economically recoverable undiscovered reserves taken from Table D.1.3, Appendix D-1, Exhibit D, July 1983.

(b) OGP fuel use summary for DOR MEAN Coal/Gas expansion plan with limited gas.

EXHIBIT 4.1

DOR MEAN SCENARIO
FUEL COSTS
(January 1983 price level)

	Crude Oil		Cook Inlet Gas		North Slope Gas		Coal	
Year	Cost ($/bbl)	Average Rate of Change Per Year (%)	Cost ($/MMBtu)	Average Rate of Change Per Year (%)	Cost ($/MMBtu)	Average Rate of Change Per Year (%)	Cost ($/MMBtu)	Average Rate of Change Per Year (%)
1983	28.95		2.47		4.00		1.80	
		-1.4		-0.1		0.0		0.0
1993[a]	25.13		2.45		4.00		1.80	
		1.5[b]		1.5		0.0		0.0
2000	27.87		2.72		4.00[c]		1.80	
		1.5		1.5		1.5		0.0
2010	32.42		3.15		4.18		1.80	
		1.5		1.5		1.5		0.0
2020	37.62		3.66		4.85		1.80	
		1.5		1.5		1.5		0.0
2030	43.66		4.25		5.63		1.80	
		1.5		1.5		1.5		0.0
2050	58.80		5.72		7.58		1.80	

(a) First year of expansion planning and economic analysis.

(b) Average rate of change in crude oil price last five years of forecast.

(c) Until 2007

EXHIBIT 4.2

SHCA - NSD SCENARIO

FUEL COSTS

(January 1983 price level)

	Crude Oil		Cock Inlet Gas		North Slope Gas		Coal	
Year	Cost ($/bbl)	Average Rate of Change Per Year %	Cost ($/MMBtu)	Average Rate of Change Per Year %	Cost ($/MMBtu)	Average Rate of Change Per Year %	Cost ($/MMBtu)	Average Rate of Change Per Year %
1983	28.95		2.47		4.00		1.72/1.86	
		0.5		2.0		0.5		2.3/1.6
1993[a]	30.49		3.02		4.22		2.17	
		3.0		3.0		3.0		1.0
2000	37.50		3.71		5.19		2.33	
		3.0		3.0		3.0		1.0
2010	50.39		5.00		6.97		2.57	
		2.5		2.5		2.5		1.0
2020	64.48		6.39		8.92		2.84	
		1.5		1.5		1.5		1.0
2030	74.84		7.41		10.35		3.13	
		1.0		1.0		1.0		1.0
2050	91.32		9.05		12.63		3.82	

(a) First year of economic analysis.

EXHIBIT 4.3

THERMAL PLANT OPERATING PARAMETERS AND COSTS (a)

Characteristics	Coal-fired	Combined Cycle	Combustion Turbine
Nameplate Capacity - MW	200	237	84
Heat Rate - Btu/kWh	9,750	8,280	11,650
Outage Rates, Percent of Time			
Scheduled (Immature)	12.0	8.8	3.2
Scheduled (Mature)	8.0	7.0	3.2
Forced (Immature)	8.6	10.0	8.0
Forced (Mature)	5.7	8.0	8.0
Immature Period - yrs	3	2	1
Construction Period, yrs	5	2	1
Unit Construction Costs - $/kW	2,175	604	500
Unit Investment Cost (b) - $/kW	2,370	625	510
Operation and Maintenance Costs			
Variable O&M costs - mills/kWh	0.6	1.69	4.90
Fixed O&M Costs - $/kW/yr	17.00	7.25	2.70
Economic Life - Years	30	30	20

(a) January 1983 price level

(b) Includes interest during construction at 3.5 percent interest, escalation not included.

EXHIBIT 4.5

CHAKACHAMNA HYDROELECTRIC PROJECT DATA[(a)]

Installed Capacity - MW	330
Total Capital Cost Including Transmission (a) - $ million	1,269
IDC - $ million	127
Total Capital Cost - $ million	1,396
Total Capital Cost - $/kW	4,230
Operation and Maintenance Cost - $ million	2.0

Monthly Power and Energy Production:

Month	Average Energy GWh	Firm Energy GWh	Minimum Plant Rating MW	Maximum Plant Rating MW
January	133	133	177	179
February	114	114	168	170
March	113	113	150	153
April	98	98	135	137
May	94	92	124	231
June	96	86	120	330
July	138	88	118	330
August	228	92	124	330
September	179	98	136	330
October	126	115	155	275
November	128	128	177	179
December	144	144	193	195
Total	1,591	1,301		

(a) Chakachamna Hydroelectric Project Interim Feasibility Assessment Report, Bechtel Civil & Minerals, Inc., Alternative E, March 1983.

ENVIRONMENT RELATED FACILITY CHARACTERISTICS FOR ALTERNATIVE POWER GENERATION OPTIONS

Environmental Factor	Location/Technology						
	Beluga (Coal Fired)	Nenana (Coal Fired)	North Slope (Nat. Gas)	Fairbanks (Nat. Gas)	Kenai (Nat. Gas)	Beluga (Nat. Gas)	Chakachamna (Hydro)
Air Environment							
Emissions							
Particulate Matter ($lb/10^6$ Btu)	0.03	0.03	a/	a/	a/	a/	Negligible
Sulfur Dioxide ($lb/10^6$ Btu)	0.6 b/	0.6 b/	a/	a/	a/	a/	
Nitrogen Oxides ($lb/10^6$ Btu)	0.6	0.6	c/	c/	c/	c/	
Physical Effects-(max. struc. height ft.)	-	-	50	50	50	50	
Water Environment							
Plant Water Requirements (gpm)	287 d/	287 d/	25-50	100-200			
Water Injection					500-800	500-800	1.64 million (ave)
Other					200	200	
Plant Discharge Requirements (gpm)			50	200			
Process Water	None	None					
Coal Pile Runoff	Infrequent	Infrequent					
Demineralizer					40	40	1.64 million (ave)
Stream Generators					70	70	
Treated Sanitary Waste					15	15	
Floor Drains					25	25	
Land Environment							
Land Requirements (acres)							
Plant	25	25	60-90 e/	90-140	120-175	120-175	40 mi, road
Construction Camp	-	-	5	5	-	-	
Solid Waste Disposal	50	50					
Socioeconomic Environment							
Construction Workforce, peak (personnel)	500	500	115-200	100-200	200	200	1,220
Operating Workforce (personnel)	109	109	140-200	50-150	130-150	130-150	1-2

a/ Below Standards
b/ Assumes 70% Reduction
c/ Emissions variable within standards. Dry control techniques would be used to meet calculated No_x standard of 0.014 percent of total volume of gaseous emissions. This value calculated based upon new source performance standards, facility heat rate and unit size.
d/ Dry Cooling. Wet Cooling = 1,947 gpm
e/ Includes Switchyard

EXHIBIT 4.6

QUALITATIVE RANKING OF ENVIRONMENTAL IMPACTS ASSOCIATED WITH ALTERNATIVE PROJECTS

Environmental Category	Location/Technology						
	Beluga (Coal Fired)	Nenana (Coal Fired)	North Slope (Nat. Gas)	Fairbanks (Nat. Gas)	Kenai/Nikiski (Nat. Gas)	Beluga (Nat. Gas)	Chakachamna (Hydro)
Air Resources	2	4	2	3	1	1	0
Water Resources	3	1	1/2	0/2	0/2	2	4
Aquatic Ecology	0	0	1/2	0/2	1/2	0	4
Terrestrial Ecology	2	2	1/3	0/3	0/3	1	2
Socioeconomics	4	1	1/2	0/2	1/2	3	3
Aesthetics	3	2	1/4	1/3	1/3	2	3

NOTE: In case where two numbers appear, the first number refers to the power plant only, while the second number incorporates secondary support facility impacts (e.g., gas line, transmission line).

Key: 0 - no impact
1 - low impact
2 - moderate impact
3 - high impact
4 - severe impact

5.0 SYSTEM EXPANSION PROGRAMS

5.0 SYSTEM EXPANSION PROGRAMS

5.1 INTRODUCTION

The objective of the expansion studies is to develop long-term power supply plans for the Railbelt electrical generation system with and without the Susitna Hydroelectric Project. Power supply programs are developed for electric power demand forecasts based on DOR Mean and SHCA-NSD oil price forecasts. With these oil price scenarios, the Watana Project would enter service in 1993 and practically all of the Susitna Project potential would be absorbed in the system by about the year 2020.

The studies are performed using a computer program developed by General Electric titled "Optimized Generation Planning" (OGP). The input data on the Susitna Project and the thermal alternatives are described in Chapters 3 and 4. A supplement to this report contains computer output from the OGP program for selected DOR Mean expansion programs analyzed in this update.

The power supply programs are developed using economic planning criteria such as discount rates, planning horizon, etc. that are described in Chapter 6. In turn, the power supply programs provide annual and present worth costs of alternative power supply programs. These results are used in the economic analysis using a life cycle approach described in Chapter 6.

In this Chapter, the existing system is first described. Next the system expansion from 1983 to 1992 is addressed. Then the criteria for system expansion from 1993 are discussed. The year 1993 is the first year that the Susitna Project is considered to be operational. The OGP computer model is described briefly. Alternative expansion programs which result from the study are then presented and discussed.

5.2 THE EXISTING RAILBELT SYSTEMS

The two major load centers of the Railbelt region are the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area, which at present operate independently. Exhibit 5.1 summarizes the total generating capacity within the Railbelt system in 1983. The total Railbelt installed capacity amounts to 1123 MW excluding installations not available for public service at military bases. The 1123 MW consists of 1077 MW of thermal generation fired by oil, gas, or coal plus the Eklutna and Cooper Lake hydroelectric plants totaling 46 MW. Average annual and firm energy estimates for the Eklutna and Cooper Lake hydroelectric projects are shown on Exhibit 5.2.

5.3 1983 - 1992 GENERATION EXPANSION

5.3.1 Planned System Additions

The Power Authority has begun the construction of an Intertie connecting the Anchorage and Fairbanks load centers with a single circuit transmission line between Willow and Healy scheduled for completion in 1984. The line will initially be energized at 138 kV, but can be operated at 345 kV as the loads grow in Anchorage and Fairbanks. The completion of the Intertie will improve the reliability of service of both load centers and provide economy exchange.

Two hydroelectric projects are assumed to be added to the Railbelt system prior to 1990: the Bradley Lake Hydroelectric Project with 90 MW of generating capacity and 347 GWh of average annual energy, and the Grant Lake Project with 7 MW of generating capacity and 25 GWh of annual energy. The average annual and firm energy estimates for the Bradley Lake and Grant Lake Projects are shown on Exhibit 5.2.

Fairbanks Municipal Utility System is considering the addition of a 25-30 MW cogeneration unit to replace Chena Units 1, 2 and 3, and Chugach Electric Association is studying the feasibility of a 34-MW combustion turbine at Bernice Lake and an 80-MW combustion turbine at the Beluga Power Station. These plans appear to be moving forward but have not been finalized and are not included as part of the 1992 Railbelt system.

Other than these plants and the Intertie, no major generation is considered to be installed since the Railbelt utilities would have factored Susitna or its alternatives into their resource planning, and any new additions would likely be limited.

5.3.2 1992 System

The Railbelt system is assumed to be identical prior to 1993 under the Susitna and Non-Susitna expansion programs.

After allowance for the retirement of oil and gas-fired units and additions of new capacity in the period 1983 to 1992, the generation system capacity (MW) at the time of the introduction of Susitna (or its alternatives) is considered to be as follows:

Oil-fired combustion turbines	181
Natural gas combustion turbines	254
Natural gas combined cycle plants	317
Coal-fired steam plants	59
Hydroelectric plants	143
Total installation in MW	954

Should it become desirable, scheduled retirements of the existing plants could be delayed so that sufficient capacities would be available to meet the system demand in 1993 when the first units from Watana enter service.

5.4 GENERATION ALTERNATIVES

5.4.1 Susitna Alternative

Study of the Susitna Project, which is described in Chapter 3, has been directed at the development of long-term power supply plans for Watana and Devil Canyon, including investigation of the timing of the Devil Canyon development. Exhibit 5.3 summarizes pertinent data and construction and investment costs for the Susitna project. The investment costs include interest during construction computed at 3.5 percent using estimated construction cash flow distributions.

5.4.2 Non-Susitna Alternatives

The major portion of the current generating capability in the Railbelt is natural gas with some hydroelectric, coal, and oil-fired installations. Chapter 4 describes natural gas-fired and coal-fired generation sources which could be attractive alternatives in the Railbelt.

In addition, the Chakachamna Hydroelectric Project is discussed. Exhibit 5.4 summarizes operating characteristics and costs of the Non-Susitna alternatives selected for the power supply plan studies.

5.5 FORMULATION OF EXPANSION PROGRAMS

Capacity expansion studies cover three major functions: (1) reliability evaluation; (2) electricity production simulation; and, (3) capacity expansion optimization. Expansion optimization analyses provide a systematic means to evaluate the timing, type, and system costs of new capacities.

The General Electric Optimized Generation Planning (OGP) model was used to develop the power supply plans. This program was used in the earlier feasibility and License Application studies, and the specific Railbelt system data base has been sufficiently developed. Exhibit 5.5 outlines the procedure used by OGP to determine an optimum generation expansion plan.

The plans are structured based on the following criteria and optimized with the procedures of the OGP model.

1) The existing system and planned additions
2) Susitna and Non-Susitna alternatives
3) Cost and characteristics of future additions
4) Fuel availability subject to limitations of reserves
5) Fuel cost and escalation
6) Generation system reliability
7) System operation

In developing an optimal plan, the program considers the existing and committed units (planned and under construction) available to the system and the operating characteristics of these units. Then the program considers the given load forecast and operation criteria to determine the need for additional system capacity based on specific reliability criteria. This determines how much capacity to add and when it should be installed. If a need exists, the program will consider additions from a list of alternatives and select the available unit best fitting the system needs. Unit selection is made by computing production costs for the system for each alternative included and comparing the results. The unit resulting in the lowest system production costs is selected and added to the system. The OGP modeling procedure contains several key elements which are discussed below.

5.5.1 Reliability Evaluation

The Loss of Load Probability (LOLP) method is used in the OGP program to determine when additional capacities are needed. The LOLP approach is concerned with the probability that cumulative system capacity after forced outages would result in a deficiency in available capacity to meet the system load. Sensitivity analyses were conducted for one day in ten years, one day in five years and one day in three years to relate the LOLP to reserve margin. The results indicated that reserve margins in the 30 to 40 percent range could be achieved with an LOLP of 0.20 days per year or one day in five years, for the Railbelt utilities. Reserve margins in this range are considered to be satisfactory for the Railbelt.

5.5.2 Conventional Hydro Scheduling

In the simulation, the initial Watana project is operated on base in order to maintain nearly uniform discharge from the powerplant. When Devil Canyon comes online, Watana is operated in a load following mode, while Devil Canyon operates on base. Under base loading, constant plant ratings are specified that correspond to the plant capacity output that produces the total energy generation estimated to be available.

5.5.3 Thermal Unit Commitment

After modifications for hydro and unit maintenance, the remaining loads are served by the thermal units on the system. The units are committed to minimize the operating costs. The operating costs are calculated from the fuel and variable O&M costs and input-output curve for each unit. Fixed O&M costs do not affect the order in which units are committed, but are included in the total production cost.

The unit commitment logic determines how many units will be on-line each hour and which units are committed in order of their full load energy costs starting with the least expensive.

5.5.4 OGP Optimization Procedure

For the year under study, a system reliability evaluation is performed to compute the need for installing additional generating capacity. If the capacity is sufficient to maintain the desired once in 5 year LOLP, the program calculates the annual production and investment costs and proceeds to the next year.

If additional capacity is needed, the program will add units from a list of available additions until the reliability index is met. For a combination of units the program calculates annual costs and selects the most economical installation.

The OGP logic utilizes a look-ahead feature that develops annual costs over a 10-year period for combinations of units to compute if unit additions beyond reliability requirements reduce system costs. If a generating unit is selected, the reliability and costing calculations are repeated for the chosen alternative.

5.6 1993-2020 SYSTEM EXPANSION

5.6.1 Transmission System Expansion Associated with Generation System Expansion

Transmission system expansion associated with the Susitna Project has been studied in detail, and the costs have been estimated and included as part of the project.

Transmission system expansion associated with the Non-Susitna alternatives is to be added as a separate item to the Non-Susitna alternatives depending on how the generation system expansion takes place.

To simplify the analysis, the following transmission system costs are added to coal-fired steam and combined cycle combustion turbines.

Coal-fired and/or combined cycle plants at Beluga:	$220 million
Coal-fired plant at Healy	$117 million

These costs provide for new lines to the existing transmission system and for increasing capacity within the present transmission system.

A preliminary review of the year-by-year transmission requirements for several specific Non-Susitna generation expansion programs indicated that the simplified cost estimates for the Non-Susitna transmission system were reasonably in line with, but slightly lower than, detailed year-by-year estimates.

5.6.2 1993 - 2020 Generation Expansion

Using OGP, alternative expansion programs were developed for the period from January 1993 to December 2020 to establish the least-cost system expansion programs for that period for both the Susitna and the Non-Susitna cases. The alternative expansion programs were tested for the DOR Mean and SHCA-NSD oil price scenarios. With these oil price scenarios, the Watana Project would enter service in 1993 and practically all of the Susitna Project potential would be absorbed in the system by about the year 2020.

In the Non-Susitna cases, coal-fired and gas-fired generation and the Chakachamna Hydroelectric Project were tested. Four basic supply plans were developed for each load forecast as follows:

- Gas and Coal (including natural gas-fired combined cycle, coal-fired steam plant, and combustion turbines)
- Gas (including natural gas-fired combined cycle and combustion turbine)
- Coal (including coal-fired steam plant and natural gas-fired combustion turbines)
- Chakachamna Hydro (including coal, combined cycle and combustion turbines).

For the supply plans, proven and economically recoverable undiscovered reserves of natural gas from Cook Inlet are considered depleted by about 2007. At that time natural gas for electricity generation is considered to be available from additional higher-cost undiscovered Cook Inlet reserves or from the North Slope with ANGTS or TAGS. An analysis is also performed for a case in which natural gas supply at a higher cost from North Slope is available by means of a 22 inch diameter, high pressure pipeline to Fairbanks. A detailed discussion of natural gas resources and prices are contained in Chapter 4.

The total costs for the planning period include all costs of fuel and operation and maintenance of all generating units. In addition, the production cost includes the annualized investment costs of any plants and transmission facilities added during the period. Costs common to all the alternatives are excluded. These would be investment costs of facilities in service prior to 1993, and administrative and customer services costs of the utilities.

The annual costs from 1993 through 2020 are developed by the OGP model and are converted to a present worth in 1983. The long-term system costs (2021-2050) are estimated from the 2020 annual costs, with adjustments for fuel escalation, for the 30-year period. The Susitna and Non-Susitna expansion plans are compared on the basis of the sum of the present worths from 1993 to 2050.

5.7 REVIEW OF EXPANSION PROGRAMS

5.7.1 Comparison of Expansion Plans under the DOR Mean Scenario

Exhibit 5.6 shows the expansion plan yearly MW additions for the Non-Susitna alternatives and Exhibit 5.7 shows similar information for the Susitna alternative. Exhibit 5.8 summarizes the generation mix, reserve margin, loss of load probability (LOLP), economic costs of power in $/MWh, and cumulative present worth of system costs for the years 2020 and 2050.

Exhibit 5.8 shows the Non-Susitna plans, with a combination of gas-fired combined cycle and coal-fired steam as being the optimum Non-Susitna plan. Reference to Exhibit 5.6 shows this plan beginning with a two-unit combined cycle plant in 1993 followed by installation of combustion turbines until 2005. After 2005, coal-fired plants are added and additional combustion turbines are brought on line to replace those added in earlier years. This plan was developed by OGP through its own internal optimization process which compares the economic advantages of various mixes including combined cycle, combustion turbine and coal-fired alternatives. To ensure that the plan is indeed superior to any other thermal alternative, the OGP program was tested with the use of a coal-fired plant in 1993, and further tested with the use of only gas-fired generation. These expansion plans are found to be less economical since they result in higher cumulative present worths for the period 1993-2050.

The Chakachamna Project was also tested as one of the Non-Susitna alternatives, and it was found to have a cumulative present worth greater than the optimum Non-Susitna plan. The 195 MW capability of the Chakachamna Hydroelectric Project, as shown in Exhibit 5.6, is based on the project's average energy generation in the month of December, which is the Railbelt area peak demand month and the month used by OGP for output reporting purposes.

Exhibits 5.9 and 5.10 compare the contribution of energy production between a Non-Susitna plan and the Susitna plan. As shown by these two exhibits, the Railbelt system will continue to be dominated by oil and gas-fired generation over the next 10 years. By 1993 a very large share of the gas and oil-fired generation can be replaced with Susitna in operation. Otherwise, natural gas will continue to be the principal source of fuel for the Railbelt through the end of this century and beyond.

5.7.2 Expansion Plans under the SHCA-NSD Scenario

Exhibit 5.11 shows the Susitna and Non-Susitna expansion plans to meet the forecast load under the SHCA-NSD oil price scenario. The exhibit provides the generation mix in the year 2020 for the alternative supply plans, reserve margin, and present worth costs.

For the gas/coal alternative, the OGP program selected a mix of natural gas-fired combined cycle plants, coal-fired steam, and combustion turbines. However, a substantially greater amount of coal-fired steam installation is added, and the only addition of a natural gas-fired combined cycle plant would be in the year 1993.

Again, to ensure that the OGP has made the correct selection, a coal expansion program was tested. The coal expansion program would result in slightly lower cumulative present worths than the gas/coal program. However, the coal alternative appears to have much less reserve, consequently these two alternative expansion plans are considered nearly equal. The gas/coal expansionplan is selected for comparison purposes.

The results of this analysis indicate that if oil prices and load growths should exceed the SHCA-NSD scenario, the logical choice for the Non-Susitna 1993 installation would be a coal-fired steam plant.

The Chakachamna Hydroelectric Project appears to be competitive when compared with the all-thermal supply plans under the SHCA-NSD case, while the project is marginal under the DOR Mean Scenario. The results appear to be reasonable in view of the higher cost of fuel under the SHCA-NSD case, and a hydroelectric project would therefore become more attractive.

The Susitna alternative is clearly favored over the Non-Susitna alternatives for the SHCA-NSD forecast scenario.

TOTAL GENERATING CAPACITY WITHIN THE RAILBELT SYSTEM - 1983
in Megawatts

Abbreviations	Railbelt Utility	Installed Capacity (a)
AMLP	Anchorage Municipal Light & Power Department	311.6
CEA	Chugach Electric Association	463.5
GVEA	Golden Valley Electric Association	221.6
FMUS	Fairbanks Municipal Utility System	68.5
MEA	Matanuska Electric Association	0.9
HEA	Homer Electric Association	2.6
SES	Seward Electric System	5.5
APA	Alaska Power Administration	30.0
U of A	University of Alaska	18.6
TOTAL		1122.8 (b)

(a) Installed capacity as of 1982 at 0°F
(b) Excludes National Defense installed capacity of 101.3 MW

EXISTING AND PLANNED RAILBELT HYDROELECTRIC GENERATION

	Average Energy-GWh					Firm Energy-GWh				
Month	Eklutna (a) (30 MW)	Cooper Lake (a) (16MW)	Bradley Lake (a)(b) (90 MW)	Grant Lake (b) (7 MW)	Total (143 MW)	Eklutna (a)	Cooper Lake (a)	Bradley Lake (a)(b)	Grant Lake (b)	Total
Jan	14	4	31	2	51	13	4	35	2	54
Feb	12	3	28	2	45	12	3	32	2	49
Mar	12	3	28	1	44	9	3	24	1	37
Apr	10	3	23	2	38	10	3	26	1	40
May	12	3	26	2	43	11	3	31	1	46
June	12	3	27	2	44	8	2	21	2	33
July	13	4	30	2	49	9	3	22	2	36
Aug	14	4	32	3	53	8	2	23	1	34
Sept	13	3	28	3	47	9	2	23	2	37
Oct	14	4	31	2	51	9	3	25	1	38
Nov	14	4	31	2	51	8	2	22	2	34
Dec	14	4	32	2	52	12	3	21	2	48
Total	154	42	347	25	568	118	34	315	19	486

(a) Source: 1982 Feasibility Study.

(b) Assumed to be scheduled on line in 1988.

EXHIBIT 5.2

SUSITNA HYDROELECTRIC PROJECT

Single Project	Installed Capacity (a)		Energy Production		Cost	
	Initial (MW)	Ultimate (MW)	Average (b) (GWh)	Reliability (GWh)	Construction (c) ($Million)	Investment (d) ($Million)
Watana 2185	724	1088	3500	2265	3338	3785
Devil Canyon	501	501	2260	2005	1554	1762
Combined Project						
Watana 2185 + Devil Canyon	1398	1752	6820	5120	4892	5547

(a) Average plant capability in megawatts for December

(b) Based on 4-unit powerstation, with system demand constraints

(c) January 1983 price level

(d) Includes interest during construction at 3.5 percent interest and an 8-year construction period; no real escalation of construction cost was included.

EXHIBIT 5.3

0 0 0 4 6

NON-SUSITNA PLANT OPERATING PARAMETERS
AND COSTS(a)

Characteristics	Coal-fired	Combined Cycle	Combustion Turbine	Chakachamna Hydroelectric Project
Nameplate Capacity - MW	200	237	84	330
Heat Rate - Btu/kWh	9,750	8,280	11,650	-
Outage Rates, Percent of Time				
Scheduled (Immature)	12.0	8.8	3.2	-
Scheduled (Mature)	8.0	7.0	3.2	-
Forced (Immature)	8.6	10.0	8.0	-
Forced (Mature)	5.7	8.0	8.0	-
Immature Period - yrs	3	2	1	-
Construction Period, yrs	5	2	1	6
Unit Construction Costs - $/kW	2,175	604	500	3,847
Unit Investment Cost (b) - $/kW	2,370	625	510	4,230
Operation and Maintenance Costs				
Variable O&M costs - mills/kWh	0.6	1.69	4.90	1.26 (a)
Fixed O&M Costs - $/kW/yr	17.00	7.25	2.70	

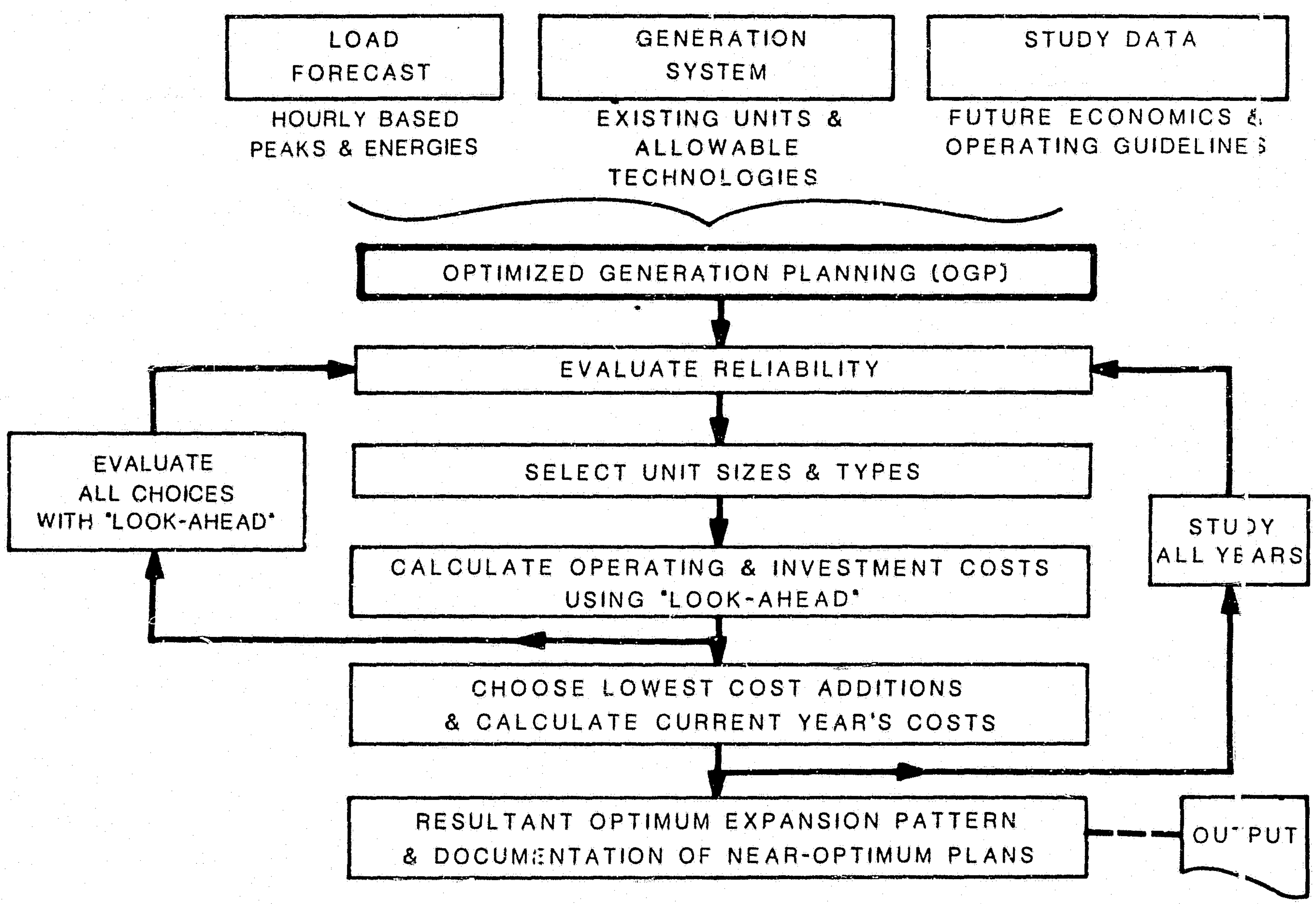
(a) January 1983 price level

(b) Includes interest during construction at 3.5 percent for the construction periods shown; no real escalation of construction cost included.

(c) Based on average annual energy generation of 1,591 GWh

EXHIBIT 5.4

EXHIBIT 5.5



ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

OPTIMIZED GENERATION PLANNING (OGP) PROGRAM INFORMATION FLOWS

SEPTEMBER 1983

EXPANSION PLAN YEARLY MW ADDITIONS
DOR MEAN LOAD FORECAST
NON-SUSITNA ALTERNATIVES

			OPTIMUM NON-SUSITNA				COAL ONLY			CHAKACHAMNA				
YR	POOL PEAK (MW)	TOTAL ENERGY (GWh)	COAL (MW)	COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	TOTAL (a) CAPABILITY (MW)	COAL (MW)	COMBUSTION TURBINE (MW)	TOTAL (a) CAPABILITY (MW)	COAL (MW)	COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	HYDRO (MW)	TOTAL (a) CAPABILITY (MW)
93	867	4167			474	1369	400		1295		84	237	195	1411
94	882	4237				1369			1295		84			1495
95	896	4306		84		1382		84	1308					1424
96	913	4387		84		1378		84	1304		168			1504
97	929	4467		84		1396		84	1322		84			1522
98	946	4548				1370			1296					1496
99	963	4629		84		1454		84	1380					1496
0	979	4709				1453			1379		84			1579
1	1001	4813				1453			1379					1579
2	1022	4916		168		1479		168	1405		168			1605
3	1043	5019				1479			1405					1605
4	1064	5122		84		1563		84	1489					1605
5	1086	5225				1542			1468			237		1821
6	1115	5369	200			1742	200		1669					1821
7	1145	5513				1742			1669					1821
8	1175	5657				1742			1669					1821
9	1205	5801				1742			1669					1821
10	1234	5954				1742			1669					1821
11	1263	6085	200			1797	200		1724	200				1876
12	1292	6229	200			1820		168	1714	400				2099
13	1323	6376				1820			1714					2015
14	1354	6526				1820	200		1914		84			2015
15	1358	6680		168		1891			1817					2002
16	1418	6837		84		1891		84	1817		252			2086
17	1451	6999	200			2007		168	1901		84			2086
18	1485	7164				2007			1901					2086
19	1520	7333		84		2007		84	1901		84			2170
20	1555	7505		84		2091	200		2101		84			2170

(a) Includes existing generation plant less retirement.

EXHIBIT 5.6

EXHIBIT 5.7

EXPANSION PLAN YEARLY MW ADDITIONS
DOR MEAN LOAD FORECAST
SUSITNA ALTERNATIVE

			WATANA 2185 + DEVIL CANYON BASE LOADING			
YR	POOL PEAK (MW)	TOTAL ENERGY (GWh)	COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	SUSITNA (MW)	TOTAL (a) CAPABILITY (MW)
93	867	4167			539	1433
94	882	4237				1432
95	896	4306				1362
96	913	4387	84			1358
97	929	4467				1292
98	946	4548	84			1350
99	963	4629				1350
0	979	4709				1349
1	1001	4813	84			1433
2	1022	4916	84			1375
3	1043	5019	84			1459
4	1064	5122				1459
5	1086	5225				1438
6	1115	5369			632	2070
7	1145	5513				2070
8	1175	5657				2070
9	1205	5801				2070
10	1234	5945				2070
11	1263	6085				1925
12	1292	6229			38	1785
13	1323	6376				1785
14	1354	6526				1785
15	1385	6680				1772
16	1418	6837	84			1772
17	1451	6999	84			1856
18	1485	7164	84			1856
19	1520	7333				1856
20	1555	7505	84			1940

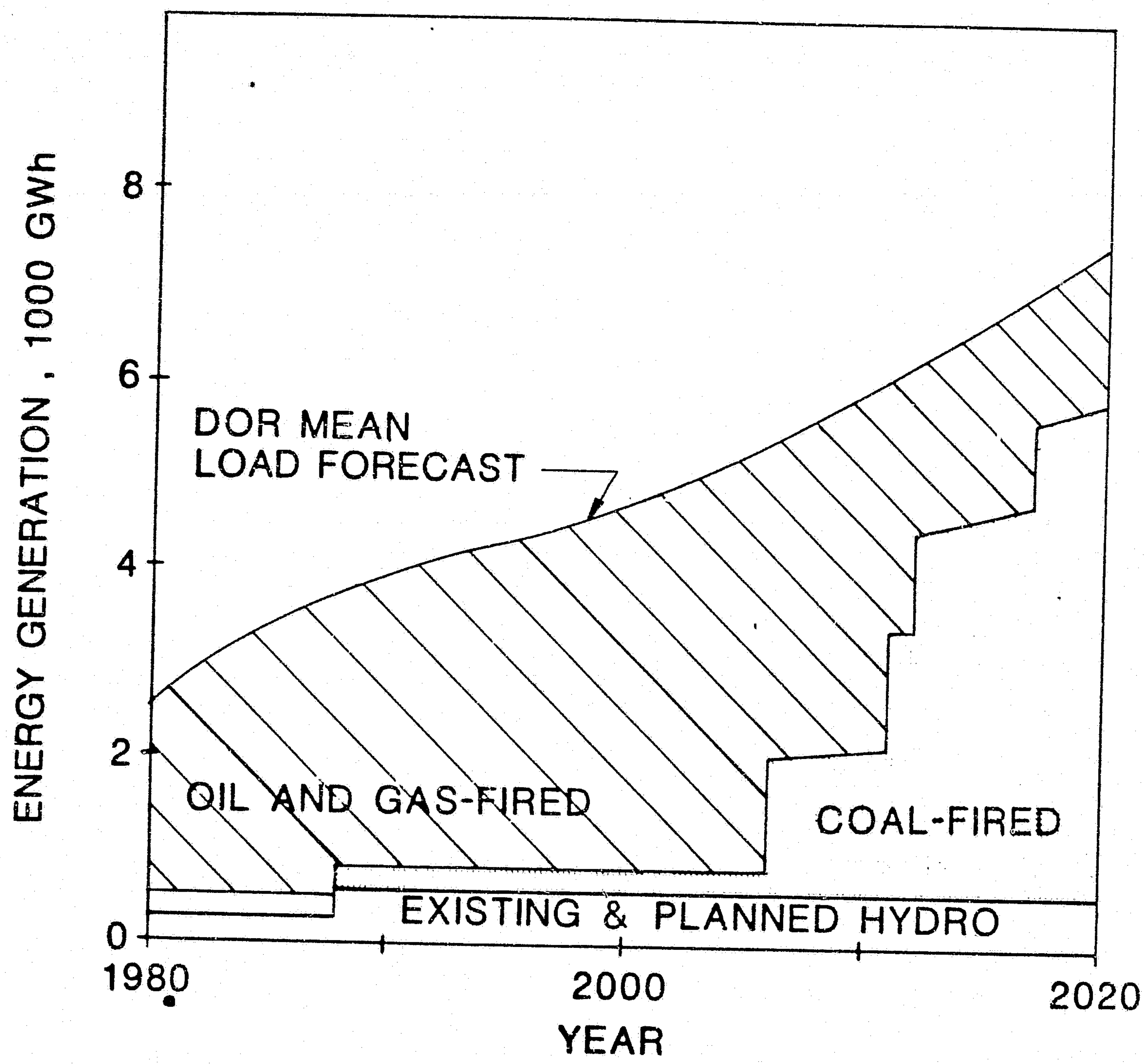
(a) Includes existing generation plant less retirements.

Year 2020 Railbelt System Generation Mix
DOR Mean Load Forecast

	NON-SUSITNA				SUSITNA - Base Loading
	Optimum Gas/Coal	Gas Only	Coal Only	Chakachamna	Watana 2185
OGP ID	LUN1	LUF5	LNN5	LUE3	LYX9
Capacity-MW					
Coal	800	0	1200	600	0
CT	672	756	756	756	588
CCCT	474	1185	0	474	0
Hydro	143	143	143	143	143
Susitna	0	0	0	0	1209
Chakachamna	0	0	0	195	0
Total	2089	2084	2099	2168	1940
2020 Reliability					
Peak Demand	1555	1555	1555	1555	1555
% Reserve	34.5	34.1	35.1	39.5	24.8
LOLP -D/Y	0.082	0.183	0.053	0.160	0.036
Total Economic Cost					
1993 $/MWh	30.84	30.84	38.34	37.72	49.15
2010 $/MWh	46.78	47.82	46.89	48.60	45.25
2020 $ MWh	50.33	56.02	50.98	51.83	40.55
Million Dollars					
2020 Cost	377.7	420.4	382.6	389.0	304.3
Cum 2020 P.W.	2844	2929	3077	3128	3142
Cum 2050 P.W.	4890	5446	5070	5227	4744

EXHIBIT 5.8

EXHIBIT 5.9

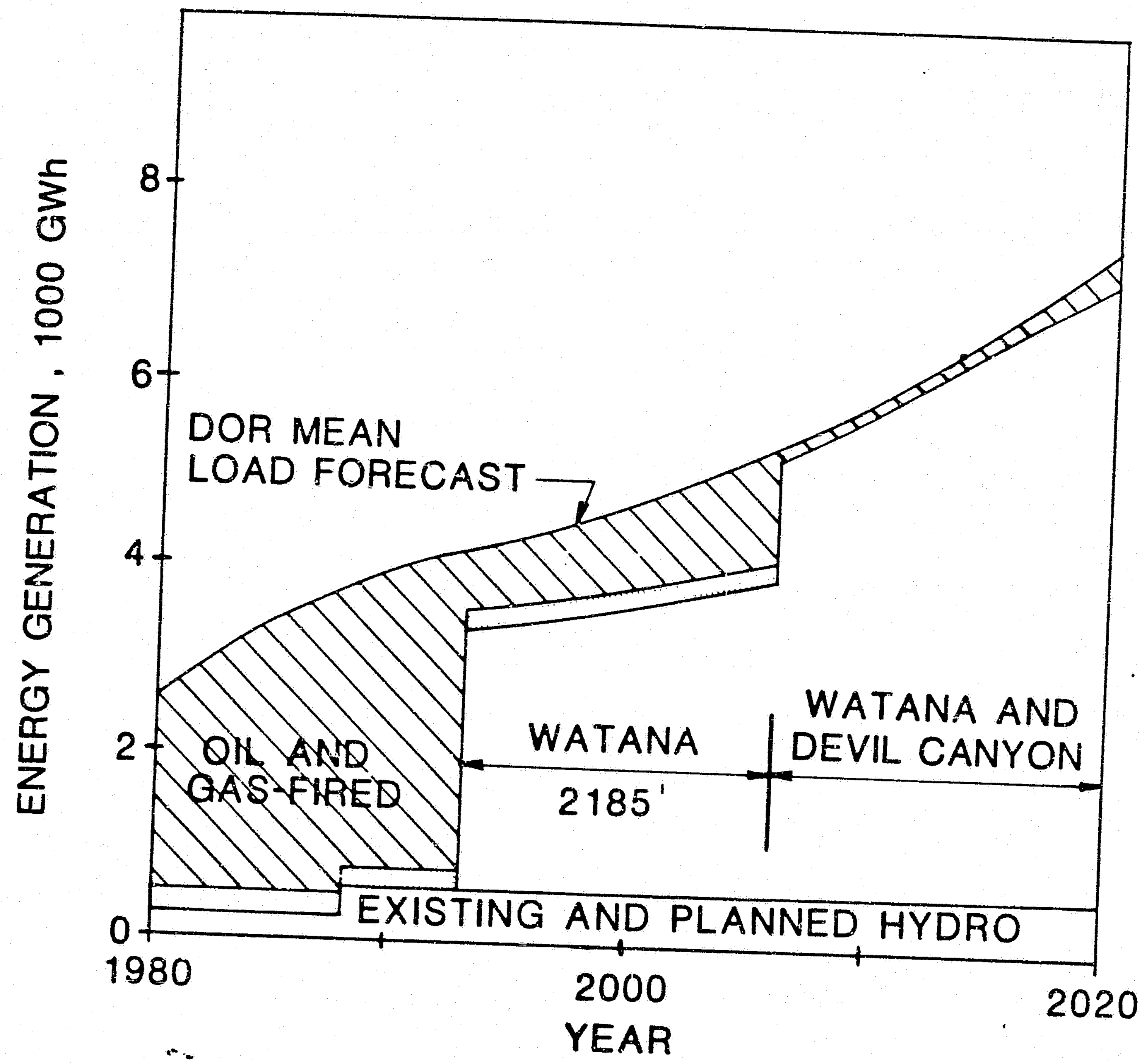


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

THERMAL ALTERNATIVE -ENERGY DEMAND & DELIVERIES

SEPTEMBER 1983

EXHIBIT 5.10



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE
SUSITNA ALTERNATIVE- ENERGY
DEMAND & DELIVERIES
SEPTEMBER 1983

Year 2020 Railbelt System Generation Mix
SHCA-NSD Load Forecast

	NON-SUSITNA				SUSITNA - Base Loading
	Gas/Coal	Gas Only	Coal Only	Chakachamna	Watana 2185
OGP ID	LN61	LRA9	LNM9	LOG9	LL79
Capacity - MW					
Coal	1400	0	1400	1200	0
CT	420	756	672	84	588
CCCT	474	1422	0	711	237
Hydro	143	143	143	143	143
Susitna	0	0	0	0	1223
Chakachamna	0	0	0	195	0
Total	2437	2321	2215	2333	2191
2020 Reliability					
Peak Demand	1724	1724	1724	1724	1724
% Reserve	41.5	34.7	28.6	35.4	27.1
LOLP - D/Y	0.025	0.124	0.077	0.082	0.085
Total Economic Cost					
1993 $/MWh	35.48	35.48	40.18	38.64	48.53
2010 $/MWh	59.95	72.90	55.06	52.23	40.69
2020 $/MWh	63.65	91.01	61.72	59.05	43.83
Million Dollars					
2020 Cost	529.0	756.5	513.0	516.6	364.3
Cum 2020 P.W.	3878.1	4448	3931	3844	3373
Cum 2050 P.W.	6795.0	8945	6758	6666	5325

EXHIBIT 5.11

6.0 ECONOMIC AND COST OF POWER ANALYSES

6.0 ECONOMIC AND COST OF POWER ANALYSES

6.1 INTRODUCTION

The economic analysis compares the Non-Susitna and Susitna system expansion programs using a life cycle approach based on the results of the study described in Chapter 5. Threshold and sensitivity analyses of the key variables were also conducted. Using the same expansion programs, the cost of power analyses determines the wholesale cost of Susitna power for various levels of state equity contribution. In addition, the affordability of the project is addressed by comparing estimated available funds for State capital projects with construction cash flow requirements of the Susitna Project.

6.2 ECONOMIC CRITERIA AND PARAMETERS

The economic analysis was performed using a life-cycle approach which is customary for studies of major capital intensive projects. For hydroelectric projects, the service life is typically 50 years. Since the Devil Canyon Project would be in operation around year 2002, the costs of Susitna generation plans have been compared with the costs of Non-Susitna alternatives over a planning period extending to 2050. Since Susitna power would come on line in 1993, the system generation costs were assumed to be the same for all alternatives between now and 1993. Hence, the economic analysis was conducted by comparing the costs of the alternative expansion programs over the period 1993-2050.

To fully utilize the total potential of the Susitna hydropower resources, it was necessary to extend the electrical demand projections until 2020. This was done by extending the 2010 projections obtained from the RED model, using the average annual growth rate of the period 2000-2010. Then, the Optimized Generation Planning (OGP) model determined the total production costs of alternative plans on a year by year basis, for the period 1993-2020. These costs include the annualized investment costs of any generation and transmission facilities that are added during that period, total system fuel costs, and operation and maintenance costs. The costs of facilities which are common to all alternatives have not been included in the economic analysis. For the period 2021-2050, it was assumed that the production costs of the final study year (2020) would simply recur for an additional 30 years, with the fuel costs adjusted to take into account real fuel price escalation.

The economic analysis was performed for the DOR Mean and SHCA-NSD scenarios. For each oil price forecast, electric load forecasts were developed and are presented in Chapter 2. The Susitna Project and Non-Susitna alternatives are presented in Chapters 3 and 4, respectively. Chapter 5 presents the system expansion programs which form the basis for the economic analysis.

The present worth analysis, based on a 3.5 percent discount rate, determines the net benefits and benefit-cost ratios. An internal rate of return analysis was performed, followed by a threshold determination of the oil price which would bring the cumulative present worth of the Susitna alternatives equal to that of the thermal alternative. A similar threshold analysis was done for the Watana construction cost estimate and real interest rate. Finally, a sensitivity analysis was performed to analyze the effects of the availability of Cook Inlet gas and real escalation of fuel costs.

Exhibit 6.1 summarizes the principal economic parameters that were used in the economic analysis. The economic life of each generating plant type used in the economic analysis is based on 20 years for combustion turbines, 30 years for combined cycle and steam turbines, and 50 years for hydroelectric plants. Transmission lines have an economic life of 40 years.

Discount rates are used to discount future costs to the present, recognizing cash flows occurring in different time periods of the planning horizon. A real rate of 3.5 percent was used as the base case discount rate for the period 1983-2050. Interest rates are applied, during the construction period, to the disbursement payments to compute the annual investment costs of each alternative.

Based on present trends in construction costs, no real capital cost escalation was assumed for either the hydroelectric or thermal plants. The costs directly related to the consumption of fuel oil for vehicles, construction equipment, heating, on-site electric power generation, etc. were estimated at about 6 percent of the total construction costs. As shown on Exhibit 2.6, the price of oil is expected to remain below the 1983 price until 1991 for the SHCA-NSD Scenario, and until 2002 for the DOR Mean Scenario. As a result, the construction costs are not expected to change due to fuel prices.

Exhibit 6.1 gives the annual fixed carrying charges (interest, depreciation, and insurance) for each alternative. An annual insurance cost equal to 0.25 percent of the total investment cost was used for the thermal plants and the transmission lines. An annual insurance cost of 0.10 percent was used for the hydro plants.

Studies on fuel availability and costs are described in Chapter 4. Exhibits 4.2 and 4.3 summarize the fuel costs which were used for each scenario. In brief, a 1983 estimated base price of $1.80/MMBtu was used for coal-fired generation, $2.47/MMBtu for gas-fired generation from Cook Inlet gas, and $6.23/MMBtu for oil-fired generation, all for fuel to be utilized for the year 1993 and thereafter. The price of coal is based on the mine-mouth price of Nenana coal adjusted for transportation to Healy and estimates of production costs for a mine-mouth coal operation at Beluga. The natural gas price is based on the most recent contracts entered into by Enstar. The base prices were escalated by real fuel escalation rates to 1993 and from 1993 to 2050 as discussed in Chapter 4. The analysis has been performed with Category 1 cost estimates for Susitna.

6.3 LIFE CYCLE ANALYSIS

The life cycle analysis is performed by comparing the cumulative present worths of the annualized investment and production costs for the period 1993-2050 between the Susitna and Non-Susitna alternatives. Table 6.1 summarizes the life cycle analysis.

Table 6.1

SUMMARY OF LIFE CYCLE ANALYSIS

Oil Price Forecast	1983 Present Worth of System Cost - $ million			Net Benefits	Benefit/ Cost Ratio
	1993-2020	2021-2050	1993-2050		
DOR Mean					
Non-Susitna	2844	2046	4890	-	-
Susitna	3142	1602	4744	146	1.03
SHCA-NSD					
Non-Susitna	3878	2917	6795	-	-
Susitna	3373	1952	5325	1,470	1.28

The net benefit of the Susitna alternative is determined by taking the difference between its cumulative present worth cost and that of the Non-Susitna expansion alternative. The least-cost thermal system, developed in Chapter 5, is used for this purpose. For each oil price forecast, there is a different optimum thermal system expansion program.

During the 1993 to 2020 study period under the DOR Mean, the 1983 present worth for the Susitna alternative is $3,142 million. The annual production cost in 2020 is $304 million. The present worth of this annual cost, which varies only by fuel cost escalation for the period 2021 to 2050, is $1,602 million. The resulting total present worth of the Susitna plan is $4,744 billion.

The Non-Susitna plan has a 1983 present worth cost of $2,844 million for the 1993 to 2020 period with a 2020 annual cost of $378 million. The total long-term cost has a present worth of $4,890 million. Therefore, the net economic benefit of adopting the Susitna plan is $146 million.

For the SHCA-NSD forecast the net economic benefit of adopting the Susitna alternative is $1,470 million. The July 1983 License Application estimated net economic benefit of Susitna at $1,827 million. The variation is due to reformulation of the thermal alternative to include gas-fired generation in the early years of the study period and a change in discount rates from 3.0 percent in the License Application to 3.5 percent in this update.

Benefit-cost ratios, as shown in Table 6.1, are determined by taking the ratio of cumulative present worths of the Susitna alternative and that of the least-cost thermal alternative. The benefit-cost ratios are 1.03 for the DOR Mean and 1.28 under the SHCA-NSD oil price forecast.

6.4 INTERNAL RATE-OF-RETURN (INTEREST RATE THRESHOLD) ANALYSIS

The internal rate-of-return for investing in Susitna is the discount rate at which the cumulative present worth of the Susitna alternative becomes equal to the optimum Non-Susitna expansion program. In this analysis, the optimized expansion plans, defined by the OGP model under a 3.5 percent discount rate, were kept the same. The new discount rate was used, as previously, to aggregate annual cash flows occurring during the period 1993-2050.

The internal rate of return of the Susitna Project is about 3.7 percent under the DOR Mean forecast and 5.4 percent under the SHCA-NSD forecast. The internal rate-of-return analysis provides a means to identify the project that maximizes return on investment. This analysis is equivalent to a threshold determination of the discount rate.

6.5 THRESHOLD DETERMINATION

6.5.1 Oil Prices

World oil price greatly influences the economics of the Susitna Project. Therefore it is useful to identify the oil price at which point the cumulative present worth of the Susitna Project is equal to that of the thermal alternative, meaning that there is no longer any economic incentive to select one alternative over the other. On inspection of the net benefits, the threshold oil price is very near the DOR Mean oil price forecast.

It is important to recognize that the DOR Mean oil price forecast shows a price trajectory that is not a single value, nor has a constant rate of change. The critical price is, however, $27.45 per barrel (in 1983 dollars) estimated for 1999. This price has been assumed to escalate at 1.5 percent for the years beyond 1999. The Susitna Project would economically break even (i.e. earn a real return of 3.5 percent) if the oil price would be slightly lower than the forecasted level of $27.45 per barrel in 1999, and escalate at a 1.5 percent real rate after 1999.

6.5.2 Capital Cost Estimate

A threshold determination has been made for the capital cost estimate of the Watana Project. In such a determination, the threshold point is the change in the estimated cost of the initial Watana Development that would cause the break-even point to be reached. The results indicate that 5 and 50 percent increases in the estimated cost of the Watana Development would be required before the threshold point is reached for the DOR Mean and SHCA-NSD forecasts, respectively.

6.5.3 Real Interest Rate

The real (inflation free) interest rate, used to calculate interest during construction, is a variable separate from the real discount rate which is used to discount net benefits over the life of a project. The real interest rates would have to be 4.9 and 15.5 percent for the DOR Mean and SHCA-NSD forecasts, respectively, in order for the threshold point to be reached.

6.6 SENSITIVITY ANALYSIS

6.6.1 Availability of Cook Inlet Gas

In the basic analysis, it is assumed that Cook Inlet gas proven reserve and economically recoverable undiscovered gas would be depleted by 2007. Either new gas would have to be discovered in the Cook Inlet area, probably at a much higher price, or North Slope gas would have to be transported to the Railbelt. The outcome of the two possibilities depends on world oil prices. If world oil prices increase sufficiently to allow the development of either ANGTS or TAGS, North Slope natural gas could be made available to the Railbelt market at the estimated price of $4.00 per MMBtu (Chapter 4). However if the world oil prices should remain at or below the present day price of $29 per barrel, it would be unlikely that either ANGTS or TAGS would go forward. In the event that additional gas cannot be obtained from Cook Inlet, a much higher cost for natural gas from North Slope would then occur. In Chapter 4, the estimated cost of natural gas from the North Slope via a small pipeline has been estimated in the range of $7.00 to $9.90 per MMBtu. A sensitivity analysis has therefore been performed for gas obtainable at $7.00 per MMBtu from 2007. The results are summarized in Table 6.2. The $7.00 per MMBtu natural gas price would increase the present worth of the Non-Susitna alternative by about $283 million.

Table 6.2

SENSITIVITY ANALYSIS OF COOK INLET GAS
2050 CUMULATIVE PRESENT WORTH (1983 $ million)

	DOR Mean
Base Case, Available until 2007, then at $4.00/MMBtu	4,890
Available until 2007, then at $7.00/MMBtu	5,173

6.6.2 Real Escalation of Fuel Costs

The present worth of the system costs includes all costs of fuel and operation and maintenance of all generating units. In addition, the costs include the investment costs of any plants and transmission facilities added during the 1993 to 2020 period. The long-term system costs (2021-2050) are estimated from the 2020 annual costs, with adjustment for real escalation of fuel costs, for the 30-year period.

The Susitna Project would supply about 80 percent of the Railbelt area electricity requirements initially and through the year 2020 with both Watana and Devil Canyon constructed. Therefore, long term forecasts of fuel prices and escalation rates are necessary to determine project economics. Several oil price forecasts were reviewed and a special analysis of long-term oil prices was prepared during the revision of the License Application to support the estimation of the long-term system costs (2021-2050).

Power Authority guideline in conducting an economic analysis calls for the escalation of fuel oil over a given planning horizon, with the price of fuel oil then remaining constant for the remaining study period beyond the planning horizon. The real price oil escalation was 2.5 percent for the 1983 fiscal year, and the planning horizon is 20 years. The methodology used for the Susitna Project has been more sophisticated because of the magnitude of the Project - including two developments -in relation to the size of the system. This requires the projection of oil prices over a long period of time. For this reason, and because specific oil prices and scenarios have been projected over the long-term, fuel cost escalation over the entire study period has been considered.

A sensitivity analysis was conducted to compare the net benefits of the Susitna alternative with the Non-Susitna alternative when no allowance was provided for real escalation of fuel costs. The results are summarized in Table 6.3.

Table 6.3

SENSITIVITY ANALYSIS OF
REAL ESCALATION OF FUEL COSTS BEYOND 2020

Oil Price Forecast	1993-2020	Present Worth of System Costs (1983 - $ million) With Fuel Escalation 2021-2050	1993-2050	Net Benefit	Without Fuel Escalation 2021-2050	1993-2050	Net Benefit
DOR Mean							
Non-Susitna	2844	2046	4890	-	1945	4789	-
Susitna	3142	1602	4744	146	1597	4739	50
SHCA-NSD							
Non-Susitna	3878	2917	6795	-	2725	6603	-
Susitna	3373	1952	5325	1470	1877	5250	1353

6.7 COST OF POWER ANALYSIS

The financial condition of the State is the single most important factor in determining the financial feasibility and cost of power from the Susitna Project. Petroleum revenues provide about 90 percent of the State income and directly affect the capability of the State to make an equity contribution. The issue has been examined by the Office of Management and Budget and there appears to be a large difference in net revenues available for capital projects under various fiscal scenarios.

The following discussion provides a preliminary analysis of the financing needs and options for the construction of the Susitna Project. Several important and interrelated issues must be resolved before a suitable financing plan can be finalized. These are:

- Size of the State equity contribution
- Financing terms; including inflation rates and interest rates, and tax exempt status of the bonds
- Target cost of power
- Affordability of the Susitna Project

6.8 PROJECT FUNDING

Two financing approaches were considered in project funding; 1) one hundred percent revenue bond financing and 2) up front State appropriation for part of the cost, with the remaining financing requirements met by revenue bond issues.

The 100 percent debt approach is designed to reflect the wholesale cost of power for purposes of broad comparison with alternative power options.

In performing this study, R. W. Beck & Associates, Inc. developed the relative annual costs of wholesale power under alternative ranges of debt/equity combinations, based on cash flow forecasts provided by Harza-Ebasco. Their analysis is documented in a separate report entitled "Susitna Financial Analysis", dated September 23, 1983 and subsequently revised November 9, 1983.

6.8.1 State Equity Contributions

State equity contributions and revenue bonds combine to provide the needed funds to build the Watana Development. A range of State equity contributions has been studied. The State equity contributions will cover the construction disbursements for the first five to six years, with revenue bonds being used to complete construction.

In the early stages of project development (1986-1988) the Watana Dam would not actually be under construction and only access and site preparation would be in progress. To ensure that revenue bond financing is available in the final stages of construction (1989-1993), earlier State equity contributions should be at appropriate levels to provide security to potential investors and reduce the total amount of borrowing. Reduced borrowing would also lower the price of Watana power in the early years of operation and enhance the competitive position of Susitna versus thermal power sources, which have much lower capital costs, though higher and escalating operating (including fuel) costs.

6.8.2 Revenue Bonds

The financial projections which follow have been based upon the assumption of a 10 percent rate of interest for bonds. The long-term inflation rate assumed at this time is 6.5 percent.

In this analysis, the bonds are issued so they fund their own interest costs for the first 24 months the bonds are outstanding. During the construction period, interest expense of previously issued bonds, to the extent not capitalized, is paid from proceeds of subsequent bond issues. Debt service for each revenue bond issued is structured so interest-only payments are made for the first 24-month period subsequent to the commercial operation date of Watana. After the initial 24-month period, debt service is levelized (including principal payment) over a 30-year period. Commencing with commercial operation, debt service expense less investment earnings on various revenue funds is paid by revenues from power sales.

The revenue bonds are assumed to have the following characteristics:

1. Maximum bond issue of $400,000,000.

2. Financing expense equal to three percent of principal amount.

3. Coupon, long- and short-term interest rates are all equal.

The reserve, contingency and working capital funds and debt service reserve account are established according to the following criteria:

1. Debt service reserve account is equal to one years levelized 30-year debt service.

2. Reserve and contingency fund is equal to one years capital renewal requirements.

3. Working capital fund is equal to 15 percent of one years operation cost plus 10 percent of one years revenue requirements.

The reserve and contingency fund and the working capital fund are fully funded regardless of the level of State equity contributions to Watana.

6.9 COST OF POWER

Railbelt costs of electricity are estimated to determine what the wholesale cost of power will be for various levels of State equity contribution. The costs are shown in nominal dollars unless otherwise indicated and are based on a 6.5 percent annual inflation rate.

The cost of power with the thermal alternatives was computed from OGP output summaries, with an investment cost adjustment for capital renewals. The wholesale costs include fuel costs for new and existing generating units, capital costs for new generating units, capital costs for new transmission facilities required, and operation and maintenance expenses on new and existing facilities. The costs do not include fixed costs for existing generation, transmission and distribution facilities, and overhead expenses associated with administration, customer service, indirect engineering and labor or other utility operations.

Depending on whether a coal-fired plant or a combined-cycle plant is built in 1993, the first year cost of power would be much different, as shown on Exhibit 6.2 for DOR Mean case. The upper curve represents the case where a coal-fired plant would be built in 1993 while the lower curve would have the natural-gas combined cycle plant constructed in 1993. Table 6.4 summarizes the first-year wholesale cost of power under the DOR Mean and SHCA-NSD cases.

Table 6.4

FIRST-YEAR WHOLESALE COST OF POWER UNDER
NON-SUSITNA EXPANSION PLANS
(Nominal cents/kWh)

	Coal	Gas/Coal
DOR Mean	11.6	7.6
SHCA-NSD	10.2	8.4

The first year cost is dependent on the thermal expansion plan and future oil prices. The initial cost of power for the combined cycle plant in the gas/coal plan is much lower because of its lower investment costs when compared with the coal-fired powerplant; however, the long-term system costs do not vary significantly.

The expansion planning analyses in the 1982 Feasibility Study and the FERC License revision in July 1983 provided coal expansion programs with first year costs of 14.7 and 13.6 cents/kWh, respectively. These costs are higher than the estimated costs of the present coal plans and substantially higher than the costs of the plans with a mix of natural gas-fired combined cycle and coal-fired steam plants. The differences are due to reductions in the current estimates of construction and fuel costs and a change in inflation rate assumptions from 7.0 percent in the feasibility and license studies to 6.5 percent in this update. The gas/coal plans have resulted from a reformulation of the previous thermal alternatives to include gas-fired generation in the early years of the study period.

For the Susitna alternative, the cost of power was also estimated starting with the OGP output. The cost of power estimates were made for a range of State equity contributions. State equity contributions are used to cover expenditures in early years of construction and revenue bonds are used to complete funding requirements. The equity and bonding requirements were determined for the Susitna portion of the expansion plan investment costs with adjustments for capital renewals. The terms for issuance of the revenue bonds have been described in an earlier section. The remaining investment costs, fuel costs, and operation and maintenance costs are taken from the OGP computer output.

Exhibits 6.3 and 6.4 show the relationship between State equity contribution and the 1993 wholesale cost of power for the DOR Mean and SHCA-NSD cases. Also shown are the coal and gas/coal thermal wholesale cost of power. The exhibits demonstrate that the State equity contribution required to match the coal and gas/coal costs of power varies considerably.

State equity contribution provides the means to bring the 1993 wholesale cost of Susitna power to the level of the alternative thermal system cost. A determination of the amount of State equity contribution that will equate the wholesale cost of Susitna power with the first year cost of the alternative thermal expansion programs was determined. Table 6.5 summarizes the funding requirements to equate the wholesale cost of power under the DOR Mean and SHCA-NSD cases.

Table 6.5

FUNDING REQUIREMENTS TO
EQUATE FIRST YEAR WHOLESALE COST OF POWER
TO THE NON-SUSITNA ALTERNATIVE
(Nominal $ Billion)

	Coal Thermal			Gas/Coal Thermal		
	State Equity	Revenue Bonds	Total	State Equity	Revenue Bonds	Total
NOMINAL $						
DOR Mean	1.96	4.32	6.28	3.28	2.41	5.69
SHCA-NSD	2.30	3.80	6.10	3.00	2.79	5.79
1983 $						
DOR Mean	1.45	2.62	4.07	2.27	1.40	3.67
SHCA-NSD	1.67	2.29	3.96	2.11	1.62	3.73

Table 6.5 shows that State equity requirements are sensitive to the thermal alternatives. The first year cost of power of the gas/coal expansion plan is much lower than the coal plan (Table 6.4). Therefore, the State equity necessary to equate first year costs of the Susitna expansion program to the first year costs of the gas/coal alternative is higher than for the coal plan. The natural gas-fired plan is sensitive to changes in oil price and depletion of natural gas reserves. Increased oil prices or gas supply contraints could increase the costs of the gas/coal plan and reduce State equity required to equate first year costs of power.

In addition, required State equity as a percentage of total funding is 60 percent under the gas/coal plan and 30 percent under coal plan for the DOR Mean case. Under the SHCA-NSD case State equity as a percent of total funding is 52 and 38 percent for the gas/coal and coal plans, respectively.

Long-term debt requirements would be substantially reduced by the amounts of State equity contribution required, thereby, providing security to potential investors in the revenue bonds.

Change in oil price from the DOR Mean to SHCA-NSD forecast would require additional equity under the coal plan and reduced equity requirements under gas/coal plan.

The funding requirements in 1983 dollars are also shown in Table 6.5. In the 1982 Feasibility Study and the FERC License revision the State equity contribution required to equate first year costs of power with the recommended coal expansion plans was $1.9 billion. This level of equity contribution is about in the middle of the range of equity contributions shown in Table 6.5 for the thermal alternatives.

Exhibit 6.5 shows the cost of power over time for the DOR Mean oil price scenario. Under the Non-Susitna gas/coal case, the cost of power will rise over time due to inflation and real cost increases in fuel. Under the Susitna case, the cost of power will be much less susceptible to inflationary cost increases. Consequently in later years, the wholesale cost of power from the Susitna plan could be less than half of the best thermal option. Exhibit 6.6 tabulates the annual costs and the annual wholesale cost of power for the Susitna Project under the DOR Mean case for both the $3,280 million state equity contribution and 100 percent debt service analyses.

6.10 INTEREST RATE SENSITIVITY

The interest rates on revenue bonds will greatly influence the cost of power. Exhibit 6.7 shows the range of power cost for different interest rates, assuming a State equity contribution of $3,280 million for the Watana Project. Interest rates from eight percent and twelve percent have been used to illustrate the effect on cost of power when compared against the base case of ten percent. First year (1993) power costs would be 6.4, 7.6, and 8.6 cents per kWh with interest rates at eight, ten and twelve percent, respectively. Since nominal interest contains two principal components, with the first component reflecting real interest on money, and the second component reflecting inflationary expectations, interest rates vary substantially from time to time depending on economic conditions. The State, by making its equity contribution up front, can provide a significant period of time during which the revenue bonds can be sold at favorable rates.

6.11 SAGE MODEL

The SAGE Model is used by the Office of Management and Budget as a tool for fiscal planning. The fiscal module of the model employs a revenue forecast and various expenditure assumptions to assess whether revenue shortfalls or surpluses can be expected, the effect of the State s spending limit, and other fiscal issues. Although the SAGE Model typically uses the 17-year revenue forecast provided by the Alaska Department of Revenue, other revenue forecasts can also be used.

The SAGE sources and uses of State funds report provides three types of information: 1) annual revenue sources, 2) annual revenue uses, and 3) expenditure assumptions. Revenue sources include only general fund unrestricted revenues, meaning that restricted federal dollars are excluded, as are the constitutionally-required Permanent Fund contributions. Data on revenue sources and uses are presented in both nominal and constant terms. Following is a breakdown of each type of information.

6.11.1 Revenue Sources

A description of each type of revenue source follows:

Oil and Gas: Included in the oil and gas revenues are forecasts of income tax from petroleum corporations, severance taxes from oil and gas production and conservation, oil and gas property taxes, and State resource revenues from bonus sales, rents, and royalties.

Other: This includes all general fund taxes and fees that are collected by the State which are not included under "Oil and Gas."

PF to GF: This includes Permanent Fund income which is deposited in the general fund. A statutory change would be required. Currently, AS 37.13.145 requires that income be used for inflation proofing the Permanent Fund and that the balance go to an undistributed income account of the Permanent Fund.

Investment: General fund investment earnings are included in this line item.

General Fund Forward: This category is unappropriated funds which have been brought forward from the previous fiscal year.

Total: This is the total of all the revenue sources for a specific fiscal year.

6.11.2 Revenue Uses

Revenue uses include actual appropriations for the current fiscal year and forecast appropriations for future fiscal years. The revenue uses (or expenditures) for the Sage Model include:

Operating budget
Capital budget
Loans programs
Supplementals/new legislation

Debt service

General fund appropriations to the Permanent Fund

Special Capital

Special Capital represents a hypothetical rather than actual revenue use. Its purpose is to provide an account for determining the amount of State revenue that could be set aside for major projects, such as the proposed Susitna Project, given certain fiscal conditions. These fiscal conditions can be varied.

For the Susitna Update, the SAGE Model has been programmed to determine the difference between the Department of Revenue 50th percentile revenue forecast and an adjusted 30th percentile revenue forecast. These revenues are then allocated to Special Capital. If the 30th percentile forecast is greater than other revenue uses, the difference is also added to Special Capital. If the 30th percentile forecast has insufficient revenues for all other revenue uses, these revenue uses are proportionately reduced. In essence, the 30th percentile revenue forecast becomes a ceiling for all other revenue uses. The purpose of this programming is to explore the possibility of saving revenue for Susitna by setting aside the difference between the 30th percentile forecast and the more likely 50th percentile forecast.

Output data for the SAGE Model includes annual growth rates for the operating and capital budgets as well as total appropriations. These growth rates illustrate when the 30th percentile ceiling becomes effective and to what degree it changes each growth rate.

The 30th percentile revenue forecast used by the SAGE Model is not identical to the Department of Revenue 30th percentile forecast. It represents the spread that is expected to occur between the 50th percentile forecast (which is assumed to be the most likely long-range revenue estimate) and the 30th percentile forecast in each year. This has the effect of reducing the difference between the 30th and 50th percentile forecasts as it appears in the Department of Revenue published reports.

6.11.3 Assumptions Under Alternative Operating Budget Scenarios

The SAGE Model was run under three different fiscal scenarios to test the sensitivity of available capital for Susitna to spending levels in the operating budget. The three operating budget growth levels tested are a +2, 0 and -2 percent real annual rate of growth from a fiscal year 1985 base of $1,925 million. Other assumptions used to determine the alternative revenue uses and special capital available for Susitna are shown in Table 6.6.

Table 6.6

SAGE MODEL ASSUMPTIONS
UNDER ALTERNATIVE OPERATING BUDGET
SCENARIOS

Variable	Percentage Adjustment to Real Operating Budget Base		
	+2	0	-2
Average growth rate for the Anchorage Consumer Price Index (CPI)	6.00	6.00	6.00
Average rate of return on the Permanent Fund	9.00	9.00	9.00
Average rate of return on the general fund balance	8.54	8.54	8.54
Average growth/decline in loan programs	-14.76	-13.36	-11.98
Actual debt service	-17.40	-17.40	-17.40
Average population growth rates	- 1.22	- 1.21	- 1.20

The assumptions used for each SAGE run are presented in the output summary data tables in two ways: 1) the value used for each assumption and 2) how these assumptions affect the growth rates for the operating and capital budgets and supplemental appropriations. In the case of the Susitna Update, the assumptions are consistent with those being used by the Office of Management and Budget for current fiscal planning.

6.11.4 Results of SAGE Model Analysis

The Sage model was used to provide some insight into the question of affordability to the State of Alaska of the level of equity contributions. Table 6.7 shows yearly (1985 through 1998) estimates of capital available for Susitna taken from Sage Model output.

The capital estimates indicated that in early years there are considerable amounts of capital available under all three operating budget growth assumptions with greater amounts of capital available under the 0 and -2 percent real growth rate assumptions. In later years the level of capital estimates reduces substantially due to the downward trend in current long-term revenue forecasts. Also, the OMB has indicated that in later years the capital estimates would in all probability be used to support regular capital and operating budget expenditures.

Table 6.7

SPECIAL CAPITAL AVAILABLE FOR
SUSITNA PROJECT
($ Million - Nominal)

	Percentage Adjustment to Real Operating Budget Base		
Year	+ 2	0	-2
1985	722	722	722
1986	523	601	677
1987	531	656	776
1988	262	439	607
1989	437	673	892
1990	333	635	911
1991	177	177	489
1992	168	168	273
1993	164	164	164
1994	161	161	161
1995	146	146	146
1996	134	134	134
1997	139	139	139
1998	136	136	136

Exhibit 6.8 shows a bar chart of estimated Watana construction cash flow requirements and capital available for the Susitna Project for the three operating budget growth scenarios. The Susitna expenditures are in nominal dollars, and real escalation and interest during construction are not included. The charts show that in the early years, annual Watana construction expenditures are about $400 million and increase to a maximum of about $1,000 million in 1991 and trend down to 1993 when the construction is completed and the project is on line. The estimates of capital availability generally have a trend that is in reverse to the construction cash flow requirements.

To ensure that revenue bond financing is available, the costs of power studies have assumed that State capital contribution will cover the construction expenditures in the early years of construction. In addition, the amount of State capital contribution that equates the first year wholesale cost of power of the Susitna and DOR Mean gas/coal alternatives is $3,280 million. This is the maximum State equity contribution. Under the coal expansion plan the State equity contribution requirements would be much lower. The accumulation of construction expenditures in the first four years of construction (1986 through 1990) plus expenditures of about $525 million in 1991 equals the $3,280 million State capital contribution, as shown on Exhibit 6.8. The remaining construction expenditures (1991 through 1993) would be met by revenue bonds.

Inspection of Exhibit 6.8 indicates that, under the 2 percent operating budget growth rate scenario, available special capital would fall short of expenditures required in 1988 through 1991. With real growth in the operating budget of 0 and -2 percent, construction expenditures are met or exceeded by estimates of available capital except in the years 1990 and 1991. If surpluses in earlier years were reserved, the construction expenditures could be met under the operating budget growth projections of 0 and -2 percent. However, if surpluses in earlier years were reserved these construction expenditures could be met.

6.12 SUMMARY

The Susitna power cost should be set at a level to assure adequate coverage of the debt service, working capital, reserve, and operating and maintenance costs. It should be priced to ensure the marketability of Susitna energy once the project is built. The rate level and pricing structure should be designed to motivate the utilities to purchase the maximum amount of energy. If the incremental rates are set too high, it may cause the utilities to take only the minimum under a take-or-pay contract arrangement. Therefore the rate structure should be set to provide some flexibility to promote maximum use. If necessary, small subsidies might even be introduced for a few years.

Different utilities have different needs for Susitna power. The Anchorage utilities are in need of capacity whereas the Fairbanks utilities are more concerned with obtaining sufficient energy to replace oil generation.

It had been previously postulated that future electricity power demand would have a major influence on the economic and financial viability of the Susitna Project. While this still holds true, it appears that in the range of the forecasts between DOR Mean and SHCA-NSD it is not as crucial as previously thought.

Financing terms also hold a key to the size of the State equity contributions and electricity rate level since interest rate is the dominant factor in determining the magnitude of the debt service. Interest rate is in turn affected by the tax exempt status of the bonds.

The affordability of the Susitna project is dependent on estimates of long-term revenue and spending levels and appropriate capital set aside to meet construction expenditures in the early years of Susitna development.

In addition to the above issues, other financing options could also influence project viability. Some interests have suggested alternative innovative financing schemes that would improve the financial marketability of the project. This subject is currently under study by others and should be explored further; it has not been treated in this update.

For this preliminary evaluation, the cost of power has been estimated in relation to State equity contributions. This is the first step towards the analysis of power marketing and setting electricity rates. Policy decisions are needed on specific issues prior to finalizing a financing plan. Rate design and marketing to electric utilities can then proceed.

EXHIBIT 6.1

PRINCIPAL ECONOMIC PARAMETERS

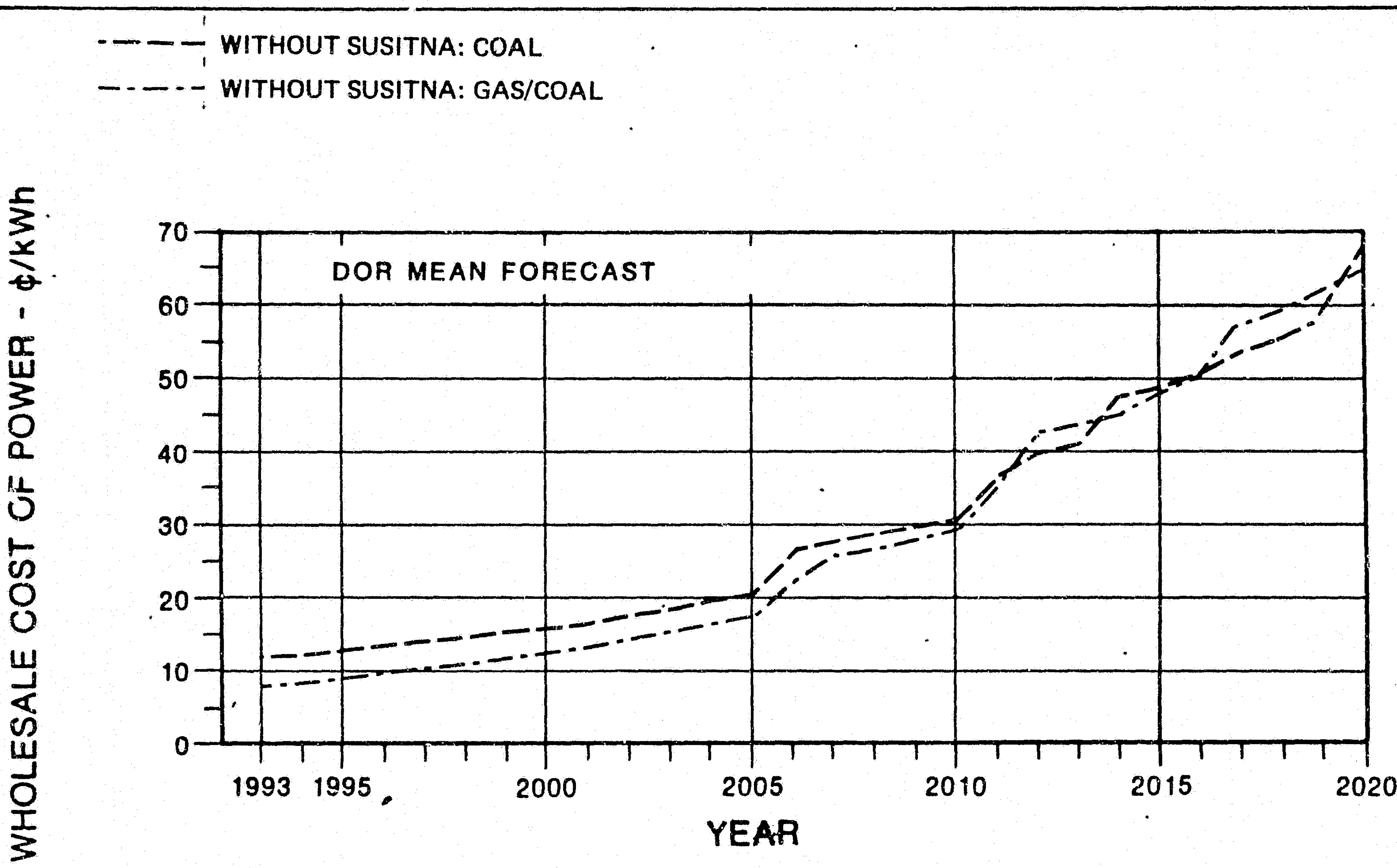
1. All costs in January 1983 dollars
2. Base year for present worth analysis: 1983
3. Long-term planning horizon: 1983 to 2020
4. Discount Rate: 3.5 percent
5. Inflation Rate: 0 percent
6. Economic Life of Projects:

Combustion turbines:	20 years
Combined cycle turbines:	30 years
Steam turbines	30 years
Hydroelectric Projects	50 years
Transmission Lines	40 years

7. Annual Fixed Carrying Charges

	20-year Life	30-year Life	40-year Life	50-year Life
Cost of Money	3.50	3.50	3.50	3.50
Amortization	3.54	1.94	1.18	0.70
Insurance	0.25	0.25	0.25	0.10
Total	7.29	5.69	4.93	4.36

0 0 0 4 6



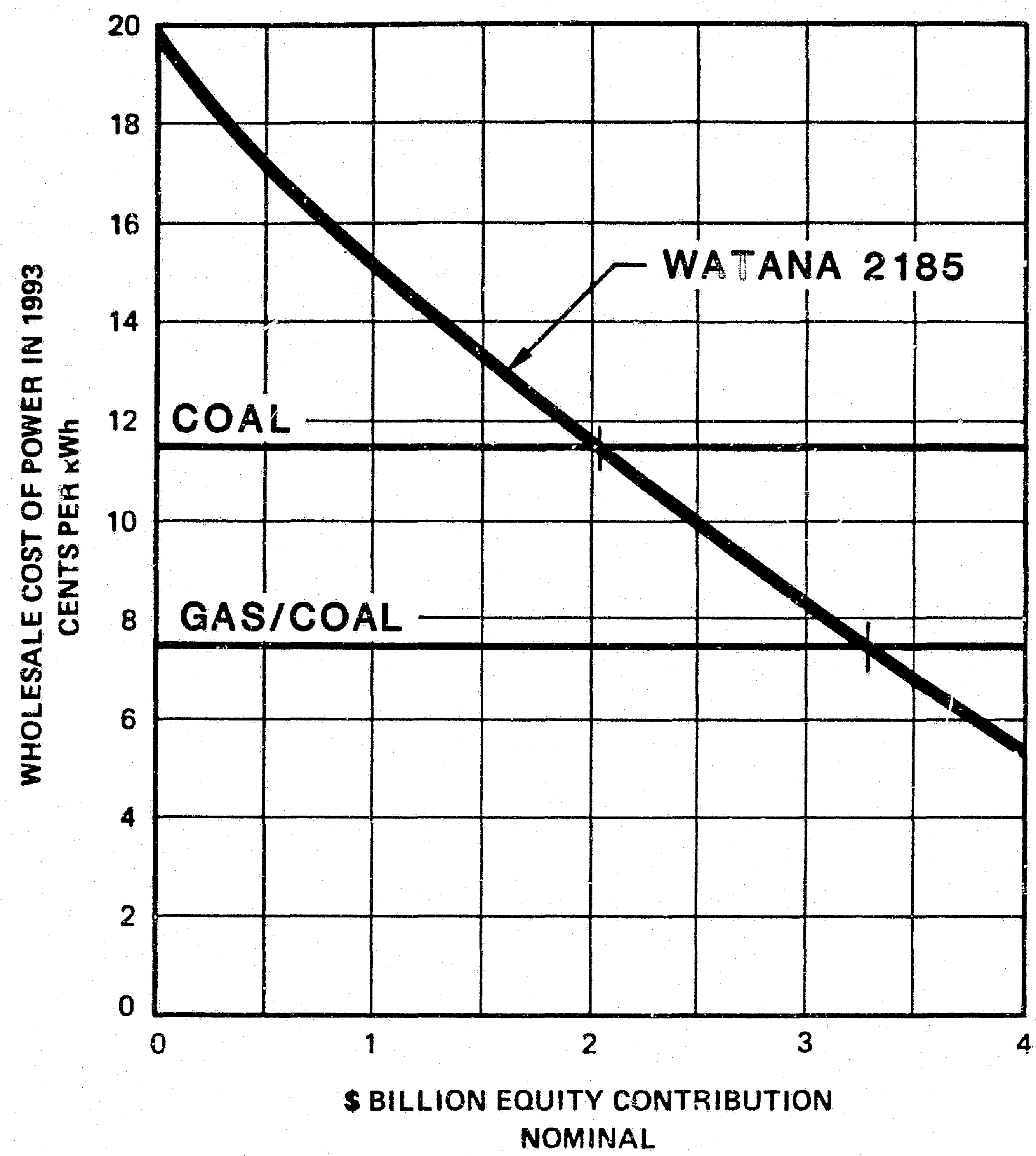
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER
FOR NON-SUSITNA CASES

SEPTEMBER 1983

EXHIBIT 6.2

EXHIBIT 6.3

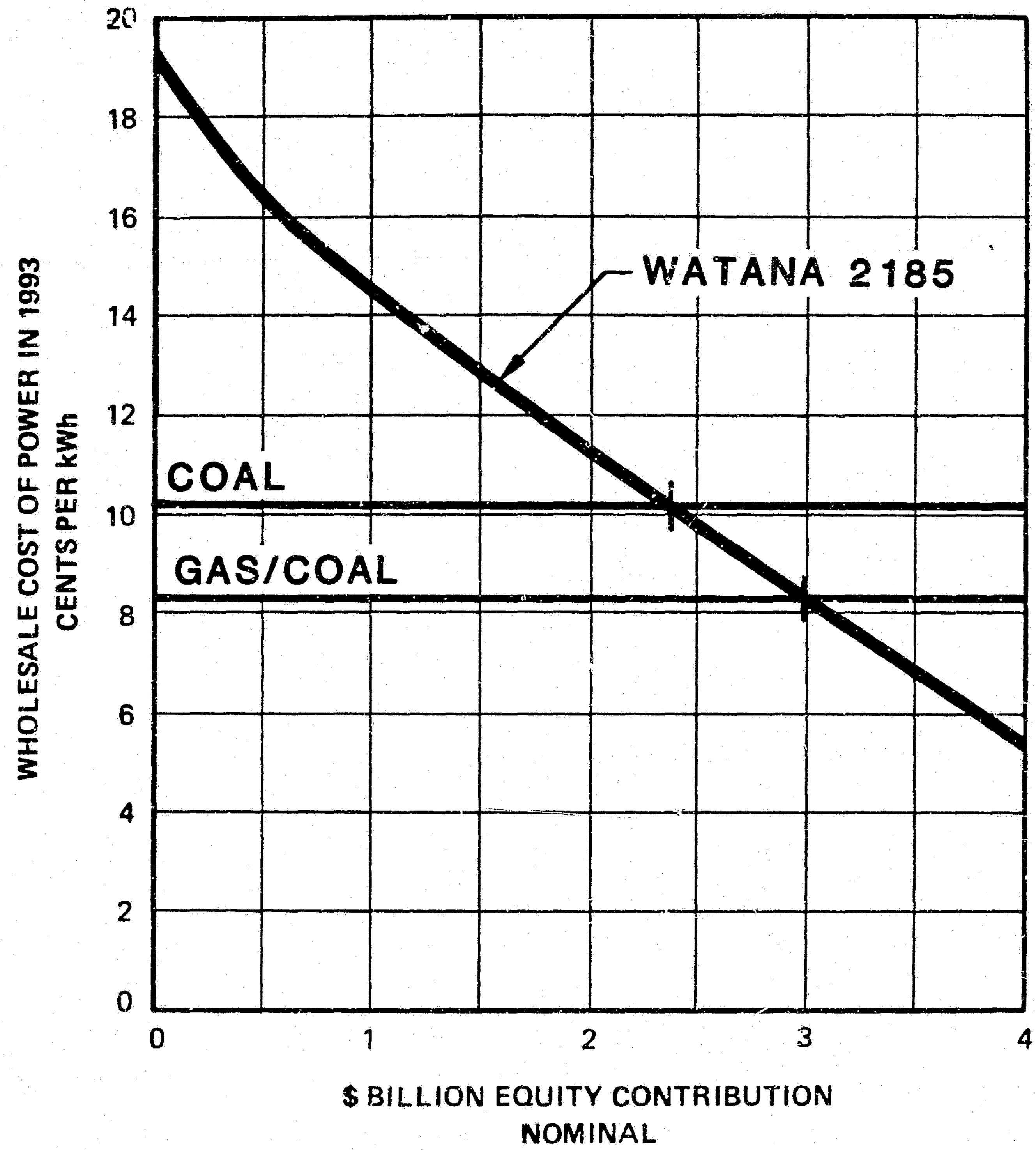


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

1993 WHOLESALE COST OF POWER
VS. STATE EQUITY CONTRIBUTION
DOR MEAN CASE

SEPTEMBER 1983

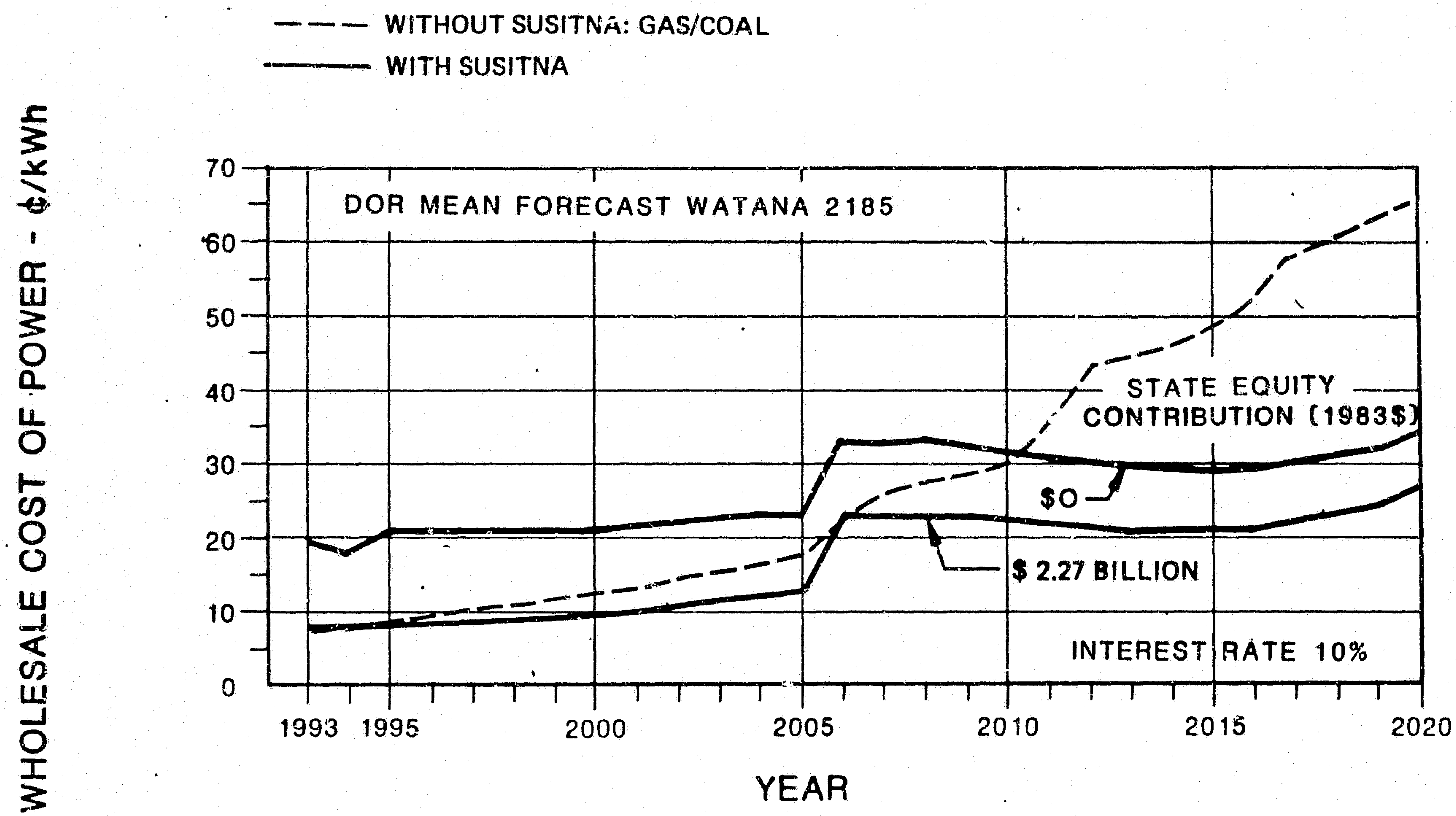
EXHIBIT 6.4



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

1993 WHOLESALE COST OF POWER VS. STATE EQUITY CONTRIBUTION SHCA-NSD CASE

SEPTEMBER 1983



ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER

(WATANA 2185)

SEPTEMBER 1983

EXHIBIT 6.5

					2185 Level 3.280 Equity	@10%	COD 2006		ANNUAL COSTS IN MILLION $					
Year	Total Energy (GWH)	Energy Less Losses	OGP INVESTMENT	OGP SUSITNA COST	Debt Service WATANA	LESS: EARNINGS	Debt Service DEVIL'S CANYON	LESS: EARNINGS	Final Debt Service	Capital Renewals	OGP Fuel	OGP Oper. & Main.	TOTAL	Cost per KWH (C/KWH)
1993	4166.90	4041.89	724.00	724.00	241.37	29.97			211.40	18.72	44.70	34.00	308.82	7.64
1994	4237.00	4109.89	724.00	724.00	241.37	29.97			211.40	19.94	48.60	36.30	316.24	7.69
1995	4306.00	4176.82	724.00	724.00	256.04	29.97			226.07	21.23	54.40	38.40	340.10	8.14
1996	4387.00	4255.39	735.60	724.00	256.04	29.97			237.67	25.54	60.90	41.00	365.11	8.58
1997	4466.90	4332.89	735.60	724.00	256.04	29.97			237.67	27.20	67.80	40.80	373.47	8.62
1998	4547.90	4411.46	748.80	724.00	256.04	29.97			250.87	32.28	76.10	44.10	403.35	9.14
1999	4629.20	4490.32	748.80	724.00	256.04	29.97			250.87	34.38	90.10	47.40	422.75	9.41
2000	4709.00	4567.73	748.80	724.00	256.04	29.97			250.87	36.61	101.50	50.80	439.78	9.63
2001	4813.00	4668.61	764.80	724.00	256.04	29.97			266.87	43.00	116.40	55.30	481.57	10.31
2002	4915.90	4768.42	781.80	724.00	256.04	29.97			283.87	50.06	131.60	57.90	523.43	10.98
2003	5019.10	4868.53	799.90	724.00	256.04	29.97			301.97	57.85	149.90	63.10	572.82	11.77
2004	5122.00	4968.34	799.90	724.00	256.04	29.97			301.97	61.61	170.80	67.80	602.18	12.12
2005	5224.80	5068.06	799.90	724.00	256.04	29.97			301.97	65.62	194.40	71.90	633.89	12.51
2006	5369.00	5207.93	1564.10	1488.20	256.04	29.97	818.77	93.66	1027.08	87.31	0.00	74.00	1188.39	22.82
2007	5513.00	5347.61	1564.10	1488.20	256.04	29.97	832.17	93.66	1040.48	92.99	0.00	78.80	1212.27	22.67
2008	5657.00	5487.29	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	99.03	0.00	83.90	1274.00	23.22
2009	5801.00	5626.97	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	105.47	0.00	89.30	1285.84	22.85
2010	5945.00	5766.65	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	112.32	0.00	83.50	1286.89	22.32
2011	6085.00	5902.45	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	119.62	0.00	83.00	1293.69	21.92
2012	6229.00	6042.13	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	119.39	0.00	80.50	1290.96	21.37
2013	6376.00	6184.72	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	135.68	0.00	85.70	1312.45	21.22
2014	6526.00	6330.22	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	144.50	16.70	92.30	1344.57	21.24
2015	6680.00	6479.60	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	153.89	16.70	96.60	1358.26	20.96
2016	6837.10	6631.99	1593.50	1488.20	256.04	29.97	882.76	93.66	1120.47	174.20	35.10	103.90	1433.67	21.62
2017	6999.00	6789.03	1637.30	1488.20	256.04	29.97	882.76	93.66	1164.27	196.49	58.70	113.80	1533.26	22.58
2018	7163.90	6948.98	1670.70	1488.20	256.04	29.97	882.76	93.66	1197.67	220.94	103.60	123.60	1645.81	23.68
2019	7333.00	7113.01	1670.70	1488.20	256.04	29.97	882.76	93.66	1197.67	235.30	177.50	135.70	1746.17	24.55
2020	7504.90	7279.75	1723.50	1488.20	256.04	29.97	882.76	93.66	1250.47	263.85	294.60	153.10	1962.02	26.95

$ 3.28 BILLION STATE EQUITY CONTRIBUTION IN NOMINAL DOLLARS.
ALL COSTS IN NOMINAL DOLLARS.

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER FOR WATANA 2185 DOR MEAN (WITH $3.28 BILLION STATE EQUITY CONTRIBUTION)

SEPTEMBER 1983

EXHIBIT 6.6
Page 1 of 2

2185 Level
0 Equity @10% COD 2006

ANNUAL COSTS IN MILLION $

Year	Total Energy (GWH)	Energy Less Losses	OGP INVESTMENT	OGP SUSITNA COST	Debt Service WATANA	LESS: EARNINGS	Debt Service DEVIL'S CANYON	LESS: EARNINGS	Final Debt Service	Capital Renewals	OGP Fuel	OGP Oper. & Main.	TOTAL	Cost per KWH (C/KWH)
1993	4166.90	4041.89	724.00	724.00	799.83	90.69			709.14	18.72	44.70	34.00	806.56	19.96
1994	4237.00	4109.89	724.00	724.00	799.83	90.69			709.14	19.94	48.60	36.30	813.98	19.81
1995	4306.00	4176.82	724.00	724.00	848.45	90.69			757.76	21.23	54.40	38.40	871.79	20.87
1996	4387.00	4255.39	735.60	724.00	848.45	90.69			769.36	25.54	60.90	41.00	896.80	21.07
1997	4466.90	4332.89	735.60	724.00	848.45	90.69			769.36	27.20	67.80	40.80	905.16	20.89
1998	4547.90	4411.46	748.80	724.00	848.45	90.69			782.[illegible]	32.28	76.10	44.10	935.04	21.20
1999	4629.20	4490.32	748.80	724.00	848.45	90.69			782.56	34.38	90.10	47.40	954.44	21.26
2000	4709.00	4567.73	748.80	724.00	848.45	90.69			782.56	36.61	101.50	50.80	971.47	21.27
2001	4813.00	4663.61	764.80	724.00	848.45	90.69			798.56	43.00	116.40	55.30	1013.26	21.70
2002	4915.90	4768.42	781.80	724.00	848.45	90.69			815.56	50.06	131.60	57.90	1055.12	22.13
2003	5019.10	4868.53	799.90	724.00	848.45	90.69			833.66	57.85	149.90	63.10	1104.51	22.69
2004	5122.00	4968.34	799.90	724.00	848.45	90.69			833.66	61.61	170.80	67.80	1133.87	22.82
2005	5224.80	5068.06	799.90	724.00	848.45	90.69			833.66	65.62	194.40	71.90	1165.58	23.00
2006	5369.00	5207.93	1564.10	1488.20	848.45	90.69	818.77	93.66	1558.77	87.31	0.00	74.00	1720.08	33.03
2007	5513.00	5347.61	1564.10	1488.20	848.45	90.69	832.17	93.66	1572.17	92.99	0.00	78.80	1743.96	32.61
2008	5657.00	5487.29	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	99.03	0.00	83.90	1805.69	32.91
2009	5801.00	5626.97	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	105.47	0.00	89.30	1817.53	32.30
2010	5945.00	5766.65	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	112.32	0.00	83.50	1818.58	31.54
2011	6085.00	5902.45	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	119.62	0.00	83.00	1825.38	30.93
2012	6229.00	6042.13	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	119.39	0.00	80.50	182[illegible].65	30.17
2013	6376.00	6184.72	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	135.68	0.00	85.70	1844.14	29.82
2014	6526.00	6330.22	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	144.50	16.70	92.30	1876.26	29.64
2015	6680.00	6479.60	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	153.89	16.70	96.60	1889.95	29.17
2016	6837.10	6631.99	1593.50	1488.20	848.45	90.69	882.76	93.66	1652.16	174.20	35.10	103.90	1965.36	29.63
2017	6999.00	6789.03	1637.30	1488.20	848.45	90.69	882.76	93.66	1695.96	196.49	58.70	113.80	2064.95	30.42
2018	7163.90	6948.98	1670.70	1488.20	848.45	90.69	882.76	93.66	1729.36	220.94	103.60	123.60	2177.50	31.34
2019	7333.00	7113.01	1670.70	1488.20	848.45	90.69	882.76	93.66	1729.36	235.30	177.50	135.70	2277.86	32.02
2020	7504.90	7279.75	1723.50	1488.20	848.45	90.69	882.76	93.66	1782.16	263.85	294.60	153.10	2493.71	34.26

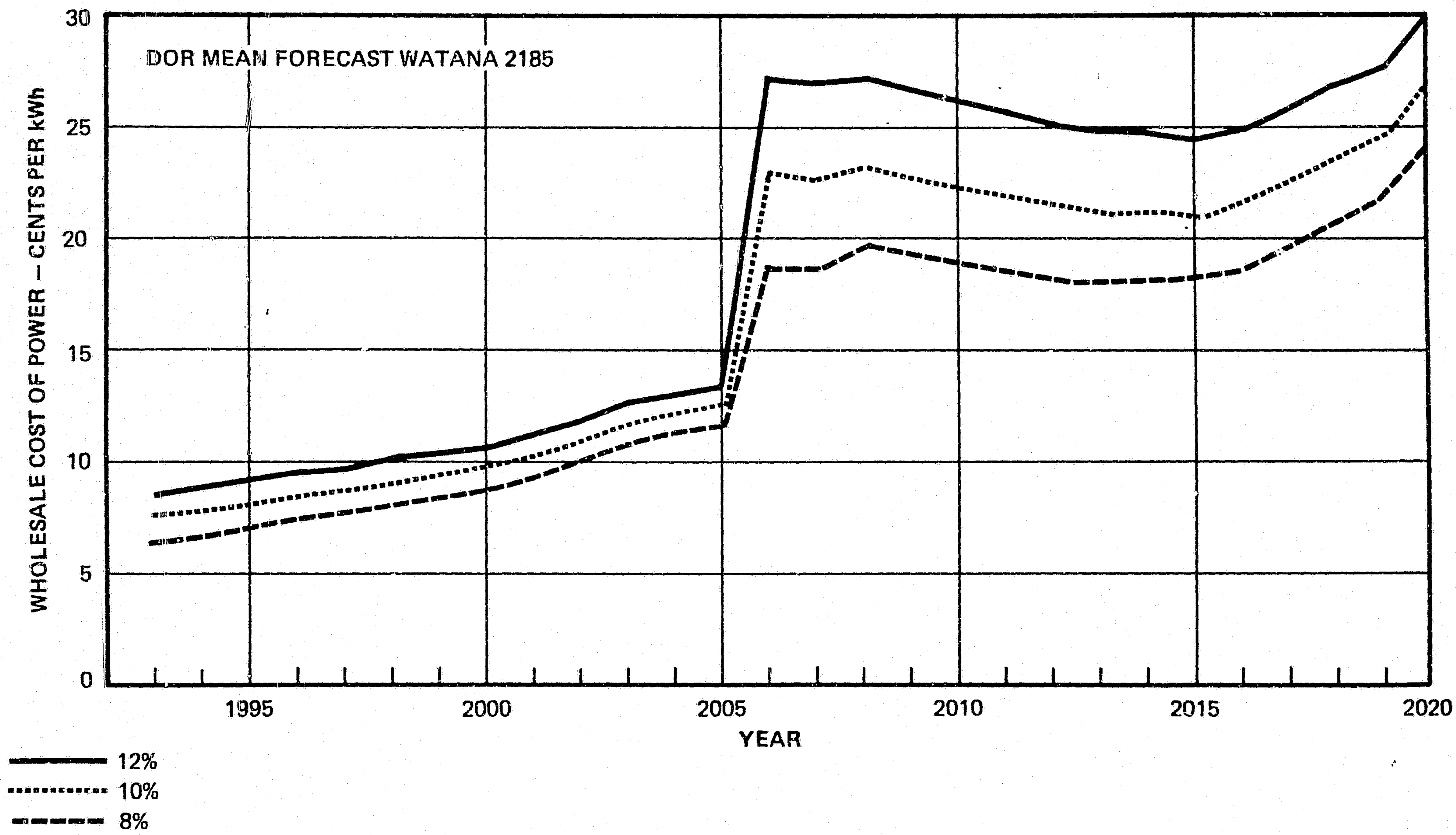
ALL COSTS IN NOMINAL DOLLARS.

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER FOR WATANA 2185 DOR MEAN (WITH ONE HUNDRED PERCENT REVENUE BOND FINANCING)

SEPTEMBER 1983

EXHIBIT 6.6



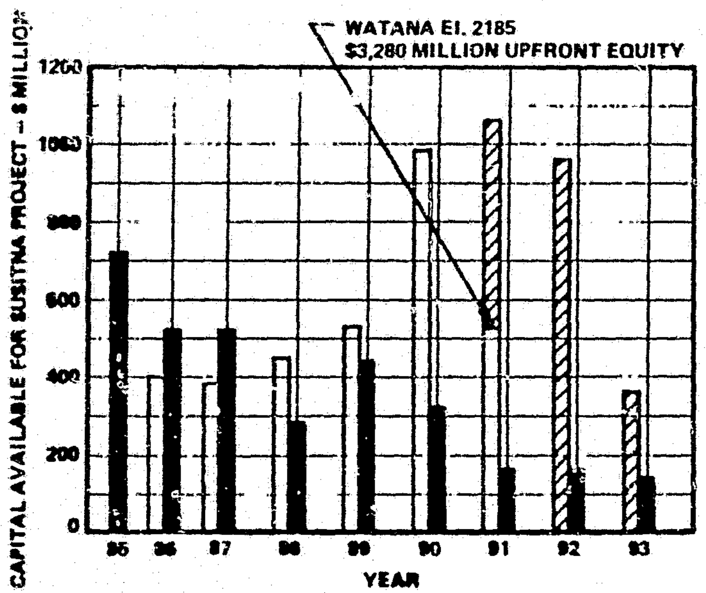
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

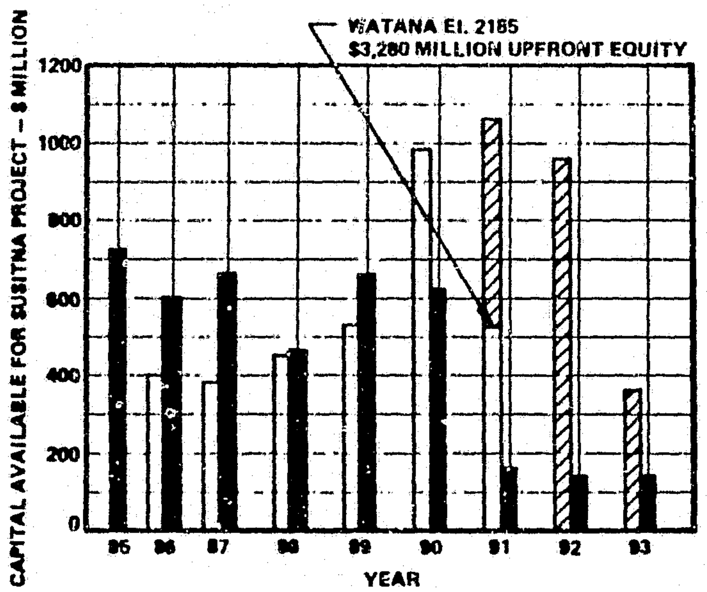
EFFECT OF INTEREST RATE ON WHOLESALE COST OF POWER

SEPTEMBER 1983

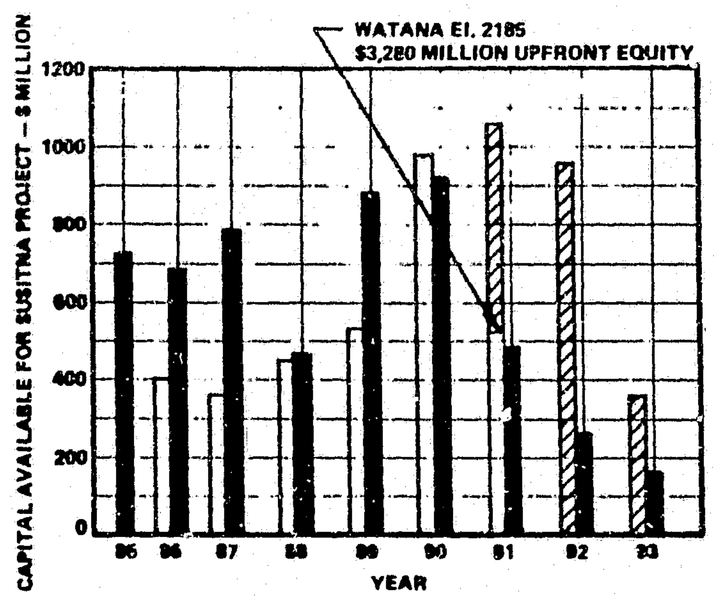
EXHIBIT 6.7



REAL RATE OF GROWTH
OF OPERATING BUDGET +2%



REAL RATE OF GROWTH
OF OPERATING BUDGET 0%



REAL RATE OF GROWTH
OF OPERATING BUDGET -2%

LEGEND

- SAGE MODEL – SPECIAL CAPITAL AVAILABLE
- WATANA El. 2185 ESTIMATED CONSTRUCTION EXPENDITURES MET BY EQUITY
- WATANA El. 2185 ESTIMATED CONSTRUCTION EXPENDITURES MET BY REVENUE BONDS

NOTE:

UPFRONT EQUITY SHOWN IS THE MAXIMUM. UNDER THE COAL EXPANSION PLAN THE UPFRONT EQUITY CONTRIBUTION WOULD BE LOWER.

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

SAGE MODEL

SPECIAL CAPITAL AVAILABILITY

SEPTEMBER 1983

EXHIBIT 6.8

7.0 ALTERNATIVE SUSITNA DEVELOPMENT SCHEMES

7.0 ALTERNATIVE SUSITNA DEVELOPMENT SCHEMES

7.1 INTRODUCTION

The studies discussed in Chapters 3 through 6 present an update of the Susitna Project as submitted in the July 1983 License Application. This Chapter presents alternative concepts of the Watana and Devil Canyon Developments. These alternative concepts would either change the power and energy production of the developments, or would change the way the projects would be operated. The primary focus is on a lower Watana Dam.

Recommended design refinements have been introduced which do not change the project performance nor its energy production, but do permit capital cost savings. The Category 1 cost estimate, based on the recommended refinements of the Susitna Project design, has been used for the analysis in the previous chapters. The cost estimate under Category 2 refinement offers potential for further cost savings and is analyzed in this Chapter to test the sensitivity of construction costs.

Improved ways the project can be operated for power purposes are described. Estimated costs, power and energy production, and associated environmental implications are then presented. The results are incorporated in the studies of alternative system expansion programs to meet future Railbelt demand. Economic and cost of power analyses are also performed.

The purpose of these studies is to determine how the economics of the proposed project compare with alternative development concepts under the new economic outlook of the State. These development concepts have not been endorsed by the Power Authority.

7.2 DEVELOPMENT ALTERNATIVES

A detailed review of the design concept and cost estimates for the Watana and Devil Canyon Developments and their associated access and transmission facilities as presented in the FERC License Application has been completed. The review process led to the identification of some design refinements that are clearly favorable based on cost and safety considerations. The recommended design refinements have been reviewed and accepted by the Alaska Power Authority and are included in the studies with the exception of relict channel treatment.

For purposes of the analysis of optimization of the Susitna Project, the following issues were examined.

- o Sizing of the Watana Project including its reservoir elevation and installed capacity.

- o Load following (rather than base load) operation of the project.

- o A reversal in the sequence of development, with Devil Canyon preceding Watana.

This section explains the features of the Susitna Project for each of the alternative conditions analyzed. The estimated construction costs are also provided.

7.2.1 Project Downsizing

Project downsizing to better match the current economic and electric demand projections can be achieved in several ways. These include reduction in installed capacity, reduction in transmission line voltage and number of circuits in view of the lower load growth and installed generating capacity, and reduction in the height of the Watana Dam with corresponding reduction in the energy generation potential.

The installed capacity of the Watana Project as presented in the Licence Application is 1020 MW. It is provided in six units, each rated at 170 MW. The fifth and sixth units provide no additional energy production. They are available for peaking use and spinning reserve but do not provide significant economic benefit in view of the reduced load growth. Cost savings amounting to $94 million (January 1983) can be achieved with the postponement of installing these two units, as shown on Exhibit 7.1.

Reduced load growth and installed capacity have made it possible to reduce the transmission voltage levels from Susitna to Fairbanks. The cost savings are already included in the design refinements.

The most significant cost reduction can be achieved by reducing the height of the Watana Dam and related installed capacity, with corresponding reduction in energy production.

The proposed reservoir elevation of 2185 is near the limiting elevation dictated by the damsite and by the reservoir conditions. Therefore, the chosen alternatives of reservoir elevations are all lower than the one originally proposed. In order to be assured of bracketing the optimum elevation, the range of elevations studied included a minimum elevation of 1900. The discrete reservoir elevations analyzed are: El. 2185 (original), 2100, 2000, and 1900, as shown in Table 7.1. The initial installations call for four units, and the ultimate installations would have six units.

Table 7.1

WATANA RESERVOIR ELEVATION AND POWER POTENTIAL

Watana Reservior Elevation (ft, msl)	Active Storage Capacity (1000 af)	Installed Capacity (December) Initial (MW)	Installed Capacity (December) Ultimate (MW)	Energy Production Average (GWh)	Energy Production Firm (GWh)
2185	3740	680	1020	3500	3400
2100	3315	585	880	3050	2800
2000	2370	475	710	2500	2150
1900	1675	380	570	1950	1400

In order to provide a consistent representation of the Watana Development under the alternative reservoir elevations, the other major elements of the development are kept as similar as possible in the layouts of the alternatives. In general, the axis of the dam is maintained at the same site and the various water release features (diversion tunnel, outlet facilities, emergency release facilities, and main spillway) are kept on the right abutment. Exhibits 7.2, 7.3, 7.4, and 7.5 show the general project arrangements for the four dam heights.

7.2.2 Cost Estimates of Alternative Watana Developments

Construction costs of the alternative Watana developments have been estimated at the January 1983 price level. The reductions in excavation, fill, and concrete quantities result in lower construction costs. There are consequential reductions in the cost estimates of some of the support features for the lower reservoir alternatives. For example, the decrease in the quantities required for the construction of the dam permits a reduction in the construction time schedule. This in turn permits reductions in the cost of operating the construction camp and maintenance of the access roads. Where a reduction of peak personnel requirements can be expected, there would be a comparable reduction in the maximum capacity and cost of the construction camp. The Category 1 cost estimates for the three lower reservoir elevations appear on Exhibits 7.6 through 7.8 and are summarized in Table 7.2 below.

Table 7.2

SUMMARY COST ESTIMATES OF ALTERNATIVE
INITIAL WATANA DEVELOPMENTS

Reservoir Elevation	Category 1 Cost Estimate ($Million)
2185	3338
2100	2996
2000	2637
1900	2414

The costs of operation and maintenance were discussed in Chapter 3. They were assumed to be unchanged for the lower reservoir alternatives.

7.2.3 Development Sequence

The recent reduction in the forecast rate of growth of the demand for electric power has raised a question about the proposed sequence of development of the Susitna Project. The possibility of constructing Devil Canyon first might be attractive, because of its lower construction cost than Watana.

If the Devil Canyon Development precedes the construction of Watana, the diversion capacity for Devil Canyon would be doubled from 36,000 cfs to 72,000 cfs by providing a second diversion tunnel.

The cofferdams are revised to provide additional freeboard required on the upstream cofferdam to resist damage from ice floes in the river. There would also be a requirement for increased spillway capacity and this is provided by increasing the spillway capacity to discharge the PMF through the Devil Canyon reservoir without the moderating effect of the Watana reservoir.

The greater drawdown required in operation of the single reservoir will require additional costs for the deeper intake structure for the penstocks.

Additional adjustments include a greater cost for the temporary buildings in the construction camp but a higher salvage value due to their use later at Watana.

The smaller reservoir requires consideration as to accumulation of sediment which would otherwise be trapped in the Watana reservoir. The Devil Canyon reservoir, with 100 feet of drawdown, will still have some 450,000 acre-feet of dead storage. This will accommodate the estimated sediment inflow of 5,000 acre-feet per year for the life of the Project.

If Devil Canyon is constructed first, the road access could be from the west with a road along the north bank of the Susitna River. The road would originate at Hurricane. A bridge would be required to provide access to both banks. The railroad spur originating near Gold Creek and running along the south bank would remain as previously planned.

The changes in costs for Watana under this scenario concern access and the construction camp. The access to Watana would be from Devil Canyon along the road already proposed for connecting the two developments but designed for heavier construction usage. The road from the Denali Highway would be eliminated. The camp buildings would be provided, in some cases, from those that would become surplus at the Devil Canyon camp. This saving would be offset to some degree by the lower salvage value.

The cost estimates for Watana and Devil Canyon constructed in reverse sequence appear on Exhibit 7.9. These costs are used in the economic evaluation of the construction sequence.

7.3. BASE LOAD AND LOAD FOLLOWING OPERATIONS

The Susitna Project has the capability to serve the bulk of the Railbelt utility system for many years to come after Watana first enters service. The quality and reliability of service of the electric system will be determined by the ability of the Susitna Project to serve the loads. A typical December weekday daily load curve is shown on Exhibit 7.10.

In the present License Application, the Watana plant initially would operate on base to maintain nearly uniform discharge from the powerplant. The Watana Project would also be utilized for spinning reserve, which would require that it follow load to some extent. When Devil Canyon comes on line, Watana would change to a peaking operation, while Devil Canyon operates on base.

The ultimate aim should be for the Susitna Project to have the flexibility to follow loads, regulate frequency and voltage, provide spinning reserve, and react to system needs under all normal and emergency conditions. The project should be dispatched to minimize thermal operation and fuel costs. Realization of the aim is dependent on environmental impacts downstream and on the timing of completion of the Watana and Devil Canyon plants.

Since the Susitna Project is capable of meeting 80 percent of the energy needs at least initially, some of the other generating plants which would normally be connected and synchronized to load would be in cold reserve. Consequently, it would be desirable for the Susitna

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Since the Susitna Project is capable of meeting 80 percent of the energy needs at least initially, some of the other generating plants which would normally be connected and synchronized to load would be in cold reserve. Consequently, it would be desirable for the Susitna

Project to follow load as closely as practical as it fluctuates on an hourly and seasonal basis.

Alternatively, Susitna Project flow release limitations can be designed to the extent that the resulting operation would meet both the power system needs and downstream flow regulation requirements. A possible approach would be to place some limitations on the magnitude, rate, and duration of the change in fluctuations.

The above definitions of project operation are intended to provide some estimate of the value of Susitna Project under two extreme cases of operating flexibility with the OGP model. In actual operation, it is neither practical to operate in the strict base load mode nor acceptable - from the environmental standpoint - to operate in the unrestricted load following mode.

Project operation should be analyzed on a real time basis using small time increments. Such analysis can provide insight into the influence of power operation on flow regime, while the restrictions of flow fluctuations can also be factored to determine the degree of Susitna operating flexibility. These analyses should be made using the instream hydraulic models to evaluate downstream impacts.

7.4 RESERVOIR OPERATION STUDIES

Operation studies were performed for the alternative developments to estimate their power and energy production capability under base load and load following operation modes. The computer simulation program, reservoir and streamflow data, turbine and generator data, and reservoir operation constraints used in the operation studies is described in Chapter 3.

Estimates of energy production and dependable capacity from the alternative developments were made. The studies considered the energy demands for the period 1993 through 2020, for the DOR Mean and SHCA-NSD load forecasts. The alternative developments are as follows:

a) Four Watana elevations;

b) Four Watana elevations, followed by Devil Canyon; and

c) Devil Canyon, followed by four alternative Watana elevations.

Table 7.3 summarizes the alternative developments considered.

Table 7.3

ALTERNATIVE DEVELOPMENTS

Developments	Nor. Max. W.S. Elev. (ft. msl)	Draw-down (ft)	Initial No. of Units	Rated Head (ft)	Initial Installed Capacity (December) (MW)
1. Watana	2185	120	4	680	680
2. Watana	2100	150	4	600	585
3. Watana	2000	150	4	500	475
4. Watana	1900	150	4	400	380
5. Devil Canyon	1455	100	4	590	600

Exhibits 7.11 and 7.12 summarize the power and energy production for Watana 2185 and 2000 under the DOR Mean forecast scenarios with load following operation for the year 2020. Similar information was presented for Watana 2185, with base loading operation, in Chapter 3.

7.5 SYSTEM EXPANSION PROGRAMS

Alternative long-term power supply plans for the Railbelt with Watana (Elev. 2185) and Devil Canyon and the Non-Susitna alternatives were discussed in Chapter 5. In the studies, coal-fired and gas-fired thermal generation and the Chakachamna Hydroelectric Project were compared to the Susitna Project for the DOR Mean and SHCA-NSD oil price forecasts. The results of these studies are repeated in this Chapter for comparison with the Susitna alternatives.

Study of the long-term power supply plans for the Susitna alternatives has been directed at the development of supply plans for the range of Watana reservoir elevations under consideration and analyzing the effect of the Project's ability to follow load with no restrictions in flow fluctuations. In addition, power supply plans with Devil Canyon preceding Watana are formulated. In all these cases, only four units at Watana are considered. Exhibit 7.13 summarizes pertinent data and construction and investment costs for the Susitna alternatives. The investment cost includes interest during construction computed at 3.5 percent using estimated construction cash flow distributions.

The General Electric Optimized Generation Planning (OGP) model was used to develop the power supply plans and the plans are structured based on the following criteria discussed in Chapters 3,4,5 and in this Chapter. The model is, however, limited in its capability to analyze in detail the performance of the hydroelectric plants to (a) minimum plant rating and (b) maximum plant rating.

The power and energy available from the Susitna alternatives is divided into two types; minimum rating and maximum rating. Under minimum rating, energy that must be produced is accounted for by subtracting a constant capacity from every hourly load in the month as shown on Exhibit 7.14. This capacity value is referred to as the plant minimum rating. After dispatching base load energy, the program uses the plant maximum capacity rating and remaining available energy of the hydro unit, if any, to reduce peak loads as much as possible.

The plant minimum and maximum ratings can be used to simulate base load operation or load following or a combination of both. Strict base loading is accomplished by specifying minimum plant ratings that correspond to plant capacity that uses the total estimated energy generation. On the other hand, unrestricted load following is simulated by specifying maximum plant ratings that correspond to the hydroelectric projects capability and the estimated energy is used to reduce peak loads.

Several expansion plans for Susitna alternatives were tested including the Watana Development at four different reservoir elevations, the installation date of Devil Canyon, and project operation under base and load following modes. Depending on the height of the Watana dam and mode of operation, the project would provide different amounts of capacity and energy. Therefore, the generation mix and costs of resulting expansion plans vary.

In the case of Watana operating in the base loading mode, the Watana Development (prior to Devil Canyon) is dispatched as shown on the left diagram of Exhibit 7.14. In this application, the plant minimum rating corresponds to the plant capacity that uses the total estimated energy production but not the maximum generating capacity. After the installation of the Devil Canyon Development, the Susitna Project is operated as shown in the far right diagram with Watana operating at maximum rating and Devil Canyon operating at minimum rating, thereby providing full utilization of Watana generating capacity and full use of energy (diagram is not to scale.)

Load following is depicted in the middle diagram. With this dispatch both the maximum plant ratings and the estimated energy production would be fully utilized. With the hydroelectric project operating in the load following mode, thermal capacity requirement can be minimized, and thermal plant output can be nearly uniform, substantially reducing cycling and spinning reserve duties and therefore system costs.

The total costs for the planning period include all costs of fuel and operation and maintenance of all generating units. In addition, the production cost includes the annualized investment costs of any plants and transmission facilities added during the period. Costs common to all the alternatives are excluded. These would be investment costs of facilities in service prior to 1993, and administrative and customer services costs of the utilities.

The annual costs from 1993 through 2020 are developed by the OGP model and are converted to a present worth in 1983. The long-term system costs (2021-2050) are estimated from the 2020 annual costs, with adjustments for fuel escalation, for the 30-year period. The Susitna and Non-Susitna expansion plans are compared on the basis of the sum of the present worth of costs from 1993 to 2050.

7.5.1 Comparison of Expansion Plans under the DOR Mean Scenario

Exhibits 7.15, 7.16 and 7.17 present the capacity additions with the DOR Mean load forecast for the Susitna and Non-Susitna alternatives. Exhibit 7.18 summarizes the generation mix, reserve margin, loss of load probability (LOLP), economic costs of power in $/MWh, and cumulative present worth of system costs for the years 2020 and 2050.

Most of the expansion plans show reserve margins in the range of 30 to 40 percent. The range of reserve margin would appear to be high by usual standards. However, the Railbelt load has a fairly long winter peak and the load factor is also relatively high.

Exhibit 7.18 also shows the Non-Susitna plan with a combination of gas-fired combined cycle and coal-fired steam as being the optimum plan. Reference to Exhibit 7.15 shows this plan to begin with a two-unit combined cycle plant in 1993. This plan was developed by OGP through its own internal optimization process. To ensure that the plan is superior to any other thermal alternative, the OGP program was tested with the use of a coal-fired plant in 1993, and further tested with the use of only gas-fired generation. These expansion plans are found to be less economical since they result in higher cumulative present worths for the period 1993-2050.

The Chakachamna Project was also tested as one of the Non-Susitna alternatives, and it was found to have a cumulative present worth of costs greater than the optimum Non-Susitna plan.

Exhibit 7.16 shows three alternative expansion plans for Watana 2185, 2100 and 2000 under the base loading case. Exhibit 7.17 shows the corresponding plans if the Susitna Project is to operate in the load following mode, which would require fewer combustion turbines or combined cycle plants to be built in the planning period. A comparison of the present worth costs shows there is a clear economic advantage if the Susitna Project can be operated in the load following mode. This is illustrated in Table 7.4 for the DOR Mean case. However, the economic analysis has not factored the effects on the environment under the load following mode.

Table 7.4

COMPARISON OF PRESENT WORTH COSTS 1993-2050
FOR BASE LOAD AND LOAD FOLLOWING OPERATIONS
(1983 - $million)

	Base Load Operation	Load Following Operation
Watana 1900	5191	4888
Watana 2000	4892	4664
Watana 2100	4797	4552
Watana 2185	4744	4593

7.5.2 Expansion Plan under the SHCA-NSD Scenario

Exhibit 7.19 shows the Susitna and Non-Susitna expansion plans to meet the forecast load under the SHCA-NSD oil price scenario. For each alternative supply plan, the generation mix in the year 2020, reserve margin, and present worth of costs, are shown.

For the Non-Susitna alternative, a mix of natural gas-fired combined cycle plants, coal-fired steam, and combustion turbines is selected.

For the Susitna alternatives, a comparison of the generation mix and present worth of costs also shows there is a clear economic advantage if the Project can be operated in the load following mode excluding the consideration of environmental impact as discussed in a later section of the Chapter.

7.5.3 Timing of Devil Canyon Development

The optimum timing of the Devil Canyon Development was established by a process of iteration. The results are shown in Table 7.5.

Table 7.5

OPTIMUM TIMING OF DEVIL CANYON DEVELOPMENT

Watana Elevation	Devil Canyon On-Line Date DOR Mean	SCHA-NSD
2185	2006	2002
2100	2005	2000
2000	2003	1998
1900	2002	1996

Thus, the timing of the Devil Canyon Development could differ by four to six years depending on the eventual outcome of the oil price scenario. In other words, if the initial Watana 2185 Development were built, Devil Canyon would be needed in 2002 under the SHCA-NSD case, but the plant would not be needed until four years later if the DOR Mean oil price scenario should prevail.

7.6 OTHER EXPANSION PROGRAMS

Other generation expansion programs and costs are developed for purposes of sensitivity analyses and further optimization. These include the following :

- Sequence of construction of Watana and Devil Canyon.
- Timing of Watana Development
- Availability and price of Cook Inlet gas

The studies have been performed using the established criteria and the results are presented below.

7.7 ECONOMIC ANALYSIS

A life cycle analysis is performed by comparing the present worth of the annualized investment and production costs for the period 1993-2050 of the Susitna alternatives and Non-Susitna alternatives.

The analysis has been performed for the Category 1 cost estimate which includes the recommended refinements of the Susitna Project design.

Since load following operation with the Susitna Project is an important factor in serving the Railbelt electric system, and the License Application currently indicates that the project will be operated as a base-load facility, both modes of operating are presented. The analysis illustrates the difference in the economics of the project depending on operation mode. By way of comparison, the difference in the present worths of the same project operated in the two modes provides a measure of the value of load-following operation.

The following paragraphs describe the net benefits, benefit/cost ratios, and net benefits as a function of initial investments, between the Susitna and Non-Susitna alternatives.

7.7.1 Net Benefits

The "net benefit" of a Susitna project is determined by taking the difference between the cumulative present worth of costs of the Susitna expansion plan and that of a Non-Susitna expansion alternative. The net benefits for the Watana alternatives are summarized in Table 7.6 for various dam elevations. Watana 1900 is less competitive and not shown in the table. Exhibit 7.20 illustrates the net benefits for all Watana alternatives.

Table 7.6

NET BENEFITS, 1993-2050
(1983 - $million)

	Watana Elevation		
	2185	2100	2000
Category 1 Cost with Base Loading			
DOR Mean	146	93	-2
SHCA-NSD	1,470	1,311	1,041
Category 1 Cost with Load Following			
DOR Mean	297	338	226
SHCA-NSD	1,631	1,503	1,342

7.7.2 Benefit Cost Ratios

Benefit-cost ratios, as shown in Table 7.7, are determined by taking the ratio of cumulative present worths of the Susitna alternative and that of the least-cost Non-Susitna alternative for the period of 1993-2050. The benefit-cost ratio tends to increase with a higher Watana reservoir elevation and a more optimistic oil price scenario.

Table 7.7

BENEFIT COST RATIOS

	Watana Elevation		
	2185	2100	2000
Category 1 Cost with Base Loading			
DOR Mean	1.03	1.02	1.00
SHCA-NSD	1.28	1.24	1.18
Category 1 Cost with Load Following			
DOR Mean	1.06	1.07	1.03
SHCA-NSD	1.31	1.28	1.25

7.7.3 Net Benefit as a Percent of Initial Investment

Net benefits and benefit cost ratios tend to increase with the higher Watana reservoir elevation, due in part to the adoption of the planning period to 2020 when the total resource for the high Watana project is utilized. With a smaller Watana dam, it is necessary to add some thermal plants for the system to meet the forecast load to 2020. The addition of thermal generation tends to obscure the net benefit in terms of the initial capital investment of the Watana Project. Net benefit as a function of initial capital cost is shown in Table 7.8.

Table 7.8

NET BENEFIT AS PERCENT OF
INITIAL WATANA CONSTRUCTION COST

	Watana Elevation		
	2185	2100	2000
Category 1 Cost with Base Loading			
DOR Mean	4.4	3.1	0.0
SHCA-NSD	44.0	43.7	39.5
Category 1 Cost with Load Following			
DOR Mean	8.9	11.3	8.6
SHCA-NSD	48.9	50.2	50.9

The table illustrates that the net benefit as a function of initial construction cost is low under the DOR Mean scenario. However, the value is high indicating the Susitna Project to be very attractive under the SHCA-NSD scenario.

7.8 INTERNAL RATE-OF-RETURN (INTEREST RATE THRESHOLD) ANALYSIS

The internal rate-of-return for investing in Susitna is the discount rate at which the cumulative present worth of the Susitna alternative becomes equal to the optimum Non-Susitna expansion program. The results of the internal rate-of-return analysis are presented in Table 7.9 and illustrated in Exhibit 7.21 for the SHCA-NSD only.

Table 7.9

INTERNAL RATE-OF-RETURN
CATEGORY 1 COST WITH BASE LOADING

	DOR Mean	SHCA-NSD
Watana 2185	3.7%	5.4%
Watana 2100	3.6%	5.3%
Watana 2000	3.5%	5.0%

The "internal rate-of-return" analysis provides a means to identify the project that maximizes investment. The optimum rate of return is obtained for Watana Elevation 2185. This analysis is equivalent to a threshold determination of the discount rate.

7.9 THRESHOLD DETERMINATION

7.9.1 Oil Prices

World oil price greatly influences the economics of the Susitna Project. Therefore it is useful to identify the oil price at which point the cumulative present worth of the Susitna alternative is equal to that of the optimum Non-Susitna alternative, meaning that there is no longer any economic incentive. Inspection of the net benefits indicates that the threshold oil price is very near the DOR Mean case. With improvements in project operation the threshold oil price would be lower than the DOR Mean case.

7.9.2 Capital Cost Estimate

A threshold determination has also been made for the capital cost estimate of the Watana Project as shown in Table 7.10. This has been done for the SHCA-NSD and DOR Mean oil price scenario for the Category 1 case threshold point. In such a determination, the threshold point is the change in the estimated cost of the initial Watana Development that would cause the break-even point to be reached. A substantial increase in the estimated cost of the Watana Development would be required before the threshold point is reached for the SHCA-NSD scenario.

Table 7.10

THRESHOLD ANALYSIS FOR
PERCENT INCREASE IN INITIAL WATANA PROJECT COST
(CATEGORY 1 COST) - %

	DOR Mean		SHCA-NSD	
	Base Loading	Load Following	Base Loading	Load Following
Watana 2185	4.9	10.0	49.6	55.0
Watana 2100	3.5	13.5	49.3	56.5
Watana 2000	0.0	10.3	45.0	58.0

7.10 SENSITIVITY ANALYSIS

7.10.1 Delay of Watana Operation

A sensitivity analysis was done to analyze the impacts of delaying Watana operation until 1996, under the DOR Mean and SHCA-NSD scenarios. The year 1996 was selected because a three-year delay would permit the addition of two combined cycle gas turbine units in 1993, which is the best thermal option. The OGP model was rerun for Watana Elevations

2185 and 2000 with base loading and load following. The 2050 cumulative present worths are presented in the Table 7.11. The results indicate that there is an economic disadvantage with the delay under the SHCA-NSD scenario and no significant difference under the DOR Mean condition.

Table 7.11

DELAY OF WATANA OPERATION
2050 CUMULATIVE PRESENT WORTH
(1983 - $million)

	DOR Mean Watana Elevation		SHCA-NSD Watana Elevation	
	2185	2000	2185	2000
Category 1 Cost with Base Loading				
Watana in 1993	4,744	4,892	5,325	5,754
Watana in 1996	4,793	4,877	5,481	5,760
Category 1 Cost with Load Following				
Watana in 1993	4,629	4,740	5,164	5,453
Watana in 1996	4,658	4,693	5,320	5,580

7.10.2 Project Sequence

Table 7.12 summarizes the 2050 cumulative present worth of the Watana-Devil Canyon sequence compared to the Devil Canyon-Watana sequence for Watana Elevations 2185 and 2000 for the DOR Mean scenario. In all cases, the present worth analysis shows construction of Devil Canyon first is less favorable than construction of Watana first.

Table 7.12

PROJECT SEQUENCE
2050 CUMULATIVE PRESENT WORTH
(1983 - $million)

	Watana Elevation	
	2185	2000
Category 1 Cost with Base Loading		
Watana First	4,744	4,892
Devil Canyon First	4,897	4,982
Category 1 Cost with Load Following		
Watana First	4,593	4,664
Devil Canyon First	4,689	4,792

7.11 SUMMARY

Net benefits are generally greater with higher Watana dam elevations. Load following operations have greater economic impacts on smaller projects. Any of the projects are at or near the threshold under the DOR Mean scenario. The threshold Watana construction cost is 50 to 60 percent above the estimated cost for the SHCA-NSD scenario. The delay of Watana operation from 1993 to 1996 does not affect the economics significantly under the DOR Mean scenario.

7.12 COST OF POWER ANALYSIS

The results of the economic analyses indicate that between the ranges of Watana 2185 and Watana 2000, there is no material influence on project economics; however, below Watana 2000 the economic benefits decrease significantly.

For this reason, the cost of power analysis is performed for only two Watana dam heights--the Watana 2185, and Watana 2000 operated in a load following mode. Cost of power studies for Watana 2185 were discussed in Chapter 6 and are repeated here for comparison purposes. The financing approach and assumptions considered in the evaluation of project funding are the same as discussed in Chapter 6. The estimated construction costs are $3,338 million (1983 $) for Watana 2185 and $2,637 million for Watana 2000. Obviously, the difference in capital cost requirements would influence the amount of State equity contribution.

The cost of power estimates were made for a range of State equity contributions including a determination of the amount of State equity contribution that will bring the wholesale cost of Susitna power equal to the first year cost of the alternative Non-Susitna expansion program. The results are summarized in Table 7.13 for the DOR Mean and SHCA-NSD cases.

Table 7.13

FUNDING REQUIREMENTS TO
EQUATE FIRST YEAR WHOLESALE COST OF POWER
TO THE NON-SUSITNA ALTERNATIVE
(In $ Billion)

	Watana 2185 Base Loading			Watana 2000 Load Following		
NOMINAL $	Equity State	Revenue Bonds	Total	Equity State	Revenue Bonds	Total
Coal Thermal						
DOR Mean	1.96	4.32	6.28	1.20	4.01	5.21
SHCA-NSD	2.30	3.80	6.10	1.57	3.44	5.01
Gas/Coal Thermal						
DOR Mean	3.28	2.41	5.69	2.35	2.32	4.67
SHCA-NSD	3.00	2.79	5.79	2.25	2.45	4.70
1983 $						
Coal Thermal						
DOR Mean	1.45	2.62	4.07	0.88	2.46	3.34
SHCA-NSD	1.67	2.29	3.96	1.12	2.03	3.15
Gas/Coal Thermal						
DOR Mean	2.27	1.40	3.67	1.61	1.35	2.96
SHCA-NSD	2.11	1.62	3.73	1.55	1.42	2.97

With reference to Table 7.13, State equity revenue bond requirements would be much reduced with a lower Watana dam height. Exhibits 7.22 and 7.23 show the State equity contribution required to match the first year cost of a thermal system served by a combination of natural gas-fired and coal-fired powerplants. The State equity contribution would be much less if the objective is to match the first year cost of a coal-fired thermal system.

The State equity contribution provides the means to bring the first year wholesale cost of Susitna power down to the level of alternative thermal system cost. It will also stabilize the future cost of power. This is illustrated in Exhibits 7.24 and 7.25 showing the cost of power over time for the DOR Mean oil price scenario. In later years, wholesale cost of power from Susitna with Watana Elevation 2000 would be about 30 percent higher than the Watana 2185 development, but would still be less than half that of the best thermal option.

Exhibits 7.26 and 7.27 show tabulated data for the DOR Mean analysis on annual costs and wholesale cost of power for Watana 2185 and Watana 2000 projects, for the State equity contribution that equates Susitna and Non-Susitna first year costs and 100 percent debt service cases.

7.13 INTEREST RATE SENSITIVITY

The interest rates on revenue bonds will greatly influence the cost of power. Exhibit 7.28 shows the range of power costs for different interest rates, assuming a State equity contribution of $1,610 million (1983 dollars) for the Watana 2000 project. Interest rates from eight percent and twelve percent have been used to illustrate the effect on cost of power when compared against the base case of ten percent. First year (1993) power costs would be 6.4, 7.6, and 8.8 cents per kWh with interest rates at eight, ten and twelve percent, respectively.

7.14 SAGE MODEL

Exhibit 7.29 shows a bar chart of estimated Watana construction cash flows for the 2185 and 2000 projects and special capital available for Susitna under the three operating budget growth scenarios (+2%, 0%, and -2%) as estimated from SAGE Model runs.

Inspection of Exhibit 7.29 indicates that, with the same on-line date (1993), the Watana 2000 project expenditures would not begin until 1987. In addition, with real growth in the operating budget of 0 and -

2 percent, construction expenditures are met or exceeded by estimated available capital except in 1990 and 1991 under the 0 percent scenario. However, if surpluses in earlier years were reserved, the 1990 capital requirements could also be met. The 2 percent operating budget growth rate scenario yields available Susitna capital estimates that would fall short of construction expenditures in 1988 through 1991. If surpluses in earlier years were reserved, these construction expenditures could be met under all the operating budget growth rates for the Watana 2000.

Since the expenditures for the Watana 2000 project are significantly less than the 2185 project, total upfront capital requirements are much less ($2,350 versus $3,280 million) and annual construction expenditures are more in line with estimated special capital available. The upfront capital requirements used in these comparisons are the maximum. Under the coal expansion plan the capital requirements would be much less.

7.15 ENVIRONMENTAL CONSIDERATIONS

The environmental implications of the alternative development concepts considered during the 1983 Update and Optimization Studies have been evaluated throughout the course of the studies. A summary of these implications is presented in this section. A more comprehensive environmental evaluation of the alternative schemes is contained in a supplemental environmental report.

Exhibit E of the FERC License Application, as filed on February 28, 1983, considered all aspects of construction and operation of the project, as proposed, in relation to probable impacts on the physical, biological, and social resources of the affected region. Changes from the License Application in the size or configuration of project features or sequence of construction would result in slightly different project impacts as compared to those discussed in Exhibit E. This section presents a discussion of the relative impacts of the design and operational alternatives considered in the present study. The development concepts will differentially impact the region upstream of Devil Canyon through construction and inundation effects (e.g., size of reservoir, construction time, manpower requirements, etc.) and will differentially affect the river downstream from Devil Canyon through different seasonal flow release patterns. This discussion is designed to highlight the differential impacts of the alternatives and to assist in their overall evaluation. It is not intended to present a comprehensive discussion of all potential impacts of each of the alternatives. A comprehensive evaluation of the project as described in the License Application is contained in Exhibit E. Comparable detailed analyses will be made only for those alternatives that may be selected for future detailed study.

7.15.1 Area Upstream of Devil Canyon

The majority of the anticipated impacts on terrestrial and aquatic resources resulting from the construction and operation of the two dam project, as described in the License Application, are related to the first phase of development, the Watana 2185 dam and reservoir. The relative impacts of the proposed Watana alternatives are therefore compared to those for the base case Watana 2185 development as discussed in Exhibit E. Projects with lower normal maximum water surface elevations at the Watana site (e.g. 2100, 2000, or 1900 feet) would result in:

- less area inundated;
- less borrow material needed;
- 1 to 2 years reduction in construction time;
- more modest remedial measures to seal the relict channel; and

- less inherent capacity for flood control and less regulation of downstream flows.

Each of these potential changes would result in a reduction of direct impacts to the resources of the project area. The most significant changes from an environmental standpoint are the extent of area inundated, the requirements for excavation of materials from borrow areas, and the less inherent capacity for regulation of downstream flows.

<u>7.15.1.1 Area Inundated.</u> At lower normal maximum reservoir elevations, the length of the reservoir would be shorter and the area inundated would be less than for the reservoir at elevation 2185 (Exhibit 7.30 and Table 7.14). Less area inundated means less impact on the terrestrial, aquatic, and other (recreational, archaeological, etc.) resources of the region.

Table 7.14

ENVIRONMENTAL CHARACTERISTICS OF ALTERNATIVE WATANA DEVELOPMENTS

Alternative Elevation (ft,msl)	2185	2100	2000	1900
Reservoir Area (acres)	38,000	28,300	19,800	14,500
Susitna River Miles Inundated	54	49	44	39
Length of Major Tributaries Inundated (stream miles)	24	18	14	11

Much of the area to be inundated by the Watana development, particularly the south-facing slopes, is important as a source of early spring foods for moose and bear, and as calving areas for moose. A reduction in the reservoir area, particularly in the length of mainstem and tributary stream inundated and the narrower reservoir width associated with the lower Watana developments, would reduce the magnitude of these impacts on the carrying capacity of the area for big game species, and would also reduce the potential for interference with movements and the possibility for big game fatalities during river crossing attempts. A reduction in the extent of inundation along Watana Creek may be particularly beneficial for maintenance of wildlife habitat.

With the reservoir at elevation 2185, up to 42 percent of the surface area of the Jay Creek mineral lick would be inundated by the Watana impoundment. This lick appears to be an important nutrient source for the Watana Hills Dall Sheep population. The lick extends from elevation 2000 to 2450, so at lower elevations of the reservoir, less of the lick area would be inundated or it might be totally avoided (e.g., at elevation 1900).

The primary long-term impact of the reservoir on aquatic resources is the loss of clear water tributary spawning habitat that currently supports a substantial population of grayling. Future aquatic habitats within the reservoir area are not expected to support a significant grayling population. In addition, some loss of burbot and whitefish spawning area is expected in mainstem habitats. The lower surface elevations of the reservoir would inundate fewer stream miles of mainstem and clearwater tributary habitat and thereby reduce impacts to aquatic resources.

<u>7.15.1.2 Borrow Material Needed</u>. The report on Recommended Design Refinements indicates that the modified design for the Watana embankment requires 10% less fill material than is discussed in Exhibit E. At lower dam elevations of 2100, 2000, or 1900, requirements for fill material are 26, 55, and 70 percent less, respectively, than the requirements for the modified 2185 design. For the elevation 1900 development, the requirements for rock excavated from an upland quarry

are 96 percent less than the modified 2185 design. Requirements for impervious fill (from an upland site) and sand and gravel (from the river channel and riparian areas) are 69 and 77 percent less, respectively, for the 1900 alternative than for the 2185 modified design. The smaller requirements for sand and gravel, which will be obtained from the Susitna River at the mouth of Tsusena Creek, will limit the extent and duration of turbidity and sedimentation in the river downstream during construction. Also, the impacts to the existing riparian habitat in the area will be less than for the higher dam alternative. The smaller requirements for material from the rock quarry and the borrow area for impervious fill will lead to less disturbance to surrounding lands, including less traffic on the haul roads, less blasting, and less overall generation of dust.

7.15.1.3 Aesthetic and Land Use Impacts. The lower alternative reservoir elevations will inundate significantly fewer acres and stream miles than the project as described in the License Application. The total magnitude of impacts on land use, recreation, aesthetic, and archaeological resources in the area will also be less significant. Although development will increase the potential for access to the area, the lower reservoir alternatives will result in larger areas remaining in primitive "before project" condition.

7.15.2 Downstream Flows

Downstream flow regimes following project construction will be altered from natural conditions, with marked increases in winter flows and decreases in summer flows. Table 7.15 summarizes average August and December flows for three demand scenarios and each alternative dam elevation for the Watana Development. The first power demand scenario assumes a year 2000 demand of 4709 GWh (DOR Mean forecast). Under this scenario, only the Watana Development would be in operation. The second scenario assumes both Devil Canyon 1455 plus one of the Watana alternatives are in operation and presents flows at Gold Greek as they would occur for a year 2010 power demand of 5945 GWh. The third scenario presents year 2020 flows for an increased power demand of 7505 GWh. These three scenarios characterize the project outflows over the life of the project.

Table 7.15

AVERAGE AUGUST AND DECEMBER
WITH-PROJECT FLOWS AT GOLD CREEK
Demand Level (GWh) and Month

Watana Alternative	Demand 4709 GWh		Demand 5945 GWh		Demand 7500 GWh	
	Aug. (cfs)	Dec. (cfs)	Aug. (cfs)	Dec. (cfs)	Aug. (cfs)	Dec. (cfs)
2185	12,680	11,146	18,436	9,430	12,678	10,979
2100	13,755	10,689	16,050	9,796	13,548	11,274
2000	15,900	8,697	19,020	9,264	17,424	8,906
1900	22,017	7,802	21,057	7,058	20,363	7,054
Natural	22,017	1,825	22,017	1,825	22,017	1,825

Monthly flow duration curves for August and December for each dam height and each power demand level are shown on Exhibit 7.31. December flows are greatly increased compared to natural conditions for all dam heights and power demand scenarios. In general, December flows are greater at greater dam heights. Conversely, August flows at Gold Creek are less with greater dam heights.

Depending on the dam elevation and power demand scenario, average August flows may be decreased from a natural flow of 22,017 cfs to a low of 12,678 cfs for the fully loaded two development project (year 2020 demand of 7505 GWh). Average December flows are increased from a natural flow of 1825 cfs to a range of 7000 to 11,300 cfs. For individual years out of the 33 year period of record, average monthly December flow may exceed 14,000 cfs. August flows are maintained at a minimum of 12,000 cfs in accordance with the "Case C" Scenario even though operation solely for power production would have resulted in less than 12,000 cfs at Gold Creek. Further downstream, these marked differences between natural and with-project flows diminish due to tributary inflow, and seasonal flow patterns more nearly approach the pre-project pattern.

7.15.3 Downstream Impacts on Aquatic and Riparian Resources

If impacts are defined as changes from natural conditions, the lowest elevation dam would have the least impact in that it has the least change from natural flow conditions and would be least likely to result in long-term changes to fishery habitat and fish populations downstream and to downstream riparian vegetation that serves as important moose habitat.

Downstream impacts of project operation on aquatic resources would occur primarily as a result of changes in the flow and water quality regimes. Flows deviate most from natural conditions at higher dam heights. Downstream turbidities would decrease from natural conditions in spring and summer and increase in the winter under all alternatives. With-project temperatures during operation would be similar to natural conditions in spring and summer but would increase over natural conditions in the winter. Changing the dam height should not substantially change downstream temperatures and turbidities.

Secondary environmental effects of altered downstream flows are less severe at lower dam heights because average monthly flows are closer to natural conditions at lower dam heights. For example, mainstem velocities and depths in spring and summer would increase (and thereby become more similar to natural conditions) at lower dam heights. Consequently, the magnitude of impacts to downstream aquatic resources would likely increase for higher normal maximum reservoir elevations because the downstream flow regimes have greater deviations from natural conditions.

During the spring and summer, the potential impacts on downstream fishery resources of the Watana project alternative are as follows.

1. Unusually high, low or unstable flows can slow or even halt upstream migrations of salmon. A reduction in the magnitude and frequency of flood flows that would result from the higher dam alternatives could reduce disruptions in upstream migrations. On the other hand, lower dam heights have higher average flows during the summer which more nearly equal natural flows and could likewise facilitate upstream movement. The net advantage of one factor over the other is under investigation.

2. Access for salmon and resident fish to spawning areas in tributaries and sloughs was identified as a critical issue in Exhibit E. The ease of access to tributaries and sloughs decreases under low flow conditions. Access problems will potentially be most significant with the Watana 2185 alternative since project flows during the summer are generally the lowest of all alternatives.

3. Project operation in the spring and summer could impact the location and availability of spawning habitat in the mainstem, side channels and sloughs. Reduced flows in the mainstem and side channels may have both positive and negative effects on spawning habitat, but changes would more likely be positive because relatively little spawning occurs in these areas under present conditions. The with-project reduction in the magnitude and frequency of flood events may decrease

disruptions to existing spawning habitat and the more stable water depths may add new spawning habitat in these areas.

4. Changes in the quality and quantity of rearing habitat for resident and juvenile anadromous species may result from project operation. Losses of rearing habitat will occur if lower flows cause depths to be reduced making areas too shallow for fish to use or reducing the extent of quiet, backwater areas. Increases in rearing habitat could result from the reduced velocities, turbidities and scour of the substrate associated with the reduction of flood flows. Net gain or loss of rearing habitat has yet to be quantified. Greater change, whether positive or negative, in habitat should occur at higher dam heights since mainstem depths and flows will be more reduced.

During fall and winter, potential impacts include:

1. The higher winter flows under project conditions, compounded by increased river stage due to ice formation, will increase the potential of overtopping the berms at the upstream ends of some sloughs. The introduction of cold mainstem flows and possible scouring of the substrate resulting from overtopping could result in slowed development rate of fish eggs or eggs could be killed due to thermal shock or physical destruction. The probability of sloughs being overtopped because of increased ice staging will be less at successively lower dam heights.

2. The increased staging downstream of the ice front might provide more overwintering habitat in some areas for resident and anadromous species if wetted perimeter and depths increase under the ice as a result of increased winter flows.

Warmer water temperatures upstream of the ice front could enhance the survival of overwintering fish by reducing mortalities due to freezing.

The types of impacts expected during reservoir filling would be comparable to those during operation. During filling, flows at Gold Creek would be reduced during the spring and summer whereas largely natural flows would occur in winter. The main effect that lower dam heights have on the magnitude of the impacts is that the impacts will occur for a shorter period of time for the lower dam heights, since the lower dam reduces the time necessary to fill the reservoir. Adverse temperature effects expected during the second open water season of filling for the Watana 2185 development may be reduced for the Watana 2000 and 1900 alternatives. The lower reservoirs would be filled more quickly and thus permit the multiple level release facilities to be operated earlier and thereby avoid most of the impacts related to release of colder waters.

Two potential operational modes were considered for the project, regardless of reservoir elevation. Base load operation results in daily and weekly regulation of flows downstream of the project. With unrestricted load following operation, hourly and daily discharges would vary significantly. These flow fluctuations would decrease with distance downstream because some attenuation of the flow extremes would occur. Although information is not available to evaluate the effects of daily flow fluctuations downstream, the following types of impacts may be expected:

1) inhibited upstream migration of adult salmon due to unstable flow conditions, which may reduce survival and spawning success of some fish;

2) reduced growth and survival of rearing anadromous and resident species because of changing amounts of suitable habitat; and

3) decreased survival of eggs as a result of impacts caused by daily watering and dewatering of the redds during incubation.

Because daily changes in discharge and stage during the winter would be greater for the lower dam alternatives, impacts of daily flow fluctuations would be more severe for these alternatives.

Downstream flow alterations and fluctuations will also impact terrestrial, particularly riparian, resources. The higher winter flows, lower summer flows, and lack of ice scouring with project operation, particularly in the reach between Talkeetna and Devil Canyon, would result in the stabilization of the river banks and the succession to climax forest of some areas now subject to vegetative recession. Although moose habitat may be improved for 10-20 years, the lack of flooding and ice scouring events will eventually result in the decreased availability of good moose habitat along the river downstream to Talkeetna, and also inhibit movements of moose and other big game to islands or across the river during cold weather. The more stable year-round flows and reduced spring and summer flooding of food caches and other beaver structures will result in improved downstream habitat for beaver and muskrat. This, in turn, may have secondary adverse impacts on fishery resources.

As with other downstream resources, the relative extent of impacts of the Watana alternatives will be dependent on the extent of change of downstream flow. Thus, the lowest elevation dam generally has the least impact in that it most nearly represents natural or pre-project conditions and would be least likely to result in long-term changes to riparian habitat. Changes that do occur will be most severe in the reach between Devil Canyon and Talkeetna. Downstream of the confluence of the Susitna, Chulitna and Talkeetna Rivers, changes in flow regimes due to project operation will be moderated due to inflow from the other rivers.

7.15.4 Regional Socioeconomic Impacts of Watana Alternatives

Differential impacts of the alternative Watana developments will result primarily from differences in associated labor requirements. With no significant differences in peak work force requirements of the alternatives, project-related population, employment and income, housing, services and facilities, and fiscal impacts will be similar to those described in Exhibit E of the License Application. Differential effects related to the Watana alternatives will result from the shorter construction schedules for the lower developments, with resultant shorter duration of peak requirements for housing and other facilities and services.

7.15.5 Environmental Aspects of Load Following Operation

The environmental implications of operating the Susitna Hydroelectric Project on a load following basis are highly dependent upon the magnitude of discharge variations during a 24-hour period and the season in which these variations occur. The most significant effects of load following are expected to occur within the aquatic ecosystem as similarly encountered at other hydroelectric projects operated on a load following or peaking basis. The effects to the terrestrial system are primarily those which would occur within the daily inundation zone, the associated riparian habitats along the river margins, and in the floodplains. In addition, load following could result in potential impacts to cultural, aesthetic and recreation resources and socioeconomic activities. A discussion of the potential impacts is presented below for each aspect.

7.15.5.1 Aquatic Ecosystem Implications. The magnitude of the expected effects of load following on the aquatic ecosystem is dependent on several hydraulic characteristics and the life stages of the aquatic species present in the river. The hydraulic characteristics which will determine the magnitude of effects include:

1. The magnitude of the change in discharge during the 24-hour period;

2. The base flow from which increase to the maximum flow is made;

3. The rate of change of discharge;

4. River channel morphology; and

5. Attenuation of the change in discharge downstream from the dams.

The following discussion outlines the types of effects that have been experienced at other hydroelectric facilities as well as some aspects which are associated with specific features of the Susitna River. It also assumes that the load following operation will occur at both the Watana and Devil Canyon facilities.

The potential effects to the fisheries and aquatic resources due to load following operation include:

1. Stranding or isolation of fish, primarily juveniles, when the water surface elevation recedes;

2. Short-term rapid changes in availability and distribution of various habitat types;

3. Delay or inhibition of upstream movement of adult salmon;

4. Dewatering and freezing of incubating eggs;

5. Inundation of incubating eggs with cold water in otherwise somewhat protected area (e.g., overtopping of upstream because of side sloughs);

6. Changes in ice process which indirectly affect aquatic resources; and

7. Potential increases in bank erosion due to bank instability.

Stranding of fish could be significant in areas where fish remain in pools isolated from the main current as waters recede. These fish also become more susceptible to predation and dessication when the habitat dewaters due to water seepage out of the pool through the gravels. Juvenile salmon are particularly succeptible because they frequently utilize shallow, near-shore access for rearing (ADF&G).

In addition to the potential for fish stranding, habitats utilized by juvenile salmon for rearing may be seriously disrupted by constantly changing mainstem discharges. Studies to date (ADF&G, 1983) indicate that, at least in some areas, the availability of rearing habitats utilized by juvenile salmon is correlated with discharge. With constantly changing discharges in the river, the ability of juvenile salmon to maintain themselves in a specific area may not be possible because of the daily disappearance of habitat or significant changes in water velocity. In other areas, juvenile rearing habitat appears to be unaffected by mainstem discharge and, therefore, may not be significantly affected by constant changes in water surface elevation. This too, is highly dependent upon the daily range of discharge fluctuation and water surface elevation.

Daily load following changes in discharges may inhibit upstream migration of adult salmon to the various spawning habitats. Data collected by ADF&G over the past three years (ADF&G 1982, ADF&G 1983, and pers. comm.) show that during periods of rapidly rising discharges due to storm events, upstream movement of adult salmon nearly ceases. As the flood peaks and discharge declines, movement of salmon resumes. Daily fluctuation in discharge could delay movement of adult salmon to the spawning areas.

Beyond the potential delay in upstream migration of adult salmon, daily discharge variation could eliminate mainstem areas as viable spawning and incubation areas for salmon due to the constant dewatering and potential freezing of the suitable sites. Associated with this, suitable spawning areas in side sloughs and side channels may be rendered unsuitable if there is daily overtopping of the upstream berms with mainstem water.

The above concerns are most commonly associated with river reaches immediately below hydroelectric projects and are generally attenuated further downstream. Upstream of the confluence of the Chulitna and Talkeetna Rivers, little attenuation of the daily fluctuation is anticipated in the Susitna River because of the steep gradient in the upstream reach. Downstream of the confluence area, some attenuation is expected because of the lower gradient and the effect of inflow from the major tributaries. The attenuation will be greatest during the open water season when flows are highest from the tributaries. However, when tributary flow is low, as in the winter months, daily fluctuation in the Susitna River downstream of the Chulitna and Talkeetna Rivers will be more significant.

Potential effects of load following during the ice covered period could possibly be more significant than during the open water season, although less directly observable. Under load following conditions, the ice processes become somewhat more complex than without the project or under base load operation of the project. In open water areas, daily changes in discharge during the winter may result in considerable build up of ice along the banks of the river. This would occur as a result of exposure of the river bank during water level changes. The implication to the fishery involves stranding of juvenile fish and freezing of incubating eggs in the spawning areas.

At the leading edge of the ice cover area, daily flow variation could cause periodic flooding of floodplain areas and could result in significant ice jams. Increased flooding is associated with the increased water surface elevations which are observed during the development of the ice cover under current conditions. Additionally, the mechanical action of discharge variation may tax the integrity of the ice cover. If the integrity of the ice cover is compromised, mechanical breakup would occur as the ice cover rides the changing water elevation as observed in the Peace River in Canada. In addition, downstream movement of the ice could form ice jams similar to what occurs during breakup under existing conditions which, in turn, could cause flooding.

The increased flooding could affect overwintering habitats for juvenile salmon and resident fish through scouring of bed materials, increased velocities in suitable habits and decreased temperatures resulting from cold mainstem water inundation of warmer groundwater.

Minimization or avoidance of all potential effects may be achieved through limitation of the range of daily flow changes and the rates of change, both on the ascending portions and receding portions of the hydrograph. The best method of defining acceptable discharge ranges would be to define the maximum acceptable range of water surface elevation change.

7.15.5.2 Botanical and Wildlife Resource Implications. The downstream effects of winter daily flow fluctuations may include impacts on moose movements, decreased beaver over-winter survival, and riparian habitat changes. These effects would mainly occur in the ice-covered portions of the river downstream of the vicinity of Talkeetna. Below the Talkeetna area, flow attenuation and dilution by major tributaries would likely reduce the effects to insignificant levels. It should be emphasized that until further hydrologic and hydraulic evaluations are completed, assessments of the effects of daily flow fluctuations on botanical and wildlife resources are preliminary in nature.

Daily flow fluctuations may create a more irregular and broken ice surface, thereby making river crossings by moose more difficult and hazardous. As a result, moose movements and habitat use along the ice-covered portion of the river would be more restricted and the potential for accidents and exposure to wolf predation would be increased.

Daily flow fluctuations may also reduce overwinter survival of beavers due to the entrapment of greater portions of food caches in ice and/or the uprooting and washing downstream of food caches. This latter mechanism may also negatively affect beavers upstream of the ice-covered portions of the river but the lack of ice cover may overshadow the negative effect in this area.

The extent of ice damage to riparian vegetation may be increased due to the greater ice movement and thickness resulting from daily flow fluctuations. As a result, the unvegetated floodplain may be widened and the stage of plant succession may be retarded along many shoreline areas, at least initially. A wider unvegetated floodplain is likely to result in the long term as well. It is not clear, however, without further evaluation, whether the long-term net result would be to increase or decrease the availability of early successional vegetation. The resultant long-term effects of these riparian habitat changes on moose and other wildlife are also unclear.

7.15.5.3 Social Science Implications. The implications of load following on cultural, socioeconomic, recreation, aesthetic, and land use resources cannot be accurately determined until additional hydrologic and hydraulic studies are conducted and until the results of those studies are factored into an analysis of load following impacts on aquatic and terrestrial resources.

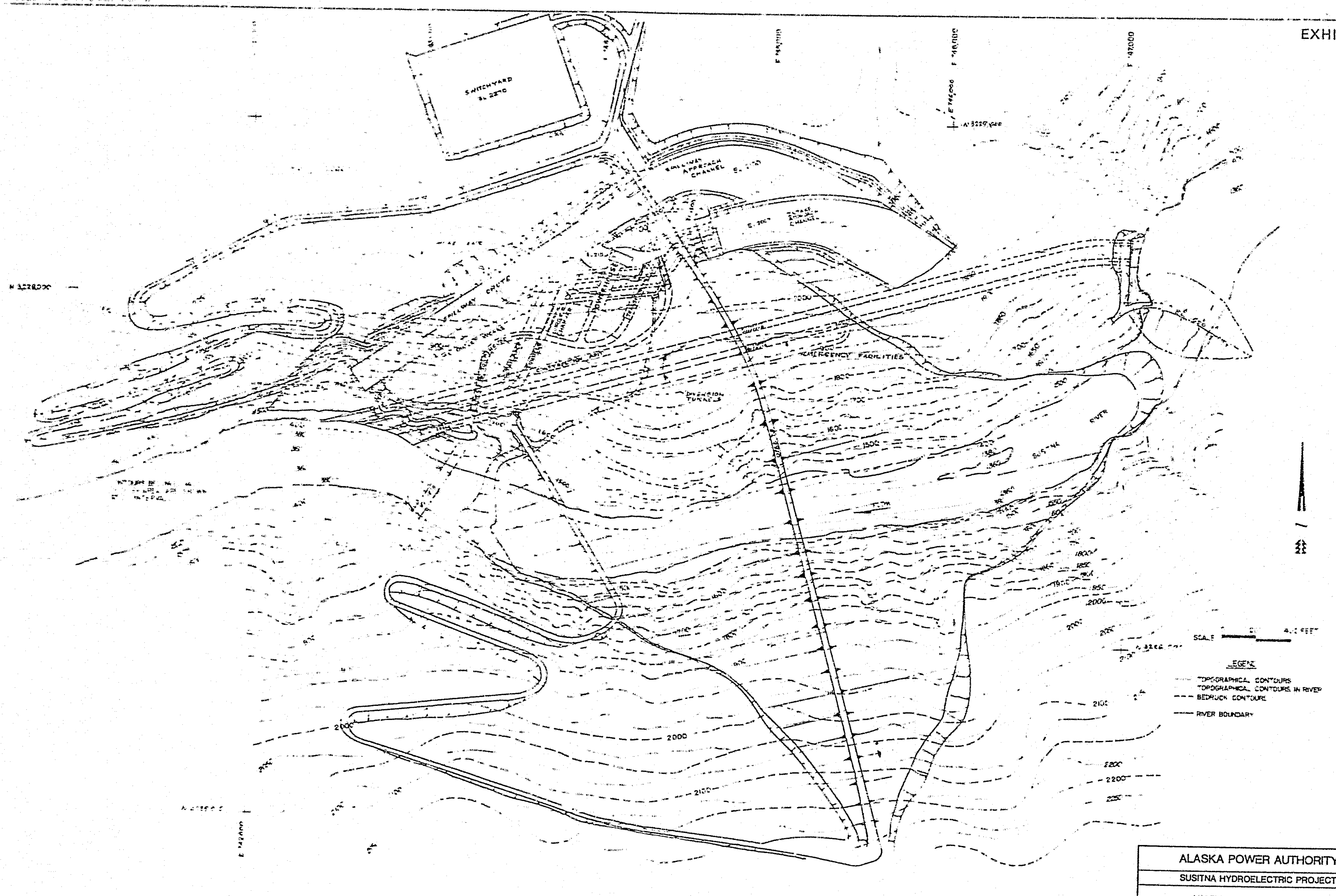
In general, based on available information, it is anticipated that load following may decrease bank stability, thereby increasing bank erosion. If this occurs, additional archeological and/or historic sites could be eliminated. In addition, increased erosion and fluctuations of the river level could potentially reduce the aesthetic quality of affected areas. Furthermore, individuals and businesses relying on fish and wildlife resources for flood, recreation, cultural, and/or commercial activities (including hunters, trappers, guides, and lodge owners) could be negatively affected if load following reduces the magnitude of available fish and wildlife resources in the project area and if load following makes navigation of the river (by boat during ice-free months and by snowmobile during the winter) more difficult or hazardous. Moreover, if load following increases the likelihood of ice jams and flooding downstream, the chances of economic losses due to flooding would increase.

EXHIBIT 7.1

SUSITNA PROJECT
WATANA 2185 COST ESTIMATES (Category 1)
FOUR AND SIX UNIT POWERPLANTS
(Millions of Dollars)

ITEM	4-UNIT POWERPLANT	6-UNIT POWERPLANT
Land and Land Rights	51	51
Powerhouse	57	72
Reservoir Clearings	54	54
Diversion Tunnels	111	111
U/S Cofferdam	17	17
D/S Cofferdam	3	3
Main Dam	773	752
Relict Channel or Saddle Dam	110	110
Outlet Facilities	36	36
Main Spillway	118	113
Emergency Spillway	---	---
Power Intake	55	72
Surge Chamber	8	12
Penstocks	23	31
Tailrace	14	16
Waterwheels, Turbines & Generators	53	79
Accessory Electrical Equipment	14	21
Misc. Power Plant Equipment	12	14
Roads, Rail & Air Facilities	214	214
Transmission Plant	405	405
General Plant	5	5
Construction Facilities	317	325
Mitigation	29	29
SUBTOTAL	2482	2543
Contingency Allowance (15%)	367	382
Total Construction Cost	2849	2925
Engineering & Administration (12.5%)	352	366
Total Cost - Jan '82 Price Levels	3201	3291
Escalation to Jan '83 (4.3%)	137	141
Total Cost - Jan '83 Price Levels	3338	3432

EXHIBIT 7.2



WATANA DAMSITE

ALASKA POWER AUTHORITY

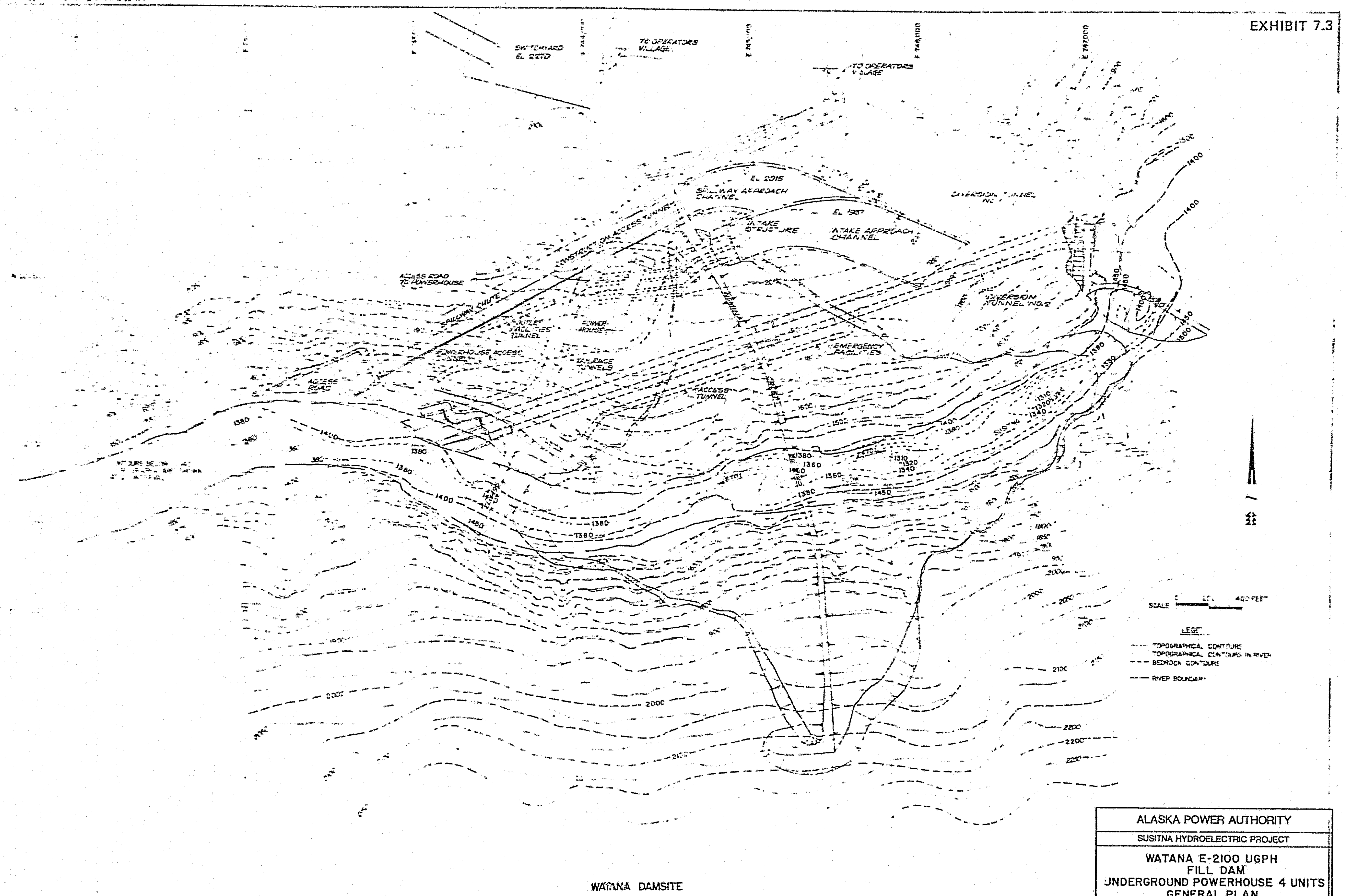
SUSITNA HYDROELECTRIC PROJECT

WATANA A-2185 UGPH
FILL DAM
UNDERGROUND POWERHOUSE 4 UNITS
GENERAL PLAN

HARZA-EBASCO SUSITNA JOINT VENTURE	APPROVED		
ANCHORAGE, ALASKA	DATE	CONTRACT NUMBER	DRAWING NUMBER WA SKC 403603

00467

EXHIBIT 7.3



ALASKA POWER AUTHORITY

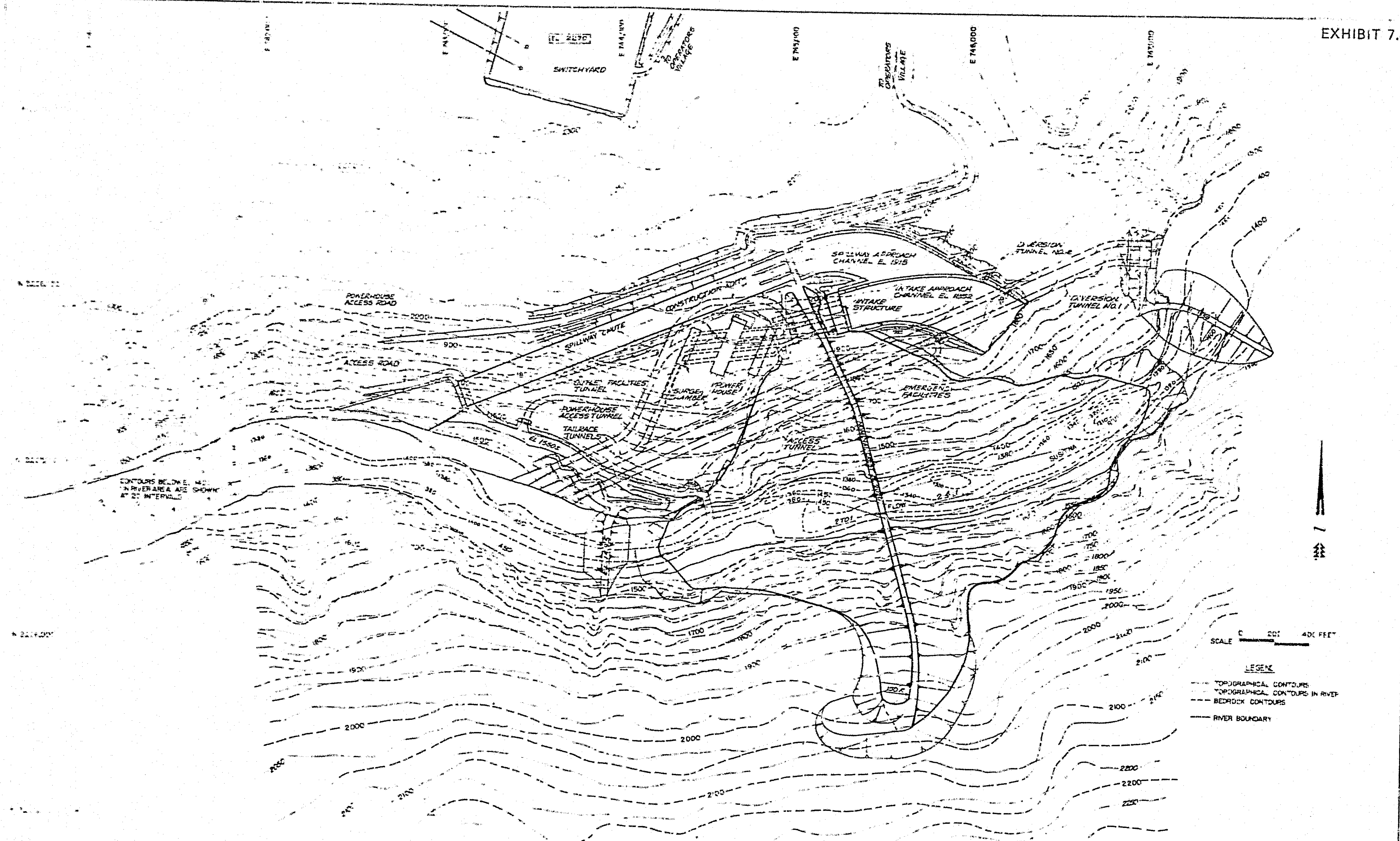
SUSITNA HYDROELECTRIC PROJECT

WATANA E-2100 UGPH
FILL DAM
UNDERGROUND POWERHOUSE 4 UNITS
GENERAL PLAN

HARZA-EBASCO
SUSITNA JOINT VENTURE
ANCHORAGE, ALASKA

APPROVED		
DATE	CONTRACT NUMBER	DRAWING NUMBER
		WA SKC 403608

EXHIBIT 7.4



WATANA DAMSITE

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

WATANA C-2000 UGPH
FILL DAM
UNDERGROUND POWERHOUSE 4 UNITS
GENERAL PLAN

HARZA-EBASCO SUSITNA JOINT VENTURE ANCHORAGE, ALASKA

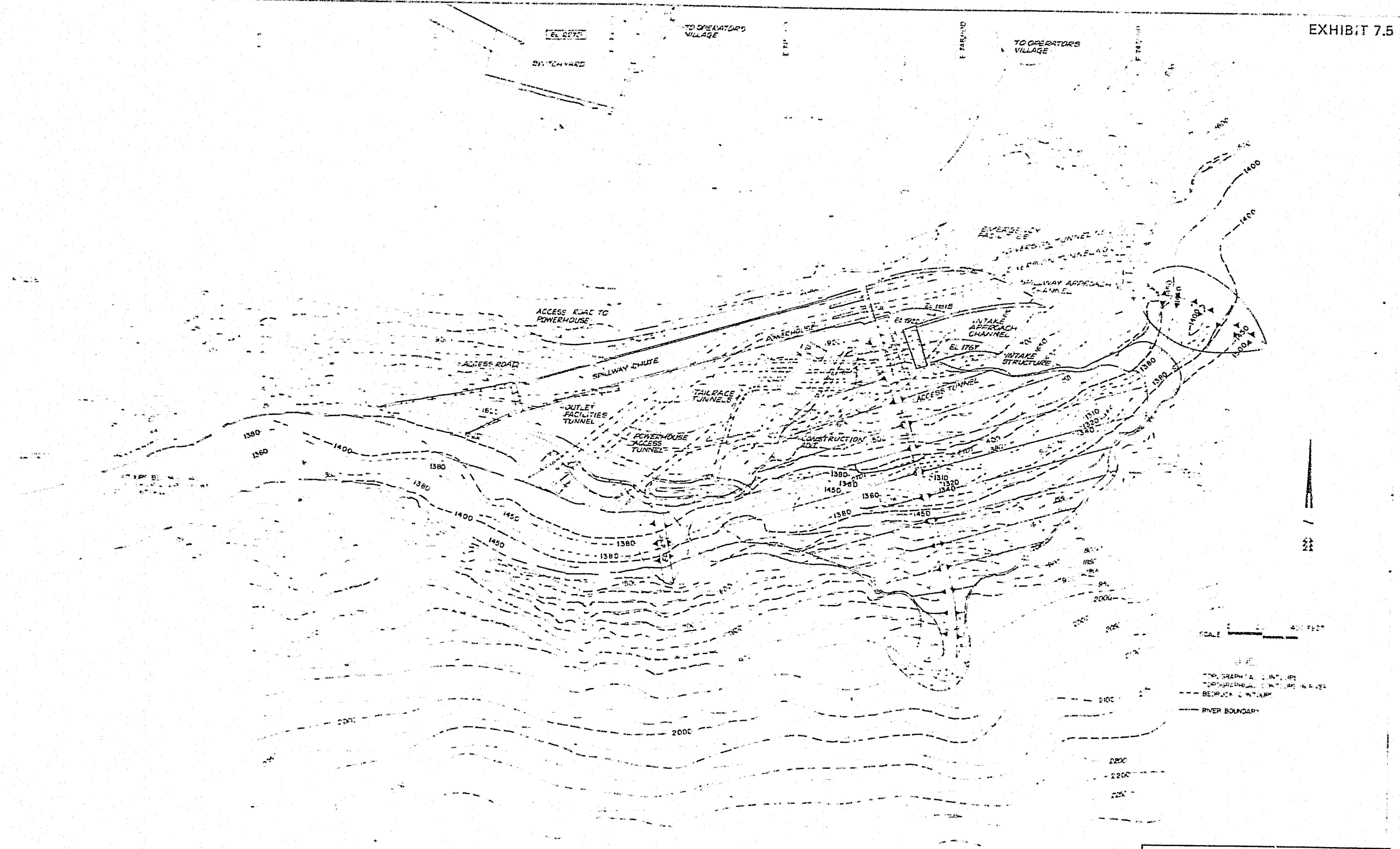
APPROVED

DATE

CONTRACT NUMBER

DRAWING NUMBER WA SKC 403604

EXHIBIT 7.5



WATANA DAMSITE

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

WATANA D-1900 UGPH
FILL DAM
UNDERGROUND POWERHOUSE 4 UNITS
GENERAL PLAN

HARZA-EBASCO

ANCHORAGE, ALASKA

DRAWING NUMBER WA SKC 403607

SUSITNA PROJECT
WATANA 2100 COST ESTIMATE
(Millions of Dollars)

ITEM	COST
Land and Land Rights	51
Powerhouse	57
Reservoir Clearings	41
Diversion Tunnels	104
U/S Cofferdam	17
D/S Cofferdam	3
Main Dam	549
Relict Channel or Saddle Dam	110
Outlet Facilities	36
Main Spillway	129
Emergency Spillway	---
Power Intake	76
Surge Chamber	8
Penstocks	21
Tailrace	13
Waterwheels, Turbines & Generators	49
Accessory Electrical Equipment	14
Misc. Power Plant Equipment	12
Roads, Rail & Air Facilities	214
Transmission Plant	405
General Plant	5
Construction Facilities	272
Mitigation	29
SUBTOTAL	2215
Contingency Allowance (15%)	335
Total Construction Cost	2550
Engineering & Administration (12.5%)	321
Total Cost - Jan '82 Price Levels	2871
Escalation to Jan '83 (4.3%)	124
Total Cost - Jan '83 Price Levels	2996

SUSITNA PROJECT
WATANA 2000 COST ESTIMATE
(Millions of Dollars)

ITEM	COST
Land and Land Rights	51
Powerhouse	55
Reservoir Clearings	30
Diversion Tunnels	100
U/S Cofferdam	17
D/S Cofferdam	3
Main Dam	353
Relict Channel or Saddle Dam	110
Outlet Facilities	35
Main Spillway	128
Emergency Spillway	---
Power Intake	61
Surge Chamber	8
Penstocks	20
Tailrace	12
Waterwheels, Turbines & Generators	43
Accessory Electrical Equipment	13
Misc. Power Plant Equipment	12
Roads, Rail & Air Facilities	214
Transmission Plant	405
General Plant	5
Construction Facilities	243
Mitigation	29
SUBTOTAL	1948
Contingency Allowance (15%)	296
Total Construction Cost	2244
Engineering & Administration (12.5%)	284
Total Cost - Jan '82 Price Levels	2528
Escalation to Jan '83 (4.3%)	109
Total Cost - Jan '83 Price Levels	2637

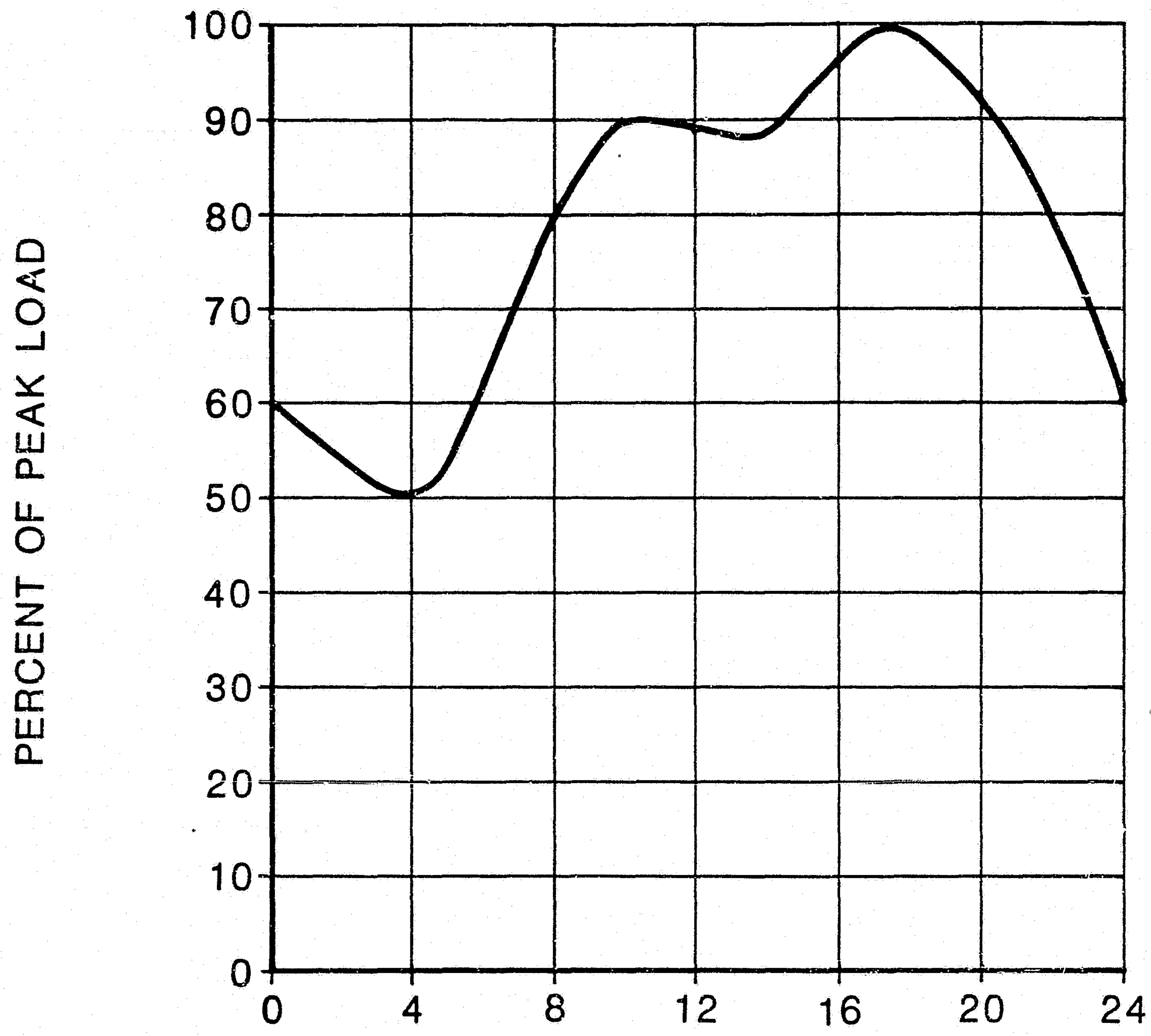
SUSITNA PROJECT
WATANA 1900 COST ESTIMATE
(Millions of Dollars)

ITEM	COST
Land and Land Rights	51
Powerhouse	52
Reservoir Clearings	21
Diversion Tunnels	102
U/S Cofferdam	17
D/S Cofferdam	3
Main Dam	238
Relict Channel or Saddle Dam	110
Outlet Facilities	35
Main Spillway	130
Emergency Spillway	---
Power Intake	51
Surge Chamber	7
Penstocks	19
Tailrace	10
Waterwheels, Turbines & Generators	38
Accessory Electrical Equipment	13
Misc. Power Plant Equipment	12
Roads, Rail & Air Facilities	214
Transmission Plant	405
General Plant	5
Construction Facilities	215
Mitigation	29
SUBTOTAL	1778
Contingency Allowance (15%)	275
Total Construction Cost	2053
Engineering & Administration (12.5%)	262
Total Cost - Jan '82 Price Levels	2315
Escalation to Jan '83 (4.3%)	99
Total Cost - Jan '83 Price Levels	2414

SUSITNA PROJECT COST ESTIMATE
DEVIL CANYON PRECEDING WATANA ALTERNATIVES
(Million Dollars)

	Devil Canyon	Watana Alternatives			
Reservoir Elev.	1,445	2,185	2,100	2,000	1,900
TOTAL CONSTRUCTION COSTS - Jan. 1983 Prices	1,891	2,644	2,311	1,987	1,763

EXHIBIT 7.9



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE
TYPICAL DECEMBER WEEKDAY
HOURLY LOAD VARIATION
SEPTEMBER 1983

POWER AND ENERGY PRODUCTION
WATANA 2185
(Load Following Operation)
DOR Mean Forecast
Year 2020 Demand Level

MONTH	WATANA ALONE			DEVIL CANYON			WATANA AFTER DEVIL CANYON		
	Capa-bility(a) (MW)	Average Energy (GWh)	Reliability Energy (GWh)	Capa-bility(a) (MW)	Average Energy (GWh)	Reliability Energy (GWh)	Capa-bility(a) (MW)	Average Energy (GWh)	Reliability Energy (GWh)
Jan	699	345	290	667	334	239	700	366	247
Feb	676	286	225	667	303	215	674	323	219
Mar	655	264	182	668	299	213	649	310	212
Apr	634	243	158	665	273	273	625	263	104
May	630	228	139	663	267	188	621	211	95
Jun	664	188	60	665	255	201	656	180	180
Jul	714	216	82	669	239	200	708	179	133
Aug	747	345	314	654	238	219	747	262	180
Sep	765	283	274	642	257	257	766	249	249
Oct	766	301	191	655	250	203	765	343	308
Nov	749	398	287	667	308	224	749	348	236
Dec	724	400	362	667	359	256	726	402	269

(a) Corresponds to four unit capability and is based on monthly net head and turbine efficiency.

EXHIBIT 7.11

POWER AND ENERGY PRODUCTION
WATANA 2000
(Load Following Operation)
DOR Mean Forecast
Year 2020 Demand Level

MONTH	WATANA ALONE			DEVIL CANYON			WATANA AFTER DEVIL CANYON		
	Capa-bility(a) (MW)	Average Energy (GWh)	Reliability Energy (GWh)	Capa-bility(a) (MW)	Average Energy (GWh)	Reliability Energy (GWh)	Capa-bility(a) (MW)	Average Energy (GWh)	Reliability Energy (GWh)
Jan	470	167	163	669	261	229	457	197	167
Feb	444	127	112	669	214	210	423	153	144
Mar	420	124	111	669	208	208	391	139	114
Apr	395	114	103	664	198	198	363	112	20
May	388	189	91	659	286	180	360	151	151
Jun	426	261	55	663	296	190	416	158	158
Jul	490	263	202	667	284	186	498	185	70
Aug	534	309	251	661	276	228	544	236	198
Sep	555	272	209	657	282	269	560	236	143
Oct	553	202	123	663	267	189	553	236	236
Nov	533	211	164	668	281	210	528	232	171
Dec	501	231	230	668	291	243	494	232	189

(a) Corresponds to four unit capability and is based on monthly net head and turbine efficiency.

EXHIBIT 7.12

SUSITNA ALTERNATIVES

Single Project	Installed Capacity (a) Initial (MW)	Installed Capacity (a) Ultimate (MW)	Energy Production Average (b) (GWh)	Energy Production Reliability (GWh)	Cost Construction (c) ($Million)	Cost Investment (d) ($Million)
Watana 2185	724	1088	3500	2265	3338	3785
Watana 2100	613	920	3005	2240	2996	3397
Watana 2000	501	748	2470	1815	2637	2948
Watana 1900	406	609	1880	1505	2414	2699
Devil Canyon	501	501	2260	2005	1554	1762
Combined Project						
Watana 2185 + Devil Canyon	1398	1752	6820	5120	4892	5547
Watana 2100 + Devil Canyon	1274	1572	6240	4900	4550	5159
Watana 2000 + Devil Canyon	1162	1410	5410	4300	4191	4710
Watana 1900 + Devil Canyon	1066	1269	4650	3835	3968	4461

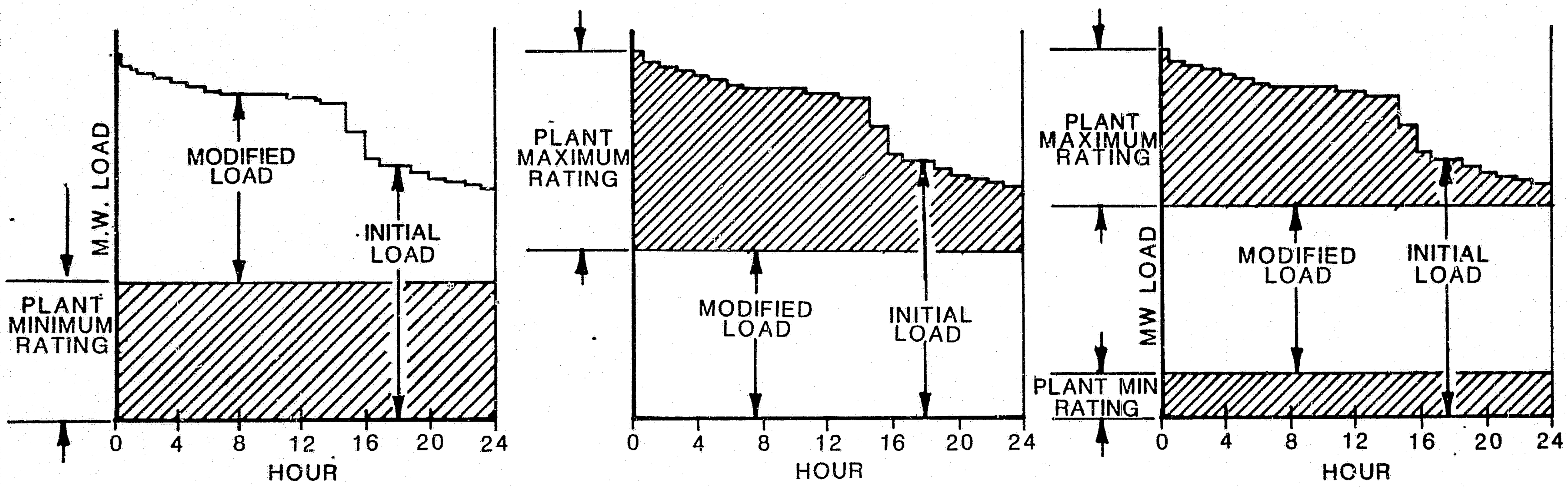
(a) Average plant capability in megawatts for December

(b) Based on 4-unit powerstation, with system demand constraints

(c) January 1983 price level

(d) Includes interest during construction at 3.5 percent interest; no real escalation of construction cost was included.

EXHIBIT 7.13



BASE LOADING

LOAD FOLLOWING

COMBINED BASE LOADING AND LOAD FOLLOWING

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

CONVENTIONAL HYDRO SCHEDULING WITH OGP MODEL

SEPTEMBER 1983

EXHIBIT 7.14

EXPANSION PLAN YEARLY MW ADDITIONS
DOR MEAN LOAD FORECAST
NON-SUSITNA ALTERNATIVES

			OPTIMUM NON-SUSITNA				COAL ONLY			CHAKACHAMNA				
YR	POOL PEAK (MW)	TOTAL ENERGY (GWh)	COAL (MW)	COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	TOTAL (a) CAPABILITY (MW)	COAL (MW)	COMBUSTION TURBINE (MW)	TOTAL (a) CAPABILITY (MW)	COAL (MW)	COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	HYDRO (MW)	TOTAL (a) CAPABILITY (MW)
93	867	4167			474	1369	400		1295		84	237	195	1411
94	882	4237				1369			1295		84			1495
95	896	4306		84		1382		84	1308					1424
96	913	4387		84		1378		84	1304		168			1504
97	929	4467		84		1396		84	1322		84			1522
98	946	4548				1370			1296					1496
99	963	4629		84		1454		84	1380					1496
0	979	4709				1453			1379		84			1579
1	1001	4813				1453			1379					1579
2	1022	4916		168		1479		168	1405		168			1605
3	1043	5019				1479			1405					1605
4	1064	5122		84		1563		84	1489					1605
5	1086	5225				1542			1468			237		1821
6	1115	5369	200			1742	200		1669					1821
7	1145	5513				1742			1669					1821
8	1175	5657				1742			1669					1821
9	1205	5801				1742			1669					1821
10	1234	5954				1742			1669					1821
11	1263	6085	200			1797	200		1724	200				1876
12	1292	6229	200			1820		168	1714	400				2099
13	1323	6376				1820			1714					2015
14	1354	6526				1820	200		1914		84			2015
15	1358	6680		168		1891			1817					2002
16	1418	6837		84		1891		84	1817		252			2086
17	1451	6999	200			2007		168	1901		84			2086
18	1485	7164				2007			1901					2086
19	1520	7333		84		2007		84	1901		84			2170
20	1555	7505		84		2091	200		2101		84			2170

(a) Includes existing generation plant less retirement.

EXHIBIT 7.15

EXPANSION PLAN YEARLY MW ADDITIONS
DOR MEAN LOAD FORECAST
SUSITNA ALTERNATIVES

YR	POOL PEAK (MW)	TOTAL ENERGY (GWh)	WATANA 2185 + DEVIL CANYON BASE LOADING: COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	SUSITNA (MW)	TOTAL (a) CAPABILITY (MW)	WATANA 2100 + DEVIL CANYON BASE LOADING: COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	SUSITNA (MW)	TOTAL (a) CAPABILITY (MW)	WATANA 2000 + DEVIL CANYON BASE LOADING: COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	SUSITNA (MW)	TOTAL (a) CAPABILITY (MW)
93	867	4167			539	1433			459	1353			311	1205
94	882	4237				1432				1352				1205
95	896	4306				1362				1282	84			1218
96	913	4387	84			1358	84			1278	84			1214
97	929	4467				1292	84			1296		237		1385
98	946	4548	84			1350	84			1354				1359
99	963	4629				1350				1354				1359
0	979	4709				1349				1353	84			1442
1	1001	4813	84			1433				1353				1442
2	1022	4916	84			1375		474		1685	168			1468
3	1043	5019	84			1459				1685			585	2053
4	1064	5122				1459				1685				2053
5	1086	5225				1438			608	2272				2032
6	1115	5369			632	2070				2272				2032
7	1145	5513				2070				2272				2032
8	1175	5657				2070				2272				2032
9	1205	5801				2070				2272				2032
10	1234	5954				2070				2272				2032
11	1263	6085				1952			36	2163				1876
12	1292	6229			38	1785				1985				1698
13	1323	6376				1785				1985	84			1782
14	1354	6526				1785				1985				1782
15	1358	6680				1772				1972	84			1769
16	1418	6837	84			1772	84			1972	84			1769
17	1451	6999	84			1856	84			1972		237		2006
18	1485	7164	84			1856	84			1972				2006
19	1520	7333				1856	84			2056				2006
20	1555	7505	84			1940				2056	84			2006
2020 MW			588	0	1209	1940	336	474	1103	2056	504	474	896	2006

(a) Includes existing generation plant less retirements.

EXHIBIT 7.16

EXPANSION PLAN YEARLY MW ADDITIONS
DOR MEAN LOAD FORECAST
SUSITNA ALTERNATIVES

			WATANA 2185 + DEVIL CANYON LOAD FOLLOWING			WATANA 2100 + DEVIL CANYON LOAD FOLLOWING				WATANA 2000 + DEVIL CANYON LOAD FOLLOWING			
YR	POOL PEAK (MW)	TOTAL ENERGY (GWh)	COMBUSTION TURBINE (MW)	SUSITNA (MW)	TOTAL (a) CAPABILITY (MW)	COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	SUSITNA (MW)	TOTAL (a) CAPABILITY (MW)	COMBUSTION TURBINE (MW)	COMBINED CYCLE (MW)	SUSITNA (MW)	TOTAL (a) CAPABILITY (MW)
93	867	4167		724	1618			613	1507			501	1335
94	882	4237			1617				1506				1394
95	896	4306			1547				1436				1324
96	913	4387			1459				1348				1236
97	929	4467			1393				1282	84			1254
98	946	4548			1367				1256	84			1312
99	963	4629			1367				1256				1312
0	979	4709			1366	84			1339				1311
1	1001	4813			1366				1339				1311
2	1022	4916	168		1392		237		1434		237		1406
3	1043	5019			1392				1434			666	2072
4	1064	5122			1392				1434				2072
5	1086	5225	84		1455			677	2090				2051
6	1115	5369		685	2140				2090				2051
7	1145	5513			2140				2090				2051
8	1175	5657			2140				2090				2051
9	1205	5801			2240				2090				2051
10	1234	5945			2140				2090				2051
11	1263	6085			1995				1929				1901
12	1292	6229			1801				1751				1723
13	1323	6376			1801				1751				1723
14	1354	6526			1801	84			1835	84			1807
15	1385	6680	84		1872				1822	84			1878
16	1418	6837			1872	84			1906				1878
17	1451	6999	84		1956				1906		237		2031
18	1485	7164			1956	84			1990				1947
19	1520	7333	84		2040				1990	84			2031
20	1555	7505			2040	168			2074				2031

(a) Includes existing generation plant less retirements.

EXHIBIT 7.17

YEAR 2020 RAILBELT SYSTEM GENERATION MIX
DOR MEAN LOAD FORECAST

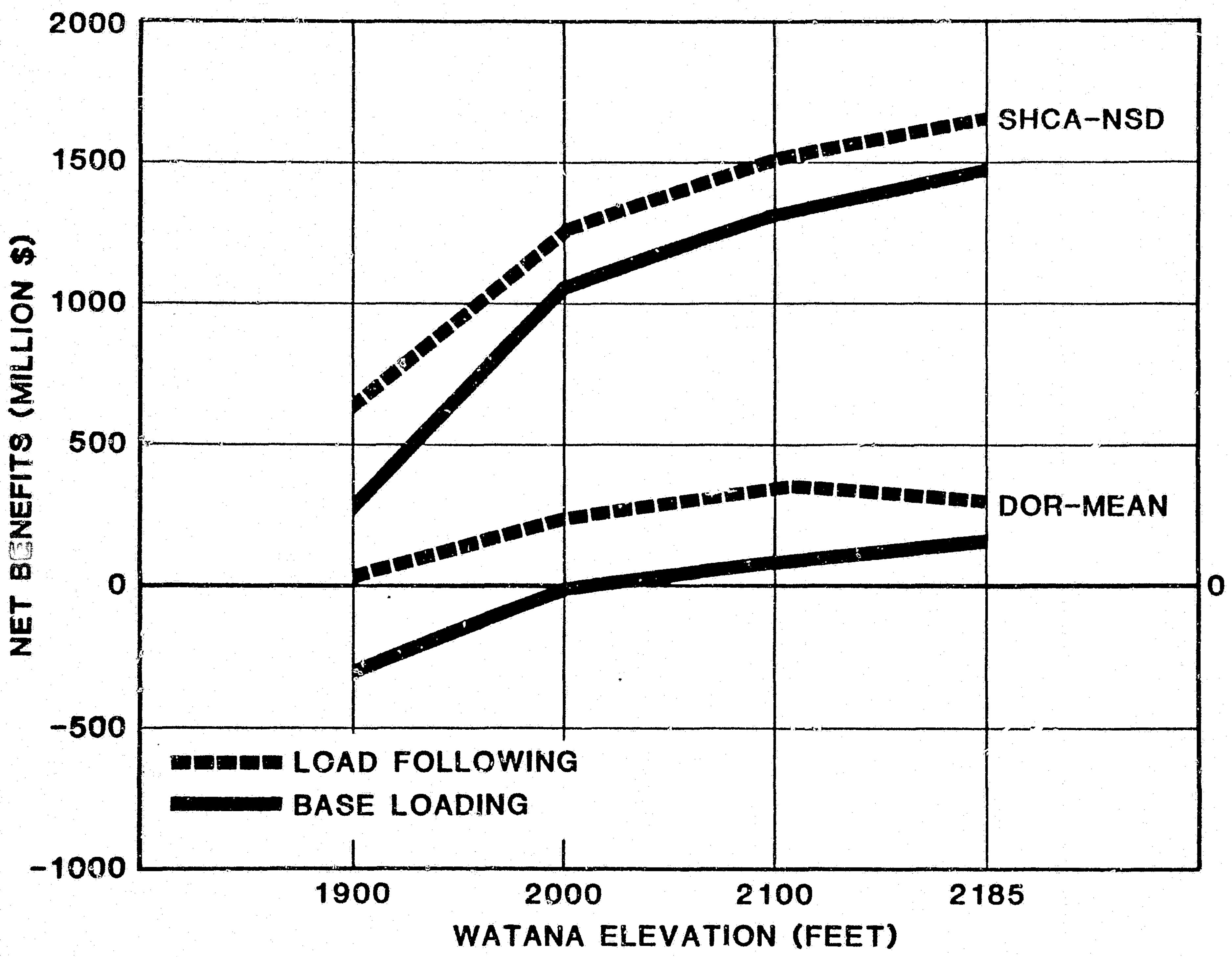
	NON-SUSITNA				SUSITNA - Base Loading				SUSITNA - Load Following			
	Gas/Coal	Gas Only	Coal Only	Chakachamna	Watana 2185	Watana 2100	Watana 2000	Watana 1900	Watana 2185	Watana 2100	Watana 2000	Watana 1900
OGP ID	LUN1	LUF5	LNN5	LUE3	LYX9	LS59	LS61	LL73	LK19	LK21	LØ19	LQM3
Capacity-MW												
Coal	800	0	1200	600	0	0	0	0	0	0	0	0
CT	672	756	756	756	588	336	504	504	504	420	252	168
CCCT	474	1185	0	474	0	474	474	711	0	237	474	711
Hydro	143	143	143	143	143	143	143	143	143	143	143	143
Susitna	0	0	0	0	1209	1103	885	701	1393	1274	1162	1061
Chakachamna	0	0	0	195	0	0	0	0	0	0	0	0
Total	2089	2084	2099	2168	1940	2056	2006	2059	2040	2074	2031	2083
2020 Reliability												
Peak Demand	1555	1555	1555	1555	1555	1555	1555	1555	1555	1555	1555	1555
% Reserve	34.5	34.1	35.1	39.5	24.8	32.2	29.0	32.4	31.2	33.4	30.6	34.0
LOLP -D/Y	0.082	0.183	0.053	0.160	0.036	0.160	0.121	0.086	-	-	-	-
Total Economic Cost												
1993 $/MWh	30.84	30.84	38.34	37.72	49.15	46.75	45.55	47.08	47.49	45.40	43.20	45.26
2010 $/MWh	46.78	47.82	46.89	48.60	45.25	45.90	44.58	46.20	44.10	42.66	42.83	43.85
2020 $/MWh	50.33	56.02	50.98	51.83	40.55	41.01	42.90	46.40	40.08	39.95	41.28	43.49
Million Dollars												
2020 Cost	377.7	420.4	382.6	389.0	304.3	307.8	322.0	348.2	300.8	299.8	309.8	326.4
Cum 2020 P.W.	2844	2929	3077	3128	3142	3167	3159	3295	3011	2964	2996	3111
Cum 2050 P.W.	4890	5446	5070	5227	4744	4797	4892	5191	4593	4552	4664	4888

EXHIBIT 7.18

YEAR 2020 RAILBELT SYSTEM GENERATION MIX
SHCA-NSD LOAD FORECAST

	NON-SUSITNA				SUSITNA - Base Loading				SUSITNA - Load Following			
	Gas/Coal	Gas Only	Coal Only	Chakachamna	Watana 2185	Watana 2100	Watana 2000	Watana 1900	Watana 2185	Watana 2100	Watana 2000	Watana 1900
OGP ID	LN61	LRA9	LMM9	LOG9	LL79	LKB1	LLA5	LLB3	L1W9	LK31	LK27	L1W3
Capacity - MW												
Coal	1400	0	1400	1200	0	200	200	400	0	0	400	400
CT	420	756	672	84	588	588	336	420	504	504	168	336
CCCT	474	1422	0	711	237	237	711	711	237	474	474	474
Hydro	143	143	143	143	143	143	143	143	143	143	143	143
Susitna	0	0	0	0	1223	1095	885	701	1387	1273	1162	1061
Chakachamna	0	0	0	195	0	0	0	0	0	0	0	0
Total	2437	2321	2215	2333	2191	2263	2275	2375	227[illegible]	2394	2347	2414
2020 Reliability												
Peak Demand	1724	1724	1724	1724	1724	1724	1724	1724	1724	1724	1724	1751
% Reserve	41.5	34.7	28.6	35.4	27.1	31.3	32.0	37.8	46.3	38.9	36.1	40.0
LOLP - D/Y	0.025	0.124	0.077	0.082	0.085	0.019	0.085	0.025	-	-	-	-
Total Economic Cost												
1993 $/MWh	35.48	35.46	40.18	38.64	48.53	47.60	47.56	49.06	46.10	45.53	44.26	47.67
2010 $/MWh	59.95	72.90	55.06	52.23	40.69	42.91	44.27	51.58	39.65	38.95	42.69	46.67
2020 $/MWh	63.65	91.01	61.72	59.05	43.83	46.43	49.69	57.35	43.23	45.38	47.32	53.56
Million Dollars												
2020 Cost	529.0	756.5	513.0	516.6	364.3	385.9	413.0	476.7	359.3	377.2	393.3	445.2
Cum 2020 P.W.	3878.1	4448	3931	3844	3373	3422	3518	3949	3240	3253	3354	3784
Cum 2050 P.W.	6795.0	8945	6758	6666	5225	5484	5754	6528	5164	5292	5453	6187

EXHIBIT 7.19



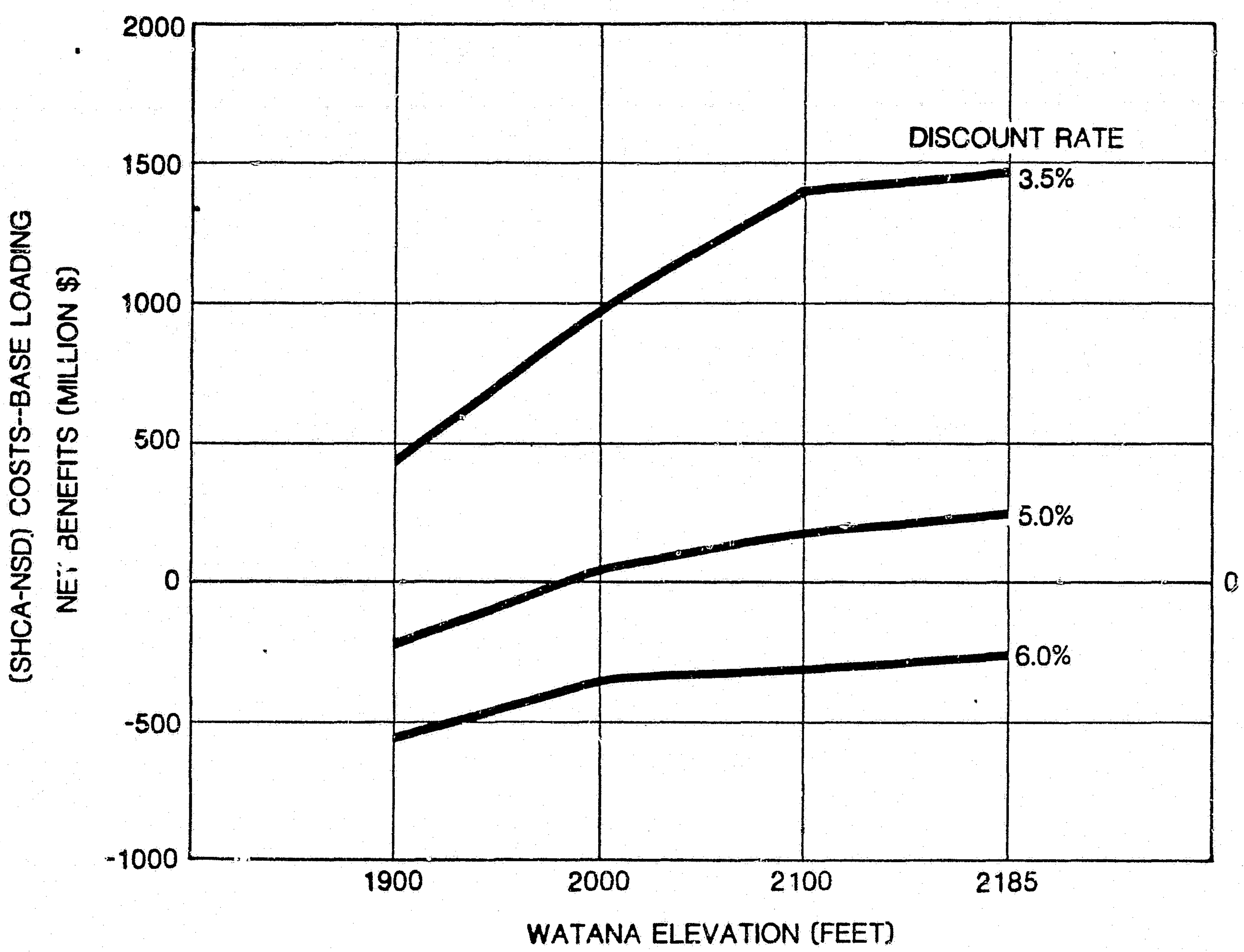
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

PRESENT WORTH ANALYSIS

SEPTEMBER 1983

EXHIBIT 7.20

EXHIBIT 7.21

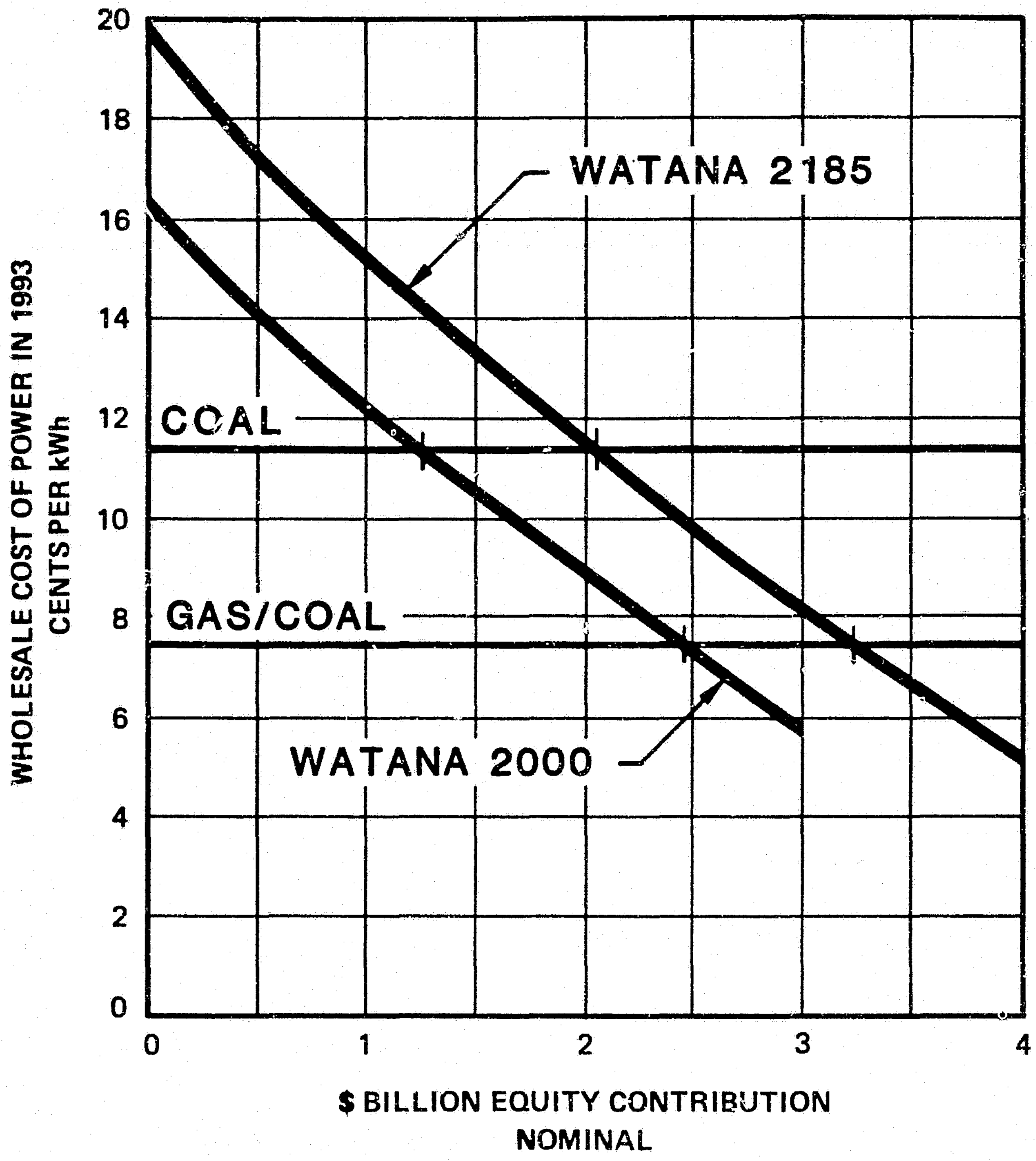


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

RATE OF RETURN ANALYSIS

SEPTEMBER 1983

EXHIBIT 7.22

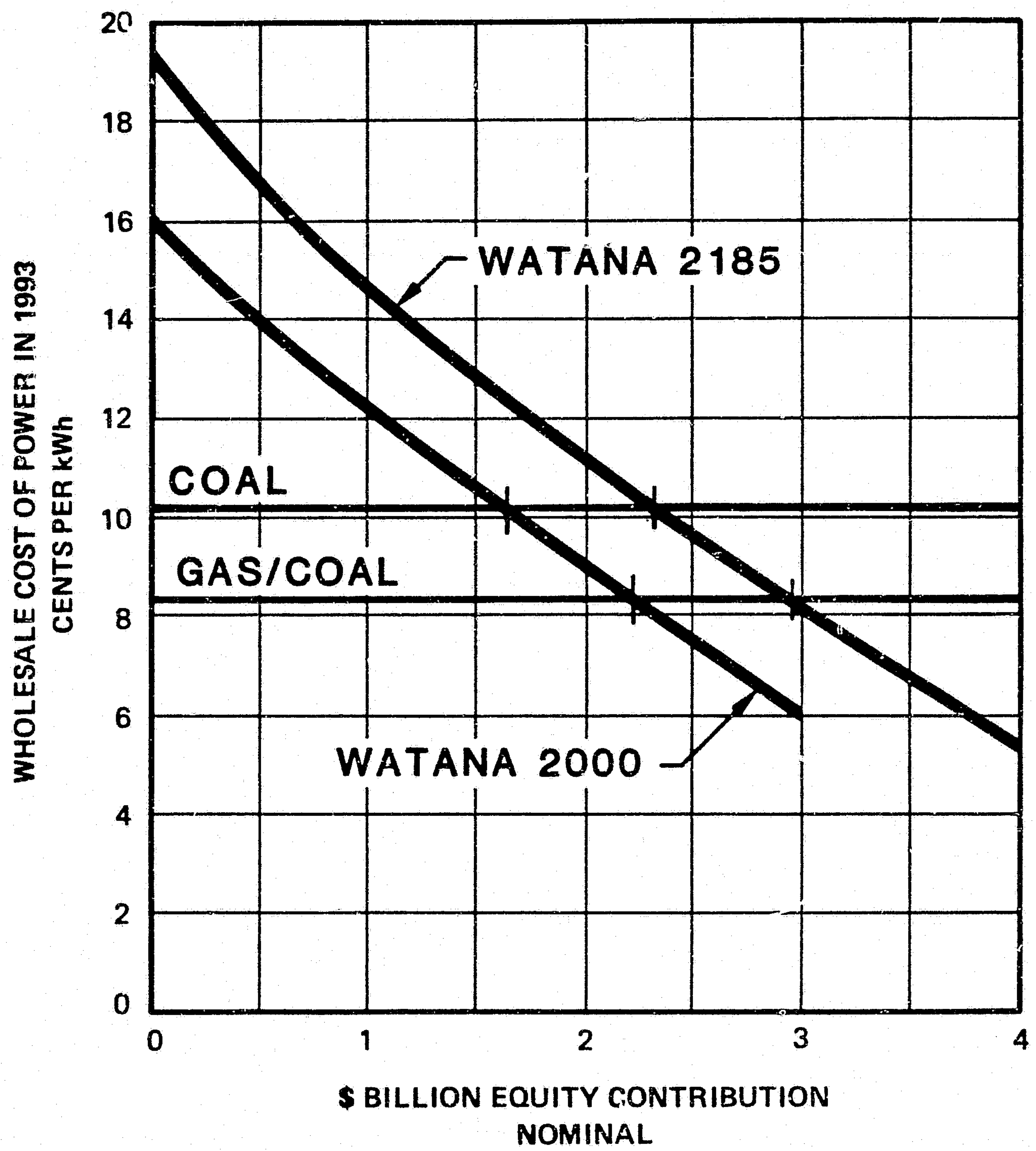


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

1993 WHOLESALE COST OF POWER VS. STATE EQUITY CONTRIBUTION DOR MEAN CASE

SEPTEMBER 1983

EXHIBIT 7.23

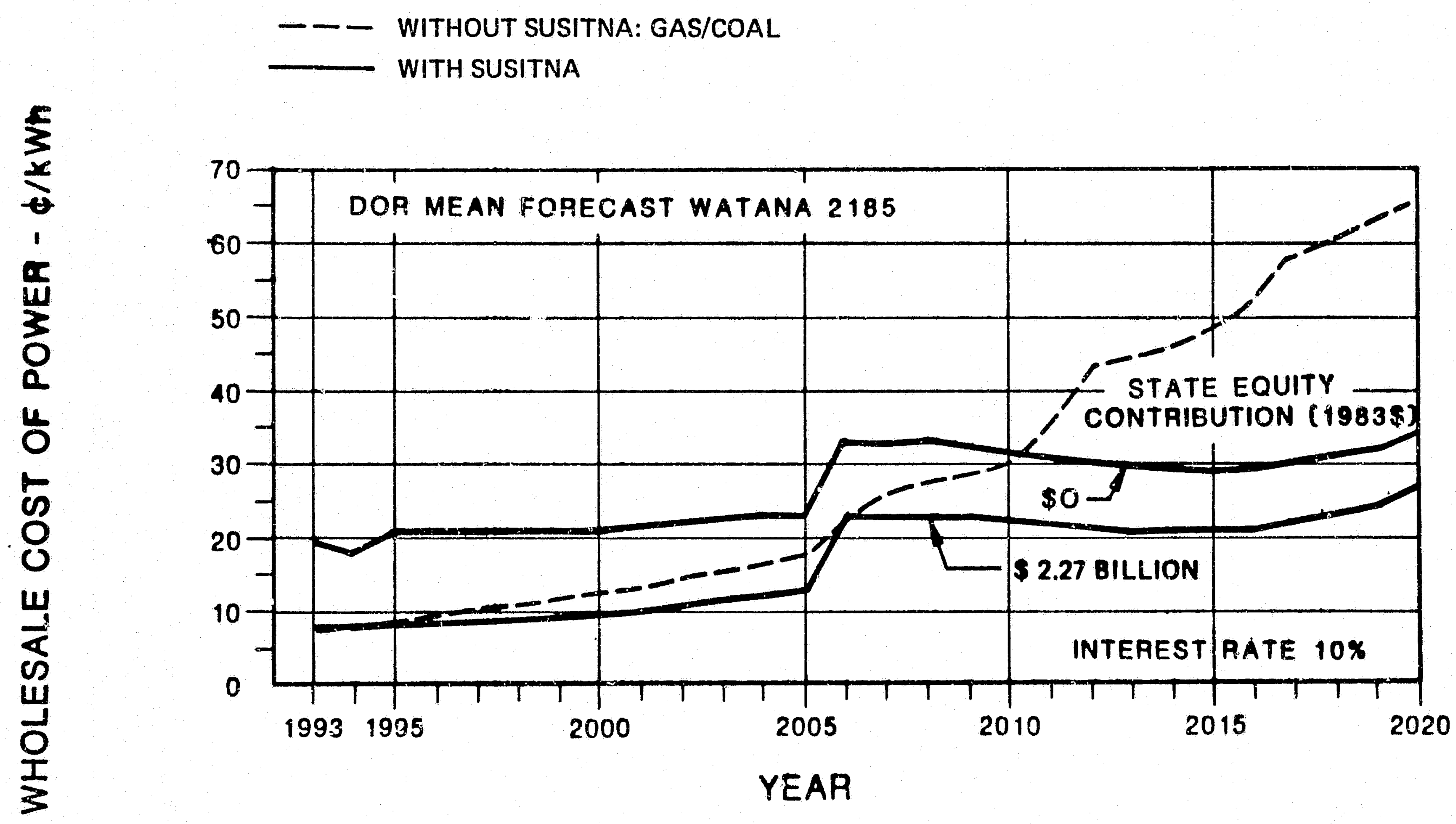


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

1993 WHOLESALE COST OF POWER VS. STATE EQUITY CONTRIBUTION SHCA-NSD CASE

SEPTEMBER 1983

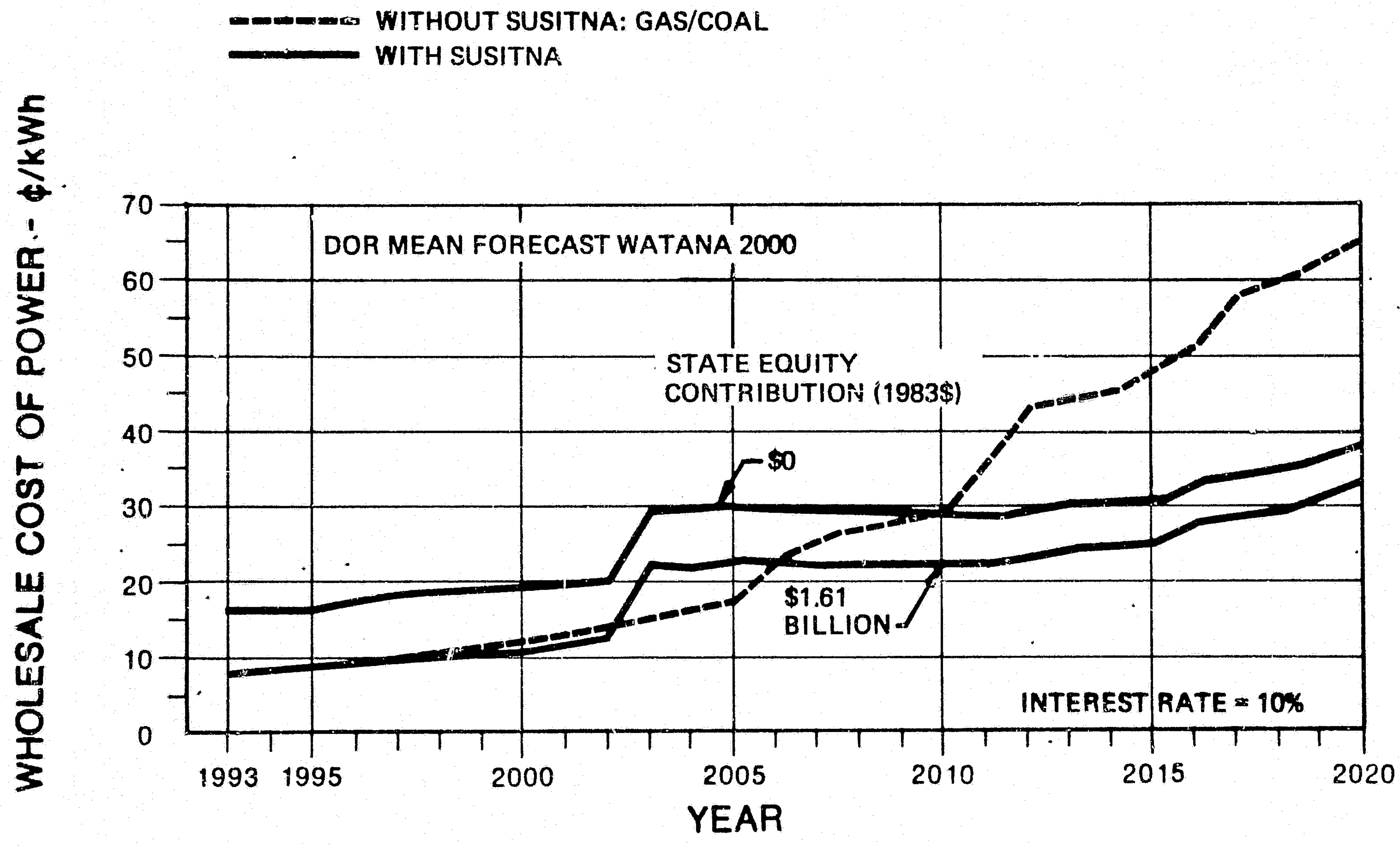


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER
(WATANA 2185)

SEPTEMBER 1983

EXHIBIT 7.24



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER FOR WATANA 2000

SEPTEMBER 1983

EXHIBIT 7.25

2185 Level
3.280 Equity @10% COD 2006

ANNUAL COSTS IN MILLION $

Year	Total Energy (GWH)	Energy Less Losses	OGP INVESTMENT	OGP SUSITNA COST	Debt Service WATANA	LESS: EARNINGS	Debt Service DEVIL'S CANYON	LESS: EARNINGS	Final Debt Service	Capital Renewals	OGP Fuel	OGP Oper. & Main.	TOTAL	Cost per KWH (C/KWH)
1993	4166.90	4041.89	724.00	724.00	241.37	29.97			211.40	18.72	44.70	34.00	308.82	7.64
1994	4237.00	4109.89	724.00	724.00	241.37	29.97			211.40	19.94	48.60	36.30	316.24	7.69
1995	4306.00	4176.82	724.00	724.00	256.04	29.97			226.07	21.23	54.40	38.40	340.10	8.14
1996	4387.00	4255.39	735.60	724.00	256.04	29.97			237.67	25.54	60.90	41.00	365.11	8.58
1997	4466.90	4332.89	735.60	724.00	256.04	29.97			237.67	27.20	67.80	40.80	373.47	8.62
1998	4547.90	4411.46	748.80	724.00	256.04	29.97			250.87	32.28	76.10	44.10	403.35	9.14
1999	4629.20	4490.32	748.80	724.00	256.04	29.97			250.87	34.38	90.10	47.40	422.75	9.41
2000	4709.00	4567.73	748.80	724.00	256.04	29.97			250.87	36.61	101.50	50.80	439.78	9.63
2001	4813.00	4668.61	764.80	724.00	256.04	29.97			266.87	43.00	116.40	55.30	481.57	10.31
2002	4915.90	4768.42	781.80	724.00	256.04	29.97			283.87	50.06	131.60	57.90	523.43	10.98
2003	5019.10	4868.53	799.90	724.00	256.04	29.97			301.97	57.85	149.90	63.10	572.82	11.77
2004	5122.00	4968.34	799.90	724.00	256.04	29.97			301.97	61.61	170.80	67.80	602.18	12.12
2005	5224.80	5068.06	799.90	724.00	256.04	29.97			301.97	65.62	194.40	71.90	633.89	12.51
2006	5369.00	5207.93	1564.10	1488.20	256.04	29.97	818.77	93.66	1027.08	87.31	0.00	74.00	1188.39	22.82
2007	5513.00	5347.61	1564.10	1488.20	256.04	29.97	832.17	93.66	1040.48	92.99	0.00	78.80	1212.27	22.67
2008	5657.00	5487.29	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	99.03	0.00	83.90	1274.00	23.22
2009	5801.00	5626.97	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	105.47	0.00	89.30	1285.84	22.85
2010	5945.00	5766.65	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	112.32	0.00	83.50	1286.89	22.32
2011	6085.00	5902.45	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	119.62	0.00	83.00	1293.69	21.92
2012	6229.00	6042.13	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	119.39	0.00	80.50	1290.96	21.37
2013	6376.00	6184.72	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	135.68	0.00	85.70	1312.45	21.22
2014	6526.00	6330.22	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	144.50	16.70	92.30	1344.57	21.24
2015	6680.00	6479.60	1564.10	1488.20	256.04	29.97	882.76	93.66	1091.07	153.89	16.70	96.60	1358.26	20.96
2016	6837.10	6631.99	1593.50	1488.20	256.04	29.97	882.76	93.66	1120.47	174.20	35.10	103.90	1433.67	21.62
2017	6999.00	6789.03	1637.30	1488.20	256.04	29.97	882.76	93.66	1164.27	196.49	58.70	113.80	1533.26	22.58
2018	7163.90	6948.98	1670.70	1488.20	256.04	29.97	882.76	93.66	1197.67	220.94	103.60	123.60	1645.81	23.68
2019	7333.00	7113.01	1670.70	1488.20	256.04	29.97	882.76	93.66	1197.67	235.30	177.50	135.70	1746.17	24.55
2020	7504.90	7279.75	1723.50	1488.20	256.04	29.97	882.76	93.66	1250.47	263.85	294.60	153.10	1962.02	26.95

$ 3.28 BILLION STATE EQUITY CONTRIBUTION IN NOMINAL DOLLARS.
ALL COSTS IN NOMINAL DOLLARS.

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER FOR WATANA 2185 DOR MEAN (WITH $3.28 BILLION STATE EQUITY CONTRIBUTION)

SEPTEMBER 1983

EXHIBIT 7.26

					2185 Level 0 Equity	@10%	COD 2006		ANNUAL COSTS IN MILLION $					
Year	Total Energy (GWH)	Energy Loss Losses	OGP INVESTMENT	OGP SUSITNA COST	Debt Service WATANA	LESS: EARNINGS	Debt Service DEVIL'S CANYON	LESS: EARNINGS	Final Debt Service	Capital Renewals	OGP Fuel	OGP Oper. & Main.	TOTAL	Cost per KWH (C/KWH)
1993	4166.90	4041.89	724.00	724.00	799.83	90.69			709.14	18.72	44.70	34.00	806.56	19.96
1994	4237.00	4109.89	724.00	724.00	799.83	90.69			709.14	19.94	48.60	36.30	813.98	19.81
1995	4306.00	4176.82	724.00	724.00	848.45	90.69			757.76	21.23	54.40	38.40	871.79	20.87
1996	4387.00	4255.39	735.60	724.00	848.45	90.69			769.36	25.54	60.90	41.00	896.80	21.07
1997	4466.90	4332.89	735.60	724.00	848.45	90.69			769.36	27.20	67.80	40.80	905.16	20.89
1998	4547.90	4411.46	748.80	724.00	848.45	90.69			782.56	32.28	76.10	44.10	935.04	21.20
1999	4629.20	4490.32	748.80	724.00	848.45	90.69			782.56	34.38	90.10	47.40	954.44	21.26
2000	4709.00	4567.73	748.80	724.00	848.45	90.69			782.56	36.61	101.50	50.80	971.47	21.27
2001	4813.00	4668.61	764.80	724.00	848.45	90.69			798.56	43.00	116.40	55.30	1013.26	21.70
2002	4915.90	4768.42	731.80	724.00	848.45	90.69			815.56	50.06	131.60	57.90	1055.12	22.13
2003	5019.10	4868.53	799.90	724.00	848.45	90.69			833.66	57.85	149.90	63.10	1104.51	22.69
2004	5122.00	4968.34	799.90	724.00	848.45	90.69			833.66	61.61	170.80	67.80	1133.87	22.82
2005	5224.80	5068.06	799.90	724.00	848.45	90.69			833.66	65.62	194.40	71.90	1165.58	23.00
2006	5369.00	5207.93	1564.10	1488.20	848.45	90.69	818.77	93.66	1558.77	87.31	0.00	74.00	1720.08	33.03
2007	5513.00	5347.61	1564.10	1488.20	848.45	90.69	832.17	93.66	1572.17	92.99	0.00	78.80	1743.96	32.61
2008	5657.00	5487.29	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	99.03	0.00	83.90	1805.69	32.91
2009	5801.00	5626.97	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	105.47	0.00	89.30	1817.53	32.30
2010	5945.00	5766.65	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	112.32	0.00	83.50	1818.58	31.54
2011	6065.00	5902.45	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	119.62	0.00	83.00	1825.38	30.93
2012	6229.00	6042.13	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	119.39	0.00	80.50	1822.65	30.17
2013	6376.00	6184.72	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	135.68	0.00	85.70	1844.14	29.82
2014	6526.00	6330.22	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	144.50	16.70	92.30	1876.26	29.64
2015	6680.00	6479.60	1564.10	1488.20	848.45	90.69	882.76	93.66	1622.76	153.89	16.70	96.60	1889.95	29.17
2016	6837.10	6631.99	1593.50	1488.20	848.45	90.69	882.76	93.66	1652.16	174.20	35.10	103.90	1965.36	29.63
2017	6999.00	6789.03	1637.30	1488.20	848.45	90.69	882.76	93.66	1695.96	196.49	58.70	113.80	2064.95	30.42
2018	7163.90	6948.98	1670.70	1488.20	848.45	90.69	882.76	93.66	1729.36	220.94	103.60	123.60	2177.50	31.34
2019	7333.00	7113.01	1670.70	1488.20	848.45	90.69	882.76	93.66	1729.36	235.30	177.50	135.70	2277.86	32.02
2020	7504.90	7279.75	1723.50	1488.20	848.45	90.69	882.76	93.66	1782.16	263.85	294.60	153.10	2493.71	34.26

ALL COSTS IN NOMINAL DOLLARS.

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER FOR WATANA 2185 DOR MEAN (WITH ONE HUNDRED PERCENT REVENUE BOND FINANCING)

SEPTEMBER 1983

2000 Level
2.35B Equity @10% COD 2003

ANNUAL COSTS IN MILLION $

Year	Total Energy (GWH)	Energy Less Losses	OGP INVESTMENT	OGP SUSITNA COST	Debt Service WATANA	LESS: EARNINGS	Debt Service DEVIL'S CANYON	LESS: EARNINGS	Final Debt Service	Capital Renewals	OGP Fuel	OGP Oper. & Main.	TOTAL	Cost per KWH (C/KWH)
1993	4167.10	4042.09	563.90	563.90	224.02	28.47			195.55	14.44	63.50	36.20	309.69	7.66
1994	4236.90	4109.79	563.90	563.90	232.03	28.47			203.56	15.38	72.70	38.90	330.54	8.04
1995	4305.90	4176.72	563.90	563.90	246.14	28.47			217.67	16.38	84.00	41.00	359.05	8.60
1996	4387.00	4255.39	575.50	563.90	246.14	28.47			229.27	20.37	92.40	44.00	386.04	9.07
1997	4467.00	4332.99	587.90	563.90	246.14	28.47			241.67	24.80	106.30	44.90	417.67	9.64
1998	4547.90	4411.46	587.90	563.90	246.14	28.47			241.67	26.42	124.00	48.20	440.29	9.98
1999	4629.00	4490.13	587.90	563.90	246.14	28.47			241.67	31.66	137.70	51.60	462.63	10.30
2000	4709.00	4567.73	602.90	563.90	246.14	28.47			256.67	33.72	153.60	56.10	500.09	10.95
2001	4813.00	4668.61	602.90	563.90	246.14	28.47			256.67	35.91	179.60	60.60	532.78	11.41
2002	4916.00	4768.52	656.20	563.90	246.14	28.47			309.97	52.97	182.60	66.90	612.44	12.84
2003	5019.00	4868.43	1288.90	1196.60	246.14	28.47	678.84	77.51	911.30	70.83	21.90	68.00	1072.03	22.02
2004	5122.00	4968.34	1288.90	1196.60	246.14	28.47	688.69	77.51	921.15	75.44	23.90	72.50	1092.99	22.00
2005	5225.00	5068.25	1288.90	1196.60	246.14	28.47	730.56	77.51	963.02	80.34	40.80	76.50	1160.66	22.90
2006	5369.00	5207.93	1288.90	1196.60	246.14	28.47	730.56	77.51	963.02	85.57	44.90	81.50	1174.99	22.56
2007	5513.00	5347.61	1288.90	1196.60	246.14	28.47	730.56	77.51	963.02	91.13	54.10	77.50	1185.75	22.17
2008	5657.00	5487.29	1288.90	1196.60	246.14	28.47	730.56	77.51	963.02	97.05	80.60	63.60	1224.27	22.31
2009	5801.00	5626.97	1288.90	1196.60	246.14	28.47	730.56	77.51	963.02	103.36	88.20	89.10	1243.68	22.10
2010	5945.00	5766.65	1288.90	1196.60	246.14	28.47	730.56	77.51	963.02	110.08	110.30	95.70	1279.10	22.18
2011	6005.00	5824.85	1288.90	1196.60	246.14	28.47	730.56	77.51	963.02	117.23	130.10	96.90	1307.25	22.44
2012	6229.00	6042.13	1320.80	1196.60	246.14	28.47	730.56	77.51	994.92	132.86	168.20	99.40	1395.38	23.09
2013	6376.00	6184.72	1354.80	1196.60	246.14	28.47	730.56	77.51	1028.92	150.02	214.00	109.30	1502.24	24.29
2014	6526.10	6330.32	1354.80	1196.60	246.14	28.47	730.56	77.51	1028.92	159.77	250.40	117.90	1556.99	24.60
2015	6680.10	6479.70	1354.80	1196.60	246.14	28.47	730.56	77.51	1028.92	170.16	297.90	126.80	1623.78	25.06
2016	6836.90	6631.79	1471.70	1196.60	246.14	28.47	730.56	77.51	1145.82	216.76	321.90	144.20	1828.68	27.57
2017	6999.20	6789.22	1503.00	1196.60	246.14	28.47	730.56	77.51	1177.12	241.82	370.50	155.20	1944.64	28.64
2018	7163.90	6948.90	1503.00	1196.60	246.14	28.47	730.56	77.51	1177.12	257.54	446.00	167.90	2048.56	29.48
2019	7332.90	7112.91	1552.60	1196.60	246.14	28.47	730.56	77.51	1226.72	286.72	518.40	183.30	2215.14	31.14
2020	7505.00	7279.85	1590.50	1196.60	246.14	28.47	730.56	77.51	1264.62	318.61	623.70	199.00	2405.93	33.05

$ 2.35 BILLION STATE EQUITY CONTRIBUTION IN NOMINAL DOLLARS.
ALL COSTS IN NOMINAL DOLLARS.

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER FOR WATANA 2000 DOR MEAN (WITH $2.35 BILLION STATE EQUITY CONTRIBUTION)

SEPTEMBER 1983

EXHIBIT 7.27
Page 1 of 2

					2000 Level 0 Equity	@10%	COD 2003		ANNUAL COSTS IN MILLION $					
											OGP			
Year	Total Energy (GWH)	Energy Less Losses	OGP INVESTMENT	OGP SUSITNA COST	Debt Service WATANA	LESS: EARNINGS	Debt Service DEVIL'S CANYON	LESS: EARNINGS	Final Debt Service	Capital Renewals	Fuel	Oper. & Main.	TOTAL	Cost per KWH (C/KWH)
1993	4167.10	4042.09	563.90	563.90	614.08	71.10			542.98	14.44	63.50	36.20	657.12	16.26
1994	4236.90	4109.79	563.90	563.90	624.13	71.10			553.03	15.38	72.70	38.90	680.01	16.55
1995	4305.90	4176.72	563.90	563.90	662.07	71.10			590.97	16.38	84.00	41.00	732.35	17.53
1996	4387.00	4255.39	575.50	563.90	662.07	71.10			602.57	20.37	92.40	44.00	759.34	17.84
1997	4467.00	4332.99	587.90	563.90	662.07	71.10			614.97	24.80	106.30	44.90	790.97	18.25
1998	4547.90	4411.46	587.[illegible]	563.90	662.07	71.10			614.97	26.42	124.00	48.20	813.59	18.44
1999	4629.00	4490.13	5[illegible]7.90	563.90	662.07	71.10			614.97	31.66	137.70	51.60	835.93	18.62
2000	4709.00	4567.73	602.90	563.90	662.07	71.10			629.97	33.72	153.60	56.10	873.39	19.12
2001	4813.00	4668.61	602.90	563.90	662.07	71.10			629.97	35.91	179.60	60.60	906.08	19.41
2002	4916.00	4768.52	656.20	563.90	662.07	71.10			683.27	52.97	182.60	66.90	985.74	20.67
2003	5019.00	4868.43	1288.90	1196.60	662.07	71.10	678.84	77.51	1284.60	70.83	21.90	68.00	1445.33	29.69
2004	5122.00	4968.34	1288.90	1196.60	662.07	71.10	688.69	77.51	1294.45	75.44	23.90	72.50	1466.29	29.51
2005	5225.00	5068.25	1288.90	1196.60	662.07	71.10	730.56	77.51	1336.32	80.34	40.80	76.50	1533.96	30.27
2006	5369.00	5207.93	1288.90	1196.60	662.07	71.10	730.56	77.51	1336.32	85.57	44.90	81.50	1548.29	29.73
2007	5513.00	5347.61	1288.90	1196.60	662.07	71.10	730.56	77.51	1336.32	91.13	54.10	77.50	1559.05	29.15
2008	5657.00	5487.29	1288.90	1196.60	662.07	71.10	730.56	77.51	1336.32	97.05	80.60	83.60	1597.57	29.11
2009	5801.00	5626.97	1288.90	1196.60	662.07	71.10	730.56	77.51	1336.32	103.36	88.20	89.10	1616.98	28.74
2010	5945.00	5766.65	1288.90	1196.60	662.07	71.10	730.56	77.51	1336.32	110.08	110.30	95.70	1652.40	28.65
2011	6005.00	5824.85	1288.90	1196.60	662.07	71.10	730.56	77.51	1336.32	117.23	130.10	96.90	1680.55	28.85
2012	6229.00	6042.13	1320.80	1196.60	662.07	71.10	730.56	77.51	1368.22	132.86	168.20	99.40	1768.68	29.27
2013	6376.00	6184.72	1354.80	1196.60	662.07	71.10	730.56	77.51	1402.22	150.02	214.00	109.30	1875.54	30.33
2014	6526.10	6330.32	1354.80	1196.60	662.07	71.10	730.56	77.51	1402.22	159.77	250.40	117.90	1930.29	30.49
2015	6680.10	6479.70	1354.80	1196.60	662.07	71.10	730.56	77.51	1402.22	170.16	297.90	126.80	1997.08	30.82
2016	6836.90	6631.79	1471.70	1196.60	662.07	71.10	730.56	77.51	1519.12	216.76	321.90	144.20	2201.98	33.20
2017	6999.20	6789.22	1503.00	1196.60	662.07	71.10	730.56	77.51	1550.42	241.82	370.50	155.20	2317.94	34.14
2018	7163.90	6948.98	1503.00	1196.60	662.07	71.10	730.56	77.51	1550.42	257.54	446.00	167.90	2421.86	34.85
2019	7332.90	7112.91	1552.60	1196.60	662.07	71.10	730.56	77.51	1600.02	286.72	518.40	183.30	2588.44	36.39
2020	7505.00	7279.85	1590.50	1196.60	662.07	71.10	730.56	77.51	1637.92	318.61	623.70	199.00	2779.23	38.18

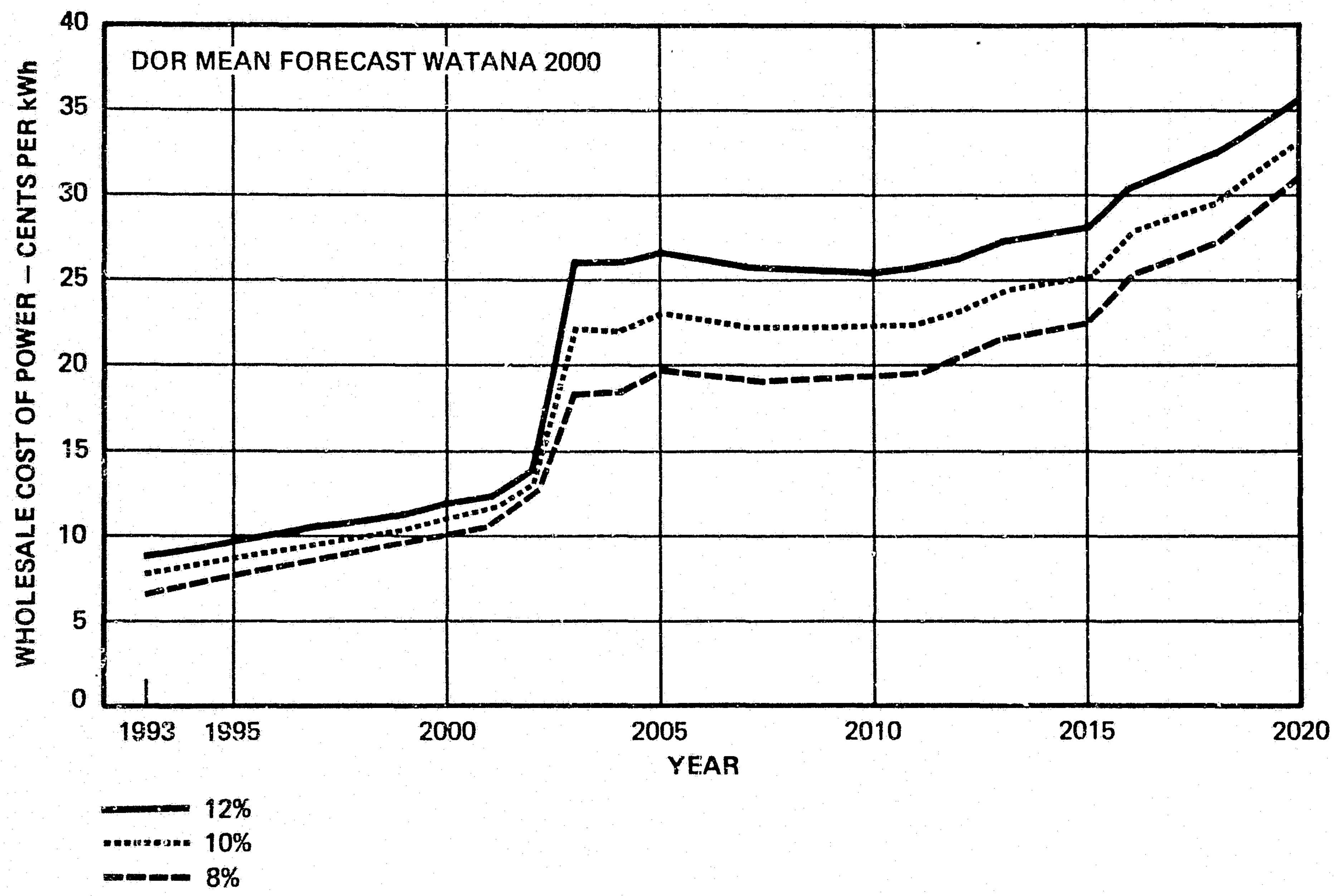
ALL COSTS IN NOMINAL DOLLARS.

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WHOLESALE COST OF POWER FOR WATANA 2000 DOR MEAN (WITH ONE HUNDRED PERCENT REVENUE BOND FINANCING)

SEPTEMBER 1983

EXHIBIT 7.27

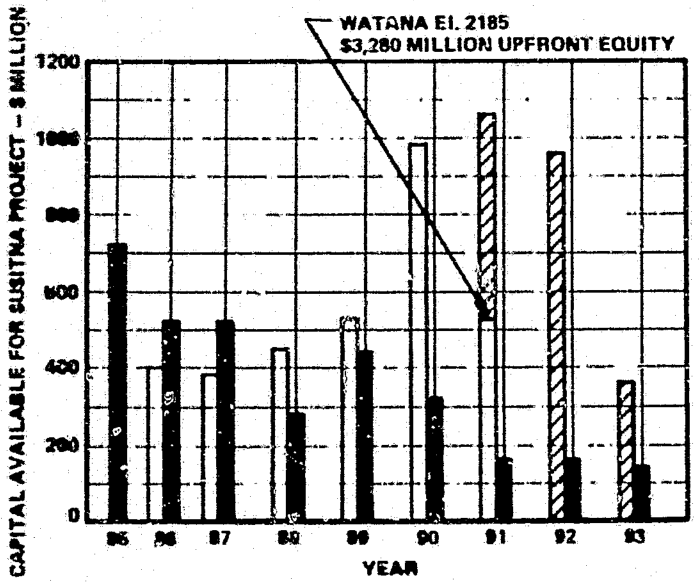


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

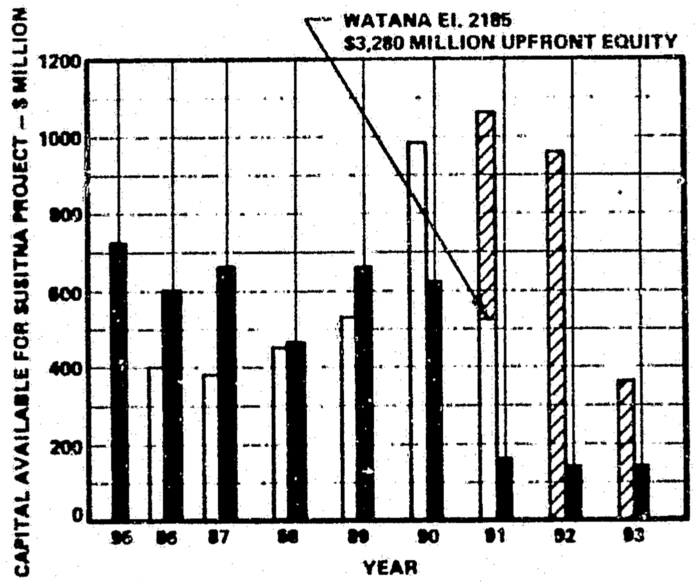
EFFECT OF INTEREST RATE
ON WHOLESALE COST OF POWER

SEPTEMBER 1983

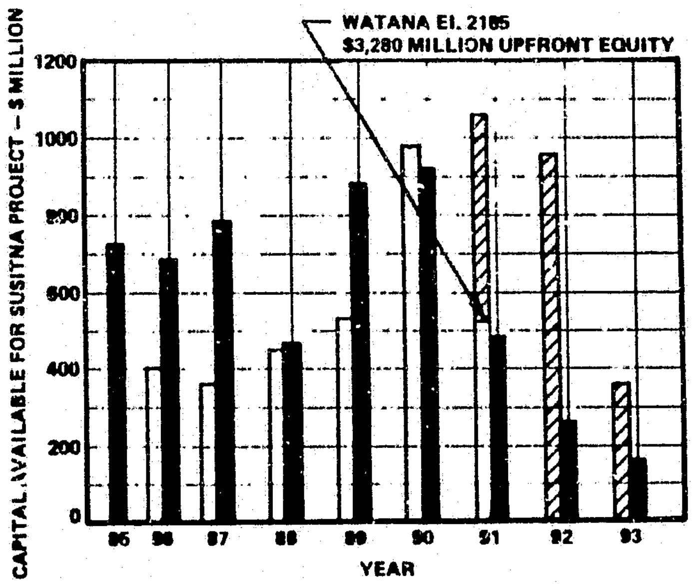
EXHIBIT 7.28



REAL RATE OF GROWTH
OF OPERATING BUDGET +2%



REAL RATE OF GROWTH
OF OPERATING BUDGET 0%



REAL RATE OF GROWTH
OF OPERATING BUDGET −2%

LEGEND

- (solid bar) SAGE MODEL – SPECIAL CAPITAL AVAILABLE
- (open bar) WATANA El. 2185 ESTIMATED CONSTRUCTION EXPENDITURES MET BY EQUITY
- (hatched bar) WATANA El. 2185 ESTIMATED CONSTRUCTION EXPENDITURES MET BY REVENUE BONDS

NOTE.

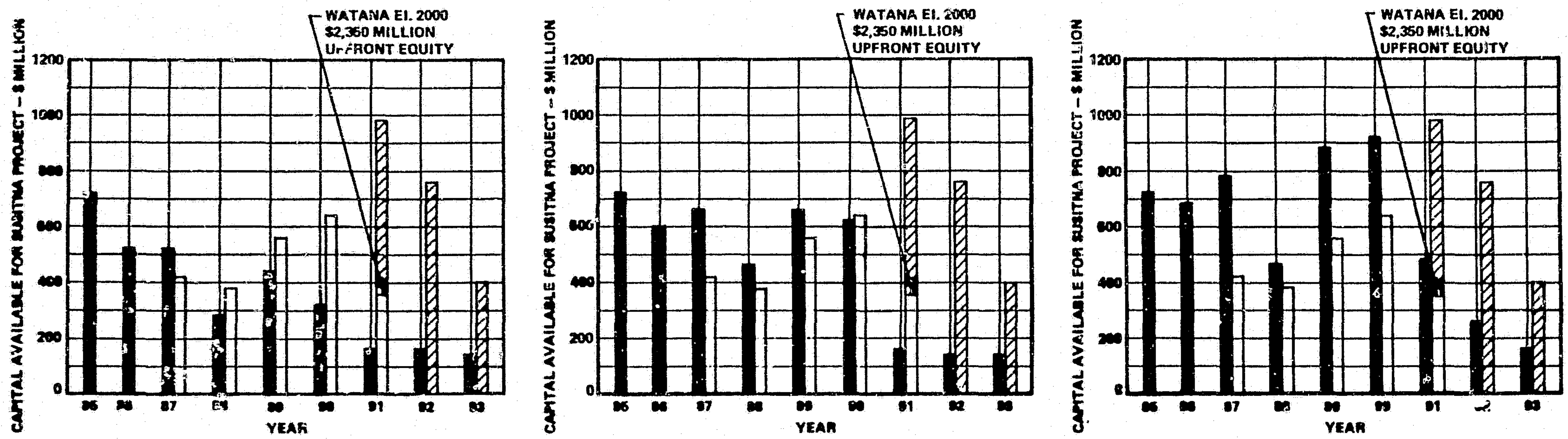
UPFRONT EQUITY SHOWN IS THE MAXIMUM. UNDER THE COAL EXPANSION PLAN THE UPFRONT EQUITY CONTRIBUTION WOULD BE LOWER.

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

SAGE MODEL
SPECIAL CAPITAL AVAILABILITY

SEPTEMBER 1983

EXHIBIT 7.29
Page 1 of 2



REAL RATE OF GROWTH OF OPERATING BUDGET +2%

REAL RATE OF GROWTH OF OPERATING BUDGET 0%

REAL RATE OF GROWTH OF OPERATING BUDGET -2%

LEGEND:

- SAGE MODEL – SPECIAL CAPITAL AVAILABLE
- WATANA El. 2000 ESTIMATED CONSTRUCTION EXPENDITURES MET BY EQUITY
- WATANA El. 2000 ESTIMATED CONSTRUCTION EXPENDITURES MET BY REVENUE BONDS

NOTE:

UPFRONT EQUITY SHOWN IS THE MAXIMUM. UNDER THE COAL EXPANSION PLAN THE UPFRONT EQUITY CONTRIBUTION WOULD BE LOWER.

ALASKA POWER AUTHORITY

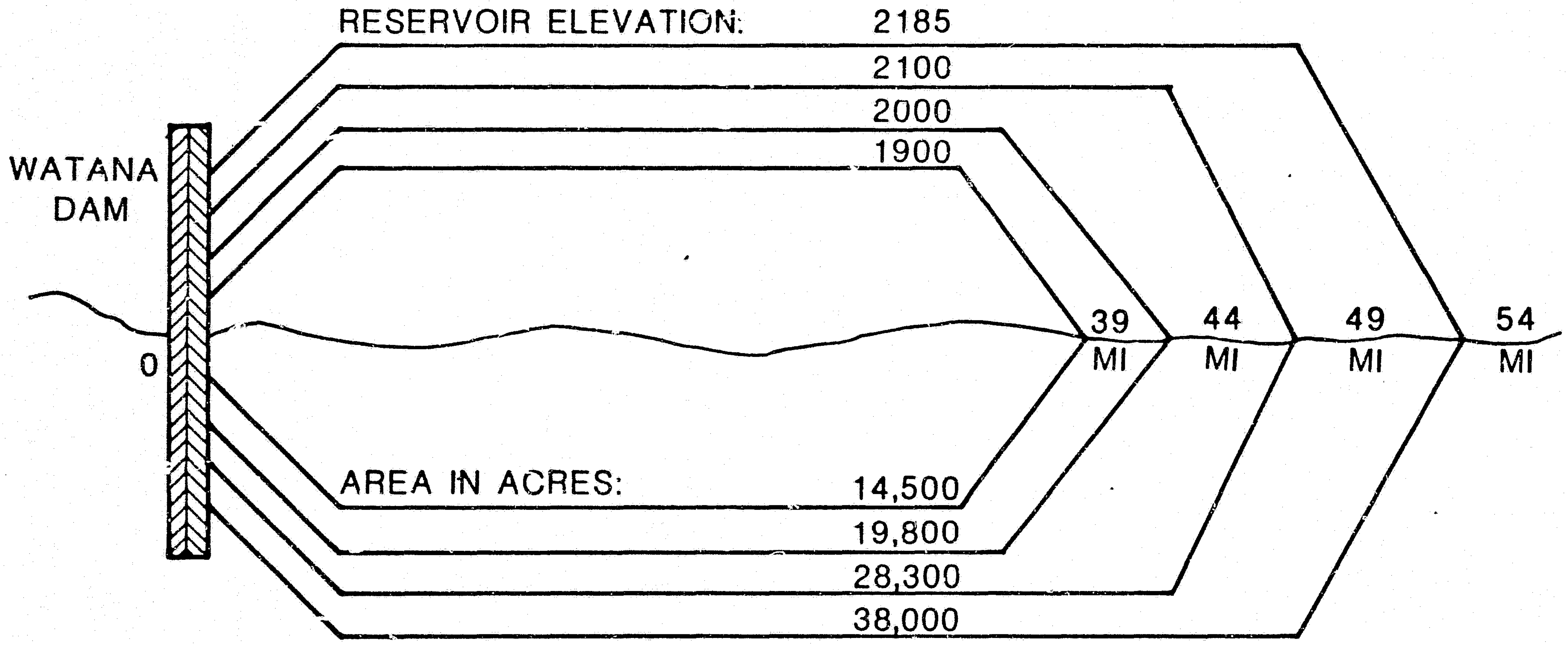
SUSITNA HYDROELECTRIC PROJECT UPDATE

SAGE MODEL

SPECIAL CAPITAL AVAILABILITY

SEPTEMBER 1983

EXHIBIT 7.29
Page 2 of 2



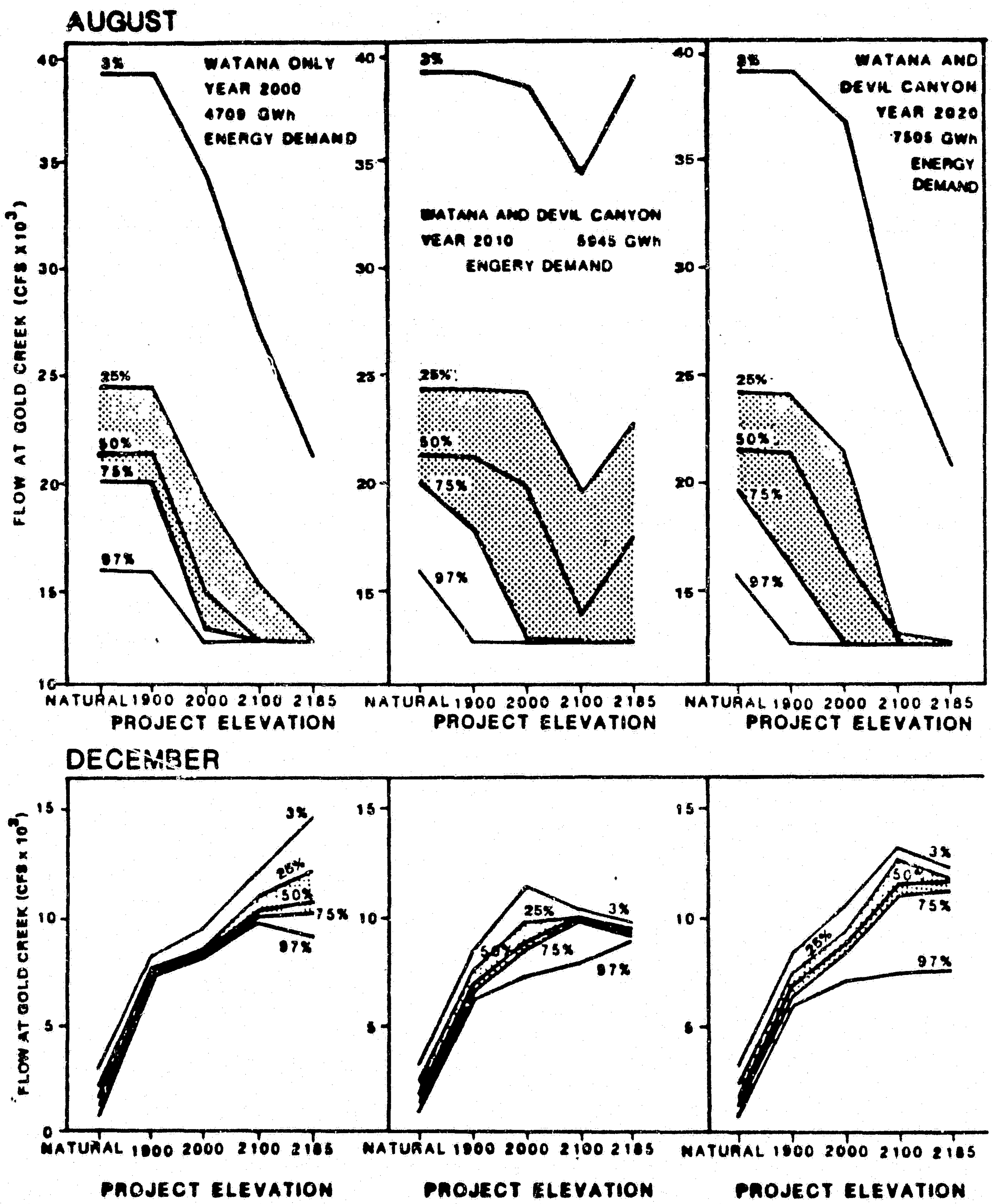
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WATANA RESERVOIR AREAS
UNDER ALTERNATIVE DEVELOPMENT CONCEPTS

SEPTEMBER 1983

EXHIBIT 7.30

EXHIBIT 7.31



ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

AUGUST AND DECEMBER FLOW DURATION CURVES NATURAL AND WITH PROJECT CONDITIONS

SEPTEMBER 1983