SUSITNA
HYDROELECTRIC PROJECT

FEDERAL ENERGY REGULATORY COMMISSION
PROJECT No. 7114

ALASKA POWER AUTHORITY COMMENTS ON THE FEDERAL ENERGY REGULATORY COMMISSION DRAFT ENVIRONMENTAL IMPACT STATEMENT OF MAY 1984

VOLUME 3
APPENDIX I -
FUELS PRICING AND ECONOMICS

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Appendix I - Fuels Pricing and Economics

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APPENDIX I
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Appendix I

FUELS PRICING AND ECONOMICS

1.0 INTRODUCTION

1.1 PURPOSE OF UPDATED ANALYSIS

This Appendix updates data and analyses presented in the Susitna Hydroelectric Project License Application related to the prices of oil, natural gas and coal, and the economics of the Susitna Project. The Alaska Power Authority and its consultants have conducted ongoing studies in these areas since the License Application was accepted for processing by the Federal Energy Regulatory Commission (FERC) in July 1983. The resulting information not only confirms the License Application analyses but also demonstrates that the Susitna Project has a more favorable benefit/cost ratio than presented in the Application. Thus, Susitna remains the economically preferred means of meeting the predicted electrical demand in the Alaska Railbelt.

1.2 SUMMARY OF CONCLUSIONS

The conclusions presented in this Appendix, based on data related to world oil prices, natural gas pricing and availability, coal pricing and availability, refinements in the design and cost estimate of the Project, and alternative thermal plant costs and characteristics are as follows:

- The Power Authority's oil price forecast, revised in May 1984 by Sherman H. Clark Associates, now projects higher prices in the later years of the planning period than the forecast utilized in the License Application, improving the economic attractiveness of Susitna.
- The revised natural gas forecast contains higher Alaskan natural gas prices than those presented in the License Application, making the operation of gas-burning units more

costly (and, therefore, less attractive compared to Susitna) than previously estimated.

- The validity of the coal price forecast set forth in the License Application has been confirmed by examination of markets available to Alaska coal and the prices attainable in those markets. The coal price forecast in the License Application shows that a generating plan based on coal is more costly than a Susitna-based plan.
- A closer examination of the prototype coal-fired powerplant used in the License Application studies has demonstrated that the heat rate and the capital and operating and maintenance costs of that plant are somewhat higher than earlier believed. Moreover, the coal quality is lower than presented in the License Application. These factors further reduce the economic attractiveness of coal-fired units in any generating plan.
- The new oil, gas and coal forecasts do not significantly alter the electrical load forecast in the License Application. Susitna, therefore, remains appropriately sized to the projected load.
- Design and cost refinements considered since the License Application reduce the cost of Susitna, thus improving its economic attractiveness.
- The conclusion of the economic analysis in this Appendix is that the Susitna Hydroelectric Project has a net benefit of $2,326 million over the "Without-Susitna" Plan. In other words, the "With-Susitna" Generating Plan has a benefit/cost (B/C) ratio of 1.41. These figures indicate a greater benefit than the License Application figures where Susitna was calculated to have a net benefit of $1,827 million and a B/C ratio of 1.33.

The information in this Appendix demonstrates that the analyses and forecasts contained in the License application were somewhat conservative and that the Susitna Project is economically more attractive than stated in the License Application.

1.3 CONTENTS OF THIS APPENDIX

This Appendix is organized into eight chapters. Chapter 2 reviews world oil price projections included in the License Application and presents a revised 1984 oil price forecast.

Chapter 3 describes the cost of natural gas used in the thermal plant alternatives analyses, both in the License Application and in this Appendix, and presents revised natural gas reserve figures based on studies performed subsequent to the License Application filing. As explained more fully in Chapter 3, new analyses have been performed that afford greater recognition to the effect that world energy markets have on the production and price of natural gas in Alaska.

Chapter 4 provides revised information on Alaska coal pricing and availability. Chapter 5 reviews the "Without-Susitna" thermal generation alternatives. The costs and performance characteristics of these generation alternatives are updated to reflect the latest available information. Chapter 6 provides a report of sensitivity analyses conducted on the Power Authority's electric demand forecast based primarily on revisions made for the 1984 oil price forecast. Chapter 7 presents engineering refinements which have been proposed for the Susitna Project which would reduce its total capital cost. The Power Authority filed these design refinements with the FERC August 14, 1984.

Finally, Chapter 8 is a summary chapter in which the revised data presented in the previous sections are utilized, along with certain new economic parameters, to generate economic indicators. As in the analysis performed in the License Application, this process involves comparing alternate means of meeting the forecasted Railbelt electrical demand. The optimum "Without-Susitna" mix of generating units is compared with the system which would be built around the Susitna Project in a "With-Susitna" plan to assess the economic feasibility of the Project.

2.0 WORLD OIL PRICES

2.1 INTRODUCTION

The revised oil prices forecast contained in this Appendix tracks the forecast in the License Application in the early years of the projections and rises significantly above the prior forecast beginning in the year 2000. Forecasted oil prices are crucial to the economic analyses in the License Application and in this Appendix because the world price of oil plays an important role in the Alaskan economy. In addition to driving the general economy, oil prices establish alternate fuel prices and directly affect the State's ability to finance the Project. Nearly 85 percent of State revenues are derived from petroleum royalties and taxes based upon the value of oil at the wellhead, which value is, in turn, a function of the world price of oil. Because of these functions, world oil prices are an important input to the econometric models utilized by the Power Authority in predicting future Railbelt electrical demand.

2.2 LICENSE APPLICATION REFERENCE CASE

In selecting a reference case forecast of world oil prices for use in preparing the License Application, the Power Authority studied a number of world oil price forecasts prepared by various government agencies and economic consultants. The Power Authority selected as the reference case a forecast prepared by Sherman H. Clark Associates (SHCA).

As explained more fully in the License Application, SHCA annually prepares a detailed 25 to 30 year projection for all types of energy of the world supply and demand and estimated pricing. The May, 1983 SHCA forecast of world oil prices was used in preparing the License Application. That analysis contained three pricing cases based on three different political-economic scenarios: Supply Disruption (SD), Zero Economic Growth (ZEG), and No Supply Disruption (NSD).

SHCA's SD case assumed a severe supply disruption in the world oil market in the late 1980's, followed by production-limiting decisions by several key petroleum producing countries. These factors resulted in projected world oil prices of $40.00 in 1990, $53.76 in 2000 and $87.80 in 2040.[1/] The ZEG scenario assumed no severe supply disruption, combined with zero economic growth in the United States and 0.4 percent growth per year in the free world through 1990 and a gradual rise thereafter. The predicted oil prices under this scenario were $17.00 in 1990 and $45.11 in 2010. Falling between these two scenarios was the No Supply Disruption case.

The NSD case was similar to the Supply Disruption case, but it assumed that there would be no supply disruption in the late 1980s. Economic growth after 1988 was assumed to be at an annual rate of 3 percent in the United States, slowing gradually to an annual rate of 2.5 percent. Economic growth in the free world was assumed to be 3.6 percent annually.

For the years 1983-1988, projected oil prices were the same for both the NSD and SD case scenarios in the May, 1983 forecast. From 1988 to 2010, prices increased under the NSD case at a 3.0 percent annual rate because of the relatively high rate of world economic growth. The rate of price escalation was then assumed to taper off as the oil price approached a level that would bring forth supplies of alternative fuels. This market condition occurred between the years 2035 and 2040.

The SHCA NSD case was selected as the Reference Case in the FERC License Application filing. The NSD case assumed that OPEC would continue operating as a viable entity, and would successfully support its benchmark pricing system. It also assumed that economic growth in the United States and the free world would continue at reasonable rates. In addition, the NSD case fell in the middle range of forecasts examined by the Power Authority and, therefore, was

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1/ All fuels prices in this Appendix, unless otherwise indicated, are stated in 1983 dollars.

determined to be an appropriately conservative forecast for the economic feasibility analysis presented to the FERC.

The three sets of oil price projections are presented in Exhibit B, Chapter 5 (Volume 2A), of the License Application. It should be noted that in May 1983 the SD case was assumed by SHCA to have the greatest likelihood of occurrence. SHCA had assigned a probability of occurrence of 40% to the SD case. It had assigned the NSD case a 35% probability and 25% to the ZEG. Therefore, the probability of equaling or exceeding Reference Case prices was 75%. The probability of occurrence of an oil price scenario lower than the Reference Case was only 25%.

As presented in greater detail in Volume 2A of the License Application, the Power Authority also studied world oil price forecasts prepared by the Alaska Department of Revenue (DOR) and Data Resources Incorporated (DRI), as well as analyzed hypothetical cases presented by the FERC Staff. These forecasts were analyzed as a means of testing and bracketing the SHCA NSD Reference Case.

2.3 REVISED WORLD OIL PRICE FORECAST

The principal assumptions upon which SHCA based its NSD forecasts have been proven sound by recent events in the United States and world economies, and the world oil markets. In keeping with its practice of performing annual updates of its projections, in May 1984 SHCA revised and reassessed its forecasts. SHCA now believes the NSD, rather than the SD, scenario represents the most likely set of assumptions. SHCA has therefore designated the NSD scenario as its 1984 base case. The probability of occurrence assigned to the NSD case is now 50 percent, the SD case 30 percent and the ZEG case 20 percent. Therefore the NSD case price forecasts have an 80 percent probability of being equaled or exceeded. Table 2-1 compares the License Application forecast with the May, 1984 SHCA NSD forecast.

As can be seen, the May 1984 forecast is the same as the License Application forecast through the early 1990's, but thereafter the prices in the May 1984 forecast rise more rapidly. The similarity in the early years is due to the fact that the primary assumptions on which the License Application forecasts were based have been revised relatively little. The primary assumptions of the 1984 projection are as follows:

- Growth in the United States economy is still projected in the 1984 scenario to continue at about 3 percent per year; the free world economy is also expected to grow at approximately the same rate.
- No major war or other oil supply disruption is assumed to occur in the NSD case, although SHCA still considers a major disruption to be a strong possibility, particularly in light of the continued hostilities in the Middle East;
- Steady improvements in energy technology will continue consistent with recent trends, although oil and gas finding rates will be somewhat lower than the rates assumed in the License Application forecast, consistent with the latest U.S. Geological Survey resource base estimates;
- OPEC will continue to allocate production among its member countries and to hold official prices for marker crude at its present level of $29 per barrel; and
- Little non-conventional petroleum supply will be developed prior to the year 2000.

These assumptions are based on events of the past year. For example, for the first five months of 1984, the U.S. economy has grown by 5.9%, while the growth rate for the free world has been over 3%. The Iran-Iraq war has not caused a major supply disruption nor has it had any lasting impact on prices.

The posted price for OPEC oil remains at $29 per barrel and OPEC has recently affirmed both existing production quotas and the posted price. The spot price for marker crude was quite stable from April 1983 through May 1984, generally running 25 cents to 50 cents per barrel below posted.

Generally, there can be a seasonal summer decline in spot price due to a seasonal decline in demand and a failure to lower production in the second quarter in anticipation of the summer decline in demand. The Power Authority and its consultants had anticipated such a seasonal reduction in spot crude prices of $1 to $2 per barrel by May or June 1984. The overproduction did take place, but the spot price did not decline at that time because producing countries and oil companies increased stocks in anticipation of a supply interruption.

The supply interruption has not taken place and for various war-related reasons, OPEC continued to overproduce for the seasonal market through July 1984. Finally, the spot prices for all types of crude oil began to drop sharply and reached levels in some cases more than $2 per barrel below posted. This is a seasonal as well as a war-related phenomenon, not caused by reduction in the annual rate of demand for OPEC crude oil. Production will be adjusted to the market and spot prices will strengthen toward posted prices, most likely stabilizing to within 50 cents of posted prices. The Iran-Iraq war may have caused a brief supply interruption with resulting price fluctuation over the short-term, but it holds no significance for long-term pricing or production.

The higher long term oil prices of the May 1984 NSD forecast compared to the License Application forecast can be explained by a change in assumptions which SHCA has made concerning oil finding rates. In the 1983 NSD case, SHCA assumed that the oil finding rate would be well above an extrapolation of the past trend. In the current NSD forecast, SHCA has assumed that the past trend in the finding rate will continue. This is confirmed by SHCA's evaluation of the latest country by country estimates of the remaining oil resource base. The result of using a lower NSD finding rate is a more rapid rate of price increase after 1990, as shown in Table 2-1.

Table 2-1

COMPARISON OF OIL PRICE PROJECTIONS

Price of Marker Crude
(1983 Dollars per Barrel)

Date	1983 SHCA-NSD Forecast License Application Reference Case	1984 SHCA NSD Forecast
1983	$28.95	$ ---
1984	27.61	27.61
1985	26.30	26.30
1986	26.30	26.30
1987	26.30	26.30
1988	26.30	26.30
1989	27.09	27.09
1990	27.09	27.90
1995	32.34	32.50
2000	37.50	40.00
2005	43.47	50.00
2010	50.39	60.00
2020	64.48	80.00
2030	74.84	90.00
2040	82.66	100.00
2050	---	110.00

3.0 NATURAL GAS AVAILABILITY AND PRICES

3.1 INTRODUCTION

It is necessary to evaluate the price and availability of natural gas over the next 50 years in order to determine Susitna's economic feasibility because gas-fired generating units are potential alternatives to the Susitna Project. The revised estimates in this Appendix of future natural gas uses and reserves reflect only small changes from the License Application estimates. However, the revised price forecast, which puts greater emphasis on the effects of world energy conditions and markets on the production and price of Alaskan natural gas, projects higher prices for natural gas consumed in the Railbelt beginning about 2005.

Approximately three-fourths of the current electric energy generated in the Railbelt is fueled by natural gas produced from the vicinity of Cook Inlet. During the next decade it is expected that Cook Inlet natural gas will continue to play an important role in electric power generation, home heating, and other uses in the Railbelt. However, as discussed more fully in the License Application, planning on the availability of Cook Inlet natural gas for power generation after 2000 involves the assumption of considerable risk, for it places an inordinate and unwarranted reliance upon the future availability of natural gas supplies from undiscovered reserves which may not exist (see Appendix D1 of the License Application). Moreover, given current Powerplant and Industrial Fuel Use Act (Fuel Use Act) constraints on fueling new electric generating plants with natural gas, there is considerable regulatory uncertainty in this approach.

There is the technical potential of delivering natural gas to the Railbelt from fields on the North Slope of Alaska, although use of such gas at present would be subject to the Fuel Use Act. The basic issue is transportation cost. Large quantities of natural gas are known to exist on the North Slope, making this source of gas, along with Cook Inlet reserves, the principal deposits to consider in evaluating the long term use of natural gas as a fuel for generating electric power in the Railbelt.

3.2 LICENSE APPLICATION PROJECTIONS OF NATURAL GAS AVAILABILITY AND PRICES

The analyses presented in the License Application found that proven reserves of Cook Inlet natural gas totalled approximately 3.5 trillion cubic feet (Tcf), and the economically recoverable, but presently undiscovered, reserves were approximately 2 Tcf. Based on the continued use of natural gas at then-current levels in the industrial and military sectors, moderate growth in the retail sector, and continued use of natural gas as a fuel for electric power generation in the Railbelt, it was concluded that proven Cook Inlet reserves would be exhausted by about the year 1998. Moreover, the License Application estimated that economically recoverable, undiscovered reserves would be exhausted by about 2007. These conclusions are graphically illustrated in Figure D-1.4 of the License Application. It was recognized that many factors could affect these conclusions, including the discovery of larger or smaller volumes of economically recoverable natural gas, the commitment of larger quantities of gas to either existing or new customers, or changes in legal aspects of natural gas exploration and development.

The forecasted prices of Cook Inlet natural gas available for generating electricity were estimated through a systematic examination of existing contracts, expectations of new contracts, the potential for additional export of natural gas, and other Railbelt market factors. It was found that in 1983 the purchase price of Cook Inlet natural gas was approximately $2.47 per million Btu (MMBtu), not including transportation costs from the wellhead. If the addition of a large export project of liquefied natural gas (LNG) were taken into account, it was concluded that the price would increase to over $3.00 per MMBtu.

The price of natural gas has closely paralleled the world price of oil in recent years. For this reason natural gas prices were escalated in the License Application as a direct function of world oil prices in the License Application filing. The results of applying this forecast method for several oil price scenarios, including projections based on the Reference case oil price forecast, are presented in Table D-1.9 of the License Application. The projected price of natural gas based on the License Application Reference Case is shown in Table 3-1.

The License Application noted that, while natural gas supplies from Cook Inlet are somewhat limited, much larger quantities of natural gas (estimated at approximately 29 Tcf) are available from the North Slope. At the time of the License Application filing (as well as at present), however, there was no means of utilizing this gas to generate electricity for the Railbelt. In the License Application four plans for future use of North Slope gas for electric generation were evaluated:

- The Alaska Natural Gas Transportation System (ANGTS), a proposed natural gas pipeline from the North Slope to the lower 48 States; gas could be taken from this pipeline for generating power in the Railbelt. Plans for construction are apparently dormant.
- Trans-Alaska Gas System (TAGS), a proposed pipeline from the North Slope to the north shore of the Kenai Peninsula; from the Kenai Peninsula the gas would be liquefied and shipped to the Pacific Rim. Gas might be made available from TAGS for use in Railbelt powerplants. There was no active plan for constructing TAGS at the time of the License Application filing.
- A natural gas pipeline from the North Slope to Fairbanks to fuel electric power generation facilities and to provide fuel for home heating and other uses. This is a particularly expensive source of natural gas for Railbelt power generation, and no plan has been developed for implementing this option.

- o Electric power generation on the North Slope, with a transmission line to the Railbelt; this option is also expensive and there is no plan for pursuing it.

The cost of developing North Slope natural gas for use in Railbelt electric power generation would range, as indicated on Table D-1.8 in the License Application, from approximately $4.00 per MMBtu to in excess of $6.00 per MMBtu, depending upon the means selected. For purposes of the License Application analysis, a conservative base year cost estimate of $4.00 per MMBtu was selected and escalated using the same method as that used for Cook Inlet natural gas. The resulting price forecast is shown in Table 3-1.

3.3 REVISED NATURAL GAS PRICE PROJECTIONS

Several refinements have been made in the forecasts of Cook Inlet natural gas consumption and North Slope natural gas prices contained in the License Application. Revised estimates of future natural gas uses and reserves reflect only small changes from the License Application in the volume of natural gas needed for electric power generation.

The revised estimates also expand the scope of the natural gas analyses to afford greater recognition to the effects that world energy conditions and markets have on the production and price of natural gas in Alaska. These analyses, undertaken by SHCA, indicate that natural gas prices will rise at a greater rate than forecasted in the earlier studies. The intent of having SHCA perform this natural gas analysis was to ensure consistency between the forecast of natural gas prices and the projected world oil price forecast previously developed by SHCA (See Section 2.3 above).

As in the License Application analysis, SHCA assumes that natural gas is a substitute fuel for petroleum in certain uses. Therefore, world oil prices play a determinant role in setting gas prices in the SHCA analysis. SHCA's analysis indicates that ANGTS could be feasible as early as 1995. TAGS, which filed a right-of-way application with the Bureau of Land Management in May, 1984, might be feasible in approximately the same time period. In the economic analysis, the Railbelt price for natural gas after the Cook Inlet supplies are exhausted (about 2007) was assumed to be the projected price of North Slope gas delivered to the Railbelt via ANGTS. The resulting projection of gas prices to Railbelt power plants, which is presented in Table 3-1, considers the transition from Cook Inlet to North Slope gas and is internally consistent with SHCA's oil price projections, Lower 48 and world gas supply/demand balances, and projections of the world economy.

Table 3-1

COMPARISON OF NATURAL GAS
PRICE PROJECTIONS
(1983 $ per MMBtu)

Year	License Application Reference Case		Revised Forecast	
	Cook Inlet Wellhead	North Slope Delivered	Cook Inlet Wellhead	North Slope Delivered
1983	2.47	4.00	2.47	-
1985	2.16	3.64	2.25	-
1990	2.74	3.98	2.80	2.86
1995	3.18	4.61	3.14	4.00
2000	3.69	5.35	3.37	4.93
2005	4.27	6.20	4.94	6.14
2010	4.95	7.18	-	7.37
2020	6.34	9.20	-	9.83
2030	7.36	10.67	-	11.00
2040	8.13	11.79	-	12.00
2050	-	-	-	13.00

4.0 COAL AVAILABILITY AND PRICES

4.1 INTRODUCTION

The studies on coal prices and availability performed since the License Application explore the methods and assumptions used to predict Alaskan coal prices and refine the escalation rate used in forecasting prices in greater detail. The new studies indicate that the two major coal fields with vast quantities of coal in Alaska are the Nenana and Beluga fields. These coal fields will serve what are essentially separate markets. Nenana coal, serving the mainly domestic interior Alaska market, would have a price of $2.05 per MMBtu in 1993 when delivered to the town of Nenana. Beluga coal, which would serve both the export as well as domestic market, would have a mine-mouth price of $1.95 per MMBtu in 2000 which would rise to $4.75 per MMBtu in 2050.

At present coal is used for electric power generation for Fairbanks and the surrounding area. The coal is mined by the Usibelli Coal Company operating in the Nenana Field, southwest of Fairbanks. Nenana coal, along with coal from the undeveloped Beluga coal field west of Anchorage, could provide fuel for electric power generation throughout the Railbelt. Other coal deposits are located on the Kenai Peninsula, the Matanuska Valley, and elsewhere in Alaska. The Nenana and Beluga fields are most likely to provide the larger quantities of long-term coal supplies for electric power plants in the Railbelt for the foreseeable future in the Without-Susitna Plan. The uncertainties surrounding the development of Nenana and Beluga reserves are the timing of Beluga coal availability in the Railbelt area, and the prices at which both Beluga coal and expanded Nenana coal development would be available.

4.2 LICENSE APPLICATION PROJECTIONS OF COAL AVAILABILITY AND PRICES

Coal availability and price studies conducted in support of the License Application established that the coal resource base of

Alaska, as concentrated in the fields discussed, is more than adequate for generating electric power sufficient to meet the projected demand of the Railbelt for at least the next 75 years. The large quantity of reserves in the Nenana field, for example, is estimated to be in excess of 450 million tons. The identified resource base in the Nenana area, some of which probably cannot economically be mined, is approximately 7 billion tons.

In the Nenana area, the only significant commercial mine currently operating is the Usibelli Coal Company mine. In the License Application it was noted that this mine is currently producing approximately 830,000 tons per year of subbituminous coal with heating value of approximately 7,400-8,200 Btu per pound (see Section 2.2 in Appendix D-1 of Exhibit D of the License Application). It was also noted that there is an export agreement pending finalization for Nenana coal which would require doubling the current Usibelli production level. This doubling will require the current mine to operate at or near full capacity. To provide coal for Railbelt electric power generation under the Without-Susitna expansion plan, Usibelli production would have to again double, rising to close to 3.5 million tons per year by year 2010. Some 2 million tons per year (MMTPY) of production capacity would have to be added at the field. Nenana area coal fields could sustain this level of production over a long period of time.

In the License Application the average mine-mouth production cost for Nenana coal was estimated to be approximately $1.40 per million Btu (MMBtu) in 1983 dollars. However, in establishing the price of coal at hypothetical electric power plants, it was necessary to add transportation costs for moving coal from the Nenana mine to hypothetical power plants at Nenana and Willow, Alaska. Those costs were estimated in the License Application to be $0.32 and $0.51 per

MMBtu, respectively, resulting in a delivered coal price of $1.72 - $2.18 per MMBtu.[1/]

The identified resource base in the Beluga field is 10 billion tons. In the License Application the price of Beluga coal was estimated on its value in the Pacific Rim market, since the principal basis for the development of the Beluga field would be to supply coal to this market. The average price of coal at a Beluga port (FOB Granite Point) calculated on this basis was estimated to be $1.86 per MMBtu. The cost of opening a small (1 to 3 million tons per year) Beluga coal mine exclusively for use in Alaska was found to result in substantially higher prices -- $2.72/MMBtu and $1.91/MMBtu, respectively. In developing an estimate of the cost of the Without-Susitna expansion plan, a conservative estimate of Beluga coal prices using the export price of $1.86 in the base year was used.

In the License Application, Nenana coal prices were escalated at a real (inflation free) rate of 2.6 percent per year, reflecting the experience in United States energy markets during the past few years. Escalation rates in the price of coal in the Pacific Rim market, however, were estimated to remain below those domestic coal rates due to continued and increased international competition among suppliers and the possible effects of a weakening United States dollar in international currency markets. Escalation of Beluga coal prices was therefore estimated to be 1.6 percent per year.[2/]

It should be noted that both Nenana and Beluga coal prices were assumed in the License Application to escalate until the date a given generating unit enters operation. At that time, the coal price

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1/ The basis for these cost estimates and other conclusions from these studies are presented in detail in Appendix D1 of Exhibit D of the License Application.

2/ The License Application forecasts of Nenana and Beluga coal prices based on these assumptions are shown on Table D-2.14 of Exhibit D of the License Application.

for the unit is assumed to remain constant in real terms until the unit is replaced. Using this approach, the average coal price escalation rate in the License Application was about 1% per year after 1993.

4.3 UPDATED FORECAST OF COAL PRICES AND AVAILABILITY

The new studies on coal prices and availability were designed to explore in greater detail the pricing of Alaska coal. Detailed analyses were conducted of net back pricing and production cost pricing in addition to refinement of the escalation rates used in making the price forecasts.[3/] Net back pricing is the calculation of what price could be obtained for Alaska coal at the mine (net of transportation costs) considering its sales price into an export market; production cost pricing is, as implied, the price of coal set on the basis of the total cost of producing coal from a mine over a long term. The studies which have been completed indicate that the Nenana and Beluga fields will serve what are essentially separate markets, due to different access to ocean transportation facilities and the timing of mine development.

4.3.1 Nenana Coal Markets and Prices

The Usibelli Coal Company's existing production of 830,000 tons per year primarily serves electric generating plants in the Fairbanks area. If arrangements for the proposed export of 800,000 metric tons (880,000 tons) per year of Nenana coal to Korea are completed under the Suneel contract, it will require a doubling of

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3/ Neither coal production costs nor coal prices can be expected to remain constant in either real or nominal terms over a fifty-year planning period. Since 1900, real coal prices have shown different trends and cycles, as well as apparently random variations. The average overall real price increased at a rate of 1.22%. This history of coal price escalation supports the proposition that Nenana and Beluga coal costs will escalate in the future, as developed more fully below.

Usibelli production to 1.7 MMTPY.[4/] The doubling could be supported within the existing capacity of the mine. The operators of the Usibelli mine have said they could expand their operations to as much as 4 MMTPY by doubling mine capacity. Further, it is recognized that other organizations besides Usibelli control substantial quantities of coal in the Nenana Field and that these deposits could also be developed. The Power Authority has made an analysis of the price that Usibelli and other producers would require to elicit this expanded production.

The size of the potential electric generation market for Nenana coal can be determined by reference to the Without-Susitna expansion plan developed by the Power Authority. In a refinement of the plan presented in the License Application, the Power Authority has estimated that six 200 MW coal-fired plants would be needed in the optimal Without-Susitna expansion plan. The first two of these plants would be located in the Fairbanks region for purposes of electrical system expansion (see discussion in Chapter 5). Given the estimate of Nenana coal quality, it has been calculated that each 200 MW coal plant would consume approximately 1 MMTPY of coal, for a total Nenana consumption of 2 MMTPY.

Usibelli has said it is capable of producing 2 MMTPY in addition to the 2 MMTPY which is to be dedicated to the pending export arrangement and to meeting its current domestic market requirements. Since Usibelli is the primary operating mine in the Nenana Field, it is therefore reasonable to assume that Usibelli would be the most likely supplier of the additional 2 MMTPY needed by the Nenana-area power plants discussed above. The production cost for the 2 MMTPY

4/ The proposed export to Korea is possible because production for this quantity comes from an incremental expansion of existing capabilities, which operations are relatively inexpensive. This enables Usibelli Company to absorb the high transportation cost to Seward and still establish a viable sales price.

"increment" from the Usibelli operation has been estimated to be $1.50 per MMBtu in 1983 dollars.

That cost estimate is only the starting point for the Nenana price analysis, because it estimates the production cost per ton for the Usibelli 2 MMTPY increment in the first year of operation. For long term projections, the real increases in the cost of Usibelli's operations in the second and succeeding years of operation must be considered. In addition, in light of environmental conditions which preclude burning coal at the Nenana Field, the cost of transporting the coal from the mine to the powerplants must be added to derive a "delivered" price, which is the proper basis for comparing coal with other fuel prices in the economic analyses.

The Power Authority has performed additional analyses of the escalation rate by reviewing those components of coal production which are expected to escalate in real terms: labor, fuels and lubricants, and electricity. Based upon the studies of historic labor rates in the United States, it is estimated that labor costs will escalate at 1.5 percent per year. Relying upon projections of future petroleum prices generated by SHCA, as described in Chapter 2, Section 2.3, projected future escalation in diesel fuel and lubricants is estimated to be 2.2 percent. Utilizing data generated by the system expansion models, electricity is estimated to escalate at approximately 1.3 percent per year in the Fairbanks region. The cost escalation rates for each factor discussed above result in the overall cost of production from the "incremental" operation escalating at a rate of 0.8 percent per year.

Consistent with the assumptions in the License Application, the analysis of Nenana pricing includes a transportation cost of $0.37 per MMBtu in 1983, which is estimated to be subject to real price escalation of 1.8% percent per year.

The result of these analyses is an estimated price of $2.05 per MMBtu in 1993 for the total delivered price of coal to the two new coal-fired plants forecasted for the Fairbanks load center, as set forth in Table 4-1.

4.3.2 Beluga Coal Prices and Availability

As previously stated, the License Application price of Beluga coal was predicated on the development of an export market. It was anticipated that Alaska coal could be sold competitively in the world market to the Pacific Rim countries. The competitive price in this market less the cost of transportation across the Pacific yields a net back price in Alaska.

In further evaluating the potential for Beluga coal to enter the Pacific Rim market, it was determined that it was essential to assess the long term demand for coal in terms of the world energy balance as projected by SHCA. SHCA forecasts that energy demand per unit of GNP will continue to decline over the forecasting period. This decline reflects increasing efficiency of energy use in economies throughout the world. There will be a growing demand for all fossil fuels which will exceed the supply of alternate fossil fuels that can be expanded. It is predicted that world demand for coal will increase and maintain the longest and strongest sustained growth of any existing established form of energy. Volumetrically, coal demand should grow at least as fast as the world economy for the next 40 years.

It is projected that Beluga coal will enter the export market in a significant manner after 1990. The quantities of Alaska coal exported will increase from 15 million MTCE[5/] in 2000 to 105 million MTCE in 2040. It is further assumed that, because of a strong market, the Pacific Rim market will dictate the price of the coal received by Alaskan producers, due to The Pacific Rim Market's favorable location and because it constitutes a major portion of projected free world demand.

5/ MTCE, Metric Ton of Coal Equivalent, is a metric ton of coal with a heat content of 12,600 Btu's per pound. One MTCE equals 1.85 Beluga "short tons" (2000 pound tons).

The production cost of coal available to the Pacific Rim market will vary not only with the producing country, but from sources within the producing markets within the country. Because production cost for Beluga coal will be lower than that of many producing countries, Beluga producers will be able to capture a significant portion of the Pacific Rim market; however, the Pacific Rim countries' desire to diversify their suppliers, the lower quality (heat content) of Alaska coal, and the international monetary exchange rates are some of the factors that would prohibit Alaska from capturing a larger share than 20% of the total market.

The price of coal in the Pacific Rim market will rise during the period that the Alaska coal exports are increasing. The price of coal will rise due to the increase in demand, due to interfuel competition, and to reflect increases in real costs of the following coal production components: labor, leasing and operations, equipment, fuels, transportation rates and distances. The increasing coal prices also reflect costs associated with government policies and regulation, such as monetary exchange rates, imposition of taxation, stricter environmental constraints, and production or export constraints.

In order to determine whether Alaska coal can be competitive with other coal exports to the Pacific Rim, the Power Authority's analysis developed an "envelope" of prices for Alaska coal, to establish the highest and lowest prices at which Alaska coal could be marketed. The Power Authority has identified the upper and lower limits to this envelope, respectively, as the gas-equivalent price of coal and the production costs.

In theory, the highest long-term price at which a producer could possibly sell his coal would be a price which could not exceed the price of natural gas as an alternate fuel. These "alternative fuel equivalent prices" have been keyed to the SHCA gas analysis set forth in Chapter 3 of this Appendix. It is estimated that this alternative fuel equivalent price would range from $1.54 per MMBtu in 2000 to $7.93 per MMBtu in 2050 in 1983 dollars. The alternative fuel equivalent price will occur infrequently, generally when there are severe constraints upon the availability of other supplies due to strikes in various regions, sudden increases in demand that cannot be met due to lack of mining capacity, and so forth.

At other times, there will be an excess of supply, market or monetary conditions unfavorable to the producer, or similar conditions. At such times, the producer will have to accept a lesser price, which would in no event fall below the level of production costs. Thus, the envelope is established by the gas equivalency price at the high end and production costs at the low end.

Given this envelope, a net back line was developed showing the trend for long term prices. This trend line was developed based upon SHCA world energy demand forecasts. Alaska producers may sell supplies at higher and lower prices at a given time in light of current market forces in the Alaska market, prevailing international energy market factors, international monetary exchange rates or other considerations. It should be understood that this line is a "trend line" which recognizes that coal prices will cycle within the envelope over time, as they have done historically. As a result of the foregoing, the export price of Alaska coal at the mine-mouth is projected to be $1.95/MMBtu in 1983 dollars in 2000, rising to $4.75/MMBtu in 2050, as indicated in Table 4-1. Following the logic of the License Application that producers will attempt to obtain the maximum price for their coal that the market will allow, the net back line is adopted as the coal price forecast for the Beluga field.

As a step in reviewing all scenarios that constitute the envelope for pricing Alaska coal, the Power Authority reassessed the production costs in the License Application. To test the full economies of scale which could be captured from production of the Beluga field, the Power Authority estimated the cost of production from large Beluga mines ranging from 8 to 12 MMTPY. The results of these studies showed that the 8 MMTPY mine would produce coal at a slightly lower cost than the 12 MMTPY mine; therefore the 8 MMTPY was selected for economic analysis. The economic cost of production from that mine in 1983 would be $1.22 per MMBtu.

As with the estimate of Nenana mining costs, it is necessary to escalate the Beluga prices. Following the same methodology utilized for determining the escalation rate of the Nenana 2 MMTPY case, it was calculated that the 8 MMTPY Beluga mine total costs would escalate at 0.8 percent per year. The same generic escalation rates for labor and fuel and lubricants used at Nenana (1.5 and 2.2 percent, respectively) are used for Beluga escalation. Electricity escalation is estimated to be 1.9 percent. The result is that the escalated production cost of Beluga coal at mine-mouth ranges from $1.31 per MMBtu in 1993 to $2.08 per MMBtu in 2050 in 1983 dollars (less than the export price of $1.95 and $4.75 per MMBtu, respectively). As previously noted, therefore, the Beluga producers will seek to sell their supplies at the price established by the export market.

In the License Application, the Power Authority also considered the unlikely possibility that an export market would not develop. Under that scenario, Beluga would be developed with small mines to meet only the Railbelt's generation requirements under the Non-Susitna Alternative. Production cost studies were conducted, and further refinements of the small mine studies were done subsequently using a new mine design reflecting a more efficient mining operation for the 1 MMTPY case. In addition, the new 1 MMTPY study assumed that transportation ended at the point the coal was delivered to the mine-mouth, rather than at port facilities as in the earlier study. The price of coal produced for the hypothetical 1 MMTPY mine was estimated to be $2.22 per MMBtu. The earlier 3 MMTPY study was revised to change the assumption regarding the delivery point; however, a new mine design was not done for the 3 MMTPY case. The result of these refined 3 MMTPY mine studies was to reduce the cost to $1.72 per MMBtu. These costs are significantly higher than the cost of the 8 MMTPY mine.

Table 4-1

COAL PRICE FORECASTS
(1983 $ per MMBtu)

Year	License Application Reference Case: Nenana Prod. Cost FOB Nenana	License Application Reference Case: Beluga Export Price Mine-mouth	Revised Forecast: Nenana Production Cost FOB Nenana	Revised Forecast: Beluga Export Price Mine-mouth
1993	2.15	-	2.05	-
2000	2.53	2.44	2.20	1.95
2010	3.18	2.85	2.43	2.40
2020	3.99	3.35	2.69	2.80
2030	5.01	3.92	3.00	3.35
2040	6.29	4.60	3.35	4.00
2050	7.89	5.39	3.76	4.75

5.0 THERMAL PLANT COSTS AND CHARACTERISTICS

5.1 INTRODUCTION

The description of the thermal plant costs and characteristics submitted in the License Application considered a number of alternative generating plants. These plants were coal-fired steam electric stations and natural gas-fired simple cycle and combined cycle combustion turbines.

Further analysis and refinement of the costs and characteristics of these plants has been conducted since the filing of the License Application. The purpose of these refinements was to document the assumptions made previously and to consider the effects of new information on these previous assumptions.

The following paragraphs present the assumptions made in the License Application and the update of that work.

5.2 SUMMARY OF THE LICENSE APPLICATION THERMAL OPTIONS

Section 4.5 of Exhibit D discusses the thermal options considered in the License Application. The size, capital cost, and operating characteristics of coal- and gas-fired units which were generally defined in the Railbelt Electric Power Alternatives Study, performed in 1982 by Battelle Northwest Laboratories, were used in the License Application analysis. Table 8-1 provides the detailed system parameters used in the License Application economic analysis.

5.3 REFINEMENT OF THERMAL OPTIONS

5.3.1 Unit Size Study of Coal-Fired Power Plants

The 1982 Railbelt Alternatives study selected a 200 MW coal-fired power plant as a representative unit size that would be reasonable for a system expansion analysis. Further analysis was subsequently conducted to confirm that this size is the most economical coal option for the "Without-Susitna" plan.

In reviewing the assumptions for the appropriate size of a hypothetical coal-fired power plant, an evaluation of the options for unit size ranging from 100 MW to 400 MW was performed. The evaluation considered the trade-off between two major driving forces or factors: economies of scale and unplanned outages.

As the size of powerplant units increases, economies of scale are realized as lower capital and O&M costs are derived on a unit kilowatt basis. For example, a single 400 MW unit has a capital cost of about 80% of two 200 MW units and requires about 60% of the operations and maintenance staff.

The factor of reliability and unplanned outages recognizes that the output of a utility system is made up of diverse generation stations all combining their capacity to meet the load. The loss of the largest single generating unit represents the design basis for the reliability and loss of load analysis.

A trade-off between the two factors of economies of scale and unplanned outages were performed using the OGP model. Within that model the reliability assessment is based upon determining the cumulative capacity outages of the system. As generating unit sizes become larger, more capacity is installed to meet the reliability requirement specified in the model. Another calculation performed in the OGP analysis is spinning reserve. The spinning reserve criteria provides the grid with the capability of meeting system load should the largest unit experience an unplanned outage.

Since any hypothetical coal-fired unit larger than 200 MW would represent the largest unit in a Without-Susitna system, a number of OGP expansion planning analyses were performed. The unit size evaluation initially consisted of allowing the OGP expansion planning program to select among 100, 200, 300, and 400 MW units. (Sizes up to 600 MW were considered, but never selected by the program.) The resulting system plan included 100 MW and 200 MW units. In the next step, unit sizes of only 100, 150, 200, and 250 MW were made available for system expansion. The program then selected a mixture of 150 MW and 200 MW units. An expansion planning program using only 200 MW units showed that the total present worth of the mixture of 150 MW and 200 MW units was essentially the same as the present worth of the program that limited plants to 200 MW as the only size. The 200 MW expansion program utilized in the License Application was therefore validated and retained. The assumptions used in this analysis are found in Table 5-1 and the results set forth in Table 5-2.

5.3.2 Location of Coal-Fired Power Plants

The location and timing of coal-fired power plants in the Without-Susitna scenario of the License Application were reviewed to ensure that the location of power plants considered economic and system planning perspectives. In the License Application, it was assumed that the initial coal-fired power plant site development would take place near the Beluga coal field, due to its proximity to the Anchorage load center. A subsequent review of this assumption was made which recognized the geographical limitations on the availability of natural gas requiring that all combined cycle and simple cycle gas-fired power plants be located in the Cook Inlet region of the Railbelt. The only alternative available in the Northern Railbelt in the Without-Susitna plan is coal-fired power plants. A comparison was therefore prepared between the License Application expansion plan and a plan called the "Nenana plan." The Nenana plan assumes the initial coal-fired power plants would be constructed in the Northern region of the Railbelt and fueled by the coal from the Nenana Field, rather than constructed at Beluga. A closer matching of the ideal distribution of generation, based on a peak comparison, is provided in the Nenana plan rather than the License Application plan. Therefore, this plan has been adopted. It resembles the DEIS coal scenario, where the initial plants also are installed in Nenana.

The existing mining operation in the Nenana field constitutes a known capacity to produce. In contrast, the development of the Beluga field is tied to the potential existence of an export market and the development of a larger infrastructure. On this basis, also, a reasonable Without-Susitna expansion plan would call for the siting of the first coal-fired power plant (two 200 MW units) in the Nenana region.

5.3.3 Location of Gas Fired Power Plants

As previously noted, the Without-Susitna plan assumes that all combined cycle and simple cycle power plants will be fueled from Cook Inlet region natural gas supplies.

Specific site locations would likely be in the Beluga gas field, Kenai field area, and sites located near yet undiscovered gas. It is assumed that the natural gas powerplants would be sited close to the source of existing transportation networks and transmission lines. This is consistent with the License Application analysis.

5.3.4 Capital Cost Estimates for Coal-Fired Power Plants

The License Application used capital cost estimates for coal-fired power plants which were based upon the Railbelt Electrical Power Alternatives study. A detailed review of the actual equipment requirements with present labor rates, budgetary equipment quotations, and shipping costs has caused a revision to the capital cost estimate. The results of this review show an average capital cost of $2300/kW installed (1982$) for a two unit coal-fired power plant in the Beluga region. The individual installed costs are $2710/kW for the first unit and $1880/kW for the extension unit. Based upon the cost differential determined in the Railbelt Study between Beluga region and Nenana region power plants, a Nenana region two-unit power plant would have an installed cost of $2350/kW.

5.3.5 Capital Cost Estimates for Gas-Fired Power Plants

The License Application values used for the capital cost estimates for simple-cycle and combined-cycle power plants were based upon work performed in the Railbelt Electric Power Alternatives Study. Subsequent to this study, costs were developed for plants based in the Kenai region in a study entitled "Use of North Slope Gas." These costs included updated technical information from original equipment manufacturers for combustion turbines that affect unit size, performance, and costs. As a result of this later study, the capital costs associated with a simple cycle gas-fired power plant have been revised to \$616/kW (1982\$). For a combined cycle gas-fired power plant, the capital costs in the Kenai region were found to be \$546/kW (1982\$).

5.3.6 Operation and Maintenance Cost Estimates for Coal-Fired Power Plants

A review was conducted of the operation and maintenance costs (O&M costs) associated with an Alaska based coal-fired power plant. This review was performed to account for the changes in environmental regulations which translate into increased operation and maintenance expenses. In addition to the new regulatory requirements, existing data was analyzed in detail from coal-fired power plant operation in other parts of the country, given the absence of comparable units in operation in Alaska.

Table 5-3 provides a summary of the costs associated with operation and maintenance of a 200-MW unit that were developed during the review. As noted previously, cost increases in environmental protection systems have caused a general increase in O&M costs of coal-fired power plants. The limited experience with this equipment in the utility industry during the preparation of the Railbelt Study resulted in an overly optimistic projection of system performance. The updated review indicates that higher maintenance costs should be assessed to the environmental control devices.

In addition to environmental changes, actual utility labor rates were used to establish costs in Alaska, as well as transportation and construction costs associated with unit operation. The basis for these values are shown in the footnotes to Table 5-3.

5.3.7 Operation and Maintenance Costs of Gas-Fired Power Plants

The gas-fired 200-MW power plants were configured first around the 200-MW combined cycle system (nominal rating) utilizing two 70-MW nominal rated gas turbines exhausting the products of combustion to a waste heat recovery boiler, which in turn provides steam at 850 psig, 950°F to a 60-MW steam turbine generator. The second gas-fired option is a 200 MW simple cycle plant configuration, represented by three 70 MW combustion turbines operating with individual inlet and exhaust systems, and with no waste heat recovery.

An analysis of operation and maintenance expenses was conducted for both cycle configurations utilizing utility report O&M costs, original equipment manufacturers suggested maintenance intervals, and FERC operating records. As the analysis progressed, it became evident that operation and maintenance costs differed for utilities operating units in the Lower 48 states from the Alaska utilities. As evidenced by the data, the Alaska utilities operate their units base loaded on average over 8,000 hours per year, while the Lower 48 utilities operate their simple and combined cycle plants as peaking units over the year at 2,000 to 4,000 hour intervals. For this reason, the reported costs for the Alaska utilities were utilized in this analysis. The combined cycle plant operation and maintenance costs were broken into fixed and variable costs and adjusted for site conditions. The fixed costs were approximately $11.75/yr./kW while the variable costs were $0.54/MWh.

For the simple cycle plant utilizing three 70 MW (nominal) gas turbines, fixed costs were approximately $6.71/yr./kW, while the variable costs were $0.28/MWh. An important aspect of the Alaska utility fixed costs is the fact that a greater percentage of in-house parts repair is carried out while less outside contracted maintenance services are utilized. This is one of the contributing factors to the higher fixed costs experienced by the Alaskan utilities than the Lower 48 utilities.

5.3.8 Cycle Efficiency of Coal-Fired Power Plants

The cycle efficiency or Net Station Heat Rate (NSHR) for power plants is affected by three major factors. These factors are thermal cycle efficiency, auxiliary power requirements, and fuel conditions.

A review of the auxiliary power requirements was conducted for coal-fired power plants of similar size with similar equipment. A value of 8.5% of gross output was used for the auxiliary power requirements in the Appendix studies. This value was confirmed with a survey of similar operating units burning similar coal. The use of 8.5% represent a realistic expected value for a 200 MW unit. The higher the auxiliary power, the lower the net output of the plant and higher the heat rate, and therefore the lower the overall efficiency of the power plant.

Based upon the changes in coal quality discussed in Section 5.4 of this document, and changes in auxiliary power requirements, the NSHR for 200-MW units has been revised. The revision results in an NSHR of 10,300 Btu/kWh, compared with a 10,000 Btu/kWh rating in the License Application analysis.

5.3.9 Cycle Efficiency of Gas-Fired Power Plants

The cycle efficiency of gas-fired power plants is affected by the same factors -- thermal cycle conditions, auxiliary power and fuel quality -- as coal-fired plants. Since the preparation of the License Application, changes have occurred in values assigned to the thermal cycle conditions and auxiliary power requirements.

In the License Application, combustion turbine performance data was used to estimate plant performance. This information has subsequently been revised by the equipment manufacturer based on a later model of combustion turbine. This change affects both the simple cycle and combined cycle gas-fired power plants.

The License Application plant characteristics assumed different conditions with respect to the auxiliary power requirements of the simple cycle and combined cycle power plants. The assumptions were the use of wet/dry cooling towers and a plant performance based upon no water injection for control of nitrogen oxides (NO_x). The current requirement for auxiliary power includes a dry cooling tower and water injection for NO_x control.

5.3.10 Coal Quality

The License Application contains the analysis of Nenana Field coal shown in Table D-2.3 of Exhibit D. Further investigation into the quality of the coal from the Nenana field has been performed and indicates that the coal performance specifications contained in the License Application should be revised.

The quality of the coal from the Usibelli Company mining operation, which could supply coal for two 200-MW units from a 2 million ton per year expansion, is best represented by an analysis of the coal being burned today. Table 5-4, which is based upon average 1983 coal data from Fairbanks Municipal Utility System's (FMUS) Chena plant, presents these data. These data were confirmed at a conference held in Alaska on October 21-23, 1980, where the average values for the Nenana Field's Poker Flats seam were shown to be those in Table 5-5. The Usibelli Company is currently mining the Poker Flats seams.

The information in Tables 5-4 and 5-5 indicate that the coal analysis presented in the License Application should be revised to reflect FMUS's 1983 average value; therefore the values shown in Table 5-6 are used in this Appendix.

Table 5-1

ANALYSIS OF COAL UNIT SIZE ASSUMPTIONS AND DATA

Economic Assumptions

Year in which costs are quoted	=	1983
Discount rate	=	3.5%
Coal Plant Life	=	30 years
Planning Horizon	=	1993-2020 by OGP 2021-2050 by extension
Load Forecast	=	SHCA-NSD Update (10% transmission losses)
Fuel Prices		
Gas	=	SHCA Gas price based on 1984 oil price projections
Coal	=	\$1.70/MMBtu in 1983. One percent annual escalation thereafter
Reliability Index (LOLP)	=	0.2 days/year
Spinning Reserve Criteria	=	Equal to the capacity of the largest unit on-line in a particular month

Coal Plant Data - 1983$

Unit Size (MW)	Construction Period (Yrs)	Capital Cost 1/ (S/kw)	Maximum Heat Rate (Btu/kWh)	Operation and Maintenance Costs Fixed (\$/kW/yr)	Operation and Maintenance Costs Variable (S/MWh)
100	5	2,589	11,000	74.40	3.10
150	5	2,434	11,000	68.40	3.10
200	5	2,290	10,876	60.36	3.10
300	5.5	2,149	10,828	49.14	3.10
400	6	2,011	10,700	37.92	3.10

1/ Includes interest during construction at 3.5 percent for the construction periods shown.

Table 5-2

ECONOMIC ANALYSES OF COAL UNIT SIZES

Unit Size, MW combinations	1983 Cumulative Present Worth in $1,000 to 2050
100, 200, 300, 400	7,919
100, 150, 200, 250	7,851
200 only	7,753

TABLE 5-3

OPERATION & MAINTENANCE COST
200 MW Coal Fired Unit 1983/$

Item	Fixed Cost	Variable Cost
Plant Staff 1/	$ 8,236,800	at 80% capacity factor
Security 2/	438,000	
Routine Maintenance 3/	534,300	$2,531,500
Overhaul Maintenance, (annual basis) 4/	1,640,000	
Consumibles 4/5/	80,000	1,102,500
Waste Disposal Costs 6/		1,770,000
TOTAL	$10,929,100	$5,384,000

Fixed Cost per kW	$54.65/kW
Variable cost per MWh	$ 3.84/MWh

Costs in 1982 $ - Based on Ebasco Fossil Plant Indices 6.4% escalation.

Fixed Cost per kW	51.36.
Variable Cost per kW	3.61.

Footnotes:

1/ Plant staff level of 110 personnel. 86 maintenance, supervisory, and administration personnel and 18 operations personnel. Average hourly rate $36/hr.

2/ Security cost based upon 2 guards, 24 hours a day, 365 days per year. Average hourly rate $25/hr.

3/ Based upon FERC Utility Records, conversations with utility operations personnel, and original equipment manufacturers estimates of costs.

4/ Based upon original equipment manufacturers recommended intervals, and actual operating experience.

Footnotes: (continued)

5/ Based upon 70% removal, use of limestone delivered in Anchorage at $380/ton, and consumption of 838 lbs/hr. at full load.

6/ Based upon an annual capital expenditure of $1,550,000 to dispose of 1,670,000 ft. of scrubber sludge, fly ash, bottom ash, and lime.

7/ Cost includes fuel, vehicles and repairs on vehicles based upon operating plant data.

Table 5-4

NENANA COAL ANALYSIS
as received, 1983 Yearly Average

Higher Heating Value Btu/lb.	7,592
Moisture Content %	26.54
Ash Content, %	8.34

Source: Fairbanks Municipal Utility System

Table 5-5

NENANA RAW COAL ANALYSIS
Weight, % as received

Analysis	Poker Flat No. 6 Seam Top	Poker Flat No. 6 Seam Top	Poker Flat No. 6 Seam Bottom	Poker Flat No. 4 Seam	Average No. 4 & No. 6 Seams
Volatile Matter	32.8	35.71	34.12	32.51	33.16
Fixed Carbon	26.54	31.40	29.83	32.51	30.88
Moisture	23.61	25.23	25.68	25.29	25.05
Ash	17.05	7.66	10.37	9.85	10.77
Higher Heating Value (Btu/lb)	7,022	81.36	7,516	7779	7668
Carbon	40.59	46.08	43.87	45.28	44.40
Hydrogen	5.98	6.30	6.05	6.30	6.20
Nitrogen	.56	.60	.59	1.13	.86
Oxygen	35.70	39.24	38.99	37.11	37.54
Sulfur (total)	.17	.12	.13	.33	.24

Source: MIRL Report No. 50, University of Alaska - Mining and Mineral Resource and Research Institute (1980)

Table 5-6

1984 NENANA COAL ANALYSIS

Higher Heating Value, Btu/lb	7,600
Moisture content, %	26
Ash content, %	8.3
Sulfur content, %	.2

Source: Fairbanks Municipal Utility System

6.0 LOAD FORECAST

6.1 INTRODUCTION

The major driving force in the Alaskan economy is oil revenues, which are dependent on world oil prices as discussed in Chapter 2. Load forecasts for the Railbelt contained in the License Application were made by using a series of three econometric computer models: a petroleum revenue forecasting model operated by Alaska Department of Revenue (DOR); the Man-in-the-Arctic Program (MAP) model operated by the Institute of Social and Economic Research (ISER); and the Railbelt Electricity Demand (RED) model operated by Battelle Northwest Laboratories. The petroleum revenue model produces State revenue forecasts based upon petroleum price forecasts. MAP converts these revenue projections into projections of State-wide economic conditions, including population, housing, and employment. The RED model then uses MAP model output, along with additional data, to produce an electrical energy and peak demand forecast for the Railbelt.

6.2 LICENSE APPLICATION LOAD FORECAST

Table B.103 of Exhibit B of the License Application summarizes the Reference Case forecast input and output data utilized in the modeling effort for the period 1983 through 2010. This was the License Application forecast period for both the MAP and RED models. That table shows that Railbelt population is expected to increase from about 320,000 in 1983 to approximately 530,000 by the year 2010. The corresponding number of households would increase from approximately 110,000 in 1983 to 196,000 in 2010. The electric energy consumption is predicted to increase from 2,803 GWh in 1983 to approximately 5,900 GWh in 2010. The corresponding average annual growth rate over the period 1983 through 2010 is 2.8 percent. Peak demand is expected to increase from about 580 MW in 1983 to approximately 1,200 MW in the year 2010.

6.3 CONTINUING STUDIES

Although the three models described above undergo continuous refinement, for the purpose of the analyses conducted in this Appendix, the versions of the models used in the License Application have been retained.

The variables which have been changed since the License Application and which are put into the three models are: (1) the world oil price forecast input to the petroleum revenue model and (2) fuel oil, natural gas and electricity prices used by the RED model. A comparison of the updated load forecast with that in the License Application shows a decrease of less than 2 percent, which would have no significant impact on these economic analyses. Therefore the License Application load forecast was used for the studies presented in Chapter 8.

7.0 DESIGN REFINEMENTS AND REVISED PROJECT COST ESTIMATE

7.1 INTRODUCTION

Since the filing of the License Application the Power Authority has conducted additional geotechnical and engineering investigations. This additional review of the area's geology and project engineering has shown that by refining certain design concepts, project design could be improved and the estimated construction costs of the project could be reduced from those originally filed. On August 14, 1984, the Power Authority submitted the proposed design refinements and revised cost estimate to the FERC. The cost savings relating to these design refinements are taken into account in the economic evaluation presented in this Appendix.

The design of the Susitna Project as filed is fully set forth in Exhibits A, C and D of the License Application, and no attempt will be made here to summarize that information. Only the specific components of the original design which are affected by the refinements will be addressed in the following discussion.

7.2 PROPOSED DESIGN REFINEMENTS

The following design refinements are contemplated for the Watana Development:

1. Reduced bedrock and alluvium excavation treatment for the dam embankment foundation.
2. Revised configuration and composition of the dam and the cofferdams' internal zoning.
3. Revised vertical setting and size of diversion tunnels and increased cofferdam height.
4. Relocation and reorientation of the transformer gallery, powerhouse and surge chamber caverns.
5. Revised arrangement of power conduits and power intake.
6. Increase in size of main service spillway to pass the Probable Maximum Flood (PMF) and elimination of the emergency (fuse-plug type) spillway.

7. Revised layout of approach channels to the power intake and spillway.
8. Construction facilities reduced in accordance with reductions in construction work.
9. Rotational speed of turbine-generator units increased from 225 to 257.1 rpm.
10. Underground SF6 gas-insulated switchgear and and SF6 gas insulated bus to the ground surface selected instead of an open-air switchyard supplied by oil-filled main leads from the underground powerhouses.
11. Selection of open-cut trench instead of tunnel for spillway chute drainage.

The savings that would result from the adoption of these changes has been calculated to be approximately $360 million.

7.3 PROJECT COST ESTIMATE

In reanalyzing the Project in conjunction with the design refinements, the Power Authority has had the opportunity also to re-calculate the cost for the Susitna Project based on more refined estimating procedures, to include cost savings in the relict channel and to consider the Project's actual and projected pre-design expenses. In the License Application, the Susitna Project was estimated to cost $5.15 billion in 1982 dollars. The re-calculation of the cost of the Project as filed has resulted in a revised cost estimate of $5.19 billion (1982 $). Adoption of the design refinements noted above would reduce the Project construction cost as noted above to result in a revised total Project costs of $4.83 billion or a total reduction of approximately $320 million over the License Application estimate.

8.0 ECONOMIC EVALUATION

8.1 INTRODUCTION

This chapter summarizes the methodology and key variables used to analyze the economic feasibility of the Susitna Project.

8.2 METHODOLOGY

The economic analyses contained in the License Application and in this Appendix compare the costs of alternative means of meeting the electrical demand of the Alaska Railbelt during the planning period 1993-2051. Load forecasts were developed and energy supply plans were formulated and compared over this planning period. For electric generation planning, a capacity expansion optimization model developed by General Electric -- the Optimized Generation Planning (OGP) program -- was used to develop alternative equivalent expansion plans.

The Power Authority used OGP to develop alternative electric generation expansion plans for the period January, 1993 to December, 2020 to establish the least costly system for that period with and without the Susitna Project. In the With-Susitna case, it was assumed that Watana would start operation in 1993, and Devil Canyon in 2002. In that plan all of the Susitna Project's energy would be absorbed in the system by about the year 2020. For purposes of evaluating Without-Susitna generating plans, several different plans were considered. Varying amounts of coal-fired and gas-fired thermal generation were added to the existing units to create these optional plans. The total costs for the alternatives include all costs of fuel and the O&M costs of the generating units. In addition, the costs include the annual investment costs of any plants and transmission facilities added during the period.

The annual costs from 1993 through 2020 were developed by the OGP model, and then converted to a 1982 present worth figure. The long-term system costs (2021-2051) were estimated by extending the 2020 annual costs, with no load growth, and adjusting fuel prices to reflect any real fuel price escalation for the 30-year period. The selection of 2051 as the last year of the planning horizon recognizes the full 50-year economic life of the Devil Canyon project, which is added to the With-Susitna expansion plan in 2002. This extended period of time is necessary to ensure that the full economic lives of hydroelectric plants are taken into account in the economic planning process.

The With-Susitna and Without-Susitna expansion plan costs are used to assess the economic benefits of the Susitna Project. Benefits are based on the difference between the costs of the most feasible, least costly Without-Susitna plan and the With-Susitna plan (net benefits). For the Susitna Project to be considered economically feasible, generally the benefit/cost ratio of the With-Susitna alternative over the Without-Susitna alternative should be greater than one.

8.3 LICENSE APPLICATION ECONOMIC PARAMETERS

Table 8-1 summarizes the principal economic parameters that were used in economic analysis contained in the License Application. The studies on fuel availability and cost are contained in the License Application Exhibit D, Appendix D-1, Fuels Pricing Studies, which are reviewed and summarized in Chapters 3 and 4 of this Appendix. Thermal plant characteristics and costs are discussed in Chapter 5. The License Application Reference Case oil price forecast and load forecast are discussed in Chapters 2 and 6, respectively.

8.4 CHANGES IN ECONOMIC PRINCIPLES AND PARAMETERS

The key variables and assumptions used in this Appendix analysis are discussed in this section and summarized in Table 8-2. The capital costs, fuel and operation and maintenance costs of the alternatives have been estimated with reference to 1982 price levels. Costs incurred in future years reflect relative price changes only. The base year for the present worth analysis, or the year to which all costs are discounted for comparison, is 1982. The real discount rate, which was 3.0 percent in the License Application, was revised to 3.5 percent in this analysis to reflect a change in financial parameters adopted by the Power Authority, after consultation with its advisors and members of the financial community.

Recent studies on fuel availability and costs are described in Chapters 3 and 4. A review of the construction, operation and maintenance costs, and heat rates used in the License Application resulted in revisions that better reflect the type of plants which would be installed in the Without-Susitna alternative. The revised values discussed in Chapter 5 were used in the present analysis. In addition, more detailed estimates were made of the operation and maintenance costs of the Susitna Project. The revised costs are shown on Table 8-2, Page 1 of 3.

The cost estimate of the Susitna Project has been revised in accordance with the discussion presented in Chapter 7. 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. These are revised values from those used by the Power Authority for the economic studies contained in the License Application. The reduced lifetime for combustion turbines reflects a current Alaska Public Utilities Commission ruling. The revised retirement schedule of existing Railbelt generating units is shown in Table 8-3.

8.5 REVISED SYSTEM EXPANSION PLANS

The OGP-6 program was run using the revised economic parameters and data discussed in the previous chapters. The resulting With-Susitna and Without-Susitna system expansion plans are shown in Table 8-4. In the Without-Susitna plan, the first two coal-fired generating units would be installed in Nenana and the remaining four units in the Beluga field, as more fully described in Chapter 5. The revised Without-Susitna expansion plan differs from that presented in the License Application by the location of the initial two coal-fired units. The installation dates of some of the units in both the Without-Susitna and With-Susitna plans have also changed due to changed assumptions regarding the first plants to be added to the expansion plans.

8.6 ECONOMIC COMPARISON

The net benefits and benefit/cost ratio of the With-Susitna alternative compared to the Without-Susitna alternative using the revised parameters are set forth in Table 8-5.

Also shown in Table 8-5 are the net benefits and benefit-cost ratio presented in the License Application. It may be observed that net benefits have increased by $499 million and that the benefit/cost ratio has increased to 1.41 from 1.33 based on the revised parameters.

LICENSE APPLICATION ECONOMIC PARAMETERS

Price Level	-	1982
Base Year Present Worth Analysis	-	1982
Planning Horizon	-	1993-2020 by OGP-6 2021-2051 by extension
Discount Rate	-	3.0%
Fuel Prices	-	See Table 8-1 Page 2 of 4
Thermal Generating Plant Parameters	-	see Table 8-1 Page 3 of 4
Load Forecast	-	Reference Case See Table 8-1 Page 4 of 4

Economic Life of Projects --

Large Coal-Fired Steam Turbines (greater than 100 MW):	30 years
Small Coal-Fired Steam Turbines (less than 100 MW):	35 years
Oil-Fired Combustion Turbines:	20 years
Natural Gas-Fired Combustion Turbines:	30 years
Combined Cycle Turbines:	30 years
Conventional Hydro:	50 years
Diesels:	30 years

Susitna Project Construction Cost, million $

Watana	3,596
Devil Canyon	1,554
TOTAL	5,150

Susitna Project Annual Operation and Maintenance Cost, million $

Watana	10.4
Devil Canyon	4.8
TOTAL	15.2

LICENSE APPLICATION ECONOMIC PARAMETERS

FUEL PRICES
(1983 Price Level)

Year	Oil Price ($/bbl)	Coal Price ($/MM Btu)		Gas Price ($/MM Btu)	
		Nenana Delivered	Beluga Minemouth	Cook Inlet Wellhead	North Slope Delivered
1983	28.95	1.72	1.86	2.47	4.00
1985	26.30	1.77	1.92	2.16	3.64
1990	27.90	2.02	2.08	2.74	3.98
		Combined			
1995	32.34	2.21		3.18	4.61
2000	37.50	2.33		3.69	5.35
2005	43.47	2.44		4.27	6.20
2010	50.39	2.57		4.95	7.18
2020	64.48	2.84		6.34	9.20
2030	74.84	3.13		7.36	10.67
2040	82.66	3.46		8.13	11.79
2050	91.32	3.82		8.99	12.63

LICENSE APPLICATION ECONOMIC PARAMETERS

SUMMARY OF THERMAL GENERATING PLANT PARAMETERS/1982$

Parameter	Coal 200 MW	Combined Cycle 200 MW	Gas Turbine 70 MW	Diesel 10 MW
Heat Rate (Btu/kWh)	10,000	8,000	12,200	11,500
Earliest Availability	1989	1980	1984	1980
O&M Costs				
Fixed O&M ($/yr/kW)	16.83	7.25	2.7	0.55
Variable O&M ($/MWH)	0.6	1.69	4.8	5.38
Outages				
Planned Outages (%)	8	7	3.2	1
Forced Outages (%)	5.7	8	8	5
Construction Period (yrs)	6	2	1	1
Startup Time (yrs)	6	4	4	1
Unit Capital Cost ($/kW)[1]				
Railbelt	2,051	1,075	627	856
Beluga	-	-	-	-
Nenana	2,107	-	-	-
Unit Capital Cost ($/kW)[2]				
Railbelt	2,242	1,107	636	869
Beluga	-	-	-	-
Nenana	2,309	-	-	-

Notes:

(1) As estimated by Battelle/Ebasco without AFDC.
(2) Including IDC at 0 percent escalation and 3 percent interest, assuming an S-shaped expenditure curve.

Source: Battelle 1983, Vol. II, IV, XII, XIII

LICENSE APPLICATION ECONOMIC PARAMETERS
REFERENCE CASE LOAD FORECAST

Year	Total System Sales[1/] Peak Demand (MW)	Total System Sales[1/] Sales (GWh)	Net Generation[2/] Peak Demand (MW)	Net Generation[2/] Energy Demand (GWh)
1983	579	2803	637	3083
1984	609	2950	670	3245
1985	639	3096	703	3406
1986	667	3224	734	3546
1987	695	3352	765	3687
1988	722	3481	794	3829
1989	750	3609	825	3970
1990	777	3737	855	4111
1991	796	3724	876	4096
1992	814	3911	895	4302
1993	832	3997	915	4399
1994	850	4084	935	4492
1995	868	4171	955	4588
1996	884	4245	972	4670
1997	899	4319	989	4751
1998	914	4394	1005	4833
1999	930	4468	1023	4915
2000	945	4542	1040	4996
2001	968	4652	1065	5117
2002	991	4762	1090	5238
2003	1013	4872	1114	5359
2004	1036	4983	1140	5481
2005	1059	5093	1165	5602
2006	1091	5246	1200	5771
2007	1122	5388	1234	5939
2008	1154	5552	1269	6107
2009	1186	5705	1305	6276
2010	1217	5858	1339[3/]	6444[3/]
2011			1373	6610
2012			1408	6780
2013			1444	6955
2014			1481	7135
2015			1519	7318
2016			1558	7507
2017			1598	7701
2018			1639	7899
2019			1681	8103
2020			1724	8312

1/ Source: RED Model output; Table B.117, Volume 2A, FERC License July 11, 1983.

2/ Includes 10 percent for transmission and distribution losses.

3/ The load forecasts produced by the RED Model were extended from 2010 to 2020 using the average annual growth for the period 2000 to 2010.

APPENDIX ECONOMIC PARAMETERS

Price Level	-	1982
Base Year Present Worth Analysis	-	1982
Planning Horizon	-	1993-2020 by OGP-6
		2021-2051 by extension
Discount Rate	-	3.5
Fuel Prices	-	See Table 8-2 Page 2 of 3
Thermal Generating Plant Parameters	-	See Table 8-2 Page 3 of 3
Load Forecast	-	License Application Reference Case See Table 8-1 Page 4 of 4

Economic Life of Projects

Coal-fired Steam Turbines:	30 years
Combustion Turbines:	20 years
Combined Cycle Turbines:	30 years
Hydroelectric Projects:	50 years
Diesels:	20 years

Susitna Project Construction Cost, million $

Watana	3,361
Devil Canyon	1,469
Total	4,830

Susitna Annual Operation and Maintenance Cost, million $

Watana (initial)	8.5
Devil Canyon (initial)	2.5
Total Susitna (combined)	7.3

APPENDIX ECONOMIC PARAMETERS

FUEL PRICES
(1983 Price Level)

Year	Oil Price ($/bbl)	Coal Price ($/MM Btu)		Gas Price ($/MM Btu)	
		Nenana Delivered	Beluga Minemouth	Cook Inlet Wellhead	North Slope Delivered
1983	28.95	1.87	-	2.47	-
1985	26.30	1.91	-	2.25	-
1990	27.90	2.00	-	2.80	2.86
1995	32.50	2.09	-	3.39	4.00
2000	40.00	2.20	1.95	4.09	4.93
2010	60.00	2.43	2.40	4.94	7.37
2020	80.00	2.69	2.80	-	9.83
2030	90.00	3.00	3.35	-	11.00
2040	100.00	3.35	4.00	-	12.00
2050	110.00	3.76	4.75	-	13.00

APPENDIX ECONOMIC PARAMETERS

SUMMARY OF THERMAL GENERATING PLANT PARAMETERS/1982$

Parameter	Coal 200 MW	Combined Cycle 228 MW 3/4/	Combustion Turbine 87 MW 3/4/	Diesel 10 MW
Heat Rate (Btu/kWh) 3/	10,300	8,300	11,060	11,500
Earliest Availability	1992	1988	1985	1985
O&M Costs				
Fixed O&M ($/yr/kW) 3/	51.36	11.75	7.61	0.55
Variable O&M ($/MWh) 3/	3.61	0.54	0.28	5.38
Outages				
Planned Outages (%)	8	7	3.2	1
Forced Outages (%)	5.7	8	8	5
Construction Period (yrs)	6	2	1	1
Startup Time (yrs)	6	4	1	1
Unit Capital Cost ($/kW) 1/				
Beluga/Railbelt	2,300	595	471	856
Nenana	2,350	-	-	-
Unit Capital Cost ($/kW) 2/				
Beluga/Railbelt	2,552	616	479	871
Nenana	2,607	-	-	-

Notes:

1/ As estimated without AFDC based on 33°F rating for combustion turbines.

2/ Including AFDC at 0 percent escalation and 3.5 percent interest, assuming an S-shaped expenditure curve.

3/ Based on 33°F rating for combustion turbines.

4/ Includes water injection for NO_x control for combustion turbines. Actual net output ISO is 217 MW and 79 MW for combined-cycle and simple-cycle plants, respectively.

Table 8-3

REVISED SCHEDULE OF
RAILBELT RETIREMENTS

	Capacity (MW) Retired						
		Combustion Turbine					
Year	Coal	Gas	Oil	Diesel	Combined Cycle	Annual Total	Cumulative
1993		53				53	53
1994						-	53
1995		58	7			65	118
1996			94			94	212
1997	25		65			90	302
1998		26				26	328
1999				1		1	329
2000	21			6		27	356
2001						-	356
2002		116				116	472
2003						-	472
2004						-	472
2005						-	472
2006						-	472
2007						-	472
2008						-	472
2009					139	139	611
2010	13					13	624
2011						-	624
2012					178	178	802
2013						-	802
2014						-	802
2015						-	802

TABLE 8-4

REVISED EXPANSION PLANS
CAPACITY ADDITIONS

	Railbelt		With-Susitna Expansion Plan Watana (1993) + Devil Canyon (2002)				Without-Susitna Plan			
Year	Demand Peak (MW)	Energy Requirements (GWh)	Coal (MW)	Combustion Turbine (MW)	Susitna (MW)	Total (a) Capability (MW)	Coal (MW)	Combustible Turbine (MW)	Combined Cycle (MW)	Total (a) Capability (MW)
1993	915	4397		87	539	1518	200	87	228	1408
1994	935	4492		87		1605				1408
1995	955	4588		87		1627		87		1430
1996	972	4670				1533	200			1536
1997	989	4751				1443		87		1533
1998	1005	4833				1417				1507
1999	1023	4915				1416				1506
2000	1040	4996		87		1476		87		1566
2001	1065	5117				1476				1566
2002	1090	5238			635	1995		174		1624
2003	1114	5359				1995				1624
2004	1140	5481				1995				1624
2005	1165	5602				1995	200			1825
2006	1200	5771				1995				1825
2007	1234	5939				1995				1825
2008	1269	6107				1995				1825
2009	1305	6276				1856	200			1886
2010	1339	6444			49	1892				1873
2011	1373	6610				1892		87		1960
2012	1408	6780		87		1801	200			1982
2013	1444	6955		174		1888		87		1982
2014	1481	7135		174		1975				1982
2015	1519	7318		87		1888		174		2069
2016	1558	7507				1975				2069
2017	1598	7701				1975	200			2182
2018	1639	7899		87		1975				2182
2019	1681	8103				2062		87		2269
2020	1724	8312	200			2175		87		2269

(a) Includes existing generation plants less retirements.

Table 8-5

NET BENEFITS AND BENEFIT-COST RATIO OF WITH-SUSITNA ALTERNATIVE

	1982 Present Worth ($ x 10^6)	
	License Application	Revised Analysis
Costs of Without Susitna Plan	7,316	8,025
Costs of With Susitna Plan	5,489	5,699
Net Economic Benefits	1,827	2,326
Benefit Cost Ratio	1.33	1.41