Southcentral Railbelt Area, Alaska
Upper Susitna River Basin

00097

SUPPLEMENTAL FEASIBILITY REPORT

HYDROELECTRIC POWER and related purposes

U.S. Department of the Army
Alaska District
Corps of Engineers

Appendix
Part 2

Anchorage, Alaska

1979

SOUTHCENTRAL RAILBELT AREA, ALASKA
UPPER SUSITNA RIVER BASIN
SUPPLEMENTAL FEASIBILITY REPORT

APPENDIX - PART II

Section G - Marketability Analysis
Section H - Transmission System
Section I - Environmental Assessment for Transmission System

Prepared by the
Alaska District, Corps of Engineers
Department of the Army

February 1979

SECTION G

MARKETABILITY ANALYSIS

United States Department of Energy
Alaska Power Administration

Department Of Energy
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

April 2, 1979

Colonel George R. Robertson
District Engineer
Corps of Engineers
P.O. Box 7002
Anchorage, Alaska 99510

Dear Colonel Robertson:

This is Alaska Power Administration's new power market report for the Upper Susitna Project. It's an update of the previous power market analyses provided for the Corps' 1976 Interim Feasibility report.

The power market report includes: a new set of load projections for the Railbelt area through year 2025 and a review of alternative sources of power. Load/resource and total power system cost analyses were prepared for different scenarios under various assumptions to determine effects on power rates.

Under the assumptions made for this report, Alaska Power Administration determines that the Upper Susitna Project is feasible from a power marketing standpoint.

A draft of this report was circulated to the area utilities and concerned State officers for informal review and comment. Comments have been incorporated and the letters of comments are appended.

Sincerely,

R. J. Cross

Robert J. Cross
Administrator

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3. LOAD/RESOURCE AND SYSTEM COST ANALYSIS FOR THE RAILBELT REGION OF ALASKA: 1978-2010 --Informal Report-- by Battelle Pacific Northwest Laboratories, Richland, Washington - January, 1979.

4. Comments.
   a. Federal Energy Regulatory Commission, San Francisco, California.
   b. Battelle Pacific Northwest Laboratories, Richland, Washington.
   c. Corps of Engineers, Anchorage, Alaska
   d. The Alaska State Clearinghouse, Juneau, Alaska
   e. Municipal Light and Power, Anchorage, Alaska

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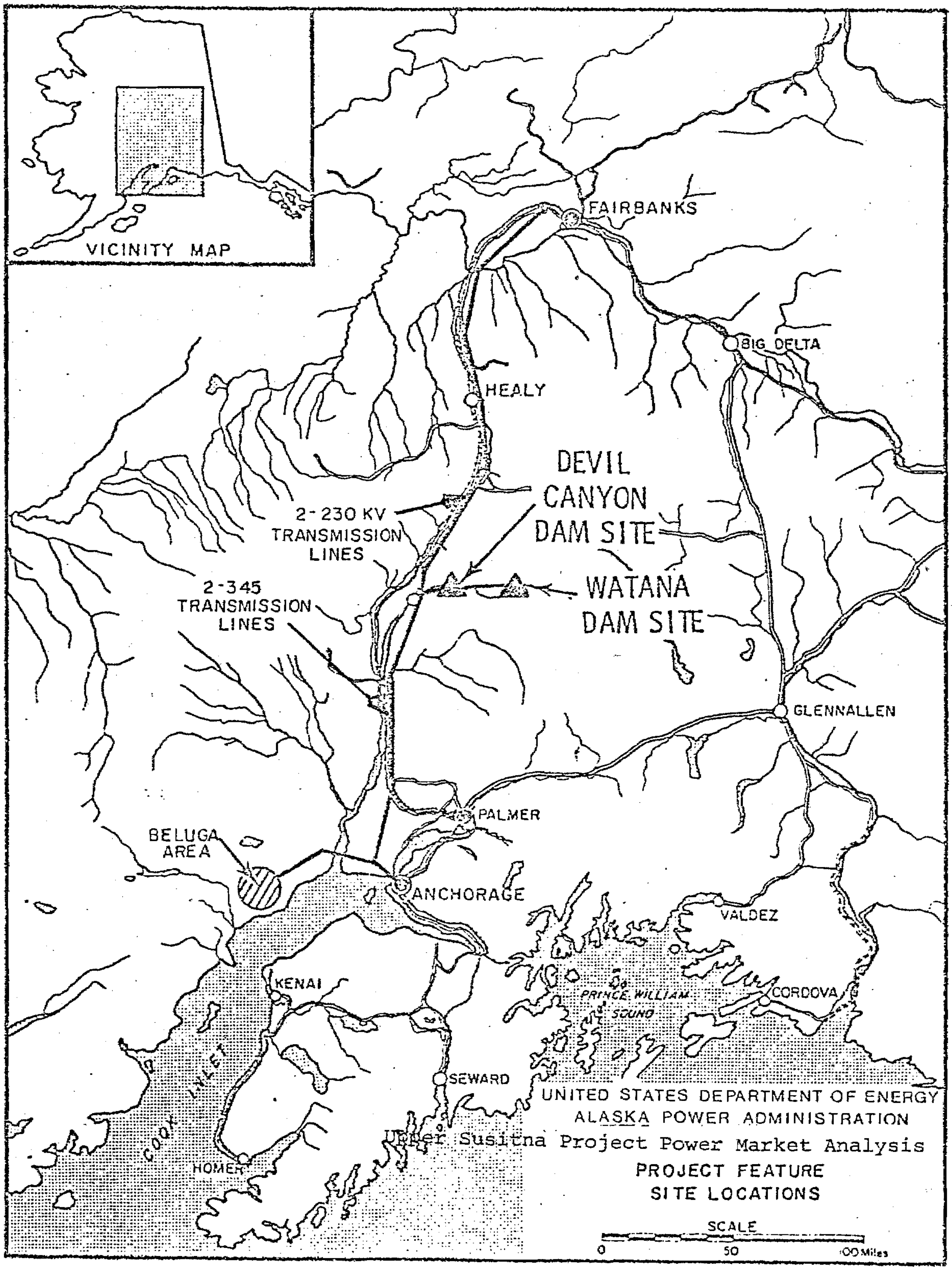

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PART I. INTRODUCTION

The Interim Feasibility Report of the Upper Susitna River Basin Project (1976 report) was completed by the Alaska District Corps of Engineers (Corps) in 1976. Alaska Power Administration (APA) provided the transmission system and power market analyses for that report.

The Corps submitted the 1976 report to the Office of Management and Budget (OMB) for review. In September 1977, OMB requested the Corps obtain additional data before submitting the report to Congress. The requested data were to: (1) provide additional geologic data for the Watana damsite; (2) reanalyze the cost estimate contingency factor; (3) reanalyze area development benefits; and (4) reanalyze the projected construction schedule. There were also questions about power supply and demand, including sensitivity to developing a large block of power in APA's area of responsibility.

This report updates the power market analysis and addresses OMB concerns. It uses three years additional data on power usage, effects of the oil embargo, and other factors. Specifically, it (1) updates the power demand forecasts reflecting data since the 1976 report; (2) updates the transmission and project OM&R costs; (3) presents load/resource analyses to determine timing of major generation and transmission investments and reflect resulting impacts on power system costs; (4) presents system power cost analyses that show annual system-wide costs of power with and without the Upper Susitna Project; (5) examines the value of an Anchorage to Fairbanks interconnection with and without Susitna; (6) provides a subanalysis of the feasibility of delivering Susitna power to the Valdez-Glennallen area; (7) determines power rates and marketability of Susitna power compared with alternative generation methods; and (8) responds to the OMB questions in APA's areas of responsibility.

APA gave the Corps, for their report purposes: updated transmission system costs and project OM&R estimates; load estimates; detailed load/resource and system cost analyses with and without Susitna project; and proposed responses to OMB questions pertinent to APA areas of responsibility.

The Corps' current proposal for the Upper Susitna Project is essentially the same as plan 5 in the 1976 report: a two-phase, two-dam complex including Watana and Devil Canyon dams and powerplants, with the Watana phase and a transmission system interconnecting Anchorage and Fairbanks coming on-line first. Power production facilities include Watana dam, reservoir, and powerplant, and Devil Canyon dam, reservoir, and powerplant. Watana dam would be an earthfill structure with reservoir normal water surface elevation of 2,185 feet; the powerplant would have 795 MW capacity. Devil Canyon dam would be a double-curvature concrete-arch structure with maximum pool elevation of 1,450 feet, providing water for a 778-MW powerplant. The transmission system would be constructed in conjunction with the first stage (Watana), and, as planned, would be totally required for system reliability. The system would incude two parallel 230-kv single circuit lines from Watana to Devil Canyon (30 miles), two parallel single circuit 345-kv lines from Devil Canyon to Pt. McKenzie (Anchorage, 135 miles), and two parallel single circuit 230-kv lines from Devil Canyon to Ester-Gold Hill (Fairbanks, 198 miles).

Several significant changes were made by the Corps since the 1976 report:

(1) The Devil Canyon dam design and costs are presented for both a gravity structure and a thin-arch concrete structure. The 1976 report was based on a thin-arch concrete structure.

(2) The construction period for Watana was increased from 6 years to 11; Devil Canyon from 4 years to 7; and the Anchorage-Fairbanks intertie re-scheduled for 1991--three years before Watana POL.

(3) Watana dam (earth fill) was redesigned, based on new geologic data.

The APA power market report uses certain assumptions that differ from the Corps plan, namely:

(1) Design power generation capacity: The Corps design capacity is based on critical year primary energy and 50 percent annual plant factor (1,392 MW). The APA load/resource analyses assume a design capacity based on average annual energy and 50 percent plant factor (1,573 MW). APA analyses include both primary and secondary energy as well as firm and non-firm power.

(2) Transmission intertie schedule:

The Corps plans show a 1991 on-line date for the transmission intertie. The APA system cost analyses examine alternative on-line dates of 1990, 1992, and 1994. The load/resource analysis showed the earliest intertie dates could be 1986, 1989, and 1991. APA financial analyses are consistent with the Corps schedule.

(3) For Devil Canyon Design:

The APA system cost and financial analyses assume the thin-arch design for Devil Canyon as presented in the 1976 report, rather than the more costly gravity structure alternative now being used by the Corps for feasibility testing. A separate analysis demonstrates the effect of the gravity dam alternative on cost of power.

The term "1976 report" is used throughout this report. This term refers to the Corps of Engineers Interim Feasibility Report on the Upper Susitna project, dated December 1975, revised June 1976. It also refers to APA's Power Market analysis dated 1975 and included as Appendix G in the revised Interim Feasibility Report.

Part II. SUMMARY

Current studies have updated and revised the power market analyses of the 1976 Upper Sustina Report (1976 report). New estimates of power requirements through the year 2025 have been prepared.

The 1976 report used energy and power estimates based on data through December 1974. The new analyses benefit from three full years of additional data through December 1977. This provides a full four years of "post oil-embargo" data--especially significant from the viewpoint of identifying conservation trends. Evidence of conservation shows in the Anchorage-Cook Inlet area growth comparisons before and after the 1973-74 fuel crisis. The 1970-73 average annual growth in net generation dropped from 14.2 percent to 12.7 percent in the 1973-77 period. The decrease was more dramatic for per capita net generation: A drop from 8 percent to 3.8 percent.

Because the net generation kwh/capita raio seemed to reflect the closest correlations, particularly in recent years, this ratio and population were used to forecast net generation values between 1980 and 2025.

The following Railbelt totals are detailed in Part V. Trended values offer an interesting comparison but are not presented as part of the forecast. The trend is an average annual growth of 12.3 percent resulting from 12.7 percent for the Anchorage area and 10.5 percent for the Fairbanks area.

Railbelt Area Energy Forecast
(GWH)

		1977 (Historic)	1980	1990	2000	2025
Utility:						
	High		3,410	8,200	16,920	38,020
	Mid	2,273	3,155	6,110	10,940	17,770
	Low		2,920	4,550	7,070	8,110
National Defense:						
	High		348	384	425	544
	Mid	338	338	338	338	338
	Low		330	299	270	210
Self-Supplied Industry:						
	High		170	2,100	3,590	8,490
	Mid	70	170	630	1,460	3,470
	Low		141	370	550	1,310
Total:						
	High		3,928	10,684	20,935	47,054
	Mid	2,681	3,663	7,078	12,738	21,578
	Low		3,391	5,219	7,890	9,630
Trend @ 1973-77 annual/growth:			(3,215)	(10,270)	(33,000)	(601,000)

Area load characteristics data were updated and new estimates of monthly energy distribution were made. The conclusion was that the 50 percent plant factor sizing assumption is still valid.

A further review of possible power supply alternatives included oil and natural gas, coal, alternative hydro projects, nuclear, wind, geothermal, and tide. It concluded again that coal-fired steam plants are the most logical alternatives for major railbelt area power supplies in the proposed Susitna project timeframe.

New estimates of cost of power from coal-fired steamplants were prepared using results of several recent studies. They indicate:

Investment costs of $1,620-$1,860/kw

Unit cost of power of 5.2-6.4¢/kwh (including transmission to load center)

A set of load/resource and annual system cost analyses were performed to examine the effects of Susitna and the transmission intertie from an overall power system approach. These analyses were needed to provide responses to OMB questions regarding: (1) the value of an interconnected transmission system between Anchorage and Fairbanks; (2) scheduling of major powerplants; and, (3) sensitivity of developing large blocks of power. APA's response to the OMB questions are appended. Three cases were analyzed using three projected load growth estimates:

Case 1. A <u>without</u> Susitna Project and <u>without</u> transmission intertie situation assuming all generating capacity to be supplied by coal-fired steamplants.

Case 2. Same as case 1 but with transmission intertie.

Case 3. A <u>with</u> Susitna Project and <u>with</u> intertie situation assuming additional generating capacity supplied by coal-fired steamplants. The load/resource analyses showed the schedule of new plant additions needed for all three cases for 1978-2011.

The system cost analyses compared annual power system costs for all three cases, assuming 0 and 5 percent inflation rates. The analyses showed annual system cost savings of $2.23 billion between 1990 and 2011, with the Susitna project. Average power system rates for the year 2000 assuming no inflation will be:

¢/KWH

Load Forecast	Case 1 Without Susitna or Intertie	Case 2 Without Sustina With Intertie	Case 3 With Susitna and Intertie
High	6.6 1/	6.4	5.8
Mid	6.9 1/	6.6	5.7
Low	7.5 1/	6.7	6.4

1/ Anchorage and Fairbanks are not interconnected for case 1; the combined system rate is shown for academic purposes only.

For the medium energy use range, system rates, compared to those without Susitna or interconnections, will be 5.7 percent less with interconnections 18.6 percent less with Susitna.1/ The analyses showed Susitna will result in cheaper power cost to Anchorage and Fairbanks in all load growth cases. It also shows that the project power could be fully used under all projected power demand cases.2/

In comparison with the 1976 report, investment costs are 89 percent ($1.567 billion) greater. Contributing factors are: interest rate increase from 6 5/8 to 7 1/2 percent total construction period increase from 6 years to 10 years, cost inflation; and redesign of Watana dam and powerplant facilities. New construction cost estimates for Watana dam (containing effects of both design quanitity changes and unit cost inflation) are $595 million (72 percent) higher. Construction cost estimates for Devil Canyon dam (thin-arch concrete) power plant facilities, and the transmission system were updated primarily by indexing. This resulted in a 54 percent increase over the 1976 report ($233 million for Devil Canyon and $82 million for the transmission system). The total interest during construction increase is 265 percent ($657 million). In summary, the increases in construction costs are:

Watana	$ 595 million	
Devil Canyon	233 "	
Transmission System	82 "	
Interest during Construction	657 "	
Total	$1567 million	- project investment cost increase

Financial analyses were based on the October 1978 price level, Fiscal Year 1979 Federal interest rate of 7 1/2 percent, intertie in 1991 or 1992, and repayment of all principal and interest within 50 years after the last unit is installed.

1/ $\frac{\text{Case 2 Value (6.6\%)}}{\text{Case 1 Value (7.0\%)}} -1 = -5.7\%$; $\frac{\text{Case 3 Value (5.7\%)}}{\text{Case 1 Value (7.0\%)}} -1 = -18.6\%$

2/ Interconnection benefits leading to lower rates involve load supply flexibility, economics of scale and operations, decreased reserve requirements, and better reliability.

A comparison of the rate for Sustina at 4.7¢/kwh with the coal-fired steamplant alternative at 5.2/kwh to 6.4¢/kwh shows Susitna is less costly.

The Glennallen-Valdez area was considered as a market area supplementary to the Railbelt. The Copper Valley Electric Association (CVEA) plans to construct a Glennallen-Valdez transmission line, and the presence of the pipeline terminal in Valdez with its related economy has made this area a more attractive market since the 1976 report. Service to the area would require a 138-kv line from Palmer to Glennallen (136 miles). Area market factors are subject to fluctuation. Potential industrial loads are difficult to project at this time, but service to utility loads can be evaluated for a probable range of demands. Energy costs to serve the incremental market area will range from 2.6¢/kwh to 1.3¢/kwh for a range of loads from 150 to 300 kwh/year in addition to the project energy cost of 4.7¢/kwh. Inclusion of the market area costs with other project costs for a single project-wide rate would not adversely affect the rate.

PART III. POWER MARKET AREAS

Throughout its history of investigations, the Upper Susitna River Basin Project has been of interest for hydroelectric power generation because of its central location to the Fairbanks and Anchorage areas. These areas have Alaska's largest concentrations of population, economic activity, services, and industry. Under any plan of development, major portions of the project power will be used in these two areas. In addition, the basic project transmission system serving Anchorage and Fairbanks could provide electric service to present and future developments between the two cities.

The potential major market areas are the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area.

Anchorage-Cook Inlet Area

This area includes the developed areas of the Matanuska Valley, Greater Anchorage Area, and Kenai Peninsula.

This general area has been the focal point for most of the State's growth in terms of population, business, services, and industry since World War II. Major building of defense installations, expansion of government services, discovery and development of natural gas and oil in the Cook Inlet area, and emergence of Anchorage as the State's center of government, finance, travel, and tourism are major elements in the history of this area.

Because of its central role in business, commerce, and government, the Anchorage area is directly influenced by economic activity elsewhere in the State. Much of the buildup in construction and operation of the Alyeska pipeline, much of the growth related to Cook Inlet oil development, and much of the growth in State and local government services since Statehood has occurred in the immediate Anchorage vicinity.

Initially, economists overestimated the impacts of completion of the trans-Alaska oil pipeline. In a recent study prepared by the University of Alaska Institute of Social and Economic Research, the projected 1980 population for Anchorage-Cook Inlet was lower than that of the historical 1977 population. Though this has been corrected, it indicates that the area's economy has been stronger than anticiapted.

The Greater Anchorage Area Borough estimated its July 1, 1977 population at 195,800, an increase of nearly 55 percent since the 1970 census. This was more than 48 percent of the total estimated State population in 1977.

The Matanuska Valley includes several small cities (Palmer, Wasilla, Talkeetna) and the State's largest agricultural community. Other economic activities include recreation and light manufacturing. Much recent growth in the Borough has been in residential and recreational homes for workers in the Anchorage area. Estimated 1977 population was 15,740, a 61 percent increase since 1974.

The Kenai Peninsula Borough includes the cities of Kenai, Soldotna, Homer, Seldovia, and Seward, with important fisheries, oil and gas, and recreation resources. Estimated 1977 population was 23,100, a 39 percent increase since 1974.

Present and proposed activities indicate likelihood of rapid growth in this general Cook Inlet area for the future. Much of this activity is related to oil and natural gas, including expansion of the refineries.

The State capital city site relocation issue remains unresolved. In the November 1978 general election, voters turned down the $966 million bond issue to relocate the capital. In the same election, voters approved an initiative which would require full disclosure of the costs to move the capital. Therefore, it is impossible at this time to include specific assumptions concerning the capital move.

The area will continue to serve as the transportation hub of western Alaska, and tourism will likely continue to increase rapidly. Major local development seems probable.

Fairbanks-Tanana Valley Area

Fairbanks is Alaska's second largest city - the trade center for much of Alaska's Interior, the service center for several major military bases, and the site of the main campus of the University of Alaska with its associated research center. The outlying communities of Nenana, Clear, North Pole, and Delta Junction are included in the Fairbanks-Tanana Valley area. Historically, the area is famous for its gold.

The completion of the pipeline construction has taken its toll in Fairbanks. The area is experiencing a severely depressed economy. Employment in the construction industry has decreased to half of the previous pipeline level. There has been a slight increase in employment generated by government, distributive industries, and retail trade. In 1977-78, Fairbanks and its outlying areas experienced a 16 percent decline in population.

The decision favoring the ALCAN route for the proposed natural gas pipeline was made in late 1977. The proposed gas pipeline will follow the route of the trans-Alaska oil pipeline route from Prudhoe Bay to Delta Junction. Fairbanks has been selected as the operation headquarters by the Northwest Pipeline Company, responsible for construction and operation of the gas pipeline. The Fairbanks-Tanana Valley area will probably be heavily impacted again by the pipeline construction; however, a more stable permanent employment base is likely to become established.

The Fairbanks-North Star Borough had an estimated 1977 population of 44,262 and an estimated additional 8,000 in the outlying communities within the power market area. The total population decreased 10 percent since 1974.

PART IV. EXISTING POWER SYSTEMS

Utility Systems and Service Areas

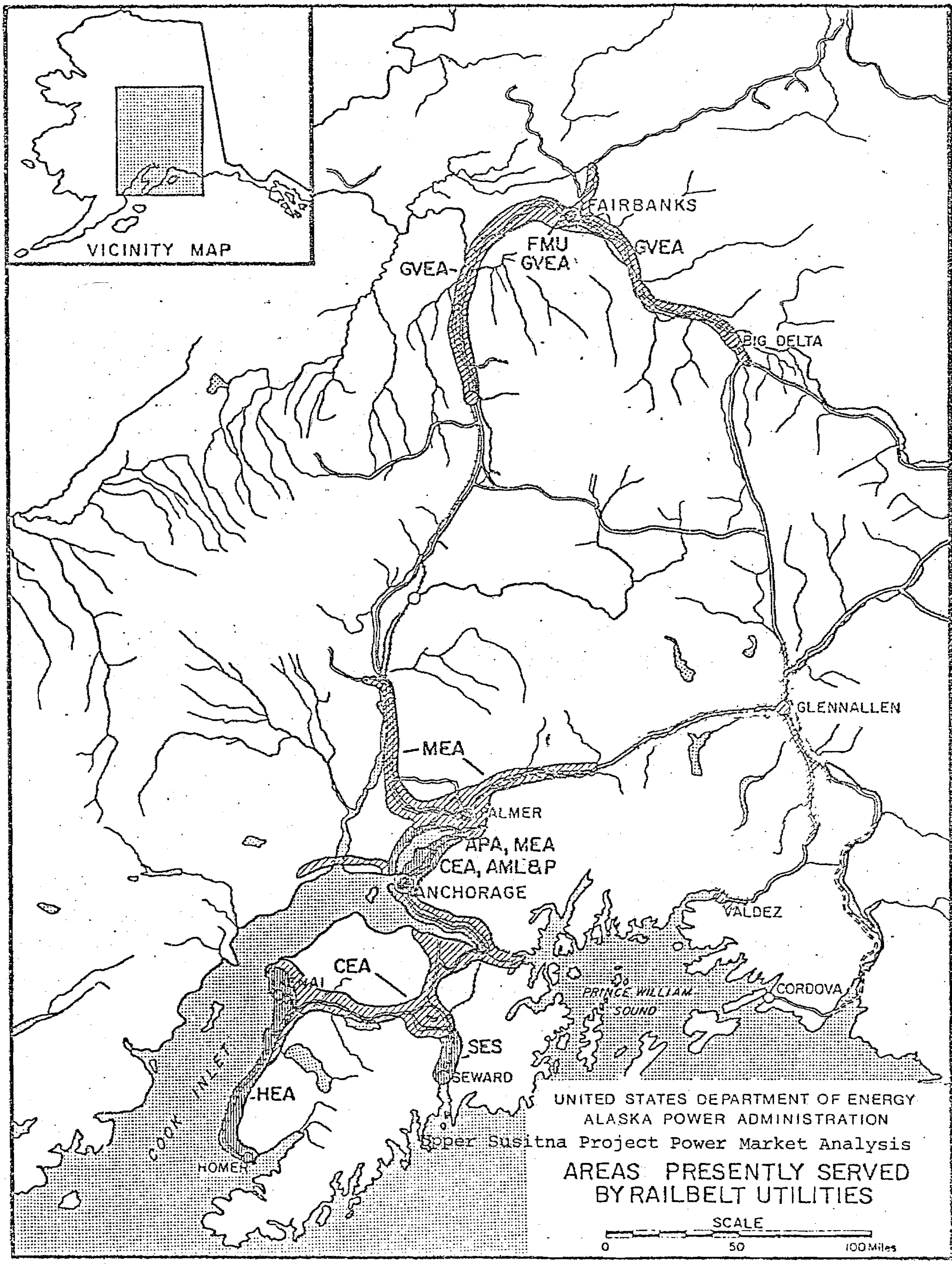
The electric utilities in the Railbelt power market area are listed below, and areas now receiving electric service are shown on figure 2. A detailed listing of power generating units is in the appended Battelle report, table 3.4.

Anchorage-Cook Inlet Area	Installed Nameplate Capacity MW 2/
Alaska Power Administration (APA)	30.0
Anchorage Municipal Light and Power (AML&P)	121.1
Chugach Electric Association (CEA)	345.7
Matanuska Electric Association (MEA)	1/
Homer Electric Association (HEA)	
Homer (Standby)	0.3 1/
Seldovia, English Bay, Port Graham	1.8
Seward Electric System (SES)	5.5 1/
Fairbanks-Tanana Valley Area	
Fairbanks Municipal Utility System (FMUS)	69.6
Golden Valley Electric Association (GVEA)	219.2

1/ Major generation supplied by CEA system.

2/ Consists of 45 MW hydro. All the rest are fuel-fired (80% gas turbine).

Figure 2



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These totals differ from the Battelle appended report because the report includes some planned units not installed in 1977 as well as use of some ratings other than nameplate.

APA operates the Eklutna hydroelectric project and markets wholesale power to CEA, AML&P, and MEA.

AML&P serves the Anchorage Municipal area. CEA supplies power to the Anchorage suburbs and surrounding rural areas, and provides power at wholesale rates to HEA, SES, and MEA. The HEA service area covers the western portion of the Kenai Peninsula, including Seldovia, across the bay from Homer. MEA serves the town of Palmer and the surrounding rural area in the Matanuska and Susitna Valleys.

The utilities serving the Anchorage-Cook Inlet area are now loosely interconnected through facilities of APA and CEA. An emergency tie is available between the AML&P and Anchorage area military installations.

FMUS serves the Fairbanks municipal area, while GVEA provides service to the rural areas. The Fairbanks area power suppliers have the most complete power pooling agreement in the State. FMUS, GVEA, the University of Alaska, and most of the military bases have an arrangement which includes provisions for sharing reserves and energy interchange.

The delivery point for Upper Susitna power to the GVEA and FMUS systems is assumed at a substation of GVEA near Fairbanks.

Other small power generating systems in the Fairbanks-Tanana Valley area were included in determining the power requirements of the region. They include:

Fairbanks-Tanana Valley Area	Installed Capacity MW
Alaska Power and Telephone Company (Tok and Dot Lake vicinity)	2.28
Northway Power and Light Company (Northway vicinity)	0.48

National Defense Power Systems

The six major national defense installations in the power market area are:

Anchorage area--

- Elmendorf Air Force Base
- Fort Richardson

Fairbanks area--

Clear Air Force Base
Eielson Air Force Base
Fort Greely
Fort Wainwright

Each major base has its own steamplant that is used for power and for central space heating. Except for Clear Air Force Base, each is interconnected with the local utility. Numerous small isolated installations are not included in this study.

In the past, national defense electric generation has been a major portion of the total installed capacity. With the projected stability of military sites and the growth of the utilities, the national defense installation will become a less significant part of the total generating capacity.

Industrial Power Systems

Three industrial plants on the Kenai Peninsula maintain their own powerplants, but are interconnected with the HEA system. The Union 76 Chemical Division plant generates its basic power to satisfy its energy needs, receiving only standby capacity from HEA. The Kenai liquified natural gas plant buys energy from HEA, but has its own standby generation. Tesoro Refinery buys from HEA and also satisfies part of its own needs.

Other self-supplied industrial generators include oil platform and pipeline terminal facilities in the Cook Inlet area.

Existing Generation Capacity

Table 1 provides a summary of existing generating capacity. The table was generally current as of 1978. The Anchorage-Cook Inlet area had a total utility installed capacity of 504.5 MW in 1977-78. Natural gas-fired turbines were the predominant energy source with 435.1 MW. Hydroelectric capacity of 45 MW was available from two projects, Eklutna and Cooper Lake. Steam turbines comprised 14.5 MW. Diesel generation, mostly in standby service, accounted for the remaining 9.8 MW.

The Fairbanks-Tanana Valley area utilities had a total installed capacity of 288.8 MW in 1977. Gas turbines (oil-fired) provided the largest block of power in the area with an installed capacity of 203.1 MW. Steam turbine generation provided 53.5 MW of power and diesel generators contributed 32.1 MW to the area.

Table 1
RAILBELT AREA GENERATION CAPACITY
Summary - 1977

Upper Susitna Project Power Market Analysis

Area	Installed Capacity - MW				
	Hydro	Diesel Int. Comb.	Gas Turbine	Steam Turbine	Total
Anchorage-Cook Inlet					
Utility System	45.0	9.8	435.1	14.5	504.5
National Defense		9.2		40.5	49.7
Industrial System		10.2	14.8		25.0
Subtotal	45.0	29.3	449.9	55.0	579.2
Fairbanks-Tanana Valley					
Utility System		32.1	203.1	53.5	288.8
National Defense		14.0		63.0	77.0
Subtotal		46.1	203.1	116.5	365.8

Notes: The majority of the diesel generation is in standby status. Rounding causes differences between summations of the parts and the totals shown.

Source: Utility reports to Alaska Public Utility Commission to the Department of Energy, the Alaska Air Command, the oil and gas companies, and APA files.

(Minor differences exist between this table and the appended Battelle Report.)

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Planned Generation Capacity

The two major utilities in the Anchorage-Cook Inlet area, AML&P and CEA, plan to add a total of approximately 420 MW installed capacity to their existing system between 1979 and 1985. AML&P plans to add a 16.5-MW combined cycle system to their existing combustion turbine. In addition, CEA has plans to complete the 230-kv interconnection loop with MEA.

In December 1978, GVEA decided to postpone development of their proposed Healy II steam turbine system (104 MW) until more favorable economic conditions prevail.

A unit by unit breakdown of planned generating systems is presented in the appended Battelle report, table 3.8.

PART V. POWER REQUIREMENTS

Introduction

This summarizes the analyses of historic data and estimates of future needs in the power market areas. The study examines in detail electric utility statistics 1970 to 1977 with special effort to identify changes in use patterns related to conservation measures since the 1973 oil embargo.

Estimates of future utility power needs are derived from estimates of individual energy use and area population. Population projections were developed by the University of Alaska, Institute of Social and Economic Research (ISER). The individual use forecast was estimated by assumed conservation-induced changes in kwh/capita growth rates. The end results are forecasts of net generation (kwh) and peak load demand (kw).

The three energy use sectors analyzed in this study are:

Utility - Includes all utilities which serve residential and commercial/industrial customers.

National Defense - Includes all military installations.

Self-Supplied Industry - Includes limited number of heavy industries, i.e., natural gas and oil processing industries on the Kenai Peninsula which generate their own power. The study assumes that these industries will purchase energy if it becomes economically feasible. Some have interchange agreements with local utilities.

Evaluations of monthly energy distribution and installed capacity requirements are included and are premised on characteristics of area power demands.

Data

This presents the basic parameters used in the analyses leading to the Susitna Power Market forecast assumptions.

The historical data summarizes the Anchorage-Cook Inlet and Fairbanks-Tanana Valley areas which comprise the Railbelt area. Each area is divided into utility, national defense, and self-supplied industrial components (Fairbanks-Tanana Valley area has no known significant self-supplied industries).

The utility component is divided into four sectors: Residential, Commercial-Industrial, Total Sales, and Net Generation.

Data was collected from utility and industry reports to various government agencies, from utilities directly, from Alaska military commands, by correspondence with industry, and from various statistical publications and news media.

Basic data needed for the 1970-1977 analysis are presented on tables 2, 3, and 4 included is utility annual energy and customers for each sector, national defense and industrial annual energy consumption, utility and national défense annual peak load, industrial installed capacity, annual population, and average annual employment. In addition, utility net generation, listed on tables 5 and 6, was compiled for the 1960-1977 period.

As part of the forecasting foundation, the following historical chronology indicates fluctuations affecting Railbelt energy use.

1970. Uncertainty concerning the oil pipeline design, construction, and approval. Native land claims legislation pending. Above average temperature.

1971. Uncertainty concerning pipeline. Below average temperature.

1972. Uncertainty concerning pipeline. Coldest year of period.

1973. Start of fuel crisis and conservation publicity in December. Below average temperature.

1974. Start of pipeline construction. Near average temperature.

1975. Peak of pipeline construction activity. Near average temperature.

1976. Start of pipeline construction "wind-down." Electric power cable across Knik Arm out of service for an extended period (all but one circuit). Above average temperature.

1977. Oil started flowing in pipeline. Warmest year of period. Residential construction boom in Anchorage. Large increase in non-residential authorizations issued.

Table 2
BASIC POWER AND ENERGY FORECASTING DATA
ANCHORAGE-COOK INLET AREA (INCLUDING SEWARD)

Upper Susitna Project Power Market Analysis

	Utility Energy Sales (GWH)			Net Generation (GWH)		
Year	Resi.	Comm./Indu.	Total 1/	Utility 2/	Nat. Def. 3/	Indu.
1970	310.5	342.3	678.7	744.1	156.2	1.65
1971	369.7	393.9	792.5	886.9	161.2	
1972	421.6	454.0	911.6	1,003.8	166.5	45.3
1973	459.5	514.8	1,012.2	1,108.5	160.6	
1974	496.1	552.8	1,087.4	1,189.7	155.1	45.3
1975	595.1	631.9	1,270.6	1,413.0	132.8	
1976	677.6	738.7	1,462.2	1,615.3	140.3	
1977	741.0	813.4	1,600.8	1,790.1	130.6	69.5

	Utility Customers			Peak Load (MW)		
Year	Resi.	Comm./Indu.	Total	Utility	Nat. Def.	Indu. 4/
1970	39,271	5,230	45,042	165.2	34.6	12.3
1971	42,501	5,581	48,670	184.8		
1972	46,724	6,104	53,278	212.8	33.9	12.3
1973	49,307	6,491	56,280	229.9		
1974	52,585	6,798	59,893	257.2	32.6	12.3
1975	56,801	7,478	64,797	345.8		
1976	61,881	8,220	70,622	349.9		
1977	68,320	9,221	78,066	423.9	40.5	24.8

	Population		Employment
	Civilian	Total	Avg. Annual
1970	135,963	149,428	47,408
1971	145,108	159,046	51,092
1972	155,084	167,765	54,329
1973	160,162	174,280	57,157
1974	165,938	179,544	65,919
1975	196,320	209,049	78,786
1976	207,090	219,337	83,604
1977	222,424	234,674	88,869

1/ Excludes deliveries to national defense.
2/ Total retail sales of energy + non-revenue energy used + losses.
3/ Includes receipts from utilities, excludes deliveries to utilities.
4/ Self-supplied industrial data is installed capacity rather than peak load.

GWH = million KWH
MW = thousand KW
KW = Kilowatt

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Table 3
BASIC POWER AND ENERGY FORECASTING DATA
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

	Utility Energy Sales (GWH)			Net Generation (GWH)	
Year	Resi.	Comm./Indu.	Total 1/	Utility 2/	Nat. Def. 3/
1970	91.7	108.3	210.2	239.3	203.5
1971	112.4	119.8	244.3	275.5	201.4
1972	122.3	127.3	262.9	306.7	203.3
1973	134.4	139.5	282.3	323.7	200.0
1974	155.8	150.3	323.0	353.8	197.0
1975	193.0	196.3	409.2	450.8	204.4
1976	195.9	204.2	420.5	468.5	217.5
1977	200.7	221.6	442.7	482.9	206.8

	Utility Customers			Peak Load (MW)	
Year	Resi.	Comm./Indu.	Total	Utility	Nat. Def.
1970	10,364	1,721	12,268	56.3	44.4
1971	11,014	1,779	12,947	65.3	
1972	11,584	1,839	13,611	66.6	41.4
1973	11,931	1,929	14,041	72.7	
1974	12,832	2,069	15,084	87.5	40.8
1975	14,025	2,247	16,447	110.0	
1976	15,569	2,435	18,179	102.6	
1977	16,709	2,580	19,463	118.9	41.0

	Population		Employment
	Civilian	Total	Avg. Annual
1970	42,310	52,141	15,681
1971	43,188	50,585	15,817
1972	45,516	52,383	16,873
1973	45,396	52,246	16,794
1974	51,137	57,836	21,960
1975	60,884	67,011	34,451
1976	58,051(e)	63,762	34,325
1977	47,155(e)	52,155	27,385

1/ Excludes deliveries to national defense.
2/ Total sales + non-revenue use + losses.
3/ Includes receipts from utilities, excludes deliveries to utilities.
4/ Self-supplied industrial data is installed capacity rather than peak load.

GWH = million KWH
MW = thousand KW

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Table 4
BASIC POWER AND ENERGY FORECASTING DATA
RAILBELT AREA

Upper Susitna Project Power Market Analysis

	Utility Energy Sales (GWH)			Net Generation (GWH)			
Year	Resi.	Comm./Indu.	Total	Utility	Nat. Def.	Indu.	Total
1970	402.2	450.6	888.9	983.4	359.7	1.6	1,344.7
1971	482.1	513.7	1,036.8	1,162.4	362.6	25(e)	1,550.0
1972	543.9	581.3	1,174.5	1,310.5	369.8	45.3	1,725.6
1973	593.9	654.3	1,294.5	1,432.2	360.6	45.3(e)	1,838.1
1974	651.9	703.1	1,410.4	1,543.5	352.1	45.3	1,940.9
1975	788.1	828.2	1,679.8	1,863.8	337.2	45.3(e)	2,246.3
1976	873.5	942.9	1,882.7	2,083.8	357.8	45.3(e)	2,486.9
1977	941.7	1,035.0	2,043.5	2,273.0	337.4	69.5	2,679.9

	Utility Customers			Peak Load (MW)			
Year	Resi.	Comm./Indu.	Total	Utility	Nat. Def.	Indu.	Total
1970	49,635	6,951	57,310	221.5	79.0	12.3	312.8
1971	53,515	7,380	61,617	250.1	77(e)	12.3(e)	[illegible]
1972	58,308	7,943	66,889	279.4	75.3	12.3	367.0
1973	61,238	8,420	70,321	302.6	74(e)	12.3(e)	388.9
1974	65,417	8,867	74,977	344.7	73.4	12.3	430.4
1975	70,826	9,725	81,244	455.8	73(e)	12.3(e)	541.1
1976	77,450	10,654	88,801	452.5	76(e)	12.3(e)	540.8
1977	85,029	11,801	97,529	542.8	81.5	24.8	649.1

	Total Population	Avg. Annual Employment
1970	201,569	63,089
1971	209,631	66,909
1972	220,148	71,202
1973	226,526	73,951
1974	237,380	87,879
1975	276,060	113,237
1976	283,099	117,929
1977	286,829	116,254

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Table 5
NET GENERATION (GWH)
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis
(Includes receipts of electric energy from military; excludes electric energy deliveries to military)

Year	AML&P	CEA	APA	MEA	HEA	KU	SES	Total	Growth %
1960	0.8	27.5	187.6	0.1	8.2	1.8	5.7	231.6	
1961	3.2	44.8	193.8	0.1	3.6	2.0	6.2	253.7	9.5
1962	20.0	101.8	150.3	0.2	0	2.3	3.7	278.2	9.7
1963	55.7	100.5	152.7	0.2	0	2.7	0	311.8	12.1
1964	97.3	94.5	146.1	0.5	1.2	3.8	0	343.4	10.1
1965	101.2	167.4	132.1	0.6	1.4	4.1	0	406.8	18.5
1966	108.6	204.6	138.2	0.7	1.4	5.2	0	458.7	12.8
1967	100.1	217.1	178.5	0.8	1.5	6.7	0	504.6	10.0
1968	125.3	280.0	155.5	0.8	1.7	10.1	0	573.4	6.5
1969	148.1	314.6	158.2	0.9	2.2	8.9	0.1	633.0	17.8
1970	186.0	385.5	154.7	1.1	2.4	9.0	0.1	738.8	16.7
1971	245.3	476.6	144.9	1.3	2.7	8.0	0.1	878.9	19.0
1972	270.0	554.2	164.0	1.5	3.3	7.0	0.1	1,000.1	13.8
1973	359.0	657.3	96.3	0.3	3.6	--	0.1	1,116.5	11.6
1974	389.6	678.4	1.1	--	4.2	--	0.1	1,197.4	7.2
1975	384.3	888.8	135.1	--	3.4	--	3.2	1,414.9	18.2
1976	442.9	1,054.5	118.5	--	0.5	--	1.5	1,617.3	14.3
1977	420.3	1,179.7	203.6	--	0.5	--	0.8	1,804.9	11.5

AML&P - Anchorage Municipal Light and Power
CEA - Chugach Electric Association
APA - Alaska Power Administration
MEA - Matanuska Electric Association
HEA - Homer Electric Association
KU - Kenai Utilities
SES - Seward Electric System

Table 6
NET GENERATION (GWH)
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis
(Includes receipts of electric energy from military;
excludes electric energy deliveries to military)

Year	FMU	GVEA	AP&T	DLE	NP&L	Total	Growth %
1960	36.7	24.4	--	0.1	0.6	61.8	
1961	38.8	29.4	--	0.1	0.6	68.9	11.5
1962	42.3	33.3	1.	0.1	0.6	77.2	12.1
1963	45.4	39.1	1.2	0.1	0.6	86.4	11.9
1964	48.4	53.6	1.5	0.1	0.6	104.2	20.6
1965	49.5	56.6	1.8	0.1	0.6	108.6	4.2
1966	52.6	67.0	2.1	0.1	0.6	122.4	12.7
1967	55.9	75.9	2.0	0.2	0.6	134.6	10.0
1968	64.0	97.9	2.0	0.2	0.6	164.7	22.4
1969	72.2	118.1	2.1	0.2	0.6	193.3	17.4
1970	85.6	150.2	1.9	0.2	0.6	238.6	23.4
1971	106.7	164.9	2.4	0.2	0.6	274.7	15.1
1972	120.3	182.2	2.6	0.2	0.8	306.1	11.4
1973	115.4	202.2	2.7	0.2	0.9	321.4	5.0
1974	123.0	214.3	3.5	0.2	1.2	342.1	6.4
1975	137.2	286.9	3.9	0.2	1.6	429.7	25.6
1976	139.6	315.1	4.2	0.2	1.4	460.4	7.1
1977	133.5	346.3	4.5	0.2	1.4	485.8	5.5

FMU - Fairbanks Municpal Utilities
GVEA - Golden Valley Electric Association
AP&T - Alaska Power and Telephone (Tok)
DLE - Dot Lake Electric (Purchased by AP&T in 1978)
NP&L - Northway Power and Light

Analysis

Detailed investigations of relationships among the basic data components are listed in tables 2, 3, and 4. Analysis was done separately for each major sector (utility, national defense, and self-supplied industry) within each geographic area.

Utility

The analysis of utility data set out to develop assumptions for forecasting net generation and peak load. Investigations evaluated the impact of changes in population, employment, customers, weather, tariffs, and other events upon energy use. These evaluations then helped to: (1) determine if energy sectors (residential, commercial-industrial, total sales) other than net generation needed to be forecast; (2) determine which energy ratio (kwh/capita, kwh/employee, kwh/customer) to use in the forecasting procedure; (3) develop procedure for forecasting utility annual net generation from energy use assumptions and demographic parameters (population, employees, or customers); (4) determine load factor with which to calculate peak load forecast from the net generation forecast.

Constants, small amplitude cycles, or trends in relationships among the energy use and customer sectors were investigated for use as forecasting aids. If, for instance, the residential energy use/net generation ratio remained almost constant from 1970 through 1977, only net generation need be subjected to the forecasting procedure. The same type of analysis was applied to energy use ratios: a look for an average or trend to be used as a factor in forecasting net generation.

After developing the net generation forecast, the peak load forecast was calculated using energy and an assumed load factor. Analysis of historic load factors determined an average or trend from which the assumed load factor was derived. Forecasted net generation and the assumed future load factor were then used in the formula: Peak load = 8,760 hr/yr. x load factor x net generation.

The evaluations showed a mix of similarity and contrast between the two Railbelt areas. In both areas, the major energy use determinants were the trans-Alaska oil pipeline construction and the fuel crisis of 1973-74. Other correlations with weather, tariffs, etc., seemed insignificant. For instance, energy growth increased in some years despite above average temperatures which reduced energy need.

<u>Anchorage-Cook Inlet Area Analysis Results</u> - The foregoing evaluation procedures resulted in the following observations for the Anchorage-Cook Inlet area.

(a) Observations indicate no significant shift in energy use patterns or in share of total load among the various utility sectors (residential, etc.). The ratios among the sectors (residential/total sales; total sales/net generation, etc.) remained essentially constant through the study period. This was true for both energy and customers. Therefore, only one sector--net generation--represents all sectors in the forecast.

(b) Energy rate of growth per customer and per capita had a significant reduction after the 1973-74 fuel crisis. The 1973-77 per capita average growth rate was about half that for 1970-73. It appears that conservation can be considered an influence after 1973.

(c) Events impinging upon energy use are listed in the previous section. Between 1973 and 1977, several events bear repeating for emphasis: fuel crisis in 1974; start of pipeline construction in 1974; peak pipeline activity in 1975; decrease of pipeline activity in 1976 and 1977; cables across Knik Arm, which carry a large share of Anchorage energy, went out of service in 1976; warmer than average weather in 1974, 1976, and especially 1977. Yearly growth rates reflected rather large fluctuations as different historical events influenced each parameter. (This is a recurring phenomenon in Alaskan history).

(d) Parameters were not influenced alike as figures 3 through 8 attest. For instance, customer growth reacted to events in a steadier pattern than did population and employment. Reasons for this are more people per customer and time needed for connecting more customers to a utility system at the initial onslought of large demographic growth.

(e) Comparing the energy fluctuations with others, such as population and employment, gave a measure of correlation between parameters. (The energy use and customer growth fluctuations correlated only in part; their patterns did not coincide every year). However, energy and population growth rate changes were coincidental for every year but 1977. That is, when the energy growth rate increased, so did the population growth rate; when the population growth rate decreased, so did the energy growth rate.

(f) Energy use and weather comparisons were inconclusive. Warm weather did not bring corresponding reduction in energy use. Cold weather increases in energy use were buried in other events (pipeline construction, etc.).

(g) Because the net generation kwh/capita ratio seemed to reflect the closest correlations, particularly in recent years, this ratio and population were used to forecast net generation values between 1980 and 2025.

(h) Values basic to the forecasting assumptions are the kwh/capita ratio averaging 3.8 percent average annual growth between 1973 and 1977 and net generation averaging 12.7 percent.

(i) Average annual growth results are summarized on table 7. Figures 3, 4, and 5 are graphs of pertinent elements of the analysis.

Fairbanks-Tanana Valley Area Analysis Results - Some of the Anchorage-Cook Inlet area evaluation results apply also to the Fairbanks-Tanana Valley area, others do not. The following observations parallel those of Anchorage-Cook Inlet.

(a) No significant shift in energy use patterns or in share of total load among the various utility sectors (residential, etc.). Again, only one sector--net generation--need be forecast.

(b) Energy growth was similar to that of Anchorage (somewhat smaller in the pre-1973 period); but customer, population, and employee growth were different in the two areas. Consequently, the energy use per customer, per capita, and per employee ratios indicate different growth patterns in Fairbanks. The large swings of employment and population in Fairbanks during pipeline construction compared to almost constant preconstruction values cloud comparisons of the two periods.

(c) Although the effects of pipeline construction are evident, the population/employee ratio (2.29 average through the study period) was constant enough to indicate that either population or employment can be used as a forecasting parameter.

(d) The effects of weather on energy use could not be detected. In some years, degree day variations were not in phase with energy use variations.

(e) Energy use/capita exhibited wider variations than the other two ratios, but, nevertheless, had the nearest to constant average annual growth rates. Because of this and the other observations, net generation kwh/capita and population were used to forecast net generation.

(f) As in the Anchorage-Cook Inlet area, values basic to the forecasting assumptions are the net generation/capita growth, averaging 10.6 percent per year, and net generation growth, averaging 10.5 percent per year between 1973 and 1977.

(g) Growth rate results are summarized on table 7. Figures 6, 7, and 8 are graphs of some pertinent elements of the analysis.

Table 7
AVERAGE ANNUAL UTILITY GROWTH SUMMARY
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis

	1970	1973	1977	Avg. Growth 1970-1973	Avg. Growth 1973-1977
Energy GWH					
Residential Sales	310	460	741	14.0%	12.6%
Commercial/Industrial	342	515	813	14.7	12.1
Total Sales	679	1,012	1,601	14.2	12.1
Net Generation	744	1,108	1,790	14.2	12.7
Energy Use, kwh/Customer					
Residential	7,907	9,319	10,846	5.6	3.8
Commercial/Industrial	65,449	79,310	88,212	5.6	2.6
Total Sales	15,068	17,985	20,506	6.0	3.3
Energy Use, kwh/Capita					
Residential	2,284	2,869	3,332	8.0	3.8
Commercial/Industrial	2,518	3,214	3,657	8.6	3.3
Total Sales	4,992	6,320	7,197	8.3	3.3
Net Generation	5,473	6,921	8,048	8.0	3.8

Fairbanks-Tanana Valley Area

	1970	1973	1977	Avg. Growth 1970-1973	Avg. Growth 1973-1977
Energy GWH					
Residential Sales	92	134	201	13.4%	10.7%
Commercial/Industrial	108	140	222	9.1	12.2
Total Sales	210	282	443	10.2	11.9
Net Generation	239	324	483	10.8	10.5
Energy Use, kwh/Customer					
Residential	8,852	11,262	12,010	8.3	1.7
Commercial/Industrial	62,931	72,303	85,899	4.8	4.4
Total Sales	17,134	20,104	22,746	5.4	3.1
Energy Use, kwh/Capita					
Residential	1,759	2,572	3,848	13.5	10.6
Commercial/Industrial	2,077	2,670	4,249	8.7	12.3
Total Sales	4,031	5,403	8,488	10.3	12.0
Net Generation	4,589	6,196	9,259	10.5	10.6

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Figure 3

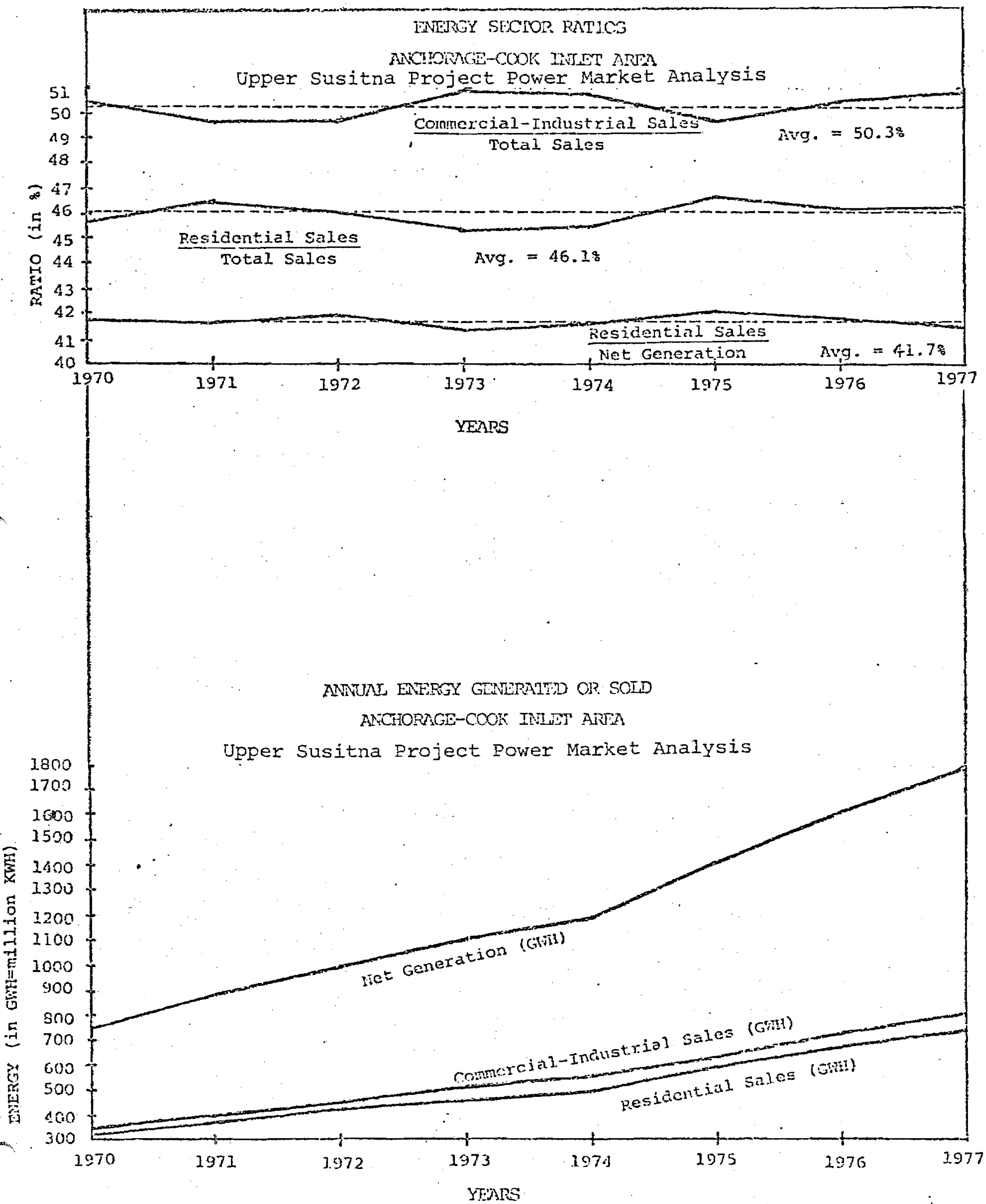

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Figure 4

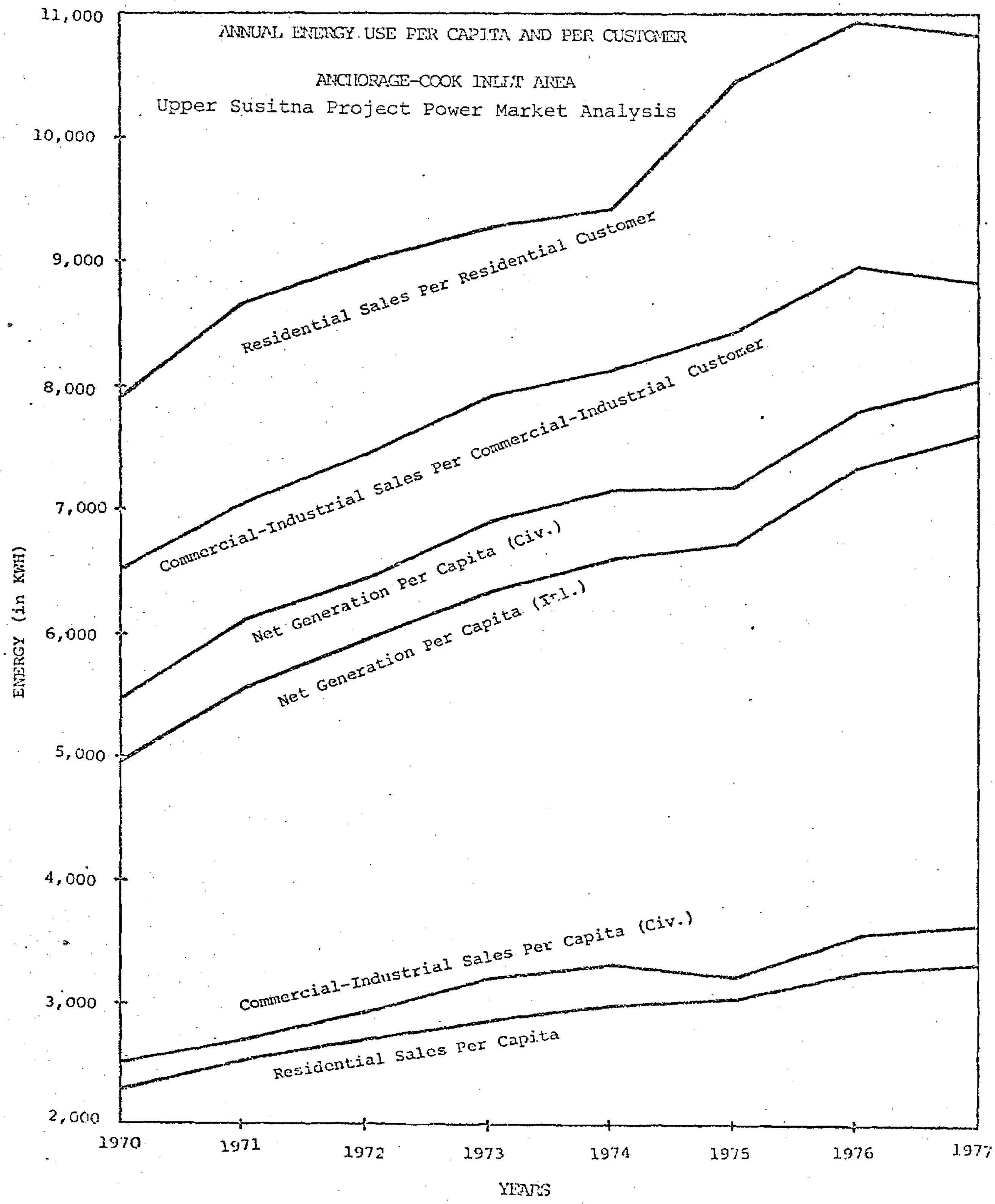

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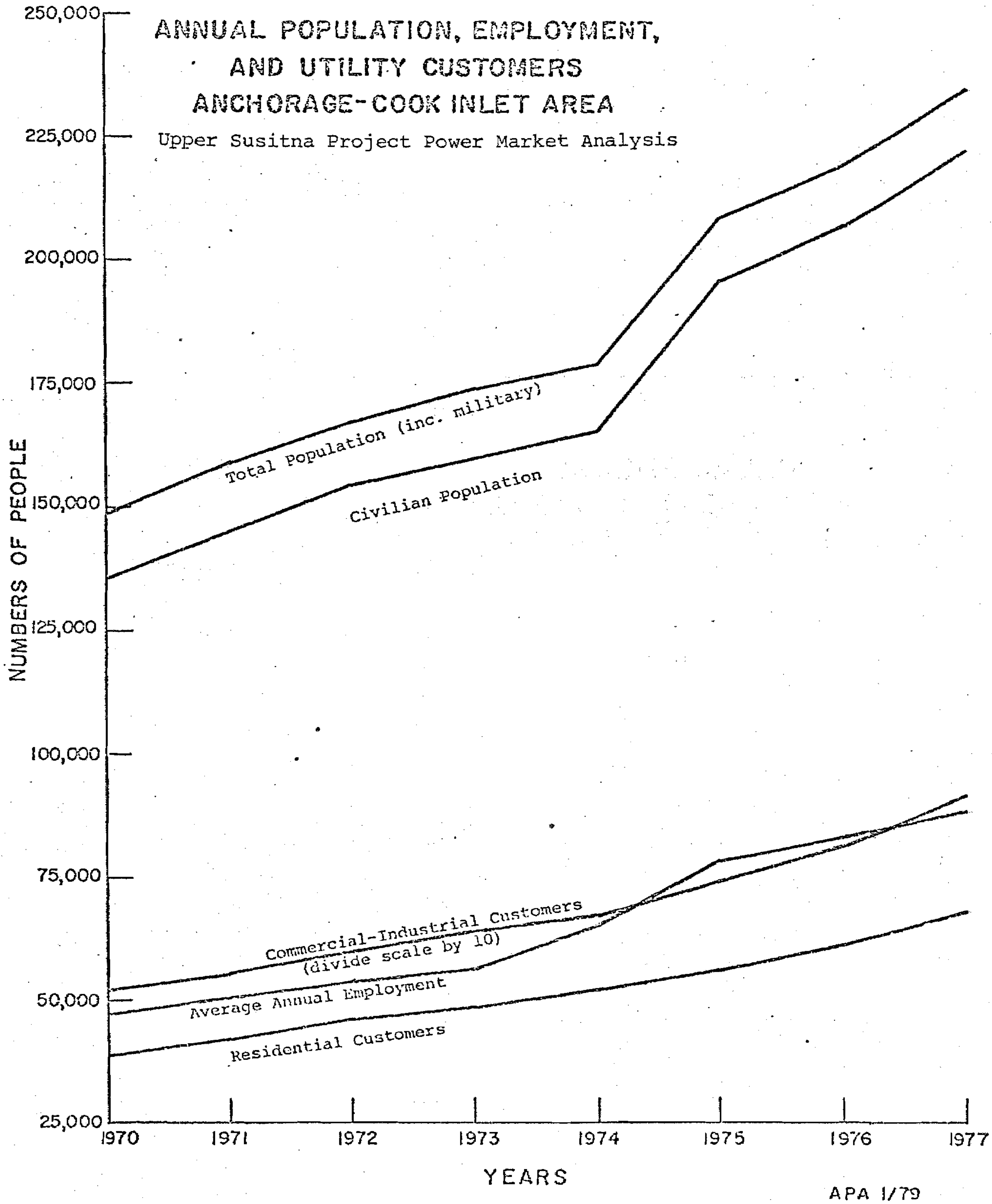
Figure 5


ANNUAL POPULATION, EMPLOYMENT,
AND UTILITY CUSTOMERS
ANCHORAGE-COOK INLET AREA
Upper Susitna Project Power Market Analysis
250,000
225,000
200,000
175,000
150,000
125,000
100,000
75,000
50,000
25,000
NUMBERS OF PEOPLE
Total Population (inc. military)
Civilian Population
Commercial-Industrial Customers
(divide scale by 10)
Average Annual Employment
Residential Customers
1970
1971
1972
1973
1974
1975
1976
1977
YEARS
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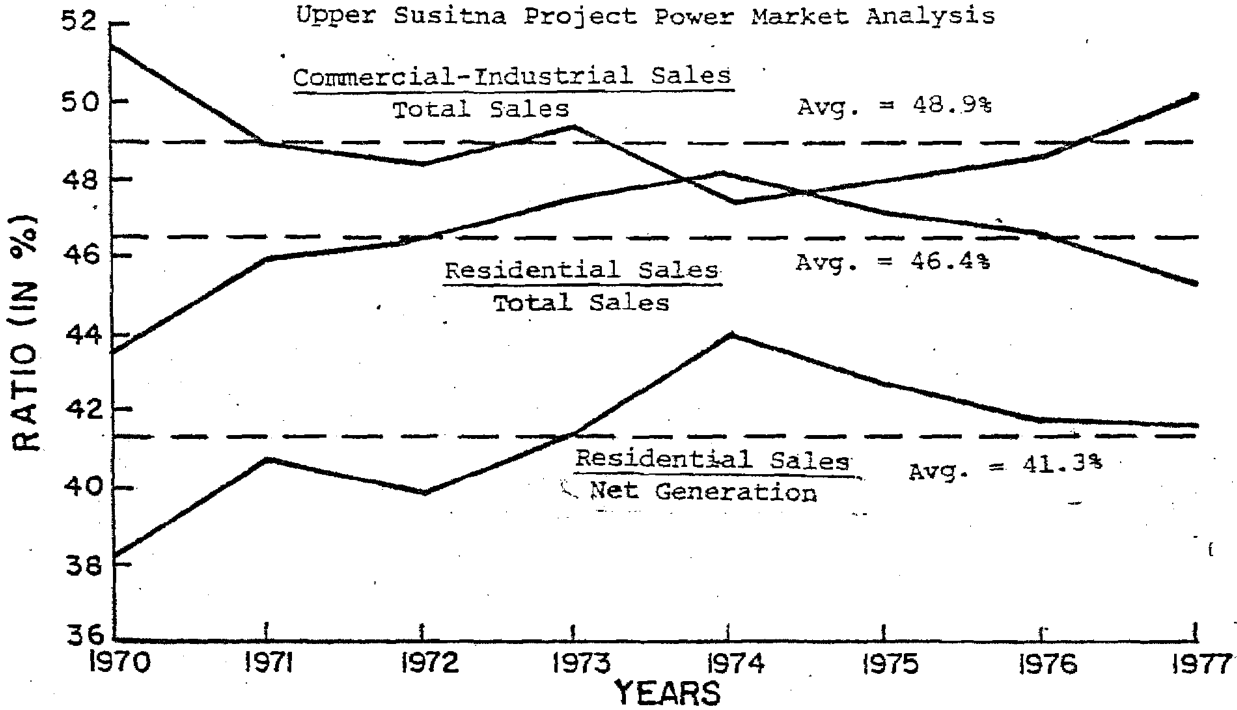
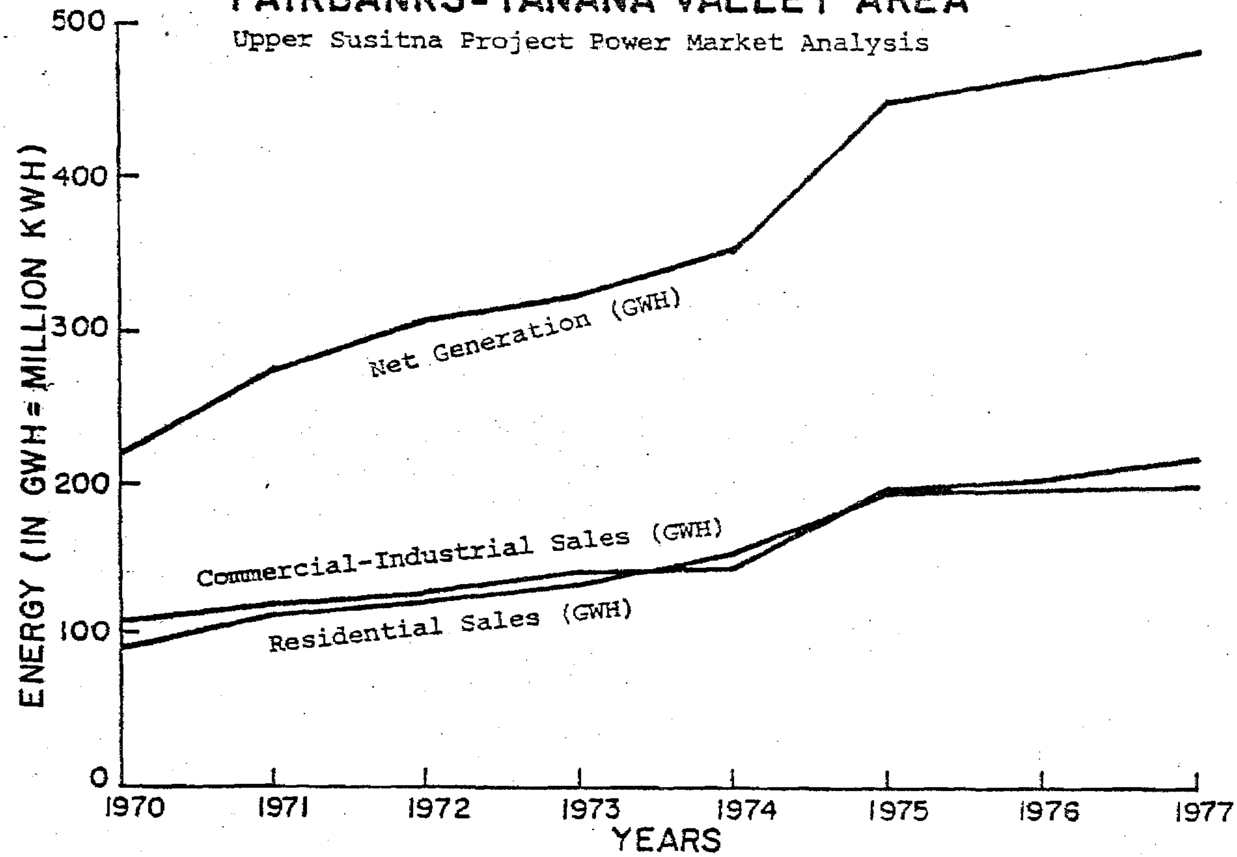
ENERGY SECTOR RATIOS
FAIRBANKS-TANANA VALLEY AREA
Upper Susitna Project Power Market Analysis



ANNUAL ENERGY GENERATED OR SOLD
FAIRBANKS-TANANA VALLEY AREA
Upper Susitna Project Power Market Analysis



ANNUAL ENERGY USE PER CAPITA AND PER CUSTOMER FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

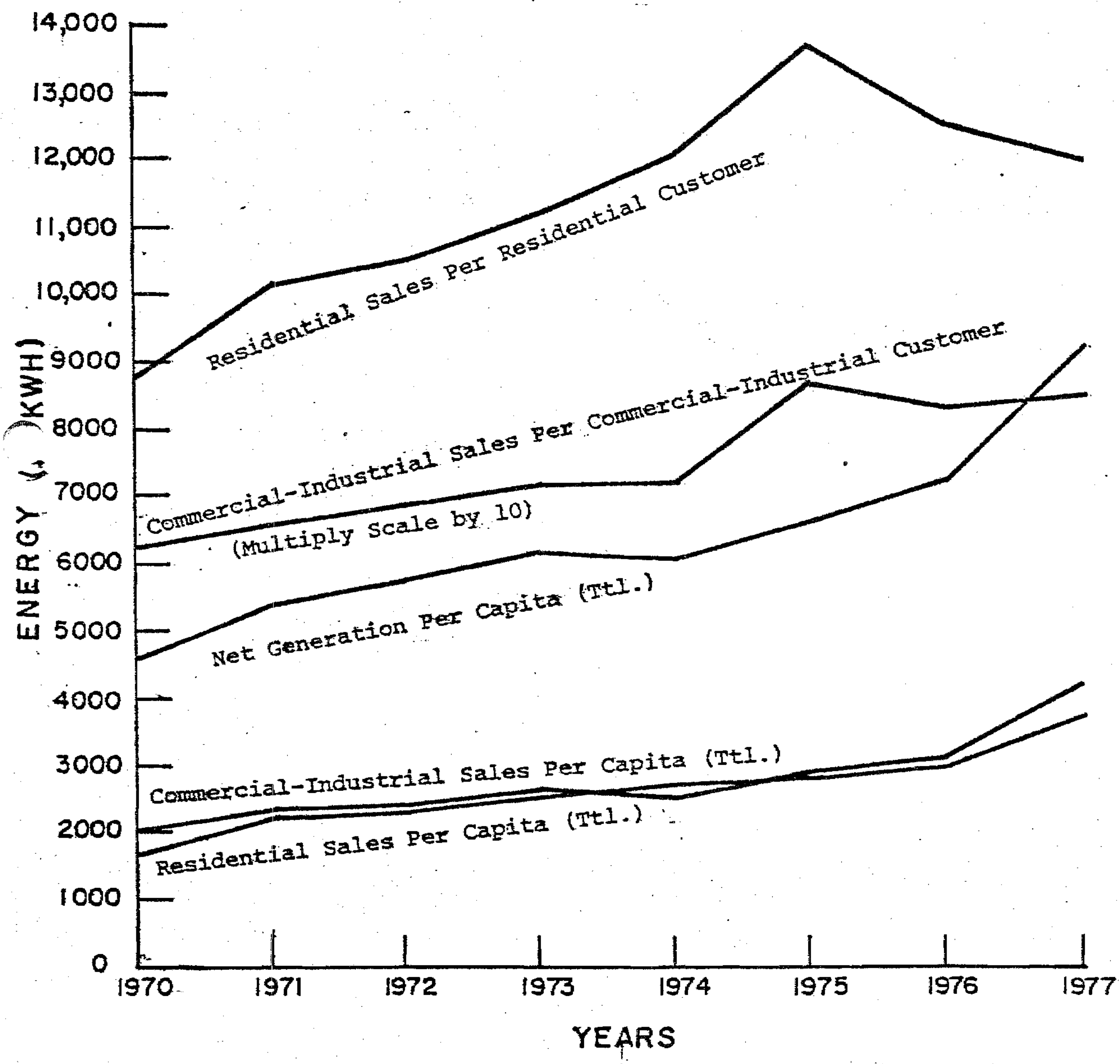


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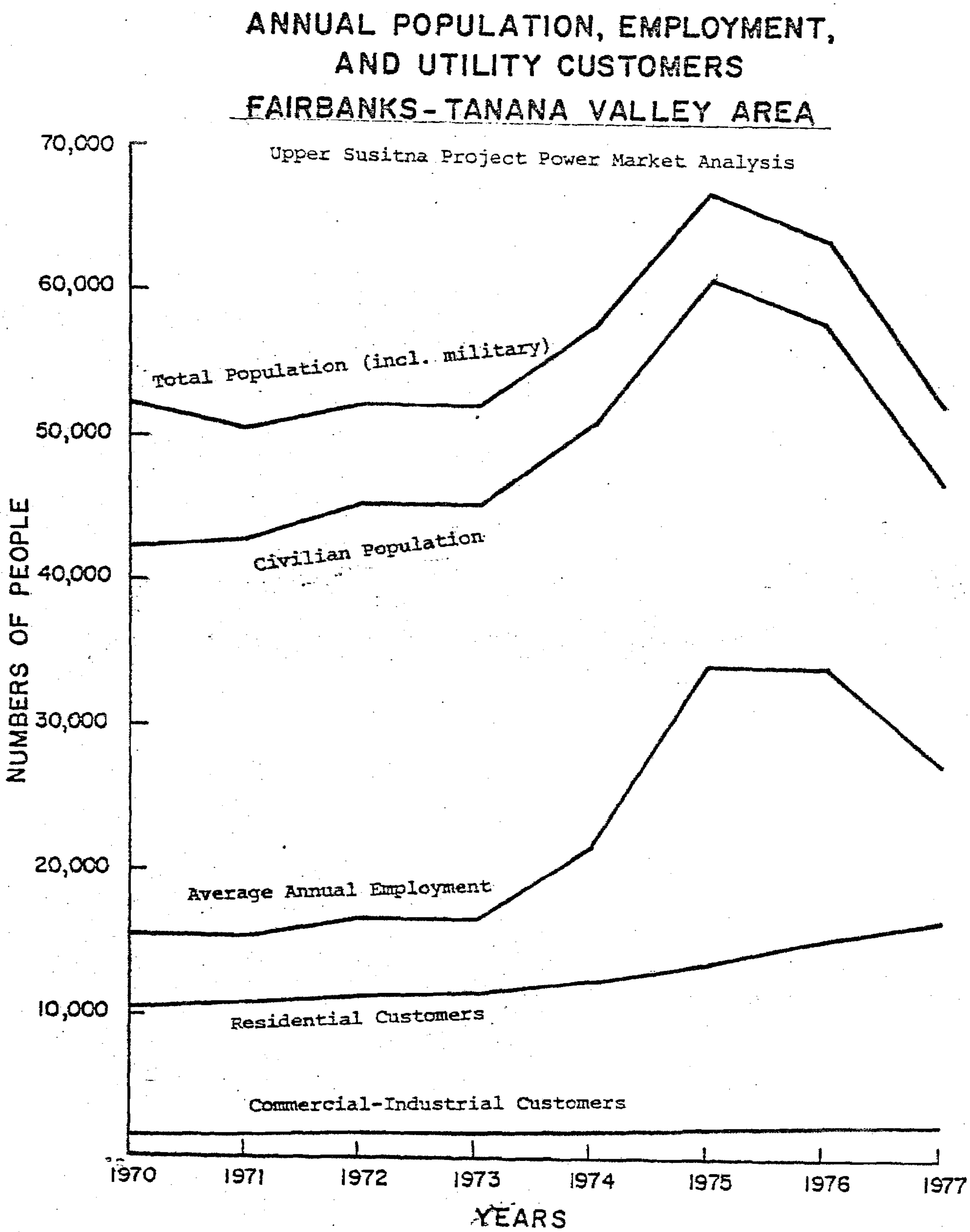
Figure 8



ANNUAL POPULATION, EMPLOYMENT, AND UTILITY CUSTOMERS
FAIRBANKS-TANANA VALLEY AREA
Upper Susitna Project Power Market Analysis
70,000
60,000
50,000
40,000
30,000
20,000
10,000
NUMBERS OF PEOPLE
Total Population (incl. military)
Civilian Population
Average Annual Employment
Residential Customers
Commercial-Industrial Customers
1970
1971
1972
1973
1974
1975
1976
1977
YEARS

National Defense

Evaluation of historical national defense data resulted in net generation and peak load averages. The analysis encompassed the U.S. Army and Air Force installations in the Anchorage and Fairbanks areas. No definite trends surfaced--only a small, cyclic decrease in the Anchorage area net generation and an increase in peak load. In the Fairbanks area, net generation increased slightly and peak load decreased. Total national defense is about 15 percent of utility for both net generation and peak load.

Self-Supplied Industry

Railbelt industry and the upper Kenai Peninsula complex showed no significant change in capacity and energy generation until 1977 when the chemical plant expanded. Therefore, the analysis consisted of a plant factor determination only. Other factors needed in forecasting are discussed as assumptions in the next section.

Energy and Power Demand Forecasts

This section presents future energy and power requirement estimates developed from the previous analyses. Work for the new estimates consisted of: (1) using the analyses to obtain forecasting assumptions; (2) using the assumptions in forecasting utility net generation/capita; (3) combining net generation/capita with Institute of Social and Economic Research (ISER) population projections to obtain the utility net generation forecast, and forecasting national defense and industry generation from pertinent assumptions; and (4) combining the net generation forecast with load factors resulting from the historical data analysis to obtain peak load (power requirement) forecasts.

Assumptions and Methodology

Population - The ISER econometric model of the Southcentral Region Water Study (Level B) furnished high and low range population forecasts. The model disaggregated the Anchorage-Cook Inlet area from a statewide population forecast. No recent, applicable forecast of Fairbanks-Tanana Valley population was available; therefore, APA assumed statewide growth rates from the ISER model applied to the Fairbanks-Tanana Valley areas. (See table 8).

Utility - Assumptions, based on the preceding analyses, lead to the net generation and peak load forecast. Net generation is the product of forecasted energy use per capita and projected population. Peak load demand is derived from net generation and the assumed utility load factor. Multiplying these growth rates by forecasted 1980 values of kwh/capita resulted in the energy use estimates.

Table 8
POPULATION ESTIMATES

1980-2025
RAILBELT AREA

Upper Susitna Project Power Market Analysis

Year	Anchorage-Cook Inlet 1/ High	Low	Statewide 1/ High	Low	Fairbanks-Tanana Valley 2/ High	Low
1980	270,200	239,200	513,766	500,225	62,020	60,390
1985	320,000	260,900	640,718	563,303	77,350	68,010
1990	407,100	299,200	790,042	618,397	95,370	74,660
1995	499,200	353,000	947,312	680,286	114,360	82,130
2000	651,300	424,400	1,157,730	743,034	139,760	89,700
2025	904,000	491,100	1,484,784	820,369	179,240	99,040

Notes: * No mid-range estimates are shown because, when the forecasts were done, ISER 1/ had made only the high and low projections. A comparison of the mid-range forecast already performed (see text for method) with one using the mid-range population, when received, indicated no reason to re-do the forecasts.

* Values shown include national defense population

1/ From Iser, Southcentral Alaska's Economy and Population: A base Study 1965-2025. September 1978 with December 1978 revisions.

2/ Calculated from statewide growth rates.

Since the ratios of residential, commercial-industrial, and total sales energy to net generation remain constant, net generation is assumed to be an appropriate forecasting parameter. The evaluations indicated that the other sectors do not need individual forecasting.

The basic energy use (net generation kwh/capita) assumption for the entire Railbelt area is a 3.5 percent average annual, mid-range, 1980-85 growth rate. It is based on the Anchorage-Cook Inlet area value of 3.8 percent annual growth from 1973-77 and an assumed continuation of the post-1973 conservation[1/] trend. As mentioned in the Anchorage-Cook Inlet area evaluations, a conservation trend was apparent when comparing energy use growth rates for 1973-77 and 1970-73 (see table 7). Tied to this is the assumption of gradually increasing effectiveness of future conservation programs coupled with perhaps upper limits of electric energy use. These are reflected in an average annual growth by the year 2000 or 2 percent for high range, 1 percent for mid-range, and 0 percent for low range. These assumptions result in decreased growth rates for each five-year increment, as shown below:

Time Period	High	Mid	Low
1980-1985	4.5%	3.5%	2.5%
1985-1990	3.5%	3.0%	2.0%
1990-1995	3.0%	2.5%	1.5%
1995-2000	2.5%	2.0%	1.0%
2000-2025	2.0%	1.0%	0%

Multiplying these growth rates by forecasted 1980 values of kwh/capita resulted in the energy use estimates.

The 1980 mid-range value of kwh/capita was derived from the 1973-1977 average annual growth of net generation. The 1980 net generation was estimated. The Anchorage-Cook Inlet mid-range assumption of 12 percent annual load growth rate for 1977-80 net generation came from a historical 12.7 percent. The respective Fairbanks-Tanana Valley values were 10.5 percent assumed, 10.6 percent historical. Mid-range 1980 kwh/capita was calculated using the estimated net generation and projected population. The 1980 high and low range average annual kwh/capita growth rates for Fairbanks-Tanana Valley were assumed 120 percent and 80 percent of the calculated mid-range value respectively. Comparable values for Anchorage-Cook Inlet were 130 percent and 80 percent. The differences between the two areas reflect population estimates and an attempt to derive a reasonable 1977-80 transition period coupled with the population estimates.

Peak load (MW) forecasts were calculated using a 50 percent load factor. Anchorage-Cook Inlet area load factor averaged 51.9 percent between 1970 and 1977 and 51.0 percent between 1973 and 1977. Fairbanks area averaged 48.9 percent and 48.4 percent in the same periods.

1/ Conservation here includes results of the fuel crisis and perhaps of nationwide publicity on the need for saving energy. Other factors may be involved, but no other events are as coincidental with reduced energy use as is the fuel crisis.

National Defense - Historical data from Army and Air Force installations in the Anchorage and Fairbanks areas indicate reasonable energy assumptions to be:

1. 0 percent annual growth for mid-range forecast, 1 percent for high range, and -1 percent for low range.

2. A 50 percent load factor was assumed for use with energy (net generation) to obtain peak load.

Self-Supplied Industries - The following assumptions were developed from existing data and conditions, consultations with many knowledgeable people in government and industry, and from reports on future developments.

1. Industries will purchase power and energy if economically feasible.

2. Forecast based on listing in the March 1978 Battelle report.

3. High range includes existing chemical plant, LNG plant, and refinery as well as new LNG plant, refinery, coal gasification plant, mining and mineral processing plants, timber industry, city and aluminum smelter or some other large energy intensive industry.

4. Mid-range includes all of the above except the aluminum smelter.

5. Low range includes all listed under high range except the aluminum smelter and the new capital.

6. In some instances, high, mid, and low range may be differentiated by amount of installed capacity as well as the type of installations assumed.

7. No self-supplied industries are assumed for the Fairbanks-Tanana Valley area. Any industrial growth has been assumed either (1) included in utility forecasts or (2) not likely to be interconnected with the area power systems.

8. Net generation forecast calculated from forecasted capacity and a plant factor of 60 percent.

The ISER model assumed the following Cook Inlet area industrial scenario. It is compared to industries assumed for the self-supplied industrial forecasts of this report.

Cook Inlet Industrial Scenarios
Assumptions

ISER	Self-Supplied Industries Forecast
HIGH RANGE	
Oil treatment and shipping facilities	Existing refinery (2.4 MW)
Small LNG	Existing LNG plant (.4 to .6 MW)
Beluga Coal (40 employees in shipping)	Coal gasification (0 to 250 MW) 2/
New capital (2,750 employees 1982-84)	New city (0 to 30 MW)
Refinery-petrochemical complex 1/	New refinery (0 to 15.5 MW)
Pacific LNG	New LNG plant (0 to 17 MW)
Bottom fish industry	
Oil lease development	Mining and mineral plants (5 to 50 MW)
No new pulp mills or sawmills	Timber (2 to 12 MW)
	Existing chemical plant (22 to 26 MW)
	Aluminum smelter or other energy intensive industry (0 to 280 MW)
MID RANGE 3/	
LOW RANGE	
Pacific LNG	New LNG plant (0 to 17 MW)
	Existing refinery (2.4 MW)
	Existing LNG plant (.4 MW)
	Existing chemical plant (22 MW)
	Coal gasification (0 to 10 MW)
	New refinery (0 to 15.5 MW)
	Mining and mineral plants (0 to 25 MW)
	Timber (2 to 12 MW)

1/ A recent decision by ALPETCO changes this to the Valdez area. The changes involved were not enough to warrant forecast revisions.

2/ Part of coal gasification could be equivalent to "Beluga Coal," but it is much more than "40 employees in shipping."

3/ At the time this forecast and analysis was performed, no ISER mid-range projections of populations and employment had been developed.

Estimate of Future Demands

Using the high and low population projections and high, mid, and low kwh/capita assumptions, six different net generation utility forecasts were obtained. From these, the high population/high energy use and the low population/low energy use were used for the high and low range final forecasts. The mid-range final forecast came from averaging the high population/low energy use and the low population/high energy use forecasts. In lieu of a mid-range net generation based on a mid-range population projection, these last two forecasts were enough alike to justify the average as mid-range net generation.

Near the completion of this analysis, ISER provided APA with a mid-range population projection. Comparing the previous results with forecasts using these mid-range projections, APA concluded that the two were consistent and that no changes were necessary.

National defense and self-supplied industrial forecasts were calculated from the assumptions and summarized with the utilities on table 10 for the Anchorage-Cook Inlet area and table 11 for the Fairbanks-Tanana Valley area. Railbelt totals, both peak load demand and net generation, are summarized on table 12. Appropriate graphs follow each table on figures 9 and 10 for Anchorage-Cook Inlet, 11 and 12 for Fairbanks-Tanana Valley, and 13 and 14 for the Railbelt totals.

Trend lines based on 1973-1977 average annual energy growth are superimposed on the energy graphs, figures 9, 11, and 13.

1973-1977 Average Annual Growth

Anchorage-Cook Inlet	10.9%
Fairbanks-Tanana Valley	7.1%
Railbelt	9.9%

Historical and forecast energy use comparisons are summarized in table 9.

Comparison with Other Forecasts

This section compares the present forecast (1978) with two previous forecasts, and forecasts available from various utilities.

The previous forecasts included the 1976 report and its 1977 update. The 1977 update used 1975 criteria and assumptions. See table 13 for a comparison tabulation. In general, the present forecasts produced values less than the previous ones.

Table 9
NET ANNUAL PER CAPITA GENERATION (KWH)
RAILBELT AREA UTILITIES

Upper Susitna Project Power Market Analysis

	1970	1977	1990	2000	2025
			Anchorage-Cook Inlet Area		
Historical	4980	7630			
High			16,300	21,400	35,100
Mid			14,000	17,500	22,400
Low			12,000	13,600	13,600
			Fairbanks-Tanana Valley Area		
Historical	5655	10,240			
High			18,400	24,000	39,000
Mid			16,300	20,300	26,000
Low			14,100	15,800	15,900

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Energy use per capita nearly doubled in both areas in the historical seven years. Growing use of electric space heating, electric cooking in place of gas and oil, and many other possibilities can justify the assumptions shown. Again, conservation has been factored in through decreasing growth rates.

Table 10
POWER AND ENERGY REQUIREMENTS
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis

PEAK POWER

	1970 MW	1973 MW	1977 MW	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY									
High				620	1,000	1,515	2,150	3,180	7,240
Mid	165	230	424	570	810	1,115	1,500	2,045	3,370
Low				525	650	820	1,040	1,320	1,520
NATIONAL DEFENSE									
High				31	32	34	36	38	48
Mid	35	33	41	30	30	30	30	30	30
Low				29	28	26	24	24	18
INDUSTRIAL									
High				32	344	399	541	683	1,615
Mid	12	12	25	32	64	119	199	278	660
Low				27	59	70	87	104	250
TOTAL									
High				683	1,376	1,948	2,727	3,901	8,903
Mid	212	275	490	632	904	1,264	1,729	2,353	4,060
Low				581	737	916	1,151	1,448	1,788

ANNUAL ENERGY

	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH
UTILITY									
High				2,720	4,390	6,630	9,430	13,920	31,700
Mid	744	1,108	1,790	2,500	3,530	4,880	6,570	8,960	14,750
Low				2,300	2,840	3,590	4,560	5,770	6,670
NATIONAL DEFENSE									
High				135	142	149	157	165	211
Mid	156	161	131	131	131	131	131	131	131
Low				127	121	115	105	104	81
INDUSTRIAL									
High				170	1,810	2,100	2,840	3,590	8,490
Mid	2	45	70	170	340	630	1,050	1,460	3,470
Low				141	312	370	460	550	1,310
TOTAL									
High				3,025	6,342	8,879	12,427	17,675	40,401
Mid	902	1,314	1,990	2,801	4,001	5,641	7,751	10,551	18,351
Low				2,568	3,273	4,075	5,125	6,424	8,061

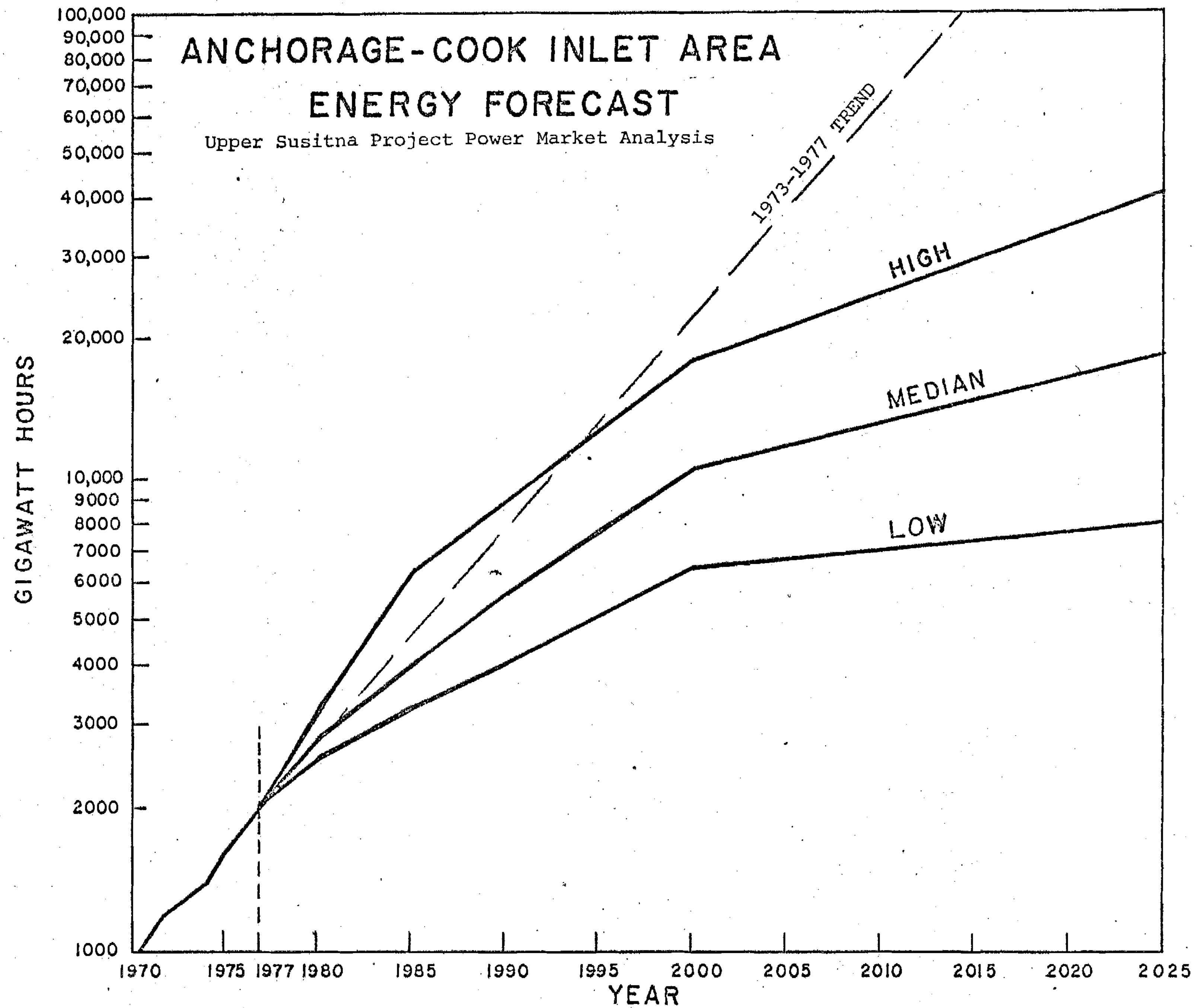

Figure 9

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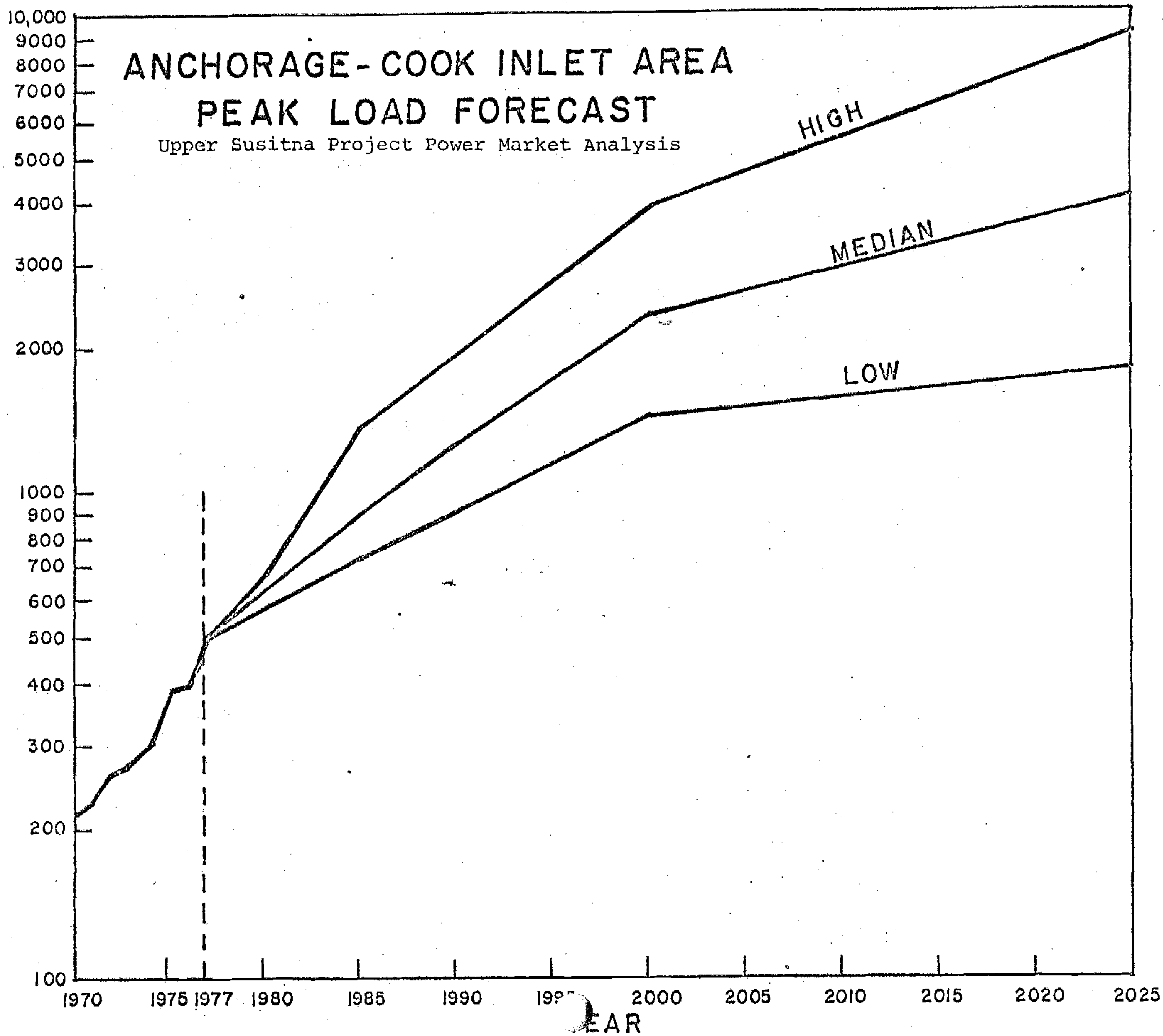

Figure 10

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Table 11
POWER AND ENERGY REQUIREMENTS
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

PEAK POWER	1970 MW	1973 MW	1977 MW	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY									
High				158	244	358	495	685	1,443
Mid	56	73	119	150	211	281	358	452	689
Low				142	180	219	258	297	329
NATIONAL DEFENSE									
High				49	51	54	56	59	76
Mid	44	41	41	47	47	47	47	47	47
Low				46	44	42	40	38	29
TOTAL									
High				207	295	412	551	744	1,519
Mid	101	114	160	197	258	328	405	499	736
Low				188	224	261	298	335	358

ANNUAL ENERGY	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH
UTILITY									
High				690	1,070	1,570	2,170	3,000	6,320
Mid	239	324	483	655	925	1,230	1,570	1,980	3,020
Low				620	790	960	1,130	1,300	1,440
NATIONAL DEFENSE									
High				213	224	235	247	260	333
Mid	203	200	207	207	207	207	207	207	207
Low				203	193	184	175	166	129
TOTAL									
High				903	1,294	1,805	2,417	3,260	6,653
Mid	443	524	690	862	1,132	1,437	1,777	2,187	3,227
Low				823	983	1,144	1,305	1,466	1,569

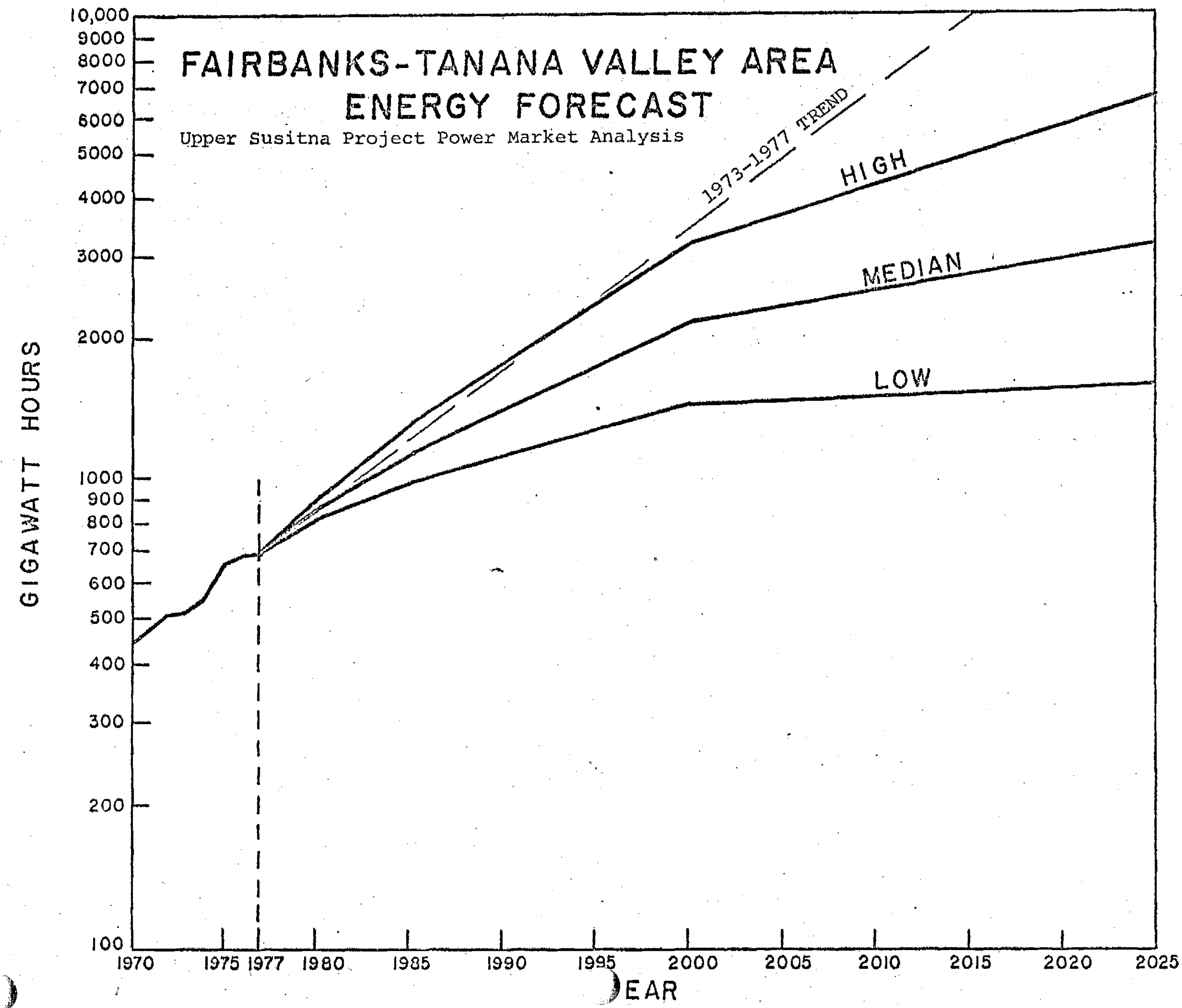

Figure 11

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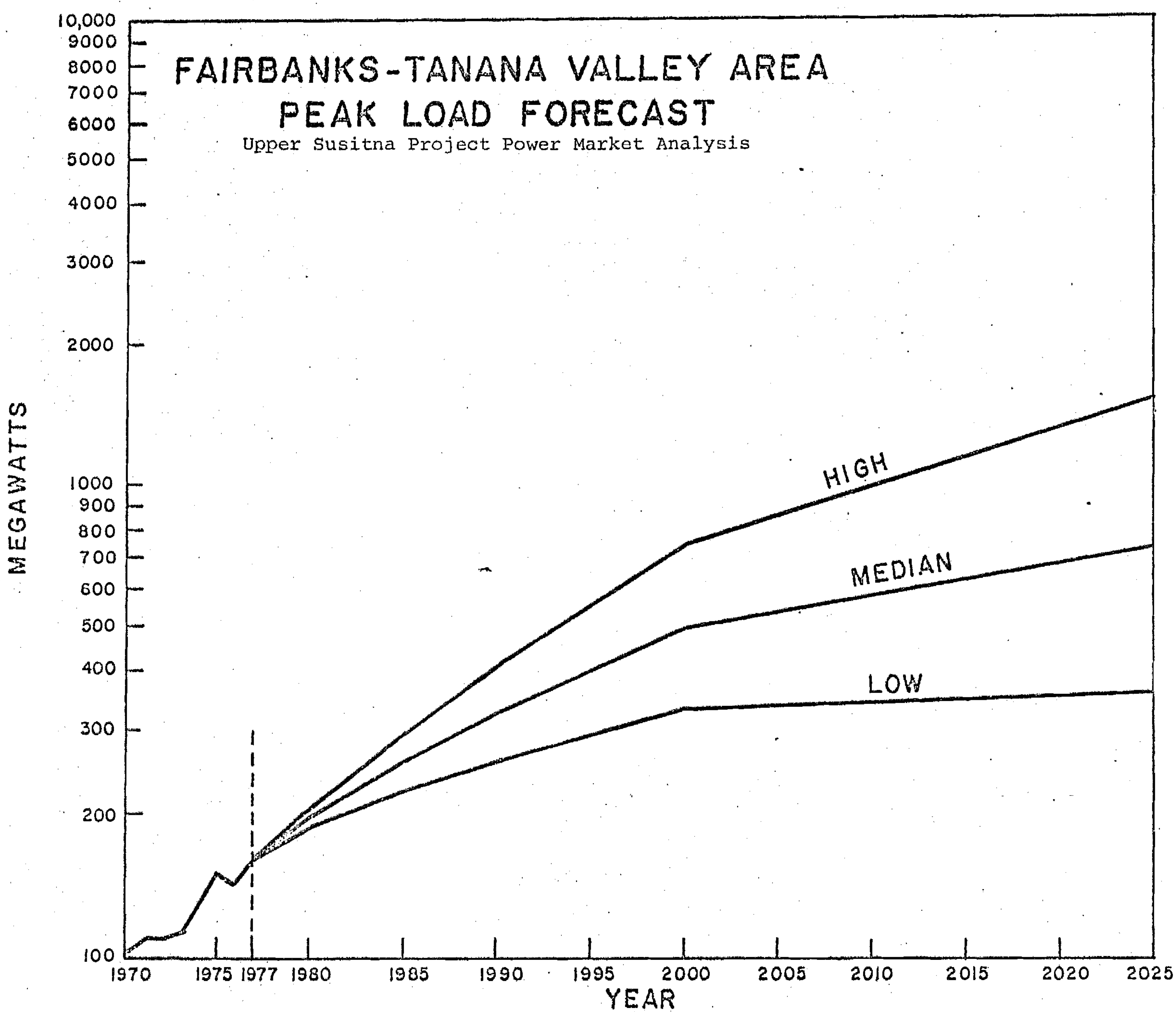

Figure 12

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Table 12
POWER AND ENERGY REQUIREMENTS
(RAILBELT AREA)

Upper Susitna Project Power Market Analysis

PEAK POWER

	1970 MW	1973 MW	1977 MW	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
TOTAL									
High				890	1,671	2,360	3,278	4,645	10,422
Mid	313	389	650	829	1,162	1,592	2,134	2,852	4,796
Low				769	961	1,177	1,449	1,783	2,146

Average Annual Growth for period	%	%	%	%	%	%	%	%
High			11.0	13.4	7.1	6.8	7.2	3.3
Mid	7.5	13.7	8.4	7.0	6.5	6.0	6.0	2.1
Low			5.8	4.6	4.1	4.2	4.2	0.7

ANNUAL ENERGY

	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH
TOTAL									
High				3,928	7,636	10,684	14,844	20,935	47,054
Mid	1,345	1,838	2,681	3,663	5,133	7,078	9,528	12,738	21,578
Low				3,391	4,256	5,219	6,430	7,890	9,630

Average Annual Growth for period	%	%	%	%	%	%	%	%
High			13.6	14.2	6.9	6.8	7.1	3.3
Mid	11.0	9.9	11.0	7.0	6.6	6.1	6.0	2.1
Low			8.1	4.6	4.2	4.3	4.2	0.8

Note: The increase in 1980-1985 high range growth rates reflects the addition in 1985 of the energy intensive self-supplied industry load (280 MW).

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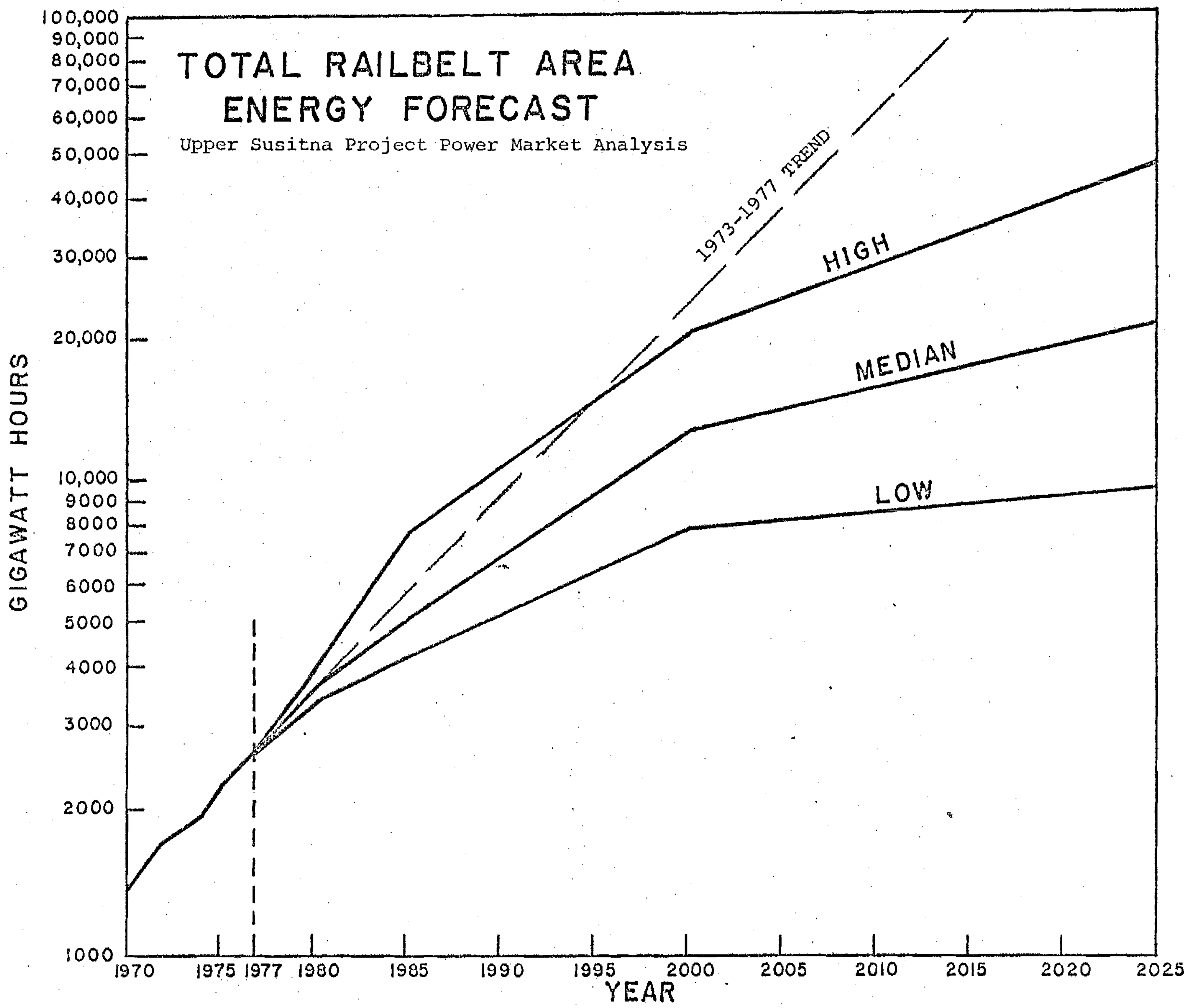

Figure 13

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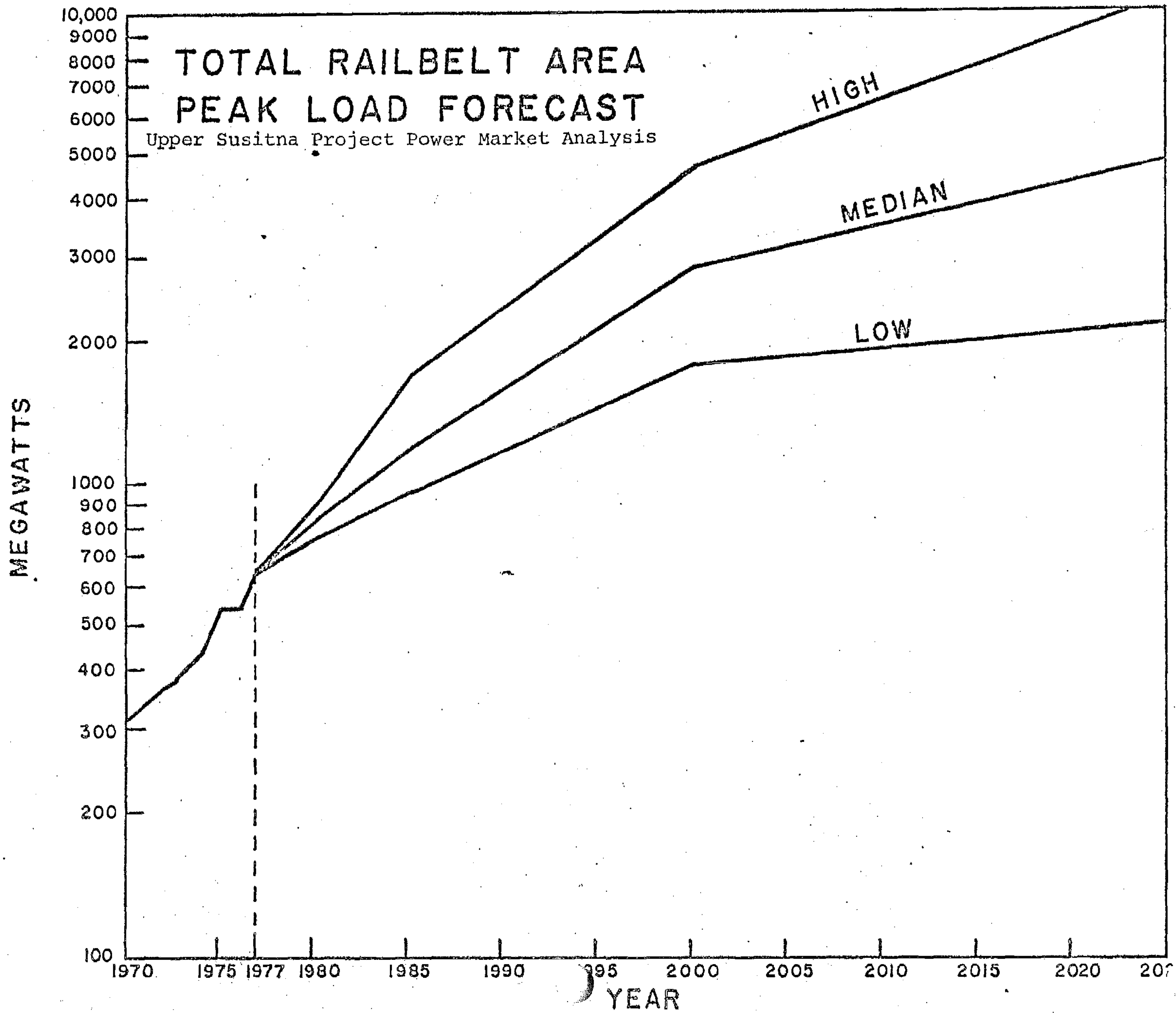

Figure 14

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Table 13
COMPARISON OF UTILITY ENERGY ESTIMATES
1976 MARKETABILITY REPORT, UPDATE OF 1976, AND 1978 ANALYSIS

Upper Susitna Project Power Market Analysis

		Anchorage-Cook Inlet			Fairbanks-Tanana Valley			Total Railbelt		
Year	Forecast Range	1976 Report	Update of 1976	1978 Forecast	1976 Report	Update of 1976	1978 Forecast	1976 Report	Update of 1976	1978 Forecast
1974	Historic	1,305 1/		1,189.7 1/	330		353.8	1,635		1,543.5
1975	High	1,489			377			1,866		
	Mid	1,467			371			1,838		
	Low	1,450			367			1,816		
	Historic			1,413.0			450.8			1,863.8
1976	High	1,699			430			2,129		
	Mid	1,649			417			2,066		
	Low	1,611			407			2,018		
	Historic			1,615.3			468.5			2,083.8
1977	High	1,939			490			2,429		
	Mid	1,853			469			2,322		
	Low	1,790			453			2,242		
	Historic		1,790.1	1,790.1		482.9	482.9		2,273.0	2,273.0
1980	High	2,850	2,660	2,720	700	720	690	3,550	3,380	3,410
	Mid	2,580	2,540	2,500	660	690	655	3,240	3,230	3,155
	Low	2,410	2,460	2,300	610	660	620	3,020	3,120	2,920
1990	High	6,880	6,300	6,630	1,660	1,700	1,570	8,540	8,000	8,200
	Mid	5,210	5,000	4,880	1,270	1,360	1,230	6,480	6,360	6,110
	Low	4,420	4,410	3,590	1,050	1,180	960	5,470	5,590	4,550
2000	High	15,020	13,600	13,920	3,500	3,670	3,000	18,520	17,270	16,920
	Mid	9,420	8,950	8,960	2,230	2,440	1,980	11,650	11,390	10,940
	Low	6,570	6,530	5,770	1,530	1,750	1,300	8,100	8,280	7,070

1/ 1974 historic data revised between 1975 and 1978.

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GWH = million kwh

Further comparisons confirm that the 1976 report forecast was valid. Historic values through 1977 fell between the high and low ranges of the forecast.

The 1976 report was based on load data through 1974 and the following assumptions for utility load growth:

Average Annual Growth Rates

	1974-1980	1980-1990	1990-2000
High Range	14.1%	9.0%	8.0%
Mid-Range	12.4	7.0	6.0
Low Range	11.1	6.0	4.0

The following percentages compare this report and the above assumptions.

Average Annual Growth Rates From
1978 Utility Energy Forecast

	1977-1980	1980-1990	1990-2000
High Range	14.5%	9.0%	7.5%
Mid-Range	11.5	6.8	6.0
Low Range	8.7	4.5	4.5

The 1976 report based the utility energy forecast on assumed average annual growth rates. The 1978 report based the forecast on assumed growth in population and per capita energy use. Both reports considered energy conservation, but it was given more specific and higher importance in the 1978 forecast.

Forecasts available from various utilities are tabulated on tables 14, 15, and 16. Some were done by the utilities, some by consultants, and some by REA. All data was tabulated and, where necessary, extrapolated as part of the State Alaska Power Authority Railbelt Intertie Study. Comparisons are summarized in 5-year increments.

	Utility Forecasts	1978 Susitna Forecasts		
		High	Mid	Low
Energy (GWH)				
1980	3,344	3,410	3,155	2,920
1985	6,277	5,460	4,455	3,630
1990	10,965	8,200	6,110	4,550
1995	17,748	11,600	8,140	5,690
2000	26,550	16,920	10,940	7,070
Peak (MW)				
1980	725	778	720	667
1985	1,377	1,244	1,021	830
1990	2,986	1,873	1,396	1,039
1995	3,835	2,645	1,858	1,298
2000	5,641	3,865	2,497	1,617

The utility forecasts run higher than those of this report. No definite reason for the differences can be made other than the utilities assumed higher growth rates. The basis of the utility assumptions was not considered in this study.

Table 14
UTILITY ENERGY FORECASTS (GWH)
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis

Year	AML&P 1/	CEA 2/	MEA 3/	HEA 4/	Total
1979	634	1,109	280	310	2,333
1980	699	1,283	333	374	2,689
1981	771	1,468	395	452	3,086
1982	847	1,679	468	546	3,541
1983	930	1,921	559	620	4,030
1984	1,018	2,197	668	705	4,588
1985	1,111	2,509	799	800	5,219
1986	1,210	2,810	954	909	5,883
1987	1,313	3,147	1,140	1,033	6,634
1988	1,422	3,525	1,322	1,155	7,424
1989	1,534	3,948	1,534	1,290	8,306
1990	1,650	4,422	1,779	1,442	9,293
1991	1,770	4,864	2,064	1,611	10,309
1992	1,891	5,350	2,394	1,801	11,437
1993	2,014	5,885	2,706	1,978	12,584
1994	2,138	6,474	3,057	2,173	13,843
1995	2,245	7,121	3,455	2,388	15,209
1996	2,357	7,691	3,904	2,623	16,575
1997	2,475	8,306	4,412	2,882	18,075
1998	2,599	8,971	4,853	3,111	19,533
1999	2,729	9,638	5,338	3,359	21,113
2000	2,865	10,463	5,872	3,626	22,826

Source: Obtained from utilities in 1978 for Alaska Power Authority Railbelt Intertie Study.

1/ Anchorage Municipal Light & Power Department
2/ Chugach Electric Association
3/ Matanuska Electric Association
4/ Homer Electric Association

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Table 15
UTILITY PEAK DEMAND FORECASTS (MW)
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis

Year	AML&P 1/	CEA 2/	MEA 3/	HEA 4/	Total
1979	124	239	67	64	495
1980	138	271	81	78	567
1981	152	310	97	94	653
1982	167	355	116	113	752
1983	184	406	142	129	860
1984	202	465	171	146	983
1985	221	530	207	166	1,124
1986	241	594	251	188	1,274
1987	263	655	303	214	1,445
1988	285	745	343	239	1,612
1989	309	835	389	267	1,800
1990	333	935	442	299	2,008
1991	358	1,028	501	334	2,222
1992	384	1,131	569	373	2,458
1993	411	1,244	630	410	2,695
1994	437	1,369	698	451	2,954
1995	461	1,505	773	495	3,234
1996	486	1,626	857	544	3,512
1997	512	1,756	950	598	3,816
1998	539	1,901	1,026	645	4,111
1999	568	2,048	1,108	696	4,421
2000	599	2,212	1,197	752	4,759

Source: Obtained from utilities in 1978 for Alaska Power Authority Railbelt Intertie Study.

1/ Anchorage Municipal Light & Power Department
2/ Chugach Electric Association
3/ Matanuska Electric Association
4/ Homer Electric Association

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Table 16
UTILITY ENERGY AND PEAK DEMAND FORECASTS
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

	Net Energy (GWH)			Peak Demand (MW)		
Year	GVEA 1/	FMU 2/	Total	GVEA	FMU	Total
1979	450	144	594	111	33	144
1980	502	153	655	123	35	158
1981	560	162	722	136	37	173
1982	625	172	796	151	39	190
1983	693	182	875	167	42	209
1984	769	193	962	186	44	230
1985	853	205	1,058	206	47	253
1986	947	217	1,164	228	50	278
1987	1,050	230	1,280	252	53	305
1988	1,155	244	1,399	278	56	334
1989	1,271	259	1,529	305	59	364
1990	1,398	274	1,672	335	63	398
1991	1,537	288	1,825	368	66	434
1992	1,691	302	1,993	405	69	474
1993	1,843	317	2,160	440	72	512
1994	2,009	333	2,342	480	76	556
1995	2,190	350	2,540	521	80	601
1996	2,387	367	2,754	569	84	653
1997	2,602	386	2,987	619	88	707
1998	2,810	405	3,215	668	92	760
1999	3,035	425	3,460	722	97	819
2000	3,278	446	3.724	780	102	882

Source: Obtained from utilities in 1978 for Alaska Power Authority Railbelt Intertie Study.

1/ Golden Valley Electric Association
2/ Fairbanks Municipal Utilities

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Load Distribution

Reservoir operation studies used in sizing reservoirs need an average monthly distribution of annual energy to help relate hydroelectric output to the electric load. This section reports updated averages of monthly energy use divided by annual energy use within the Anchorage-Cook Inlet area.

This section also reports a study of hourly load distribution in the weeks of winter peak load (same as annual peak) and summer minimum peak load. By studying these load curves from several years, hydroelectric plant factor is evaluated. (See capacity section).

The utility systems have had combined annual load factors slightly over 50 percent in the past few years (54 percent in 1977 as shown on figure 17). Data presented in table 17 shows that mid-summer peaks have been running about 60 percent of mid-winter peaks and that monthly load factors generally exceeded 70 percent. For 1977, the December load factor was 76 percent. Figures 15 and 16 illustrate that winter and summer loads are quite similar. The load duration curves of figure 17 present these daily load curves concisely. The 1976 report contains daily load curves of previous years. Winter and summer curves are plotted together showing similarities of slope and shape.

The update of average monthly energy is presented as percent of the annual value in table 18. Average percentages used in the 1976 report compare closely with 1970-77 averages. Slight changes are reflected in the "recommended distribution" column. Winter load is about two-thirds of total.

SYSTEM DAILY GENERATION CURVE
ANCHORAGE AREA

Upper Susitna Project Power Market Analysis

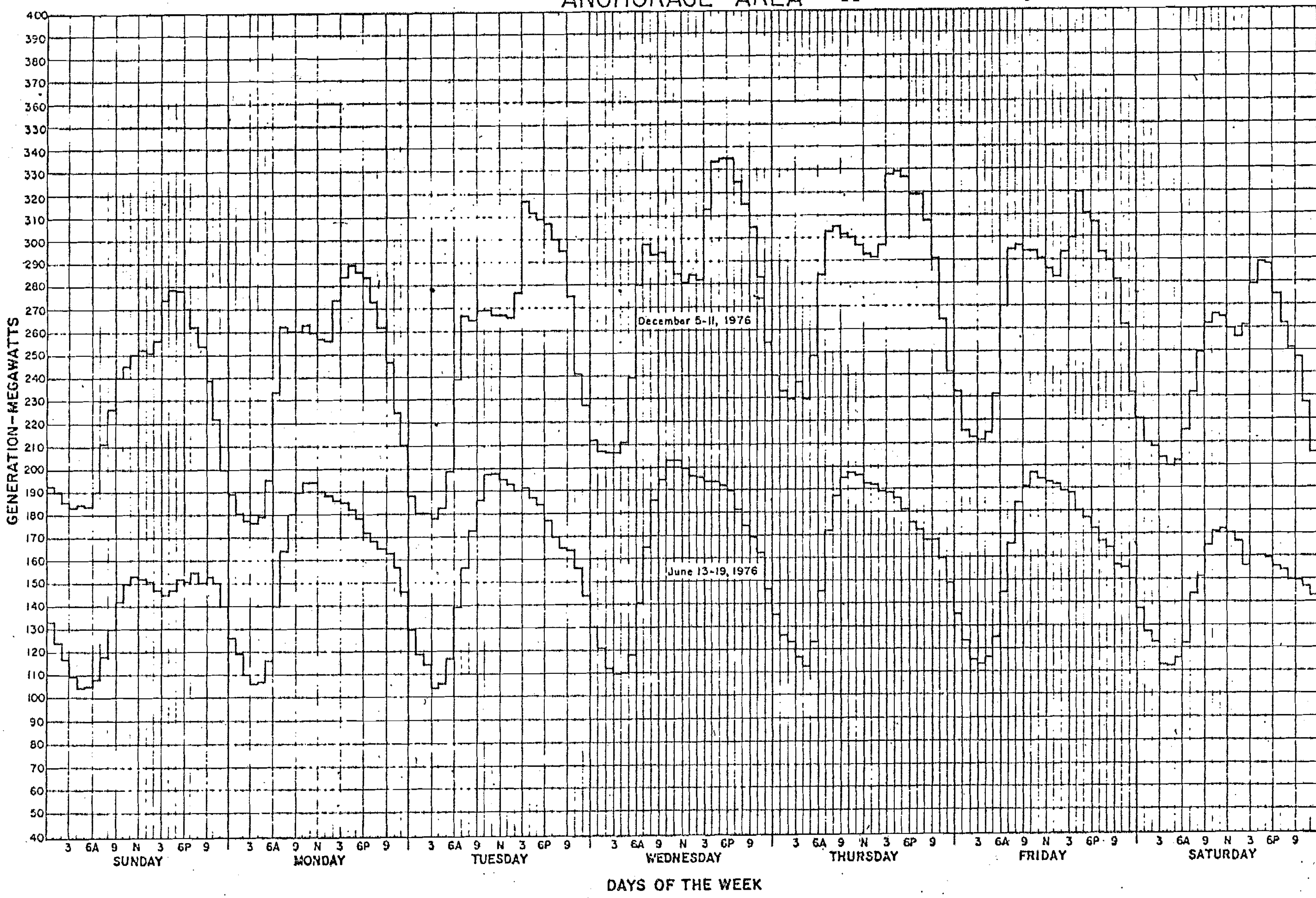

Figure 15

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SYSTEM DAILY GENERATION CURVE
ANCHORAGE AREA

Upper Susitna Project Power Market Analysis

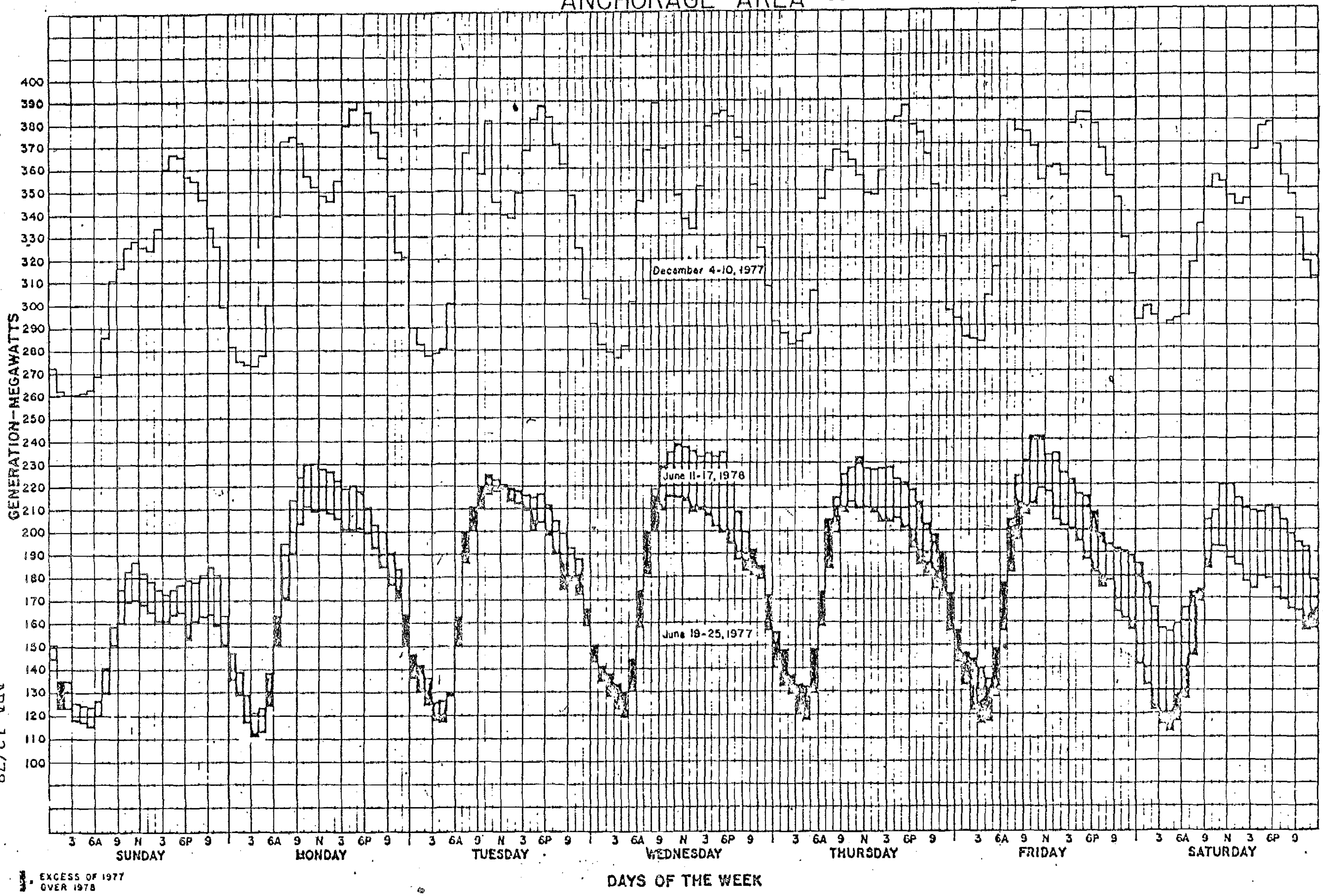

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Figure 16

ANCHORAGE AREA LOAD DURATION CURVE 1977

Upper Susitna Project Power Market Analysis

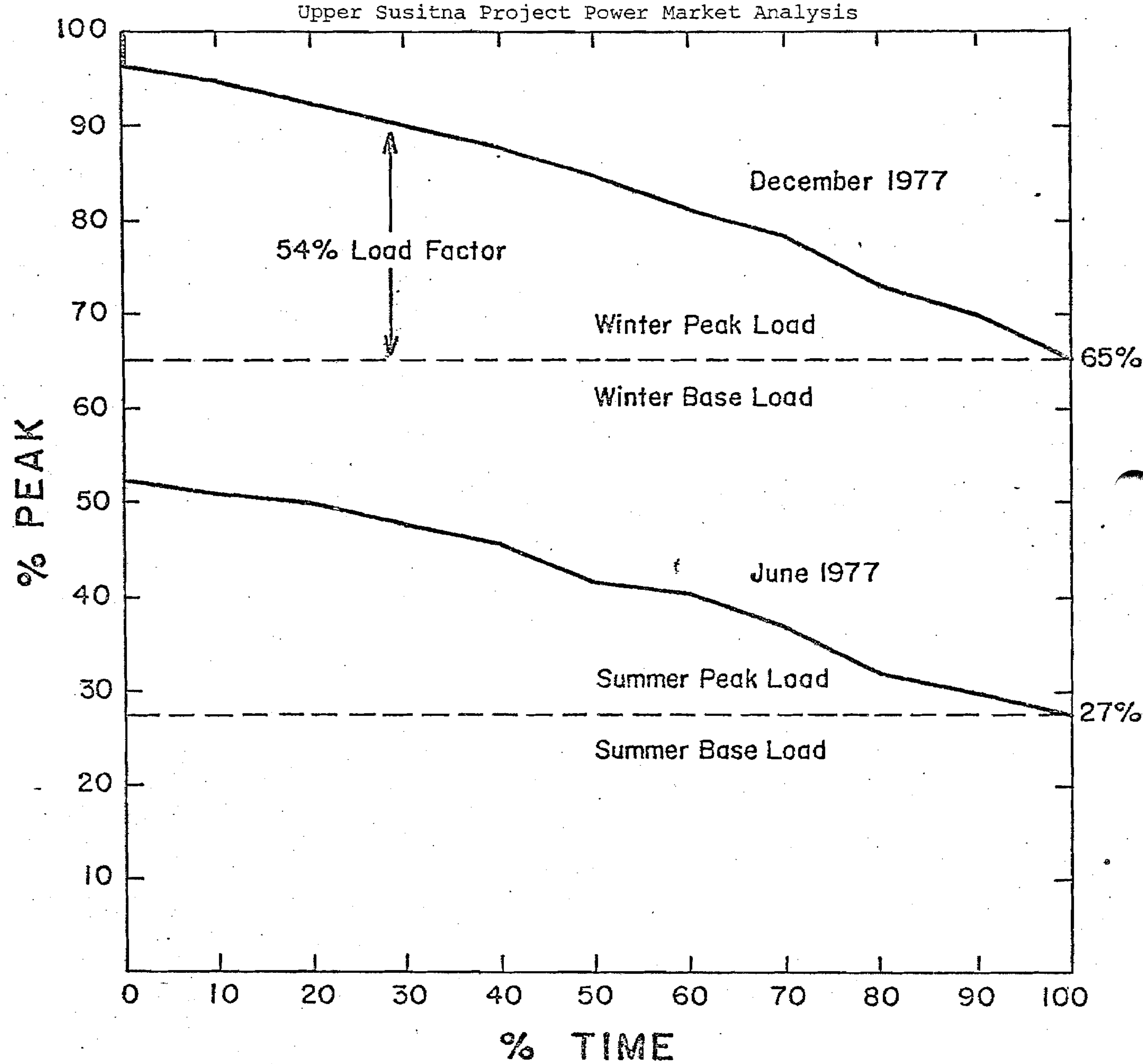

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Table 17

LOAD DISTRIBUTION CHARACTERISTICS
MONTHLY PEAK LOADS AND LOAD FACTORS

Upper Susitna Project Power Market Analysis

Month	1971-1972 Peak MW	% Annual Peak	Energy 10^6 KWH	Mon. Load Fact.	1972-1973 Peak MW	% Annual Peak	Energy 10^6 KWH	Mon. Load Fact.	1973-1974 Peak MW	% Annual Peak	Energy 10^6 KWH	Mon. Load Fact.
October	185.8	73	94.1	68	209.2	74	108.8	70	224.3	82	122.7	73
November	222.8	88	113.0	70	236.3	83	124.4	73	269.6	98	144.6	74
December	236.2	93	121.1	70	260.7	92	143.3	74	266.9	97	147.0	74
January	254.5	100	135.3	72	283.0	100	153.6	72	274.5	100	159.3	78
February	224.5	88	115.3	76	259.6	92	127.5	73	264.5	96	139.4	79
March	222.8	87	119.2	70	225.1	80	125.5	75	249.4	91	135.5	73
April	176.7	69	96.6	76	196.4	69	105.4	75	201.6	73	112.4	77
May	157.9	62	87.8	75	176.7	62	98.5	75	180.4	66	104.1	78
June	152.1	66	78.5	72	165.2	58	87.6	74	176.2	64	95.4	75
July	146.8	52	76.6	70	162.8	59	89.8	74	178.9	65	97.5	73
August	154.5	54	86.9	75	175.9	64	96.2	73	195.7	71	101.9	70
September	179.6	64	92.9	72	194.5	71	100.8	72	210.3	77	106.1	70
Min. Summer Peak / Max. Winter Peak	= 57.7%				57.5%				64.2%			

Month	1974-1975 Peak MW	% Annual Peak	Energy 10^6 KWH	Mon. Load Fact.	1975-1976 Peak MW	% Annual Peak	Energy 10^6 KWH	Mon. Load Fact.	1976-1977 Peak MW	% Annual Peak	Energy 10^6 KWH	Mon. Load Fact.
October	252.9	71	134.3	71	342.2	81	153.0	60	359.8	88	182.2	68
November	266.2	75	156.0	81	367.6	87	196.2	74	360.7	88	193.8	75
December	314.9	89	170.7	73	420.5	100	226.3	72	402.3	100	223.4	74
January	354.1	100	180.8	69	394.1	94	213.3	73	376.4	92	209.9	75
February	316.7	89	166.9	78	383.3	91	203.5	76	356.8	87	181.7	76
March	268.6	76	156.6	78	342.1	81	187.6	74	369.0	90	208.6	76
April	249.0	70	129.2	72	285.3	68	159.0	77	334.4	82	177.0	73
May	222.0	63	120.9	73	253.6	60	145.0	77	284.8	70	161.3	76
June	209.0	59	113.0	75	236.1	56	128.9	76	265.0	65	148.1	78
July	207.0	58	110.9	72	248.0	59	134.4	73	257.1	63	141.3	74
August	211.5	61	118.3	73	250.6	60	139.9	75	271.8	67	151.7	75
September	247.4	70	131.9	74	278.0	66	151.2	76	318.9	79	166.7	73
Min. Summer Peak / Max. Winter Peak	58.5%				56.1%				63.0%			

1/ Represents sum of loads for the Anchorage (AML&P, CEA) and Fairbanks (FMU, GVEA) utilities

Table 18
MONTHLY ENERGY REQUIREMENTS AS PERCENT OF ANNUAL REQUIREMENT

Upper Susitna Project Power Market Analysis

MONTH	1970-1972 Utility Loads 1/	1970-1977 Utility Loads 2/	Recommended Distribution 3/
Oct.	7.9	8.1	8.2
Nov.	8.9	9.2	9.0
Dec.	10.2	10.2	9.7
Jan.	11.3	10.8	10.2
Feb.	9.2	9.3	9.1
Mar.	9.8	9.4	9.1
April	8.0	7.8	7.9
May	7.2	7.3	7.6
June	6.5	6.6	7.0
July	6.4	6.7	7.1
Aug.	7.1	7.1	7.4
Sept.	7.5	7.5	7.7
Total	100.0	100.0	100.0
SEASONAL			
Oct.-April	65.3	64.8	63.2
May-Sept.	34.7	35.2	36.8

1/ Combined loads of CEA, AML&P, GVEA, FMUS, for Oct. 1970-Sept. 1972. Basis for (1975 Susitna Power market analysis) 1976 report.

2/ Combined net generation of CEA, AML&P, APA, GVEA, FMUS, for Oct. 1970-Sept. 1977. Updated Basis.

3/ Assumes total requirements consisting of 25 percent industrial loads and 75 percent utility loads. Update of previous recommendations.

Capacity Requirements

With reference to the load factor evaluations in the previous section, a trend towards somewhat higher annual load factors in the future is anticipated. In addition to benefitting from any load diversity in the interconnected system, peak load management (including such practices as peak load pricing) offers considerable opportunity for improving load factors, which in turn reduces overall capacity requirements for the system in any given year. For planning purposes, it is assumed that the annual system load factor will be in the range of 55 to 60 percent by the latter part of the century.

System capacity requirements are determined by winter peak load requirements plus allowances for reserves and unanticipated load growth. The lower summer peaks provide latitude for scheduled unit maintenance and repairs.

System daily peak load shapes indicate that a very small portion of the capacity is needed for very low load factor operation. Some of the gas turbine capacity now used for base load is expected to be used mainly for peak shaving purposes, eventually. It will be operating during peak load hours for the few days each year when loads approach annual peak, and will be in standby reserve for the balance of the year. Figure 17, the annual peak week duration curve, shows that the highest 10 percent load occurs for 30 percent of the week (about two days).

Reliability standards would be upgraded as the power systems develop. Likely inclusions are specific provisions for maintaining spinning reserve capacity to cover possible generator outages and substantial improvements in system transmission reliability.

Results - Examination of the winter load duration curve (figure 9) indicates that the base load portion is about 65 percent of total load and the peak load is about 35 percent of total load. Load factor for the peak portion is about 54 percent. Winter weekly load factors are approximately 80 percent. This is illustrated in the winter and summer load duration curves by proportioning the areas under the curves to the total possible area if peak load occurred 100 percent of the time.

An annual plant factor of 50 percent is recommended for the proposed Upper Susitna Project. This is largely a judgment factor and is based on the following considerations:

1. The recommended plant factor provides for serving a proportional share of both peaking and energy requirements throughout the year while maintaining adequate flexibility to meet changing conditions in any given year.

2. Any significant reduction in this capacity could materially reduce flexibility.

3. A significant market for low load factor peaking capacity seems unlikely within the foreseeable future. Load management and additional industrial loads will probably increase the overall system load factor in the future. It is expected that several existing and planned gas turbine units could eventually be used for peak shaving.

4. It is recognized that the mode of operation for the hydro will change through time. In the initial years of operation, it is likely that the full peaking capacity will be used infrequently. For example, the mid-range Railbelt estimated system peak load for the year 2000 is 2,852 MW. Assuming load shapes similar to the current Anchorage area loads, the winter peak week would require about 1,850 MW of continuous power to cover the base loads and about 1,000 MW of peaking power. Load factors of the peak portion would be about 50 percent.

A design capacity based on 50 percent plant factor applied to average annual energy (primary plus secondary) appears appropriate. Machine overload capability contributes to spinning reserves for emergencies or other short term contingencies.

The Corps based nameplate capacity on 50 percent plant factor applied to critical year firm energy. This smaller capacity, when applied to average annual energy, results in a 56 percent plant factor. APA feels the smaller design capacity may unduly reduce flexibility.

PART VI. ALTERNATIVE POWER SOURCES

Introduction

This section examines alternative power supply options in the Railbelt in lieu of the Upper Susitna Project and presents detailed cost estimates of power from new coal-fired steam plants.

Alternatives premised on unproven technology were eliminated.

Alternatives Considered

Potential alternative sources of electric power generation are identified by energy type. They are coal, oil and natural gas, hydro, nuclear, wind, geothermal, and tide.

Some alternatives will be restricted in time or capacity because of Federal energy policy controlling use of energy resource. Others will be restricted by practical available energy supply. Still others are impractical because of lack of large-scale technology.

Coal

Evaluation of coal utilization is based on mine-mouth coal-fired steam generation. Potential advanced technology, such as gasification, is not considered because development would not be available within this study period.

Recent studies provide general information about possible locations, sizing, and cost of new steamplants, but Alaska specific data are limited and extrapolations have been made for local conditions.

Information sources of specific interest for this analysis are: studies by Battelle Pacific Northwest Laboratories (March 1978); the Electric Power Research Institute (EPRI) (January 1977); and the Washington Public Power Supply System (WPPSS) (June 1977); the Federal Energy Regulatory Commission (FERC) determination of power values for the Bradley Lake Project (October 1977) and the Upper Susitna Project (October 1978); and evaluations of costs for the proposed Golden Valley Electric Association (GVEA) plant additions at Healy. These are all listed in the bibliography.

Location - It is assumed that new coal-fired steamplants would be located near the Beluga fields for service to the Anchorage-Cook Inlet area and at Healy for service to the Fairbanks-Tanana Valley area. The plants would use known but undeveloped coal resources at Beluga and the existing coal mining operation near Healy.

It is recognized that other locations are possible. For example, it may be possible to locate a coal-fired plant on the Kenai Peninsula and use coal from either local reserves or Beluga. A Kenai location might offer co-generation possibilities because steam could be reused in manufacturing by the petrochemical industry. The potential for mining coal on the Kenai Peninsula is substantially less attractive than for Beluga because of thin coal seams and other geologic factors.

Capacity - These analyses are for two-unit 200-MW and 500-MW plants. This size range is considered appropriate for new coal-fired plants that might come on-line between 1985 and 2000.

Investment Cost - Table 19 summarizes unit investment costs for new coal-fired plants presented in several recent studies. The data assembled by each entity is quite complex with respect to original estimated price levels, inflation to updated price levels, or projected future on-line dates, size, pollution control equipment, location, type of plant, and other items. Price levels were not adjusted to a uniform date because of the complexity of data involved.

All 1977 and 1978 estimates are substantially higher than APA estimates for the 1976 Alaska Power Survey and the 1976 report.

The most in-depth analysis was the WPPSS study which investigated the construction of 1,000-MW steamplants at 10 plant sites in Washington, Montana, and Wyoming. Several grades and sources were assumed. Costs were estimated for with and without sulphur dioxide scrubbers (scrubbers). Twenty-two options of plant sites, coal supply, and transportation were investigated.

APA's estimate of coal-fired steamplant investment costs is derived from the WPPSS study. Procedures for adjusting costs to current Alaska conditions are similar to the analysis used in the appended Battelle report.

The basic cost in the WPPSS study for a 1,000 MW single unit plant in operation during mid-1976 was:

Without Scrubbers	$554/kw
With Scrubbers	$684/kw

The WPPSS procedure increased these costs for the quality of the coal used and other specific powerplant site conditions. The coal quality problems have not been considered in this estimate, and the construction site variable is assumed to be included in the Alaska factor.

Table 19

COMPARISON OF INVESTMENT COSTS FOR COAL-FIRED STEAMPLANTS

Upper Susitna Project Power Market Analysis

Source of Estimate	Price Level	Location	Size, MW	No. of Units	Scrubbers	Investment Cost, $/kw
ALASKA LOCATIONS						
APA 1/	Oct. 1978	Healy or Beluga	200	2	No	1,500
	Oct. 1978	Healy or Beluga	200	2	Yes	1,860
	Oct. 1978	Healy or Beluga	500	2	No	1,300
	Oct. 1978	Healy or Beluga	500	2	Yes	1,610
APA Susitna River Studies						
	Jan. 1975	Healy or Beluga	200	2	Yes	726
	Jan. 1975	Healy or Beluga	500	2	Yes	630
Golden Valley Electric Association 2/	1974	Healy	132	2	No	950
	1977	Healy	150	2	No	1,400
	1977	Healy	150	2	Yes	1,700
	1978	Healy	100	1	Yes	1,800
Battelle 3/	Jan. 1977	Beluga	200	1	No	1,220 to 1,571
	Jan. 1977	Beluga	200	1	Yes	1,400 to 1,766
	Jan. 1977	Healy or Nenana	200	1	No	1,470 to 1,920
	Jan. 1977	Healy or Nenana	200	1	Yes	1,710 to 2,158
	Jan. 1977	Anchorage	200	1	No	1,120 to 1,440
	Jan. 1977	Anchorage	200	1	Yes	1,280 to 1,690
Federal Energy Regulatory Commission 4/	Jan. 1977	Anchorage or Kenai Areas	450	2	Yes	900
	Oct. 1978	Anchorage or Kenai Areas	450	2	Yes	1,220 to 1,240
	Oct. 1978	Healy	230	2	Yes	1,475 to 1,510

Table 19 (cont.)
COMPARISON OF INVESTMENT COSTS FOR COAL-FIRED STEAMPLANTS

Upper Susitna Project Power Market Analysis

Source of Estimate	Price Level	Location	Size, MW	No. of Units	Scrubbers	Investment Cost, $/kw
PACIFIC NORTHWEST AND WESTERN U.S. LOCATIONS						
Washington Public Power Supply System 5/	Mid 1976	Pacific Northwest	1,000	2	No	554
	Mid 1976	Pacific Northwest	1,000	2	Yes	684
	July 1987	Pacific Northwest	1,000	2	No	848
	July 1987	Pacific Northwest	1,000	2	Yes	1,056
Electric Power Research Institute 6/	July 1976	Western U.S. Remote	500	1	No	896
	July 1976	Western U.S. Remote	500	1	Yes	1,036
	July 1976	Western U.S. Remote	1,000	2	No	830
	July 1976	Western U.S. Remote	1,000	2	Yes	960
Idaho Nuclear Energy Commission 7/	1984	Boise, Idaho	1,000	2	No	828
	1984	Boise, Idaho	1,000	2	Yes	934

1/ APA's estimate is based largely on the WPPSS study with adjustments for Alaska conditions and size of plant. Future inflation not shown.
2/ GVEA 1974 estimate assumed units becoming operational in 1983 and 1986. The 1978 estimates assume operation in 1984 at $2,500/kw assuming 7% inflation.
3/ Battelle's estimates are based on adjusting both WPPSS and EPRI study data. The higher figures are from the EPRI study. Their studies with future operation dates include inflation.
4/ Scrubbers are assumed included in the cost.
5/ This is the basic study adjusted by APA and Battelle above. The 1987 costs include 5 percent annual inflation.
6/ The July 1976 price level includes costs for init operation in 1978.
7/ The price level is 1975 costs adjusted to show costs for a 1984 operation date.

Adjusting the cost for the time between mid-1976 and October 1978 using the Handy-Whitman Steamplant Cost Index increased the cost 18.4 percent.

Without Scrubbers	\$656/kw
With Scrubbers	\$810/kw

Powerplants smaller than the 1,000 MW that will fit near-future Alaska power needs have a smaller total cost, but a larger cost per installed kilowatt. An adjustment needs to be applied to the costs to compensate for the loss of economy of the large scale plants. The factor recommended is the ratio of the plant size to the 0.85 exponent. A 500-MW plant thus costs 55.5 percent of a 1,000 MW plant, and a 200-MW plant costs 25.5 percent. Scaling the plants to 200 MW and 500 MW gives:

Plant Size	200 MW		500 MW	
	\$ Million	\$/kw	\$ Million	\$/kw
Without Scrubbers	167,000	835	364,000	728
With Scrubbers	207,000	1,035	450,000	899

An Alaska factor of 1.8 was used to adjust Pacific Northwest costs to Alaska wages and conditions:

Plant Size	200 MW		500 MW	
	\$ Million	\$/kw	\$ Million	\$/kw
Without Scrubbers	300,000	1,500	655,000	1,310
With Scrubbers	372,000	1,860	810,000	1,620

Fuel Cost and Availability - There is a wide range of opinions about the probable future cost of coal. For many years, coal prices were set at a small margin above production costs so that coal could compete with low-cost oil and natural gas. This situation has changed drastically because of price increases for oil and gas and incentives for power generation and has resulted in industrial conversion to coal. Coal production costs are also increasing rapidly due to normal inflationary and regulation factors. FERC reported the national average price of coal at 96.2¢/million Btu in July 1977, up from 80.8¢ in July 1975, and 39.8¢ in August 1973.

Alaskan coal prices have shown sizable increases recently. The cost of coal at Healy in September 1978 was 80 cents per million Btu, up from 62 cents in 1975. The Fairbanks Municipal Utility System (FMUS) pays an additional \$6/ton shipping cost for Healy coal resulting in a price of \$1.15 per million Btu at the powerplant in Fairbanks.

In October 1978, owners of the Beluga coal field stated that large reserves in the Beluga coal field may compete in the world energy market at a price of $1.10 to $1.40/million Btu stockpiled on the shore of Cook Inlet. The conclusions were based on company studies that included geologic investigations, drilling, bulk sampling programs, mining preparation, environmental evaluation, and navigation and shipping studies.

FERC estimated $1.00/million Btu for determination of power values in the Bradley Lake Project (October 1977). Other recent studies suggest this is a reasonable current (1978) cost for Beluga coal delivered to a steamplant at Beluga, with no allowance for price increase in future years.

Earlier APA studies for the 1976 FPC Power Survey and the 1976 Susitna report assumed $1.00 to $1.50/million Btu for coal at 1985 price levels in 1974 dollars. This included consideration of future economies of scale of larger mining operations.

APA analyses for this report are still based on a coal cost of $1.00 to $1.50/million Btu for a mine-mouth plant at either Beluga or Healy for mid-1980 conditions. This is comparable with $1.28 in 1985, estimated by GVEA for Healy coal by increasing the current 80 cents by 7 percent annually. Because of the wide diversity of studies and opinions, analyses based on a range of costs are presented.

In this study, we are assuming fuel values will increase about 2 percent per year--more rapidly than overall price indexes. This is consistent with other analyses.

Table 20
GENERATION COSTS FOR CONVENTIONAL COAL-FIRED STEAMPLANTS

Upper Susitna Project Power Market Analysis

1985 COSTS (1978 PRICES)1/	Plant Size, MW			
	200		500	
Number of Units	2		2	
Investment Cost, Railbelt, $/kw	1,860		1,620	
Capital Cost, mills/kwh	38.5		33.5	
Operation and Maintenance, mills/kwh	6.5		5.6	
Subtotal	45.0		39.1	
			1.00/mmBtu	1.50/mmBtu
Assumed Fuel Costs, mills/kwh	10.0	15.0	10.0	15.0
Transmission Cost to Load Center	4.0	4.0	3.0	3.0
Total Energy Cost, mills/kwh	59.0	64.0	52.1	57.1
1994 ENERGY COST	Fuel escalated 2%/year 1985 to 1994			
Capital Cost, mills/kwh	38.5		33.5	
Operation and Maintenance, mills/kwh	6.5		5.6	
Transmission Cost, mills/kwh	4.0		3.0	
Subtotal	49.0		42.1	
Fuel, Inflated 2% 1985 to 1994	12.0	17.9	12.0	17.9
Total	61.0	66.9	54.1	60.0
Fuel Escalated 7%/Year from 1985 to 1994; Capital Cost and O&M Escalated 5%/Year from 1978 to 1994				
Capital Cost	80.0		69.7	
Operation and Maintenance	13.5		11.6	
Transmission	8.3		6.2	
Subtotal	101.8		87.5	
Fuel	18.4	27.6	18.4	27.6
Total	120.2	129.4	105.9	115.1

1/ APA estimate based on studies by Washington Public Power Supply System Studies 1977.

Cost of Power - The estimated total cost of electric power that would be generated by a coal-fired steamplant alternative to the Susitna project is presented in table 20. Development of the estimated cost applied to a plant in either the Beluga or Healy area is based on the investment and fuel costs discussed earlier in this section, and includes other criteria developed in this report. In summary, the parameters are:

1. Investment cost includes all construction, overhead, and interest during construction, and is based on updating and adjusting WPPSS Pacific Northwest costs for Alaska conditions. Annual capital costs are based on a 35-year life and 7 percent interest rate.

2. Operation and maintenance costs are based on a detailed WPPSS personnel and materials estimate adjusted for plant capacity in the same manner as investment costs, increased by 50 percent for Alaska conditions, as developed in the 1976 Alaska Power Survey, and indexed from January 1977 to October 1978 using the U.S. Department of Labor index.

3. Fuel costs of both $1.00 and $1.50/kw are presented with a heat rate of 10,000 Btu/kwh.

4. Transmission costs are for lines connecting Beluga with Anchorage, and Healy with Fairbanks.

The resulting average unit cost of electric power from coal-fired steamplants to supply the Railbelt market area ranges from 5.21 to 6.40¢/kwh, varying with fuel cost and plant capacity.

Table 20 also presents an analysis of the cost of energy with fuel costs escalated at 2 percent anually from 1985 through 1994 (Susitna project, Watana phase on-line) and fuel cost escalated at 7 percent annually from 1985 through 1994.

Comparative Cost of Power (FERC) - FERC evaluated alternative costs for coal-fired steam plants at Beluga for the Anchorage area and Healy for the Fairbanks area as part of their power benefit studies for the Upper Susitna Project.

The FERC estimates of 4.93 to 5.64¢/kwh are in the same range as those estimated by APA for the Anchorage area. However, the FERC estimates of 4.02 to 4.30¢/kwh for the Fairbanks area are low compared to APA estimates. FERC estimated construction costs (July 1978) at $1,475/kw compared to $1,810/kw estimated by APA. In addition, GVEA recently estimated a cost of $1,800/kw for a comparable Healy steamplant.

FERC data are based on:

1. An Anchorage area plant assumed to be a two-unit 450-MW plant with fuel cost of $1.10/million Btu and a heat rate of 10,000 Btu/kwh. The Fairbanks plant is assumed to be two units, totaling 230 MW, with a fuel cost of $0.80/million Btu and a heat rate of 10,500 Btu/kwh. For non-Federal cases, the Anchorage area plant investment cost was estimated at $1,240/kw and the Fairbanks investment cost at $1,475/kw.

2. Financing is based on a composite Anchorage-Kenai interest rate of 7.9 percent with 75 percent financing by REA at 8.5 percent and 25 percent by the municipality of Anchorage at 6.25 percent. The interest rate for Fairbanks is 5.75 percent assuming State of Alaska Power Authority financing. In comparison, a Federal rate of 6.875 percent is used for both areas, the same rate used in the Corps of Engineers benefit analysis.

Oil and Natural Gas

The Upper Susitna Project involves a large new power supply beginning in 1994, with an expected life in excess of 100 years.

APA does not believe that oil and natural gas are realistic alternatives for equivalent power supplies, particularly in view of the timeframe (start in 1994) and very long life (through 2094).

Hydro

Criteria - Evaluation of possible hydroelectric generation alternatives to the Susitna project is based on comparing: (1) the potential generation capability, and (2) unit cost of power. Possible sites are identified by: (1) single sites with sufficient capacity to supply the projected power demands; (2) combinations of smaller sites within selected geographic areas and river basins; and (3) a combination of the best sites from all areas accessible to the Railbelt.

The hydro evaluation considered power requirements ranging from 600 MW to 2,290 MW, which are, respectively, the low-range and high-range projected increases in Railbelt demands from 1990 to 2000. Associated annual firm energy requirements would range from 2,670 gwh to 10,260 gwh. By comparison, the Susitna project is scheduled to provide about 1,573 MW capacity and 6,100 gwh annual firm energy.

Possible hydro generation alternatives were selected from the APA inventory of hydroelectric resources. The inventory estimates unit cost of power at the generator bus bar based on 1965-1966 cost at 3 1/4 percent interest rate. Susitna inventory cost data indexed to 1975 price levels give unit costs within 10 percent of that determined for the 1976 report.

Single Large Capacity Sites - Seven single sites have sufficient capacity potential to be an alternative to supplying minimum Susitna market area requirements. These are within a maximum of 1.4 times the unit cost for Susitna power. However, land use designations (National Parks and Monuments and Wild and Scenic Rivers) and/or known major environmental impacts preclude consideration of developing any of the sites at the present time.

The sites are:

Site	Stream	Firm Energy GWH/yr	Capacity MW	Percent of Susitna Cost
Holy Cross	Yukon R.	12,300	2,800	140
Ruby	Yukon R.	6,400	1,460	62
Rampart	Yukon R.	34,200	5,040	32
Porcupine	Porcupine R.	2,320	530	79
Woodchopper	Yukon R.	14,200	3,200	71
Yukon-Taiya	Yukon R.	21,000	3,200	52
Wood Canyon	Copper R.	21,900	3,600	51

None of the above sites can be considered available resources in the 1990's timeframe. This is due to: (1) Holy Cross, Ruby, Rampart, and Woodchopper are main-stem Yukon River sites with known major environmental problems, (2) Porcupine, Woodchopper, and Yukon-Taiya have major international considerations, and (3) Wood Canyon has a known major fishery problem.

Sites within the Nenana River basin have also been identified in past work. Their economic feasibility depends upon being developed as a unit. However, several of the sites are located partially within Mount McKinley National Park and are precluded from development.

In conclusion, no single, large hydro generation sites are available as alternatives to the Upper Susitna Project.

Combination of Small Capacity Sites - Combinations of single sites with less capacity than the Susitna project consist of 78 sites within the Matanuska, Tanana, Yentna-Skwentna, Talkeetna, and Chulitna River basins, the northwest drainage of Cook Inlet, the Kenai Peninsula, and scattered small sites and small basins within the Railbelt area. None of these areas contain sites with total capacity potential to supply minimum Susitna requirements. (Site combinations with the most capacity--the Yentna-Skewntna River basin and Kenai Peninsula--total 609 MW and 646 MW respectively, but with costs for individual sites ranging from 1.4 to 20 times Susitna costs.)

If consideration is given to combining the best small sites from each of the geographic areas, 12 sites totalling 1,276 MW are within the range of twice the cost of Susitna. Only one (Chakachamna) is near Susitna cost (103 percent), and has 366 MW potential.

Chakachamna is partly within the new Lake Clark National Monument. Other new or proposed Federal land withdrawals would preclude sites with about half of the total potential of the combined sites. Other sites have various environmental impact potentials. Some streams that would be affected have major anadromous fish resources. Also, because the sites are widely distributed, the needed transmission systems would be fairly extensive and costly.

Summary - Based on examination of individual sites and combinations of sites, there are no hydro generation opportunities available to provide enough power to be an alternative to the Susitna Project. Small individual sites may be available, but would satisfy only a small portion of the market area demand. Other sites, with apparently acceptable quantity and economic capability, have been or will be precluded by land status designation.

Nuclear

Nuclear generation may be technically viable in Alaska, but probable cost and siting problems eliminate it as a potential alternative to Susitna. Available information indicates that in other states, nuclear is economically competitive with coal, depending on specific conditions. Difficult conditions, possible seismic and environmental siting problems, and readily available coal indicate that nuclear generation will probably not be economically attractive in Alaska in the foreseeable future.

Wind

The State has shown serious interest in wind generation technology by developing pilot projects in the bush communities of Ugashik, Nelson Lagoon, and Kotzebue. Wind seems to provide near-term power for small communities presently dependent on high-cost diesel generation.

The cost and applicable scale of technology does not make wind power a viable alternative for large near-future power demands.

Geothermal

Investigations to date have found no high quality geothermal resources suitable for power development in areas accessible to the Railbelt area. Geothermal potential is considered high in the Wrangell Mountains and portions of the Alaska Range, and may be applicable to the Railbelt in the future. At this time, insufficient data are available to define the resource, even for appraisal of the large Susitna project market.

Tide

There is a large physical potential for tidal power development in the Cook Inlet area where the State estimates that a total of 8,560 MW could be harnessed. A potential of 785 MW is estimated for Knik Arm alone, and approximately twice that amount for Turnagain Arm.

Several different concepts have been developed for the Cook Inlet tidal potential because of the interest in alternative energy sources. There is merit to preparing a good reconnaissance of this alternative, as pointed out in the 1976 report. However, the scope of work involved to develop the tidal resource, the large cost of development, and the important environmental considerations eliminate tidal power as a reasonable alternative to the Susitna project.

Conclusion

The range of power options for the Alaska Railbelt is narrowing rapidly.

1. Oil and natural gas are very suspect in terms of long-range national supply and availability for use in power production.

2. Coal is proving to be far more expensive as a power source than previously anticipated.

3. Many hydroelectric alternatives have moved to the "unavailable" classes because of land area designations. The remaining are less desirable in terms of cost and ability to meet projected requirements.

4. Nuclear is expected to be as expensive as coal.

5. Geothermal, tide, and wind are unrealistic planning alternatives at this time.

PART VII. LOAD/RESOURCE AND SYSTEM POWER COST ANALYSES

Introduction

A series of load/resource and system cost analyses were made to demonstrate impacts of the Susitna project in terms of overall power system costs.

The load/resource analysis determined probable timing of new major investments in generation and transmission facilities. It also shows annual energy from each type of plant. The load/resource analyses were prepared for these basic power supply strategies:

Case 1. All additional generating capacity assumed to be coal-fired steam turbines without a transmission interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area load centers.

Case 2. All additional generating capacity assumed to be coal-fired steam turbines, including a transmission interconnection.

Case 3. Additional capacity to include the Upper Susitna project (including transmission intertie) plus additional coal as needed, and for the three load limits (high, medium, and low).

The system cost analyses, keyed to the load/resource, determined cost by year to amortize investments and pay all annual costs (fuel, O&M expenses, etc). Inflation rates of 0 and 5 percent were considered.

APA developed a number of the key inputs, e.g., demands, unit sizes and costs, etc. APA contracted with Battelle to make the studies and prepare the report.

This section summarizes key assumptions and results. More detailed information is available in the appended Battelle report.

Basic Data and Assumptions

Basic data and assumptions used in the load/resource and system power cost analyses are:

1. Interest rate for repayment of facilities = 7 1/2 percent.

2. Inflation rates of 0 and 5 percent, with construction costs increasing at inflation rate, and fuel costs increasing at 2 percent above inflation rate.

3. System reserve capacity of 25 percent for non-interconnected load centers and 20 percent for interconnected systems.

4. Transmission losses of 1.5 percent for energy and 5 percent for capacity.

5. Retirement schedules for proposed generating facilities (economic facility lifetime):1/

	Years
Coal-Fired Steam	35
Oil-Fired Steam	35
Gas-Fired Combustion Turbine	20
Oil-Fired Combustion Turbine	20
Hydroelectric	50
Diesel	20

6. Plant factors for new and most of the existing facilities are:

	Percent
Hydro	50
Steam	75
Combustion turbine	50
Diesel	10

The factor for combustion turbines was reduced to 10 percent in the study when adequate steam turbine capacity was available.

1/ See tables 3.4 and 3.5 of appended Battelle report for estimated retirement dates of existing facilities.

7. Hydro plants designed for 115 percent of nameplate capacity for limited reserve requirements.

8. Watana power on-line (POL) in 1994 and Devil Canyon POL in 1998.

9. Existing and planned generating facilities for Anchorage and Fairbanks are shown in the appended Battelle report.

10. New coal-fired steamplants for Fairbanks assumed to be 100-MW units (first six), then 200-MW units. Anchorage units assumed to be 200 MW (first five), then 400-MW units.

11. New coal-fired steamplants to be located at Beluga for Anchorage area and at Healy (or other sites within 100 miles) for Fairbanks.

12. Fuel costs--see appended Battelle report.

13. Power demands will be met by resource allocation using Susitna hydro generation first, coal-fired second, and natural gas and oil last.

14. Heat rate for new coal-fired steamplants = 10,500 Btu/kwh.

15. Total investment cost in October 1978 dollars.

Plant	($ million)	($/kw)
100-MW Coal Steam Turbine	245.4	2,454
200-MW Coal Steam Turbine	372.0	1,860
400-MW Coal Steam Turbine	646.8	1,617
Watana Dam (795 MW) and	2,020.7	2,554
Transmission Line	470.5	--
Devil Canyon Dam (778 MW)	834.0	1,072
Total Susitna Project (1,573 MW)	3,335.2	2,120

16. Operation, maintenance, and replacement costs.

Plant	($ million/yr.)	($/KW/yr.)
100-MW Coal Steam Turbine	3.76	37.6
200-MW Coal Steam Turbine	5.7	28.5
400-MW Coal Steam Turbine	9.8	24.5
Watana Dam (795 MW)	0.74	0.94 1/
Devil Canyon Dam (778 MW)	0.73	0.94 1/
New Transmission Facilities	--	2.0 1/

Study Methodology

As stated in the introduction, three cases were analyzed to determine timing of generation and transmission (G&T) investments and their impact on total power system costs.

The first step in estimating the cost of power from alternative generation and transmission system configurations was to perform a series of load/resource analyses. These analyses determined the schedule of major investments based on assumptions of load growths, capacity and energy production of the potential generating facilities, and constraints as to when the facilities could come on-line. The load/resource analyses also determined the annual power production from each type of generating plant in the system.

The system cost analyses then determined the annual cost for amortizing and operating the facilities. Summing the annual cost for generation and transmission of each of the generating facilities gave a total cost, by year, for the entire system being analyzed. Dividing the total annual cost by the power produced gave an average annual cost of power for the entire system.

1/ This breakdown of OM&R costs by project feature for convenience of the load/resource analysis resulted in slightly higher cost. Significance to Susitna rate is, at most, less than 1 percent.

Rounded Thermal generating capacity additions to the year 2010 from the previous tables are summarized as follows:

Table 21
SUMMARY OF THERMAL GENERATING CAPACITY ADDITIONS TO THE YEAR 2010

Upper Susitna Project Power Market Analysis

Case 1: Without Interconnection & Without Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	2,600	471	3,071
Mid	4,600	871	5,471
High	8,200	1,471	9,671

Case 2: Interconnection Without Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	2,200	471	2,671
Mid	4,200	671	4,871
High	8,200	1,271	9,471

Case 3: Interconnection With Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	1,000	171	1,171
Mid	3,000	371	3,371
High	6,600	1,071	7,671

Note: Bradley Lake and Susitna hydroelectric projects are not included.

Results

Load/Resource Analyses

The schedule of new plant additions for Anchorage and Fairbanks for 1978-2011 are shown in the appended Battelle report. A summary of the thermal generating capacity additions is in table 21. Further discussion of the computer model results and graphs are also shown in the appended Battelle report.

Under the criteria used, completion of construction for interconnection is scheduled in 1986, 1989, and 1994 for high, mid and low load growth cases, respectively, without Upper Susitna. With Upper Susitna, the corresponding dates are 1986, 1989, and 1991.

System Power Costs

Annual system costs and unit power costs are presented in detail, both tabular and graphically, in the appended Battelle report. The following tabulations summarize these findings. Table 22 shows annual power system costs for cases 1, 2, and 3, high, mid and low range, with 0 percent inflation. The first few years after Watana comes on-line, the total annual power system costs increase slightly. However, comparing the total annual power system costs for the 1990-2011 period to case 1, construction of the Susitna project results in a savings of $2.20 billion, or 12 percent.

Figure 18 shows the relative savings in annual cost for case 3, with Susitna, and case 1, without Susitna, for the three load growth assumptions.

Tables 23, 24, and 24a summarize Anchorage and Fairbanks separately plus the combined system average annual power costs in ¢/kwh for 1978-2011. The tables verify the feasibility of the intertie in power cost savings for Anchorage and Fairbanks. By the year 2000, system wide power rates would be:

Average Power System Rates for Anchorage and Fairbanks - 0% Inflation
(¢/kwh)

	Case 1 Without Susitna or Intertie			Case 2 With Intertie			Case 3 With Susitna and Intertie		
	Anch.	Fbks.	Combined System	Anch.	Fbks.	Combined System	Anch.	Fbks.	Combined System
High	6.2	8.8	6.6 1/	6.1	8.0	6.4	5.8	6.2	5.8
Mid	6.6	8.9	6.9 1/	6.2	8.4	6.6	5.5	6.7	5.7
Low	7.1	9.2	7.5 1/	6.2	8.8	6.7	6.1	7.8	6.4

Comparison of Power Costs by Year 2000
Percent Change in Cost of Power Below Case 1 - 0% Inflation

	Case 2			Case 3		
	Anch.	Fbks.	Combined System	Anch.	Fbks.	Combined System
High	-1.6	-10.0	-3.1	-6.7	-41.9	-13.8
Mid	-6.5	-6.0	-4.5	-20.0	-32.8	-21.1
Low	-14.5	-4.5	-11.9	-16.4	-17.9	-17.2

For the Anchorage-Cook Inlet area, inclusion of the Susitna Project into the system (case 3) generally raises the cost of power above cases 1 and 2 during the first two to four years after Watana comes on-line, but lowers power costs during the 1996-2011 period. This reduction in the cost of power is significant in most cases.

For the Fairbanks-Tanana Valley load center construction of the interconnection (case 2) again generally reduces the cost of power compared to without an interconnection (case 1). The inclusion of the Susitna project (case 3) generally raises the cost of power above case 2 for about two years after Watana comes on-line, but, as with the Anchorage-Cook Inlet area, results in lower power costs during the 1996-2011 period.

1/ Anchorage and Fairbanks are not interconnected for case 1, the combined system rate is shown for academic comparison purposes only.

Table 22

COMBINED ANCHORAGE-COOK INLET AND FAIRBANKS-TANANA VALLEY ANNUAL POWER SYSTEM COSTS - 0% INFLATION

Upper Susitna Project Power Market Analysis ($ Million)

YEAR	CASE I LOW	CASE I MEDIUM	CASE I HIGH	CASE II LOW	CASE II MEDIUM	CASE II HIGH	CASE III LOW	CASE III MEDIUM	CASE III HIGH
1978-79	68.4	68.3	68.3	68.4	68.3	68.3	68.4	68.3	68.3
1979-80	80.3	80.2	80.2	80.3	80.2	80.2	80.3	80.2	80.2
1980-81	89.1	89.0	89.0	89.1	89.0	89.0	89.1	89.0	89.0
1981-82	95.9	95.9	95.9	95.9	95.9	95.9	95.9	95.9	95.9
1982-83	108.4	146.0	203.5	108.4	146.0	203.5	108.4	146.0	203.5
1983-84	107.1	147.4	245.3	107.1	147.4	245.3	107.1	147.4	245.3
1984-85	109.3	152.1	321.6	109.3	152.1	321.6	109.3	152.1	321.6
1985-86	120.7	252.5	383.2	120.7	252.5	383.2	120.7	252.5	383.2
1986-87	119.1	257.9	456.8	119.1 *	257.9	434.0	119.1 *	257.9	434.0
1987-88	173.4	296.7	464.7	173.4	296.7	502.1	173.4	296.7	502.1
1988-89	170.8	298.5	547.9	170.8	298.5	510.8	170.8	298.5	510.8
1989-90	236.8	362.6	575.3	236.8	338.7 *	593.7	236.8	338.7 *	593.7
1990-91	243.5	371.0	587.7	243.5	382.8	603.1	243.5	382.8	603.1
1991-92	256.8	422.4	667.7	256.8	434.0	682.0	293.4	434.0	682.0 *
1992-93	292.5	507.0	754.9	292.5	498.1	735.1	290.5	498.1	735.1
1993-94	297.3	512.6	766.1	297.3	503.3	832.8	330.9	503.3	832.8
1994-95	364.4	521.1	865.0	339.6	536.2	847.4 *	487.9 #	658.0 #	990.7 #
1995-96	404.8	591.3	863.6	382.7	629.8	951.3	487.6	662.7	1,004.1
1996-97	464.4	701.4	1,060.8	441.0	714.7	1,068.2	486.0	667.0	1,097.1
1997-98	480.6	783.7	1,164.7	517.4	737.2	1,172.2	479.1	688.5	1,165.6
1998-99	511.1	819.7	1,282.6	525.1	832.8	1,254.6	485.8 +	721.4 +	1,210.4 +
1999-2000	592.9	888.2	1,389.3	527.2	841.7	1,333.7	506.6	722.9	1,222.4
2000-2001	586.2	886.7	1,450.2	600.2	899.8	1,423.1	495.9	719.9	1,253.7
2001-2002	588.7	894.8	1,471.2	602.7	907.9	1,503.9	494.8	725.9	1,355.3
2002-2003	584.1	955.3	1,544.0	598.1	931.3	1,576.7	487.2	827.2	1,426.4
2003-2004	587.5	998.7	1,661.5	601.6	999.4	1,634.5	488.6	834.7	1,482.0
2004-2005	590.1	1,008.2	1,684.5	604.1	1,009.5	1,691.9	488.9	841.4	1,583.7
2005-2006	651.9	1,096.1	1,787.1	606.2	1,018.0	1,774.8	488.7	847.8	1,662.9
2006-2007	655.6	1,106.3	1,872.1	632.6	1,028.2	1,859.8	490.2	915.6	1,686.0
2007-2008	659.2	1,117.0	1,935.1	636.2	1,118.2	1,965.2	491.7	923.9	1,769.6
2008-2009	662.4	1,127.6	2,021.4	639.9	1,128.9	1,991.8	493.3	932.4	1,853.8
2009-2010	666.6	1,139.7	2,108.5	643.6	1,140.0	2,078.9	494.9	941.3	1,913.4
2010-2011	670.4	1,209.5	2,136.6	647.5	1,151.1	2,163.1	496.6	1,010.0	2,018.6
Total	12,290.3	19,905.4	32,606.3	12,115.1	19,666.1	32,671.7	10,981.4	17,682.0	31,076.3
Subtotal 1990-2010	10,811.0	17,658.3	29,074.6	10,796.4	17,442.9	29,144.1	9,502.1	15,458.8	27,548.7

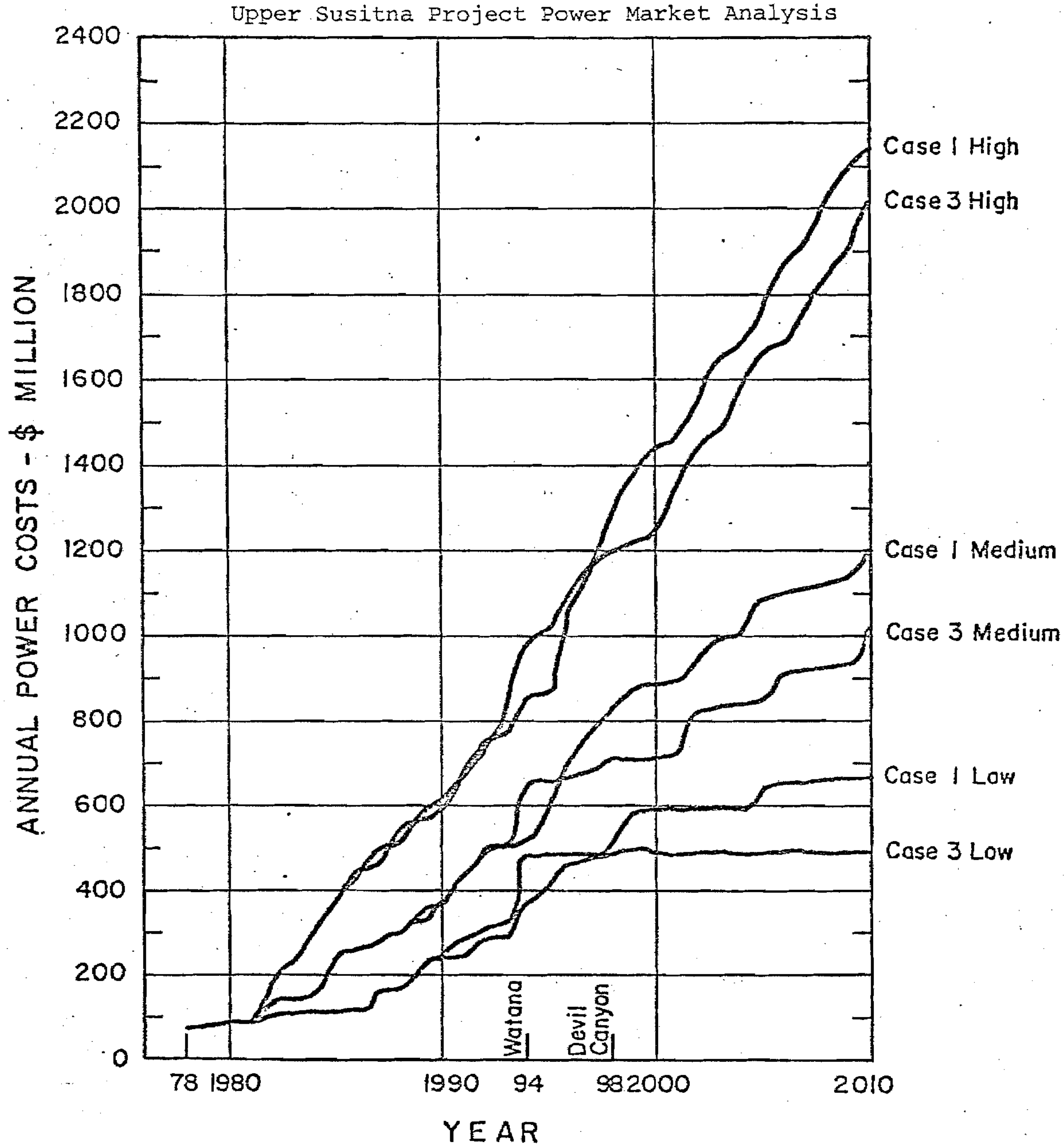
Note: Savings to total power system 1990-2010 for mid range case 1 of $17,658.3 million less case 3 $15,458.8 million is $2,199.5 million.

* Interconnection installed
\# Watana on-line
\+ Devil Canyon on-line

Figure 18

COMBINED ANCHORAGE-COOK INLET AND FAIRBANKS-TANANA VALLEY ANNUAL POWER SYSTEM COSTS WITH AND WITHOUT SUSITNA

Upper Susitna Project Power Market Analysis



Case 1: without Susitna
Case 3: with Susitna

APA 1/79

Table 23
ANCHORAGE-COOK INLET AREA
AVERAGE POWER COSTS - CENTS PER KILOWATT HOUR - 0% INFLATION

Upper Susitna Project Power Market Analysis

	Case 1			Case 2			Case 3		
Year	High	Medium	Low	High	Medium	Low	High	Medium	Low
78-79	1.3	1.3	1.4	1.3	1.3	1.4	1.3	---	1.4
79-80	1.4	1.5	1.7	1.4	1.5	1.7	1.4	---	1.7
80-81	1.3	1.6	1.8	1.3	1.6	1.8	1.3	---	1.8
81-82	1.2	1.6	1.9	1.2	1.6	1.9	1.2	---	1.9
82-83	3.2	2.9	2.2	3.2	2.9	2.2	3.2	---	2.2
83-84	3.6	2.8	2.1	3.6	2.8	2.1	3.6	---	2.1
84-85	4.0	2.8	2.2	4.0	2.8	2.2	4.0	---	2.2
85-86	4.6	4.3	2.4	4.6	4.3	2.4	4.6	---	2.4
86-87	5.0	4.2	2.3	4.8 *	4.2	2.3	4.8 *	---	2.3
87-88	4.8	4.7	3.7	5.3	4.7	3.7	5.3	---	3.7
88-89	5.4	4.4	3.5	5.1	4.4	3.5	5.1	4.4	3.5
89-90	5.1	4.8	4.2	5.7	4.5 *	4.2	5.7	4.5 *	4.2
90-91	4.8	4.5	4.1	5.4	4.8	4.1	5.4	4.8	4.1
91-92	5.2	5.0	4.1	5.7	5.3	4.1	5.7	5.3	4.6 *
92-93	5.5	5.6	4.7	5.4	5.9	4.7	5.4	5.9	4.4
93-94	5.3	5.3	4.6	5.7	5.6	4.6	5.7	5.6	5.0
94-95	5.5	5.1	5.3	5.5	5.4	4.9 *	6.4 #	6.9 #	7.3 #
95-96	5.8	5.6	5.7	5.6	5.8	5.4	6.0	6.5	6.8
96-97	5.9	6.2	6.5	5.8	6.4	5.8	6.2	6.1	6.5
97-98	6.0	6.5	6.3	5.9	6.1	6.6	6.2 +	5.8 +	6.3 +
98-99	6.1	6.3	6.1	6.0	6.5	6.4	6.1	5.8	6.1
99-2000	6.2	6.6	7.1	6.1	6.2	6.2	5.8	5.5	6.1
00-01	6.3	6.4	6.9	6.2	6.6	7.2	5.5	5.3	5.9
01-02	6.1	6.3	6.9	6.3	6.4	7.2	5.6	5.2	5.6
02-03	6.2	6.6	6.8	6.4	6.3	7.1	5.7	5.7	5.7
03-04	6.3	6.5	6.8	6.2	6.7	7.1	5.6	5.6	5.6
04-05	6.1	6.4	6.7	6.1	6.6	7.0	5.8	5.5	5.6
05-06	6.3	6.9	7.6	6.2	6.5	7.0	5.9	5.4	5.5
06-07	6.4	6.8	7.5	6.3	6.4	7.0	5.8	5.8	5.5
07-08	6.3	6.8	7.5	6.5	6.9	7.0	5.9	5.8	5.5
08-09	6.4	6.7	7.5	6.3	6.8	6.9	6.0	5.7	5.4
09-10	6.5	6.6	7.5	6.4	6.7	6.9	5.9	5.6	5.4
10-11	6.3	6.9	7.5	6.5	6.7	6.9	6.0	5.9	5.4

* Interconnection Installed
# Watana on-line
\+ Deveil Canyon on-line

Table 24
AVERAGE POWER COSTS - 0% INFLATION (¢/KWH)
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

	Case 1			Case 2			Case 3		
Year	High	Medium	Low	High	Medium	Low	High	Medium	Low
78-79	4.1	4.3	4.4	4.1	4.3	4.4	1.3	4.3	4.4
79-80	4.1	4.3	4.5	4.1	4.3	4.5	1.4	4.3	4.5
80-81	4.1	4.3	4.7	4.1	4.3	4.7	1.3	4.3	4.7
81-82	4.0	4.3	4.7	4.0	4.3	4.7	1.2	4.3	4.7
82-83	3.8	4.2	4.7	3.8	4.2	4.7	3.2	4.2	4.7
83-84	3.4	3.8	4.3	3.4	3.8	4.3	3.6	3.8	4.3
84-85	5.2	3.4	3.9	5.2	3.4	3.9	4.0	3.4	3.9
85-86	4.7	5.4	3.6	4.7	5.4	3.6	4.6	5.4	3.6
86-87	5.9	5.1	3.3	5.5 *	5.1	3.3	4.8 *	5.1	3.3
87-88	5.6	4.8	3.0	5.1	4.8	3.0	5.3	4.8	3.0
88-89	5.5	4.8	3.1	5.0	4.8	3.1	5.1	4.8	3.1
88-90	6.5	6.3	5.6	4.7	5.8 *	5.6	5.7	5.8 *	5.6
90-91	6.5	6.4	5.8	4.6	5.9	5.8	5.4	5.9	5.8
91-92	6.2	6.2	5.9	4.4	5.7	5.9	5.7	5.7	7.2
92-93	6.8	7.3	5.6	6.3	5.4	5.6	5.4	5.4	6.9
93-94	6.6	7.1	5.5	7.3	5.2	5.5	5.7	5.2	6.8
94-95	7.4	6.9	7.1	7.0	6.5	6.7 *	6.4 #	6.8 #	8.8 #
95-96	7.2	6.9	7.3	7.8	7.7	6.9	6.0	6.7	8.9
96-97	7.6	7.8	7.1	8.2	7.4	8.3	6.2	6.4	8.6
97-98	8.1	8.3	7.9	8.7	7.8	9.1	6.2	6.9	7.8
98-99	8.9	9.1	9.4	8.3	8.7	8.9	6.1 +	6.9 +	7.6 +
99-2000	8.8	8.9	9.2	8.0	8.4	8.8	5.8	6.7	7.8
00-01	8.3	8.7	9.3	7.7	8.3	8.8	5.5	6.6	7.8
01-02	8.0	8.6	9.3	7.5	8.2	8.8	5.6	6.5	7.7
02-03	7.7	8.4	9.1	7.2	9.0	8.7	5.7	7.3	7.6
03-04	8.5	9.8	9.1	8.0	8.9	8.7	5.6	7.2	7.6
04-05	8.2	9.7	9.1	8.7	8.8	8.7	5.8	7.1	7.5
05-06	8.0	9.5	9.0	8.4	8.6	8.6	5.9	7.0	7.4
06-07	7.8	9.4	9.0	8.2	8.6	10.1	5.8	6.9	7.4
07-08	8.5	9.3	9.1	8.1	8.5	10.1	5.9	6.8	7.4
08-09	8.4	9.2	9.0	7.9	8.4	10.1	6.0	6.8	7.4
09-10	8.2	9.1	9.1	7.7	8.3	10.2	5.9	6.7	7.4
10-11	8.0	9.1	9.1	7.6	8.2	10.2	6.0	6.6	7.4

* Interconnection Installed
# Watana on-line
+ Devil Canyon on-line

Table 24a
COMBINED ANCHORAGE-COOK INLET AND FAIRBANKS-TANANA VALLEY
AREA AVERAGE ANNUAL POWER COST 1/ (¢/KWH)

Upper Susitna Project Power Market Analysis

	Case 2			Case 3		
YEAR	HIGH	MEDIUM	LOW	HIGH	MEDIUM	LOW
1978-79						
1979-80						
1980-81						
1981-82						
1982-83						
1983-84						
1984-85						
1985-86						
1986-87	4.90 *			4.90 *		
1987-88	5.31			5.31		
1988-89	5.07			5.07		
1989-90	5.56	4.79 *		5.56	4.79 *	
1990-91	5.24	5.06		5.24	5.06	
1991-92	5.52	5.39		5.52	5.39	5.14
1992-93	5.58	5.83		5.58	5.83	4.89
1993-94	5.94	5.57		5.94 #	5.57 #	5.35 #
1994-95	5.71	5.63	5.28 *	6.67	6.91	7.59
1995-96	5.92	6.19	5.69	6.25	6.52	7.25
1996-97	6.18	6.61	6.29	6.35	6.17	6.93
1997-98	6.34	6.44	7.08	6.30	6.01	6.56
1998-99	6.36	6.88	6.91	6.14 +	5.96 +	6.39 +
1999-2000	6.37	6.61	6.68	5.84	5.68	6.42
2000-2001	6.47	6.87	7.54	5.70	5.50	6.23
2001-2002	6.53	6.75	7.51	5.89	5.40	6.16
2002-2003	6.55	6.75	7.39	5.93	5.99	6.02
2003-2004	6.51	7.06	7.37	5.90	5.90	5.98
2004-2005	6.47	6.96	7.33	6.05	5.80	5.93
2005-2006	6.52	6.85	7.30	6.11	5.71	5.88
2006-2007	6.58	6.76	7.55	5.97	6.02	5.85
2007-2008	6.71	7.18	7.53	6.04	5.94	5.82
2008-2009	6.57	7.09	7.51	6.11	5.86	5.79
2009-2010	6.62	7.01	7.50	6.10	5.78	5.76
2010-2011	6.67	6.92	7.48	6.23	6.07	5.74

1/ Case I not interconnected, therefore combined system rate does not apply.

* Interconnection Installed
\# Watana on-line
\+ Devil Canyon on-line

Part VIII. INVESTMENT COSTS

Construction costs for power producing facilities were prepared by the Corps of Engineers (Corps); those for the transmission facilites by Alaska Power Administration (APA). APA prepared estimates of interest during construction based on 7 1/2 percent.

Corps estimates include alternative design concepts for Devil Canyon--thin-arch, as orginally proposed by Bureau of Reclamation (USBR), and the concrete gravity design, which is more costly and conservative.

Transmission estimates are based on same plan presented in 1976 report, with costs updated by indexing.

Current costs for transmission facilities are based on indexing construction costs presented in the 1976 report (January 1975 prices) to current levels (October 1978 prices) by applying a factor of 1.38 to clearing and rights-of-way, 1.33 to all other transmission line components (access roads, structures, etc.), and 1.28 to substations and switchyards, resulting in an overall factor of about 1.32. The clearing and rights-of-way factor is based on experience of the Alaska Department of Transportation and on recent experience of the USBR and Bonneville Power Administration (BPA). The 1975 prices are based on component prices from BPA with an increase of 90 percent for labor and 10 percent for material transportation from the Pacific Northwest to Alaska. Examination indicated that these factors are also valid for this analysis, but should be reevaluated if more detailed cost estimates are made in future years.

Transmission system costs are summarized in table 25.

Investment costs are calculated by adding interest during construction at the annual rate of 7 1/2 percent to construction costs presented previously.

The project schedule includes (1) first-stage construction of Watana dam and powerplant and the total project transmission system, and (2) second-stage Devil Canyon dam and powerplant. The transmission system will be completed about three years before completion of Watana to develop interconnection benefits by deferring of required steamplant capacity (discussed in Part XIII, Load Resource Analysis).

Table 26 summarizes the investment costs required.

Table 25
CONSTRUCTION COST SUMMARY
Upper Susitna Project Power Market Analysis

Item	Construction Cost ($1,000 - 10/78) System No. 5
Transmission Lines	
Clearing	$ 3,350
Right-of-Way	5,000
Access Roads	19,110
Line Structures	242,190
Subtotal - T.L.	$269,650
Switchyards and Substations	
Fairbanks Substation	$ 11,710
Talkeetna Substation	10,100
Anchorage Substation	15,890
Healy Switchyard	4,770
Watana Switchyard	6,360
Devil Canyon Switchyard	19,660
Subtotal - S.S.	$ 68,490
Total	$338,140
Rounded	$338,000

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Table 26

INVESTMENT COST SUMMARY ($/MILLION)

Upper Susitna Project Power Market Analysis

Stage	Watana (1st)	Devil Canyon (2nd)	Total
Power Production Facilities			
Construction	1,427.0	665.0	2,092.0
Interest during Construction	603.7	168.6	772.3
Investment	2,030.7	833.6	2,864.3
Power Transmission Facilities			
Construction	338.0		338.0
Interest during Construction	132.5		132.5
Investment	470.5		470.5
Total Investment - Susitna	2,501.2	833.6	3,334.8

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PART IX. OPERATION, MAINTENANCE, AND REPLACEMENT PLAN AND COSTS

Operation and Maintenance

This updates information furnished in the 1976 report. Operation, maintenance, and replacement costs were indexed for this report.

Plan Description

This plan assumes Federal operation of the facilities.

The plan assumes the headquarters and main operations center for the Susitna project will be near Talkeetna or at some other equally accessible point. Equipment at the center will remotely control the operation of the generation and transmission system and operation of Devil Canyon and Watana dams and reservoirs. Electrician/operators and mechanic/operators will be located at the powerplants to provide routine maintenance and manual operation when required.

Specialized personnel, such as electronic technicians and meter and relay repairmen, will service both powerplants and the substations and switchyards from the project headquarters. Project administration, including supervision of power production, water scheduling, and transmission facilities, will also be from the project headquarters.

Major turbine and generator inspection and maintenance will be done by electricians, mechanics, engineers, and other experienced personnel from APA. Manufacturers' representatives and other specialized expertise will be consulted.

Alaska Power Administration's (APA) headquarters office in Juneau will handle power marketing, accounting, personnel management, and general administrative services.

Transmission line maintenance will be performed by two line crews, with assistance from the existing Eklutna Project line crew. Transmission line maintenance warehouses and parts storage yards will be at Devil Canyon or Watana, approximately mid-way between Devil Canyon and Fairbanks, and at the project headquarters. Line crew personnel will be stationed along the lines at designated maintenance stations and at the major substations to provide routine line patrol and maintenance tasks. Crews from throughout the project will be assembled for major work.

Visitor facilities with provisions for self-guided powerplant tours will need assistance from operation personnel.

Project-related recreation facilities will require cooperation between Federal, State, and local interests, and are assumed to be maintained by a State or local entity.

Project operation, maintenance, and administration could be combined with the existing Eklutna Project. Eklutna could be supervisory controlled from the Susitna project operations center with electrician/operators and mechanic/operators stationed at Eklutna. It is estimated that approximately $100,000/year could be saved by joint operation.

Marketing and Administration

Marketing and administration include three main functions:

1. Administration

    Personnel management
    Property management
    Budgeting
    Marketing policy
    Rate and repayment studies

2. Accounting

    Customer billing
    Collecting
    Accounts payable
    Financial records
    Payroll

3. Marketing

    Rate schedules
    Power sales contracts
    Operating agreements
    System reliability and coordination

Part of this work would be carried out by the project, with overall administration and support services provided by the APA headquarters staff.

Annual Costs

The estimated annual costs for operation, maintenance, marketing, and administration are based on itemized estimates of personnel, equipment, supplies, and services needed to do the work, with a provision for contingencies.

The estimate assumes Federal classified personnel providing management and administrative functions and wage grade personnel performing technical operation and maintenance activities. Classified salaries are based on a mid-grade rate. Wage grade rates are based on those in effect in the Anchorage area and include basic hourly rates, benefits, and overtime.

Costs of supplies, equipment, and personnel requirements are based on Bureau of Reclamation (USBR) guidelines and the experience of the Eklutna and Snettisham Projects. The Eklutna Project is fully staffed, including a line crew, which has been in operation since 1955. The Snettisham Project is isolated; it is separated from the Juneau load center by 45 miles of rugged terrain and water. A maintenance crew resides and performs routine maintenance at the powerplant; project operations are remotely controlled from Juneau. The Susitna project would have some characteristics of both projects.

Itemized costs for operation, maintenance, marketing, and administration are presented in table 27.

Costs by major category and number of personnel are summarized in table 28.

Replacements

The annual replacement cost provision establishes a sinking fund to finance replacement of major items which have an expected service life of less than the 50-year project repayment period. The objective is to cover costs and ensure financing for a timely replacement of major cost items to keep the project operating efficiently throughout its life.

The replacement cost is based on factors developed from USBR experience. The factors apply to the total powerplant, substation, switchyard, transmission tower, fixtures, and conductors. Replaceables include generator windings, communication equipment, a small percent of the transmission towers, and items in the substation and switchyards. Items covered by routine annual maintenance costs include vehicles, small buildings, camp utilities, and materials and supplies. Major features, such as dams and powerplant structures, are considered to have service lives longer than the 50-year repayment period. Their costs are not covered by the replacement funds. Right-of-way and clearing costs are not included. The 7½ percent interest rate used for project repayment was used to establish the replacement sinking fund.

Table 29 presents calculations of the annual replacement fund.

The following tabulation summarizes the operation, maintenance, and replacement costs:

	Annual Operation and Maintenance $1,000	Annual Replacement $1,000	Total OM&R $1,000
Watana	$2,360	$260	$2,620
Devil Canyon	530	170	700
Total	$2,890	$430	$3,320

Price base - October 1978.

Table 27
ANNUAL OPERATION & MAINTENANCE COST ESTIMATE

Upper Susitna Project Power Market Analysis

October 1978 Prices
Dam and Powerplant, Total Transmission System

Personnel	Number	Grade or Rate	Annual Cost
Supervisory & Classified			
Project Manager	1	GS-14	$ 35,000
Assistant Project Manager	1	GS-13	29,500
Electrical Engineer	1	GS-12	24,800
Mechanical Engineer	1	GS-12	24,800
Supply & Property Clerk	1	GS-9	17,100
Administrative Assistant	1	GS-7	14,000
Clerk-Steno	1	GS-5	11,300
Subtotal Supervisory & Classified	7		$ 156,500
Wage Grade			
Electrician	2	17.00/hr.	$ 70,720
Mechanic	2	17.00/hr.	70,720
Heavy Duty Equip. Operator	1	17.00/hr.	35,360
Laborer	2	13.00/hr.	54,080
Meter Relay Mechanic	1	17.00/hr.	35,360
Electronic Technician	1	17.00/hr.	35,360
Powerplant Operator	6	17.00/hr.	212,160
Ass't. Powerplant Operator	4	15.00/hr.	124,800
Subtotal Wage Grade	19		$ 638,560
Line Crew			
Foreman	2	19.00/hr.	$ 79,040
Lineman	4	17.00/hr.	141,440
Equipment Operator	2	17.00/hr.	70,720
Groundman	4	17.00/hr.	141,440
Subtotal Line Crew	12		$ 432,640
Allowances			
C.O.L.A.-Sup. & Class x 25%			39,130
Shift Differential			22,430
Sunday Pay			12,030
Overtime			32,000
Government Contributions			96,410
Longevity N. A.			--
Subtotal-Allowances			$ 202,000
TOTAL PERSONNEL COST	38		$1,429,700

Table 27 (cont.)
ANNUAL OPERATION & MAINTENANCE COST ESTIMATE

Miscellaneous	Annual Cost
Telephone	$ 10,000
Official travel	19,000
Vacation travel	19,000
Supplies, Services & Maintenance--Powerplant	125,000
Supplies & Services--Vehicles & Equipment	50,000
Employee training	6,000
Line spray	25,000
Government camp maintenance	19,000
Subtotal - Miscellaneous	$ 273,000

Equipment Operation, Maintenance, and Replacement

	No.	Initial Cost	Service Life	
Tractor with Dozer	1	$150,000	10	$ 15,000
Loader	1	75,000	10	7,500
Maintainer	1	75,000	10	7,500
Pickup	10	80,000	7	11,400
Sedan	1	5,000	7	700
Tractor & Lowboy	1	75,000	10	7,500
Dumptruck	1	25,000	10	2,500
Flatbed	2	20,000	7	2,900
Firetruck	1	25,000	10	2,500
Sno trac	2	16,000	7	2,300
Backhoe	1	35,000	10	3,500
Crane, 50 ton	1	200,000	20	10,000
Hydraulic Crane, 20 ton	1	100,000	20	5,000
Line truck	4	200,000	10	20,000
Subtotal - Equipment				$ 98,300

APA Headquarters Marketing and Administration	165,000
Subtotal	1,966,000
Contingencies (20% $\pm$)	394,000
TOTAL WATANA & TRANSMISSION	$2,360,000

Table 27 (cont.)
ANNUAL OPERATION & MAINTENANCE COST ESTIMATE

Devil Canyon Dam and Powerplant

Personnel

Watana and Devil Canyon, supervisory controlled from a remote operation-dispatch center.

Increase base staff for Devil Canyon.			
Assistant operators	2@15.00/hr.		$ 62,400
Electricians	2@17.00/hr.		70,720
Mechanics	1@17.00/hr.		70,720
Maintenance	1@15.00/hr.		31,200
Subtotal			$ 235,040
Overtime			12,000
Government Contributions			21,160
Foreman Pay			6,500
Subtotal			$ 39,660
Subtotal - Personnel			$ 274,700
Miscellaneous			
Vacation travel			$ 3,800
Employee training			1,200
Supplies, Services & Materials			112,500
Supplies and Services			13,400
Subtotal - Miscellaneous			$ 130,900
Equipment			
	Initial Cost	Service/ Life	
Pick up	2 @ 16,000	7	$ 2,300
Snow tractor	1 @ 10,000	7	1,100
Subtotal - Equipment			$ 3,400
APA Headquarters Marketing and Administration			$ 35,000
Subtotal Devil Canyon Additions			444,000
Contingencies (20% ±)			86,000
TOTAL DEVIL CANYON O&M ADDITION			$ 530,000
TOTAL WATANA AND TRANSMISSION			2,360,000
TOTAL SUSITNA PROJECT			$2,890,000

Table 28
OPERATION AND MAINTENANCE COST SUMMARY

Upper Susitna Project Power Market Analysis

	Watana & Transmission System		Devil Canyon		Total Devil Canyon, Watana & Transmission	
	Number	Dollars	Number	Dollars	Number	Dollars
Personnel:						
Salaries/Wages, Allowances		$1,429,700		$274,700		$1,704,400
Classified Personnel	7		0		7	
Wage Board Personnel	31		7		38	
Miscellaneous:						
Telephone, Travel, Supplies, Services, Training, Line Spray, Camp Maintenance		273,000		130,900		403,900
Equipment:						
Annual cost Replacement		98,300		3,400		101,700
Marketing and Administration						
APA Headquarters		165,000		35,000		200,000
Subtotal		$1,966,000		$444,000		$2,410,000
Contingencies (20% $\pm$)		394,000		86,000		480,000
TOTAL		$2,360,000		$530,000		$2,890,000

Table 29
REPLACEMENT COSTS

Upper Susitna Project Power Market Analysis

Feature	Annual Replacement Factor	Watana and Transmission System: Construction Cost	Watana and Transmission System: Annual Replacement Cost	Devil Canyon: Construction Cost	Devil Canyon: Annual Replacement Cost	Total: Construction Cost	Total: Annual Replacement Cost
Powerplant	0.0010	$197,370,000	$197,370	$120,860,000	$120,860	$318,230,000	$318,230
Transmission towers, fixtures, & conductors	0.0001	251,324,000	25,130	--	--	251,324,000	25,130
Substations and switchyards	0.0033	11,000,000	36,300	14,760,000	48,710	25,760,000	85,010
Total			$258,000		$169,570		$428,370
Rounded			$260,000		$170,000		$430,000

Replacement factors are based on 7 1/2 percent interest rate.

Construction cost based on the portion of the feature subject to replacement.

PART X. FINANCIAL ANALYSIS

This part estimates the market for project power and evaluates power rates needed to repay the investment in power facilities. Power market size is in more detail in this study than in the 1976 report. Likewise, costs are slightly more detailed.

The Upper Susitna Project is primarily for hydroelectric power generation and transmission. Minor portions of project costs (less than 1 percent) would be allocated to other purposes, such as recreation and flood control. Project financial viability is the essential element in demonstrating feasibility of the power development. The repayment rate is influenced principally by size of the market, amount of investment, and applicable interest rates. Operation, maintenance, and replacement costs are a minor part of total annual costs; they influence these rates insignificantly. If rates needed to repay the hydro project are attractive in comparison to other available alternatives, the project is economically justifiable.

The 1976 report compared the costs of five dam and reservoir plans for developing the Susitna River hydroelectric potential and found all costs were within a 15 percent range. Therefore, the scoping analysis was not repeated for this study.

In addition to analyzing the basic Susitna project plan, variations were also analyzed for sensitivity. These included interconnection with additional service areas, different timing for interconnection between Anchorage and Fairbanks, use of the more expensive Devil Canyon gravity dam instead of the arch dam, low load growth, and the effect of inflation. In addition, the load/resource and system cost analyses examine impact of the Susitna Project on overall system costs.

Market for Project Power

Upper Susitna will operate as part of a hydro/thermal power system.

The 1976 report assumed the market for Susitna firm energy as 75 percent of the mid-range utility requirements. Average rates for firm energy were estimated on that basis.

For this analysis, the market for firm energy was assumed to be approximated by load growth after Susitna power becomes available, plus market made available through retirement of older plants.

The balance of the Susitna energy is assumed marketable as secondary energy for fuel replacement, as long as all energy fits under the load curve. A value is assigned for marketable secondary energy based on estimated future coal costs. The actual value is probably significantly higher.

The value of fuel replacement energy is the same as that used in the load resource analysis, which is $1.00 to $1.50/million Btu by 1985. This is based on the concept that large, efficient coal mines will be developed in the Beluga area by then. The price is escalated at 2 percent per year above the zero inflation rate from 1985 to 1994, resulting in a cost of $1.20 and $1.80/million Btu's.

Table 30 summarizes the estimated market for Susitna energy using these criteria.

Cost of Project

Table 31 summarizes the construction cost, interest during construction, operation, maintenance, and replacement costs for Devil Canyon and Watana phases. Construction costs were furnished by the Corps for an October 1978 price level. Interest during construction was calculated from Corps construction cash flow estimates with interest accumulated until the project becomes operational. OM&R costs were updated from APA earlier estimates.

Costs have increased from the 1976 report for several reasons. Table 32 presents a summary comparison of the cost factors. Interest rates have increased from 6 5/8 to 7 1/2 percent. Design and cost changes were made by the Corps as a result of foundation drilling. Costs were updated for the Devil Canyon dam and the transmission line by indexing procedures. The major change in operation, maintenance, and replacement costs was due to inflation in personnel wages and provisions for contingencies such as unlisted items and state of the art. Watana's construction period was extended from 6 years to 10 years, increasing its construction period from 10 years to 14 years. The revised project investment cost is 89 percent higher than in the 1976 report.

TABLE 30
MARKET FOR UPPER SUSITNA POWER
ANCHORAGE AND FAIRBANKS AREAS

Upper Susitna River Project Power Market Analysis

MEDIUM ESTIMATE

Year	Firm Energy Sales GWH	Fuel Replacement Sales GWH
1994	633	2,401
1995	1,385	2,043
1996	2,231	1,197
1997	2,873	555
1998	3,531	2,872
1999	4,244	2,543
2000	4,686	2,101
2001	5,055	1,732
2002	5,630	1,115
2003	5,983	804
2004	6,352	235
2005	6,767	20
2006	6,787	0

COMPARISON WITH TOTAL AREA POWER REQUIREMENTS

	Estimated Anchorage and Fairbanks Energy	Estimated Market for New Hydroelectric Power
Year	Annual Energy Million KWH	Annual Energy Million KWH
1995	10,323	1,385 (13)1/
2000	13,288	4,686 (35)1/
2005	15,083	6,767 (45)1/

1/ Percent of total area requirements

Data Source: APA Load/Resources Analysis
Medium Load Growth Estimates,
Energy Losses are included.

Table 31
INVESTMENT AND OM&R COST SUMMARY

Upper Susitna Project Power Market Analysis

Unit	Watana	Devil Canyon	Total System
Completion Date	1994	1998	
Costs - $1,000			
Power Production Facilities			
Construction Costs	1,427,000	665,000 1/	
Interest During Construction	603,700	168,600	
Investment Cost	2,030,700	833,600	2,864,300
Transmission Facilities 2/			
Construction Costs	338,000		
Interest During Construction	132,500		470,500
Investment Cost	470,500		3,334,800
Total System Investment Cost			
Annual Operation and Maintenance			2,890
Annual Replacement			430
Annual OM&R			3,320

Price level is October 1978. Interest rate for repayment purposes in FY 1979 is 7-1/2%.

1/ Costs are for arch dam plan at Devil Canyon.
2/ Transmission system assumed online in 1991.

Average Rate Determination

Table 33 summarizes the estimated average firm energy rate for firm energy needed to repay project facilities investment for mid-range load growth conditions. The method used is similar to that used in the 1976 report. Present Federal criteria for power producing facilities require repayment of project costs, with interest, within 50 years after the unit becomes revenue producing. The applicable interest rate for Fiscal Year 1979 is 7 1/2 percent. Revenues were credited to the project from sale of secondary energy at a fuel replacement rate of 1.2¢/kwh during early years of project operation. The average required rate for repayment over 50 years after the last unit is installed is 4.7¢/kwh. Total repayment period will be 54 years with Devil Canyon coming on-line four years after Watana.

Alternatives to the basic project plan were analyzed to determine effects on average power rates:

1. Devil Canyon gravity dam in lieu of the thin-arch dam:

Investment cost increased $204.9 million.

Average rate for firm energy increased to a total of 4.9¢/kwh.

2. Transmission investment deferred until Watana phase comes on-line (1994):

Watana phase investment reduced $76 million.

Average rate reduced 0.1¢/kwh to a total of 4.6¢/kwh.

3. Mid load growth case, 5 percent inflation:

Investment cost increased $3.598 billion.

Revenue needs increased $243 million annually.

Firm energy is the same for all mid growth cases.

Average rate for firm energy increased 4.7¢/kwh to 9.7¢/kwh.

4. Low load growth case:

Revenue needs same as for mid range growth case.

Firm energy sales decreased; fuel replacement sales increased.

Average firm energy rate increased 1.7¢/kwh.

All Corps plans are based on completing Watana first, followed by Devil Canyon four years later. This is appropriate for mid range and high range growth conditions, but if low range conditions remain, it may mean the Devil Canyon unit could be deferred a few years.

Power Marketing Considerations

The average rate is useful for comparing the proposal with the alternatives. Actual marketing contracts will likely include separate provisions for demand and energy charges, wheeling charges, reserve agreements, and other factors.

There are some built-in inequities for any method of pricing. What amounts to a postage stamp rate is used by most utilities and large Federal systems. That is, power rates are the same for all delivery points on the system. Actual costs vary with the distance, size, and characteristics of load--it is more costly to serve a small load several miles from the power source than to serve a large load nearby. Policies vary from system to system as to "hookup" costs born by the customers.

Table 32
COST SUMMARY COMPARISON
WITH 1976 INTERIM FEASIBILITY REPORT

Upper Susitna Project Power Market Analysis

Item (Costs $ Million)	1976 Interim Feasibility Report	1978 Marketability Analysis Update	Difference Amount	Difference Percent
Interest Rate for Repayment	6-5/8%	7-1/2%	+ 7/8%	+ 13
Construction Period				
Watana	6 yrs.	10 yrs.	+ 4 yrs.	+ 67
Devil Canyon	5	8	+ 3	+ 60
Transmission System	3	3	0	0
Total	10 yrs.	14 yrs.	+ 4 yrs	+ 40
Construction Cost				
Watana	832.0	1,427.0	+ 595.0	+ 72
Devil Canyon	432.0	665.0	+ 233.0	+ 54
Transmission System	256.0	338.0	+ 82.0	+ 32
Total	1,520.0	2,430.0	+ 910.0	+ 60
Interest During Construction				
Watana	165.4	603.7	+438.3	+265
Devil Canyon	57.2	168.6	+111.4	+195
Transmission System	25.4	132.5	+107.1	+422
Total	248.0	904.8	656.8	+265
Investment Cost				
Watana	997.4	2,030.7	+1,033.3	+104
Devil Canyon	489.2	833.6	+ 344.4	+ 70
Transmission System	281.4	470.5	+ 189.1	+ 67
Total	1,768.0	3,334.8	+1,566.8	+ 89
Annual Cost for Repayment of Investment	113.34	239.20	+125.86	+111
Annual Equivalent OM&R	2.27	3.14	+ 0.87	+ 38
Total Annual Equiv. Cost	115.61	242.34	+126.73	+110
(Less Secondary Energy Sales - (Fuel Replacement Sales)1/	5.77	11.34	+ 5.57	+ 97
Total Net Annual Equiv. Cost	109.84	231.00	121.16	+110
Annual Equiv. Energy GWH1/	5,218	4,923	-295	-6
Total Annual Equiv. Energy Cost - ¢/KWH	2.11	4.69	2.58	+123

1/ Median load growth

Note: Total energy during period of analysis is the same in both reports. Difference is due to variation in load build-up.

Table 33
AVERAGE RATE DETERMINATION
(WATANA AND DEVIL CANYON)
Upper Susitna Project Power Market Analysis

	Project Costs $1,000		1994 PW Costs $1,000				Project Energy Sales Million KWH	
Year	Revenue Producing Investment	OM&R	Investment	OM&R	Firm Energy	Fuel Replacement Energy Sales	1994 PW Firm Energy (1994-2005)	Fuel Replacement Sales
1994	2,501,200	2,620	2,501,200	2,437	633	2,401	589	2,233
1995		2,620		2,267	1,385	2,043	1,198	1,768
1996		2,620		2,109	2,231	1,197	1,796	964
1997		2,620		1,962	2,873	555	2,151	416
				(1998-2047)				
1998	833,600	3,320	624,200	32,256	3,531	2,872	2,459	2,000
1999		3,320			4,244	2.543	2.750	1,648
2000		3,320			4,686	2,101	2,824	1,266
2001		3,320			5,055	1,732	2,834	971
2002		3,320			5,630	1,115	2,937	582
2003		3,320			5,983	804	2,903	390
2004		3,320			6,352	235	2,867	106
2005		3,320			6,767	20	2,841	8
2006-2047					6,787	000	36,171	
Totals	3,334,800		3,125,400	41,031			64,320	12,352
Annual Equivalents			239,200	3,141			4,923	845

Average Rate Computation:

(1) Annual Costs:

Capital	$239,200,000
OM&R	3,140,000
Total	$242,340,000

(2) Revenue From Fuel Replacement Energy at 12 mills per kilowatt hour -11,340,000

$231,000,000

(3) Equivalent Annual Firm Energy Sales 4,923,000,000 KWH

(4) Average Rate For Repayment ($231,000,000/ 4,923,000,000 KWH) = 46.9 mills/KWH

Actual rates for the Susitna system could reflect several items of costs and revenues not identified in the project studies. For example, during its life, project facilities would likely be used to wheel power from other sources. Wheeling revenues will lower overall project power rates somewhat. Conversely, wheeling costs for project power delivered over non-Federal transmission lines will be added to project rate schedules. This is now done under APA marketing contracts for the Snettisham Project; there are similar situations in other Federal power systems.

Market Aspects of Other Transmission Alternatives

It is reasonable to expect modifications of the project transmission system as requirements (or needs) change. The main 345-kv and 230-kv lines could be upgraded substantially by adding compensation and transformer capacity. Substations could be added as future loads increase to a case-by-case determination of economics. Similarly, extensions of the project transmission lines to serve other areas would be considered on the basis of needs, economics, and available alternatives.

Anchorage-Cook Inlet Area

The costs in the proposed plan are premised on delivery points to substations near Talkeetna and Anchorage. Rough estimates indicate similar costs for a plan with delivery points at Talkeetna, Anchorage, and the existing APA Palmer substation. Basically the proposed plan includes costs to provide for delivery points on the existing CEA and APA systems north of Knik Arm, but does not include costs of delivering power across or around the Arm.

With or without the Susitna project, additional transmission capability is needed on the approaches to Anchorage. CEA plans for a Knik Arm system considers 230-kv transmission an important step in developing this capability, but more capacity will be needed by the mid-1980's. Essentially the same problems will exist with alternative power sources, such as the Beluga coals.

Following project authorization, detailed studies will be needed to consider alternatives for providing power across Knik Arm. Costs would be worked into rate structures through wheeling charges on non-Federal lines or annual costs on project lines, if needed.

The transmission plan to deliver project power in Anchorage will need to be worked out in the detailed post authorization studies. It will involve added costs, either wheeling charges for project power over non-Federal lines, or constructing project transmission lines around or under Knik Arm. These costs could be about the same for alternative power sources such as the Beluga coals.

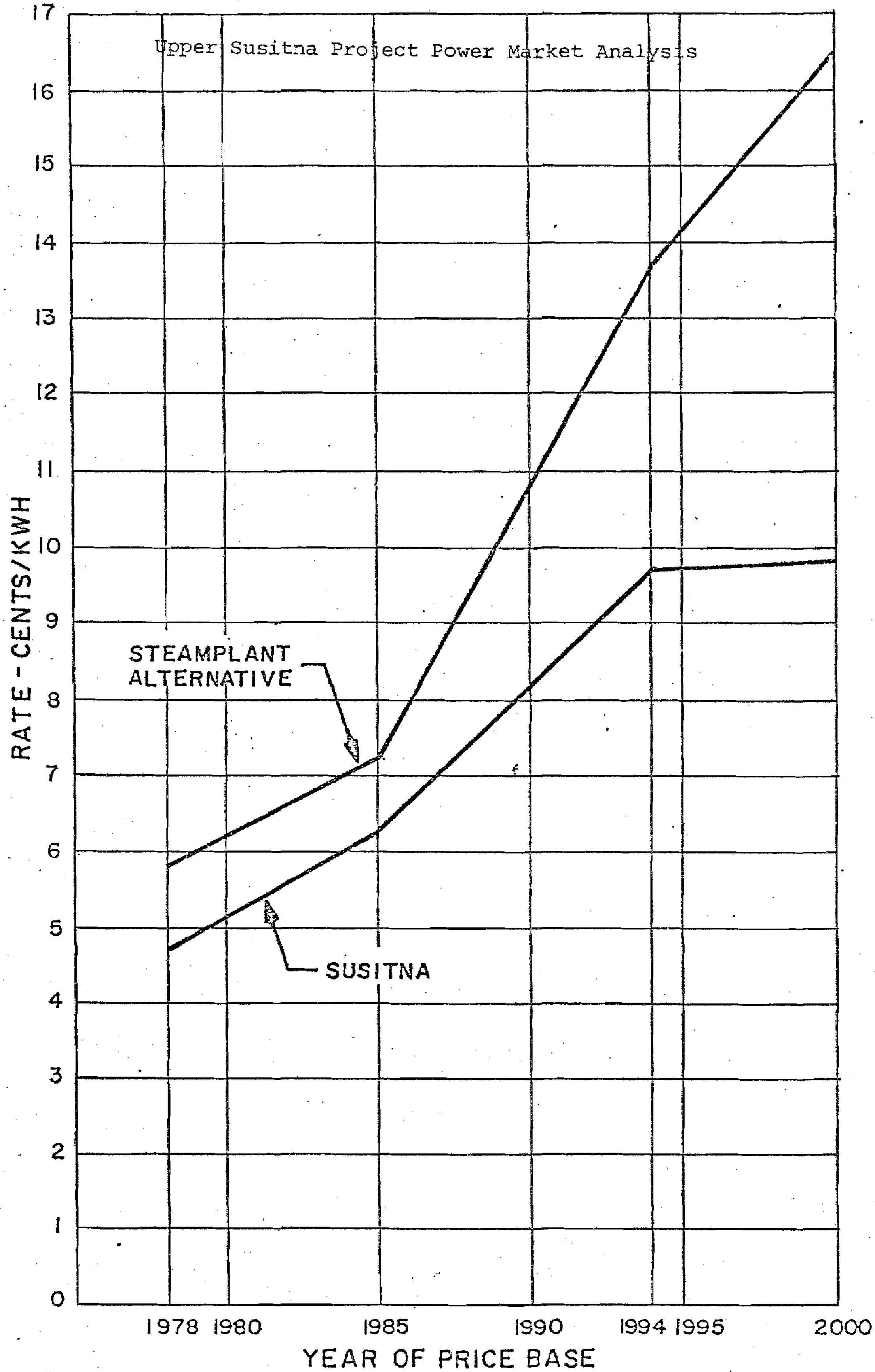
It is essential that scheduling of project facilities be closely tied to the marketing function.

Comparison of Susitna to Steamplants With and Without Inflation

Without inflation, the 4.7¢/kwh rate for the Susitna project is significantly lower than the estimated cost of power from coal-fired steamplants at 5.2 to 6.4¢/kwh at October 1978 costs. Considering inflation, the capital costs of both the steamplant and hydro powerplant increase until construction is complete. For the completed projects, inflation affects only the hydro project operation and maintenance cost, a small part of the energy cost. For the steamplant, inflation continues to increase the fuel cost as well as the much larger operation and maintenance cost.

The difference of the effect of inflation is shown on figure 19. Capital and O&M costs are assumed to inflate at 5 percent per year for both. Fuel costs are assumed to inflate 2 percent per year higher than a base price of $1.00 or $1.50 per million Btu in 1985. The conclusions are that Susitna is considerably less susceptible to inflation than steamplants.

COMPARISON OF SUSITNA
AND ALTERNATIVE COAL-FIRED STEAMPLANT RATES
CONSIDERING 5% ANNUAL INFLATION



*(Fuel cost inflated 2% higher)

PART XI. GLENNALLEN AND VALDEZ

Introduction

The primary justification for the Upper Susitna project is to supply power and energy to the State's two largest power market areas, Anchorage-Cook Inlet and Fairbanks-Tanana Valley.

The Glennallen-Valdez area is recognized as a possible additional market area. The two communities are the principal load centers for the Copper Valley Electric Association (CVEA). At present, both are supplied from oil-fired generators.

CVEA is now moving into initial construction phases of its Solomon Gulch hydroelectric plant near Valdez, and is in final design stages for a 138-kv transmission line extending 104 miles to interconnect Valdez and Glennallen. CVEA could be interconnected with the major uitlities in the Anchorage-Cook Inlet area by adding a transmission line between Palmer and Glennallen. The transmission distance is 136 miles; minimum transmission voltage would likely be 139 kv. Depending on future demand, a higher voltage such as 230 kv may be justified.

Very preliminary studies summarized in the following section indicate a good chance that the Palmer-Glennallen intertie is feasible.

Power Market Area

Introduction

Similar to Fairbanks, both Glennallen and Valdez have been heavily impacted by trans-Alaska oil pipeline construction and operation. The pipeline terminal storage and shipping facilities are at Valdez. The pipeline was completed and went into operation in 1977. The Glennallen-Valdez area 1977 population was approximately 9,905, 39 percent higher than in 1974. However, the 1976 population (13,000) decreased 31 percent in 1977.

Valdez is the proposed site of a major refinery and petrochemical complex to process the State's royalty share of Prudhoe Bay oil. Plans are not yet finalized, but construction could begin as early as 1980. This would have major impacts in terms of both construction employment and a long term increase in employment and population for Valdez. The operations phase of the refinery involves 1,000 new jobs according to recent reports. Glennallen's population and economy are expected to continue to grow.

Existing Power System

The Copper Valley Electric Association (CVEA) serves both Glennallen and Valdez. CVEA's radial distribution lines extend from Glennallen, 30 miles north on the Copper River, 55 miles south on the Copper River to Lower Tonsina, and 70 miles west on the Glenn Highway. Figure 2 outlines the area.

CVEA plans to construct 104 miles of 138-kv long transmission line between Valdez and Glennallen. This is related to the Solomon Gulch 12-MW hydro development now beginning construction. At present, the utility loads are served totally by diesel generation of 17.7 MW: 10.1 MW at Valdez and 7.6 MW at Glennallen. Two small utilities serving limited areas on the highways north of Glennallen are included in historical data. Their installed diesel capacity totals 1/3 MW.

The Alyeska oil terminal facility at Valdez has 37.5 MW in oil-fired steam-turbine capacity. This is a total energy facility that satisfies the terminal's electrical and steam requirements.

Power Requirements

This section summarizes historic energy use and related data, information from a 1976 load forecast prepared for CVEA, and some general observations on likely magnitude of future power requirements.

Historic Data

Energy use and peak demand data were obtained from three power generating sources in the Valdez-Glennallen area: CVEA, the utility serving over 95 percent of the area; Chistochina Trading Post; and Paxson Lodge, Incorporated. The utility data yielded information on energy use, peak demand, and customer sector breakdowns.

Population and employment data were derived from statistics provided by the State of Alaska Department of Labor. This information illustrates demographic characteristics of the study area.

The 1970-77 Valdez-Glennallen area is summarized on table 34. Net generation by utility from 1960-77 is on table 35.

Analysis

The energy use, population, and employment data reflect events tied to construction and operation of the Alyeska oil pipeline. The large jumps in population and employment during the construction years cannot be directly tied to utility power requirements since most of the workers were housed in construction camps that supplied their own power.

The 1977 use data show total utility requirements at more than four times the 1970 level. Total number of customers tripled during the period.

Per customer residential use increased from 3,846 to 6,423 kwh per year over the 7-year period.

This historic data provides no clear insight to probable future levels of power use--any trends that would be useful in forecasting are hidden by the construction impacts.

Forecast

Table 36 summarizes future power demand estimates from CVEA's 1976 power requirements study. The study included estimates of demands through 1991; APA made a rough extension to the year 2000, assuming a 6 percent rate of increase.

The average energy capability of the Solomon Gulch project is estimated at 55 million kwh/year. The forecasts indicate that the Solomon Gulch power would be fully utilized as soon as it comes on-line. By the time Upper Susitna power would be available, CVEA total demands would exceed Solomon Gulch capability by around 100 million kwh/year.

The CVEA study predated the plans for the oil refinery at Valdez, hence there is substantial likelihood that the actual requirements will exceed the forecast amounts.

Transmission Plan And Cost

Incremental service to the Glennallen-Valdez market areas would require constructing transmission facilities from Palmer to Glennallen to connect to the CVEA system serving the market area. Susitna project generation and transmission to the Anchorage-Cook Inlet area would be sufficient to accomodate the incremental service.

The Palmer-Glennallen transmission system would have 136 miles of single circuit 138-kv line, with a substation at Palmer and a switchyard at Glennallen. The Palmer substation would have a 230/138-kv transformer, a 230-kv breaker, and a 138-kv circuit breaker. The Glennallen switchyard would include two 138-kv circuit breakers, and would connect with the planned CVEA 138-kv line extending to Valdez. Peak capacity of the 138-kv Palmer-Glennallen line would likely be from 50 to 80 MW. This is an assumption for study purposes (stability, sizing, and power flow studies were not made).

System costs are based on comparable elements of other project transmission systems, indexed from the 1976 report (January 1975 prices) to October 1978 prices (about 32 percent increase). The basic prices are based on Bureau of Reclamation (USBR) and Bonneville Power Administration (BPA) with adjustments for Alaska conditions (refer to Part VIII). Advance planning would analyze evaluations of structural, operation control, environment, and other elements affecting route location, design, and operation of the system serving this area.

Investment costs are calculated by adding 7½ percent interest annually during construction. The Palmer-Glennallen line would be constructed during the same period as other facilities, and would be ready for service when project power is available in 1994. Table 37 summarizes construction and investment costs.

Table 34
HISTORIC DATA
GLENNALLEN-VALDEZ AREA

Upper Susitna Project Power Market Analysis

	Utility Energy Sales (GWH)			Net Generation	
	Res	CI	Total	Utility	Industry
1970	2.1	7.4	9.9	11.9	
1971	2.6	7.8	10.8	12.8	
1972	2.8	7.6	10.8	13.0	
1973	2.9	8.3	11.6	13.8	
1974	3.7	10.4	14.5	16.8	
1975	7.7	16.0	24.4	28.2	
1976	10.3	22.4	33.5	40.7	
1977	10.9	31.0	42.9	48.7	39.4

	Utility Customers			Peak Load (MW)	
	Res	CI	Total	Utility	Industry
1970	546	221	793	2.4	
1971	681	226	939	2.5	
1972	655	237	926	2.6	
1973	684	247	965	2.7	
1974	911	317	1,268	4.0	
1975	1,172	361	1,576	7.3	
1976	1,677	404	2,128	8.6	
1977	1,697	427	2,183	9.3	37 (38.6 installed capacity)

	Population (Total)	Employment (Avg. Annual)
1970	3,098	831
1971	2,932	1,085
1972	3,464	904
1973	3,568	985
1974	3,833	1,526
1975	9,639	4,626
1976	13,000	7,818
1977	9,905	3,918

Res = residential
CI = Commercial-industrial

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Table 35
UTILITY NET GENERATION (GWH)
GLENNALLEN-VALDEZ AREA

Upper Susitna Project Power Market Analysis

Year	CVEA	CTP	PLI	Total	Growth %
1960	3.2		0.1	3.3	
1961	3.4		0.1	3.5	6.1
1962	4.0		0.1	4.1	17.1
1963	4.5		0.1	4.6	12.2
1964	4.2		0.1	4.3	-6.5
1965	6.5		0.2	6.7	55.8
1966	8.0		0.2	8.2	22.4
1967	8.2		0.3	8.5	3.7
1968	8.6		0.4	9.0	5.9
1969	9.7	0.4	0.5	10.6	17.8
1970	10.7	0.4	0.7	11.8	11.3
1971	11.7	0.4	0.7	12.8	8.5
1972	11.8	0.4	0.7	12.9	0.8
1973	12.6	0.4	0.7	13.7	6.2
1974	16.6	0.4	0.7	17.7	29.2
1975	26.9	0.4	0.7	28.0	58.2
1976	39.3	0.4	0.7	40.4	44.3
1977	47.4	0.4	0.7	48.5	20.1

CVEA - Copper Valley Electric Association
CTP - Chistochina Trading Post
PLI - Paxson Lodge, Inc.

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Table 36
VALDEZ-GLENNALLEN AREA UTILITY FORECASTS

Upper Susitna Project Power Market Analysis

	Energy (gwh)				Peak Demand (MW)	
	CVEA 1/				CVEA 1/	
Year	Glennallen	Valdez	Total		Glennallen	Valdez
1976	12.5	24.5	37.0	40.7 2/	3.1	6.0
1977	21.0	27.0	48.0	48.7 2/	4.2	5.9
1978	22.1	27.2	49.3		4.4	5.8
1979	24.0	27.6	51.6		4.6	5.8
1980	45.9	27.9	73.8		7.3	5.8
1981	48.5	30.5	79.0		7.7	6.3
1982	50.0	33.0	83.0		8.1	6.8
1983	52.2	35.5	87.7		8.5	7.4
1984	55.0	38.2	93.2		9.0	8.0
1985	57.6	41.4	99.0		9.5	8.6
1986	60.0	45.0	105.0		10.1	9.3
1987	63.1	48.5	111.6		10.6	10.1
1988	66.0	52.5	118.5		11.1	10.9
1989	69.1	56.8	125.9		11.7	11.8
1990	72.3	61.4	133.7		12.4	12.8
1991	75.0	66.4	141.4		13.0	13.8
1995			180			
2000			240			
2025			1,025			

1/ Copper Valley Electric Association Forecast from 1976 REA Power Requirements Study.

2/ Historical values

Table 37
INVESTMENT COST SUMMARY
GLENNALLEN-VALDEZ AREA TRANSMISSION SYSTEM
Upper Susitna Project Power Market Analysis

	(Costs-$1,000 10/78)		
	Construction	Interest During Construction	Investment
Transmission Line (Palmer-Glennallen)			
Clearing	$ 1,540		
Right-of-Way	310		
Access Roads	5,490		
Line Structures	25,760		
Subtotal	$33,100		
Switchyards & Substations			
Palmer Substation	$ 3,880		
Glennallen Switchyard	920		
Subtotal	$ 4,800		
Total	$37,900	$2,900	$40,800

Operation and Maintenance Costs

Addition of the 136-mile Palmer-Glennallen transmission line would involve comparatively minor increases in overall system operation, maintenance, and replacement costs.

For purpose of this analysis we are assuming the incremental O&M costs would be roughly equivalent to 1/3 of the annual cost of one transmission line maintenance crew. Adding an allowance for replacements, the annual OM&R cost is estimated at $131,000 per year. This is indicated on Table 38.

Table 38
OPERATION, MAINTENANCE, AND REPLACEMENT COST SUMMARY
GLENNALLEN-VALDEZ AREA TRANSMISSION SYSTEM

Upper Susitna Project Power Market Analysis

	Annual Cost - $1,000	
Operation and Maintenance	Full Crew	1/3 Crew
Personnel		
Salary & allowances for 6 Wage Grades	240	80
Miscellaneous		
Telephone, travel, supplies, services training, line spray, camp maintenance	10	3.3
Equipment (Replacement)	8	2.7
Marketing and Administration	22	7.3
Subtotal	280	93.3
Contingencies 20% ±	60	20
Subtotal - O&M	340	113.3
Rounded		113
Replacement		
Transmission towers, fixtures, conductors 0.0001 x $25,766,000	2.6	
Substations & Switchyards 0.0033 x $4,800,000	15.8	
Subtotal - Replacement	18.4	
Rounded	18	
Total OM&R	131	

Assessment of Feasibility

A minimum intertie between Palmer and Glennallen would involve incremental investment costs on the order of \$40.8 million. Incremental annual costs are estimated as:

Amortization	\$3,140,000
OM&R	131,000
Total Annual Cost	\$3,271,000

Based on the utility forecast for CVEA, it is possible that a market in excess of 100 million kwh/year could be supplied over the Palmer-Glennallen line. This would equate to transmission costs of 3.3¢/kwh.

The 100 million kwh/year would be equivalent to 22.8 MW at 50 percent annual load factor. This is substantially less than half the estimated capacity for a 138-kv Palmer-Glennallen line.

Full utilization of the intertie could involve transmission of 200 to 300 million kwh/year, in which case, average transmission cost would drop from one-half to one-third the cost indicated above.

Regardless of the source of power--coal, oil, hydro--generation costs for CVEA will likely be higher than for the larger utility systems serving the Anchorage-Cook Inlet area. In this context, transmission costs on the order of 1.1 to 3.3¢/kwh between Palmer and Glennallen may be justifiable.

APA concludes that the Palmer-Glennallen intertie has a good chance for feasibility, and that a more detailed examination is warranted.

APPENDIX

1. Letter dated January 3, 1979 to Col. G. R. Robertson, Alaska District Corps of Engineers, transmitting responses to OMB questions falling in APA's area of responsibility.

2. Previous Studies and Bibliography.

3. LOAD/RESOURCE AND SYSTEM COST ANALYSIS FOR THE RAILBELT REGION OF ALASKA: 1978-2010 -- Informal Report - by Battelle Pacific Northwest Laboratories, Richland, Washington - January, 1979.

4. Comments.
   a. Federal Energy Regulatory Commission, San Francisco, California, March 6, 1979.

   b. Battelle Pacific Northwest Laboratories, Richland, Washington, February 27, 1979.

   c. Corps of Engineers, Anchorage, Alaska, March 19, 1979.

   d. The Alaska State Clearinghouse, Juneau, Alaska, March 23, 1979.

   e. Municipal Light and Power Company, Anchorage, Alaska, March 1, 1979.

Department Of Energy
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

January 3, 1979

Colonel George R. Robertson
Alaska District Engineer
Corps of Engineers
P.O. Box 7002
Anchorage, AK 99510

Dear Colonel Robertson:

Attached are our responses to the Susitna Project OMB questions we agreed to provide (re: our letters dated January 20, 24, 1978).

Copies of these responses were sent via Goldstreak direct to Captain Mohn December 28, 1978.

Sincerely,

Donald L. Shira
Chief, Planning Division

OMB question 5.1, and .2.

OMB asked that the analysis of the "without" project condition be expanded to clearly analyze:

1. *Why, with natural gas projected to be in such short supply, the Anchorage utilities have only contracted for 55 percent of proved reserves or 25 percent of estimated ultimate reserves, and,*

2. *The sensitivity of the analysis to the collapse of OPEC and the cost of shipping oil to the East Coast.*

Both questions must be considered in terms of national energy policy. The Nation needs to reduce dependency on oil imports on both a short-term and a long-term basis, and to accomplish a major shift away from oil and natural gas to alternative energy sources. The reasons for this include national economic considerations, as well as very real limits on national and world supplies of oil and natural gas.

In terms of national energy policy, oil and natural gas are not available alternatives for long-term production of electric power. There are remaining questions as to how quickly existing uses will be phased out and on how complete the prohibitions will be on new oil and natural gas-fired powerplants.

There is general agreement that implementation of national policy must include strong efforts in conservation, substantial increase in use of coal, and major efforts to develop renewable energy sources. Each of these components is sensitive to energy price and supply variables. A reduction in world oil prices or a period of oversupply serves as a marketplace disincentive for conservation efforts and work on alternative energy sources.

The lowest cost alternatives and those with fully proven technology are the least sensitive; those that depend on further R&D are most easily sidetracked.

The Susitna Project involves large blocks of power and new energy from a renewable source, fully proven technology, long revenue-producing period (in excess of 100 years), and essential freedom from long-term price increases. Its unit costs appear attractive in comparison to coal-fired powerplants. It is a two-stage project with opportunity to defer the second stage if demands are lower than present estimates or if price relationships change.

The above factors suggest that the Upper Susitna Project is much less sensitive to short-term oil price and supply variations than most other U.S. energy options.

If it is assumed that Alaskan oil and natural gas will be isolated from U.S. and world demand and pricing, Alaska would probably continue to use its oil and gas for most of its power. This assumption did, in fact, prevail between the initial oil and gas discoveries in the Cook Inlet area and the 1973 oil embargo. In 1960, the Anchorage-Cook Inlet area power supplies came almost entirely from coal and hydro. The low cost, abundant gas brought a halt to hydro development and destroyed the area's coal industry. The one remaining Alaskan coal mine barely made it through the 1960's because of competition from relatively cheap oil.

The Cook Inlet gas has been subjected to increasing competition in the last few years, including proposals for LNG facilities, additional petrochemical plants, and consideration of pipeline alternatives to tie in with the Alcan pipeline project. The competition resulted in increasing prices and increasing difficulty in obtaining long-term commitments of gas for power. The competitions and the price increases are expected to continue.

The real question on gas availability as it pertains to Upper Susitna is: What is the outlook for long-term gas supplies for power after 1990? That outlook is not good in terms of competing uses and national policy.

Response to OMB question 5.3.

"The Necessity for an Anchorage-Fairbanks intertie at a cost of $200-300 million"

The estimated construction cost (1978 dollars) for the transmission lines from the Susitna Project to the Fairbanks area is $152 million, and $186 million for the lines from the project to the Anchorage area (total $338 million).

There are several previous studies[1/] that demonstrate inherent feasibility of an Anchorage-Fairbanks intertie with or without construction of the Upper Susitna Project. The main reason that the intertie is not now in place is that short term benefits to the Anchorage area are quite small, i.e., most of the short term benefits for the intertie would occur through reduced energy and power costs in the Fairbanks area.

APA studies in the 1975 feasibility report evaluated Susitna Project power to Fairbanks on a cost-of-service basis (see Appendix I, p. 6-89). This was a specific demonstration of feasibility of including Fairbanks as part of the Upper Susitna Power Market area.

1/ Among the previous studies are:

Alaska Power Survey, Federal Power Commission, 1969.

Central Alaska Power Pool, working paper, Alaska Power Administration, October 1969.

Alaska Railbelt Transmission System, working paper, Alaska Power Administration, December 1967.

Electric Generation and Transmission Intertie System for Interior and Southcentral Alaska, CH2M Hill, 1972.

Central Alaska Power Study, The Ralph M. Parsons Company, undated.

Alaska Power Feasibility Study, The Ralph M. Parsons Company, 1962.

Further verification of feasibility of the intertie is provided in the new load-resource analyses and system cost analyses prepared for the current studies. These general cases were analyzed:

Case 1. All future generating capacity assumed to be coal-fired steam turbines without intertie.

Case 2. All future generating capacity assumed to be coal-fired steam turbines with intertie.

Case 3. Future generating capacity to include Upper Susitna Project plus coal-fired steam plants as needed. Includes intertie.

Results of power cost analyses for Anchorage and Fairbanks for the year 2000, with and without intertie are as follows:

Power Costs for Anchorage and Fairbanks (0% Inflation)
(¢/KWH)

	Case 1 Without Intertie		Case 2 With Intertie		Case 3 With Susitna and Intertie	
	Anchorage	Fairbanks	Anchorage	Fairbanks	Anchorage	Fairbanks
High	6.2	8.8	6.1	8.0	5.8	6.2
Med	6.6	8.9	6.2	8.4	5.5	6.7
Low	7.1	9.2	6.2	8.8	6.1	7.8

The following table presents a comparison of the costs of power in the year 2000 for Case 2, and 3 as compared to Case 1. As shown the costs of power are reduced below the cost of power for Case 1 in all cases. The reduction in the cost of power is typically greater in the

Fairbanks-Tanana Valley area than in the Anchorage-Cook Inlet area because the Anchorage-Cook Inlet area will have a higher percent of its generation supplied by steam plants which are more costly than Susitna.

Comparison of Power Costs for Year 2000

Percent Change in Cost of Power Below Case 1 - 0% Inflation

	Anchorage			Fairbanks		
	High	Medium	Low	High	Medium	Low
Case 2	-1.6	-6.5	-14.5	-10.0	-6.0	-4.5
Case 3	-6.9	-20.0	-16.4	-41.9	-32.8	-17.9

Table 1 compares annual system costs for all three cases for Anchorage and Fairbanks during the 1990-2011 period.

Table 1 shows the following percent savings in system costs (1990-2011) for Cases 2 and 3 compared to Case 1:

	Anchorage	Fairbanks	Total
Case 2	-0.4	-7.9	-1.4
Case 3	-10.7	-28.1	-14.1

Table 1. Annual Power System Costs for Power Supply Under Cases I, II, and III - Mid-Range Load Projections - 0% Inflation ($Million)

Period	Case I		Case II		Case III	
	Anchorage	Fairbanks	Anchorage	Fairbanks	Anchorage	Fairbanks
1980-90	272.0	90.6	254.5	84.2	254.5	84.2
90-91	274.2	96.8	293.8	89.0	293.8	89.0
91-92	324.2	98.2	343.8	90.2	343.8	90.2
92-93	387.5	119.5	409.9	88.2	409.9	88.2
93-94	391.7	120.9	414.1	89.2	414.1	89.2
94-95	398.9	122.2	421.3	114.9	537.5	120.5
95-96	463.7	127.6	486.1	143.7	537.9	124.8
96-97	549.0	152.4	571.5	143.2	543.0	124.0
97-98	615.9	167.8	578.7	158.5	549.3	139.2
98-99	627.7	192.0	650.2	182.6	576.3	145.1
1999-2000	694.4	193.8	657.2	184.5	577.2	145.7
Sub total	4,999.4	1,481.8	5,081.1	1,368.2	5,037.3	1,240.1
00-01	691.8	194.9	714.3	185.5	573.4	146.5
01-02	698.6	196.2	721.1	186.8	578.5	147.4
02-03	760.3	195.0	723.1	208.2	658.6	168.6
03-04	767.9	230.8	789.8	209.6	665.1	169.6
04-05	776.0	232.2	798.5	211.0	670.8	170.6
05-06	864.0	232.1	807.1	210.9	677.6	170.2
06-07	872.8	233.5	815.9	212.3	744.4	171.2
07-08	881.9	235.1	904.4	213.8	751.6	172.3
08-09	891.1	236.5	913.6	215.2	759.0	173.4
09-10	901.6	238.1	923.1	216.9	766.7	174.6
10-11	969.9	239.6	932.7	218.4	834.3	175.7
Total	14,075.1	3,945.8	14,124.7	3,656.9	12,717.3	3,080.2

Response to OMB question 5.4.

"Scheduling of powerplants and the reduced risk of building small increments."

The Load/Resource analysis for without project condition addresses the scheduling of steamplants and size of units needed. This is demonstrated in Chapter VII of the marketability report. Annual power system costs shown in Table 1 under question 5.3 show savings from Susitna over the without Susitna case. The steamplants are smaller units than Susitna, but their higher cost contributes to higher overall system costs. An analysis of hydro alternatives indicate that there are not economical sites available in sufficient quantity to be comparable to Susitna. This is supported by APA's draft report on "Analysis of Potential Alternative Hydroelectric Sites to Serve Railbelt Area."

Response to OMB question 6.1, .2, and .3.

Demand Estimates

The analysis of load growth should be more specific with respect to:

1. *Increasing use by consumers; and,*

2. *Increasing number of consumers.*

3. *Industrial growth, i.e., where does Alaska's comparative advantage lie outside the area of raw materials and government functions?*

The new estimates of future power demand are responsive to the first two parts of this question. APA completed a very careful analysis of recent power use trends by class of customer, with particular emphasis on identifying recent trends that could be attributed to conservation efforts. The future demands are based on future population estimates developed by the University of Alaska's Institute of Social and Economic Research and incorporate assumptions of substantially improved efficiency in use of electric power through conservation.

The third part of the question requires consideration of the overall Alaskan economy, present and future, and the role of Upper Susitna power.

Alaska is not a heavily industrialized State nor is it expected to be. The oil and gas industry is presently the dominating sector of the State's GNP, and will continue to be so for at least the balance of the 20th century. This is the principle source of revenues for the State and thus the driving force behind State programs for education, local government assistance, welfare, and so on. Other important industries are the fisheries, forest products, and recreation-tourism.

The low- and mid-range population estimates incorporate very modest assumptions of industrial expansion based on pioneering of Alaskan natural resources for the most part. The specific industrial assumptions reflect proven sources of natural resources and projects that are well along in the planning stages.

Extraction and processing of natural resources will undoubtedly continue to be major aspects of the Alaskan economy. Other important aspects include business activities of Native Corporations and increasing amounts of land made available to State and private ownership. Actions pending on the new National Parks, Refuges, and Wild and Scenic Rivers will encourage further development of the recreation and tourism industries.

As in most parts of the country, Alaska employment is not dominated by the industrial sectors. Most jobs are in service industries, the commercial establishments, transportation, utilities, and government. The new population estimate by ISER indicates that the distribution of employment will not change substantially. The anticipated growth in the economy, employment, and in power demands is primarily in the non-industrial sectors.

It should be noted that the Railbelt area demands for electric energy in 1977 were 2.7 billion kilowatt-hours, which is approaching the firm energy capability of the Watana Project. The load resource analyses demonstrate full utilization of Watana energy essentially as soon as it becomes available, even under the lower power demand case. This basically leads us to a finding that the Upper Susitna justification is not dependent on major industrial expansion in Alaska.

Response to OMB Question 7.

Under the topic Sensitivity Analysis, OMB provided the following comments:

"Power demand should be subjected to a sensitivity analysis to better assess the uncertainties in development of such a large block of power. The typical utility invests on the basis of an 8-10 year time horizon. The Susitna plan has an 11-16 year horizon in face of risks that loads may not develop and the option of wheeling power to other markets is not available. It should be noted that the power demand for Snettisham was unduly optimistic when it was built. This resulted in delays in installing generators. A similar error in a project the size of Susitna would be much more costly and would have a major adverse effect on the project's economics."

The new power demand estimates, load resources analyses, and financial analysis presented in this report, all provide a better basis for examining these questions. In addition, there is need to review some of the Snettisham Project history to bring out similarities and differences with the Upper Susitna case.

Snettisham Review

The Snettisham Hydroelectric Project is located near Juneau, Alaska, and is now the main source of power for the greater Juneau area. The project was authorized in 1962 on the basis of feasibility investigations by the Bureau of Reclamation, constructed by the Corps of Engineers, and operated by the Alaska Power Administration.

The project was conceived as a two-stage development and construction of the first, or Long Lake, stage was completed in late 1973 with first commercial power to Juneau in December 1973. The second, or Crater Lake, stage would be added when power demands dictate.

Juneau was, and is, an isolated power market area. Difficult terrain and long distances have thus far prevented electrical interconnection with other Southeast Alaska communities and neighboring areas of Canada; however, such interconnections may prove feasible within the next 15 to 20 years. The project planning and justification was premised on service only to the greater Juneau area.

The Snettisham authorization was based on power demand estimates by the Alaska District, Bureau of Reclamation (now Alaska Power Administration). 1/ The estimates were based on actual power use through 1960 and projections to the year 1987. The outlook at that time was that the first stage construction would be completed in 1966, and that total project capability would not be needed until 1987.

A comparison of power demand estimates at the time of authorization with actual demands is shown on Table 1. The 1977 energy load was 112,197 megawatt-hours or 81 percent of the amount estimated in 1961 based on historical records through 1960.

1/ Reappraisal of the Crater-Long Lakes Division, Snettisham Project, Alaska, USBR, November 1961.

Table 1 Power and Energy Requirements-Juneau Area

Fiscal Year (Oct. 1 - Sept. 30)	Actual Demands MWH	Actual Demands Peak MW	Forecasted Demands at Time of Authorization 1/ MWH	Forecasted Demands at Time of Authorization 1/ Peak MW
1958	23,945	4,788,		
1959	26,297	5,321		
1960	28,499	5,465		
1970	58,266	12,420	73,400	15,230
1971	63,786	13,780	80,700	16,750
1972	70,225	14,910	88,800	18,430
1973	75,753	15,470	97,500	20,240
1974	83,059	16,220	106,900	22,190
1975	94,609	17,840	116,900	24,260
1976	106,296	19,800	127,600	26,480
1977	112,197	20,440	139,100	28,870

1/ From Reappraisal of the Crater-Long Lakes Division, Snettisham Project, Alaska, USBR, November 1961.

The inherent flexibility of a staged project proved to be very beneficial in the case of Snettisham. APA made periodic updates of the power demand estimates during construction of the Long Lake stage. For several years, these forecasts indicated a need to proceed with the Crater Lake stage construction immediately on completion of the Long Lake stage. The Corps of Engineers construction schedules and budget requests, based on the APA power demand estimates, anticipated start of construction on Crater Lake in FY 1977. Major factors in these forecasts were plans for a major new pulp mill in the Juneau area and for iron ore mining and reduction facility in the vicinity of Port Snettisham. Neither of these developments were anticipated at the time of authorization. Both of these resource developments fell through, and this resulted in a substantial reduction in the APA power demand estimate and a decision in late 1975 to defer the Crater Lake construction start.

The pulp mill was particularly influential in the change in demand estimates. The mill was planned for operation in the early 1970's with a large population and commercial impact on Juneau. Initial access facilities were constructed and site preparation was well underway when the project became entangled in protracted law suits involving logging practices in Southeast Alaska. Several court decisions were made in favor of the development, but a last minute remand put the project back to base one and led to cancellation in early 1975.

This type of uncertainty faces all utility planners. The staged project like Snettisham affords a great deal of capability to adjust to changes in demand.

Many other factors influenced Juneau area power demands and utilization of project power. Of particular concern at the moment is impact of Alaska's capital move initiative. This would certainly change use of project power, with the most likely outcome that the community would move more quickly into an all-electric mode (space heating and electric vehicles appear particularly attractive in this area) and industrial use of power would increase through economic diversification.

The key points of the Snettisham review are:

1. The project was planned and authorized with intent to handle growth in area power requirements for a 20-year period.

2. The load forecasts used as a basis for authorization were reasonably accurate.

3. The actual use of project power may turn out to be substantially different than originally anticipated.

4. The flexibility of staged projects was actually used.

5. The outlook for financial viability appears excellent at this time in history.

Implications for Susitna

First, the norm for utility investments cannot remain as the basis of an 8 to 10 year time horizon. This is evidenced by experiences since about 1970 on time required to plan, obtain necessary permits or authorizations, find financing, and then build new powerplants and major transmission facilities. The 8 to 10 years is much too short for nuclear, coal, and hydro plants and for major transmission lines.

It appears appropriate to require a 20-year planning horizon with careful checks at each step in the process and business-like decisions to shift construction schedules if conditions (demands) change. We believe the Snettisham experience is very positive in this light.

The Susitna Project is similar in that project investment is keyed to two major stages. The commitment of construction funds for Watana would be needed in 1986 or 1987 to have power on line by 1993 or 1994. If conditions in 1986 indicate need to defer the project, it should be deferred. Similarly, start of actual construction on Devil Canyon can and should be based on conditions that actually prevail at the time the decision is made.

The level of uncertainty for Upper Susitna is greater than was the case for Snettisham on counts of higher interest costs and larger total investment. Sensitivity to change in demands is much less for Susitna because of its large and diversified power market area. There are many more ways that Susitna Project power could be effectively utilized in the event that traditional utility power markets are smaller than anticipated at the present.

Upper Susitna does not have as many uncertainities in terms of environmental questions as would equivalent power supplies from coal or nuclear plants. Uncertainties on air quality are particularly relevant for any larger Alaskan coal-fired powerplants.

Current Evaluation

Power demands were estimated for High, Medium, and Low cases to year 2025 assuming logical variations in population and energy use per capita. The projections reflect energy use per capita based on detailed studies of 1970-1977 data from both the Anchorage and Fairbanks areas. The projections considered variations in per capita use ranging from increased use of electricity in the home to anticipated effects of conservation on decreasing the growth rates. A detailed discussion of the development of the power demands is included in Chapter 5 of this report.

The load/resource and cost analysis provided system cost for comparison of cases both with and without the Susitna Project. The analysis also compared the power demands to the resources required to determine sizes and timing of new plants (the load/resource analysis is summarized in Chapter VII). Table 2 summarizes the resources needed during the 1990's for the range of projections.

The Table indicates that even under the most conservative load growth condition (low), 1,500 MW are needed to meet the combined Anchorage-Fairbanks demands, which is roughly the capability of Susitna.

Tables 3 and 4 show the power costs for Anchorage and Fairbanks during the 1990's with an interconnection and with and without the Susitna Project. It is readily apparent the rates are less for the case with Susitna.

For example, in the medium case for the year 2000, Anchorage costs are 5.5¢/kwh or 13 percent less than without Susitna. In the Fairbanks costs, the difference is much larger, 6.7¢/kwh or 25 percent less than without Susitna.

In Table 5, annual system interest costs are composed with and without Susitna with intertie from 1990 to 2011. Examination of the system cost on an annual basis reveals the case with Susitna is cheaper than the without Susitna case for each year except the first few years after Watana comes on line.

Table 2. Schedule of Plant Additions -MW

Cases with Interconnection without Upper Susitna

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	400	*	200	-	*	100
90-91	-	200	-	-	-	-
91-92	400	200	-	-	-	-
92-93	-	400	200	200	-	-
93-94	400	-	-	100	-	-
94-95	-	-	*	-	100	*
95-96	400	400	200	100	100	-
96-97	400	400	200	100	-	100
97-98	400	-	400	200	100	100
98-99	400	400	-	-	100	-
99-00	400	-	-	-	-	-
TOTAL 90-2000	3200	2000	1200	700	400	300

*Interconnection Installed in 1987 for high case, 1990 for median case, & 1995 for low case.

Replacement of military powerplants, many of which also supply heat for buildings are additional but not shown here.

TABLE 3. Power Costs for Anchorage and Fairbanks Areas With Interconnection and Without Upper Susitna - 0% Inflation (cents/kwh)

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	5.7	4.5	4.2	4.7	5.8	5.6
90-91	5.4	4.8	4.1	4.6	5.9	5.8
91-92	5.7	5.3	4.1	4.4	5.7	5.8
92-93	5.4	5.9	4.7	6.3	5.4	5.6
93-94	5.7	5.6	4.6	7.3	5.2	5.5
94-95	5.5	5.4	4.9	7.0	6.5	6.7
95-96	5.6	5.8	5.4	7.8	7.7	6.9
96-97	5.8	6.4	5.8	8.2	7.4	8.3
97-98	5.9	6.1	6.6	8.7	7.8	9.1
98-99	6.0	6.5	6.4	8.3	8.7	8.9
99-00	6.1	6.2	6.2	8.0	8.4	8.8

TABLE 4. Power Costs for Anchorage and Fairbanks Areas With Interconnection and With Upper Susitna Coming on Line in 1994 - 0% Inflation
(cents/kwh)

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	5.7	4.5	4.2	4.7	5.8	5.6
90-91	5.4	4.8	4.1	4.6	5.9	5.8
91-92	5.7	5.3	4.6	4.4	5.7	7.2
92-93	5.4	5.9	4.4	6.3	5.4	6.9
93-94	5.7	5.6	5.0	7.3	5.2	6.8
94-95	6.4	6.9	7.3	7.9	6.8	8.8
95-96	6.0	6.5	6.8	7.7	6.7	8.9
96-97	6.2	6.1	6.5	7.2	6.4	8.6
97-98	6.2	5.8	6.3	6.6	6.9	7.8
98-99	6.1	5.8	6.1	6.5	6.9	7.6
99-00	5.8	5.5	6.1	6.2	6.7	7.8

TABLE 5. Power System Annual Costs for Anchorage and Fairbanks With Upper Susitna Coming On Line in 1994 - 0% Inflation (million $)

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	508.5	254.5	173.4	85.2	84.2	63.4
90-91	514.1	293.8	175.0	89.0	89.0	68.5
91-92	591.8	343.8	206.0	90.2	90.2	87.4
92-93	597.3	409.9	205.0	137.8	88.2	85.5
93-94	666.0	414.1	244.5	166.8	89.2	86.4
94-95	798.5	537.5	372.3	192.2	120.5	115.6
95-96	806.1	537.9	368.4	198.0	124.8	119.2
96-97	898.6	543.0	368.5	198.5	124.0	117.5
97-98	793.1	549.3	369.9	192.5	139.2	109.2
98-99	1,009.1	576.3	376.1	201.3	145.1	109.7
99-00	1,018.9	577.2	391.7	203.5	145.7	114.9
00-01	1,025.1	573.4	381.4	228.6	146.5	114.5
01-02	1,101.3	578.5	380.3	254.0	147.4	114.5
02-03	1,172.1	658.6	375.3	254.3	168.6	111.9
03-04	1,190.4	665.1	376.6	291.6	169.6	112.0
04-05	1,287.7	670.8	376.8	296.0	170.6	112.1
05-06	1,366.8	677.6	378.0	296.1	170.2	110.7
06-07	1,386.8	744.4	379.4	299.2	171.2	110.8
07-08	1,467.2	751.6	380.8	302.4	172.3	110.9
08-09	1,548.1	759.0	382.2	305.7	173.4	111.1
09-10	1,569.9	766.7	383.7	343.5	174.6	111.2
10-11	1,671.6	834.3	385.2	347.0	175.7	111.4
Total	22,989.0	12,717.3	7,430.5	4,973.4	3,080.2	2,308.4

(continued)

TABLE 5. Power System Annual Costs for Anchorage and Fairbanks Without Upper Susitna Coming On Line in 1994 - 0% Inflation (million $)

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	508.5	254.5	173.4	85.2	84.2	63.4
90-91	514.1	293.8	175.0	89.0	89.0	68.5
91-92	591.8	343.8	185.7	90.2	90.2	71.1
92-93	597.3	409.9	223.3	137.8	88.2	69.2
93-94	666.0	414.1	227.2	166.8	89.2	70.1
94-95	678.0	421.3	252.4	169.4	114.9	87.2
95-96	750.0	486.1	290.9	201.3	143.7	91.8
96-97	843.4	571.5	327.9	224.8	143.2	113.1
97-98	918.8	578.7	389.8	253.4	158.5	127.6
98-99	998.3	650.2	396.7	256.3	182.6	128.4
99-00	1,074.0	657.2	397.9	259.7	184.5	129.3
00-01	1,160.8	714.3	470.6	262.3	185.5	129.6
01-02	1,238.6	721.1	472.5	265.3	186.8	130.2
02-03	1,310.9	723.1	469.8	265.8	208.2	128.3
03-04	1,331.0	789.8	472.8	303.5	209.6	128.8
04-05	1,350.7	798.5	474.8	341.2	211.0	129.3
05-06	1,431.7	807.1	477.8	343.1	210.9	128.4
06-07	1,513.3	815.9	480.9	346.5	212.3	151.7
07-08	1,615.1	904.4	484.0	350.1	213.8	152.2
08-09	1,638.1	913.6	487.1	353.7	215.3	152.8
09-10	1,721.4	923.1	490.3	357.5	216.9	153.3
10-11	1,801.7	932.7	493.6	361.4	218.4	153.9
Total	24,253.5	14,124.7	8,314.4	5,484.3	3,656.9	2,558.2

It should be noted that in the low energy use estimate the total system cost for Anchorage during this period amounts to $883.9 million less with Susitna than without the project. The difference is even larger in the medium and high cases. The combined Anchorage-Fairbanks cash savings for the same period based on the medium power use estimate is almost $2 Billion.

Previous Studies

There was a fairly substantial backlog of power system and project studies relevant to the 1976 evaluation of the Upper Susitna River Project. The previous studies most relevant include:

1. Advisory Committee studies completed in 1974 for the Federal Power Commission's (FPC) 1976 Alaska Power Survey. The studies include evaluation of existing power systems and future needs through the year 2000, and the main generation and transmission alternatives available to meet the needs. The power requirement studies and alternative generation system studies for the 1976 power survey were used extensively.

2. A series of utility system studies for Railbelt area utilities include assessments of loads, power costs, and generation and transmission alternatives.

3. Previous work by the Alaska Power Administration, the Bureau of Reclamation, the utility systems, and industry on studies of various plans for Railbelt transmission interconnections and the Upper Susitna hydroelectric potential.

It should be noted that many of the studies listed in the bibliography represent a period in history when there was very little concern about energy conservation, growth, and needs for conserving oil and natural gas resources. Similarly, many of these studies reflected anticipation of long term, very low cost energy supplies. In this regard, the studies for the 1976 power survey are considered particularly significant in that they provide a first assessment of Alaska power system needs reflecting the current concerns for energy and fuels conservation and the environment, and the rapidly increasing costs of energy in the economy.

The latter concern for conservation, etc. has been carried even further in this report. As yet unpublished studies by the Alaska Power Administration have made a definite reflection of conservation assumptions. The resulting load forecasts were used in load/resource analyses done and reported by Battelle Pacific Northwest Laboratories in 1978 and 1979. (Battelle also published a report in 1978 entitled Alaska Electric Power, and Analysis of Future Requirements and Supply Alternatives for the Railbelt Region.) Population and employment used in the recent forecasts were projected and reported by the Institute of Social and Economic Research in September 1978. The result of their econometric model is entitled South Central Alaska's Economy and Population, 1965-2025: A Base Study and Projection. A partial bibliography of related studies including those of the 1976 Susitna report, is appended.

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INFORMAL REPORT

LOAD/RESOURCE AND SYSTEM COST ANALYSIS FOR THE RAILBELT REGION OF ALASKA: 1978-2010

for
ALASKA POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

by
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January 1979

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LOAD/RESOURCE AND SYSTEM COST ANALYSIS FOR THE RAILBELT REGION OF ALASKA - 1978-2010

Prepared for the
Alaska Power Administration

by

Battelle
Pacific Northwest Laboratories

January 1979

1.0 INTRODUCTION

The Alaska Railbelt region presents some unique attributes for consideration in future power system planning. The region currently consumes 83% of the State's electric power and even the lower estimates of electrical load growth (5% per annum) for the region are above the national average.

The State, and particularly this region, is a difficult one in which to forecast load growths. This difficulty results from the nature of the economic activity base being influenced by external forces such as oil and gas developments and transportation systems with their cyclical tendency. Also, since the economic base is still not large, the injection of a competitively scaled industry such as major petroleum refinery or electrochemical industry can significantly perturb a forecast.

A major shift in the Alaskan Railbelt future power generating mode appears inevitable. The Cook Inlet Region's capacity is presently dominated by combustion turbines fired by currently low-cost natural gas; the Fairbanks-North Star Borough by a mix of coal-fired steam turbine generation and oil-fired combustion turbines. The oil and gas based mode of generation, however, are highly exposed to inflationary pressures, external market forces, and Federal regulatory intervention.

The Railbelt region, however, does have a number of options open in the future. These include:

- Continued use of oil and gas in existing plants.
- Increased coal based thermal generation both in the interior based on the Healy Coal Field and in the Cook Inlet Region based on several coal fields, including the very large reserves in the Beluga Region.
- Development of the significant hydroelectric potential, including Upper Susitna River and Bradley Lake.
- A transmission intertie between the Cook Inlet and Fairbanks load centers is of obvious interest as a means of increasing reliability or alternately reducing additional generating capacity needed for reliability. Marketing of power from Upper Susitna projects will be dependent upon such an intertie.

Electric power generation by whatever means is a very capital intensive activity. Different forms of generation, however, have different levels of exposure to inflation and escalation and, cost comparisons on a straight $/kW of installed capacity can be misleading. Thus a higher cost per kilowatt hydro-electric project has this exposure largely limited to the time period during planning and construction. On the other hand, a fossil fueled plant faces rising fuel costs as well as operating and maintenance costs in the future. Regardless of these factors, all generation options are faced with long lead times from decision to proceed to commercial operating date.

The purpose of this report is to examine the probable timing of major generation and transmission investments and their impact on system power costs under a range of assumptions about power demands and inflation and escalation rates for the following general Railbelt power supply strategies:

Case 1. All additional generating capacity assumed to be coal fired steam turbines without a transmission interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area load centers.

Case 2. All additional generating capacity assumed to be coal fired steam turbines, including a transmission interconnection.

Case 3. Additional capacity to include the Upper Susitna Project (including transmission intertie) plus additional coal as needed.

The first step involved in estimating the cost of power from alternative generation and transmission system configurations is to perform a series of load/resource analyses. These analyses determine the schedule of major investments based on assumptions about the load growth, the capacity and power production of the prospective generating facilities, and constraints as to when the facilities can come on line.

The load/resource analyses provide information on the annual power production of the various types of generating plants. Once the annual plant utilizations are known, they can be used in conjunction with estimates of annual system costs to calculate the annual cost of producing power from the facilities. Summing the annual cost for generation and transmission of each of the generating facilities gives a total cost for the entire system being analyzed. Dividing the total annual cost by the power produced gives an average annual cost of power for the entire system. By comparing the average annual power costs over the period of interest (1978-2010) the alternative configurations can be ranked based on the cost of power. All other things being equal, the system configuration producing power at the lowest cost should be selected as the most desirable system.

The report was prepared on contract to the Alaska Power Administration (APA) as input to APA's power market analysis for the Upper Susitna Project. The APA furnished, and is responsible for, all data on power requirements, cost assumptions, and certain key criteria for the study. The balance of the criteria were developed jointly by the APA and Battelle.

Chapter 2 contains a brief summary of the results of the study. The load/resource analyses are described in Chapter 3. Chapter 4 presents the methodology and results of the cash flow and power cost calculations. Appendix A contains the data used in the load/resource analyses. Appendix B contains a listing of the computer model (AEPMOD) used to perform the load/resource matching. The output of AEPMOD for the cases analyzed in this report are presented in Appendix C. Appendix D contains a listing of the model used to compute the cost of power and Appendix E contains some selected results of ECOST 4 model runs.

2.0 SUMMARY AND CONCLUSIONS

Load/Resource Matching

- Forecasted peak loads for the Anchorage/Cook Inlet and the Fairbanks/Tanana Valley load centers have been matched with schedules of plant additions for low, median, and high forecasted load growths. These were replicated for cases considering 1) continued separation of the load centers, 2) interconnection without development of Upper Susitna hydroelectric power, 3) interconnection including development of the proposed Upper Susitna hydroelectric projects beginning in 1994.
- Thermal generating capacity additions to the year 2010 were estimated as follows:

Case 1: Without Interconnection and Upper Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	2600	471	3071
Median	4600	871	5471
High	8200	1471	9671

Case 2: Interconnection without Upper Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	2200	471	2671
Median	4200	671	4871
High	8200	1271	9471

Case 3: Interconnection with Upper Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	1000	171	1171
Median	3000	371	3371
High	6600	1071	7671

- Provision of the interconnection without Upper Susitna reduces thermal plant addition requirements by 200 to 600 MW over the period.
- Interconnection with Upper Susitna reduces thermal plant addition requirements by 1500 to 1800 MW depending on the assumed load growth.
- Under the criteria used, the interconnection is called for in 1986, 1989, and 1994 for high, median, and low load growth cases, respectively, without Upper Susitna projects. With Upper Susitna, the corresponding dates are 1986, 1989, and 1991.

System Power Cost

- For the Anchorage-Cook Inlet load center construction of the interconnection reduces the cost of power compared to the case without an interconnection.
- For the Anchorage-Cook Inlet area inclusion of the Upper Susitna project into the system generally raises the cost of power above the other cases during the first 2 to 4 years after the Watana Dam comes on line with results in lower power costs during the 1996-2010 time period.
- For the Fairbanks-Tanana Valley area construction of the interconnection again generally reduces the cost of power.
- For the Fairbanks-Tanana Valley load center inclusion of the Upper Susitna project generally raises the cost of power above the case with the interconnection for about 2 years after the Watana Dam comes on line but, as with the Anchorage-Cook Inlet area, results in lower power costs during the 1996-2010 time period.
- Table 2.1 presents a comparison of the costs of power in the year 2005 for the cases evaluated in the report using the case without either the interconnection or the Upper Susitna projects (Case 1) as the base. The costs of power computed in Case 1 are compared to cases with the interconnection (Case 2), and with Upper Susitna coming on line in 1994 (Case 3). As shown, the costs of power are reduced below the cost of power for Case 1 in but one case. This reduction varies from 4.3% to 39.3% depending upon the situation.

TABLE 2.1. Comparison of Power Costs for Year 2005

	Percent Change in Cost of Power Below Case 1 5% Inflation					
	Anchorage			Fairbanks		
	High	Median	Low	High	Median	Low
Case 2	-4.3	-10.1	-12.2	+8.9	-9.6	-4.2
Case 3	-10.5	-30.3	-39.3	-8.9	-30.8	-26.3

3.0 LOAD/RESOURCE ANALYSES

The load/resource analysis is intended to match forecasted electric power requirements with appropriate generating capability additions. The analysis schedules new plant additions, keeps track of older plant retirements, and computes the loading of installed capacity on a year-by-year basis over the period 1978 to 2010.

The analysis schedules the additions to assure that both peak loads and energy requirements (including reserves) are met on a year-by-year basis with the least amount of installed capacity and with generating plants loaded in any preselected order, typically in order of lowest to highest marginal power costs.

A number of factors must be taken into account:

1. Forecasted loads in terms of peak power requirements in megawatts (MW) and annual energy requirements in millions of killowatt hours (MMkWh).
2. The stock of existing generating capacity by type, size, year of retirement, and maximum allowable plant factor.
3. Desired reliability reserve margin to provide [illegible]ance against forced outages, unforeseen delays in plant availability, or load growths in excess of those anticipated.
4. Transmission and distribution losses.
5. Construction schedule constraints; i.e., lead times necessary between unit selection and first power on line date.
6. Plant availability constraints based on types and age. (Thermal plants generally have lower availability at the start and end of their economic life.)
7. Assumptions about the economic size of future generating plants in relation to the loads.
8. System configuration; i.e., interconnections, alternative siting strategies.

3.1 ANALYSIS METHODOLOGY

The load/resource matching is done on an annual basis. The Alaskan electric utility systems experience their annual peak load requirements during the winter months and resources must be available to meet these peak loads. During recent years the *annual* load factor for Railbelt electrical demand has typically been about 46-50%. It is expected to remain in the range of 50-52% during the time horizon of this study. The existing and planned future generating capacity in the Railbelt region is capable of operating at a capacity factor either equal to or greater than 50%. Because of this, the decision to add new capacity will usually be based on the need for capacity (kW) rather than energy (kWh). Thus in this analysis capacity additions are scheduled based on peak loads rather than upon average annual energy.

The general approach to load/resource analysis is to summarize existing and planned gross resources for each year, adjust them downward for a reliability margin and for system transmission losses to arrive at net resources. If these net resources exceed the critical period load for the year being analyzed, plant additions are not called up and the analysis proceeds to the next year and is repeated. At some point, the net resources will not meet the forecasted peak loads and additional capacity must be added. Also, for each year, the energy generated by each class of plants (e.g., hydro, steam turgine, combustion turbine, and diesel is computed so that plant utilization factors are available for review and system energy costs can be developed. The stepwise calculations are continued to the end of the period being studies (2010).

3.2 ASSUMPTIONS

3.2.1 Forecasted Power and Energy Requirements

The analyses are based on forecasts prepared by the Alaska Power Administration for both the Anchorage-Cook Inlet and the Fairbanks-Tanana Valley areas. Probable high and low bounds were provided along with median forecasts. These are presented in Tables 3.1 through 3.3 and are shown graphically in Figures 3.1 through 3.3. In addition to utility loads, Anchorage-Cook Inlet forecasts include both national defense and industrial loads and the Fairbanks-Tanana Valley forecasts include national defense loads.

TABLE 3.1. Anchorage-Cook Inlet Area Power and Energy Requirements

PEAK POWER

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY							
High		620	1,000	1,515	2,150	3,180	7,240
Median	424	570	810	1,115	1,500	2,045	3,370
Low		525	650	820	1,040	1,320	1,520
NATIONAL DEFENSE							
High		31	32	34	36	38	48
Median	41	30	30	30	30	30	30
Low		29	28	26	24	24	18
INDUSTRIAL							
High		32	344	399	541	683	1,615
Median	25	32	64	119	199	278	660
Low		27	59	70	87	104	250
TOTAL							
High		683	1,376	1,948	2,727	3,901	8,903
Median	490	632	904	1,264	1,729	2,353	4,060
Low		581	737	916	1,151	1,448	1,788

ANNUAL ENERGY

	GWh 1/	GWh	GWh	GWh	GWh	GWh	GWh
UTILITY							
High		2,720	4,3[illegible]	6[illegible]	9,430	13,920	31,700
Median	1,790	2,500	3,530	4,[illegible]	6,570	8,960	14,750
Low		2,300	2,840	3,5[illegible]	4,56[illegible]	5,770	6,670
NATIONAL DEFENSE							
High		135	142	149	157	165	211
Median	131	131	131	131	131	131	131
Low		127	121	115	105	104	81
INDUSTRIAL							
High		170	1,810	2,100	2,840	3,590	8,490
Median	70	170	34[illegible]	630	1,050	1,460	3,470
Low		141	312	370	460	550	1,310
TOTAL							
High		3,025	6,342	8,879	12,427	17,675	40,401
Median	1,991	2,801	4,001	5,641	7,751	10,551	18,351
Low		2,568	3,273	4,075	5,125	6,424	8,061

1/ MW = Megawatts
GWh = Gigawatt-hours (Equivalent to MMkWh = Millions of kilowatt-hours)

Source: Alaska Power Administration, October 1978

TABLE 3.2. Fairbanks-Tanana Valley Area Power and Energy Requirements

PEAK POWER

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY							
High		158	244	358	495	685	1,443
Median	119	150	211	281	358	452	689
Low		142	180	219	258	297	329
NATIONAL DEFENSE							
High		49	51	54	56	59	76
Median	41	47	47	47	47	47	47
Low		46	44	42	40	38	29
TOTAL							
High		207	295	412	551	744	1,519
Median	160	197	258	328	405	499	736
Low		188	224	261	298	335	358

ANNUAL ENERGY

	GWh 1/	GWh	GWh	GWh	GWh	GWh	GWh
UTILITY							
High		690	1,070	1,570	2,170	3,000	6,320
Median	483	655	925	1,230	1,570	1,980	3,020
Low		620	790	960	1,130	1,300	1,440
NATIONAL DEFENSE							
High		213	224	235	247	260	333
Median	207	207	207	207	207	207	207
Low		203	193	184	175	166	129
TOTAL							
High		903	1,294	1,805	2,417	3,260	6,653
Median	690	862	1,132	1,437	1,777	2,187	3,227
Low		823	983	1,144	1,305	1,466	1,569

1/ MW = Megawatts
GWh = Gigawatt-hours (Equivalent to MMkWh = Millions of kilowatt-hours)

Source: Alaska Power Administration, October 1978

TABLE 3.3. Total Power Requirements; ... rage-Cook Inlet Area and Fairbanks-Tanana Valley ... Combined

PEAK POWER

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
TOTAL							
High		890	1,671	2,360	3,278	4,645	10,422
Median	650	829	1,162	1,592	2,134	2,852	4,796
Low		769	961	1,177	1,449	1,783	2,146

ANNUAL ENERGY

	GWh 1/	GWh	GWh	GWh	GWh	GWh	GWh
TOTAL							
High		3,928	7,636	10,684	14,844	20,935	47,054
Median	2,681	3,663	5,133	7,078	9,528	12,738	21,578
Low		3,391	4,256	5,219	6,430	7,890	9,630

1/ MW = Megawatts
GWh = Gigawatt-hours (Equivalent to MMkWh = Millions of kilowatt-hours)

Source: Alaska Power Administration, Octo...

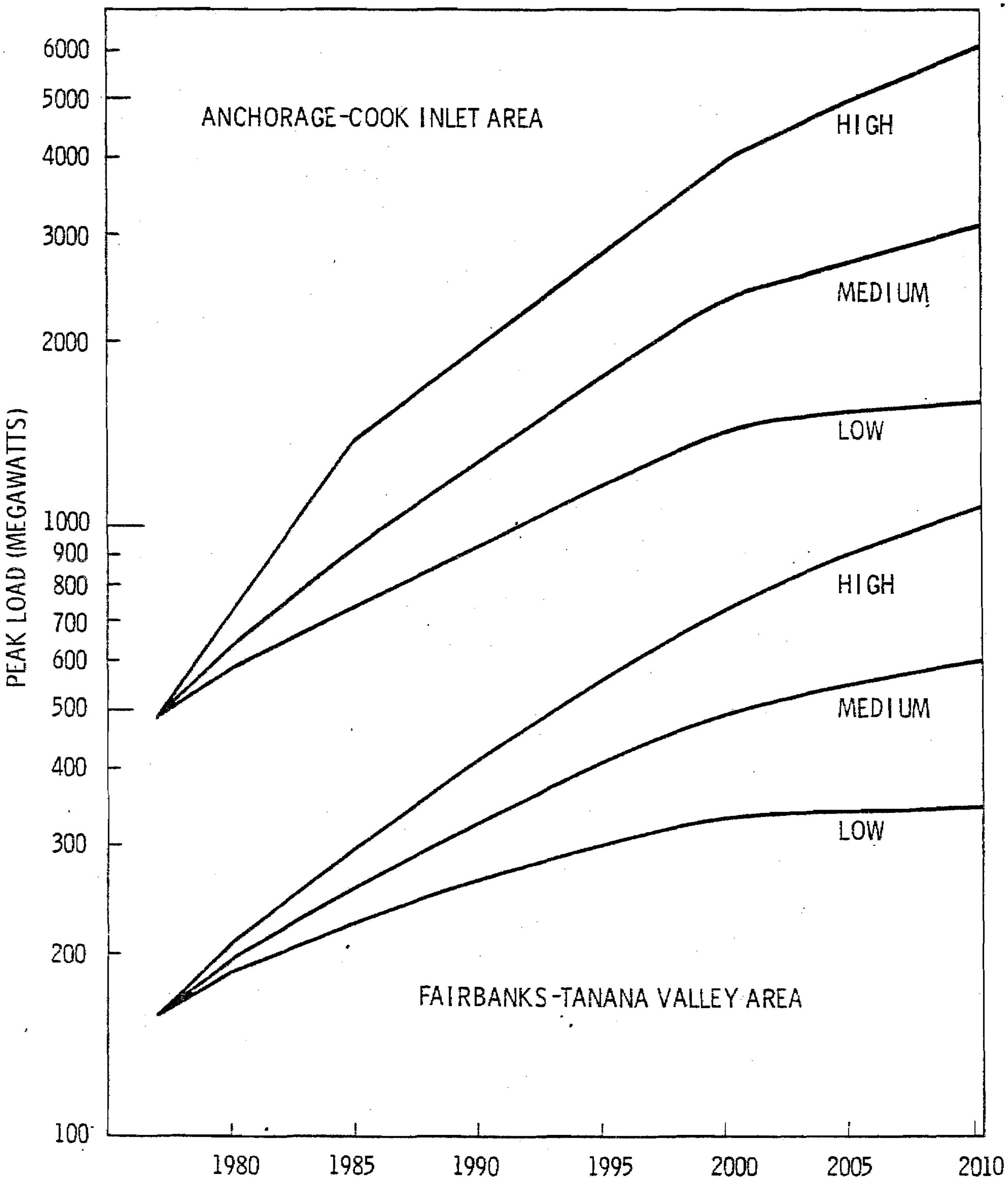

FIGURE 3.1. Railbelt Region Peak Loads

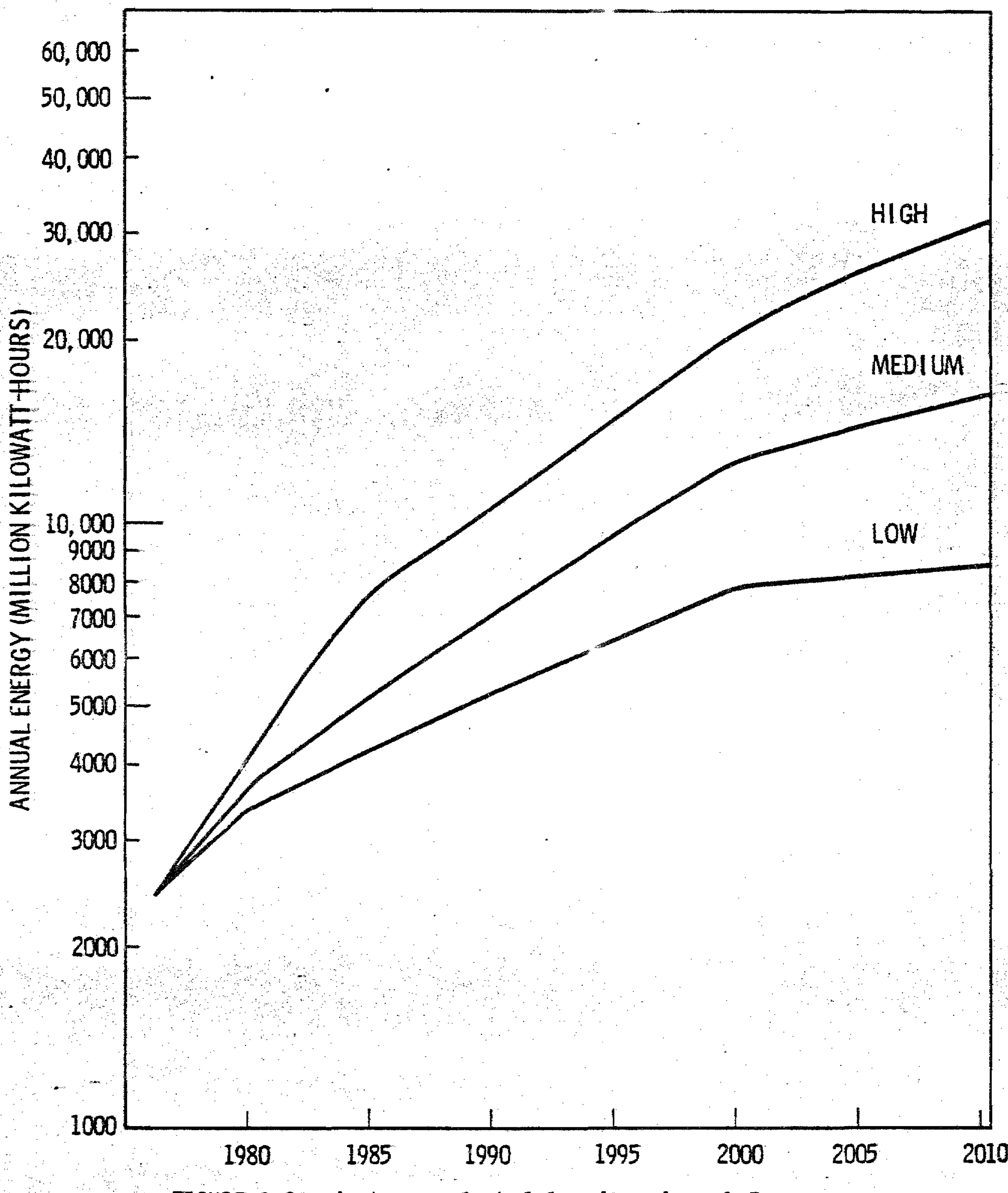

FIGURE 3.2. Anchorage-Cook Inlet Area Annual Energy

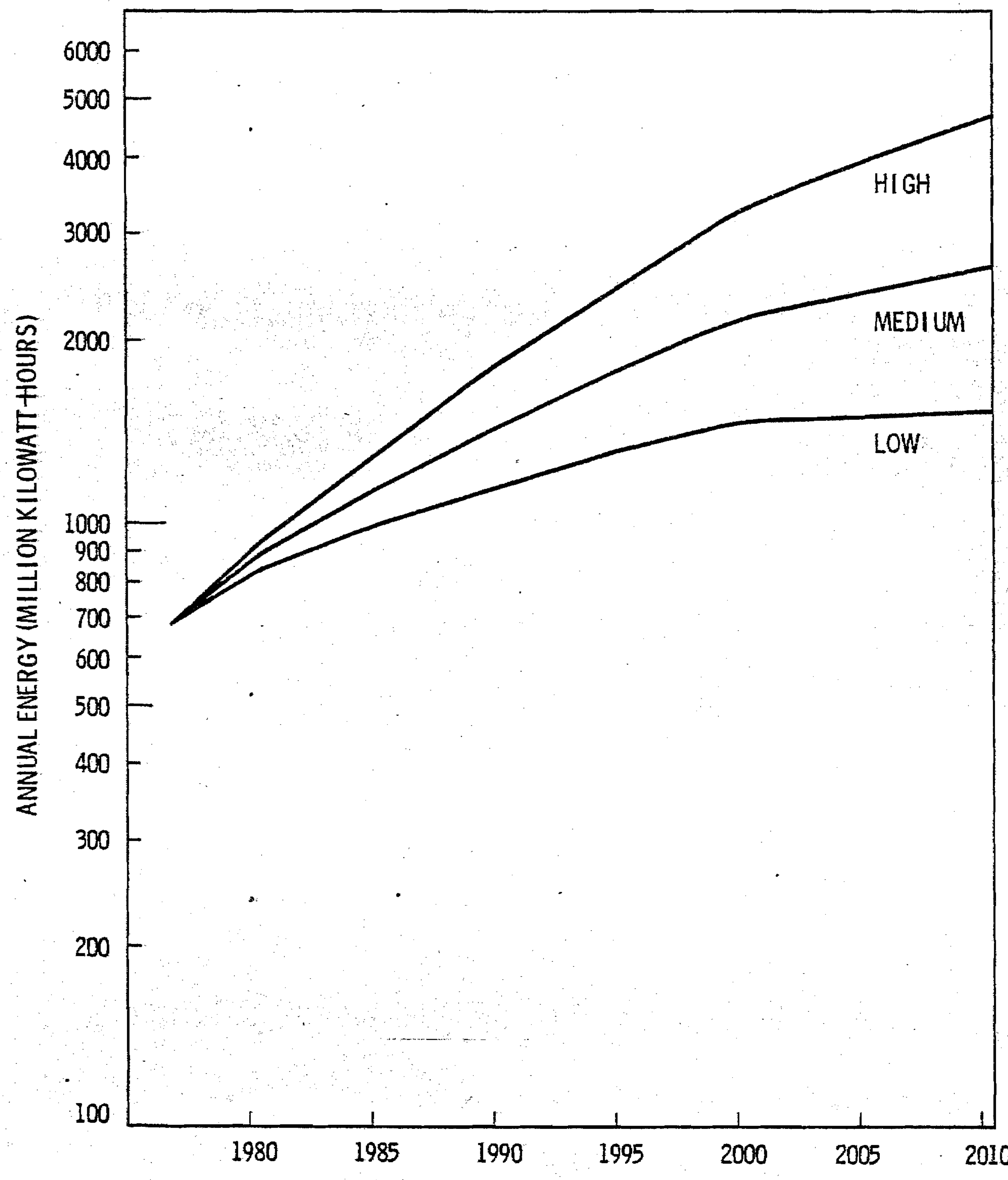

FIGURE 3.3. Fairbanks Area Annual Energy

The Alaska Power Administration data indicate that approximately 80% of the Railbelt region loads are expected to be in the Anchorage-Cook Inlet area. These loads have been interpreted as recognizing distribution losses.

3.2.2 Existing and Planned Generating Capacity

The existing stock of generating capacity for the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area is presented in Tables 3.4 and 3.5, respectively.

The total existing capacities and maximum plant utilization factors for the various generating types for the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area are shown in Tables 3.6 and 3.7, respectively. The load/resource matching analyses use these totals for the first year of the analyses (1978-1979).

Generating capacity additions can be specified to be added in one of two ways. It can either be added in a specified year or can be added when it is required to maintain adequate generating capacity. In the former case the generating units are added whether they are required or not. The planned additions shown in Table 3.8 are brought on line in the years specified. National defense generating units are assumed to be replaced by steam turbine generating units the same year as they are retired. (See Section 3.2.7 for a discussion of the units added as required to maintain adequate generating capacity.)

3.2.3 Reserve Margin

Utility systems invariably carry a reserve margin of generating and transmission capacity as insurance against loss of load, unexpected peak requirements as a result of severe weather, load growths more rapid than anticipated, adverse hydroelectric conditions, and delays in the commercial operation of new generation. The most appropriate reserve margin will vary from system to system depending on the nature of the loads and types of resources and special factors. Typically, a reserve capacity at peak of 20% is used nationally. However, this can vary to as low as 12% as is the present case for the Pacific Northwest with its predominance of reliable hydropower and interruptable loads.

TABLE 3.4. Existing (Fall 1978) Generating Capacities for Anchorage-Cook Inlet Area

Unit Reference/Name	Location	Type of Generation	Capacity (kW)	Retirement Year
ANCHORAGE MUNICIPAL LIGHT AND POWER (AML&P)				
Deisel	Anchorage	Diesel	2,200	1982
Unit 1	Anchorage	S.C.C.T.*	15,130	1982
Unit 2	Anchorage	S.C.C.T.	15,130	1984
Unit 3	Anchorage	S.C.C.T.	18,650	1988
Unit 4	Anchorage	S.C.C.T.	31,700	1992
Unit 5	Anchorage	S.C.C.T.	36,000	1995
Unit 6	Anchorage	C.C.	16,500	1995
		Subtotal	137,500(a)	
CHUGACH ELECTRIC ASSOCIATION (CEA)				
Beluga				
Unit 1	Beluga	S.C.C.T.	33,000	1988
Unit 2	Beluga	S.C.C.T.		
Unit 3	Beluga	R.C.C.T.*	54,600	1993
Unit 4	Beluga	S.C.C.T.	9,300	1996
Unit 5	Beluga	R.C.C.T.	65,000	1995
Unit 6	Beluga	S.C.C.T.	67,810	1996
Unit 7	Beluga	S.C.C.T.	68,000(e)	1996
Unit 8	Beluga	C.C.	32,200	1996
Bernice Lake				
Unit 1	Bernice Lake	S.C.C.T.	8,370	1983
Unit 2	Bernice Lake	S.C.C.T.	17,860	1992
Unit 3	Bernice Lake	S.C.C.T.	18,000	1998
Cooper Lake	Cooper Lake	Hydro	16,500	NA
International				
Unit 1		S.C.C.T.	30,510	1985
Unit 2		S.C.C.T.		
Unit 3		S.C.C.T.	18,140	1991
Knik Arm Combined		S.T.*	10,000(f)	1987
		Subtotal	449,790	
MATANUSKA ELECTRIC ASSOCIATION (MEA)				
Talkeetna	Talkeetna	Diesel	600(b)	1993
HOMER ELECTRIC ASSOCIATION (HEA)				
English Bay	English Bay	Diesel	100	1993
Homer & Kenaie Combined	Homer	Diesel	300(c)	1993
Homer Combined	Homer	S.C.C.T.	7,000(d)	1995
Port Graham Combined	Port Graham	Diesel	200	1993

TABLE 3.4 (contd)

Unit Reference/Name	Location	Type of Generation	Capacity (kW)	Retirement Year
		HOMER ELECTRIC ASSOCIATION (HEA) (contd)		
Seldovia Combined	Seldovia	Diesel	1,500	1980
		Subtotal	9,100	
		SEWARD ELECTRIC SYSTEM (SES)		
Seward Combined	Seward	Diesel	3,000(b)	1985
			2,500	1996
		Subtotal	5,500	
		ALASKA POWER ADMINISTRATION (APA)		
Eklutna	Eklutna	Hydro	30,000	NA
		Subtotal	30,000	
		NATIONAL DEFENSE		
Ft. Richardson/	-	S.T.	40,500	1991
Emendorf	-	Diesel	7,300	1985
	-	Diesel	2,000	1991
		Subtotal	49,800	
		INDUSTRIAL		
Kenai	-	S.C.C.T.	12,300(g)	1988
		TOTAL	685,290	

* S.C.C.T. - Simple Cycle Combustion Turbine
R.C.C.T. - Regenerative Cycle Combustion Turbine
S.T. - Steam Turbine
C.C. - Combined Cycle

(a) Capacities for individual units are from sources 1 and 2. These sum to 118,810 kW. Total shown is from source 2.
(b) Standby
(c) Leased to CEA
(d) Leased to HEA by Golden Valley Electric Assoc[illegible]ion for 1977-1979.
(e) Included in this study, but late 1978 plans are to defer Betuga 8 until 1980 and double the capacity.
(f) Nameplate capacity derated to 10,000 KW from 14,500 KW.
(g) Recent data shows industrial load to be 25,000 KW rather than 12,300 KW.

SOURCES:

1. Electric Power in Alaska, 1976-1995, ISER, University of Alaska, pp. J.5.2-7.4, August 1976.
2. Alaska Electric Power Statistics 1960-1976, Alaska Power Administration, pp. 15-17, July 1977.
3. 1976 Power System Study, Chugach Electric Association, Inc., Tippett and Gee, Dallas, TX, p. 7, March 1976.
4. Alaska Power Administration, August 1978.

TABLE 3.5. Existing (Fall 1978) Generating Capacities for Fairbanks-Tanana Valley Area

Unit Reference Name	Location	Type Generation	Capacity (kW)	Year of Retirement
FAIRBANKS MUNICIPAL UTILITIES SYSTEM (FMUS)				
Chena 2	Fairbanks	S.T.	2,000	1988
Chena 3	Fairbanks	S.T.	1,500	1988
Chena 1	Fairbanks	S.T.	5,000	1988
Chena 4	Fairbanks	S.C.C.T.	5,350	1983
Diesel 1	Fairbanks	Diesel	2,664	1988
Diesel 2	Fairbanks	Diesel	2,665	1988
Diesel 3	Fairbanks	Diesel	2,665	1988
Chena 5	Fairbanks	S.T.	20,000	2005
Chena 6	Fairbanks	S.C.C.T.	23,500	1996
		Subtotal	65,345	
GOLDEN VALLEY ELECTRIC ASSOCIATION (GVEA)				
-	Fairbanks	Diesel	24,000	1984
Healy #1	Healy	S.T.	25,000	2002
-	Fairbanks	S.C.C.T.	40,000	1992
-	Delta	Diesel	500	1988
North Pole #1	North Pole	S.C.C.T.	70,000	1997
North Pole #2	North Pole	S.C.C.T.	70,000	1997
		Subtotal	229,500	
NATIONAL DEFENSE				
Combined Clear A.F.B. and Ft. Greely	-	Diesel	14,000	1988
	-	S.T.	24,500	1995
Ft. Wainwright and Eilson A.F.B.	-	S.T.	32,000 (a)	1990
		Subtotal	70,500	

(a) 5 MW plant at Eilson A.F.B. installed in 1970 and old 1.5 MW plant at Ft. Wainwright were inadvertantly omitted.

SOURCE:
1. Interior Alaska Energy Analysis Team, Final Report, June 1977.
2. Alaska Power Administration, August 1978.

TABLE 3.6. Anchorage-Cook Inlet Area Existing Capacity and Maximum Annual Plant Utilization (October 1978)

	Capacity (MW)	Plant Utilization (%)
Hydro	46.5	50.0
Steam Electric	50.5	75.0
Combustion Turbine	575.01	50.0
Diesel	19.13	15.0

TABLE 3.7. Fairbanks-Tanana Valley Area Existing Capacity and Maximum Annual Plant Utilization (October 1978)

	Capacity (MW)	Plant Utilization (%)
Hydro	0	50.0
Steam Electric	110	75.0
Combustion Turbine	208.9	50.0
Diesel	46	10.0

TABLE 3.8. Planned Additions for Railbelt Region (1979-1995)

Unit Reference/ Name	Year of Installation	Location	Type of Generation	Capacity (kW)
		ANCHORAGE MUNICIPAL LIGHT AND POWER (AML&P)		
Unit 7	1979	Anchorage	S.C.C.T.	65,000[a]
Unit 6	1979	Anchorage	C.C.	16,500[b]
		CHUGACH ELECTRIC ASSOCIATION (CEA)		
Beluga #9	1979	Beluga	C.C.	32,200[c]
X-1	1980		S.C.C.T.	100,000
Bernice Lake #4	1981	Bernice Lake	S.C.C.T.	18,000
X-2	1982		S.C.C.T.	100,000
Bernice Lake #5	1984	Bernice Lake	S.C.C.T.	18,000
		GOLDEN VALLEY ELECTRIC ASSOCIATION (GVEA)		
Healy #2	As Required	Healy	S.T.	100,000
		ALASKA POWER ADMINISTRATION (APA)		
Bradley Lake	1985	Bradley Lake	Hydro	70,000
		NATIONAL DEFENSE		
-	1985	Ft. Richardson and Emendorf A.F.G.	S.T.	7,300
-	1988	Fairbanks Combined	S.T.	14,000
-	1990	Ft. Greely and Clear A.F.B.	S.T.	32,000
-	1991	Ft. Richardson and Emendorf A.F.B.	S.T.	42,500
-	1995	Ft. Greely and Clean A.F.B.	S.T.	24,500

(a) Unit #7 is a simple cycle combustion turbine unit which also supplies exhaust heat to Unit #6.
(b) This increase reflects the increase in capacity resulting from the addition of Unit #7.
(c) Beluga #9 is a steam unit addition to Beluga #7 (converts these to a 100 MW combined cycle unit).

SOURCES:

1. 1976 Power System Study, Chugach Electric Association, Inc., Tippett and Gee, Dallas, TX, pp. 7 and 25, March 1976.
2. Electric Power in Alaska, 1976-1995, ISER, University of Alaska, pp. J.5.2-7.4, August 1976.
3. Alaska Power Administration, August 1978.

Since a reserve margin effectively increases the amount of generating capacity in place at any given time, it does contribute costs to the system. Therefore, an excessive reserve margin is to be avoided while at the same time recognizing that an inadequate reserve margin could, on outage, result in a wide variety of social costs.

For the purposes of this study, the Alaska Power Administration has suggested that the analysis be based on reserve margins of 25% and 20% for non-interconnected load centers and the interconnected systems, respectively. In the future, a more refined analysis of the desired reserve margin appears warranted.

3.2.4 Transmission Losses

Transmission losses must be added to forecasts of peak and energy loads to establish net capacity and energy at the plant substations. The Alaska Power Administration expects losses as follows:

	%
Capacity	5
Energy	1.5

The results of the load/resource analysis are thus in *net* deliverable capacity and energy and do not include energy and capacity required for internal plant operations.

The above losses are reasonably applicable for the independent operation of the load centers, for interconnected systems including the Upper Susitna project and for configurations with future generation capacity additions being distributed proportionally near the load centers. In the case of interconnection without Upper Susitna and with a tendency to centralize Railbelt thermal generation, the transmission losses may be considerably higher as discussed later in Section 3.2.8.

3.2.5 Construction Schedule Constraints

Due to the lead times necessary for the permit processes and construction, generating unit and site selection must take place a number of years in advance of the forecasted date when the units commercial operation will be required. For coal-fired thermal plants, the Pacific Northwest Utilities Conference Committee estimates a 62 month (5.2 years) period from final site selection to commercial operation for plants in the 500 MW and higher range based on recent U.S. experience.

Although individual thermal plant capacities appropriate to Alaska's loads are somewhat smaller and may require less field erection work, the construction season is shorter and the 5 to 6 year scheduling period appears reasonable.

For the potential Upper Susitna hydroelectric projects, the scale of effort is more demanding and increased site evaluation is necessary. Current understanding is that the Watana Dam and power plant could be brought to commercial operation by 1994, followed by Devil Canyon no sooner than 1998.

A transmission interconnection between Anchorage-Cook Inlet and Fairbanks-Tanana Valley could be brought into service prior to completion of Watana, possibly as early as 1986.

The load/resource analysis technology recognizes the above schedule constraints by not allowing callup of new generation or transmission capacity that could not be made available.

3.2.6 Plant Availability Constraints

Generating and transmission plant availability can be expressed in terms of maximum and minimum plant utilization factors (PUF). These factors are primarily dependent upon plant type and plant age. For purposes of this analysis we have assumed the following economic facility lifetimes after which the facility is retired from service.(1)

	Years
Coal-Fired Thermal Generation	35
Oil-Fired Steam Generation	35
Gas-Fired Combustion Turbine	20
Oil-Fired Combustion Turbine	20
Hydroelectric Generation	50

(1) See Tables 3.4 and 3.5 for dates of expected retirements for existing systems.

Due to the nature of the system, some plants could be retired from service prior to the expiration of their economic life. In actual practice, however, it is expected that utilities may elect to retain the units on standby. In order to assure their availability in emergencies, the utilities will periodically operate the units to make sure they are in working condition.

Experience has shown that large thermal plants experience a learning curve during the first few years of operation as "bugs" are worked out. Once past this period they reach a maximum that allows for scheduled maintenance and replacement conducted during the off-peak season. Toward the end of the economic life, increased frequency and duration of outages for maintenance usually occur and the maximum plant utilization factor declines. For purposes of this analysis, we have assumed constraints on the maximum PUF for new coal-fired steam electric plants as shown in Figure 3.4.

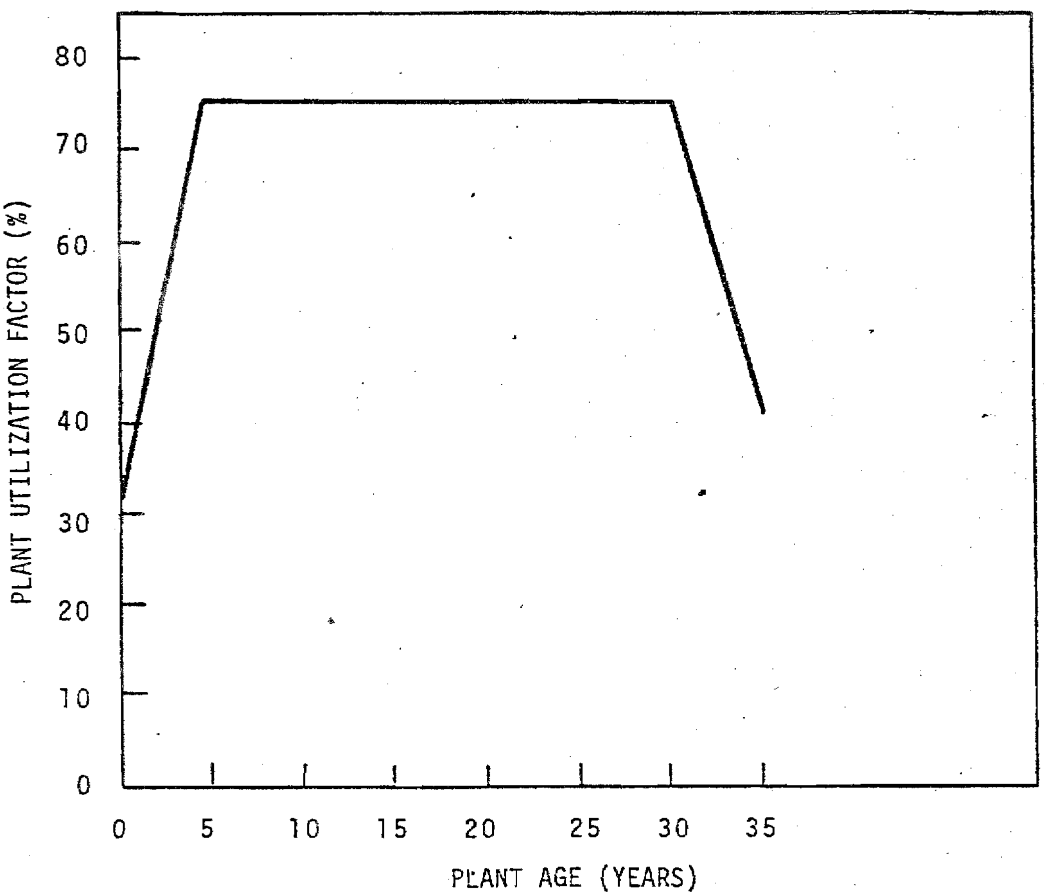

FIGURE 3.4. Plant Utilization Factor versus Plant Age

Other types of generating capacity are allowed to run at their maximum PUF from the start. For new capacity and most types of existing capacity, the following maximum PUFs are assumed:

	Maximum Plant Utilization (%)
Hydro	50.0
Steam Electric	75.0
Combustion Turbine	50.0
Diesel	10.0

Hydroelectric generation systems, as a result of their storage ability and conservative ratings, can make additional power available for peaking and it is assumed they can be scheduled at 115% of design capacity for this service.

As pointed out earlier in Section 3.1, the peak demand during the winter usually determines the amount of generating capacity required rather than the annual energy. Because of this, some generating units are utilized at less than their maximum annual plant utilization factors. The decision as to which units should not be loaded is usually based on the margin cost of operating the facilities. In this analysis it is assumed that diesel capacity has the highest margin operating cost followed by combustion turbines, steam turbines and hydroelectric capacity in that order. It is assumed that diesel PUFs can be reduced to 0.0 while the PUFs for combustion turbine and steam electric capacity is not allowed to go below 10%.

Transmission plant availability is generally not as schedule constrained as are generating plants with their long lead times. For purposes of these analyses, the interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area will be provided 3 years before the completion of the Watana dam or when the Healy 1 (existing 25 MW) and Healy 2 (planned 100 MW net) plants become fully loaded, whichever occurs first.(2) This assumption in effect places oil-fired plants serving the area on standby after that date.

(2) It will probably be desirable to provide at least a portion of the interconnection prior to Watana date on-line as a source of power for construction.

3.2.7 Economic Generating Unit Size

The selection of optimum generating size can be a complex process involving uncertain assumptions regarding probability of future load growth paths, desirability of sizing individual units in comparable sizes and types for each of maintenance, assuring that system reliability is not penalized by addition of too large a single unit, smoothing of construction schedules for possible multiunit plants, and maintaining as small as possible departure from the desired reliability margin. A full optimization does not appear warranted at this stage and is beyond the scope of this analysis.

Thus for the purposes of this study, the first six coal-fired steam electric plants in the Fairbanks anana Valley area are assumed to be 100 MW units. Any additional units are assumed to be 200 MW units. In the Anchorage-Cook Inlet area the first five coal-fired steam electric plants are assumed to be 200 MW units, while any additional plants are assumed to be 400 MW units. These size ranges, though probably not exact optimums, appear reasonable block sizes for introduction and typically become fully loaded at about 10% of plant life.

3.3 SYSTEM CONFIGURATIONS: DEFINITION OF CASES ANALYZED

3.3.1 Case 1 Without Interconnection and Without Upper Susitna Project

The base case consists of power supply to the Anchorage-Cook Inlet and Fairbanks-Tanana Valley on a noninterconnected basis. In this instance, no power is available from the Upper Susitna project.

Future capacity additions for the Anchorage-Cook Inlet load center are assumed to be near-mine-mouth coal-fired units located on the west side of Cook Inlet with a nominal 50-mile transmission distance using two 345 kV circuits with a capacity of 1600 MW. Capital cost of this transmission system is $228 million in October 1978 prices.

Further capacity additions for the Fairbanks-Tanana Valley load center are assumed to be coal-fired units with a nominal 100-mile transmission distance. The Healy site is used as a proxy recognizing, however, that the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act may preclude the siting of additional plants beyond the planned Healy 2 100 MW unit. A 230 kV single circuit will transmit up to 400 MW and a 230 kV double circuit, 800 MW. Capital costs are $44 million and $70 million, respectively. Table 3.9 provides a summary of the transmission system alternatives. A map of the Railbelt region showing the Watana and Devil Canyon dam sites, a possible route for the interconnection, and the Beluga area is presented in Figure 3.5.

3.3.2 Case 2: With Interconnection, Without Upper Susitna Project

In the case of an interconnected system *without* the Upper Susitna project and all new capacity coal fired, the load/resource analysis is not as straightforward in that it is not readily apparent what strategy for siting plants should be followed. Two primary options are apparent:

1. All coal plants sited at a single location(1) (Concentrated Siting).

   Advantages

   a) Lower capital and operating costs for generation.
   b) Economies of scale can be achieved.
   c) Siting problems in the interior may be avoided.

   Disadvantages

   a) Higher transmission losses (and costs) are incurred for the fraction of power flowing to the Fairbanks-Tanana Valley load center. These costs may cancel out savings from the advantages.

   b) The latter area becomes strongly dependent upon reliability of the transmission system--possibly to the point of requiring a second circuit or maintenance of additional standby combustion turbine capacity.

   c) Any adverse environmental effects are borne by a single area not necessarily benefiting in proportion.

2. Coal Plants Sited in Proportion to Relative Load Growth (Distributed Siting).

(1) For the purposes of this analysis, mine-mouth location at Beluga is used as a proxy.

TABLE 3.9. Transmission System Alternatives[1]

Location	Circuit	Capacity MW	Capacity Loss %	Approx. Investment Cost - $MM	$/kW
Isolated Load Centers					
Healy - Fairbanks 100 miles	230 kV Single	400	6	44	110
	230 kV Double	800	6	70	88
Beluga - Anchorage 100 miles	345 kV Single	400	2	114	285
		800	3	114	142
	Two 345 kV Single	800	2	228	285
		1600	3	228	142
Interconnected Without Susitna					
Anchorage - Healy 200 miles	230 kV Single	200	6	88	293
		300	8	88	225
	345 kV Single	400	3	228	570
		560	5	228	407
Interconnection With Susitna		1573[2]	5	471	(299)

(1) Source: Alaska Power Administration
(2) Actual peak power availability could be about 15% higher or 1808 MW.

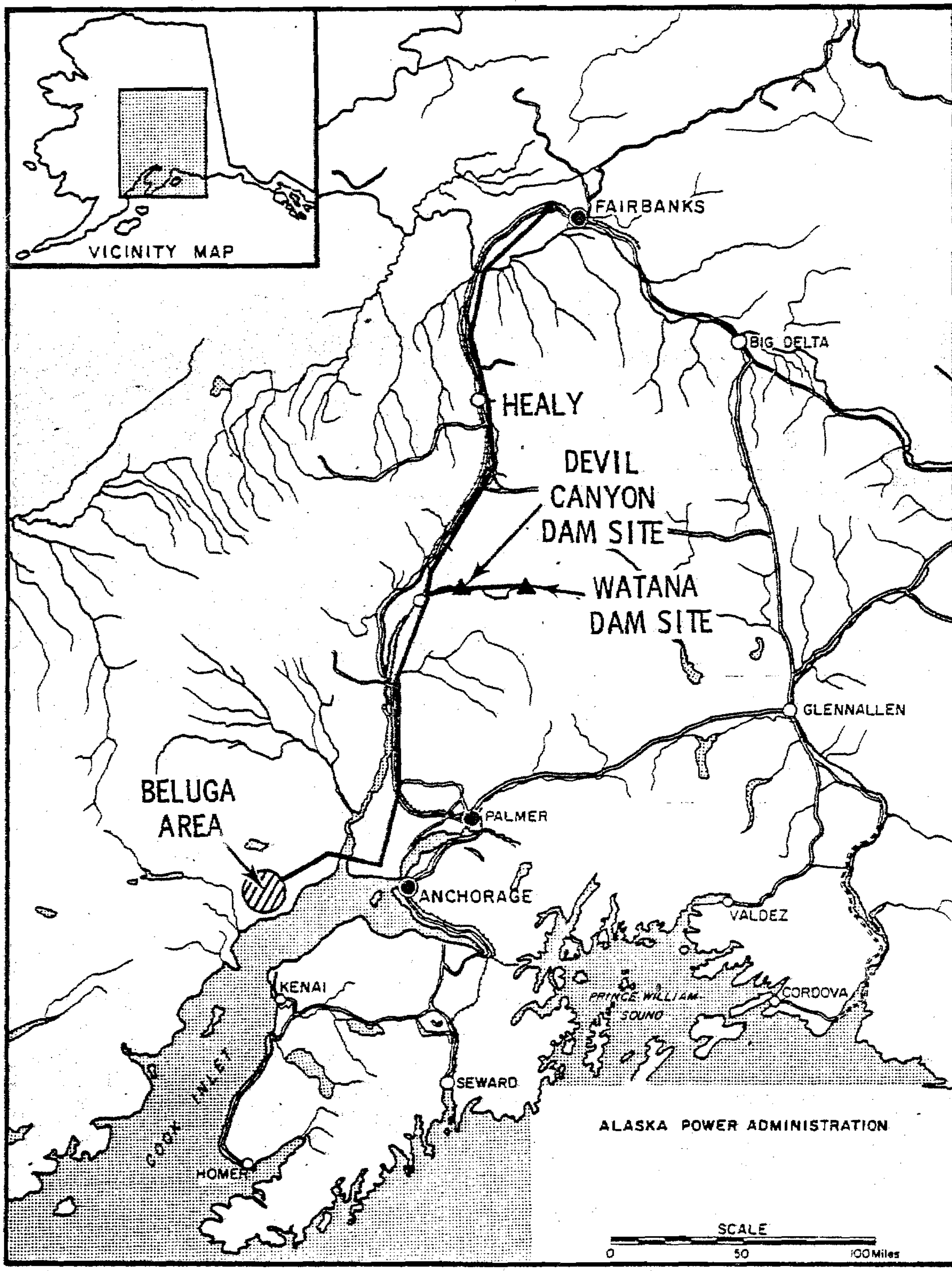

FIGURE 3.5. Railbelt Region Showing the Watana and Devil Canyon Damsites, a Possible Route for the Interconnection, and the Beluga Area

Advantages

a) The interconnection becomes lightly loaded, thus reducing transmission losses to some degree although charging losses would continue.

b) Transmission interconnection reliability dependence is reduced as the intertie assumes more of a capacity reserve characteristic.

c) Environmental burdens are distributed, possibly with more equity.

Disadvantages

a) Possible economies of scale are lost.

b) Generation costs in the Fairbanks-Tanana Valley are increased.

c) Siting problems related to meteorological considerations may result in the latter area.

In this report coal plants are assumed to be sited in proportion to the relative load growths of the two load centers. As with Case 1, additional coal-fired generating units are sited at Beluga to serve the Anchorage-Cook Inlet area and at Healy/Nenana to serve the Fairbanks-Tanana Valley areas.

The transmission interconnection is used for capacity reserve allowing the reserve margin for both load centers to be reduced from 25% to 20% (see Section 3.2.3 Under this scenario there is no net energy transfer during any single year. If one load center is low on capacity the other load center provides the additional capacity required assuming it has a surplus. If no surplus exists the original load center must add capacity.

The interconnection is assumed to be brought on line in the same year as the Healy 2 coal plant becomes fully loaded and new generating capacity would be required in the Fairbanks-Tanana Valley area. Addition of the interconnection allows the Fairbanks-Tanana Valley area to get capacity reserve from the Anchorage-Cook Inlet Area. This allows the Fairbanks area to postpone the construction of additional capacity by 2 to 6 years depending upon the scenario.

In the high load growth case the interconnection would be completed in 1986, in the medium load growth case it would come on line in 1989, and in the low load growth case it would come on line in 1994. In all cases 45% of the cost of the interconnection is assigned to the Fairbanks-Tanana Valley load center.

3.3.3 Case 3: Interconnected System With Upper Susitna Project

In addition to the interconnection described in the previous section, Case 3 includes two hydroelectric generating facilities. The Watana dam is scheduled to come on line in 1994. The date is assumed to be the same for all three load growth scenarios. The Devil Canyon dam is assumed to come on line as soon as required following 1994 but not before 1998. It is assumed it would take at least 4 years to complete the Devil Canyon dam following completion of the Watana dam. It turns out that the Devil Canyon dam is required in 1998 in the medium of high load growth scenarios but not until 1999 in the low load growth scenario.

Because of reservoir filling requirements it is assumed that both dams will take 2 years to reach full capacity and power output. The capacities, power production and plant utilization factors for the two dams are show below.

Year	Capacity (MW)	Energy (MMkWh)	Utilization (%)
Watana			
1	703	3080	50.0
2+	795	3480	50.0
Devil Canyon			
1	689	3020	50.0
2+	778	3410	50.0

For the medium and high load growth the transmission interconnection is assumed to come on line in 1989 and 1986 respectively; the same years as for Case 2. In the low load growth scenario the interconnection comes on line in 1991 rather than 1994. This earlier completion date will allow the Watana dam construction site to be supplied with power from either the Anchorage-Cook Inlet area or the Fairbanks-Tanana Valley area.

The power output of the two dams is divided between the two load centers in proportion to their relative energy consumption in 1994. This results in the percentage divisions shown below.

Load Growth Scenario	Anchorage-Cook Inlet	Fairbanks-Tanana Valley
Low	80%	20%
Medium	81%	19%
High	84%	16%

3.4 RESULTS OF LOAD/RESOURCE ANALYSES

Using the methodology outlined in Section 3.1 and the assumptions explained in Section 3.2, a series of load/resource analyses were performed. As pointed out earlier, three basic cases were evaluated:

Case 1 All additional generating capacity beyond utility plans assumed to be coal-fired steam turbines without a transmission interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area load centers.

Case 2 All additional generating capacity beyond utility plans assumed to be coal-fired steam turbines including a transmission interconnection.

Case 3 All additional generating capacity beyond utility plans assumed to be coal-fired steam turbines but including the Upper Susitna project (including a transmission intertie) coming on line in 1994.

For each of these three cases. Three load growth scenarios (low, medium and high) are evaluated resulting in a total of nine load/resource analyses.

The assumptions discussed in this chapter are incorporated in a computer model called AEPMOD. The output of AEPMOD for Case 3 assuming the medium load growth scenario is presented in Table 3.10. The results of all nine cases are presented in Appendix C. The AEPMOD computer code is presented in Appendix B and the data base necessary to make the runs is presented in Appendix A.

The capacity additions called up in the various cases are presented in Tables 3.11, 3.12 and 3.13.

The results of the runs are summarized in Figures 3.6 through 3.11.

TABLE 3.10. Load/Resource Balance for Case 3: Medium Load Growth Scenario

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1978-1979				1979-1980				1980-1981			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	585.			2531.	632.			2801.	686.			3041.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	53.	.50	.50	204.
STEAM/ELEC	51.	.75	.75	332.	51.	.75	.75	332.	51.	.75	.75	332.
COMB.TURBINE	575.	.50	.40	2034.	575.	.50	.36	1810.	689.	.50	.35	2113.
DIESEL	19.	.15	.00	0.	19.	.15	.00	0.	19.	.15	.00	0.
TOTAL	698.			2569.	698.			2346.	812.			2649.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	114.	.50	.50	497.	100.	.50	.50	438.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	2.	.00	.00	0.
GROSS RESOURCES	698.			2569.	812.			2843.	910.			3087.
CAP RES. MARGIN	0.193				0.284				0.326			
RESERVE REQ.	146.				158.				172.			
LOSSES	29.			38.	32.			42.	34.			46.
NET RESOURCES	523.			2531.	622.			2801.	704.			3041.
TRANSFERED	0.				0.				0.			
SURPLUS	-62.			0.	-10.			0.	18.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES: DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1978-1979				1979-1980				1980-1981			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	184.			804.	197.			862.	209.			916.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.66	633.	110.	.75	.72	692.	110.	.75	.75	723.
COMB.TURBINE	209.	.50	.10	183.	209.	.50	.10	183.	209.	.50	.11	207.
DIESEL	46.	.10	.00	0.	46.	.10	.00	0.	46.	.10	.00	0.
TOTAL	365.			816.	365.			875.	365.			930.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	365.			816.	365.			875.	365.			930.
CAP RES. MARGIN	0.983				0.852				0.746			
RESERVE REQ.	46.				49.				52.			
LOSSES	9.			12.	10.			13.	10.			14.
NET RESOURCES	310.			804.	306.			862.	302.			916.
TRANSFERED	0.				0.				0.			
SURPLUS	126.			0.	109.			0.	93.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1981-1982 PEAK	MPUF	APUF	ENERGY	1982-1983 PEAK	MPUF	APUF	ENERGY	1983-1984 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	741.			3281.	795.			3521.	850.			3761.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	53.	.50	.50	204.
STEAM/ELEC	51.	.75	.75	332.	51.	.75	.75	332.	251.	.75	.42	923.
COMB.TURBINE	789.	.50	.39	2716.	807.	.50	.32	2250.	891.	.50	.35	2691.
DIESEL	17.	.15	.00	0.	17.	.15	.00	0.	15.	.15	.00	0.
TOTAL	910.			3251.	928.			2785.	1210.			3817.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	200.	.75	.20	350.	-	-	-	-
COMB.TURBINE	18.	.50	.50	79.	100.	.50	.50	438.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	15.	.00	.00	0.	8.	.00	.00	0.
DIESEL	-	-	-	-	2.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	928.			3330.	1210.			3574.	1202.			3817.
CAP RES. MARGIN	0.252				0.523				0.414			
RESERVE REQ.	185.				199.				213.			
LOSSES	37.			49.	40.			53.	43.			56.
NET RESOURCES	706.			3281.	972.			3521.	947.			3761.
TRANSFERED	-0.				0.				0.			
SURPLUS	-35.			0.	177.			0.	97.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1981-1982				1982-1983				1983-1984			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	221.			970.	233.			1024.	245.			1078.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.75	723.	110.	.75	.75	723.	110.	.75	.75	723.
COMB.TURBINE	209.	.50	.14	262.	209.	.50	.17	317.	209.	.50	.21	371.
DIESEL	46.	.10	.00	0.	46.	.10	.00	0.	46.	.10	.00	0.
TOTAL	365.			985.	365.			1039.	365.			1094.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	5.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	365.			985.	365.			1039.	360.			1094.
CAP RES. MARGIN	0.651				0.566				0.467			
RESERVE REQ.	55.				58.				61.			
LOSSES	11.			15.	12.			15.	12.			16.
NET RESOURCES	299.			970.	295.			1024.	286.			1078.
TRANSFERED	0.				0.				0.			
SURPLUS	73.			0.	62.			0.	41.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

	CRITICAL PERIOD											
	1984-1985				1985-1986				1986-1987			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	904.			4001.	976.			4329.	1048.			4657.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	134.	.50	.50	510.
STEAM/ELEC	251.	.75	.53	1164.	251.	.75	.64	1405.	458.	.75	.56	2259.
COMB.TURBINE	883.	.50	.34	2615.	886.	.50	.28	2116.	855.	.50	.26	1958.
DIESEL	15.	.15	.00	0.	15.	.15	.00	0.	5.	.15	.00	0.
TOTAL	1202.			3982.	1205.			3724.	1452.			4727.
ADDITIONS												
HYDRO	-	-	-	-	81.	.50	.50	307.	-	-	-	-
STEAM/ELEC	-	-	-	-	207.	.75	.20	363.	-	-	-	-
COMB.TURBINE	18.	.50	.50	79.	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	15.	.00	.00	0.	31.	.00	.00	0.	-	-	-	-
DIESEL	-	-	-	-	10.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	1205.			4061.	1452.			4394.	1452.			4727.
CAP RES. MARGIN	0.333				0.488				0.385			
RESERVE REQ.	226.				244.				262.			
LOSSES	45.			60.	49.			65.	52.			70.
NET RESOURCES	934.			4001.	1159.			4329.	1138.			4657.
TRANSFERED	0.				0.				0.			
SURPLUS	30.			0.	183.			0.	90.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS).

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1984-1985 PEAK	MPUF	APUF	ENERGY	1985-1986 PEAK	MPUF	APUF	ENERGY	1986-1987 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	258.			1132.	272.			1193.	286.			1254.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.75	723.	110.	.75	.75	723.	210.	.75	.55	1018.
COMB.TURBINE	204.	.50	.24	426.	204.	.50	.18	313.	204.	.50	.14	254.
DIESEL	46.	.10	.00	0.	22.	.10	.00	0.	22.	.10	.00	0.
TOTAL	360.			1149.	336.			1036.	436.			1273.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	100.	.75	.20	175.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	24.	.00	.00	0.	-	-	-	-	-	-	-	-
GROSS RESOURCES	336.			1149.	436.			1211.	436.			1273.
CAP RES. MARGIN	0.300				0.601				0.523			
RESERVE REQ.	65.				68.				72.			
LOSSES	13.			17.	14.			18.	14.			19.
NET RESOURCES	258.			1132.	354.			1193.	350.			1254.
TRANSFERED	0.				0.				0.			
SURPLUS	0.			0.	82.			0.	64.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1987-1988				1988-1989				1989-1990			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1120.			4985.	1192.			5313.	1264.			5641.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	134.	.50	.50	510.
STEAM/ELEC	458.	.75	.63	2413.	643.	.75	.58	3254.	643.	.75	.66	3745.
COMB.TURBINE	855.	.50	.24	1786.	855.	.50	.23	1628.	791.	.50	.21	1471.
DIESEL	5.	.15	.00	0.	5.	.15	.00	0.	5.	.15	.00	0.
TOTAL	1452.			4709.	1637.			5393.	1573.			5726.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	200.	.75	.20	350.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	15.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	64.	.00	.00	0.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	1637.			5060.	1573.			5393.	1573.			5726.
CAP RES. MARGIN	0.462				0.320				0.245			
RESERVE REQ.	280.				298.				253.			
LOSSES	56.			75.	60.			80.	63.			85.
NET RESOURCES	1301.			4985.	1216.			5313.	1257.			5641.
TRANSFERED	0.				0.				7.			
SURPLUS	181.			0.	24.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1967-1988 PEAK	MPUF	APUF	ENERGY	1988-1989 PEAK	MPUF	APUF	ENERGY	1989-1990 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	300.			1315.	314.			1376.	328.			1437.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	210.	.75	.62	1139.	210.	.75	.68	1194.	216.	.75	.68	1280.
COMB.TURBINE	204.	.50	.11	196.	204.	.50	.10	178.	204.	.50	.10	178.
DIESEL	22.	.10	.00	0.	22.	.10	.00	0.	0.	.10	.00	0.
TOTAL	436.			1335.	436.			1372.	419.			1459.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	14.	.75	.20	25.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	9.	.00	.00	0.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	22.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	436.			1335.	419.			1397.	419.			1459.
CAP RES. MARGIN	0.452				0.334				0.277			
RESERVE REQ.	75.				79.				66.			
LOSSES	15.			20.	16.			21.	16.			22.
NET RESOURCES	46.			1315.	325.			1376.	337.			1437.
TRANSFERED	[illegible]				0.				-7.			
SURPLUS	46.			0.	11.			0.	2.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1990-1991				1991-1992				1992-1993			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1357.			6063.	1450.			6485.	1543.			6907.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	134.	.50	.50	510.
STEAM/ELEC	643.	.75	.71	3986.	843.	.75	.65	4552.	1045.	.75	.56	5166.
COMB.TURBINE	791.	.50	.19	1308.	791.	.50	.16	1095.	773.	.50	.10	634.
DIESEL	5.	.15	.00	0.	5.	.15	.00	0.	3.	.15	.00	0.
TOTAL	1573.			5804.	1773.			6157.	1955.			6310.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	200.	.75	.20	350.	243.	.75	.20	425.	400.	.75	.20	701.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	41.	.00	.00	0.	-	-	-	-
COMB.TURBINE	-	-	-	-	18.	.00	.00	0.	50.	.00	.00	0.
DIESEL	-	-	-	-	2.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	1773.			6154.	1955.			6582.	2306.			7011.
CAP. RES. MARGIN	0.307				0.349				0.494			
RESERVE REQ.	271.				290.				309.			
LOSSES	68.			91.	73.			97.	77.			104.
NET RESOURCES	1434.			6063.	1593.			6485.	1920.			6907.
TRANSFERED	0.				-29.				-89.			
SURPLUS	77.			0.	114.			0.	289.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1990-1991				1991-1992				1992-1993			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	343.			1505.	358.			1573.	374.			1641.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	216.	.75	.73	1172.	216.	.75	.68	1283.	216.	.75	.71	1339.
COMB.TURBINE	204.	.50	.17	300.	204.	.50	.18	313.	204.	.50	.23	327.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	419.			1472.	419.			1597.	419.			1666.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	32.	.75	.20	56.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	32.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	40.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	419.			1528.	419.			1597.	374.			1666.
CAP RES. MARGIN	0.222				0.170				0.013			
RESERVE REQ.	69.				72.				75.			
LOSSES	17.			23.	18.			24.	19.			25.
NET RESOURCES	333.			1505.	330.			1573.	286.			1641.
TRANSFERED	0.				29.				89.			
SURPLUS	-10.			0.	0.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1993-1994				1994-1995				1995-1996			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1636.			7329.	1729.			7751.	1654.			8311.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	792.	.50	.50	3015.
STEAM/ELEC	1445.	.75	.50	6343.	1445.	.75	.34	4266.	1445.	.75	.36	4614.
COMB.TURBINE	724.	.50	.10	586.	669.	.50	.10	586.	669.	.50	.10	477.
DIESEL	3.	.15	.00	0.	3.	.15	.00	0.	3.	.15	.00	0.
TOTAL	2306.			7439.	2251.			5362.	2909.			8106.
ADDITIONS												
HYDRO	-	-	-	-	656.	.50	.50	2505.	86.	.50	.50	329.
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	55.	.00	.00	0.	-	-	-	-	125.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	2251.			7439.	2909.			7867.	2871.			8436.
CAP RES. MARGIN	0.376				0.682				0.548			
RESERVE REQ.	327.				346.				371.			
LOSSES	82.			110.	86.			116.	93.			125.
NET RESOURCES	1842.			7329.	2476.			7751.	2407.			8311.
TRANSFERED	-107.				0.				0.			
SURPLUS	99.			0.	747.			0.	553.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1993-1994 PEAK	1993-1994 MPUF	1993-1994 APUF	1993-1994 ENERGY	1994-1995 PEAK	1994-1995 MPUF	1994-1995 APUF	1994-1995 ENERGY	1995-1996 PEAK	1995-1996 MPUF	1995-1996 APUF	1995-1996 ENERGY
REQUIREMENTS	389.			1709.	405.			1777.	423.			1859.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	151.	.50	.50	574.
STEAM/ELEC	216.	.75	.73	1377.	216.	.75	.58	1086.	216.	.75	.63	1053.
COMB.TURBINE	164.	.50	.25	357.	164.	.50	.10	143.	164.	.50	.10	143.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	379.			1735.	379.			1224.	530.			1770.
ADDITIONS												
HYDRO	-	-	-	-	151.	.50	.50	574.	19.	.50	.50	74.
STEAM/ELEC	-	-	-	-	-	-	-	-	25.	.75	.20	43.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	25.	.00	.00	0.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	379.			1735.	530.			1804.	549.			1887.
CAP RES. MARGIN	-0.026				0.308				0.298			
RESERVE REQ.	78.				81.				85.			
LOSSES	19.			26.	20.			27.	21.			28.
NET RESOURCES	282.			1709.	429.			1777.	443.			1859.
TRANSFERED	107.				0.				0.			
SURPLUS	0.			0.	24.			0.	20.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/-U.S.-1994.

CRITICAL PERIOD

	1996-1997 PEAK	1996-1997 MPUF	1996-1997 APUF	1996-1997 ENERGY	1997-1998 PEAK	1997-1998 MPUF	1997-1998 APUF	1997-1998 ENERGY	1998-1999 PEAK	1998-1999 MPUF	1998-1999 APUF	1998-1999 ENERGY
REQUIREMENTS	1979.			8871.	2103.			9431.	2228.			9991.
RESOURCES												
EXISTING												
HYDRO	878.	.50	.50	3344.	878.	.50	.50	3344.	878.	.50	.50	3344.
STEAM/ELEC	1445.	.75	.42	5366.	1445.	.75	.47	5934.	1445.	.75	.32	4025.
COMB.TURBINE	545.	.50	.10	294.	335.	.50	.10	294.	335.	.50	.10	278.
DIESEL	3.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	2871.			9004.	2659.			9572.	2659.			7648.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	654.	.50	.50	2493.
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	210.	.00	.00	0.	-	-	-	-	18.	.00	.00	0.
DIESEL	2.	.00	.00	0.	-	-	-	-	-	-	-	-
GROSS RESOURCES	2659.			9004.	2659.			9572.	3295.			10141.
CAP RES. MARGIN	0.343				0.264				0.479			
RESERVE REQ.	396.				421.				446.			
LOSSES	99.			133.	105.			141.	111.			150.
NET RESOURCES	2164.			8871.	2133.			9431.	2738.			9991.
TRANSFERED	-27.				0.				0.			
SURPLUS	158.			0.	30.			0.	510.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
*ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1996-1997 PEAK	MPUF	APUF	ENERGY	1997-1998 PEAK	MPUF	APUF	ENERGY	1998-1999 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	442.			1941.	461.			2023.	480.			2105.
RESOURCES												
EXISTING												
HYDRO	170.	.50	.50	648.	170.	.50	.50	648.	170.	.50	.50	648.
STEAM/ELEC	216.	.75	.64	1200.	216.	.75	.65	1230.	316.	.75	.35	963.
COMB.TURBINE	164.	.50	.10	123.	140.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	549.			1970.	526.			1878.	486.			1611.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	138.	.50	.50	525.
STEAM/ELEC	-	-	-	-	100.	.75	.20	175.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	24.	.00	.00	0.	140.	.00	.00	0.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	526.			1970.	486.			2053.	624.			2137.
CAP RES. MARGIN	0.189				0.053				0.299			
RESERVE REQ.	88.				92.				96.			
LOSSES	22.			29.	23.			30.	24.			32.
NET RESOURCES	415.			1941.	370.			2023.	504.			2105.
TRANSFERED	27.				0.				0.			
SURPLUS	0.			0.	-91.			0.	24.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1999-2000 PEAK	1999-2000 MPUF	1999-2000 APUF	1999-2000 ENERGY	2000-2001 PEAK	2000-2001 MPUF	2000-2001 APUF	2000-2001 ENERGY	2001-2002 PEAK	2001-2002 MPUF	2001-2002 APUF	2001-2002 ENERGY
REQUIREMENTS	2353.			10551.	2421.			10863.	2490.			11175.
RESOURCES												
EXISTING												
HYDRO	1533.	.50	.50	5837.	1617.	.50	.50	6160.	1617.	.50	.50	6160.
STEAM/ELEC	1445.	.75	.34	4343.	1445.	.75	.37	4747.	1445.	.75	.40	5080.
COMB.TURBINE	317.	.50	.10	206.	236.	.50	.10	119.	136.	.50	.10	103.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3295.			10386.	3298.			11026.	3198.			11343.
ADDITIONS												
HYDRO	85.	.50	.50	323.	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	82.	.00	.00	0.	100.	.00	.00	0.	18.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3298.			10709.	3198.			11026.	3180.			11343.
CAP RES. MARGIN	0.402				0.321				0.277			
RESERVE REQ.	471.				484.				498.			
LOSSES	118.			158.	121.			163.	125.			168.
NET RESOURCES	2710.			10551.	2593.			10863.	2558.			11175.
TRANSFERED	0.				0.				-6.			
SURPLUS	357.			0.	172.			0.	61.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 5, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1999-2000 PEAK	MPUF	APUF	ENERGY	2000-2001 PEAK	MPUF	APUF	ENERGY	2001-2002 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	499.			2187.	508.			2229.	518.			2270.
RESOURCES												
EXISTING												
HYDRO	308.	.50	.50	1173.	326.	.50	.50	1240.	326.	.50	.50	1240.
STEAM/ELEC	316.	.75	.35	980.	316.	.75	.37	1022.	316.	.75	.38	1064.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	624.			2153.	641.			2262.	641.			2304.
ADDITIONS												
HYDRO	18.	.50	.50	67.	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	641.			2220.	641.			2262.	641.			2304.
CAP RES. MARGIN	0.285				0.262				0.238			
RESERVE REQ.	100.				102.				104.			
LOSSES	25.			33.	25.			33.	26.			34.
NET RESOURCES	516.			2187.	514.			2229.	512.			2270.
TRANSFERED	0.				0.				6.			
SURPLUS	17.			0.	6.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2002-2003 PEAK	2002-2003 MPUF	2002-2003 APUF	2002-2003 ENERGY	2003-2004 PEAK	2003-2004 MPUF	2003-2004 APUF	2003-2004 ENERGY	2004-2005 PEAK	2004-2005 MPUF	2004-2005 APUF	2004-2005 ENERGY
REQUIREMENTS	2558.			11487.	2626.			11799.	2694.			12111.
RESOURCES												
EXISTING												
HYDRO	1617.	.50	.50	6160.	1617.	.50	.50	6160.	1617.	.50	.50	6160.
STEAM/ELEC	1445.	.75	.38	4783.	1845.	.75	.36	5801.	1845.	.75	.38	6133.
COMB.TURBINE	118.	.50	.10	15.	18.	.50	.10	15.	18.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3180.			10959.	3480.			11976.	3480.			12293.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	400.	.75	.20	701.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	100.	.00	.00	0.	-	-	-	-	18.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3480.			11659.	3480.			11976.	3462.			12293.
CAP RES. MARGIN	0.361				0.325				0.285			
RESERVE REQ.	512.				525.				539.			
LOSSES	126.			172.	131.			177.	135.			182.
NET RESOURCES	2841.			11487.	2824.			11799.	2789.			12111.
TRANSFERED	0.				0.				0.			
SURPLUS	283.			0.	198.			0.	95.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	2002-2003 PEAK	2002-2003 MPUF	2002-2003 APUF	2002-2003 ENERGY	2003-2004 PEAK	2003-2004 MPUF	2003-2004 APUF	2003-2004 ENERGY	2004-2005 PEAK	2004-2005 MPUF	2004-2005 APUF	2004-2005 ENERGY
REQUIREMENTS	527.			2312.	537.			2353.	546.			2395.
RESOURCES												
EXISTING												
HYDRO	326.	.50	.50	1240.	326.	.50	.50	1240.	326.	.50	.50	1240.
STEAM/ELEC	316.	.75	.37	931.	391.	.75	.34	1148.	391.	.75	.35	1191.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	641.			2171.	716.			2388.	716.			2431.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	100.	.75	.20	175.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	25.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	716.			2347.	716.			2388.	716.			2431.
CAP RES. MARGIN	0.359				0.333				0.311			
RESERVE REQ.	105.				107.				109.			
LOSSES	26.			35.	27.			35.	27.			36.
NET RESOURCES	584.			2312.	582.			2353.	580.			2395.
TRANSFERED	0.				0.				0.			
SURPLUS	57.			0.	45.			0.	34.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2005-2006				2006-2007				2007-2008			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	2763.			12423.	2831.			12735.	2899.			13047.
RESOURCES												
EXISTING												
HYDRO	1617.	.50	.50	6160.	1617.	.50	.50	6160.	1617.	.50	.50	6160.
STEAM/ELEC	1845.	.75	.40	6450.	1845.	.75	.38	6066.	2245.	.75	.36	7083.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3462.			12609.	3462.			12225.	3862.			13243.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	400.	.75	.20	701.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3462.			12609.	3862.			12926.	3862.			13243.
CAP RES. MARGIN	0.253				0.364				0.332			
RESERVE REQ.	553.				566.				580.			
LOSSES	138.			186.	142.			191.	145.			196.
NET RESOURCES	2771.			12423.	3154.			12735.	3137.			13047.
TRANSFERED	0.				-10.				-23.			
SURPLUS	8.			0.	313.			0.	216.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	2005-2006 PEAK	2005-2006 MPUF	2005-2006 APUF	2005-2006 ENERGY	2006-2007 PEAK	2006-2007 MPUF	2006-2007 APUF	2006-2007 ENERGY	2007-2008 PEAK	2007-2008 MPUF	2007-2008 APUF	2007-2008 ENERGY
REQUIREMENTS	556.			2437.	565.			2478.	575.			2520.
RESOURCES												
EXISTING												
HYDRO	326.	.50	.50	1240.	326.	.50	.50	1240.	326.	.50	.50	1240.
STEAM/ELEC	391.	.75	.38	1234.	371.	.75	.39	1275.	371.	.75	.41	1318.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	716.			2474.	696.			2515.	696.			2558.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	20.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	696.			2474.	696.			2515.	696.			2558.
CAP RES. MARGIN	0.252				0.232				0.211			
RESERVE REQ.	111.				113.				115.			
LOSSES	28.			37.	28.			37.	29.			38.
NET RESOURCES	557.			2437.	555.			2478.	552.			2520.
TRANSFERED	0.				10.				23.			
SURPLUS	1.			0.	0.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	2008-2009 PEAK	MPUF	APUF	ENERGY	2009-2010 PEAK	MPUF	APUF	ENERGY	2010-2011 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	2968.			13359.	3036.			13671.	3104.			13983.
RESOURCES												
EXISTING												
HYDRO	1617.	.50	.50	6160.	1617.	.50	.50	6160.	1617.	.50	.50	6160.
STEAM/ELEC	2245.	.75	.38	7400.	2245.	.75	.39	7716.	2245.	.75	.37	7332.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3862.			13559.	3862.			13876.	3862.			13492.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	400.	.75	.20	701.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3862.			13559.	3862.			13876.	4262.			14193.
CAP RES. MARGIN	0.301				0.272				0.373			
RESERVE REQ.	594.				607.				621.			
LOSSES	148.			200.	152.			205.	155.			210.
NET RESOURCES	3120.			13359.	3103.			13671.	3486.			13983.
TRANSFERED	-34.				-46.				-58.			
SURPLUS	118.			0.	21.			0.	325.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES: DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	2008-2009				2009-2010				2010-2011			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	584.			2561.	594.			2603.	603.			2645.
RESOURCES												
EXISTING												
HYDRO	326.	.50	.50	1240.	326.	.50	.50	1240.	326.	.50	.50	1240.
STEAM/ELEC	371.	.75	.42	1359.	371.	.75	.43	1402.	371.	.75	.45	1445.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	696.			2599.	696.			2642.	696.			2685.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	696.			2599.	696.			2642.	696.			2685.
CAP RES. MARGIN	0.192				0.172				0.154			
RESERVE REQ.	117.				119.				121.			
LOSSES	29.			38.	30.			39.	30.			40.
NET RESOURCES	550.			2561.	548.			2603.	545.			2645.
TRANSFERED	34.				46.				58.			
SURPLUS	0.			0.	0.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.11. Schedule of Plant Additions - (Megawatts)
Base Cases Without Interconnections

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
78-79	-	-	-	-	-	-
79-80	114[1]	114[1]	114[1]	-	-	-
80-81	100[1]	100[1]	100[1]	-	-	-
81-82	18[1]	18[1]	18[1]	-	-	-
82-83	500[2]	300[4]	100[1]	-	-	-
83-84	200	-	-	-	-	-
84-85	218[4]	18[1]	18[1]	100	-	-
85-86	288[6]	288[6]	88[5]	-	100	-
86-87	400	-	-	100	-	-
87-88	-	200	200	-	-	-
88-89	400	-	-	14[7]	14[7]	14[7]
89-90	-	200	200	100	100	100
90-91	-	-	-	32[7]	32[7]	32[7]
91-92	443[9]	243[8]	43[7]	-	-	-
92-93	400	400	200	100	100	-
93-94	-	-	-	-	-	-
94-95	400[3]	-	200	100	-	100
95-96	400[3]	400	200	25[7]	25[7]	25[7]
96-97	400[3]	400	400	100	100	-
97-98	400[3]	400	-	200	100	100
98-99	400[3]	-	-	200	100	100
99-00	400[3]	400	400	-	-	-
00-01	400[3]	-	-	-	-	-
01-02	-	-	-	-	-	-
02-03	400[3]	400	-	-	-	-
03-04	400[3]	-	-	200	200	-
04-05	-	-	-	-	-	-
05-06	400[3]	400	400	-	-	-
06-07	400[3]	-	-	-	-	-
07-08	-	-	-	200	-	-
08-09	400[3]	-	-	-	-	-
09-10	400[3]	-	-	-	-	-
10-11	-	400	-	-	-	-
TOTAL 78-11	8,281	4,681	2,681	1,471	871	471

See footnotes next page

TABLE 3.11. (contd)

(1) Scheduled Combustion Turbines

(2) Scheduled Combustion Turbines + 400 MW S.T.

(3) Anchorage 400 MW Coal-Fired Units Could be Replaced with Staged 800 MW Capacity Units

(4) Scheduled Combustion Turbine + 200 MW S.T.

(5) Bradley Lake (70 MW) x 1.15 for Peaking + 7 MW S.T. National Defense

(6) Bradley Lake (70 MW) x 1.15 for Peaking + 200 MW S.T. + 7 MW S.T. National Defense

(7) National Defense

(8) 200 MW S.T. + 43 MW S.T. National Defense

(9) 400 MW S.T. + 43 MW S.T. National Defense

TABLE 3.12. Schedule of Plant Additions - (Megawatts)
Cases With Interconnection Without Upper Susitna

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
78-79	-	-	-	-	-	-
79-80	114[1]	114[1]	114[1]	-	-	-
80-81	100[1]	100[1]	100[1]	-	-	-
81-82	18[1]	18[1]	18[1]	-	-	-
82-83	500[2]	300[3]	100[1]	-	-	-
83-84	200	-	-	-	-	-
84-85	218[6]	18[1]	18[1]	100	-	-
85-86	288[5]	288[5]	88[4]	-	100	-
86-87	-*	-	-	-*	-	-
87-88	400	200	200	-	-	-
88-89	-	-	-	14[8]	14[8]	14[8]
89-90	400	-*	200	-	-*	100
90-91	-	200	-	32[8]	32[8]	32[8]
91-92	443[11]	243[9]	43[8]	-	-	-
92-93	-	400	200	200	-	-
93-94	400	-	-	100	-	-
94-95	-	-	-*	-	100	-*
95-96	400[7]	400	200	125[10]	125[10]	25[8]
96-97	400[7]	400	200	100	-	100
97-98	400[7]	-	400	200	100	100
98-99	400[7]	400	-	-	100	-
99-00	400[7]	-	-	-	-	-
00-01	400[7]	400	400	-	-	-
01-02	400[7]	-	-	-	-	-
02-03	400[7]	-	-	-	100	-
03-04	-	400	-	200	-	-
04-05	-	-	-	200	-	-
05-06	400[7]	-	-	-	-	-
06-07	400[7]	-	-	-	-	100
07-08	400[7]	400	-	-	-	-
08-09	-	-	-	-	-	-
09-10	400[7]	-	-	-	-	-
10-11	400[7]	-	-	-	-	-
TOTAL 78-11	8,281	4,281	2,281	1,271	671	471

See footnotes next page

TABLE 3.12. (contd)

*Interconnection Installed

(1) Scheduled Combustion Turbine Additions

(2) 100 MW Scheduled Combustion Turbine + 400 MW S.T.

(3) 100 MW Scheduled Combustion Turbine + 200 MW S.T.

(4) Bradley Lake (70 MW) x 1.15 for Peaking + 7 MW S.T. National Defense

(5) Bradley Lake (70 MW) x 1.15 for Peaking + 200 MW S.T. + 7 MW S.T. National Defense

(6) 18 MW Scheduled Combustion Turbine + 200 MW S.T.

(7) Anchorage 400 MW Coal-Fired Units Could be Replaced with Staged 800 MW Units

(8) National Defense

(9) 200 MW S.T. + 43 MW S.T. National Defense

(10) 100 MW S.T. + 25 MW S.T. National Defense

(11) 400 MW S.T. + 43 MW S.T. National Defense

TABLE 3.13. Schedule of Plant Additions - (Megawatts) Cases With Interconnection With Upper Susitna Coming On Line in 1994

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
78-79	-	-	-	-	-	-
79-80	114[1]	114[1]	114[1]	-	-	-
80-81	100[1]	100[1]	100[1]	-	-	-
81-82	18[1]	18[1]	18[1]	-	-	-
82-83	500[2]	300[5]	100[1]	-	-	-
83-84	200	-	-	-	-	-
84-85	218[6]	18[1]	18[1]	100	-	-
85-86	288[7]	288[7]	88[6]	-	100	-
86-87	-*	-	-	-*	-	-
87-88	400	200	200	-	-	-
88-89	-	-	-	14[10]	14[10]	14[10]
89-90	400	-*	200	-	-*	100
90-91	-	200	-	32[10]	32[10]	32[10]
91-92	443[14]	243[12]	43[10]	-	-	-*
92-93	-	400	-	200	-	-
93-94	400	-	200	100	-	-
94-95	677[3]	658[3]	644[3]	132[3]	151[3]	164[3]
95-96	89[3]	86[3]	85[3]	42[11]	44[11]	46[11]
96-97	400	-	-	-	-	-
97-98	400	-	-	-	100	-
98-99	688[4]	654[4]	-	124[4]	138[4]	-
99-00	86[4]	85[4]	645[4]	16[4]	18[4]	147[4]
00-01	-	-	83[4]	100	-	19[4]
01-02	400[9]	-	-	100	-	-
02-03	400[9]	400	-	-	100	-
03-04	-	-	-	200	-	-
04-05	400[9]	-	-	-	-	-
05-06	400[9]	-	-	-	-	-
06-07	-	400	-	-	-	-
07-08	400	-	-	-	-	-
08-09	400[9]	-	-	-	-	-
09-10	-	-	-	200	-	-
10-11	400[9]	400	-	-	-	-
TOTAL 78-11	8,221	4,564	2,538	1,360	697	522

See footnotes next page

TABLE 3.13. (contd)

*Interconnection Installed

(1) Scheduled Combustion Turbine Additions

(2) Scheduled 100 MW Combustion Turbine + 400 MW S.T.

(3) Share of Watana Capacity x 1.15 for Peaking

(4) Share of Devil Canyon Capacity x 1.15 for Peaking

(5) Scheduled 100 MW Combustion Turbine + 200 MW S.T.

(6) Bradley Lake (70 MW) x 1.15 for Peaking + 7 MW S.T. National Defense

(7) Bradley Lake (70 MW) x 1.15 for Peaking + 200 MW S.T. + MW S.T. National Defense

(8) Scheduled 18 MW Combustion Turbine +200 MW S.T.

(9) Anchorage 400 MW Coal-Fired Units Could be Replaced with Staged 800 MW Units

(10) National Defense

(11) Share of Watana Capacity x 1.15 for Peaking + 25 MW S.T. National Defense

(12) 200 MW S.T. + 43 MW S.T. National Defense

(13) Share of Watana Capacity x 1.15 for Peaking + 25 MW S.T. National Defense

(14) 400 MW S.T. + 43 MW S.T. National Defense

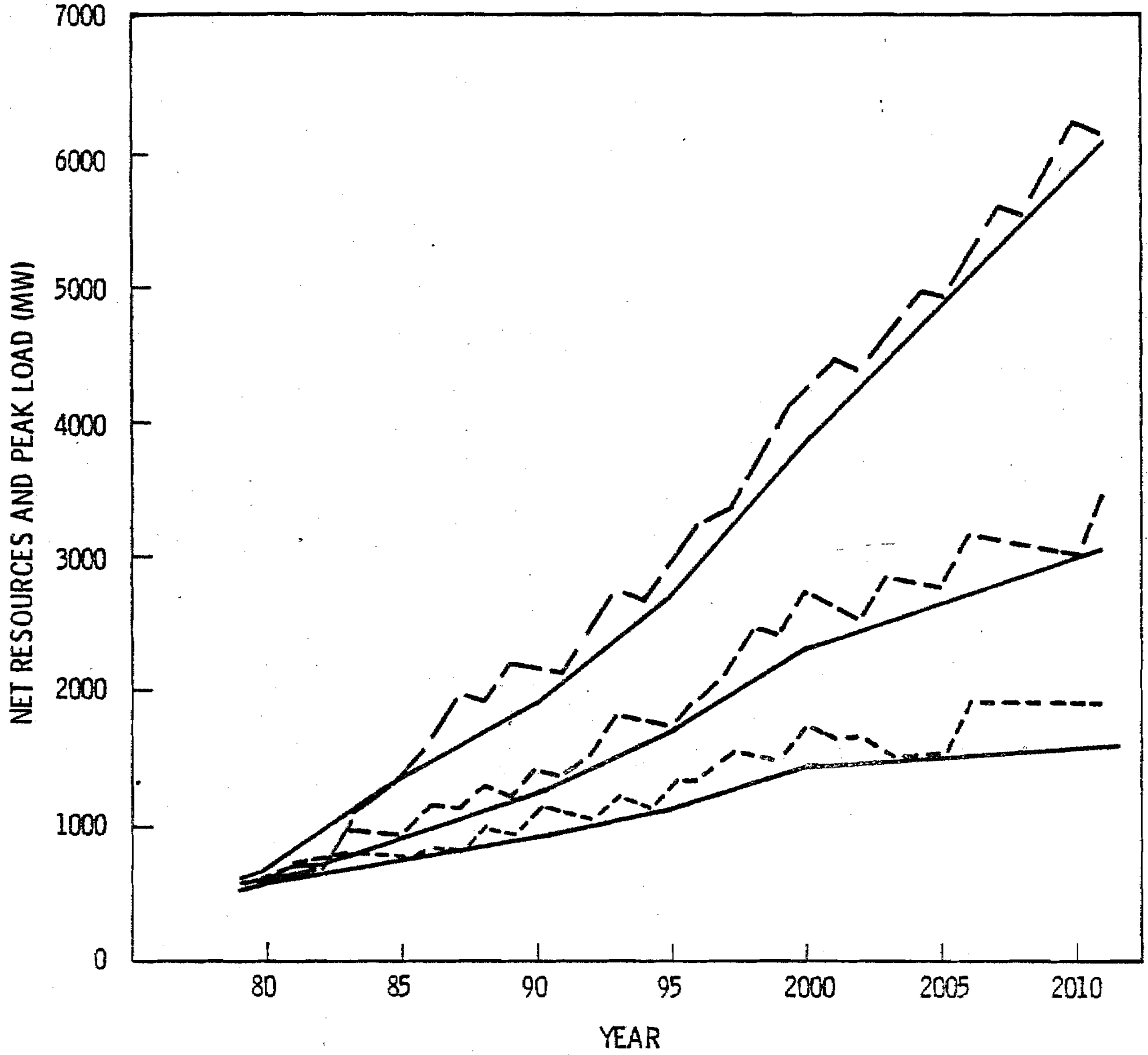

FIGURE 3.6. Load/Resource Analysis for Anchorage-Cook Inlet Area Without Interconnection and Without Susitna Project (Case 1). Low, Medium, and High Load Growth Scenarios

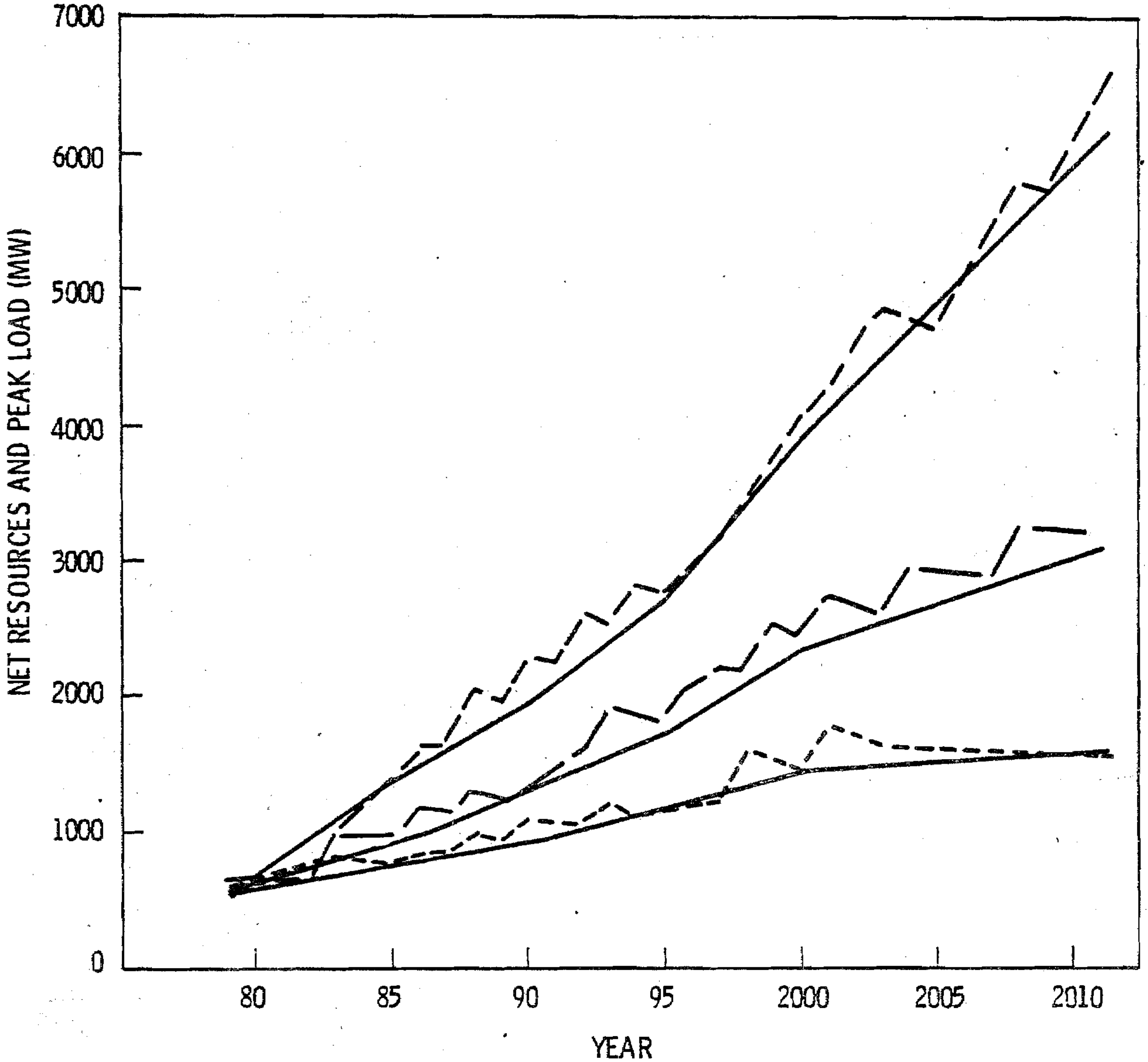

FIGURE 3.7. Load/Resource Analysis for Anchorage-Cook Inlet Area With Interconnection but Without Upper Susitna Project (Case 2). Low, Medium, and High Load Growth Scenarios

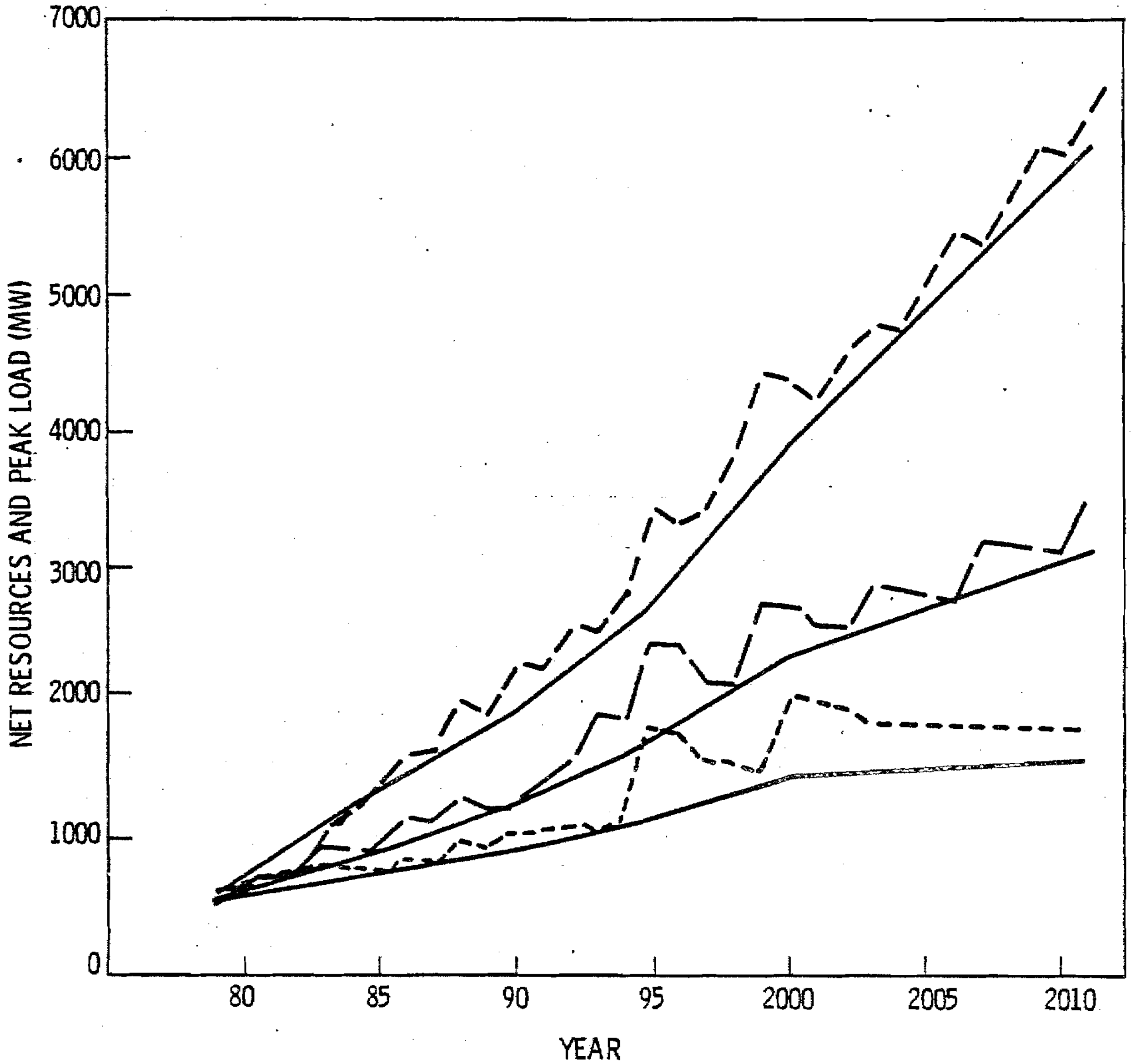

FIGURE 3.8. Load/Resource Analysis for Anchorage-Cook Inlet Area With Interconnection and With Upper Susitna Project Coming On Line in 1994 (Case 3). Low, Medium, and High Load Growth Scenarios

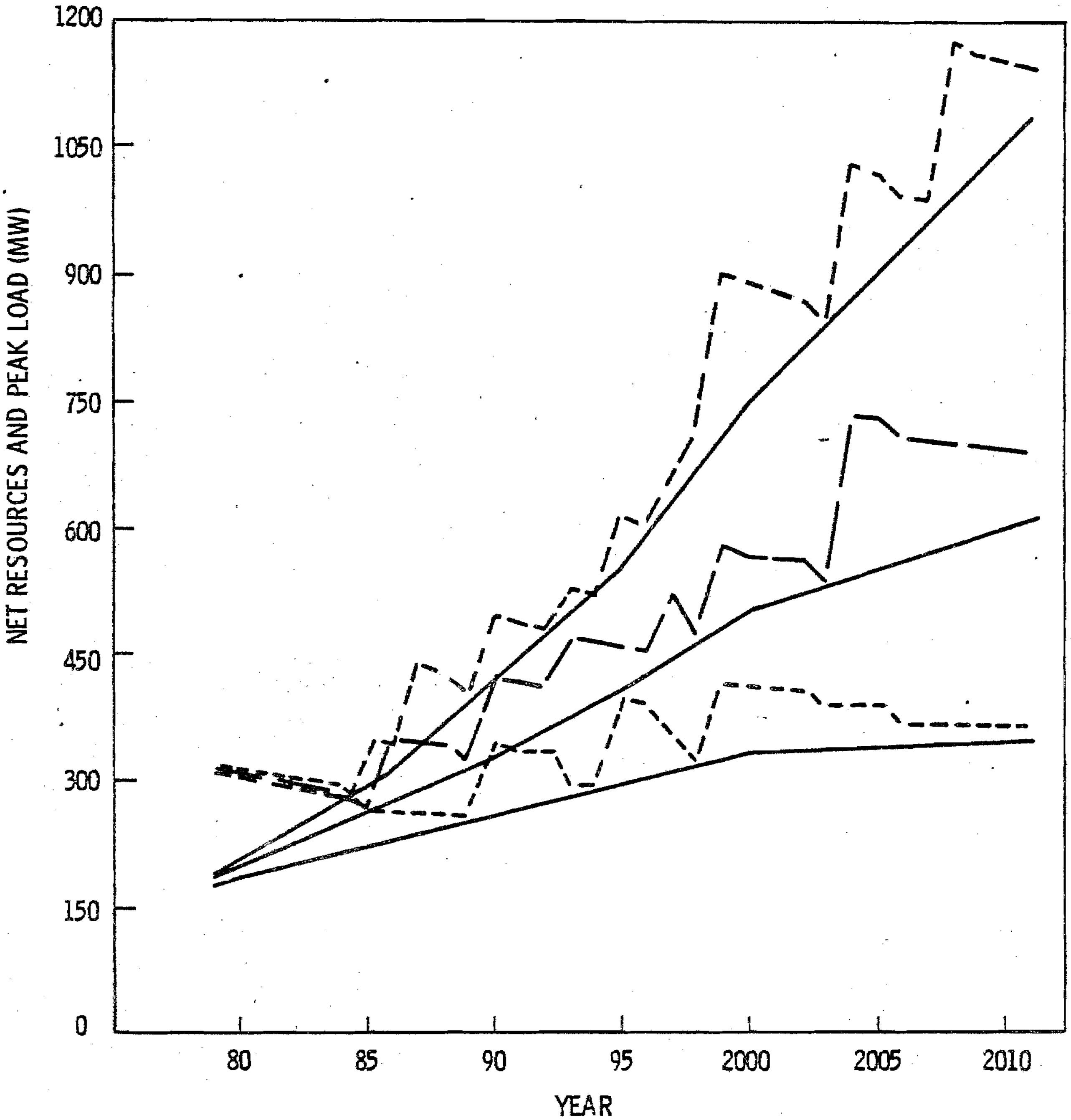

FIGURE 3.9. Load/Resource Analysis for Fairbanks-Tanana Valley Area Without Interconnection and Without Upper Susitna Project (Case 1). Low, Medium, and High Load Growth Scenario

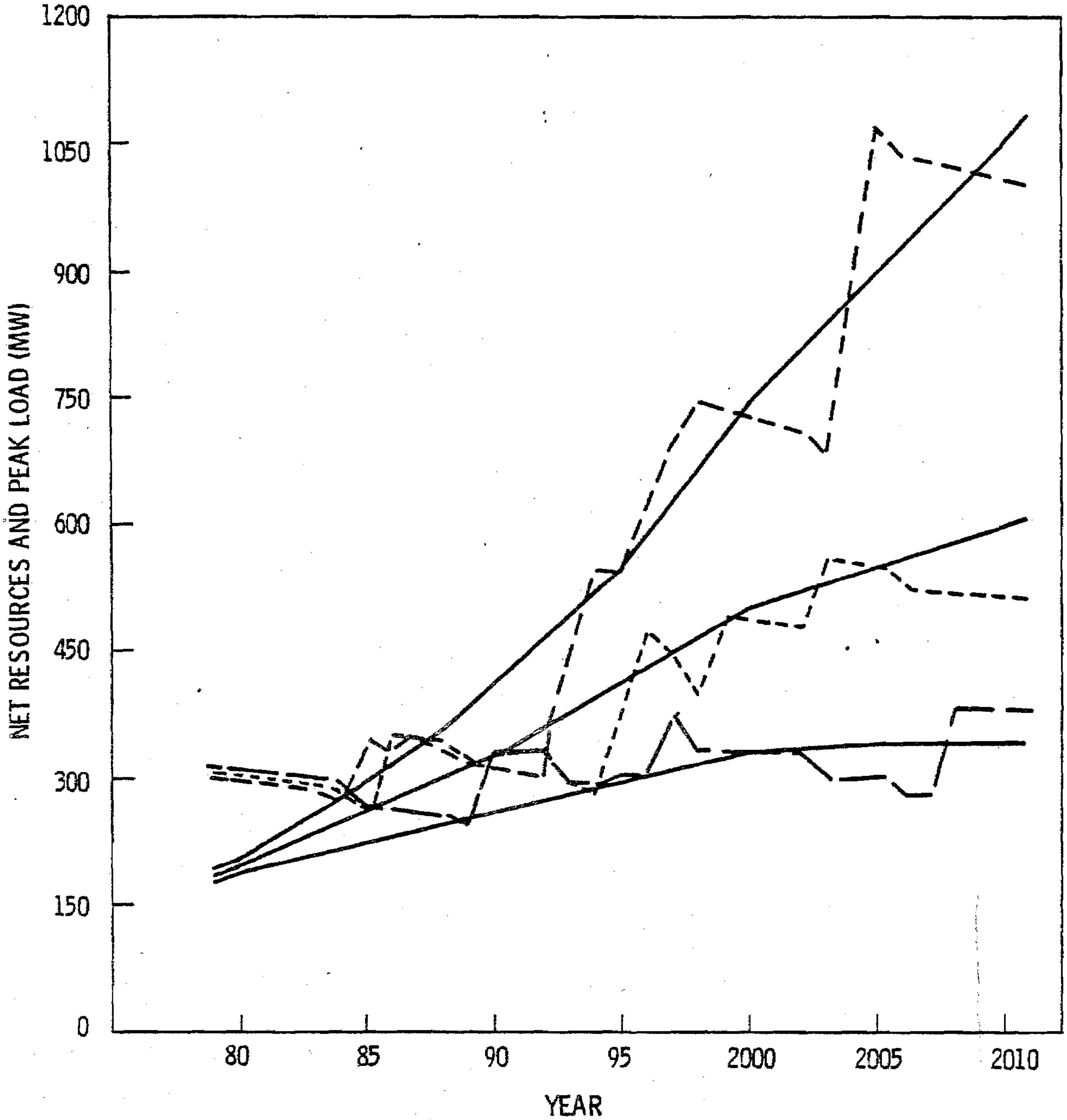

FIGURE 3.10. Load/Resource Analysis for Fairbanks-Tanana Valley Area With Interconnection but Without Upper Susitna Project (Case 2). Low, Medium, and High Load Growth Scenari

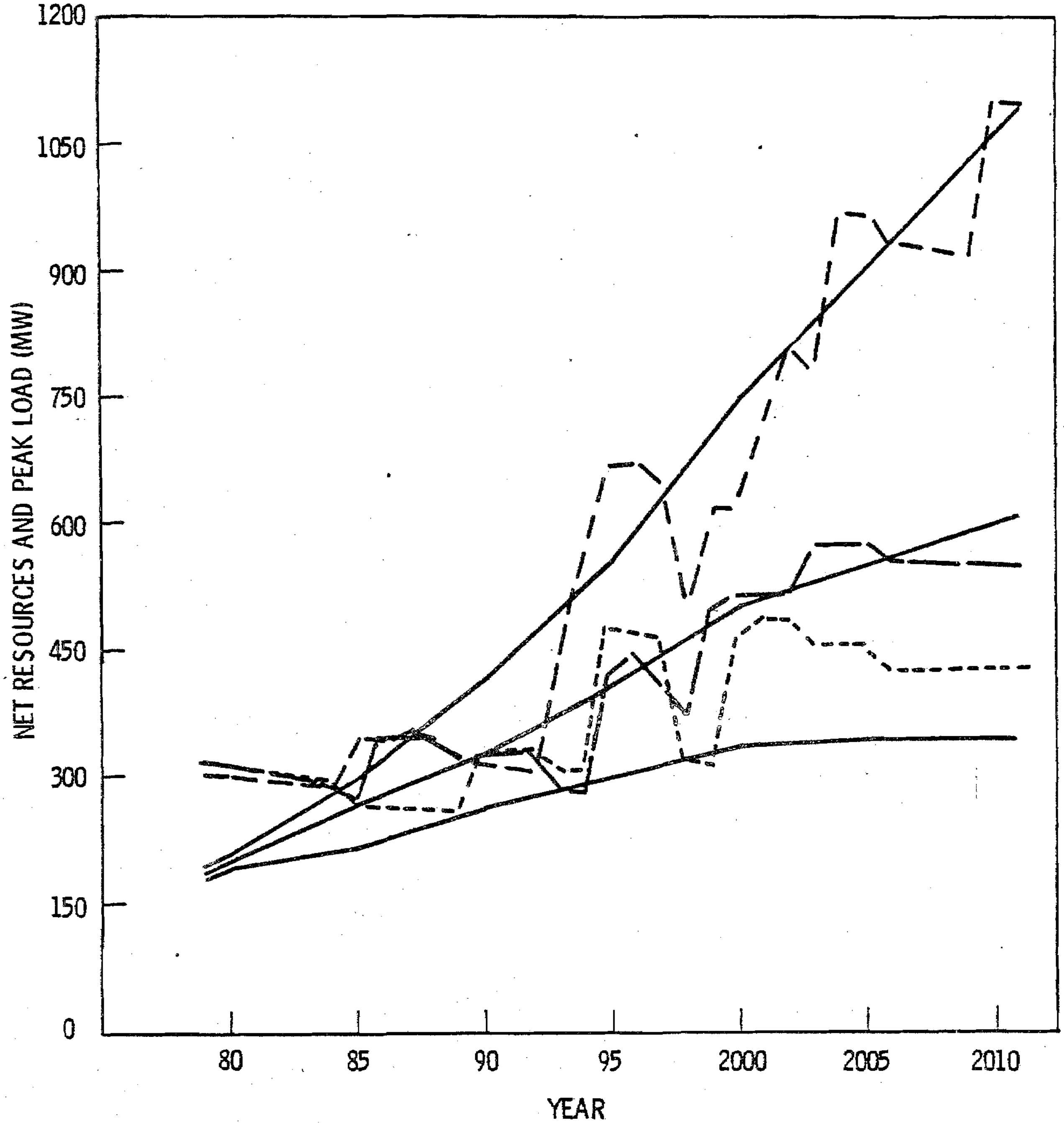

FIGURE 3.11. Load/Resource Analysis for Fairbanks-Tanana Valley Area With Interconnection and With Upper Susitna Project Coming On Line in 1994 (Case 3). Low, Medium, and High Load Growth Scenarios

4.0 SYSTEM POWER COST ANALYSES

This chapter describes the methodology used to evaluate the annual cost of power from individual generating facilities (or groups of similar generating facilities), the method of computing the average system-wide power costs, and presents the results of the system power cost analyses. The first section briefly discusses the factors which determine the cost of power. The second section describes the computational method used to compute the annual cost of power. This method is incorporated into a computer model titled ECOST4. A listing of the computer code is given in Appendix D.

The third section of this chapter contains a discussion of how the system-wide power costs are computed given the power costs for the individual facilities. The results are presented in the last part of the chapter.

4.1 FACTORS DETERMINING THE COST OF POWER

Three cost categories are evaluated in this report: 1) interest and amortization charges (capital cost); 2) fuel costs; and 3) operating, maintenance and replacement costs. Of course, there are other cost items included in the cost of power to the consumer, such as taxes, insurance, distribution and billing charges, but these costs are not evaluated in this report since they typically do not vary among the three cases evaluated.

These components of the cost of power are shown in Figure 4.1. The annual plant capital expenses are fixed by the initial financing and are typically constant over the life of the plant. Operation, maintenance, and replacement fuel costs typically increase over time as affected by inflation and real price increases. As a result, the total annual cost of power progressively increases over time.

4.1.1 Capital Costs

The capital costs represent the total cost of constructing a generating facility. The capital cost estimates used in this analysis include

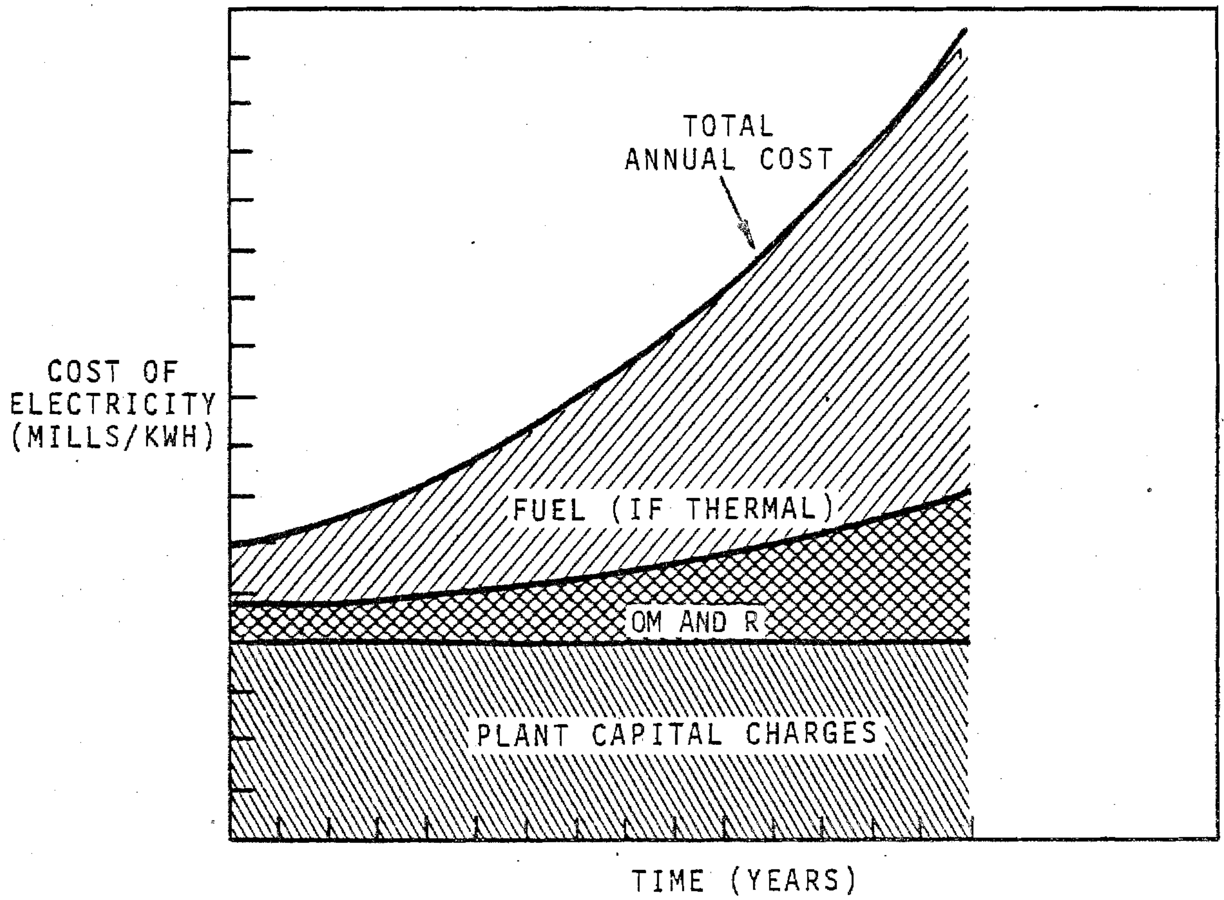

FIGURE 4.1. Components of the Total Annual Cost of Power

interest and escalation during construction. It is assumed that the capital costs are repaid in equal annual payments over the payback period of the plant. The capital cost estimates used are in terms of constant October 1978 dollars.

The total investment cost for the coal-fired and hydroelectric generating facilities are shown below.

	Total Investment Cost	
	(million $)	($/kW)
100 MW Coal Steam Turbine	245.4	2454
200 MW Coal Steam Turbine	372.0	1860
400 MW Coal Steam Turbine	646.8	1617
Watana Dam (795 MW)	2501.2	3146
Devil Canyon Dam (778 MW)	834.0	1071.9

SOURCE: Alaska Power Administration, August 1978.

Transmission facility costs are presented in Table 3.7.

4.1.2 Heat Rate

The heat rate is the ratio of the Btu's going into the plant as fuel to the kWh's of electricity produced by the plant. The heat rate is assumed to remain constant for all plant utilization factors over the lifetime of the plant. The heat rate for new coal-fired steam electric plants is assumed to be 10,500 Btu/kWh.

4.1.3 Operation, Maintenance, and Replacement Costs

The operating, maintenance, and replacement (OM&R) costs include the administrative and general expenses as well as the interim replacement costs. All estimates are expressed in terms of October 1978 dollars. They are escalated at a rate equal to the rate of general inflation.

The OM&R costs for coal-fired steam electric and hydroelectric generating facilities and transmission facilities are shown below.

	OM&R Costs (million $)	OM&R Costs ($/kW/yr)
100 MW Coal Steam Turbine	3.76	37.6
200 MW Coal Steam Turbine	5.7	28.5
400 MW Coal Steam Turbine	9.8	24.5
Watana Dam (795 MW)	0.74	0.94
Devil Canyon Dam (778 MW)	0.73	0.94
New transmission facilities	-	2.0

SOURCE: Alaska Power Administration, August 1978.

4.1.4 Financing Discount Rate

The financing discount rate represents the cost of capital to utility. A rate of 7.0% is assumed in this report. This is assumed to be an average of all types of financing available.

4.1.5 Payback Period

The length of time over which the plant is financed is the payback period. This is assumed to be equal to the plant lifetime except for hydro projects where a 50-year payback period is assumed versus at least a 100-year plant lifetime (see Section 3.2.6).

4.1.6 Annual Plant Utilization Factor

The plant utilization factor (PUF) is the ratio of the actual power production during a year to the theoretical maximum if the plant was to run 8760 hours at 100% capacity during the year.

The annual plant utilization factor is highly variable depending upon many factors (e.g., forced outage rate, cost of power from alternative sources, and power production requirements). Because of this, it is necessary to explicitly consider the effects of the PUF on the cost or power over the lifetime of a plant. As pointed out earlier, the PUFs used in the report are determined by the load/resource analyses (see Section 3.2.6).

4.1.7 Unit Fuel Costs

Fuel costs for thermal generation plants are expected to increase over times following paths shown in Figures 4.2 through 4.4 for natural

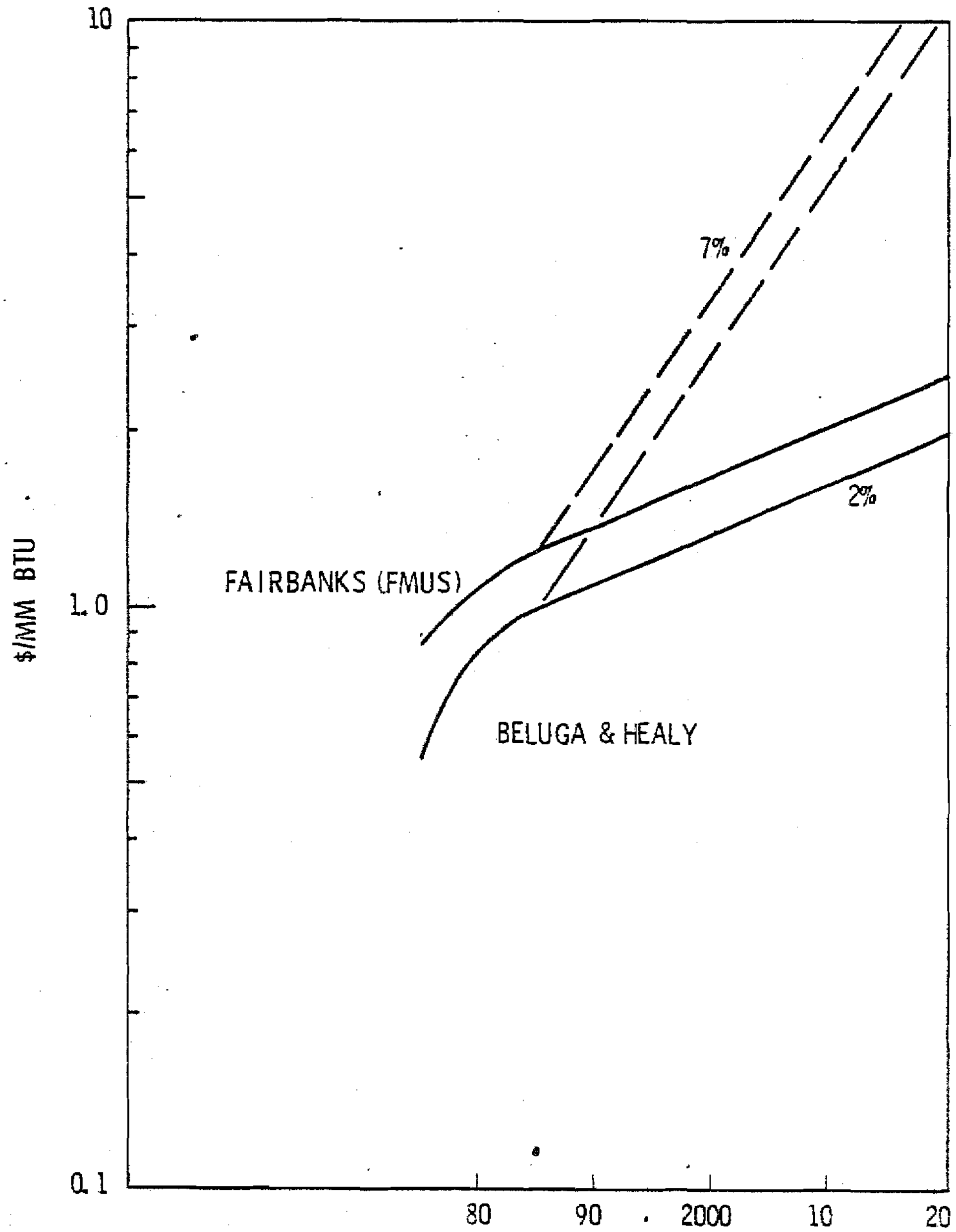

FIGURE 4.2. Estimates of Future Coal Prices - 2% and 7% Escalation

SOURCE: Alaska Power Administration, August 1978.

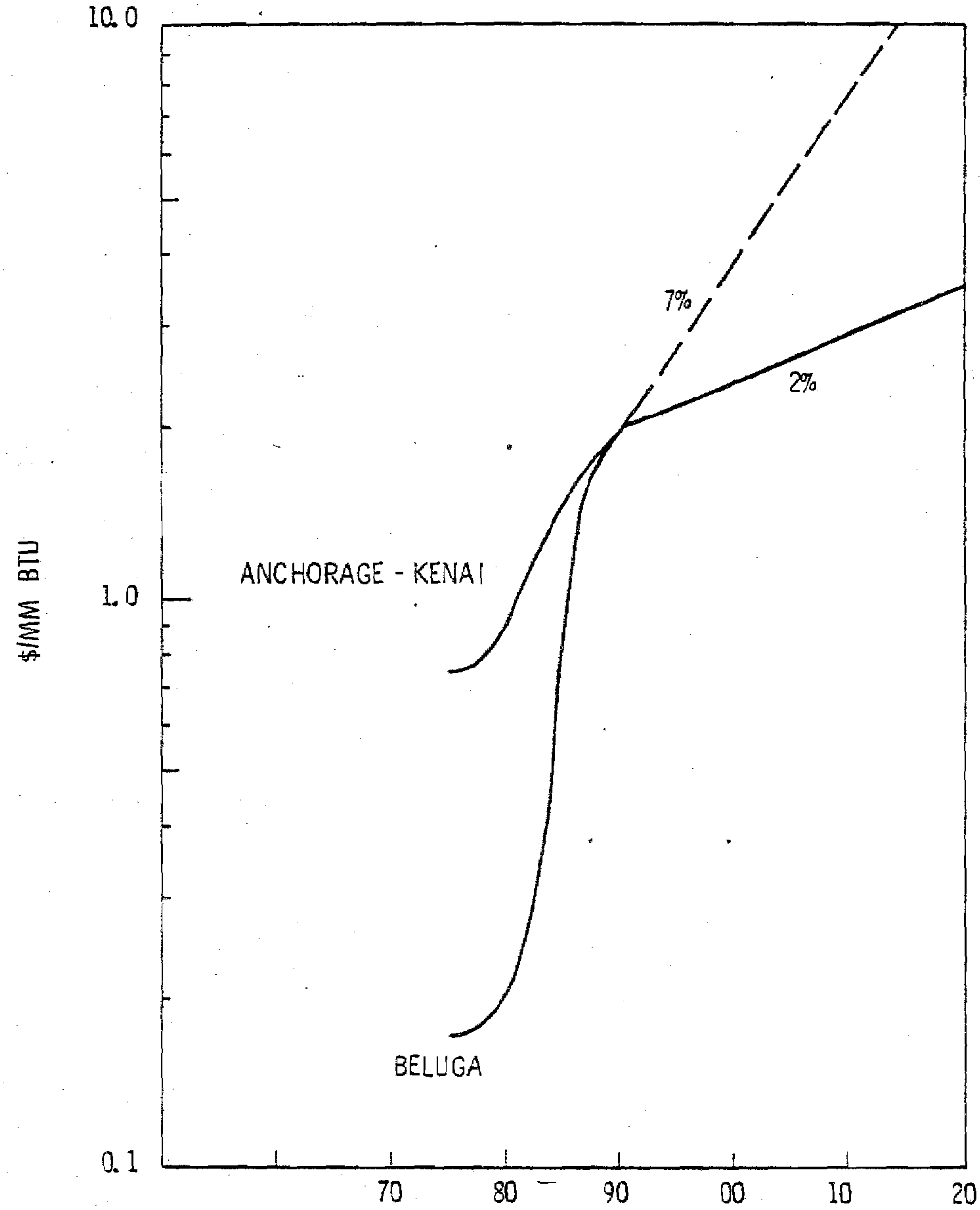

FIGURE 4.3. Estimates of Future Natural Gas Prices - 2% and 7% Escalation

SOURCE: Alaska Power Administration, August 1978

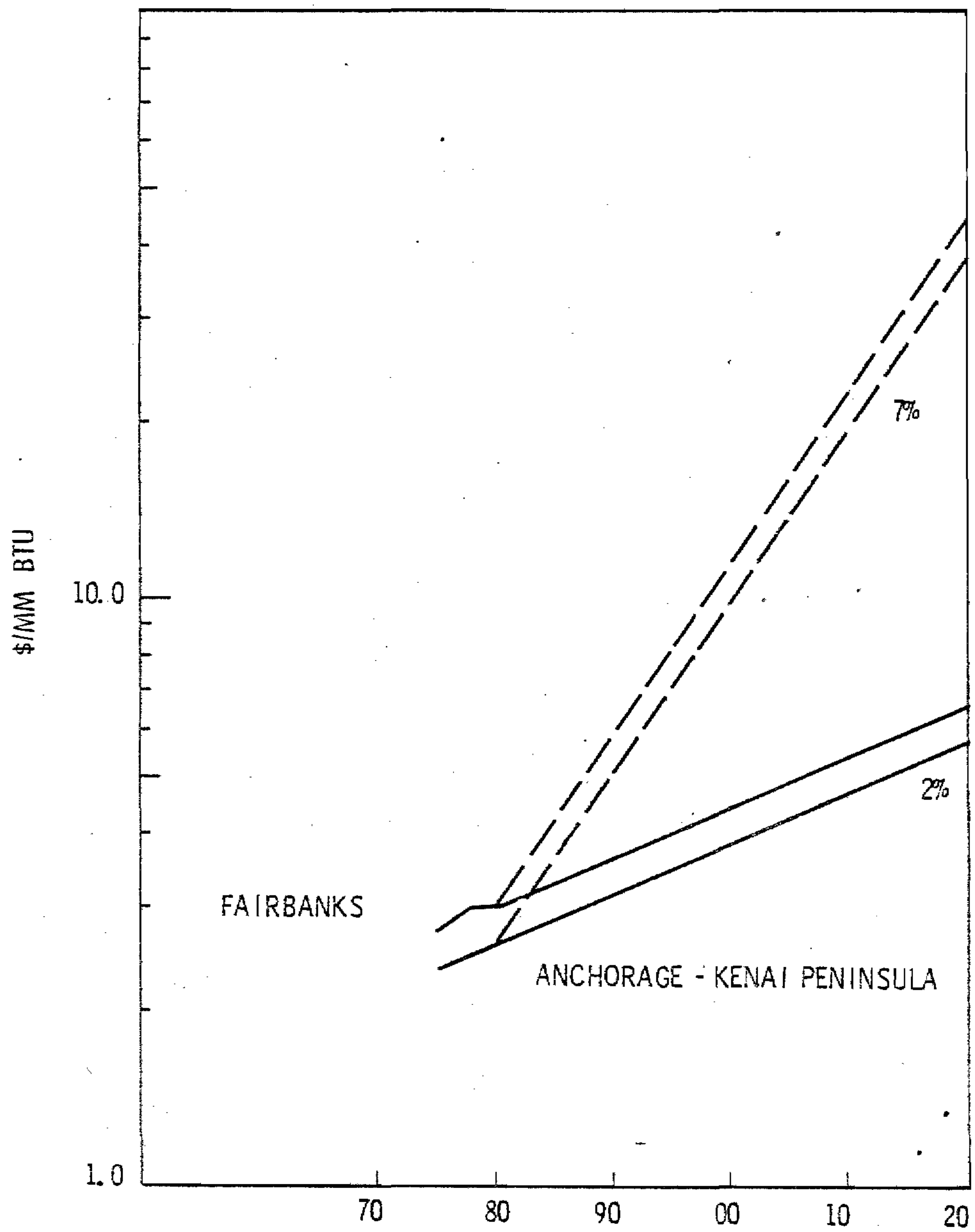

FIGURE 4.4. Estimates of Future Fuel Oil and Diesel Prices - 2% and 7% Escalation

SOURCE: Alaska Power Administration, August 1978.

gas (Cook Inlet areas), coal and distillable oil. Although natural gas is likely to become available in the Fairbanks region in the early to mid 1980's, Federal policies are expected to preclude its use for power generation except for probing and the cost is indeterment at the present time.

4.1.8 General Inflation Rate

Because of the uncertainty involved in estimating the future rate of inflation, two alternative cases are evaluated. A constant dollar case (0% inflation), and a 5% inflation case.

4.1.9 Construction Escalation Rate

In this analysis, construction costs are assumed to escalate at the same rate as the rate of general inflation.

4.1.10 Fuel Escalation Rate

The fuel escalation rate is set to equal the general inflation rate plus 2%.

4.2. METHOD OF COMPUTING THE ANNUAL COST OF POWER FROM INDIVIDUAL GENERATING FACILITIES

During any year the electrical power production is computed thus:

$$EPPR_i = (ICAP * PUF_i * HPY)/ 1000^*$$

where:

$ICAP$ = Installed capacity (MW)
PUF_i = Plat utilization factor in year i (fraction)
HPY = Hours per year (8760 hours/year)

* Parameters with the subscript i are assumed to vary each year over the lifetime of the plant. Parameters without the subscript are assumed to be constant over the lifetime of the plant.

The total annual costs (TAC) are composed of two elements: variable costs and fixed costs. In equation form:

$$TAC_i = VARC_i + FIXC_i$$

where:

$VARC_i$ = Variable costs in year i ($/Year)
$FIXC_i$ = Fixed costs in year i ($/Year)

The variable costs consist only of the fuel costs.

$$VARC_i = FUELC_i$$

where:

$FUELC_i$ = Fuel costs in year i ($/Year).

In turn, fuel costs are computed:

$$FUELC_i = HEATR * EPPRO_i * UFUELC_i$$

where:

HEATR = Heat rate (Btu/kWh)
$EPPRO_i$ = Electrical power production in year i (MMkWh)
$UFUELC_i$ = Unit fuel costs in year i ($/MMBtu)

The fixed costs consist of two factors. These factors can be written in the following equation form:

$$FIXC_i = INTAM + OMRC_i$$

where:

INTAM = Interest and amortization (capital recovery) charges ($/Year)
$OMRC_i$ = Operations, maintenance and replacement costs in year i ($/Year).

The interest and amortization charges (INTAM) represent the annual debt service payments.

$$INTAM = CRF * TINVC$$

where:

CRF = Capital Recovery Factor

$TINVC$ = Total Investment Costs ($)

The capital recovery factor is used to compute a future series of equal end-of-year payments that will just recover a present sum p over n periods at compound interest (IR). It is computed thus:[1, p.26]

$$CRF = \frac{IR(1 + IR)^{PBP}}{(1 + IR)^{PBP} - 1}$$

where:

PBP = Payback period (years)

The methodology described in this section is incorporated into a computer model called ECOST4.

4.3 METHOD OF COMPUTING AVERAGE SYSTEM POWER COST

Once the costs of producing power from the various individual generating facilities in a system are known, a method of comparing the total cost of power from the three alternative system configurations evaluated in this report is needed.

To compare the overall cost of power produced by these alternatives a relatively straightforward method is used. The costs of producing and transmitting power for each of the generation and transmission facilities are added together for each year during the period 1978-2010. In equation form:

$$TAC_j = \sum_{i=1}^{n} AC_{ij}$$

where:

TAC_j = total annual cost of power production for the system in year j ($)

AC_{ij} = annual cost of producing or transmitting power for facility i during year j ($)

n = number of generation and transmission facilities in system.

Likewise the amount of power produced by each facility during each year is summed to give a system-wide total.

$$TAPP_j = \sum_{i=1}^{n} PP_{ij}$$

where:

$TAPP_j$ = total annual power production for the system in year j (kWhs)

PP_{ij} = power produced by each generating facility i during year j (KWHs)

n = number of generating facilities in system

By dividing the total cost by the total generation an average cost of power for the system is obtained for each year.

$$EPCOST_j = \frac{TAC_j}{TAPP_j}$$

where:

$EPCOST_j$ = average system-wide cost of power for year j ($/kWh)

By comparing the costs of power, the system producing the lowest cost of power can be selected.

4.4 RESULTS OF SYSTEM CASH FLOW AND POWER COST CALCULATIONS

The results of the system cash flow and power cost calculations are presented in this section. As pointed out earlier in the report three cases were evaluated:

Case 1. All additional generating capacity assumed to be coal-fired steam turbines without a transmission interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley load centers.

Case 2. All additional generating assumed to be coal-fired steam turbines including a transmission interconnection.

Case 3. Additional capacity to include the Upper Susitna project (including transmission interconnection) plus additional coal as needed. Upper Susitna assumed to come on line in 1994.

Tables 4.1 through 4.36 present the cash flow and power cost calculated for the 3 cases. The contents of these tables are summarized below:

Table Number	Area	Load Growth Scenario	Case	Inflation Rate (%)
4.1	Anchorage	Low	1	0
2	"	"	"	5
3	"	"	2	0
4	"	"	"	5
5	"	"	3	0
6	"	"	"	5
7	"	Medium	1	0
8	"	"	"	5
9	"	"	2	0
10	"	"	"	5
11	"	"	3	0
12	"	"	"	5
13	"	High	1	0
14	"	"	"	5
15	"	"	2	0
16	"	"	"	5
17	"	"	3	0
18	"	"	"	5
19	Fairbanks	Low	1	0
20	"	"	"	5
21	"	"	2	0
22	"	"	"	5
23	"	"	3	0
24	"	"	"	5
25	"	Medium	1	0
26	"	"	"	5
27	"	"	2	0
28	"	"	"	5
29	"	"	3	0
30	"	"	"	5
31	"	High	1	0
32	"	"	"	5
33	"	"	2	0
34	"	"	"	5
35	"	"	3	0
36	"	"	"	5

TABLE 4.1. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2376	1.4
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	2568	1.7
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	2706	1.8
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	2850	1.9
82-83	61.1	---	---	3.1	---	---	0.6	0.4	---	65.3	2991	2.2
83-84	62.0	---	---	3.3	---	---	0.6	0.4	---	66.3	3132	2.1
84-85	66.7	---	---	3.3	---	---	0.6	0.4	---	71.1	3273	2.2
85-86	66.7	1.3	0.2	3.6	10.9	0.4	0.6	0.4	12.8	84.1	3433	2.4
86-87	67.2	1.3	0.2	3.7	10.9	0.4	0.6	0.4	12.8	84.8	3594	2.3
87-88	66.4	30.0	5.9	6.7	10.9	0.4	17.1	3.6	58.0	141.0	3754	3.7
88-89	59.0	30.0	5.9	9.6	10.9	0.4	17.1	3.6	58.0	136.6	3915	3.5
89-90	54.5	58.7	11.6	16.6	10.9	0.4	17.1	3.6	86.7	173.4	4075	4.2
90-91	50.2	58.7	11.6	22.5	10.9	0.4	17.1	3.6	86.7	175.0	4285	4.1
91-92	47.1	66.8	13.2	26.6	10.9	0.4	17.1	3.6	94.8	185.7	4495	4.1
92-93	42.4	95.5	18.9	34.5	10.9	0.4	17.1	3.6	123.5	223.3	4705	4.7
93-94	38.9	95.5	18.9	41.9	10.9	0.4	17.1	3.6	123.5	227.2	4915	4.6
94-95	39.4	124.2	24.6	50.7	10.9	0.4	17.1	3.6	152.2	270.9	5125	5.3
95-96	34.5	152.9	30.3	56.9	10.9	0.4	17.1	3.6	180.9	306.6	5385	5.7
96-97	28.3	202.8	40.1	64.1	10.9	0.4	17.1	3.6	230.8	367.3	5645	6.5
97-98	25.4	202.8	40.1	69.1	10.9	0.4	17.1	3.6	230.8	369.4	5904	6.3
98-99	27.4	202.8	40.1	74.1	10.9	0.4	17.1	3.6	230.8	376.4	6164	6.1
99-2000	22.6	252.7	49.9	80.4	10.9	0.4	33.5	6.8	297.1	457.2	6424	7.1
00-01	12.2	252.7	49.9	83.8	10.9	0.4	33.5	6.8	297.1	450.2	6489	6.9
01-02	11.0	252.7	49.9	86.9	10.9	0.4	33.5	6.8	297.1	452.1	6555	6.9
02-03	4.8	252.7	49.9	90.4	10.9	0.4	33.5	6.8	297.1	449.4	6620	6.8
03-04	4.8	252.7	49.9	93.3	10.9	0.4	33.5	6.8	297.1	452.3	6686	6.8
04-05	3.6	252.7	49.9	96.6	10.9	0.4	33.5	6.8	297.1	454.4	6751	6.7
05-06	3.6	302.6	59.7	99.6	10.9	0.4	33.5	6.8	347.0	517.1	6817	7.6
06-07	3.6	302.6	59.7	102.7	10.9	0.4	33.5	6.8	347.0	520.2	6882	7.5
07-08	3.6	302.6	59.7	105.8	10.9	0.4	33.5	6.8	347.0	523.3	6948	7.5
08-09	3.6	302.6	59.7	108.9	10.9	0.4	33.5	6.8	347.0	526.4	7013	7.5
09-10	3.6	302.6	59.7	112.1	10.9	0.4	33.5	6.8	347.0	529.6	7079	7.5
10-11	3.6	302.6	59.7	115.4	10.9	0.4	33.5	6.8	347.0	532.9	7144	7.5

TABLE 4.2. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2376	1.3
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.1	2568	1.6
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	2706	1.7
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	2850	1.7
82-83	59.5	---	---	3.1	---	---	0.7	0.5	---	63.9	2991	2.1
83-84	63.6	---	---	3.3	---	---	0.7	0.5	---	68.1	3132	2.2
84-85	68.7	---	---	3.3	---	---	0.7	0.5	---	73.3	3273	2.2
85-86	68.9	2.0	0.4	3.6	14.8	0.6	0.7	0.5	17.5	90.8	3433	2.6
86-87	69.8	2.0	0.4	3.9	14.8	0.6	0.7	0.5	17.5	92.7	3594	2.6
87-88	67.1	46.6	9.2	7.3	14.8	0.6	24.1	5.4	85.5	175.2	3754	4.7
88-89	60.6	46.6	9.7	11.1	14.8	0.6	24.1	5.7	85.5	173.2	3915	4.4
89-90	56.4	95.7	19.9	20.1	14.8	0.7	24.1	6.0	134.6	237.8	4075	5.8
90-91	52.5	95.7	20.9	28.6	14.8	0.7	24.1	6.3	134.6	243.6	4285	5.7
91-92	49.8	111.1	24.8	35.2	14.8	0.7	24.1	6.6	150.0	267.2	4495	5.9
92-93	47.4	168.0	37.4	48.4	14.8	0.8	24.1	6.9	206.9	347.8	4705	7.4
93-94	46.5	168.0	39.2	61.3	14.8	0.8	24.1	7.3	206.9	362.0	4915	7.4
94-95	48.5	230.7	51.6	77.9	14.8	0.9	24.1	7.7	269.6	456.2	5125	8.9
95-96	43.8	296.5	67.3	92.2	14.8	0.9	24.1	8.1	335.4	547.7	5385	10.2
96-97	36.3	416.7	94.3	108.6	14.8	0.9	24.1	8.5	455.6	704.2	5645	12.5
97-98	37.7	416.7	99.0	122.6	14.8	1.0	24.1	8.0	455.6	724.8	5904	12.3
98-99	37.5	416.7	103.9	138.4	14.8	1.0	24.1	9.3	455.6	745.7	6164	12.1
99-2000	31.7	555.8	136.4	156.6	14.8	1.1	68.3	18.4	638.9	983.1	6424	15.3
00-01	16.7	555.8	143.3	172.0	14.8	1.1	68.3	19.3	638.9	991.3	6498	15.3
01-02	15.3	555.8	150.4	186.5	14.8	1.2	68.3	20.3	638.9	1012.6	6555	15.4
02-03	5.4	555.8	157.9	204.8	14.8	1.3	68.3	21.3	638.9	1029.6	6620	15.5
03-04	5.5	555.8	165.8	221.6	14.8	1.3	68.3	22.4	638.9	1055.5	6686	15.8
04-05	3.6	555.8	174.1	240.4	14.8	1.4	68.3	23.5	638.9	1081.9	6751	16.0
05-06	3.7	742.3	219.4	259.8	14.8	1.5	68.3	24.6	825.4	1334.4	6817	19.6
06-07	3.9	742.3	230.4	280.8	14.8	1.5	68.3	25.9	825.4	1367.9	6882	19.9
07-08	4.0	742.3	241.9	303.6	14.8	1.6	68.3	27.2	825.4	1403.7	6948	20.2
08-09	4.1	742.3	254.0	328.2	14.8	1.7	68.3	28.5	825.4	1441.9	7013	20.6
09-10	4.2	472.3	266.7	354.6	14.8	1.8	68.3	30.0	825.4	1482.7	7079	20.9
10-11	4.4	742.3	280.1	382.9	14.8	1.9	68.3	31.5	825.4	1526.2	7144	21.4

TABLE 4.3. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	OM&R Costs	Coal Costs	New Hydroelectric Costs Investment Costs	OM&R Costs	Transmission Systems Investment Costs	OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2376	1.4
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	2568	1.7
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	2706	1.8
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	2850	1.9
82-83	61.1	---	---	3.1	---	---	0.6	0.4	---	65.3	2991	2.2
83-84	62.0	---	---	3.3	---	---	0.6	0.4	---	66.3	3132	2.1
84-85	66.7	---	---	3.3	---	---	0.6	0.4	---	71.1	3273	2.2
85-86	66.7	1.3	0.2	3.6	10.9	0.4	0.6	0.4	12.8	84.1	3433	2.4
86-87	67.2	1.3	0.2	3.7	10.9	0.4	0.6	0.4	12.8	84.8	3594	2.3
87-88	66.4	30.0	5.9	6.7	10.9	0.4	17.1	3.6	58.0	141.0	3754	3.7
88-89	59.0	30.0	5.9	9.6	10.9	0.4	17.1	3.6	58.0	136.6	3915	3.5
89-90	54.5	58.7	11.6	16.6	10.9	0.4	17.1	3.6	86.7	173.4	4075	4.2
90-91	50.2	58.7	11.6	22.5	10.9	0.4	17.1	3.6	86.7	175.0	4285	4.1
91-92	47.1	66.8	13.2	26.6	10.9	0.4	17.1	3.6	94.8	185.7	4495	4.1
92-93	42.4	95.5	18.9	34.5	10.9	0.4	17.1	3.6	123.5	223.3	4705	4.7
93-94	38.9	95.5	18.9	41.9	10.9	0.4	17.1	3.6	123.5	227.2	4915	4.6
94-95	39.4	95.5	18.9	46.3	10.9	0.4	35.9	5.6	142.3	252.4	5125	4.9
95-96	34.5	124.2	24.6	55.3	10.9	0.4	35.9	5.6	171.0	290.9	5385	5.4
96-97	28.3	152.9	30.3	64.1	10.9	0.4	35.9	5.6	199.7	327.9	5645	5.8
97-98	25.4	202.8	40.1	69.2	10.9	0.4	35.9	5.6	249.6	389.8	5904	6.6
98-99	27.4	202.8	40.1	74.1	10.9	0.4	35.9	5.6	249.6	396.7	6164	6.4
99-2000	22.6	202.5	40.1	80.4	10.9	0.4	35.9	5.6	249.6	397.9	6424	6.2
00-01	12.2	252.7	49.9	83.8	10.9	0.4	52.4	8.8	316.0	470.6	6489	7.2
01-02	11.0	252.7	49.9	86.9	10.9	0.4	52.4	8.8	316.0	472.5	6555	7.2
02-03	4.8	525.7	49.9	90.4	10.9	0.4	52.4	8.8	316.0	469.8	6620	7.1
03-04	4.8	252.7	49.9	93.4	10.9	0.4	52.4	8.8	316.0	472.8	6686	7.1
04-05	3.6	252.7	49.9	96.6	10.9	0.4	52.4	8.8	316.0	474.8	6751	7.0
05-06	3.6	525.7	49.9	99.6	10.9	0.4	52.4	8.8	316.0	477.8	6817	7.0
06-07	3.6	252.7	49.9	99.6	10.9	0.4	52.4	8.8	316.0	480.9	6882	7.0
07-08	3.6	252.7	49.9	105.7	10.9	0.4	52.4	8.8	316.0	484.0	6948	7.0
08-09	3.6	252.7	49.9	108.9	10.9	0.4	52.4	8.8	316.0	487.1	7013	6.9
09-10	3.6	252.7	49.9	112.1	10.9	0.4	52.4	8.8	316.0	490.3	7079	6.9
10-11	3.6	252.7	49.9	115.4	10.9	0.4	52.4	8.8	316.0	493.6	7144	6.9

TABLE 4.4. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2376	1.3
79-80	39.1	---	---	---		---	0.7	0.4	---	40.1	2568	1.6
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	2706	1.7
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	2850	1.7
82-83	59.5	---	---	3.1	---	---	0.7	0.5	---	63.9	2991	2.1
83-84	63.6	---	---	3.3	---	---	0.7	0.5	---	68.1	3132	2.2
84-85	68.7	---	---	3.3	---	---	0.7	0.5	---	73.3	3273	2.2
85-86	68.9	2.0	0.4	3.6	14.8	0.6	0.7	0.5	17.5	90.8	3433	2.6
86-87	69.8	2.0	0.4	3.[illegible]	14.8	0.6	0.7	0.5	17.5	92.7	3594	2.6
87-88	67.1	46.6	9.2	7.3	14.8	0.6	24.1	5.4	85.5	175.2	3754	4.7
88-89	60.6	46.6	9.7	11.1	14.8	0.6	24.1	5.7	85.5	173.2	3915	4.4
89-90	56.4	95.7	19.9	20.1	14.8	0.7	24.1	6.0	134.6	237.8	4075	5.8
90-91	52.5	95.7	20.9	28.6	14.8	0.7	24.1	6.3	134.6	243.6	4285	5.7
91-92	49.8	111.1	24.8	35.2	14.8	0.7	24.1	6.6	150.0	267.2	4495	5.9
92-93	47.4	168.0	37.4	48.4	14.8	0.8	24.1	6.9	206.9	347.8	4705	7.4
93-94	46.5	168.0	39.2	61.3	14.8	0.8	24.1	7.3	206.9	362.0	4915	7.4
94-95	48.5	168.0	39.3	71.2	14.8	0.9	63.6	9.7	246.4	416.0	5125	8.1
95-96	43.8	233.8	54.4	89.5	14.8	0.9	63.6	10.3	312.2	511.1	5385	9.5
96-97	36.3	302.9	70.8	108.6	14.8	0.9	63.6	10.8	381.3	608.7	5645	10.8
97-98	37.7	429.1	99.1	122.6	14.8	1.0	63.6	11.3	507.5	779.2	5904	13.2
98-99	37.5	429.1	104.1	138.4	14.8	1.0	63.6	11.9	507.5	800.4	6164	13.0
99-2000	31.7	429.1	109.3	156.6	14.8	1.1	63.6	12.5	507.5	818.7	6424	12.7
00-01	16.7	575.2	143.4	172.0	14.8	1.1	110.0	22.1	700.0	1055.3	6489	16.3
01-02	15.3	575.2	150.6	186.4	14.8	1.2	110.0	23.2	700.0	1076.7	6555	16.4
02-03	5.4	575.2	158.1	204.9	14.8	1.3	110.0	24.4	700.0	1094.1	6620	16.5
03-04	5.5	575.2	166.1	221.6	14.8	1.3	110.0	25.6	700.0	1120.1	6686	16.7
04-05	3.6	575.2	174.4	240.4	14.8	1.4	110.0	26.9	700.0	1146.7	6751	17.0
05-06	3.7	575.2	183.1	259.8	14.8	1.5	110.0	28.2	700.0	1176.3	6817	17.2
06-07	3.9	575.2	192.2	280.8	14.8	1.5	110.0	29.6	700.0	1208.0	6882	17.5
07-08	4.0	575.2	201.8	303.6	14.8	1.6	110.0	31.1	700.0	1242.1	6948	17.9
08-09	4.1	575.2	211.9	328.2	14.8	1.7	110.0	32.7	700.0	1278.6	7013	18.2
09-10	4.2	575.2	222.5	354.6	14.8	1.8	110.0	34.3	700.0	1317.4	7079	18.6
10-11	4.4	575.2	233.7	382.9	14.8	1.9	110.0	36.0	700.0	1358.9	7144	19.0

TABLE 4.5. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2376	1.4
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	2568	1.7
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	2706	1.8
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	2850	1.9
82-83	61.1	---	---	3.1	---	---	0.6	0.4	---	65.3	2991	2.2
83-84	62.0	---	---	3.3	---	---	0.6	0.4	---	66.3	3132	2.1
84-85	66.7	---	---	3.3	---	---	0.6	0.4	---	71.1	3273	2.2
85-86	66.7	1.3	0.2	3.6	10.9	0.4	0.6	0.4	12.8	84.1	3433	2.4
86-87	67.2	1.3	0.2	3.7	10.9	0.4	0.6	0.4	12.8	84.8	3594	2.3
87-88	66.4	30.0	5.9	6.7	10.9	0.4	17.1	3.6	58.0	141.0	3754	3.7
88-89	59.0	30.0	5.9	9.6	10.9	0.4	17.1	3.6	58.0	136.6	3915	3.5
89-90	54.5	58.7	11.6	16.6	10.9	0.4	17.1	3.6	86.7	173.4	4075	4.2
90-91	50.2	58.7	11.6	22.5	10.9	0.4	17.1	3.6	86.7	175.0	4285	4.1
91-92	47.1	66.8	13.2	26.6	10.9	0.4	35.9	5.6	113.6	206.0	4495	4.6
92-93	42.4	66.8	13.2	30.3	10.9	0.4	35.9	5.6	113.6	205.0	4705	4.4
93-94	38.9	95.5	18.9	38.9	10.9	0.4	35.9	5.6	142.3	244.5	4915	5.0
94-95	39.4	95.5	18.9	20.6	155.9	1.0	35.9	5.6	287.3	372.3	5125	7.3
95-96	34.5	95.5	18.9	21.6	155.9	1.0	35.9	5.6	287.3	368.4	5385	6.8
96-97	28.3	95.5	18.9	27.9	155.9	1.0	35.9	5.6	287.3	368.5	5645	6.5
97-98	25.4	95.5	18.9	32.2	155.9	1.0	35.9	5.6	287.3	369.9	5904	6.3
98-99	27.4	95.5	18.9	26.4	155.9	1.0	35.9	5.6	287.3	376.1	6164	6.1
99-2000	22.6	95.5	18.9	7.9	204.2	1.6	35.9	5.6	335.6	391.7	6424	6.1
00-01	12.2	95.5	18.9	8.0	204.2	1.6	35.9	5.6	335.6	381.4	6489	5.9
01-02	11.0	95.5	18.9	8.1	204.2	1.6	35.9	5.6	335.6	380.3	6555	5.6
02-03	4.8	95.5	18.9	9.3	204.2	1.6	35.9	5.6	335.6	375.3	6620	5.7
03-04	4.8	95.5	18.9	10.6	204.2	1.6	35.9	5.6	335.6	376.6	6686	5.6
04-05	3.6	95.5	18.9	12.0	204.2	1.6	35.9	5.6	335.6	376.8	6751	5.6
05-06	3.6	95.5	18.9	13.2	204.2	1.6	35.9	5.6	335.6	378.0	6817	5.5
06-07	3.6	95.5	18.9	14.6	204.2	1.6	35.9	5.6	335.6	379.4	6882	5.5
07-08	3.6	95.5	18.9	16.0	204.2	1.6	35.9	5.6	335.6	380.8	6948	5.5
08-09	3.6	95.5	18.9	17.4	204.2	1.6	35.9	5.6	335.6	382.2	7013	5.4
09-10	3.6	95.5	18.9	18.9	204.2	1.6	35.9	5.6	335.6	383.7	7079	5.4
10-11	3.6	95.5	18.9	20.4	204.2	1.6	35.9	5.6	335.6	385.2	7144	5.4

TABLE 4.6. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2376	1.3
79-80	39.1	---	---	---	--	---	0.7	0.4	---	40.1	2568	1.6
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	2706	1.7
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	2850	1.7
82-83	59.5	---	---	3.1	---	---	0.7	0.5	---	63.9	2991	2.1
83-84	63.6	---	---	3.3	---	---	0.7	0.5	---	68.1	3132	2.2
84-85	68.7	---	---	3.3	---	---	0.7	0.5	---	73.3	3273	2.2
85-86	68.9	2.0	0.4	3.6	14.8	0.6	0.7	0.5	17.5	90.8	3433	2.6
86-87	69.3	2.0	0.4	3.9	14.8	0.6	0.7	0.5	17.5	92.7	3594	2.6
87-88	67.1	46.6	9.2	7.3	14.8	0.6	24.1	5.4	85.5	175.2	3754	4.7
88-89	60.6	46.6	9.7	11.1	14.8	0.6	24.1	5.7	85.5	173.2	3915	4.4
89-90	56.4	95.7	19.9	20.1	14.8	0.7	24.1	6.0	134.6	237.8	4075	5.8
90-91	52.5	95.7	20.9	28.6	14.8	0.7	24.1	6.3	134.6	243.6	4285	5.7
91-92	49.8	111.1	24.8	35.3	14.8	0.7	58.2	8.4	184.1	303.1	4495	6.7
92-93	47.4	111.1	26.1	42.5	14.8	0.8	58.2	8.8	184.1	309.7	4705	6.6
93-94	46.5	170.8	29.2	56.9	14.8	0.8	58.2	9.3	243.8	396.5	4915	8.1
94-95	48.5	170.8	41.1	31.7	319.9	2.1	58.2	9.7	548.9	682.0	5125	13.3
95-96	43.8	170.8	43.2	35.0	319.9	2.2	58.2	10.2	548.9	683.3	5385	12.7
96-97	36.3	170.8	45.4	47.4	319.9	2.3	58.2	10.7	548.9	691.0	5645	12.2
97-98	37.7	170.8	47.6	56.9	319.9	2.4	58.2	11.3	548.9	704.8	5904	11.9
98-99	37.5	170.8	50.0	68.1	319.9	2.5	58.2	11.8	548.9	718.8	6164	11.7
99-2000	31.7	170.8	52.5	15.4	449.7	4.2	58.2	12.4	678.7	794.9	6424	12.4
00-01	16.7	170.8	55.0	16.3	449.7	4.5	58.2	13.5	678.7	784.8	5489	12.1
01-02	15.3	170.8	57.9	17.4	449.7	4.7	58.2	13.7	678.7	787.7	6555	12.0
02-03	5.4	170.8	60.8	21.2	449.7	4.9	58.2	14.4	678.7	785.4	6620	11.9
03-04	5.5	170.8	63.8	25.1	449.7	5.2	58.2	15.1	678.7	793.4	6686	11.9
04-05	3.6	170.8	67.0	29.9	449.7	5.4	58.2	15.9	678.7	800.5	6751	11.9
05-06	3.7	170.8	70.4	34.3	449.7	5.7	58.2	16.7	678.7	809.5	6816	11.9
06-07	3.9	170.8	73.9	40.0	449.7	6.0	58.2	17.5	678.7	820.0	6882	11.9
07-08	4.0	170.8	77.6	45.9	449.7	6.3	58.2	18.4	678.7	830.9	6948	11.9
08-09	4.1	170.8	81.5	52.4	449.7	6.6	58.2	19.3	678.7	842.6	7013	12.0
09-10	4.2	170.8	85.5	59.7	449.7	6.9	58.2	20.2	678.7	855.2	7079	12.1
10-11	4.4	170.8	89.8	67.5	449.7	7.3	58.2	21.3	678.7	869.0	7144	12.2

TABLE 4.7. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	33.1	---	---	---	---	---	.6	.4	---	34.1	2531	1.3
79-80	42.2	---	---	---	---	---	.6	.4	---	43.2	2801	1.5
80-81	48.2	---	---	---	---	---	.6	.4	---	49.2	3041	1.6
81-82	52.8	---	---	---	---	---	.6	.4	---	53.8	3281	1.6
82-83	61.1	28.7	5.7	6.5	---	---	.6	.4	29.3	103.0	3521	2.9
83-84	62.0	28.7	5.7	9.2	---	---	.6	.4	29.3	106.6	3761	2.8
84-85	66.7	28.7	5.7	11.8	---	---	.6	.4	29.3	114.0	4001	2.8
85-86	66.7	58.7	11.6	18.5	10.9	.4	17.1	3.6	86.7	187.6	4329	4.3
86-87	67.2	58.7	11.6	24.19	10.9	.4	17.1	3.6	86.7	193.7	4657	4.2
87-88	66.4	87.4	17.3	29.9	10.9	0.4	17.1	3.6	115.4	233.0	4985	4.7
88-89	59.0	87.4	17.3	36.2	10.9	0.4	17.1	3.6	115.4	231.9	5313	4.4
89-90	54.5	116.1	23.0	46.4	10.9	0.4	17.1	3.6	144.1	272.0	5641	4.8
90-91	50.2	116.1	23.0	52.9	10.9	0.4	17.1	3.6	144.1	274.2	6063	4.5
91-92	47.1	152.9	30.3	61.9	10.9	0.4	17.1	3.6	180.9	324.2	6485	5.0
92-93	42.4	202.8	40.1	70.2	10.9	0.4	17.1	3.6	230.8	387.5	6907	5.6
93-94	38.9	202.8	40.1	77.9	10.9	0.4	17.1	3.6	230.8	391.7	7329	5.3
94-95	39.4	202.8	40.1	84.6	10.9	0.4	17.1	3.6	230.8	398.9	7751	5.1
95-96	34.5	252.7	49.9	94.6	10.9	0.4	17.1	3.6	280.7	463.7	8311	5.6
96-97	28.3	302.6	59.7	106.8	10.9	0.4	33.5	6.8	347.0	549.0	8871	6.2
97-98	25.4	352.5	69.5	116.9	10.9	0.4	33.5	6.8	396.9	615.9	9431	6.5
98-99	27.4	353.5	69.5	126.7	10.9	0.4	33.5	6.8	396.9	627.7	9991	6.3
99-2000	22.6	402.4	79.3	138.5	10.9	0.4	33.5	6.8	446.8	694.4	10551	6.6
00-01	12.2	402.4	79.3	146.3	10.9	0.4	33.5	6.8	446.8	691.8	10863	6.4
01-02	11.0	402.4	79.3	154.3	10.9	0.4	33.5	6.8	446.8	698.6	11175	6.3
02-03	4.8	452.3	89.1	162.5	10.9	0.4	33.5	6.8	496.7	760.3	11487	6.6
03-04	4.8	452.3	89.1	170.7	10.9	0.4	33.5	6.8	496.7	767.9	11799	6.5
04-05	3.6	452.3	89.1	179.4	10.9	0.4	33.5	6.8	496.7	776.0	12111	6.4
05-06	3.6	502.2	98.9	188.0	10.9	0.4	50.0	10.0	563.1	864.0	12423	6.9
06-07	3.6	502.2	98.9	196.8	10.9	0.4	50.0	10.0	563.1	872.8	12735	6.8
07-08	3.6	502.2	98.9	205.9	10.9	0.4	50.0	10.0	563.1	881.9	13047	6.8
08-09	3.6	502.2	98.9	215.1	10.9	0.4	50.0	10.0	563.1	891.1	13359	6.7
09-10	3.6	502.2	98.9	224.6	10.9	0.4	50.0	10.0	563.1	901.6	13671	6.6
10-11	3.6	552.1	108.7	234.2	10.9	0.4	50.0	10.0	613.0	969.9	13983	6.9

TABLE 4.8. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Costs Investment Costs	Transmission Systems Costs OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2531	1.2
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.2	2801	1.4
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3041	1.5
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	3281	1.5
82-83	59.5	34.9	6.9	6.5	---	---	0.7	0.5	35.6	109.1	3521	3.1
83-84	63.6	34.9	7.2	9.2	---	--	0.7	0.5	35.6	116.1	3761	3.1
84-85	68.7	34.9	7.6	11.8	---	---	0.7	0.5	35.6	124.3	4001	3.1
85-86	68.9	77.3	16.4	18.1	14.8	0.6	23.0	4.9	115.1	224.0	4329	5.2
86-87	69.8	77.3	17.2	25.3	14.8	0.6	23.0	5.1	115.1	233.2	4657	5.0
87-88	67.1	121.9	26.8	32.7	14.8	0.6	23.0	5.4	159.7	292.3	4985	5.9
88-89	60.6	121.9	28.2	41.6	14.8	0.6	23.0	5.7	159.7	296.5	5313	5.6
89-90	56.4	171.0	39.3	56.3	14.8	0.7	23.0	6.0	208.8	367.5	5641	6.5
90-91	52.5	171.0	41.3	67.3	14.8	0.7	23.0	6.3	208.8	376.9	6063	6.2
91-92	49.8	240.6	56.9	82.2	14.8	0.7	23.0	6.6	278.4	474.6	6485	7.3
92-93	47.4	339.5	79.2	98.6	14.8	0.8	23.0	6.9	377.3	608.6	6907	8.8
93-94	46.5	339.5	83.2	113.9	14.8	0.3	23.0	7.2	377.3	628.9	7329	8.6
94-95	48.5	339.5	87.3	130.1	14.8	0.9	23.0	7.6	377.3	659.3	7751	8.5
95-96	43.8	454.0	114.2	153.3	14.8	0.9	23.0	8.0	491.8	812.0	8311	9.7
96-97	36.3	574.2	143.5	180.8	14.8	0.9	63.0	16.0	652.0	1029.5	8871	11.6
97-98	37.7	700.4	175.5	207.2	14.8	1.0	63.0	16.6	778.2	1216.2	9431	12.9
98-99	37.5	700.4	184.2	236.7	14.8	1.0	63.0	17.4	778.2	1255.0	9991	12.6
99-2000	31.8	839.5	220.8	269.7	14.8	1.1	63.0	18.3	917.3	1459.0	10551	13.8
00-01	16.7	839.5	231.8	300.2	14.8	1.1	63.0	19.2	917.3	1486.3	10863	13.7
01-02	15.3	839.5	243.4	331.2	14.8	1.2	63.0	20.2	917.3	1528.6	11175	13.7
02-03	5.4	1000.6	287.2	368.3	14.8	1.3	63.0	21.2	1078.4	1761.8	11487	15.3
03-04	5.5	1000.6	301.5	405.2	14.8	1.3	63.0	22.2	1078.4	1814.1	11799	15.4
04-05	3.6	1000.6	316.6	446.6	14.8	1.4	63.0	23.3	1078.4	1869.9	12111	15.4
05-06	3.7	1187.1	369.0	490.4	14.8	1.5	116.7	34.9	1319.6	2218.1	12423	17.8
06-07	3.9	1187.1	387.5	538.4	14.8	1.5	116.7	36.6	1318.6	2286.5	12735	17.9
07-08	4.0	1187.1	406.8	590.9	14.8	1.6	116.7	38.5	1318.6	2360.4	13047	18.1
08-09	4.1	1187.1	427.2	648.1	14.8	1.7	116.7	40.4	1318.6	2440.1	13359	18.3
09-10	4.2	1187.1	448.5	710.1	14.8	1.8	116.7	42.4	1318.6	2525.6	13671	18.5
10-11	4.4	1425.1	517.7	777.3	14.8	1.9	116.7	44.6	1556.6	2902.5	13983	20.7

TABLE 4.9. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2531	1.3
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	2801	1.5
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	3041	1.6
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	3281	1.6
82-83	61.1	28.7	5.7	6.5	---	---	0.6	0.4	29.3	103.0	3521	2.9
83-84	62.0	28.7	5.7	9.2	---	---	0.6	0.4	29.3	106.6	3761	2.8
84-85	66.7	28.7	5.7	11.8	---	---	0.6	0.4	29.3	114.0	4001	2.8
85-86	66.7	58.7	11.6	18.5	10.9	0.4	17.1	3.6	86.7	187.6	4329	4.3
86-87	67.2	58.7	11.6	24.19	10.9	0.4	17.1	3.6	86.7	193.7	4657	4.2
87-88	66.4	87.4	17.3	29.9	10.9	0.4	17.1	3.6	115.4	233.0	4985	4.7
88-89	59.0	87.4	17.3	36.2	10.9	0.4	17.1	3.6	115.4	231.9	5313	4.4
89-90	54.5	87.4	17.3	42.5	10.9	0.4	35.9	5.6	134.2	254.5	5641	4.5
90-91	50.2	116.1	24.6	50.1	10.9	0.4	35.9	5.6	162.9	293.8	6063	4.8
91-92	47.1	152.9	31.9	59.1	10.9	0.4	35.9	5.6	199.7	343.8	6485	5.3
92-93	42.4	202.8	41.7	70.2	10.9	0.4	35.9	5.6	249.6	409.9	6907	5.9
93-94	38.9	202.8	41.7	77.9	10.9	0.4	35.9	5.6	249.6	414.1	7329	5.6
94-95	39.4	202.8	41.7	84.6	10.9	0.4	35.9	5.6	249.6	421.3	7751	5.4
95-96	34.5	252.7	51.5	94.6	10.9	0.4	35.9	5.6	299.5	486.1	8311	5.8
96-97	28.3	302.6	61.3	106.8	10.9	0.4	52.4	8.8	365.9	571.5	8871	6.4
97-98	25.4	302.6	61.3	116.9	10.9	0.4	52.4	8.8	365.9	578.7	9431	6.1
98-99	27.4	352.5	71.1	126.7	10.9	0.4	52.4	8.8	415.8	650.2	9991	6.5
99-2000	22.6	352.5	71.1	138.5	10.9	0.4	52.4	8.8	415.8	657.2	10551	6.2
00-01	12.2	402.4	80.9	146.3	10.9	0.4	52.4	8.8	465.7	714.3	10863	6.6
01-02	11.0	402.4	80.9	154.3	10.9	0.4	52.4	8.8	465.7	721.1	11175	6.4
02-03	4.8	402.4	80.9	162.5	10.9	0.4	52.4	8.8	465.7	723.1	11487	6.3
03-04	3.6	452.3	90.7	170.7	10.9	0.4	52.4	8.8	515.6	789.8	11799	6.7
04-05	3.6	452.3	90.7	179.4	10.9	0.4	52.4	8.8	515.6	798.5	12111	6.6
05-06	3.6	452.3	90.7	188.0	10.9	0.4	52.4	8.8	515.6	807.1	12423	6.5
06-07	3.6	452.3	90.7	196.8	10.9	0.4	52.4	6.6	515.6	815.9	12735	6.4
07-08	3.6	502.2	100.5	205.9	10.9	0.4	68.9	12.0	582.0	904.4	13047	6.9
08-09	3.6	502.2	100.5	215.1	10.9	0.4	68.9	12.0	582.0	913.6	13359	6.8
09-10	3.6	502.2	100.5	224.6	10.9	0.4	68.9	12.0	582.0	923.1	13671	6.7
10-11	3.6	502.2	100.5	234.2	10.9	0.4	68.9	12.0	582.0	932.7	13983	6.7

TABLE 4.10. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems Costs		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2531	1.2
79-80	39.1	---	---	---	-	---	0.7	0.4	---	40.2	2801	1.4
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3041	1.5
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	3281	1.5
82-83	59.5	34.9	6.9	6.5	---	---	0.7	0.5	35.6	109.1	3521	3.1
83-84	63.6	34.9	7.2	9.2	---	--	0.7	0.5	35.6	116.1	3761	3.1
84-85	68.7	34.9	7.6	11.8	---	---	0.7	0.5	35.6	124.3	4001	3.1
85-86	68.9	77.3	16.4	18.1	14.3	0.6	23.0	4.9	115.1	224.0	4329	5.2
86-87	69.8	77.3	17.2	25.3	14.8	0.6	23.0	5.1	115.1	233.2	4657	5.0
87-88	67.1	121.9	26.8	32.7	14.8	0.6	23.0	5.4	159.7	292.3	4985	5.9
88-89	60.6	121.9	28.2	41.6	14.8	0.6	23.0	5.7	159.7	296.5	5313	5.6
89-90	56.4	121.9	29.6	51.5	14.8	0.7	53.9	9.3	190.6	338.1	5641	6.0
90-91	52.5	173.6	41.3	63.7	14.8	0.7	53.9	9.7	242.2	410.1	6063	6.8
91-92	49.8	243.1	56.9	78.3	14.8	0.7	53.9	10.2	311.8	507.8	6485	7.8
92-93	47.4	342.0	79.2	98.5	14.8	0.8	53.9	10.7	410.7	647.4	6907	9.4
93-94	46.5	342.0	83.2	113.8	14.8	0.8	53.9	11.3	410.7	666.4	7329	9.1
94-95	48.5	342.0	87.3	130.1	14.8	0.9	53.9	11.8	410.7	689.3	7751	8.9
95-96	43.8	465.5	114.2	153.3	14.8	0.9	53.9	12.4	534.2	858.8	8311	10.3
96-97	36.5	576.7	143.5	180.8	14.8	0.9	93.9	20.9	685.4	1067.8	8871	12.0
97-98	37.7	576.7	150.6	207.1	14.8	1.0	93.9	21.9	685.4	1103.8	9431	11.7
98-99	37.5	709.2	184.2	236.6	14.8	1.0	93.9	23.0	817.9	1300.3	9991	13.0
99-2000	31.7	709.2	193.4	269.7	14.8	1.1	93.9	24.2	817.9	1338.1	10551	12.7
00-01	16.7	855.3	231.7	300.2	14.8	1.1	93.9	25.4	964.0	1539.1	10863	14.2
01-02	15.3	855.3	243.3	331.2	14.8	1.2	93.9	26.7	964.0	1581.7	11175	14.1
02-03	5.4	955.3	225.5	368.3	14.8	1.3	93.9	28.0	964.0	1592.5	11487	13.9
03-04	5.5	1024.4	301.5	405.2	14.8	1.3	93.9	29.4	1133.1	1876.0	11799	15.9
04-05	3.6	1024.4	316.6	446.6	14.8	1.4	93.9	30.9	1133.1	1932.2	12111	15.9
05-06	3.7	1024.4	332.4	490.4	14.8	1.5	93.9	32.4	1133.1	1993.5	12423	16.0
06-07	3.9	1024.4	349.0	538.4	14.8	1.5	93.9	34.0	1133.1	2059.9	12735	16.2
07-08	4.0	1230.0	406.8	590.9	14.8	1.6	148.9	46.7	1393.7	2443.7	13047	18.7
08-09	4.1	1230.0	427.1	648.1	14.8	1.7	148.9	49.0	1393.7	2523.7	13359	18.9
09-10	4.2	1230.0	448.4	710.1	14.8	1.8	148.9	51.5	1393.7	2609.7	13671	19.1
10-11	4.4	1230.0	470.8	777.3	14.8	1.9	148.9	54.1	1393.7	2702.2	13983	19.3

TABLE 4.11. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	1.0	---	---	---	---	34.1	2531	---
79-80	42.2	---	---	---	1.0	---	---	---	---	43.2	2801	---
80-81	78.2	---	---	---	1.0	---	---	---	---	49.2	3041	---
81-82	52.8	---	---	---	1.0	---	---	---	---	53.8	3281	---
82-83	61.1	28.7	5.7	6.5	1.0	---	---	---	29.3	103.0	3521	---
83-84	62.0	28.7	5.7	9.2	1.0	---	---	---	29.3	106.6	3761	---
84-85	66.6	28.7	5.7	11.8	20.7	---	---	---	29.3	114.0	4001	---
85-86	66.7	58.7	11.6	18.4	20.7	---	---	---	86.7	187.6	4329	---
86-87	67.1	58.7	11.6	24.1	20.7	---	---	---	86.7	193.7	4657	---
87-88	66.3	87.4	17.3	30.1	20.7	---	---	---	115.4	233.0	4985	---
88-89	59.0	87.4	17.3	36.2	10.9	0.4	17.1	3.6	115.4	231.9	5313	4.4
89-90	54.5	87.4	17.3	42.5	10.9	0.4	35.9	5.6	134.2	254.5	5641	4.5
90-91	50.2	116.1	24.6	50.1	10.9	0.4	35.9	5.6	162.9	293.8	6063	4.8
91-92	47.1	152.9	31.9	59.1	10.9	0.4	35.9	5.6	199.7	343.8	6485	5.3
92-93	42.4	202.8	41.7	70.2	10.9	0.4	35.9	5.6	249.6	409.9	6907	5.9
93-94	38.9	202.8	41.7	77.9	10.9	0.4	35.9	5.6	249.6	414.1	7329	5.6
94-95	39.4	202.8	41.7	53.3	157.7	1.1	35.9	5.6	396.4	537.5	7751	6.9
95-96	34.5	202.8	41.7	58.6	157.7	1.1	35.9	5.6	396.4	537.9	8311	6.5
96-97	28.3	202.8	41.7	69.9	157.7	1.1	35.9	5.6	396.4	543.0	8871	6.1
97-98	25.4	202.8	41.7	79.1	157.7	1.1	35.9	5.6	396.4	549.3	9431	5.8
98-99	27.4	202.8	41.7	54.5	206.6	1.8	35.9	5.6	445.3	576.3	9991	5.8
99-2000	22.6	202.8	41.7	60.2	206.6	1.8	35.9	5.6	445.3	577.2	10,551	5.5
00-01	12.2	202.8	41.7	66.8	206.6	1.8	35.9	5.6	445.3	573.4	10,863	5.3
01-02	11.0	202.8	41.7	73.1	206.6	1.8	35.9	5.6	445.3	578.5	11,175	5.2
02-03	4.8	252.7	51.5	80.0	206.6	1.8	52.4	8.8	511.7	658.6	11,487	5.7
03-04	4.8	252.7	51.5	86.5	206.6	1.8	52.4	8.8	511.7	665.1	11,799	5.6
04-05	3.6	252.7	51.5	93.4	206.6	1.8	52.4	8.8	511.7	670.8	12,111	5.5
05-06	3.6	252.7	51.5	100.2	206.6	1.8	52.4	8.8	511.7	677.6	12,423	5.4
06-07	3.6	302.6	61.3	107.3	206.6	1.8	52.4	8.8	561.6	744.4	12,735	5.8
07-08	3.6	302.6	61.3	114.5	206.6	1.8	52.4	8.8	561.6	751.6	13,047	5.8
08-09	3.6	302.6	61.3	121.9	206.6	1.8	52.4	8.8	561.6	759.0	13,359	5.7
09-10	3.6	302.6	61.3	129.6	206.6	1.8	52.4	8.8	561.6	766.7	13,671	5.6
10-11	3.6	352.5	71.1	137.5	206.6	1.8	52.4	8.8	611.5	834.3	13,983	5.9

TABLE 4.12. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 3, 5% Inflation

		New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems					
Year	Total Cost of Existing Capacity	Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2531	1.2
79-80	39.1	---	---	---		---	0.7	0.4	---	40.2	2801	1.4
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3041	1.5
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	3281	1.5
82-83	59.5	34.9	6.9	6.5	---	---	0.7	0.5	35.6	109.1	3521	3.1
83-84	63.6	34.9	7.2	9.2	---	--	0.7	0.5	35.6	116.1	3761	3.1
84-85	68.7	34.9	7.6	11.8	---	---	0.7	0.5	35.6	124.3	4001	3.1
85-86	68.9	77.3	16.4	18.1	14.3	0.6	23.0	4.9	115.1	224.0	4329	5.2
86-87	69.8	77.3	17.2	25.3	14.8	0.6	23.0	5.1	115.1	233.2	4657	5.0
87-88	67.1	121.9	26.8	32.7	14.8	0.6	23.0	5.4	159.7	292.3	4985	5.9
88-89	60.6	121.9	28.2	41.6	14.8	0.6	23.0	5.7	159.7	296.5	5313	5.6
89-90	56.4	121.9	29.6	51.5	14.8	0.7	53.9	9.3	190.6	338.1	5641	6.0
90-91	52.5	173.5	41.3	63.7	14.8	0.7	53.9	9.7	242.2	410.1	6063	6.8
91-92	49.8	243.1	56.9	78.3	14.8	0.7	53.9	10.2	311.8	507.8	6485	7.8
92-93	47.4	342.0	79.2	98.5	14.8	0.8	53.9	10.7	410.7	647.4	6907	9.4
93-94	46.5	342.0	83.2	113.8	14.8	0.8	53.9	11.3	410.7	666.4	7329	9.1
94-95	48.5	342.0	87.4	82.1	323.7	2.4	53.9	11.8	719.6	951.8	7751	12.3
95-96	43.8	342.0	91.7	94.9	323.7	2.5	53.9	12.4	719.6	964.9	8311	11.6
96-97	36.3	342.0	96.3	118.3	323.7	2.7	53.9	13.0	719.6	986.2	8871	11.1
97-98	37.7	342.0	101.1	140.2	323.7	2.8	53.9	13.7	719.6	1015.1	9431	10.8
98-99	37.5	342.0	106.2	101.8	448.8	4.4	53.9	14.3	844.7	1109.0	9991	11.1
99-2000	31.7	342.0	111.5	117.2	448.8	4.6	53.9	15.1	844.7	1124.8	10,551	10.7
00-01	16.7	342.0	117.1	137.1	448.8	4.9	53.9	15.8	844.7	1136.3	10,863	10.5
01-02	15.3	342.0	122.9	156.8	448.8	5.1	53.9	16.6	844.7	1161.4	11,175	10.4
02-03	5.4	503.1	160.7	181.4	448.8	5.4	104.9	26.9	1056.8	1436.6	11,487	12.5
03-04	5.5	503.1	168.7	205.3	448.8	5.6	104.9	28.2	1056.8	1470.1	11,799	12.4
04-05	3.6	503.1	177.1	232.5	448.8	5.9	104.9	29.6	1056.8	1505.5	12,111	12.4
05-06	3.7	503.1	185.9	261.4	448.8	6.2	104.9	31.1	1056.8	1545.1	12,423	12.4
06-07	3.9	698.9	233.7	293.5	448.8	6.5	104.9	32.7	1252.6	1822.9	12,735	14.3
07-08	4.0	698.9	245.4	328.7	448.8	6.8	104.9	34.3	1252.6	1871.8	13,047	14.3
08-09	4.1	698.9	257.6	367.5	448.8	7.2	104.9	36.0	1252.6	1925.0	13,359	14.4
09-10	4.2	698.9	270.5	409.9	448.8	7.5	104.9	37.8	1252.6	1982.2	13,671	14.5
10-11	4.4	936.9	330.7	456.3	448.8	7.9	104.9	39.7	1490.6	2329.6	13,983	16.7

TABLE 4.13. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2680	1.3
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	3025	1.4
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	3688	1.3
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	4352	1.2
82-83	61.1	57.4	11.4	9.8	---	---	17.1	3.6	74.5	160.5	5015	3.2
83-84	62.0	86.1	17.1	18.6	---	---	17.1	3.6	103.2	204.5	5679	3.6
84-85	66.7	114.8	22.8	29.9	---	---	17.1	3.6	131.9	254.9	6342	4.0
85-86	66.7	144.8	28.7	44.8	10.9	0.4	17.1	3.6	142.8	317.0	6849	4.6
86-87	67.2	164.7	38.5	66.2	10.9	0.4	17.1	3.6	192.7	368.6	7357	5.0
87-88	66.4	164.7	38.5	73.4	10.9	0.4	17.1	3.6	192.7	375.0	7864	4.8
88-89	59.0	214.6	48.3	81.2	10.9	0.4	33.6	6.8	259.1	454.8	8372	5.4
89-90	54.5	214.6	48.3	88.6	10.9	0.4	33.6	6.8	259.1	457.7	8879	5.1
90-91	50.2	214.6	48.3	98.5	10.9	0.4	33.6	6.8	259.1	463.3	9589	4.8
91-92	47.1	272.6	59.7	109.9	10.9	0.4	33.6	6.8	317.1	541.0	10,298	5.2
92-93	42.4	322.5	69.5	120.1	10.9	0.4	33.6	6.8	367.0	606.2	11,008	5.5
93-94	38.9	322.5	69.5	132.6	10.9	0.4	33.6	6.8	367.0	615.2	11,717	5.3
94-95	39.4	372.4	79.3	143.9	10.9	0.4	33.6	6.8	416.9	686.7	12,427	5.5
95-96	34.5	422.3	89.1	161.3	10.9	0.4	50.1	10.0	483.3	778.6	13,477	5.8
96-97	28.3	472.2	98.9	181.5	10.9	0.4	50.1	10.0	533.2	852.3	14,526	5.9
97-98	25.4	522.1	108.7	200.1	10.9	0.4	50.1	10.0	583.1	927.7	15,576	6.0
98-99	27.4	572.0	118.5	217.9	10.9	0.4	50.1	10.0	633.0	1008.2	16,625	6.1
99-2000	22.6	621.9	128.3	238.7	10.9	0.4	66.6	13.2	699.4	1102.6	17,675	6.2
00-01	12.2	671.8	138.1	256.6	10.9	0.4	66.6	13.2	749.3	1169.8	18,584	6.3
01-02	11.0	671.8	138.1	275.8	10.9	0.4	66.6	13.2	749.3	1187.8	19,493	6.1
02-03	4.8	721.7	147.9	294.6	10.9	0.4	66.6	13.2	799.2	1260.1	20,402	6.2
03-04	4.8	771.6	157.7	314.7	10.9	0.4	66.6	13.2	849.1	1339.9	21,311	6.3
04-05	3.6	771.6	157.7	335.6	10.9	0.4	66.6	13.2	849.1	1359.6	22,220	6.1
05-06	3.6	821.6	167.5	356.9	19.9	0.4	83.1	16.4	915.5	1460.3	23,129	6.3
06-07	3.6	871.4	177.3	378.8	10.9	0.4	83.1	16.4	965.4	1541.9	24,038	6.4
07-08	3.6	871.4	177.3	401.2	10.9	0.4	83.1	16.4	965.4	1564.3	24,947	6.3
08-09	3.6	921.3	187.1	424.2	10.9	0.4	83.1	16.4	1015.3	1647.0	25,856	6.4
09-10	3.6	971.2	196.9	447.8	10.9	0.4	83.1	16.4	1065.2	1730.3	26,765	6.5
10-11	3.6	971.2	196.9	472.0	10.9	0.4	83.1	16.4	1065.2	1754.5	27,674	6.3

TABLE 4.14. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2680	1.1
79-80	39.1	---	---	---	--	---	0.7	0.4	---	40.2	3025	1.3
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3688	1.3
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	4352	1.1
82-83	59.5	69.8	13.8	9.9	---	---	21.0	4.4	90.8	178.4	5015	3.6
83-84	63.6	106.4	21.8	18.6	---	---	21.0	4.6	127.4	236.0	5679	4.2
84-85	68.7	144.9	30.5	29.9	---	---	21.0	4.9	165.9	299.9	6342	4.7
85-86	68.9	187.3	38.9	44.8	14.8	0.6	21.0	5.1	223.1	381.4	6849	5.6
86-87	69.8	261.1	49.2	69.4	14.8	0.6	21.0	5.4	296.9	491.3	7356	6.7
87-88	67.1	261.1	51.7	80.5	14.8	0.6	21.0	5.6	296.9	502.4	7864	6.4
88-89	60.6	342.5	70.2	93.4	14.8	0,6	48.1	11.2	405.4	641.4	8372	7.7
89-90	56.4	342.5	73.7	107.4	14.8	0.7	48.1	11.7	405.4	655.3	8870	7.4
90-91	52.5	342.5	77.4	125.4	14.8	0.7	48.1	12.3	405.4	673.7	9589	7.0
91-92	49.8	452.1	102.6	145.9	14.8	0.7	48.1	12.9	515.0	826.9	10,298.	8.0
92-93	47.4	551.0	127.2	168.5	14.8	0.8	48.1	13.6	613.9	971.4	11,008	8.8
93-94	46.5	551.0	133.5	193.8	14.8	0.8	48.1	14.3	613.9	1002.8	11,717	8.6
94-95	48.5	660.0	161.6	221.3	14.8	0.9	48.1	15.0	722.9	1170.2	12,427	9.4
95-96	43.8	774.5	192.2	261.2	14.8	0.9	87.1	22.7	876.4	1397.2	13,477	10.4
96-97	36.3	894.7	225.4	307.4	14.8	0.9	87.1	23.9	996.6	1590.5	14,526	10.9
97-98	37.7	1020.9	261.5	354.5	14.8	1.0	87.1	25.1	1122.8	1802.6	15,576	11.6
98-99	37.5	1153.4	300.5	407.1	14.8	1.0	87.1	26.3	1255.3	2027.7	16,625	12.2
99-2000	31.7	1292.6	342.8	464.8	14.8	1.1	131.3	36.2	1438.7	2315.3	17,675	13.1
00-01	16.7	1438.7	388.7	526.5	14.8	1.1	131.3	37.9	1584.8	2555.7	18,584	13.8
01-02	15.3	1438.7	408.1	592.6	14.8	1.2	131.3	39.9	1584.8	2641.9	19,493	13.6
02-03	5.4	1599.8	460.1	667.5	14.8	1.3	131.3	41.9	1745.9	2922.1	20,402	14.3
03-04	5.5	1769.0	516.3	746.8	14.8	1.3	131.3	43.9	1915.1	3228.9	21,311	15.1
04-05	3.6	1769.0	542.2	835.5	14.8	1.4	131.3	46.1	1915.1	3343.9	22,220	15.0
05-06	3.7	1955.5	605.9	930.8	14.8	1.5	184.3	58.4	2154.6	3754.9	23,129	16.2
06-07	3.9	2151.3	674.6	1035.9	14.8	1.5	184.3	61.3	2350.4	4127.6	24,038	17.2
07-08	4.0	2151.3	708.3	1151.5	14.8	1.6	184.3	64.4	2350.4	4280.2	24,947	17.2
08-09	4.1	2367.2	786.1	1278.1	14.8	1.7	184.3	67.6	2566.3	4703.9	25,856	18.2
09-10	4.2	2593.9	869.9	1416.3	14.8	1.8	184.3	70.9	2793.0	5156.1	26,765	19.3
10-11	4.4	2593.9	913.4	1566.6	14.8	1.9	184.3	74.5	2793.0	5353.8	27,674	19.3

TABLE 4.15. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2680	1.3
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	3025	1.4
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	3688	1.3
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	4352	1.2
82-83	61.1	57.4	11.4	9.8	---	---	17.1	3.6	74.5	160.5	5015	3.2
83-84	62.0	86.1	17.1	18.6	---	---	17.1	3.6	103.2	204.5	5679	3.6
84-85	66.7	114.8	22.8	29.9	---	---	17.1	3.6	131.9	254.9	6342	4.0
85-86	66.7	144.8	28.7	44.8	10.9	0.4	17.1	3.6	142.8	317.0	6849	4.6
86-87	67.2	144.8	28.7	58.7	10.9	0.4	35.9	5.6	191.6	352.2	7357	4.8
87-88	66.4	194.7	33.5	73.4	10.9	0.4	35.9	5.6	241.5	420.8	7864	5.3
88-89	59.0	194.7	38.5	81.2	10.9	0.4	35.9	5.6	241.5	426.2	8372	5.1
89-90	54.5	244.6	48.3	88.6	10.9	0.4	52.4	8.8	307.9	508.5	8879	5.7
90-91	50.2	244.6	48.3	98.5	10.9	0.4	52.4	8.8	307.9	514.1	9589	5.4
91-92	47.1	302.6	59.7	109.9	10.9	0.4	52.4	8.8	365.9	591.8	10,298	5.7
92-93	42.4	302.6	59.7	120.1	10.9	0.4	52.4	8.8	365.9	597.3	11,008	5.4
93-94	38.9	352.5	69.5	132.6	10.9	0.4	52.4	8.8	415.8	666.0	11,717	5.7
94-95	39.4	352.5	69.7	143.9	10.9	0.4	52.4	8.8	415.8	678.0	12,427	5.5
95-96	34.5	402.4	79.3	161.3	10.9	0.4	52.4	8.8	465.7	750.0	13,477	5.6
96-97	28.3	452.3	89.1	181.5	10.9	0.4	68.9	12.0	532.1	843.4	14,526	5.8
97-98	25.4	502.2	98.9	200.1	10.9	0.4	68.9	12.0	582.0	918.8	15,576	5.9
98-99	27.4	552.1	108.7	217.9	10.9	0.4	68.9	12.0	631.9	998.3	16,625	6.0
99-2000	22.6	602.0	118.5	238.7	10.9	0.4	68.9	12.0	681.8	1074.0	17,675	6.1
00-01	12.2	651.9	128.3	256.5	10.9	0.4	85.4	15.2	748.2	1160.8	18,584	6.2
01-02	11.0	701.8	138.1	275.8	10.9	0.4	85.4	15.2	798.1	1238.6	19,493	6.3
02-03	4.8	751.7	147.9	294.6	10.9	0.4	85.4	15.2	848.0	1310.9	20,402	6.4
03-04	4.8	751.7	147.9	314.7	10.9	0.4	85.4	15.2	848.0	1331.0	21,311	6.2
04-05	3.6	751.7	147.9	335.6	10.9	0.4	85.4	15.2	848.0	1350.7	22,220	6.1
05-06	3.6	801.6	157.7	356.9	10.9	0.4	85.4	15.2	897.9	1431.7	23,129	6.2
06-07	[illegible].6	851.5	167.5	378.8	10.9	0.4	85.4	15.2	947.8	1513.3	24,038	6.3
07-08	3.6	901.4	177.3	401.2	10.9	0.4	101.9	18.4	1014.2	1615.1	24,947	6.5
08-09	3.6	901.4	177.3	424.2	10.9	0.4	101.9	18.4	1014.2	1638.1	25,856	6.3
09-10	3.6	951.3	187.1	447.8	10.9	0.4	101.9	18.4	1064.1	1721.4	26,765	6.4
10-11	3.6	1001.2	196.9	472.0	10.9	0.4	101.9	18.4	1114.0	1801.7	27,674	6.5

TABLE 4.16. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2680	1.1
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.2	3025	1.3
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3688	1.3
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	4352	1.1
82-83	59.5	69.8	13.8	9.9	---	---	21.0	4.4	90.8	178.4	5015	3.6
83-84	63.6	106.4	21.8	18.6	---	---	21.0	4.6	127.4	236.0	5679	4.2
84-85	68.7	144.9	30.5	29.9	---	---	21.0	4.9	165.9	299.9	6342	4.7
85-86	68.9	187.3	38.9	44.8	14.8	0.6	21.0	5.1	223.1	381.4	6849	5.6
86-87	69.8	187.3	40.8	61.5	14.8	0.6	47.7	8.1	249.8	430.6	4357	5.8
87-88	67.1	264.8	58.0	80.5	14.8	0.6	47.7	8.6	327.3	542.1	7864	6.9
88-89	60.6	264.8	60.9	93.4	14.8	0.6	47.7	9.0	327.3	551.8	8372	6.6
89-90	56.4	350.2	80.8	107.4	14.8	0.7	74.8	14.7	439.8	699.8	8879	7.9
90-91	52.5	350.2	84.8	125.4	14.8	0.7	74.8	15.4	439.8	718.6	9589	7.5
91-92	49.8	459.8	110.5	145.9	14.8	0.7	74.8	16.2	549.4	872.5	10,298	8.5
92-93	47.4	459.8	115.9	168.5	14.8	0.8	74.8	17.0	549.2	899.0	11,008	8.2
93-94	46.5	563.6	142.2	193.9	14.8	0.8	74.8	17.9	653.2	1054.5	11,717	9.0
94-95	48.5	563.6	149.3	221.3	14.8	0.9	74.8	18.8	563.2	1092.0	12,427	8.8
95-96	43.8	678.1	179.2	261.2	14.8	0.9	74.8	19.7	767.7	1272.5	13,477	9.4
96-97	36.3	798.3	211.8	307.4	14.8	0.9	113.8	27.7	926.9	1511.0	14,526	10.4
97-98	37.7	924.5	247.2	354.5	14.8	1.0	113.8	29.1	1053.1	1722.6	15,576	11.1
98-99	37.5	1057.0	285.5	407.1	14.8	1.0	113.8	30.5	1185.6	1947.2	16,625	11.7
99-2000	31.7	1196.2	327.1	464.8	14.8	1.1	113.8	32.0	1324.8	2181.5	17,675	12.3
00-01	16.7	1342.3	372.2	526.5	14.8	1.1	160.2	42.6	1517.3	2476.4	18,584	13.3
01-02	15.3	1495.7	420.9	591.8	14.8	1.2	160.2	44.7	1670.7	2744.6	19,493	14.1
02-03	5.4	1656.8	473.5	667.5	14.8	1.3	160.2	46.9	1831.8	3026.4	20,402	14.8
03-04	5.5	1656.8	497.2	746.8	14.8	1.3	160.2	49.3	1831.8	3131.9	21,311	14.7
04-05	3.6	1656.8	522.1	835.5	14.8	1.4	160.2	51.8	1831.8	3246.2	22,220	14.6
05-06	3.7	1843.3	584.8	930.8	14.8	1.5	160.2	54.4	2018.3	3593.5	23,129	15.5
06-07	3.9	2039.1	652.4	1035.9	14.8	1.5	160.2	57.1	2214.1	3964.9	24,038	16.5
07-08	4.0	2244.7	725.3	1151.5	14.8	1.6	215.2	70.9	2474.7	4428.0	24,947	17.7
08-09	4.1	2244.7	761.6	1278.1	14.8	1.7	215.2	74.5	2474.7	4594.7	25,856	17.8
09-10	4.2	2471.4	844.2	1416.3	14.8	1.8	215.2	78.2	2701.4	5046.1	26,765	18.8
10-11	4.4	2709.4	933.1	1566.6	14.8	1.9	215.2	82.1	2939.4	5527.5	27,674	19.9

TABLE 4.17. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2680	1.3
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	3025	1.4
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	3688	1.3
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	4352	1.2
82-83	61.1	57.4	11.4	9.8	---	---	17.1	3.6	74.5	160.5	5015	3.2
83-84	62.0	86.1	17.1	18.6	---	---	17.1	3.6	103.2	204.5	5679	3.6
84-85	66.7	114.8	22.8	29.9	---	---	17.1	3.6	131.9	254.9	6342	4.0
85-86	66.7	144.8	28.7	44.8	10.9	0.4	17.1	3.6	142.8	317.0	6849	4.6
86-87	67.2	144.8	28.7	58.7	10.9	0.4	35.9	5.6	191.6	352.2	7357	4.8
87-88	66.4	194.7	33.5	73.4	10.9	0.4	35.9	5.6	241.5	420.8	7864	5.3
88-89	59.0	194.7	38.5	81.2	10.9	0.4	35.9	5.6	241.5	426.2	8372	5.1
89-90	54.5	244.6	48.3	88.6	10.9	0.4	52.4	8.8	307.9	508.5	8879	5.7
90-91	50.2	244.6	48.3	98.5	10.9	0.4	52.4	8.8	307.9	514.1	9589	5.4
91-92	47.1	302.6	59.7	109.9	10.9	0.4	52.4	8.8	365.9	591.8	10,298	5.7
92-93	42.4	302.6	59.7	120.1	10.9	0.4	52.4	8.8	365.9	597.3	11,008	5.4
93-94	38.9	352.5	69.5	132.6	10.9	0.4	52.4	8.8	415.8	666.0	11,717	5.7
94-95	39.4	352.5	69.5	111.7	163.1	1.1	52.4	8.8	568.0	798.5	12,427	6.4
95-96	34.5	352.5	69.5	124.2	163.1	1.1	52.4	8.8	568.0	806.1	13,477	6.0
96-97	28.3	402.4	79.3	143.5	163.1	1.1	68.9	12.0	634.4	898.6	14,526	6.2
97-98	25.4	452.3	89.1	161.2	163.1	1.1	68.9	12.0	684.3	973.1	15,576	6.2
98-99	27.4	452.3	89.1	143.9	213.8	1.7	68.9	12.0	684.3	1009.1	16,625	6.1
99-2000	22.6	452.3	89.1	158.5	213.8	1.7	68.9	12.0	684.3	1018.9	17,675	5.8
00-01	12.2	452.3	89.1	175.1	213.8	1.7	68.9	12.0	684.3	1025.1	18,584	5.5
01-02	11.0	502.5	98.9	192.5	213.8	1.7	68.9	12.0	785.2	1101.3	19,493	5.6
02-03	4.8	552.1	108.7	210.1	213.8	1.7	68.9	12.0	834.8	1172.1	20,402	5.7
03-04	4.8	552.1	108.7	228.4	213.8	1.7	68.9	12.0	834.8	1190.4	21,311	5.6
04-05	3.6	602.0	118.5	247.5	213.8	1.7	85.4	15.2	901.2	1287.7	22,220	5.8
05-06	3.6	651.9	128.3	266.9	213.8	1.7	85.4	15.2	951.1	1366.8	23,129	5.9
06-07	3.6	651.9	128.3	286.9	213.8	1.7	85.4	15.2	951.1	1386.8	24,038	5.8
07-08	3.6	701.8	138.1	307.6	213.8	1.7	85.4	15.2	1001.0	1467.2	24,947	5.9
08-09	3.6	751.7	147.9	328.8	213.8	1.7	85.4	15.2	1050.9	1548.1	25,856	6.0
09-10	3.6	751.7	147.9	350.6	213.8	1.7	85.4	15.2	1050.9	1569.9	26,765	5.9
10-11	3.6	801.6	157.7	372.9	213.8	1.7	101.9	18.4	1117.3	1671.6	27,674	6.0

TABLE 4.18. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2680	1.1
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.2	3025	1.3
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3688	1.3
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	4352	1.1
82-83	59.5	69.8	13.8	9.9	---	---	21.0	4.4	90.8	178.4	5015	3.6
83-84	63.6	106.4	21.8	18.6	---	---	21.0	4.6	127.4	236.0	5679	4.2
84-85	68.7	144.9	30.5	29.9	---	---	21.0	4.9	165.9	299.9	6342	4.7
85-86	68.9	187.3	38.9	44.8	14.8	0.6	21.0	5.1	223.1	381.4	6849	5.6
86-87	69.8	187.3	40.8	61.5	14.8	0.6	47.7	8.1	249.8	430.6	4357	5.8
87-88	67.1	264.8	58.0	80.5	14.8	0.6	47.7	8.6	327.3	542.1	7864	6.9
88-89	60.6	264.8	60.9	93.4	14.8	0.6	47.7	9.0	327.3	551.8	8372	6.6
89-90	56.4	350.2	80.8	107.4	14.8	0.7	74.8	14.7	439.8	699.8	8879	7.9
90-91	52.5	350.2	84.8	125.4	14.8	0.7	74.8	15.4	439.8	718.6	9589	7.5
91-92	49.8	459.8	110.5	145.9	14.8	0.7	74.8	16.2	549.4	872.6	10,298	8.5
92-93	47.4	459.8	115.9	168.5	14.8	0.8	74.8	17.0	549.2	899.0	11,008	8.2
93-94	46.5	563.6	142.2	193.9	14.8	0.8	74.8	17.9	653.2	1054.5	11,717	9.0
94-95	48.5	563.6	149.3	171.3	335.2	2.2	74.8	18.8	973.6	1364.2	12,427	10.9
95-96	43.8	563.6	156.8	201.2	335.2	2.3	74.8	19.7	973.6	1397.4	13,477	10.4
96-97	36.3	683.8	188.2	243.1	335.2	2.4	114.8	27.7	1133.8	1595.2	14,526	10.9
97-98	37.7	810.0	222.4	285.6	335.2	2.5	114.8	29.1	1260.0	1837.3	15,576	11.8
98-99	37.5	810.0	233.5	268.9	464.9	4.2	114.8	30.5	1389.7	1964.3	16,625	11.8
99-2000	31.7	810.0	245.2	308.5	464.9	4.4	114.8	32.0	1389.7	2011.5	17,675	11.4
00-01	16.7	810.0	257.5	359.3	464.9	4.6	114.8	33.6	1389.7	2061.4	18,584	11.1
01-02	15.3	963.4	300.5	413.1	464.9	4.8	114.8	35.3	1543.1	2312.1	19,493	11.9
02-03	5.4	1124.5	347.1	476.1	464.9	5.1	114.8	37.1	1704.2	2575.0	20,402	12.6
03-04	5.5	1124.5	364.4	541.9	464.9	5.3	114.8	38.9	1704.2	2660.2	21,311	12.5
04-05	3.6	1302.1	417.5	616.1	464.9	5.6	168.5	51.9	1935.5	3030.2	22,220	13.6
05-06	3.7	1488.6	474.9	696.2	464.9	5.9	168.5	54.5	2122.0	3357.2	23,129	14.5
06-07	3.9	1488.6	498.7	784.9	464.9	6.2	168.5	57.2	2122.0	3472.9	24,038	14.4
07-08	4.0	1694.2	563.9	882.8	464.9	6.5	168.5	60.1	2327.6	3844.9	24,947	15.4
08-09	4.1	1910.1	634.5	990.5	464.9	6.8	168.5	63.1	2543.5	4238.4	25,856	16.4
09-10	4.2	1910.1	666.3	1108.7	464.9	7.1	168.5	66.2	2543.5	4396.0	26,765	16.4
10-11	4.4	2148.1	746.3	1237.8	464.9	7.5	222.0	81.5	2835.0	4912.5	27,674	17.7

TABLE 4.19. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.3	778	4.4
79-80	36.6	---	---	---			0.3	0.2	---	37.1	823	4.5
80-81	39.4	---	---	---			0.3	0.2	---	39.9	855	4.7
81-82	41.6	---	---	---			0.3	0.2	---	42.1	887	4.7
82-83	35.6	---	---	6.9			0.3	0.2	---	43.1	919	4.7
83-84	33.1	---	---	7.2			0.3	0.2	---	40.8	951	4.3
84-85	30.3	---	---	7.3			0.3	0.2	---	38.2	983	3.9
85-86	28.2	---	---	7.5			0.3	0.2	---	36.6	1015	3.6
86-87	26.1	---	---	7.7			0.3	0.2	---	34.3	1047	3.3
87-88	24.0	---	---	7.8			0.3	0.2	---	32.4	1079	3.0
88-89	22.9	2.6	0.5	7.7			0.3	0.2	2.9	34.2	1111	3.1
89-90	23.1	21.5	4.3	10.0			3.5	1.0	25.0	63.4	1144	5.6
90-91	20.9	27.6	5.5	10.0			3.5	1.0	31.4	68.5	1176	5.8
91-92	21.1	27.6	5.5	12.4			3.5	1.0	31.7	71.1	1208	5.9
92-93	18.2	27.6	5.5	13.3			3.5	1.0	31.1	69.2	1240	5.6
93-94	18.4	27.6	5.5	14.1			3.5	1.0	31.1	70.1	1272	5.5
94-95	18.5	46.5	9.3	14.7			3.5	1.0	50.0	93.5	1305	7.1
95-96	16.9	51.2	10.2	15.4			3.5	1.0	54.7	98.2	1337	7.3
96-97	14.3	51.2	10.2	16.4			3.5	1.0	54.7	97.1	1369	7.1
97-98	3.8	70.1	14.0	18.9			3.5	1.0	73.6	111.2	1401	7.9
98-99	3.8	89.0	17.8	19.6			3.5	1.0	92.5	134.7	1433	9.4
99-2000	3.8	89.0	17.8	20.6			3.5	1.0	92.5	135.7	1466	9.2
00-01	3.8	89.0	17.8	20.9			3.5	1.0	92.5	136.0	1470	9.3
01-02	3.8	89.0	17.8	21.5			3.5	1.0	92.5	136.6	1474	9.3
02-03	1.5	89.0	17.8	21.9			3.5	1.0	92.5	134.7	1478	9.1
03-04	1.5	89.0	17.8	22.4			3.5	1.0	92.5	135.2	1482	9.1
04-05	1.5	89.0	17.8	22.9			3.5	1.0	92.5	135.7	1437	9.1
05-06	---	89.0	17.8	23.5			3.5	1.0	92.5	134.8	1491	9.0
06-07	---	89.0	17.8	24.1			3.5	1.0	92.5	135.4	1495	9.0
07-08	---	89.0	17.8	24.6			3.5	1.0	92.5	135.9	1499	9.1
08-09	---	89.0	17.8	24.7			3.5	1.0	92.5	136.0	1503	9.0
09-10	---	89.0	17.8	25.7			3.5	1.0	92.5	137.0	1507	9.1
10-11	---	89.0	17.8	26.2			3.5	1.0	92.5	137.5	1511	9.1

TABLE 4.20. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---			0.2	0.2	---	30.9	778	4.0
79-80	33.9	---	---	---			0.2	0.2	---	34.2	823	4.2
80-81	37.4	---	---	---			0.2	0.2	---	37.8	855	4.4
81-82	40.7	---	---	---			0.2	0.2	---	41.0	887	4.6
82-83	36.6	---	---	6.9			0.2	0.2	---	43.9	919	4.8
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	951	4.5
84-85	33.5	---	---	7.3			0.2	0.2	---	41.3	983	4.2
85-86	32.3	---	---	7.5			0.2	0.2	---	40.[illegible]	1015	4.0
86-87	30.4	---	---	8.1			0.2	0.3	---	38.9	1047	3.7
87-88	28.7	---	---	8.6			0.2	0.3	---	37.8	1079	3.5
88-89	27.9	4.2	0.7	8.9			0.2	0.3	4.4	42.4	1111	3.8
89-90	29.3	36.5	7.0	12.1			4.5	1.7	41.0	91.3	1144	7.9
90-91	28.4	48.0	7.4	12.7			4.5	1.6	52.5	102.6	1176	8.7
91-92	30.1	48.0	7.4	16.5			4.5	1.9	52.5	108.2	1208	8.9
92-93	26.7	48.0	7.4	18.7			4.5	2.0	52.5	107.6	1240	8.6
93-94	28.1	48.0	7.8	20.6			4.5	2.1	52.5	110.8	1272	8.7
94-95	29.5	89.4	17.0	22.6			4.5	2.2	93.9	165.1	1305	12.7
95-96	28.8	100.2	17.2	24.9			4.5	2.3	104.7	177.6	1337	13.3
96-97	27.7	100.2	18.0	27.9			4.5	2.4	104.7	180.4	1369	13.2
97-98	6.1	148.1	28.5	33.5			4.5	2.5	152.6	222.9	1401	15.9
98-99	6.4	198.4	39.6	36.7			4.5	2.6	202.9	287.9	1433	20.1
99-2000	6.6	198.4	41.6	40.1			4.5	2.7	202.9	294.0	1466	20.0
00-01	7.0	198.4	43.6	43.1			4.5	2.8	202.9	299.4	1470	20.4
01-02	7.3	198.4	46.0	46.2			4.5	2.9	202.9	305.2	1474	20.7
02-03	2.7	198.4	48.4	49.6			4.5	3.0	202.9	306.5	1478	20.7
03-04	2.8	198.4	50.8	53.2			4.5	3.2	202.9	312.6	1482	21.1
04-05	2.9	198.4	53.6	57.1			4.5	3.3	202.9	319.6	1487	21.5
05-06	---	198.4	56.0	61.3			4.5	3.4	202.9	323.6	1491	21.7
06-07	---	198.4	58.8	65.8			4.5	3.5	202.9	330.9	1495	22.1
07-08	---	198.4	60.0	70.6			4.5	3.7	202.9	337.0	1499	22.5
08-09	---	198.4	56.2	75.8			4.5	3.9	202.9	347.5	1503	23.1
09-10	---	198.4	68.0	81.3			4.5	4.2	202.9	356.4	1507	23.6
10-11	---	198.4	71.6	87.1			4.5	4.3	202.9	365.9	1511	24.2

TABLE 4.21. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.3	778	4.4
79-80	36.6	---	---	---			0.3	0.2	---	37.1	823	4.5
80-81	39.4	---	---	---			0.3	0.2	---	39.9	855	4.7
81-82	41.6	---	---	---			0.3	0.2	---	42.1	887	4.7
82-83	35.6	---	---	6.9			0.3	0.2	---	43.1	919	4.7
83-84	33.1	---	---	7.2			0.3	0.2	---	40.8	951	4.3
84-85	30.3	---	---	7.3			0.3	0.2	---	38.2	983	3.9
85-86	28.2	---	---	7.5			0.3	0.2	---	36.6	1015	3.6
86-87	26.1	---	---	7.7			0.3	0.2	---	34.3	1047	3.3
87-88	24.0	---	---	7.8			0.3	0.2	---	32.4	1079	3.0
88-89	22.9	2.6	0.5	7.7			0.3	0.2	2.9	34.2	1111	3.1
89-90	23.1	21.5	4.3	10.0			3.5	1.0	25.0	63.4	1144	5.6
90-91	20.9	27.6	5.5	10.0			3.5	1.0	31.4	68.5	1176	5.8
91-92	21.1	27.6	5.5	12.4			3.5	1.0	31.7	71.1	1208	5.9
92-93	18.2	27.6	5.5	13.3			3.5	1.0	31.1	69.2	1240	5.6
93-94	18.4	27.6	5.5	14.1			3.5	1.0	31.1	70.1	1272	5.5
94-95	18.5	27.6	5.5	14.7			18.8	2.0	46.4	87.2	1305	6.7
95-96	16.9	32.3	6.4	15.4			18.8	2.0	51.1	91.8	1337	6.9
96-97	14.3	51.2	10.2	16.4			18.8	2.0	70.0	113.1	1369	8.3
97-98	3.7	70.1	14.0	18.9			18.8	2.0	88.9	127.6	1401	9.1
98-99	3.7	70.1	14.0	19.6			18.8	2.0	88.9	128.4	1433	8.9
99-2000	3.7	70.1	14.0	20.6			18.8	2.0	88.9	129.3	1466	8.8
00-01	3.8	70.1	14.0	20.9			18.8	2.0	88.9	129.6	1470	8.8
01-02	3.8	70.1	14.0	21.5			18.8	2.0	88.9	130.2	1474	8.8
02-03	1.5	70.1	14.0	21.8			18.8	2.0	88.9	128.3	1478	8.7
03-04	1.5	70.1	14.0	22.4			18.8	2.0	88.9	128.8	1482	8.7
04-05	1.5	70.1	14.0	22.9			18.8	2.0	88.9	129.3	1487	8.7
05-06	---	70.1	14.0	23.5			18.8	2.0	88.9	128.4	1491	8.6
06-07	---	89.0	17.8	24.0			18.8	2.0	107.8	151.7	1495	10.1
07-08	---	89.0	17.8	24.5			18.8	2.0	107.8	152.2	1499	10.1
08-09	---	89.0	17.8	25.1			18.8	2.0	107.8	152.8	1503	10.1
09-10	---	89.0	17.8	25.7			18.8	2.0	107.8	153.3	1507	10.2
10-11	---	89.0	17.8	26.2			18.8	2.0	107.8	153.9	1511	10.2

TABLE 4.22. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	OM&R Costs	Coal Costs	New Hydroelectric Costs Investment Costs	OM&R Costs	Transmission Systems Investment Costs	OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.57	---	---	---			0.2	0.2	---	30.9	778	4.0
79-80	33.9	---	---	---			0.2	0.2	---	34.2	823	4.2
80-81	37.4	---	---	---			0.2	0.2	---	37.8	855	4.4
81-82	40.7	---	---	---			0.2	0.2	---	41.0	887	4.6
82-83	36.6	---	---	6.9			0.2	0.2	---	43.9	919	4.8
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	951	4.5
84-85	33.5	---	---	7.3			0.2	0.2	---	41.3	983	4.2
85-86	32.3	---	---	7.5			0.2	0.2	---	40.3	1015	4.0
86-87	30.4	---	---	8.1			0.2	0.3	---	38.9	1047	3.7
87-88	28.7	---	---	8.6			0.2	0.3	---	37.8	1079	3.5
88-89	27.9	4.2	0.7	8.9			0.2	0.3	4.4	42.4	1111	3.8
89-90	29.3	36.6	7.0	12.1			4.5	1.7	41.1	91.3	1144	7.9
90-91	28.4	48.0	7.4	12.7			4.5	1.8	52.5	102.8	1176	8.7
91-92	30.1	48.0	7.4	16.5			4.5	1.9	52.5	108.2	1208	8.9
92-93	26.7	48.0	7.4	18.7			4.5	2.0	52.5	107.0	1240	8.6
93-94	28.1	48.0	7.8	20.6			4.5	2.1	52.5	110.8	1272	8.7
94-95	29.5	48.0	11.9	22.6			36.8	4.0	84.8	153.0	1305	11.7
95-96	28.8	58.8	14.6	24.9			36.8	4.2	95.6	168.1	1337	12.6
96-97	27.7	105.4	24.4	27.9			36.8	4.4	142.2	226.6	1369	16.5
97-98	6.1	153.3	35.2	33.5			36.8	4.6	190.1	269.6	1401	19.2
98-99	6.4	153.3	36.9	36.7			36.8	4.8	190.1	275.0	1433	19.2
99-2000	6.6	153.3	38.7	40.1			36.8	5.1	190.1	280.6	1466	19.1
00-01	7.0	153.3	40.7	43.0			36.8	5.3	190.1	286.2	1470	19.4
01-02	7.3	153.3	42.7	46.1			36.8	5.6	190.1	291.9	1474	19.8
02-03	2.7	153.3	44.9	49.6			36.8	5.9	190.1	293.2	1478	19.8
03-04	2.8	153.3	47.1	53.2			36.8	6.2	190.1	299.4	1482	20.2
04-05	2.9	153.3	49.5	57.1			36.8	6.5	190.1	306.2	1487	20.6
05-06	---	153.3	51.9	61.3			36.8	6.8	190.1	310.1	1491	20.8
06-07	---	227.6	69.2	65.7			36.8	7.2	264.4	406.6	1495	27.2
07-08	---	227.6	72.6	70.5			36.8	7.5	264.4	415.1	1499	27.7
08-09	---	227.6	76.3	75.7			36.8	7.9	264.4	424.4	1503	28.2
09-10	---	227.6	80.1	81.2			36.8	8.3	264.4	434.1	1507	28.8
10-11	---	227.6	84.1	87.1			36.8	8.7	264.4	443.3	1511	29.4

TABLE 4.23. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---	---	---	0.3	0.2	---	34.3	778	4.4
79-80	36.6	---	---	---	---	---	0.3	0.2	---	37.1	823	4.5
80-81	39.4	---	---	---	---	---	0.3	0.2	---	39.9	855	4.7
81-82	41.6	---	---	---	---	---	0.3	0.2	---	42.1	887	4.7
82-83	35.6	---	---	6.9	---	---	0.3	0.2	---	43.1	919	4.7
83-84	33.1	---	---	7.2	---	---	0.3	0.2	---	40.8	951	4.3
84-85	30.3	---	---	7.3	---	---	0.3	0.2	---	38.2	983	3.9
85-86	28.2	---	---	7.5	---	---	0.3	0.2	---	36.6	1015	3.6
86-87	26.1	---	---	7.7	---	---	0.3	0.2	---	34.3	1047	3.3
87-88	24.0	---	---	7.8	---	---	0.3	0.2	---	32.4	1079	3.0
88-89	22.9	2.6	0.5	7.7	---	---	0.3	0.2	2.9	34.2	1111	3.1
89-90	23.1	21.5	4.3	10.0	---	---	3.5	1.0	25.0	63.4	1144	5.6
90-91	20.9	27.6	5.5	10.0	---	---	3.5	1.0	31.4	68.5	1176	5.8
91-92	21.1	27.6	5.5	12.4	---	---	18.8	2.0	46.4	87.4	1208	7.2
92-93	18.2	27.6	5.5	13.3	---	---	18.8	2.0	46.4	85.5	1240	6.9
93-94	18.4	27.6	5.5	14.1	---	---	18.8	2.0	46.4	86.4	1272	6.8
94-95	18.5	27.6	5.5	6.9	36.2	0.1	18.8	2.0	82.6	115.6	1305	8.8
95-96	16.9	32.3	6.4	6.5	36.2	0.1	18.8	2.0	82.6	119.2	1337	8.9
96-97	14.3	32.3	6.4	7.3	36.2	0.1	18.8	2.0	82.6	117.5	1369	8.6
97-98	3.8	32.3	6.4	9.6	36.2	0.1	18.8	2.0	82.6	109.2	1401	7.8
98-99	3.8	32.3	6.4	10.1	36.2	0.1	18.8	2.0	82.6	109.7	1433	7.6
99-2000	3.8	32.3	6.4	3.1	48.3	0.2	18.8	2.0	99.4	114.9	1466	7.8
00-01	3.8	32.3	6.4	2.7	48.3	0.2	18.8	2.0	99.4	114.5	1470	7.8
01-02	3.8	32.3	6.4	2.7	48.3	0.2	18.8	2.0	99.4	114.5	1474	7.7
02-03	1.5	32.3	6.4	2.4	48.3	0.2	18.8	2.0	99.4	111.9	1478	7.6
03-04	1.5	32.3	6.4	2.5	48.3	0.2	18.8	2.0	99.4	112.0	1482	7.6
04-05	1.5	32.3	6.4	2.6	48.3	0.2	18.8	2.0	99.4	112.1	1487	7.5
05-06	---	32.3	6.4	2.7	48.3	0.2	18.8	2.0	99.4	110.7	1491	7.4
06-07	---	32.3	6.4	2.8	48.3	0.2	18.8	2.0	99.4	110.8	1495	7.4
07-08	---	32.3	6.4	2.9	48.3	0.2	18.8	2.0	99.4	110.9	1499	7.4
08-09	---	32.3	6.4	3.1	48.3	0.2	18.8	2.0	99.4	111.1	1503	7.4
09-10	---	32.3	6.4	3.2	48.3	0.2	18.8	2.8	99.4	111.2	1507	7.4
10-11	---	32.3	6.4	3.4	48.3	0.2	18.8	2.0	99.4	111.4	1511	7.4

TABLE 4.24. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---	---	---	0.2	0.2	---	30.9	778	4.0
79-80	33.9	---	---	---	---	---	0.2	0.2	---	34.2	823	4.2
80-81	37.4	---	---	---	---	---	0.2	0.2	---	37.8	855	4.4
81-82	40.7	---	---	---	---	---	0.2	0.2	---	41.0	887	4.6
82-83	36.6	---	---	6.9	---	---	0.2	0.2	---	43.9	919	4.8
83-84	35.6	---	---	7.2	---	---	0.2	0.2	---	43.2	951	4.5
84-85	33.5	---	---	7.3	---	---	0.2	0.2	---	41.3	983	4.2
85-86	32.3	---	---	7.5	---	---	0.2	0.2	---	40.3	1015	4.0
86-87	30.4	---	---	8.1	---	---	0.2	0.3	---	38.9	1047	3.7
87-88	28.7	---	---	8.6	---	---	0.2	0.3	---	37.8	1079	3.5
88-89	27.9	4.2	0.7	8.9	---	---	0.2	0.3	4.4	42.4	1111	3.8
89-90	29.3	36.6	7.0	12.1	---	---	4.5	1.7	41.1	91.3	1144	7.9
90-91	28.4	48.0	7.4	12.7	---	---	4.5	1.8	52.5	102.8	1176	8.7
91-92	30.1	48.0	10.3	16.4	---	---	32.4	3.5	80.4	140.7	1208	11.6
92-93	26.7	48.0	10.8	18.7	---	---	32.4	3.6	80.4	140.3	1240	11.3
93-94	28.1	48.0	11.4	20.6	---	---	32.4	3.8	80.4	144.3	1272	11.3
94-95	29.5	48.0	11.9	10.7	76.2	0.3	32.4	4.0	156.6	213.1	1305	16.3
95-96	28.8	58.8	14.6	10.5	76.2	0.3	32.4	4.2	167.4	225.8	1337	16.9
96-97	27.7	58.8	15.3	12.4	76.2	0.3	32.4	4.4	167.4	227.5	1369	16.6
97-98	6.1	58.8	16.1	16.9	76.2	0.4	32.4	4.6	167.4	211.5	1401	15.1
98-99	6.4	58.8	16.9	18.9	76.2	0.4	32.4	4.8	167.4	214.8	1433	15.0
99-2000	6.6	58.8	17.7	5.9	108.6	0.8	32.4	5.1	199.8	236.0	1466	16.1
00-01	7.0	58.8	18.6	5.4	108.6	0.8	32.4	5.3	199.8	236.9	1470	16.1
01-02	7.3	58.8	19.6	5.8	108.6	0.9	32.4	5.6	199.8	239.0	1474	16.2
02-03	2.7	58.8	20.5	5.5	108.6	0.9	32.4	5.9	199.8	235.3	1478	15.9
03-04	2.8	58.8	21.6	5.9	108.6	1.0	32.4	6.2	199.8	237.3	1482	16.0
04-05	2.9	58.8	22.6	6.5	108.6	1.0	32.4	6.5	199.8	239.3	1487	16.1
05-06	---	58.8	23.7	7.1	108.6	1.1	32.4	6.8	199.8	238.5	1491	16.0
06-07	---	58.8	24.9	7.8	108.6	1.1	32.4	7.2	199.8	240.8	1495	16.1
07-08	---	58.8	26.2	8.5	108.6	1.2	32.4	7.5	199.8	243.2	1499	16.2
08-09	---	58.8	27.5	9.3	108.6	1.2	32.4	7.9	199.8	245.7	1503	16.3
09-10	---	58.8	28.9	10.2	108.6	1.3	32.4	8.3	199.8	248.5	1507	16.5
10-11	---	58.8	30.3	11.1	108.6	1.4	32.4	8.7	199.8	251.3	1511	16.6

TABLE 4.25. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.2	804	4.3
79-80	36.6	---	---	---			0.3	0.2	---	37.0	862	4.3
80-81	39.4	---	---	---			0.3	0.2	---	39.8	916	4.3
81-82	41.6	---	---	---			0.3	0.2	---	42.1	970	4.3
82-83	35.6	---	---	6.9			0.3	0.2	---	43.0	1024	4.2
83-84	33.1	---	---	7.2			0.3	0.2	---	40.8	1078	3.8
84-85	30.3	---	---	7.3			0.3	0.2	---	38.1	1132	3.4
85-86	28.2	18.9	3.8	9.4			3.5	1.0	22.4	64.9	1193	5.4
86-87	26.1	18.9	3.8	10.9			3.5	1.0	22.4	64.2	1254	5.1
87-88	24.0	18.9	3.8	12.4			3.5	1.0	22.4	63.7	1315	4.8
88-89	22.9	21.5	4.3	13.3			3.5	1.0	25.0	66.6	1376	4.8
89-90	23.1	40.4	8.1	14.5			3.5	1.0	43.9	90.6	1437	6.3
90-91	20.9	46.5	9.3	15.5			3.5	1.0	50.0	96.8	1505	6.4
91-92	21.1	46.5	9.3	16.8			3.5	1.0	50.0	98.2	1573	6.2
92-93	18.2	65.4	13.1	18.2			3.5	1.0	68.9	119.5	1641	7.3
93-94	18.4	65.4	13.1	19.5			3.5	1.0	68.9	120.9	1709	7.1
94-95	18.5	65.4	13.1	20.7			3.5	1.0	68.9	122.2	1777	6.9
95-96	16.9	70.1	14.0	22.1			3.5	1.0	73.6	127.6	1859	6.9
96-97	14.3	89.0	17.8	24.0			5.3	1.8	94.3	152.4	1941	7.8
97-98	3.7	107.9	21.6	27.3			5.3	1.8	113.2	167.8	2023	8.3
98-99	3.7	126.8	25.4	28.9			5.3	1.8	132.1	192.0	2105	9.1
99-2000	3.7	126.8	25.4	30.7			5.3	1.8	132.1	193.8	2187	8.9
00-01	3.8	126.8	25.4	31.8			5.3	1.8	132.1	194.9	2229	8.7
01-02	3.8	126.8	25.4	33.1			5.3	1.8	132.1	196.2	2270	8.6
02-03	1.5	126.8	25.4	34.2			5.3	1.8	132.1	195.0	2312	8.4
03-04	1.5	155.5	31.1	35.6			5.3	1.8	160.8	230.8	2353	9.8
04-05	--	155.5	31.1	37.0			5.3	1.8	160.8	232.2	2395	9.7
05-06	---	155.5	31.1	38.4			5.3	1.8	160.8	232.1	2437	9.5
06-07	---	155.5	31.1	39.9			5.3	1.8	160.8	233.5	2478	9.4
07-08	---	155.5	31.1	41.4			5.3	1.8	160.8	235.1	2520	9.3
08-09	---	155.5	31.1	42.8			5.3	1.8	160.8	236.5	2561	9.2
09-10	---	155.5	31.1	44.4			5.3	1.8	160.8	238.1	2603	9.1
10-11	---	155.5	31.1	45.9			5.3	1.8	160.8	239.6	2645	9.1

TABLE 4.26. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---			0.2	0.2	---	30.9	804	3.8
79-80	33.9	---	---	---			0.2	0.2	---	34.2	862	4.0
80-81	37.4	---	---	---			0.2	0.2	---	37.8	916	4.1
81-82	40.7	---	---	---			0.2	0.2	---	41.0	970	4.2
82-83	36.6	---	---	6.9			0.2	0.2	---	43.9	1024	4.3
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	1078	4.0
84-85	33.5	---	---	7.3			0.2	0.2	---	41.3	1132	3.6
85-86	32.3	26.6	5.3	9.4			4.4	1.2	31.0	79.2	1193	6.6
86-87	30.4	26.6	5.5	11.4			4.4	1.3	31.0	79.6	1254	6.3
87-88	28.7	26.6	5.8	13.6			4.4	1.4	31.0	80.5	1315	6.1
88-89	27.9	30.8	7.0	15.4			4.4	1.5	35.2	87.0	1376	6.3
89-90	29.3	63.2	13.6	17.6			4.4	1.5	67.6	129.7	1437	9.0
90-91	28.4	74.6	16.4	19.8			4.4	1.6	79.0	145.3	1505	9.6
91-92	30.1	74.6	16.4	22.3			4.4	1.7	79.0	149.5	1573	9.5
92-93	26.7	112.1	23.8	25.5			4.4	1.8	116.5	194.4	1641	11.8
93-94	28.1	112.1	25.0	28.5			4.4	1.9	116.5	200.1	1709	11.7
94-95	29.5	112.1	26.2	31.8			4.4	2.0	116.5	206.1	1777	11.6
95-96	28.8	122.9	29.7	35.8			4.4	2.2	127.3	223.8	1859	12.0
96-97	27.7	169.5	40.1	40.7			8.5	2.3	178.0	288.8	1941	14.9
97-98	6.1	217.4	51.7	48.5			8.5	2.4	225.9	334.6	2023	16.5
98-99	6.4	267.7	64.1	54.0			8.5	2.6	276.2	403.4	2105	19.2
99-2000	6.6	267.7	67.3	59.9			8.5	2.7	276.2	412.7	2187	18.9
00-01	7.0	267.7	70.7	65.3			8.5	2.8	276.2	422.0	2229	18.9
01-02	7.3	267.7	74.3	71.1			8.5	3.0	276.2	431.9	2270	19.0
02-03	2.7	267.7	77.9	77.6			8.5	3.2	276.2	437.6	2312	18.9
03-04	2.8	365.0	77.9	77.6			8.5	3.4	373.5	561.5	2353	23.9
04-05	2.9	365.0	102.1	92.1			8.5	3.6	373.5	574.2	2395	24.0
05-06	- -	365.0	107.2	100.3			8.5	3.7	373.5	584.7	2437	24.0
06-07	---	365.0	112.6	109.1			8.5	3.8	373.5	599.0	2478	24.2
07-08	---	365.0	118.2	118.7			8.5	4.2	373.5	614.4	2520	24.4
08-09	---	365.0	124.1	129.1			8.5	4.2	373.5	630.9	2561	24.6
09-10	---	365.0	130.3	140.4			8.5	4.4	373.5	648.6	2603	24.9
10-11	---	365.0	136.8	152.5			8.5	4.5	373.5	667.3	2645	25.2

TABLE 4.27. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.2	804	4.3
79-80	36.6	---	---	---			0.3	0.2	---	37.0	862	4.3
80-81	39.4	---	---	---			0.3	0.2	---	39.8	916	4.3
81-82	41.6	---	---	---			0.3	0.2	---	42.1	970	4.3
82-83	35.6	---	---	6.9			0.3	0.2	---	43.0	1024	4.2
83-84	33.1	---	---	7.2			0.3	0.2	---	40.8	1078	3.8
84-85	30.3	---	---	7.3			0.3	0.2	---	38.1	1132	3.4
85-86	28.2	18.9	3.8	9.4			3.5	1.0	22.4	64.9	1193	5.4
86-87	26.1	18.9	3.8	10.9			3.5	1.0	22.4	64.2	1254	5.1
87-88	24.0	18.9	3.8	12.4			3.5	1.0	22.4	63.7	1315	4.8
88-89	22.9	21.5	4.3	13.3			3.5	1.0	25.0	66.6	1376	4.8
89-90	23.1	21.5	4.3	14.5			18.8	2.0	40.3	84.2	1437	5.8
90-91	20.9	27.6	5.5	19.1			18.8	2.0	46.4	89.0	1505	5.9
91-92	21.1	27.6	5.5	15.2			18.8	2.0	46.4	90.2	1573	5.7
92-93	18.2	27.6	5.5	16.0			18.8	2.0	26.4	88.2	1641	5.4
93-94	13.4	27.6	5.5	16.9			18.8	2.0	46.4	89.2	1709	5.2
94-95	18.5	46.5	9.2	19.8			18.8	2.0	65.3	114.9	1777	6.5
95-96	16.9	70.1	13.8	22.1			18.8	2.0	88.9	143.7	1859	7.7
96-97	14.3	70.1	13.8	24.0			18.8	2.0	88.9	143.2	1941	7.4
97-98	3.76	89.0	17.5	27.3			18.8	2.0	107.8	158.5	2023	7.8
98-99	3.7	107.9	21.2	28.9			18.8	2.0	126.7	182.6	2105	8.7
99-2000	3.7	107.9	21.2	30.7			18.8	2.0	126.7	184.5	2187	8.4
00-01	3.8	107.9	21.2	31.8			18.8	2.0	126.7	185.5	2229	8.3
01-02	3.8	107.9	21.2	33.1			18.8	2.0	126.7	186.8	2270	8.2
02-03	1.5	126.8	24.9	34.2			18.8	2.0	145.6	208.2	2312	9.0
03-04	1.5	126.8	24.9	35.6			18.8	2.0	145.6	209.6	2353	8.9
04-05	1.5	126.8	24.9	37.0			18.8	2.0	145.6	211.0	2395	8.8
05-06	---	126.8	24.9	38.44			18.8	2.0	145.6	210.9	2437	8.6
06-07	---	126.8	24.9	39.8			18.8	2.0	145.6	212.3	2478	8.6
07-08	---	126.8	24.9	41.3			18.8	2.0	145.6	213.8	2520	8.5
08-09	---	126.8	24.9	42.8			18.8	2.0	145.6	215.3	2561	8.4
09-10	---	126.8	24.9	44.3			18.8	2.0	145.6	216.9	2603	8.3
10-11	---	126.8	24.9	45.9			18.8	2.0	145.6	218.4	2645	8.2

TABLE 4.28. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	OM&R Costs	Coal Costs	New Hydroelectric Costs Investment Costs	OM&R Costs	Transmission Systems Investment Costs	OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---			0.2	0.2	---	30.9	804	3.8
79-80	33.9	---	---	---			0.2	0.2	---	34.2	862	4.0
80-81	37.4	---	---	---			0.2	0.2	---	37.8	916	4.1
81-82	40.7	---	---	---			0.2	0.2	---	41.0	970	4.2
82-83	36.6	---	---	6.9			0.2	0.2	---	43.9	1024	4.3
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	1078	4.0
84-85	33.5	---	---	7.3			0.2	0.2	---	41.3	1132	3.6
85-86	32.3	26.6	5.3	9.4			4.4	1.2	31.0	79.2	1193	6.6
86-87	30.4	26.6	5.5	11.4			4.4	1.3	31.0	79.6	1254	6.3
87-88	28.7	26.6	5.8	13.6			4.4	1.4	31.0	80.5	1315	6.1
88-89	27.9	30.8	7.0	15.4			4.4	1.5	35.2	87.0	1376	6.3
89-90	29.3	30.9	7.3	17.6			29.7	3.2	60.6	118.1	1437	8.2
90-91	28.4	42.3	9.8	18.0			29.7	3.4	72.0	131.8	1505	8.7
91-92	30.1	42.3	10.3	20.2			29.7	3.5	72.0	136.1	1573	8.6
92-93	26.7	42.3	10.8	22.4			29.7	3.7	72.0	135.7	1641	8.3
93-94	28.1	42.3	11.4	24.7			29.7	3.9	72.0	140.1	1709	8.2
94-95	29.5	83.7	20.2	30.5			29.7	4.1	113.4	197.8	1777	11.1
95-96	28.8	137.9	31.9	35.8			29.7	4.3	167.6	268.5	1859	14.4
96-97	27.7	137.9	33.5	40.7			29.7	4.5	167.6	274.0	1941	14.1
97-98	6.1	185.8	44.7	48.5			29.7	4.7	215.5	319.5	2023	15.8
98-99	6.4	236.1	56.8	54.0			29.7	5.0	265.8	388.1	2105	18.4
99-2000	6.6	236.1	59.6	59.9			29.7	5.2	265.8	397.1	2187	18.2
00-01	7.0	236.1	62.6	65.3			29.7	5.5	265.8	406.2	2229	18.2
01-02	7.3	236.1	65.7	71.1			29.7	5.7	265.8	415.6	2270	18.3
02-03	2.7	297.2	81.1	77.5			29.7	6.0	326.9	494.3	2312	21.4
03-04	2.8	297.2	85.2	84.4			29.7	6.3	326.9	505.7	2353	21.5
04-05	2.9	297.2	89.5	92.1			29.7	6.7	326.9	518.2	2395	21.6
05-06	---	297.2	93.9	100.2			29.7	7.0	326.9	528.1	2437	21.7
06-07	---	297.2	98.6	109.1			29.7	7.3	326.9	541.9	2478	21.9
07-08	---	297.2	103.6	118.7			29.7	7.7	326.9	556.9	2520	22.1
08-09	---	297.2	108.7	129.1			29.7	8.1	326.9	572.8	2561	22.4
09-10	---	297.2	114.2	140.3			29.7	8.5	326.9	590.0	2603	22.7
10-11	---	297.2	119.9	152.5			29.7	8.9	326.9	608.2	2645	23.0

TABLE 4.29. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	33.8	---	---	---	---	---	0.3	0.2	---	34.2	804	4.3
79-80	36.6	---	---	---	---	---	0.3	0.2	---	37.0	862	4.3
80-81	39.4	---	---	---	---	---	0.3	0.2	---	39.8	916	4.3
81-82	41.6	---	---	---	---	---	0.3	0.2	---	42.1	970	4.3
82-83	35.6	---	---	6.9	---	---	0.3	0.2	---	43.0	1024	4.2
83-84	33.1	---	---	7.2	---	---	0.3	0.2	---	40.8	1078	3.8
84-85	30.3	---	---	7.3	---	---	0.3	0.2	---	38.1	1132	3.4
85-86	28.2	18.9	3.8	9.4	---	---	3.5	1.0	22.4	64.9	1193	5.4
86-87	26.1	18.9	3.8	10.9	---	---	3.5	1.0	22.4	64.2	1254	5.1
87-88	24.0	18.9	3.8	12.4	---	---	3.5	1.0	22.4	63.7	1315	4.8
88-89	22.9	21.5	4.3	13.3	---	---	3.5	1.0	25.0	66.6	1376	4.8
89-90	23.1	21.5	4.3	14.5	---	---	18.8	2.0	40.3	84.2	1437	5.8
90-91	20.9	27.6	5.5	19.1	---	---	18.8	2.0	46.4	89.0	1505	5.9
91-92	21.1	27.6	5.5	15.2	---	---	18.8	2.0	46.4	90.2	1573	5.7
92-93	18.2	27.6	5.5	16.0	---	---	18.8	2.0	26.4	88.2	1641	5.4
93-94	13.4	27.6	5.5	16.9	---	---	18.8	2.0	46.4	89.2	1709	5.2
94-95	18.5	27.6	5.5	13.6	34.4	0.1	18.8	2.0	80.8	120.5	1777	6.8
95-96	16.9	32.3	6.4	13.9	34.4	0.1	18.8	2.0	85.5	124.8	1859	6.7
96-97	14.3	32.3	6.4	15.6	34.4	0.1	18.8	2.0	85.4	124.0	1941	6.4
97-98	3.7	51.2	10.2	18.7	34.4	0.1	18.8	2.0	104.4	139.2	2023	6.9
98-99	3.7	51.2	10.2	13.0	45.9	0.2	18.8	2.0	115.9	145.1	2105	6.9
99-2000	3.7	51.2	10.2	13.6	45.9	0.2	18.8	2.0	115.9	145.7	2187	6.7
00-01	3.8	51.2	10.2	14.4	45.9	0.2	18.8	2.0	115.9	146.5	2229	6.6
01-02	3.8	51.2	10.2	15.3	45.9	0.2	18.8	2.0	115.9	147.4	2270	6.5
02-03	1.5	70.1	14.0	16.1	45.9	0.2	18.8	2.0	134.8	168.6	2312	7.3
03-04	1.5	70.1	14.0	17.1	45.9	0.2	18.8	2.0	134.8	169.6	2353	7.2
04-05	1.5	70.1	14.0	18.1	45.9	0.2	18.8	2.0	134.8	170.6	2395	7.1
05-06	---	70.1	14.0	19.2	45.9	0.2	18.8	2.0	134.8	170.2	2437	7.0
06-07	---	70.1	14.0	20.2	45.9	0.2	18.8	2.0	134.8	171.2	2478	6.9
07-08	---	70.1	14.0	21.3	45.9	0.2	18.8	2.0	134.8	172.3	2520	6.8
08-09	---	70.1	14.0	22.4	45.9	0.2	18.8	2.0	134.8	173.4	2561	6.8
09-10	---	70.1	14.0	23.6	45.9	0.2	18.8	2.0	134.8	174.6	2603	6.7
10-11	---	70.1	14.0	24.7	45.9	0.2	18.8	2.0	134.8	175.7	2645	6.6

TABLE 4.30. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---	---	---	0.2	0.2	---	30.9	804	3.8
79-80	33.9	---	---	---	---	---	0.2	0.2	---	34.2	862	4.0
80-81	37.4	---	---	---	---	---	0.2	0.2	---	37.8	916	4.1
81-82	40.7	---	---	---	---	---	0.2	0.2	---	41.0	970	4.2
82-83	36.6	---	---	6.9	---	---	0.2	0.2	---	43.9	1024	4.3
83-84	35.6	---	---	7.2	---	---	0.2	0.2	---	43.2	1078	4.0
84-85	33.5	---	---	7.3	---	---	0.2	0.2	---	41.3	1132	3.6
85-86	32.3	26.6	5.3	9.4	---	---	4.4	1.2	31.0	79.2	1193	6.6
86-87	30.4	26.6	5.5	11.4	---	---	4.4	1.3	31.0	79.6	1254	6.3
87-88	28.7	26.6	5.8	13.6	---	---	4.4	1.4	31.0	80.5	1315	6.1
88-89	27.9	30.8	7.0	15.4	---	---	4.4	1.5	35.2	87.0	1376	6.3
89-90	29.3	30.9	7.3	17.6	---	---	29.7	3.2	60.6	118.1	1437	8.2
90-91	28.4	42.3	9.8	18.0	---	---	29.7	3.4	72.0	131.8	1505	8.7
91-92	30.1	42.3	10.3	20.2	---	---	29.7	3.5	72.0	136.1	1573	8.6
92-93	26.7	42.3	10.8	22.4	---	---	29.7	3.7	72.0	135.7	1641	8.3
93-94	28.1	42.3	11.4	24.7	---	---	29.7	3.9	72.0	140.1	1709	8.2
94-95	29.5	42.2	11.9	20.9	72.5	0.2	29.7	4.1	144.4	211.2	1777	11.8
95-96	28.8	53.0	14.7	22.6	72.5	0.3	29.7	4.3	155.2	225.9	1859	12.1
96-97	27.7	53.0	15.4	26.5	72.5	0.3	29.7	4.5	155.2	229.6	1941	11.8
97-98	6.15	100.9	25.7	33.2	72.5	0.3	29.7	4.7	203.1	273.1	2023	13.5
98-99	6.4	100.9	26.9	24.4	101.8	0.7	29.7	4.9	232.4	295.7	2105	14.0
99-2000	6.6	100.9	28.3	26.4	101.8	0.7	29.7	5.2	232.4	299.6	2187	13.7
00-01	7.0	100.9	29.7	29.5	101.8	0.8	29.7	5.5	232.4	305.1	2229	13.7
01-02	7.3	100.9	31.2	32.8	101.8	0.8	29.7	5.7	232.4	310.2	2270	13.7
02-03	2.7	162.0	44.9	36.6	101.8	0.9	29.7	6.1	293.5	384.7	2312	16.6
03-04	2.8	162.0	47.1	40.6	101.8	0.9	29.7	6.4	293.5	391.3	2353	16.6
04-05	2.9	162.0	49.5	45.1	101.8	1.0	29.7	6.7	293.5	398.7	2395	16.6
05-06	---	162.0	51.9	50.0	101.8	1.0	29.7	7.0	293.5	403.4	2437	16.6
06-07	---	162.0	54.6	55.3	101.8	1.1	29.7	7.3	293.5	411.8	2478	16.6
07-08	---	162.0	57.3	61.2	101.8	1.1	29.7	7.7	293.5	420.8	2520	16.7
08-09	---	162.0	60.2	67.5	101.8	1.2	29.7	8.7	293.5	430.5	2561	16.8
09-10	---	162.0	63.2	74.5	101.8	1.2	29.7	8.5	293.5	440.9	2603	16.9
10-11	---	162.0	66.4	82.1	101.8	1.3	29.7	8.9	293.5	452.2	2645	17.1

TABLE 4.31. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	38.8	---	---	---			0.3	0.2	---	34.2	832	4.1
79-80	36.6	---	---	---			0.3	0.2	---	37.0	903	4.1
80-81	39.4	---	---	---			0.3	0.2	---	39.8	931	4.1
81-82	41.7	---	---	---			0.3	0.2	---	42.1	1059	4.0
82-83	35.7	---	---	6.9			0.3	0.2	---	43.0	1137	3.8
83-84	33.2	---	---	7.2			0.3	0.2	---	40.8	1215	3.4
84-85	30.4	13.9	3.8	9.1			3.5	1.0	22.4	66.7	1294	5.2
85-86	28.3	18.0	3.8	10.6			3.5	1.0	22.4	66.2	1396	4.7
86-87	26.1	37.8	7.6	12.1			3.5	1.0	41.3	88.2	1498	5.9
87-88	24.1	37.8	7.6	15.6			3.5	1.0	41.3	89.7	1600	5.6
88-89	22.9	40.4	8.1	17.2			3.5	1.0	43.9	93.1	1702	5.5
89-90	23.1	59.3	11.9	18.7			3.5	1.0	62.8	117.6	1805	6.5
90-91	20.9	65.4	13.1	20.5			3.5	1.0	68.9	124.4	1927	6.5
91-92	21.1	65.4	13.1	22.5			3.5	1.0	68.9	126.7	2049	6.2
92-93	18.3	84.3	16.9	24.6			3.5	1.0	87.8	148.7	2172	6.8
93-94	18.4	84.3	16.9	26.8			3.5	1.0	87.8	150.9	2294	6.6
94-95	18.5	103.2	20.7	28.8			5.3	1.8	108.5	178.3	2417	7.4
95-96	16.9	107.9	21.6	31.5			5.3	1.8	113.2	85.0	2585	7.2
96-97	14.4	126.8	25.4	34.8			5.3	1.8	132.1	208.5	2754	7.6
97-98	3.8	155.5	31.1	39.5			5.3	1.8	160.8	237.0	2922	8.1
98-99	3.8	184.2	36.8	42.4			5.3	1.8	189.5	274.4	3091	8.9
99-2000	3.8	184.2	36.8	45.8			5.3	1.8	189.5	286.7	3260	8.8
00-01	3.8	184.2	36.8	48.5			5.3	1.8	189.5	280.4	3396	8.3
01-02	3.8	184.2	36.8	51.5			5.3	1.8	189.5	283.4	3531	8.0
02-03	1.5	184.2	36.8	54.3			5.3	1.8	189.5	283.9	3667	7.7
03-04	1.5	212.9	42.5	57.6			5.3	1.8	218.2	321.6	3803	8.5
04-05	1.5	212.9	42.5	60.9			5.3	1.8	218.2	324.9	3939	8.2
05-06	--	212.9	42.5	64.3			5.3	1.8	218.2	326.8	4074	8.0
06-07	---	212.9	42.5	67.7			5.3	1.8	218.2	330.2	4210	7.8
07-08	---	241.6	48.2	71.3			7.1	2.6	248.7	370.8	4346	8.5
08-09	---	241.6	48.2	74.9			7.1	2.6	248.7	374.4	4481	8.4
09-10	---	241.6	48.2	78.7			7.1	2.6	248.7	378.2	4617	8.2
10-11	---	241.6	48.2	82.6			7.1	2.6	248.7	382.1	4753	8.0

TABLE 4.32. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.6	---	---	---			0.2	0.2	---	30.9	832	3.7
79-80	33.9	---	---	---			0.2	0.2	---	34.2	903	3.8
80-81	37.5	---	---	---			0.2	0.2	---	37.8	081	3.9
81-82	40.7	---	---	---			0.2	0.2	---	41.0	1059	3.9
82-83	36.7	---	---	6.9			0.2	0.2	---	43.9	1137	3.9
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	1215	3.6
84-85	33.6	25.4	5.0	9.1			4.4	1.2	29.8	78.8	1294	6.1
85-86	32.4	25.4	5.2	10.6			4.4	1.3	29.8	79.4	1396	5.7
86-87	30.4	43.3	11.0	12.7			4.4	1.3	57.7	113.2	1498	7.6
87-88	28.7	53.3	11.5	17.1			4.4	1.4	57.7	116.5	1600	7.3
88-89	27.9	57.5	13.0	19.8			4.4	1.5	61.9	124.1	1702	7.3
89-90	29.4	89.9	20.1	22.7			4.4	1.6	94.3	168.1	1805	9.3
90-91	28.5	101.3	23.2	26.1			4.4	1.7	105.7	185.3	1927	9.6
91-92	30.1	101.3	24.3	29.9			4.4	1.7	105.7	191.7	2049	9.4
92-93	26.8	138.8	32.9	34.6			4.4	1.8	143.2	239.3	2172	11.0
93-94	28.1	138.8	34.6	39.2			4.4	1.9	143.2	247.0	2294	10.8
94-95	29.6	180.2	44.5	44.3			8.4	3.6	188.6	310.7	2417	12.8
95-96	28.8	191.0	48.9	51.0			8.4	3.8	199.4	331.9	2585	12.8
96-97	25.7	237.6	57.9	58.9			8.4	4.0	246.0	392.5	2754	14.2
97-98	6.2	310.2	75.2	70.0			8.4	4.3	318.6	474.3	2922	16.2
98-99	6.4	386.4	94.0	79.3			8.4	4.6	394.8	579.2	3091	18.7
99-2000	6.7	386.4	98.7	89.3			8.4	4.8	394.8	594.3	3260	18.2
00-01	7.0	386.4	103.7	99.5			8.4	5.1	394.8	610.1	3396	17.9
01-02	7.3	386.4	108.8	110.7			8.4	5.3	394.8	626.9	3531	17.7
02-03	2.7	386.4	114.3	123.1			8.4	5.6	394.8	640.5	3667	17.5
03-04	2.8	483.7	139.3	136.6			8.4	5.8	492.1	776.6	3803	20.4
04-05	2.9	433.7	146.3	151.5			8.4	6.0	492.1	798.8	3939	20.3
05-06	---	433.7	153.6	167.6			8.4	6.3	492.1	819.6	4074	20.1
06-07	---	483.7	161.2	185.3			8.4	6.7	492.1	845.3	4210	20.1
07-08	---	602.0	192.8	204.7			16.5	10.2	618.5	1026.2	4346	23.6
08-09	---	602.0	202.5	225.9			16.5	10.5	618.5	1057.4	4431	23.6
09-10	---	602.0	212.6	248.9			16.5	10.9	618.5	1090.9	4617	23.6
10-11	---	602.0	223.2	274.0			16.5	11.4	618.5	1127.1	4753	23.7

TABLE 4.33. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	33.8	---	---	---			0.3	0.2	---	34.2	832	4.1
79-80	36.6	---	---	---			0.3	0.2	---	37.0	903	4.1
80-81	39.4	---	---	---			0.3	0.2	---	39.8	981	4.1
81-82	41.7	---	---	---			0.3	0.2	---	42.1	1059	4.0
82-83	35.7	---	---	6.9			0.3	0.2	---	43.0	1137	3.8
83-84	33.2	---	---	7.2			0.3	0.2	---	40.8	1215	3.4
84-85	30.4	13.9	3.8	9.1			3.5	1.0	22.4	66.7	1294	5.2
85-86	28.3	18.0	3.8	10.6			3.5	1.0	22.4	66.2	1396	4.7
86-87	26.1	18.9	3.8	12.1			18.8	2.0	37.7	81.8	1498	5.5
87-88	24.0	18.9	3.8	13.7			18.8	2.0	37.7	81.3	1600	5.1
88-89	22.9	21.5	4.3	15.0			18.8	2.0	40.3	84.6	1702	5.0
89-90	23.1	21.5	4.3	15.4			18.8	2.0	40.3	85.2	1805	4.7
90-91	20.9	27.6	5.5	14.1			18.8	2.0	46.4	89.0	1927	4.6
91-92	21.1	27.6	5.5	15.2			18.8	2.0	46.4	90.2	2049	4.4
92-93	18.2	65.4	13.1	20.2			18.8	2.0	84.2	137.8	2172	6.3
93-94	18.4	84.3	16.9	26.3			18.8	2.0	103.1	166.8	2294	7.3
94-95	18.5	84.3	16.9	28.8			18.8	2.0	103.1	169.4	2417	7.0
95-96	16.9	107.9	21.6	31.5			20.6	2.8	128.5	201.3	2585	7.8
96-97	14.3	126.8	25.4	34.8			20.6	2.8	147.4	224.8	2754	8.2
97-98	3.7	155.5	31.1	39.5			20.6	2.8	176.1	253.4	2922	8.7
98-99	3.7	155.5	31.1	42.4			20.6	2.8	176.1	256.3	3091	8.3
99-2000	3.7	155.5	31.1	45.8			20.6	2.8	176.1	259.7	3260	8.0
00-01	3.8	155.5	31.1	48.4			20.6	2.8	176.1	262.3	3396	7.7
01-02	3.8	155.5	31.1	51.5			20.6	2.8	176.1	265.3	3531	7.5
02-03	1.5	155.5	31.1	54.3			20.6	2.8	176.1	265.8	3667	7.2
03-04	1.5	184.2	36.8	57.5			20.6	2.8	204.8	303.5	3803	8.0
04-05	1.5	212.9	42.5	60.8			20.6	2.8	233.5	341.2	3939	8.7
05-06	---	212.9	42.5	64.2			20.6	2.8	233.5	343.1	4074	8.4
06-07	---	212.9	42.5	67.7			20.6	2.8	233.5	346.5	4210	8.2
07-08	---	212.9	42.5	71.3			20.6	2.8	233.5	350.1	4346	8.1
08-09	---	212.9	42.5	74.9			20.6	2.8	233.5	353.7	4481	7.9
09-10	---	212.9	42.5	78.7			20.6	2.8	233.5	357.5	4617	7.7
10-11	---	212.9	42.5	82.5			20.6	2.8	233.5	361.4	4753	7.6

TABLE 4.34. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.6	---	---	---			0.2	0.2	---	30.9	832	3.7
79-80	33.9	---	---	---			0.2	0.2	---	34.2	903	3.8
80-81	37.5	---	---	---			0.2	0.2	---	37.8	981	3.9
81-82	40.7	---	---	---			0.2	0.2	---	41.0	1059	3.9
82-83	36.7	---	---	6.9			0.2	0.2	---	43.9	1137	3.9
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	1215	3.6
84-85	33.6	25.4	5.0	9.1			4.4	1.2	29.8	78.8	1294	6.1
85-86	32.4	25.4	5.2	10.6			4.4	1.3	29.8	79.4	1396	5.7
86-87	30.4	25.4	5.5	12.7			26.3	2.8	51.7	103.3	1498	6.9
87-88	28.7	25.4	5.8	14.9			26.3	2.9	51.7	104.1	1600	6.5
88-89	27.9	29.6	7.0	17.2			26.3	3.1	55.9	111.2	1702	6.5
89-90	29.3	29.6	7.3	18.7			26.3	3.2	55.9	114.6	1805	6.3
90-91	28.4	41.0	9.8	18.0			26.3	3.4	67.3	127.1	1927	6.6
91-92	30.1	41.0	10.3	20.2			26.3	3.6	67.3	131.5	2049	6.4
92-93	26.7	116.0	25.6	28.3			26.3	3.7	142.3	226.8	2172	10.4
93-94	28.1	155.4	34.7	38.4			26.3	3.9	181.7	286.9	2294	12.5
94-95	29.5	155.4	36.4	44.3			26.3	4.1	181.7	296.2	2417	12.3
95-96	28.8	209.6	48.9	51.0			30.4	6.0	240.0	374.8	2585	14.5
96-97	27.7	256.2	60.3	58.9			30.4	6.3	286.6	439.8	2754	16.0
97-98	6.1	328.8	77.7	70.7			30.4	6.6	359.2	519.7	2922	17.8
98-99	6.4	328.8	81.6	79.3			30.4	6.9	359.2	533.5	3091	17.3
99-2000	6.6	328.8	85.7	89.2			30.4	7.3	359.2	548.1	3260	16.8
00-01	7.0	328.8	89.9	99.5			30.4	7.7	359.2	563.3	3396	16.6
01-02	7.3	328.8	94.5	110.6			30.4	8.1	359.2	579.7	3531	16.4
02-03	2.7	328.8	99.2	123.1			30.4	8.5	359.2	592.7	3667	16.2
03-04	2.8	426.1	123.4	136.6			30.4	8.9	456.5	728.2	3803	19.2
04-05	2.9	528.3	149.9	151.5			30.4	9.3	558.7	872.3	3939	22.1
05-06	---	528.3	157.4	167.6			30.4	9.8	558.7	893.5	4074	21.9
06-07	---	528.3	165.3	185.3			30.4	10.3	558.7	919.6	4210	21.8
07-08	---	528.3	173.5	204.7			30.4	10.8	558.7	947.7	4346	21.8
08-09	---	528.3	182.2	225.8			30.4	11.4	558.7	978.1	4481	21.8
09-10	---	528.3	191.3	248.9			30.4	11.9	558.7	1010.8	4617	21.9
10-11	---	528.3	200.9	274.0			30.4	12.5	558.7	1046.1	4753	22.0

TABLE 4.35. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	38.8	---	---	---	---	---	0.3	0.2	---	34.2	832	4.1
79-80	36.6	---	---	---	---	---	0.3	0.2	---	37.0	903	4.1
80-81	39.4	---	---	---	---	---	0.3	0.2	---	39.8	931	4.1
81-82	41.7	---	---	---	---	---	0.3	0.2	---	42.1	1059	4.0
82-83	35.7	---	---	6.9	---	---	0.3	0.2	---	43.0	1137	3.8
83-84	33.2	---	---	7.2	---	---	0.3	0.2	---	40.8	1215	3.4
84-85	30.4	13.9	3.8	9.1	---	---	3.5	1.0	22.4	66.7	1294	5.2
85-86	28.3	18.0	3.8	10.6	---	---	3.5	1.0	22.4	66.2	1396	4.7
86-87	26.1	18.9	3.8	12.1	---	---	18.8	2.0	37.7	81.8	1498	5.5
87-88	24.0	18.9	3.8	13.7	---	---	18.8	2.0	37.7	81.3	1600	5.1
88-89	22.9	21.5	4.3	15.0	---	---	18.8	2.0	40.3	84.6	1702	5.0
89-90	23.1	21.5	4.3	15.4	---	---	18.8	2.0	40.3	85.2	1805	4.7
90-91	20.9	27.6	5.5	14.1	---	---	18.8	2.0	46.4	89.0	1927	4.6
91-92	21.1	27.6	5.5	15.2	---	---	18.8	2.0	46.4	90.2	2049	4.4
92-93	18.2	65.4	13.1	20.2	---	---	18.8	2.0	84.2	137.8	2172	6.3
93-94	18.4	84.3	16.9	26.3	---	---	18.8	2.0	103.1	166.8	2294	7.3
94-95	18.5	84.3	16.9	22.6	29.0	0.1	18.8	2.0	132.1	192.2	2417	7.9
95-96	16.9	89.0	17.8	24.4	29.0	0.1	18.8	2.0	136.8	198.0	2585	7.7
96-97	14.4	89.0	17.8	27.4	29.0	0.1	18.8	2.0	136.8	198.5	2754	7.2
97-98	3.8	89.0	17.8	32.0	29.0	0.1	18.8	2.0	136.8	192.5	2922	6.6
98-99	3.8	89.0	17.8	28.4	38.7	0.2	20.6	2.8	148.3	201.3	3091	6.5
99-2000	3.8	89.0	17.8	30.6	28.7	0.2	20.6	2.8	148.3	203.5	3260	6.2
00-01	3.8	107.9	21.6	33.0	38.7	0.2	20.6	2.8	167.2	228.6	3396	6.7
01-02	3.8	126.8	25.4	35.7	38.7	0.2	20.6	2.8	186.1	254.0	3531	7.2
02-03	1.5	126.8	25.4	38.3	38.7	0.2	20.6	2.8	186.1	254.3	3667	6.9
03-04	1.5	155.5	31.1	41.2	38.7	0.2	20.6	2.8	214.8	291.6	3803	7.7
04-05	1.5	155.5	31.1	45.6	38.7	0.2	20.6	2.8	214.8	296.0	3939	7.5
05-06	---	155.5	31.1	47.2	38.7	0.2	20.6	2.8	214.8	296.1	4074	7.3
06-07	---	155.5	31.1	50.3	38.7	0.2	20.6	2.8	214.8	299.2	4210	7.1
07-08	---	155.5	31.1	53.5	38.7	0.2	20.6	2.8	214.8	302.4	4346	7.0
08-09	---	155.5	31.1	56.8	38.7	0.2	20.6	2.8	214.8	305.7	4481	6.8
09-10	---	184.2	36.8	60.2	38.7	0.2	20.6	2.8	243.5	343.5	4617	7.4
10-11	---	184.2	36.8	63.7	38.7	0.2	20.6	2.8	243.5	347.0	4753	7.3

TABLE 4.36. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	30.6	---	---	---	---	---	0.2	0.2	---	30.9	832	3.7
79-80	33.9	---	---	---	--	---	0.2	0.2	---	34.2	903	3.8
80-81	37.5	---	---	---	---	---	0.2	0.2	---	37.8	981	3.9
81-82	40.7	---	---	---	---	---	0.2	0.2	---	41.0	1059	3.9
82-83	36.7	---	---	6.9	---	---	0.2	0.2	---	43.9	1137	3.9
83-84	35.6	---	---	7.2	---	---	0.2	0.2	---	43.2	1215	3.6
84-85	33.6	25.4	5.0	9.1	---	---	4.4	1.2	29.8	78.8	1294	6.1
85-86	32.4	25.4	5.2	10.6	---	---	4.4	1.3	29.8	79.4	1396	5.7
86-87	30.4	25.4	5.5	12.7	---	---	26.3	2.8	51.7	103.3	1498	6.9
87-88	28.7	25.4	5.8	14.9	---	---	26.3	2.9	51.7	104.1	1600	6.5
88-89	27.9	29.6	7.0	17.2	---	---	26.3	3.1	55.9	111.2	1702	6.5
89-90	29.3	29.6	7.3	18.7	---	---	26.3	3.2	55.9	114.6	1805	6.3
90-91	28.4	41.0	9.8	18.0	---	---	26.3	3.4	67.3	127.1	1927	6.6
91-92	30.1	41.0	10.3	20.2	---	---	26.3	3.6	67.3	131.5	2049	6.4
92-93	26.7	116.0	25.6	28.3	---	---	26.3	3.7	142.3	226.8	2172	10.4
93-94	28.1	155.4	34.7	38.4	---	---	26.3	3.9	181.7	286.9	2294	12.5
94-95	29.6	155.4	36.4	34.8	61.0	0.3	26.3	4.1	242.7	347.9	2417	14.4
95-96	28.8	166.2	40.3	39.5	61.0	0.3	26.3	4.3	253.5	366.7	2585	14.2
96-97	27.7	166.2	42.3	46.4	61.0	0.3	26.3	4.5	253.5	374.7	2754	13.6
97-98	6.2	166.2	44.5	56.7	61.0	0.3	26.3	4.7	253.5	365.9	2922	12.5
98-99	6.4	166.2	46.7	53.1	85.7	0.7	30.5	6.8	282.4	396.1	3091	12.8
99-2000	6.7	166.2	49.1	59.6	85.7	0.7	30.5	7.1	282.4	405.6	3260	12.4
00-01	7.0	224.4	62.4	67.8	85.7	0.8	30.5	7.5	340.6	486.1	3396	14.3
01-02	7.3	282.6	77.0	76.7	85.7	0.8	30.5	7.8	398.8	568.4	3531	16.1
02-03	2.7	282.6	80.9	86.7	85.7	0.8	30.5	8.2	398.8	578.1	3667	15.8
03-04	2.8	380.0	104.2	97.7	85.7	0.9	30.5	8.6	496.2	710.4	3803	18.7
04-05	2.9	380.0	109.5	113.6	85.7	0.9	30.5	9.1	496.2	732.2	3939	18.6
05-06	---	380.0	114.9	123.0	85.7	1.0	30.5	9.5	496.2	744.6	4074	18.3
06-07	---	380.0	120.7	137.6	85.7	1.0	30.5	10.0	496.2	765.5	4210	18.2
07-08	---	380.0	126.7	153.7	85.7	1.1	30.5	10.5	496.2	788.2	4346	18.1
08-09	---	380.0	133.0	171.3	85.7	1.1	30.5	11.0	496.2	812.6	4481	18.1
09-10	---	510.4	165.5	190.5	85.7	1.2	30.5	11.6	626.6	995.4	4617	21.6
10-11	---	510.4	173.7	211.5	85.7	1.3	30.5	12.2	626.4	1025.3	4753	21.6

All entries in the tables are in millions of dollars unless noted. The first column is the total cost of the existing capacity. This includes investment, OM&R, and fuel costs except coal costs after 1982-1983 as noted below. This column includes the cost of the combustion turbine units planned through 1984 in the Anchorage area. The cost of existing capacity is assumed to be the same for all load growth scenarios and system configurations. This assumption is warrented in this case for two reasons. First, an examination of the load resource analyses for the alternative load growth scenarios and cases reveals relatively little variation in the plant utilization factors among the various scenarios and cases. Second, the cost of operating the existing capacity is a relatively small part of the overall system costs in the 1990-2010 time period which is of primary interest in this report.

The next three columns present the costs for the new coal-fired capacity. The investment cost is the total of all the individual plant investments. The OM&R costs are the sum of all the OM&R costs of the individual plants. Entries in these two columns begin the same year as the first coal-fired plant comes on line. The coal costs include the coal costs of the new coal-fired capacity. In addition, the coal costs of the existing capacity are included in this column after 1982-1983. (It is subtracted out of the existing capacity after 1982-1983.)

The next two columns present the costs for any new hydroelectric capacity that is added. These are the Bradley Lake project, the Watana dam and the Devil Canyon dam. As pointed out earlier the Watana and Devil Canyon costs are divided between the Anchorage-Cook Inlet area and the Fairbanks-Tanana area in proportion to their relative energy consumption in 1994.

The transmission system costs are shown in the next two columns. These columns contain the investment and OM&R costs for all the transmission lines required. The total investment cost column represents the sum of the new coal-fired capacity investment costs, the hydroelectric capacity investment costs, and the transmission system investment costs.

The total system cost is the sum of all the costs (not including the new investment cost column). The total system consumption figures are the same as

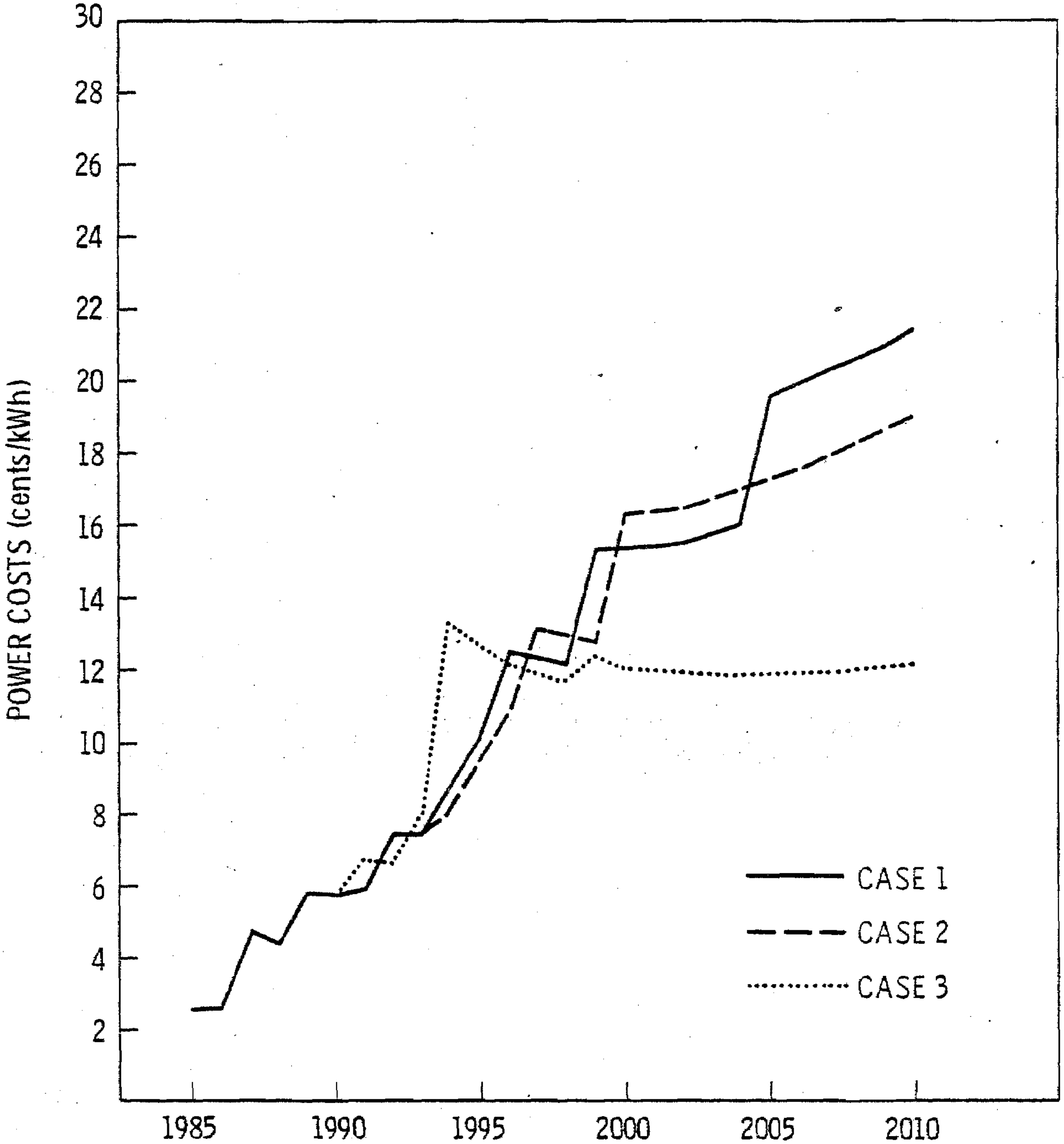

FIGURE 4.5. Power Costs for Anchorage Low Load Growth Scenario

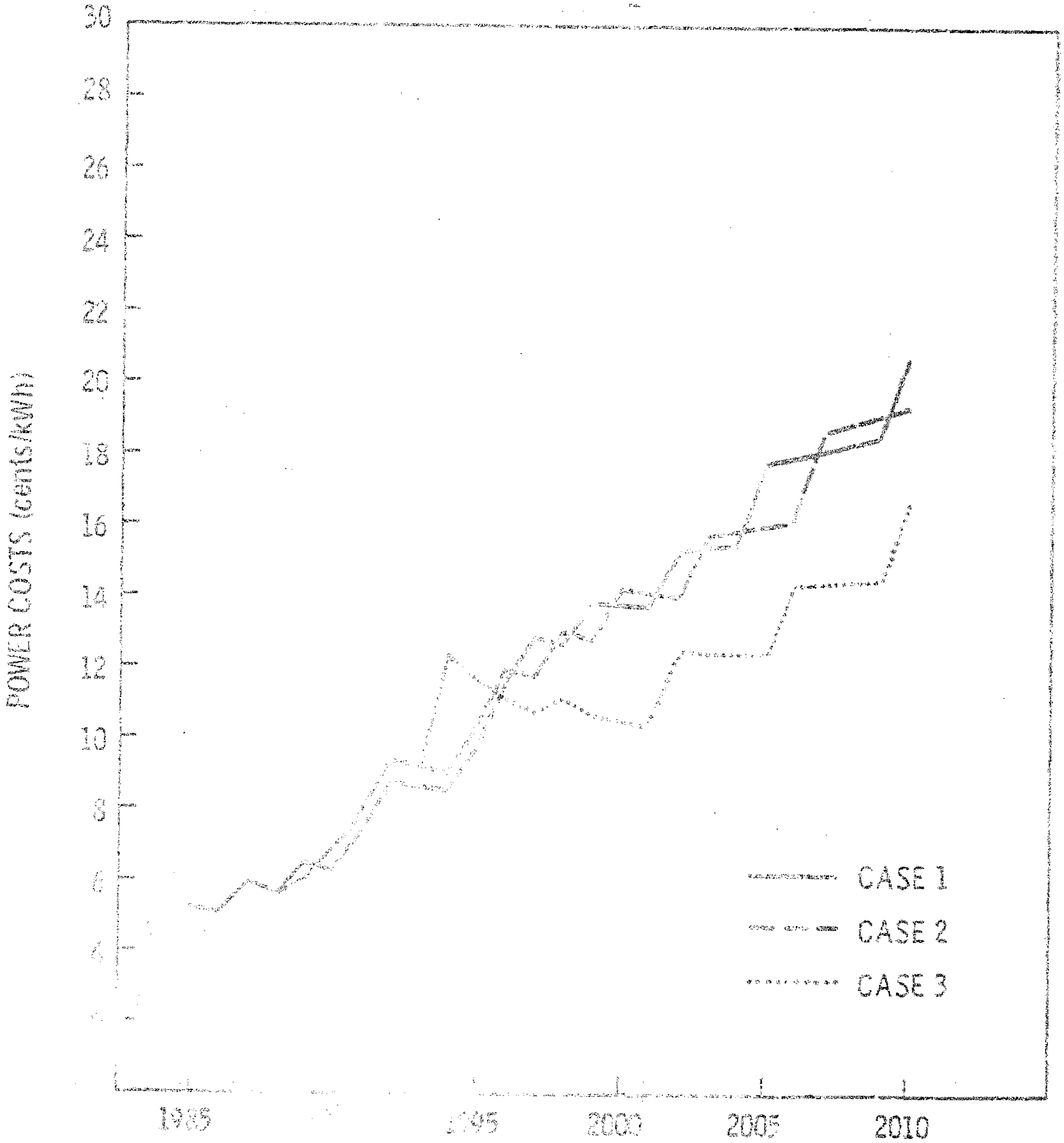

FIGURE 4.6. Costs for Anchorage Medium Load Growth Scenario

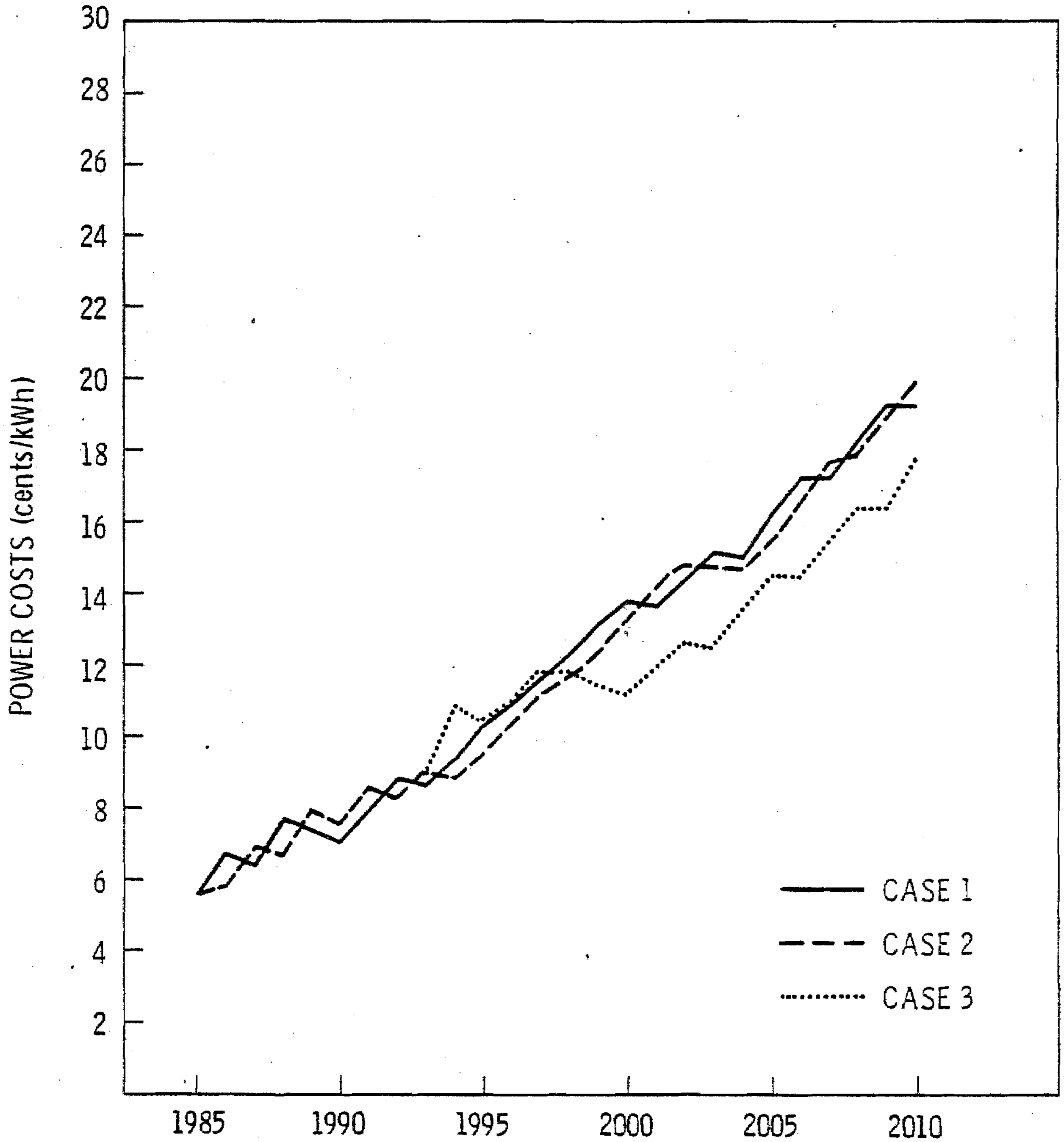

FIGURE 4.7. Power Costs for Anchorage High Load Growth Scenario

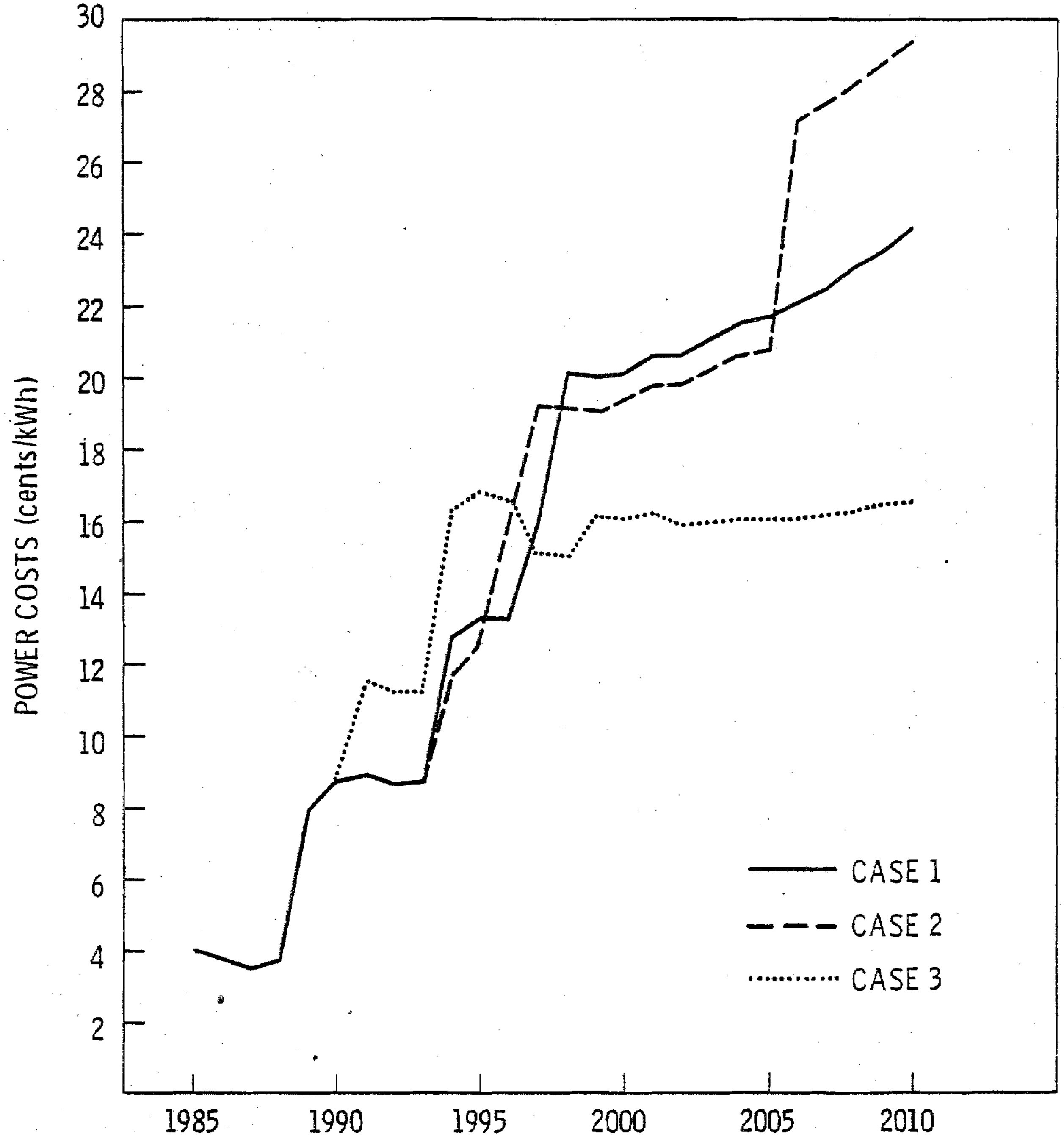

FIGURE 4.8. Power Costs for Fairbanks Low Load Growth Scenario

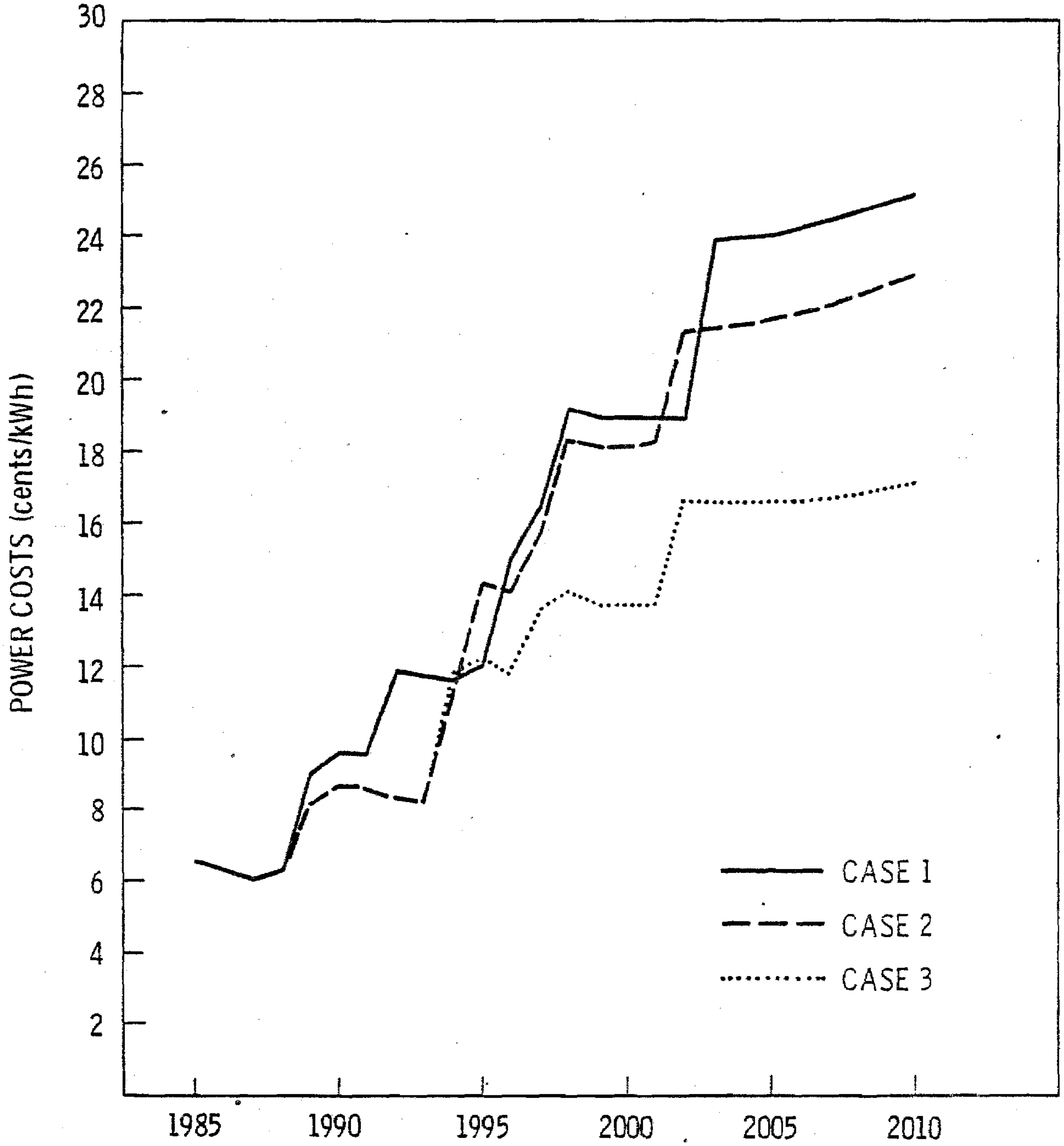

FIGURE 4.9. Power Costs for Fairbanks Medium Load Growth Scenario

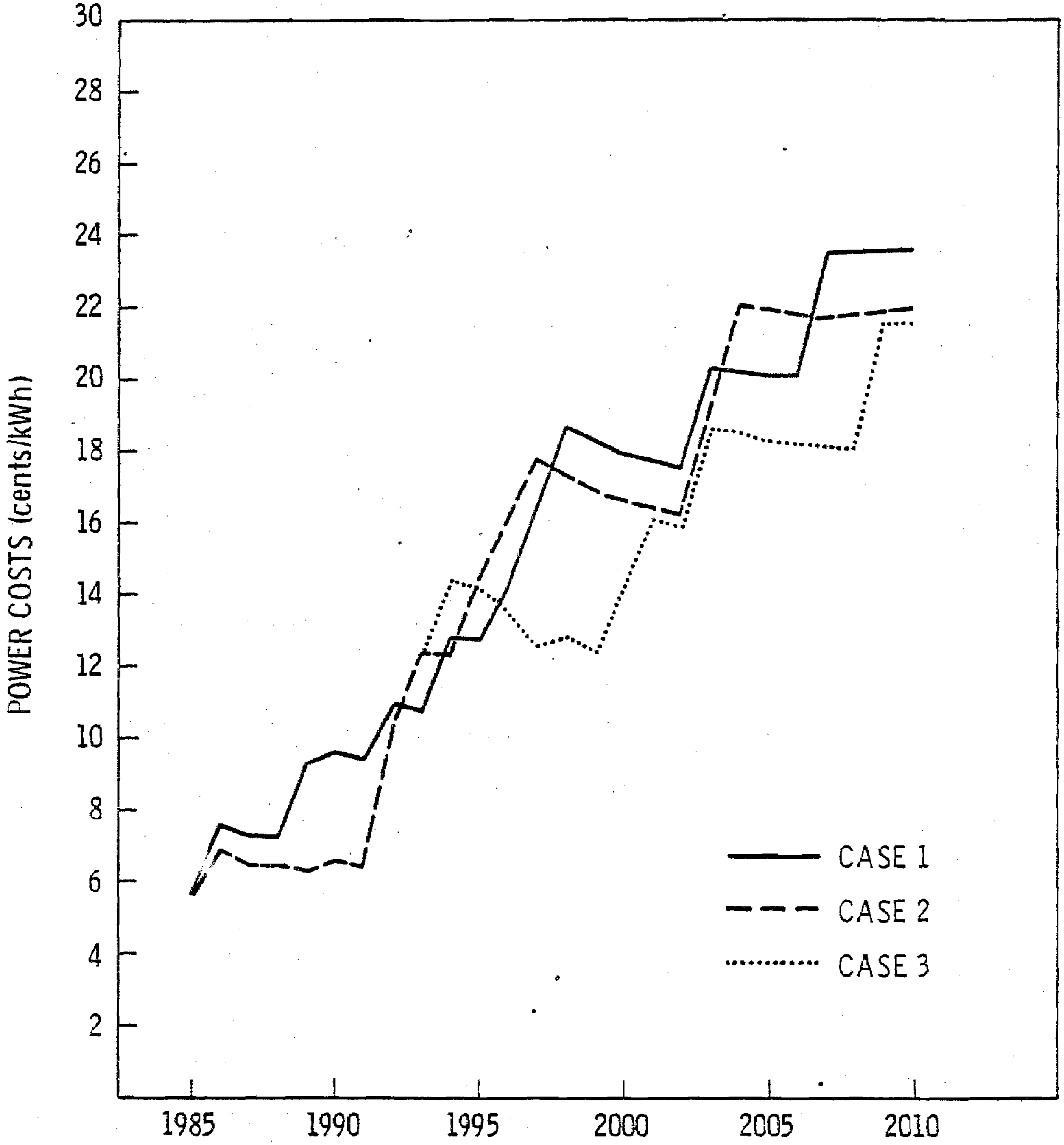

FIGURE 4.10. Power Costs for Fairbanks High Load Growth Scenario

$$PW = \sum_{i=n}^{n} APC_i * \frac{1}{(1+r)^i}$$

where:

PW = Present worth of the cost of power

APC_i = Average power cost in year i

r = Discount rate

n = Total number of years.

Using this formula the total investment cost and the average power cost over a period of years can be more easily compared. A 7% discount rate is used in these analyses.

The results for each of the load growth scenarios for both of the load centers are briefly discussed below.

Anchorage-Cook Inlet - Low Load Growth

The present worth of the total investment and the present worth of average power costs are shown below.

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	2	2329	78
2	4	2251	76
3	6	2504	70

Case 3 results in the lowest cost of power followed by Case 2 and Case 1. Case 2 gives the lowest overall investment costs while Case 3 results in the highest investment costs.

Anchorage-Cook Inlet - Medium Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	8	3920	83
2	10	3930	83
3	12	3920	77

The present worth of the total investment is almost identical for all three cases. The present worth of the cost of power is the same for Cases 1 and 2, while the present worth power cost for Case 3 is lowest.

Anchorage-Cook Inlet - High Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	14	7053	86
2	16	6837	85
3	18	7084	83

Again Case 3 results in the lowest present worth for the cost of power. For this scenario Case 2 results in the lowest present worth investment with Cases 1 and 3 slightly higher.

Fairbanks-Tanana Valley - Low Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	20	666	110
2	22	699	113
3	24	742	104

Case 3 gives the lowest cost of power while Case 1 gives the lowest investment cost. Case 3 results in the highest present worth investment cost.

Fairbanks-Tanana Valley - Medium Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	26	1128	117
2	28	1042	111
3	30	970	99

Again Case 3 results in the lowest present worth cost of power. In this scenario however, Case 3 also gives the lowest present worth total investment costs.

Fairbanks-Tanana Valley - High Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	32	1642	115
2	34	1587	110
3	36	1527	103

Again Case 3 results in the lowest present worth cost of power and the lowest present worth total investment.

REFERENCES - CHAPTER 4

1. Taylor, G. A., Managerial and Engineering Economy, D. van Nostrand Company, Inc., Princeton, NJ, 1964.

RECEIVED
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ALASKA POWER ADM.

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REGIONAL OFFICE
555 BATTERY STREET, ROOM 415
SAN FRANCISCO, CA 94111

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100	RC	3/8
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721	Work Cop	

March 6, 1979

Mr. Robert J. Cross
Administrator
Department of Energy
Alaska Power Administration
P. O. Box 50
Juneau, Alaska 99802

Dear Mr. Cross:

This will respond to your letter of February 2, 1979, requesting our informal review and comments on your Upper Susitna Project Power Market Draft Report.

Although we were unable to make an in-depth review of the draft report due to time and staffing limitations, we do wish to make the following comments:

Page 9 , second paragraph, third sentence. FERC estimated costs are as of July 1, 1978, not October 1978 as stated.

Page 95, second paragraph, last sentence. The San Francisco Regional Office of FERC did include cost adjustments for Alaska conditions in its power value study as it routinely does for all studies in Alaska.

Page 95, last paragraph, last sentence. The investment cost estimates of the Fairbanks plant are $1475/kW (@ 5.75% financing) and $1510/kW (@ 6.875% financing). Cost estimates of the Anchorage-Kenai area plant are $1240/kW (@ 7.94% financing) and $1220/kW (@ 6.875% financing).

Page 96, Oil and Natural Gas. Our thoughts on this subject were stated in our October 31, 1978, letter to the District Engineer, Alaska District, Corps of Engineers. In that letter we stated that oil-fired combined cycle and regenerative combustion turbine plants were significantly less costly than alternative coal-fired plants for the Upper Susitna River Basin. We are not able to state, however, which alternative is the more probable source. The determining factors would be the Alaska fuel situation and the interpretation of the Fuel Use Act.

While the Fuel Use Act prohibits the use of oil or natural gas as primary fuel for electrical generation, the Department of Energy, Economic Regulatory Administration (ERA), is promulgating regulations which will provide for various exemptions. The regulations are expected to be issued in May. We suggest that you contact ERA on this matter.

Page 105, item 5. The retirement schedule for combustion turbine is stated to be 20 years. Most studies in the Continental United States use 30 years.

Pages 159 and 160, Assessment of Feasibility. A cost estimate of Copper Valley Electric Association's purchase of Upper Susitna power would be useful to this discussion.

Appendix, page 21, 3.2.4, Transmission Losses. The 1.5% for energy loss appears to be low.

We appreciate the opportunity to review and comment on your draft report.

Sincerely,

Eugene Neblett
Regional Engineer

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721	GS	
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Battelle
Pacific Northwest Laboratories
P.O. Box 999
Richland, Washington 99352
Telephone (509) 942-4745
Telex 32-6345

February 27, 1979

Mr. Robert Cross
Department of Energy
Alaska Power Administration
P. O. Box 50
Juneau, AK 99802

Dear Mr. Cross:

Thank you for the opportunity to comment on your Draft Power Market Analysis. Both Ward Swift and I read it over and came up with only a few minor comments. The primary focus of our review was the consistency between the body of the report and our background analysis presented in Appendix 3.

1. Page 4, 2nd paragraph - The alternative on-line dates of 1990, 1992, and 1994 seem to refer to the interconnection on-line dates for high, medium, and low load growth cases respectively. I believe those dates should be 1986, 1989, and 1991. This would be consistent with the dates given in the last line on page 109.

2. Page 8, table at bottom - It appears that the costs of power listed for Case should be the same numbers listed for the Case 1 of the combined system in the table at the top of page 111.(i.e., the costs of power should be 6.6, 6.9, and 7.5¢/KWh rather than 7.0, 7.0 and 6.6¢/KWh for the high, medium, and low load growths respectively).

3. Page 17, Installed name plate capacities - As pointed out on page 19 the totals differ from those used by us in Appendix 3. Most of the differences are relatively minor. The only major difference seems to be the capacity listed for the Chugach Electric Association. As you indicate these differences are due to recent changes in plans to install new capacity. The difference would have a minor impact on the 1978 through 1985 results and practically no impact on the results after 1985.

4. Pages 52, 59, 80, and Appendix 3 page 8 - Annual Load Factors - On page 42 and Appendix 3, page 8, both reports are generally in agreement that the annual load factor is presently between 46-52%. In Appendix 3 we go on to say that it appears the annual load factor will remain in the 50-52% range during the time horizon of the report. On page 80 it is stated that for planning purposes it is assumed that the annual system load factor will be in the range of 55-60% by the latter part of the century.

If the load factor is defined as:

$$ALF = \frac{GEN}{CAP * 8.760}$$

where:

ALF = Annual load factor (fraction)
GEN = Generation (MW)
CAP = Capacity (GWH)

and use data for the year 2000, low load growth as presented on page 59 we compute an annual load factor of 51%.

i.e.

$$ALF = \frac{6424}{1448 * 8.760} = .51$$

This is lower than the 55-60% mentioned on page 80.

5. Page 95, Healy II plant costs - It would be good to point out that the GVEA estimate is probably in terms of 1985$.

6. Page 101-102, Conclusions - I think your summary of the alternatives available to Alaska is good.

7. Cover Sheet, Appendix 3 - Enclosed are different cover pages for our report presented in Appendix 3 and the Appendices to our report. Please replace the cover pages you presently have.

Thank you for the opportunity to comment on the report.

Sincerely,

Jay Jacobsen

J. Jay Jacobsen
Energy Assessment Unit
Energy Systems Department

JJJ:tw
Enclosures

DEPARTMENT OF THE ARMY
ALASKA DISTRICT, CORPS OF ENGINEERS
P.O. BOX 7002
ANCHORAGE, ALASKA 99510

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REPLY TO
ATTENTION OF:
NPAEN-PL-R

19 MAR 1979

Mr. Robert J. Cross
Administrator
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

Dear Mr. Cross:

I am writing to advise you of actions taken in response to your comments on the draft Susitna Supplemental Feasibility Report and also to comment on your draft Power Market Analysis.

Your letter of 26 January 1979 transmitting your comments on our draft report arrived during the final report printing. Any delay at that point would have caused us to miss our deadline which I was unwilling to permit except under extreme circumstances. On the verbal assurance from your staff that there was nothing of such gravity that the integrity of the report would be jeopardized, the decision was made to proceed with the printing as scheduled.

I regret that your written comments did not arrive sooner, because the report would have benefited from their incorporation. I am especially sensitive to your contention that insufficient credit was given where APA materials were used. In the future, my staff will be more careful in this regard.

Our review of your excellent draft Power Market Analysis has resulted in only one comment. On page 4 you note that the more costly gravity structure for Devil Canyon is "currently proposed" by the Corps. This is inaccurate in that the gravity structure was presented to insure that estimated costs were sufficient to cover a range of possible foundation conditions at the Devil Canyon site. With appropriate word changes to correct this matter, we find nothing else requiring alteration.

Since the Main Report and Appendix Part 1 are already in Washington, please transmit 20 copies of the final Appendix Part 2 to HQDA (DAEN-CWP-W), 19 MAR 1979

Washington D.C. 20314; 2 copies to Division Engineer, North Pacific Corps of Engineers, 210 Custom House, Portland, Oregon 97209, ATTN; NPDPL; and the remaining 138 copies to the Alaska District, ATTN: NPAEN-US.

If you have any questions, Mr. Chuck Bickley at (907) 752-5135 can provide assistance.

Sincerely yours,

VERNELLE T. SMITH
Lt Colonel, Corps of Engineers
Acting District Engineer

DEPARTMENT OF THE ARMY
ALASKA DISTRICT, CORPS OF ENGINEERS
P.O. BOX 7002
ANCHORAGE, ALASKA 9951

REPLY TO
ATTENTION OF:

NPAEN-PL-R

19 MAR 1979

Mr. Robert J. Cross
Administrator
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

Dear Mr. Cross:

I am writing to advise you of actions taken in response to your comments on the draft Susitna Supplemental Feasibility Report and also to comment on your draft Power Market Analysis.

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Washington D.C. 20314; 2 copies to Division Engineer, North Pacific Corps of Engineers, 210 Custom House, Portland, Oregon 97209, ATTN: NPDPL; and the remaining 138 copies to the Alaska District, ATTN: NPAEN-US.

If you have any questions, Mr. Chuck Bickley at (907) 752-5135 can provide assistance.

Sincerely yours,

s/LTC. Vernelle T. Smith

VERNELLE T. SMITH
Lt Colonel, Corps of Engineers
Acting District Engineer

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1200 EAST FIRST AVENUE — ANCHORAGE, ALASKA 99501
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noted.

March 1, 1979

Robert J. Cross, Administrator
Department of Energy
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

Dear Mr. Cross:

This letter responds to your letter of February 2, 1979, which requested informal comments on the draft Power Market Analyses of the Upper Susitna River Project.

Mr. Stahr is out of town and I am writing without knowledge of his personal opinion and comments. The Municipal Light and Power's staff comments appear in the two attached memorandums. Mr. Stahr may forward more comments upon his return.

Thank you for the opportunity to review the draft. If you have any questions or want more comments please do not hesitate to contact us.

Very truly yours,

Max Foster

Max Foster
Revenue Requirements Supervisor

MF:bw

Enclosure

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900	file	

March 23, 1979

Mr. Jim Cheatham
U.S. Department of Energy
Alaska Power Administration
P.O. Box 50
Juneau, AK 99801

Subject: Power Market Analysis - Draft on the Upper Susitna River Project
State I.D. No. 79020902

Dear Mr. Cheatham:

The Alaska State Clearinghouse has completed review on the subject project.

The State Clearinghouse has no comment on this project.

This letter wi. satisfy the review requirements of the office of Management and .udget's Circular A-95.

Sincerely,

Jerry L. Madden

Jerry Madden
State-Federal Coordinator

JM/cz

Municipality of Anchorage

MEMORANDUM

DATE: February 15, 1979

TO: Thomas R. Stahr, General Manager

FROM: H. C. Purcell, Assistant Chief Engineer

SUBJECT: DOE APA UPPER SUSITNA RIVER PROJECT POWER MARKET ANALYSES

I have reviewed the January 1979 draft of this report and find nothing controversial in it. There is an error, and there are a few points I will comment on, none of which, however, affect the conclusions reached.

On page 33, Table 5 shows AML&P generation in 1965 as 156.2 GWH. This results in area growth 1964-1965 of 34.4% and 1965-1966 growth of -0.6%. AML&P generation in 1965 was actually 101.5 GWH. This changes the area total in 1965 to 407.0 GWH, 1964-1965 growth to 18.5% and 1965-1966 growth to 12.7%.

101.15
106.8

On pages 37 and 38, the report states ". . . correlations with weather . . . seemed indeterminable or of little significance." and "Energy use and weather comparisons were inconclusive." This does not agree with my work or with plain common sense. Growth between 1973 and 1977 is used to forecast energy requirements. In three of these four years, 1974, 1976 and 1977, the weather was warmer than normal. Ignoring the influence of weather depresses the growth rate. However, this does not affect the report materially, since it winds up using three different growth rates (low, medium and high) in its market analyses.

It is interesting that the situation hasn't changed in twenty years. Page 98 lists six major hydro projects with much better economics than the Upper Susitna. But they all remain tied up by "major environmental and land use problems."

On pages 100-102 the report brushes off exotic energy sources as "not realistic planning alternatives . . ." I applaud this, but suspect that much more work will have to be done to convince the vocal proponents of "natural energy."

On page 104 the report specifies "System reserve capacity of 25 percent for non-interconnected load centers and 20 percent for interconnected systems." I checked these numbers against the PROBS runs I made in connection with DOE regulations on transitional facilities. For the Anchorage area at present, PROBS showed a loss of load probability of 0.2 days per year with a peak load of 466.3 MW. On the same basis, 25% reserve capacity would correspond to a peak load of 468.8 MW. 25% reserve capacity would result in LOLP only slightly over 0.2 days per year. With the larger interconnected system ten or twelve years in the future, 20% reserve capacity will probably provide reasonable LOLP.

Page 34 of the Battelle Informal Report schedules a 200 MW steam plant to be on line in 1982, three years hence. Yet Battelle page 22 says "the 5 to 6 year scheduling period [from final site selection to commercial operation] appears reasonable." Either CEA is about to break ground for its coal-fired steam plant or Battelle's dates are inconsistent. Again, however, it doesn't really matter. The relative economics of Susitna vs. coal-fired steam would not be affected.

HCPurcell

H. C. Purcell

cc: Koski

91-010 (3/78)

Municipality of Anchorage

MEMORANDUM

DATE: March 1, 1979

TO: Thomas R. Stahr, General Manager, ML&P

FROM: MF. Max Foster, Revenue Requirements Supervisor, ML&P

SUBJECT: DOE-APA Upper Susitna River Project Power Market Analyses

This memo comments on the Alaska Power Administration's Upper Susitna River Project Power Market Analysis draft dated January 1979. My impression is that the demand projections for the Anchorage area are conservative. I also think that the installed cost of coal plants is conservative. The Susitna project costs are probably the most reliable cost estimates appearing in the report. I am not happy with the methodology developing the cost of coal. I think coal could actually cost much more than $1.00 to $1.50 per million BTU. The inflation rates used in the analysis (0% and 5%) seem low in light of recent trends.

Significantly, despite the conservative assumptions contained within the report, the Susitna project represented the least cost option in every case.

My page by page review of the report elicited the following comments:

Page 37 - The lack of correlation to weather and price disburbs me. It may indicate improper equation specification caused by omitting important variable or failing to insert dummy variables in the regression equations to correct for cyclical abnormalities. Additionally, it seems to me demand projections by rate class would be more statistically significant. Correlation w/ weather is strong on a monthly, cyclical basis but not annually.

Page 77 - The shape of the Anchorage Area load duration curve suggests that a heavy proportion of generation for the area could be large base load increments. This is very favorable for hydroelectric development.

Page 94 - I don't like the treatment of O & M costs. How does this relate to prosent actual Anchorage labor costs and trends? I think the prices should be measured directly, not arbitrarily increased.

Page 150 - The pipline terminal's 37.5 MW generation plant is not interconnected with CVEA. It is not a cogeneration facility. Total energy facility rather than

Appendix 3, Pages 66 to 75 - Where is the present worth or annualized cost of power computed? This is a major change from the earlier ECOST2 model. I think the present worth analysis is an important part of any power cost analysis.

In general, the analysis seems complete. The conclusions echo those of previous studies. From an economic prospective, the Susitna Project is unquestionably justified. Its time to stop revising feasibility analyses and get on with licensing and construction. Ame

MF:bw

SECTION H

TRANSMISSION SYSTEM

None of the OMB comments were directed at the engineering aspects of the transmission system. There are therefore no changes made to this section. Costs of transmission have been updated and appear in Section B, Project Description and Cost Estimates. The economic justification for the transmission intertie is discussed in Section G, Marketability Analysis.

SECTION I

ENVIRONMENTAL ASSESSMENT FOR TRANSMISSION SYSTEMS

This section has not been supplemented because no changes were made to the transmission plan.

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SECTION I

ENVIRONMENTAL ASSESSMENT FOR
TRANSMISSION SYSTEMS

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Southcentral Railbelt Area, Alaska
Upper Susitna River Basin

00097

SUPPLEMENTAL FEASIBILITY REPORT

HYDROELECTRIC POWER
and related purposes

U.S. Department of the Army
Alaska District
Corps of Engineers

Appendix
Part 2

Anchorage, Alaska

1979