ALASKA POWER AUTHORITY

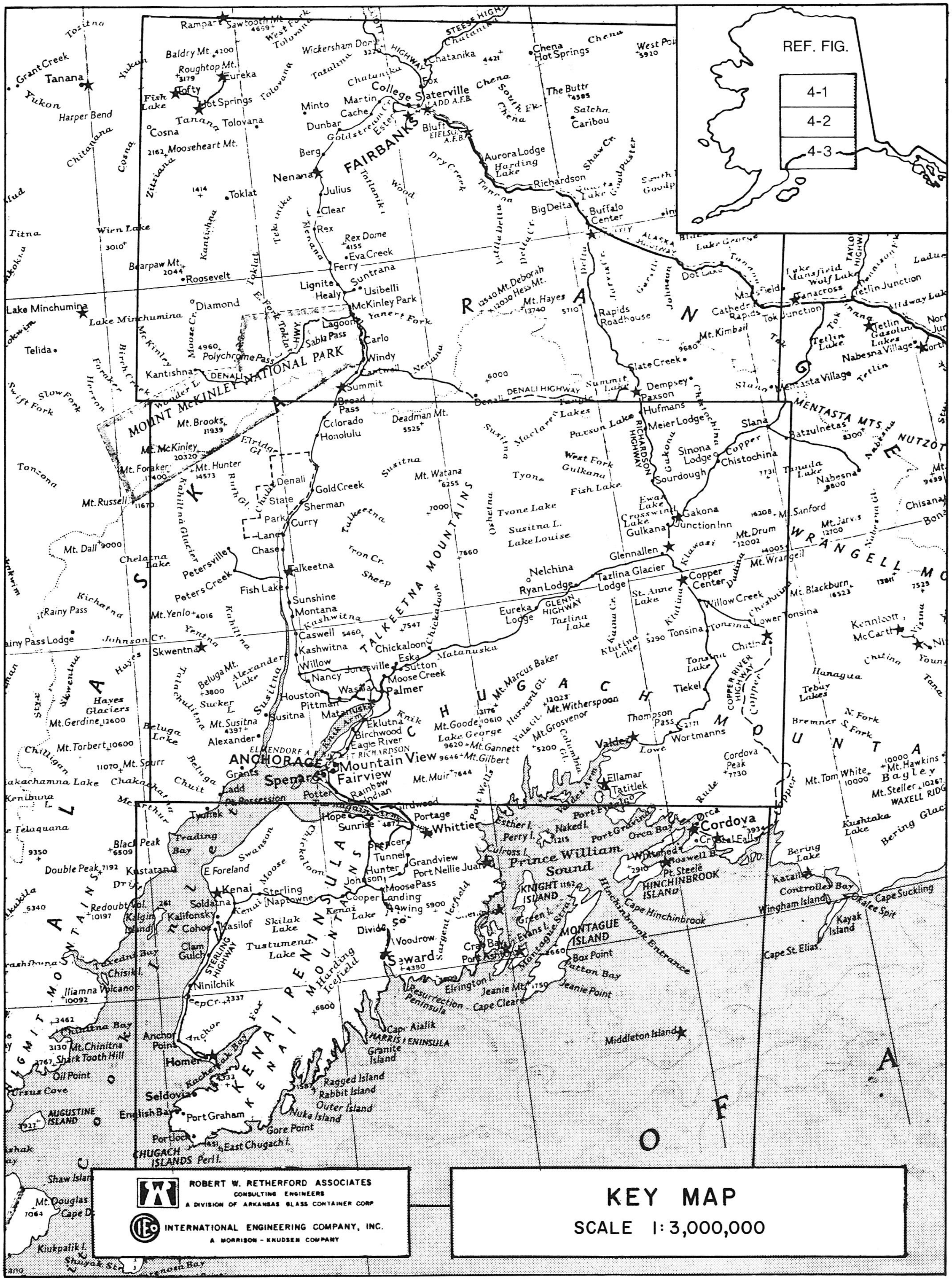
Anchorage - Fairbanks Transmission Intertie

Economic Feasibility Study Report

December 1979

INTERNATIONAL ENGINEERING COMPANY, INC.

ROBERT W. RETHERFORD ASSOCIATES



KEY MAP

SCALE 1: 3,000,000

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ABREVIATIONS

ac alternating current

ACF annual cost of fuel

ACSR aluminium conductor, steel reinforced

AIA Alaskan Intertie Agreement

AML&P Anchorage Municipal Light and Power Company

APA Alaska Power Authority

A.R.R. Alaska Railroad

AVF average value factor

bpd barrels per day

BTU British thermal units

CEA Chugach Electric Association, Inc.

CFC Cooperative Finance Corporation

dc direct current

DOE U.S. Department of Energy

EEI Edison Electric Institute

FFB Federal Finance Bank

FGD flue gas desulphurization

FOH forced outage hours

FMUS Fairbanks Municipal Utility System

ft feet

gal gallon

GVEA Golden Valley Electric Association, Inc.

GWh gigawatt-hours (million kilowatt-hours)

HEA Homer Electric Association, Inc.

HVDC high voltage, direct current

IAEAT Interior Alaska Energy Analysis Team

IECO International Engineering Company, Inc.

IEEE Institute of Electrical and Electronics Engineers

ISER Institute for Social and Economic Research

kcmil thousand circular mils

kV kilovolts

kVa kilovolt-amperes

kW kilowatts

kWh kilowatt-hours

LNG liquid nitrate gas

LOLP loss of load probability

MAREL Multi-Area Reliability, a computer program developed by PTI

MBTU Million British thermal unit

MEA Matanuska Electrical Association, Inc.

MVA megavolt-amperes

MW megawatts

NESC National Electrical Safety Committee

NOx nitrous oxide

O&M operations and maintenance

ORV off-road vehicle

PCF Plant capacity factor

P.I. point of intersection

PRS power requirements studies

PTI Power Technology, Inc.

REA Rural Electrification Administration

RI radio interference

RWRA Robert W. Retherford Associates, Inc.

S/C single circuit

SCGT simple cycle combustion turbine

SIL surge impedance loading

TLCAP Transmission Line Cost Analysis Program, a computer program developed by IECO

TLEAP Transmission Line Economic Analysis Program, a computer program developed by IECO

TLFAP Transmission Line Financial Analysis Program, a computer program developed by IECO

tpy tons per year

TVI television interference

USA United States of America

USGS United States Geological Survey

VAR volt-amperes reactive

CHAPTER 1
INTRODUCTION

This report presents a determination of the economic feasibility for a transmission line interconnection between the utility systems of the Anchorage and Fairbanks areas. It includes an objective evaluation of the specific conditions under which the intertie is economically feasible. An interconnection between the two previously independent power systems will reduce total installed generation reserve capacity, provide means for the interchange of energy, reduce spinning reserve requirements, and provide the means for optimum economic dispatch of generating plants on the interconnected system basis. The later integration of the Upper Susitna Hydropower Project into the interconnected Anchorage-Fairbanks power system would serve to increase the benefits already available from early operation of the intertie. The work described in this report was performed under the authority of the 26 October 1978 contract between the Alaska Power Authority and the joint-venture of International Engineering Company, Inc. (IECO) and Robert W. Retherford Associates (RWRA).

Alternative system expansion plans were developed and analyzed during this study for each of the following areas:

- Independent Anchorage area
- Independent Fairbanks area
- Interconnected Anchorage-Fairbanks area (generation reserve sharing option)
- Interconnected Anchorage-Fairbanks area (generation reserve sharing and firm power transfer option)
- Interconnected Anchorage-Fairbanks area (with inclusion of the Upper Susitna Hydropower Project)

This study confirms the economic feasibility of the Anchorage-Fairbanks transmission line interconnection as well as the possibility of an early implementation date for the project, prior to longer-range development of the Upper Susitna Hydropower Project. This study also establishes additional intertie benefits from the supply of construction power to the sites of the Upper Susitna Hydropower Project. It also evaluated potential benefits from firm power supply to Matanuska Electric Association's system at the intermediate Palmer substation of the intertie. Preliminary financial and management plans for the implementation of the project were developed and are presented in the last two chapters of this report.

An Intertie Advisory Committee, composed of managers of Railbelt area utilities with the chairmanship of the Executive Director of the Alaska Power Authority, was formed. During the performance of this study three Intertie Advisory Committee meetings were held (4 December 1978, 8 January 1979, 14 February 1979, and 18 May 1979) to review factors related to the intertie and to discuss preliminary findings of this study. The following Railbelt utilities were represented on the Intertie Advisory Committee:

- Anchorage Municipal Light & Power (AML&P)
- Copper Valley Electric Association (CVEA)
- Chugach Electric Association (CEA)
- Fairbanks Municipal Utility System (FMUS)
- Golden Valley Electric Association (GVEA)
- Homer Electric Association (HEA)
- Matanuska Electric Association (MEA)

The Consultants wish to acknowledge the valuable information, comments, and support received from the managers and engineers of the Railbelt utilities, and the Alaska Power Administration during the performance of this economic feasibility study.

CHAPTER 2

SUMMARY AND CONCLUSIONS

The purpose of this economic feasibility study is to determine the conditions under which a transmission interconnection between the utility systems of Anchorage and Fairbanks would be economically feasible. Following are the important aspects of work performed and the conclusions of this study.

2.1 STUDY SUMMARY

A. Load Forecasts for Railbelt Area

Load forecast is the basis for system expansion planning. The most recent load forecasts for the utility service areas in the Railbelt area were examined to establish the basis for projection of future trends.

The sum of the most recent forecasts made by the individual utilities in the area has been selected as the upper growth limit to the forecast ranges for the Railbelt area. The median forecast prepared by the Alaska Power Administration, as a revision to the Susitna Project Market Study, was selected as the lower limit. The statistical average of these two forecasts was calculated and used in this study as the "probable" forecast.

The long-range "probable" load demand projections in MW for the load areas are:

	Anchorage	Fairbanks	Combined Area
1980	573	153	749
1985	977	231	1194
1990	1581	338	1896
1995	2402	477	2842
2000	3446	663	4054

B. Selection of Intertie Route

Alternative transmission corridors considered in previous studies were analyzed as to accessibility, cost of right-of-way, transmission line design, and environmental and aesthetic considerations. The preferred corridor described in the Susitna Report, along the Parks Highway from Anchorage to Fairbanks, was selected for the intertie route. It was selected because of its favorable length, accessibility, and environmental considerations. This corridor was further defined by preparing preliminary layouts. Field trips to important sites along this 323-mile line route were made to confirm the suitability at this corridor for the intertie.

C. Transmission Line Design

To provide a basis for intertie cost estimation, conceptual designs for 230-kV and 345-kV transmission lines and substations were made. The transmission Line Cost Analysis Program (TLCAP), a computer program developed by IECO, was used to select optimum designs. The results favored relatively long spans (1300 feet) and high-strength conductors. Tubular steel, guyed towers and pile-type foundations were selected for both the 230-kV and 345-kV lines as being well suited for Alaska conditions.

D. System Expansion Plans

To determine the intertie's economic feasibility, alternative system expansion plans were prepared with and without the Anchorage-Fairbanks intertie. System expansion plans were developed to meet both the "probable" and "low" load demand projections.

To assume a nearly constant level of power generation reliability (LOLP Index) for all system expansion plans, a multi-area reliability (MAREL) computer study was performed. Annual load models for both areas were developed. The load models indicate that there is little diversity between the loads in the Anchorage and Fairbanks areas.

The 1984-1997 study period was selected to best suit system requirements. The earliest year when the intertie can be operational is 1984. Based on optimistic assumptions, the last generating unit of Upper Susitna Hydropower Project will be on-line in January 1997.

E. Facility Cost Estimates

Cost estimates were developed for alternative system facilities to allow for economic comparisons. All costs were adjusted to January 1979 levels. Transmission line costs were calculated by using the TLCAP program. The same computer program calculated the line losses.

To provide a means for optimum economic dispatch of generating units on an interconnected system basis, costs for control and communication systems were included in the intertie cost estimates. Cost estimates for new generating plant facilities (gas-turbine units and coal-fired steam plants) were based on cost information in the Power Supply Study - 1978 report to GVEA, prepared by Stanley Consultants. Appropriate Alaskan construction cost location adjustment factors were applied to derive specific site cost estimates.

Construction power costs for the proposed Susitna Project were calculated. The results indicate a clear advantage for utilizing the intertie as a source of construction power.

F. Economic Feasibility Analysis

The economic feasibility analysis of the intertie was performed by discounting two cash flows (independent and interconnected systems) to a common year and then measuring the project benefits by the net present worth value. Facility costs for those new generating plants not affected by the introduction of the intertie were excluded from the analysis. The Transmission Line Economic Analysis Program (TLEAP), a computer program, was used to analyze the sensitivity of different escalation and discount rates on the capital costs of various alternatives. For principal investigations to establish definite feasibility analysis a 10% rate was used to discount cash flow in constant 1979 dollars.

G. Financial and Institutional Planning

A preliminary financial plan for implementation of the transmission intertie on a progressive basis was developed. The probable composition of institutions and participating utilities for ownership, management, and operating responsibilities is reviewed in this report, and present arrangements and possible future requirements are discussed.

2.2 CONCLUSIONS

The study shows that:

- The 230-kV single circuit intertie, having a 130-MW line loading capability (Case IA), is economically feasible in 1984, based only on benefits due to reduction of generation reserve plant capacity (reserve sharing). The net present-worth or the benefits are $12,475,000. The benefits become marginal ($945,000) if intertie costs are increased by 25 percent. In the case of "low" load forecast scenario the benefits are $2,704,000.

- An increase in benefits is obtained if the 230-kV single circuit intertie (double circuit after 1992), in addition to generation reserve sharing, includes firm power transfer capability (Case IB). The benefits are $24,054,000 or an increase of 93 percent over Case IA. Additional benefits due to supply of construction power to the Upper Susitna Project sites are $5,579,000.

- The 345-kV single circuit intertie (Case IC) is not economically feasible in 1984 based on the two scenarios developed in this study: generation reserve sharing only and reserve sharing plus firm power transfer capability. In the second scenario the results are negative ($-426,000). Further studies are recommended to pursue the economic feasibility of the 345-kV intertie because from technical point of view the 345-kV voltage is more appropriate for the transmission distance between Anchorage and Fairbanks.

- The 230-kV single circuit intertie with intermediate substations at Palmer and Healy (Case ID) is economically feasible in 1984. The benefits are $20,344,000 including the power supplies to MEA system to Palmer and the proposed Upper Susitna Hydropower Project sites. If intertie costs are increased by 25 percent the benefits become $11,656,000.

- The fully integrated interconnected system operation generates additional benefits which are not quantified in this study. These benefits could be due to:

  - Decrease in spinning reserve requirements by reducing the on-line plant capacity for the combined system.

  - Coordination of maintenance scheduling which would improve combined system security and provide cost savings.

  - Economies from optimum dispatch of generating units on the interconnected system basis. It is definitely recommended that a multi-area production costing simulation study be performed to establish these additional benefits.

- Expansion plans for the interconnected system with the proposed Upper Susitna Project were developed to determine the effect of this project on the interconnected system expansion plans, the displacement of thermal generating units, and intertie transmission requirements with Susitna Project.

- If an early 230-kV transmission intertie is constructed in 1984, due considerations should be given for constructing the Anchorage-Susitna portion of this intertie for 345-kV and operating it temporarily at 230-kV.

- The average value of energy transfer cost (1984-2015) thru the 230-kV intertie is 8 Mills/kWh at 55 percent load factor when financed by 40/60% REA/FFB loan package and municipal bonds issued by Anchorage and Fairbanks.

- This Intertie Feasibility Study is only a part of the over- all power system expansion plans for the Railbelt area. Further studies will be required to establish definitive characteristics for this transmission intertie. These studies should be closely coordinated with the future expansion plans of all utilities in the Railbelt area.

CHAPTER 3

LOAD FORECASTS FOR RAILBELT AREA

3.1 ENERGY AND DEMAND FORECAST RANGE

The basis for establishing a range of future load projections for the Anchorage - Cook Inlet and Fairbanks - Tanana Valley areas, together with a combined forecast for an interconnected system service area in the Railbelt, was obtained from an examination of previous forecasts[1/] compared in the Battelle Report of March 1978 (Ref. 1). These were examined in relation to a combination of the most recent utility forecasts prepared for the REA and an August 1978 revision of previous forecasts for the Upper Susitna Project, issued by the Alaska Power Administration in December 1975 (Ref. 2).

A. Range of Energy Consumption Resulting from Battelle Study

The Battelle study provides a compendium of previous forecasts and an analysis of assumptions intrinsic to their projections. It attempts to eliminate low probability scenarios and select a range of utility and industrial loads for the intertied Railbelt system. The following summary of annual energy consumption, excluding national defense and non-interconnected users, represents the definitive results of the Battelle study:

	1974		1980		1990		2000
Annual Consumption-GWh							
Upper Range Limit	1,600		3,400		10,800		22,500
Interval Growth Rate		13.4%		15.3%		10.2%	
Lower Range Limit	1,600		2,600		8,500		16,000
Interval Growth Rate		8.4%		9.6%		4.0%	

1/ See Section 3.3 for references used in this chapter.

Battelle selected this energy consumption range after carefully evaluating the methodology used in several previous forecasts and relevant assumptions pertaining to economic factors. Two load studies were deemed most appropriate to future load projections for the Railbelt. They are, in order of preference, the Upper Susitna Project Power Market Study by the Alaska Power Administration, and the report Electric Power in Alaska, 1976-1995 (Ref 3.) by the Institute for Social and Economic Research (ISER) of the University of Alaska.

1. Forecasts for Anchorage - Cook Inlet Area - From the several load forecasts corresponding to various growth scenarios of the ISER study, Battelle selected Forecasts 2 and 4 as most appropriate for the Anchorage and Cook Inlet area. These forecasts assume limited petroleum development, which was considered to be the most likely prospect. The assumptions underlying the scenario for limited petroleum development are:

- Petroleum Production will be 2 million bpd in 1980, and 3.6 million in 1990.
- A natural gas pipeline will be constructed from Prudhoe Bay through Canada.
- An LNG plant for natural gas from the Gulf of Alaska will be constructed.

The assumptions regarding electrical energy consumption are:

Sector	Case 2	Case 4
• Residential	Moderate Electrification	No Growth
• Commercial/Industrial	Growth as Usual	Minimum Electrification

The ISER study did not include new industrial consumption in forecasts, other than expansion of existing loads served by utilities. However, it did relate utility forecasts to economic scenarios, in which future energy consumption was quantitatively projected according to specified assumptions of petroleum development, population, aggregate income, saturation levels, and average usage per customer.

In 1975 the Alaska Power Administration prepared forecasts for the potential power market of the Upper Susitna Project. The forecasts contained projections of industrial load for existing and possible future installations. Battelle modified these projections to include the following assumptions:

- In addition to gradual expansion of existing refinery capacity, a new 150,000-bpd refinery will be built by 1983.
- An aluminum smelter with a capacity of 300,000 tpy will be constructed, to be on-line by 1985.
- A nuclear fuel enrichment plant, included in previous load projections, was deleted from future industrial load.
- Industrial development in the interior region was assumed to be excluded from the load area of an intertied Railbelt system.

A summary of industrial facilities included in the Battelle forecast for the Anchorage and Cook Inlet area is as follows:

Existing Facilities	New Facilities
Chemical Plant	Aluminum Smelter
LNG Plant	LNG Plant
Refinery	Refinery
Timber Mills	Timber Mills
	Coal Gasification Plant
	Mining and Mineral Processing Plants
	New City

2. Forecasts for Fairbanks - Tanana Valley Area - A similar evaluation by Battelle defined the most probable forecasts for the Fairbanks and Tanana Valley area. It assumed that industrial development in the interior region will consist largely of self-supplied mining operations in remote areas. Thus, load growth will be attributable only to utility customers in the service areas of the Fairbanks Municipal Utilities System (FMUS) and the Golden Valley Electric Association, Inc. (GVEA).

In the judgment of Battelle, the most likely consumption range for the Fairbanks area is bounded by the mid-range projections of the Upper Susitna Market Study, with mid-range forecasts prepared by the Interior Alaska Energy Analysis Team (IAEAT) (Ref. 4) as the upper bound and the ISER Case 4 as the lower bound.

3. Combined Forecasts for the Railbelt - The Battelle energy and demand forecast range for the combined utility and industrial load of the Railbelt, encompassing the Anchorage - Cook Inlet and Fairbanks - Tanana Valley areas, is shown graphically on Figures 3-1 and 3-4, respectively. These are intended to serve as background comparisons with combined utility forecasts and the revised projections of the Alaska Power Administration for the potential market of the Upper Susitna Project.

B. Forecasts by Utilities and the Alaska Power Administration

The most recent Power Requirements Studies (PRS) of the REA utilities (Ref. 5) in the Anchorage and Fairbanks areas were obtained, together with the most probable load forecasts, as projected for the Anchorage Municipal Light and Power Company (AML&P) and the Fairbanks Municipal Utilities System (FMUS).

Tables 3-1 and 3-2 provide tabulations of utility forecasts and extrapolated projections to the horizon year 2000, for the Anchorage - Cook Inlet area and the Fairbanks - Tanana Valley area, respectively. The Valdez - Copper Valley area is not included in the forecasts for the

Railbelt, as these load areas are assumed not to be interconnected with the intertied Railbelt system until after the completion of the Upper Susitna Project. As the PRS provided load projections for a base year and at two 5-year intervals, interpolations were made on the basis of assumed compound growth between reported values. On the further assumption that growth rates will decline progressively to the horizon year, extrapolations were made of net energy generation with growth rates declining from reported values at 5-year intervals to 2000. These growth rates were applied on the assumption that there will be no abrupt transition to low growth rates. Rather, growth will diminish in gradual steps as markets are saturated and the effects of conservation and price elasticity reflect in future energy consumption levels. Reported load factors were interpolated for intermediate years and the trend extrapolated to the horizon year to obtain projections of annual peak demand.

The utility forecasts were combined for the Anchorage - Cook Inlet area, the Fairbanks - Tanana Valley area, and the total Railbelt. Table 3-3 provides tabulations of net energy generation, load factor, and annual peak diversified demand. It is obtained by the application of coincidence factors to the sum of individual utility peak demands. These load forecasts are shown on Figures 3-1 through 3-6, in comparison with load projections prepared in August 1978 by the Alaska Power Administration for the Upper Susitna Project, as revisions to previous power market forecasts evaluated as part of the Battelle study. A summary of the Alaska Power Administration load forecasts is given in Table 3-4. These forecasts include only utility and industrial load projections on the assumption that national defense installations will not be supplied as part of the interconnected system load. Since the Battelle forecasts also excluded load forecasts for national defense installations, direct comparisons can be made. The range of Alaska Power Administration load forecasts for peak demand and annual energy was as follows:

		1980	1985	1990	1995	2000
% Differential	High	+ 8	+ 21	+ 31	+ 41	+ 54
from median:	Low	- 8	- 18	- 27	- 33	- 38

The range of load forecasts exhibited this diverging spread from the 1977 base-year load level. The industrial load projected by Battelle was included in the Alaska Power Administration forecast range on a selective basis. The differential between the "high" and "extra high" forecasts is an additional 280 MW of load, representing an aluminum smelter. The "low" forecast excludes the load projected for the New City.

C. Comparison and Selection of Forecast Range

The forecasts of net energy generation for the Railbelt are shown on Figure 3-1. Curve 1 represents the combination of the most recent forecasts for municipal and REA utilities, as presented in Tables 3-1, 3-2, and 3-3. The forecast aligns closely up to 1990 with the upper bound of the Battelle forecast range. Beyond 1990 the divergence arises from the different assumptions made in regard to growth rates in the 1990-2000 period. The upper bound of the Battelle range exhibits an abrupt change of growth rate, from 15.3% to 10.2%, applied to total energy in the Railbelt, while the combined utilities forecast exhibits a more gradual transition to lower growth rates. Although many economic factors will contribute to lower overall growth rates in energy consumptio, a reasonable approach to establishing an upper limit has been taken, in that individual utility forecasts were assumed to decline without abrupt change. This assumption is based on the fairly constant percentage expenditure from disposable income for energy needs, as determined by the study of future consumption patterns in Alaskan service areas (Ref. 6), the results of which are given in an extract from the RWRA report (Ref. 7) presented in Appendix A.

Accordingly, the combined utilities forecast has been selected as the upper limit to the possible range of total energy forecasts for the Railbelt. The median forecast prepared by the Alaska Power Administration, as a revision to the Susitna Project Market Study, has been selected as the lower limit to the forecast range for the Railbelt. This recently prepared forecast exhibits lower growth than the 1975 forecast for the Susitna Project, and represents a prudent choice for a conservative growth scenario.

Figures 3-2 and 3-3 show the relationship between the combined utilities forecast and the range of forecasts prepared by the Alaska Power Administration. The effect of the aluminum smelter load can be observed as the differential between curves 2C and 3C on Figure 3-2, and curves 2A and 3A on Figure 3-3. The median forecast also excludes the aluminum smelter load but provides for a reasonable realization of the industrial potential in the Anchorage area. In setting the lower limit of the forecast range in the context of the considerable industrial growth potential of this area of Alaska, it is thought that the selected forecast range will provide a good test of the economic feasibility of establishing an interconnection in the Railbelt.

A similar comparison of forecast demand can be made by reference to Figures 3-4, 3-5, and 3-6. The combined utilities demand forecast is below the upper bound of the Battelle range until after 1985 and aligns in fairly close proximity until 1990. Beyond 1990 divergence occurs based upon the assumption discussed previously in relation to energy growth. The median demand forecast for the Susitna Project, prepared by the Alaska Power Administration, exhibits a growth characteristic that roughly parallels the lower bound of the Battelle range between 1985 and 2000. As the low growth limit to the range of demand beyond 1981 selected for the interconnection study, it represents a moderately conservative view of overall growth potential.

Prior to 1981, the short-range combined utilities demand forecast is below the median forecast for the Susitna Project, approximately at Battelle mid-range. The demand forecasts for the Susitna Project may be observed in relation to the combined utilities demand forecasts of Figures 3-5 and 3-6. The selected range of demand forecasts represents a moderate to high expectation of a continued growth of the Railbelt economy through the end of the century, this being accentuated by the interconnection of utility systems in the area.

3.2 DEMAND FORECASTS FOR GENERATION PLANNING

The range exhibited by load forecasts for the Railbelt Area is considerable. Therefore, it remains to select definitive demand forecasts for generation expansion planning that are a reasonable representation of anticipated load growth under projected economic conditions.

A. Selection of Peak Load Demand Forecasts

The combined utilities forecast is appropriate to a high growth scenario that may not be possible under future economic constraints and prevailing trends towards greater conservation. The median forecast by the Alaska Power Administration does not include the entire industrial load potential that could be realized by a steady commitment towards economic growth in the State. It also specifically excludes the possibility of development of the aluminum smelter in the Anchorage area.

The selection of the statistical average forecasts, given in Table 3-5, for peak load demand is consistent with the moderate to high expectation of continued growth in the Railbelt economy. The natural resources of Alaska, particularly oil and gas, will largely determine the extent of future growth possible within the State. A steady pressure for additional domestic oil and gas supplies for the lower forty-eight will be engendered by the continuing energy crisis within the United States. The impact of additional exploitation of the North Slope on the State economy will be reflected in continued growth within the Railbelt. Thus, the conditions are present to ensure the realization of optimistic expectations for moderate to high growth of load demand.

B. Forecast Range for Sensitivity Analysis

In order to determine the effect of load growth on the economic feasibility of the Anchorage-Fairbanks Intertie, a suitable range of load growth must be established for sensitivity analysis.

The uncertainty associated with a load forecast increases with time, so the range of demand should also increase with time. The values given in Table 3-6 correspond to a range of load demand that steadily increases through time from a bandwidth of ± 1% in 1979 to ± 21% in 2000.

The long-range load projections for the Anchorage-Cook Inlet and Fairbanks-Tanana Valley areas are shown on Figure 3-7, with their corresponding range limits. The diversified demand for the combined areas of the Railbelt is given on Figure 3-8, the peak load rising to approximately 4000 MW in the year 2000.

3.3 REFERENCES

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TABLE 3-1

ANCHORAGE - COOK INLET AREA
UTILITY FORECASTS AND EXTRAPOLATED PROJECTIONS

	Anchorage Municipal Light and Power Company			Alaska 2 - Matanuska Electric Association, Inc.			Alaska 5 - Kenai: Homer Electric Assoc., Inc.			Alaska 5 - Kenai: Kenai City Light System			Alaska 8 - Chugach Electric Association, Inc.		
Year	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)
1979	633.6	58.1	124.4	280.4	47.5	67.4	275.2	55.0	57.1	34.4	56.0	7.0	1,108.9	53.0	238.8
1980	699.4	58.1	137.5	332.8	47.0	80.8	336.6	55.0	69.9	37.5	56.0	7.6	1,283.0	54.0	271.2
1981	770.6	57.9	151.8	395.1	46.5	97.0	411.6	55.0	85.4	40.8	56.0	8.3	1,467.8	54.0	310.3
1982	847.3	57.8	167.3	468.0	56.0	116.1	502.0	55.0	104.2	44.4	56.0	9.1	1,679.1	54.0	355.0
1983	929.6	57.7	183.9	559.3	45.0	141.9	572.3	55.0	118.8	48.1	56.0	9.8	1,920.9	54.0	406.1
1984	1,017.5	57.6	201.2	668.3	44.5	171.4	652.4	55.0	135.4	52.1	56.0	10.6	2,197.5	54.0	464.5
1985	1,110.8	57.4	220.8	798.6	44.0	207.2	743.7	55.0	154.4	56.4	56.0	11.5	2,509.0	54.0	530.4
1986	1,209.5	57.3	241.1	954.4	43.5	250.5	847.9	55.0	176.0	61.1	56.0	12.5	2,810.1	54.0	594.1
1987	1,313.2	57.1	262.5	1,140.0	43.0	302.6	967.0	55.0	201.0	66.3	56.0	13.5	3,147.3	54.0	665.3
1988	1,421.6	56.9	285.0	1,322.4	44.0	343.1	1,083.0	55.0	224.8	71.5	56.0	14.6	3,525.0	54.0	745.2
1989	1,534.2	56.8	308.5	1,534.0	45.0	389.1	1,213.0	55.0	251.8	77.0	56.0	15.7	3,948.0	54.0	834.6
1990	1,650.5	56.6	333.0	1,779.4	46.0	441.6	1,358.6	55.0	282.0	83.1	56.0	16.9	4,421.7	55.0	934.7
1991	1,769.8	56.4	358.2	2,064.1	47.0	501.3	1,521.6	55.0	315.8	89.5	56.0	18.2	4,863.9	55.0	1,028.2
1992	1,891.3	56.2	384.1	2,394.4	48.0	569.4	1,704.2	55.0	353.7	96.5	56.0	19.7	5,350.3	55.0	1,131.0
1993	2,014.4	56.0	410.5	2,705.7	49.0	630.3	1,874.6	55.0	389.1	103.5	56.0	21.1	5,885.3	55.0	1,244.1
1994	2,138.0	55.8	437.2	3,057.4	50.0	698.0	2,062.1	55.0	428.0	111.1	56.0	22.6	6,473.9	55.0	1,368.6
1995	2,244.9	55.6	460.9	3,454.9	51.0	773.3	2,268.3	55.0	470.8	119.2	56.0	24.3	7,121.2	55.0	1,505.4
1996	2,357.1	55.4	485.7	3,904.0	52.0	857.0	2,495.1	55.0	517.9	127.9	56.0	26.1	7,690.9	55.0	1,625.8
1997	2,475.0	55.2	511.8	4,411.5	53.0	950.2	2,744.6	55.0	569.7	137.3	56.0	28.0	8,306.2	55.0	1,755.9
1998	2,598.8	55.0	539.4	4,852.7	54.0	1,025.9	2,964.2	55.0	615.2	146.9	56.0	29.9	8,970.7	55.0	1,900.6
1999	2,728.7	54.8	568.4	5,337.9	55.0	1,107.9	3,201.3	55.0	664.4	157.2	56.0	32.0	9,688.3	55.0	2,048.1
2000	2,865.0	54.6	599.0	5,871.7	56.0	1,196.9	3,457.4	55.0	717.6	168.2	56.0	34.3	10,463.4	55.0	2,211.9

Growth Rates:

	Anchorage Municipal Light and Power Company	Alaska 2 - Matanuska	Homer Electric Assoc., Inc.	Kenai City Light System	Alaska 8 - Chugach
Reported	Logistic Curve 3	18.7% (1977-1982) 19.5% (1983-1987)	22.3% (1977-1982) 14.0% (1983-1987)	8.8% (1977-1982) 8.3% (1983-1987)	15.7% (1977-1980) 14.4% (1981-1985)
Projected	5.0% (1995-2000)	16.0% (1988-1992) 13.0% (1993-1997) 10.0% (1998-2000)	12.0% (1988-1992) 10.0% (1993-1997) 8.0% (1998-2000)	7.8% (1988-1992) 7.3% (1993-1997) 7.0% (1998-2000)	12.0% (1986-1990) 10.0% (1991-1995) 8.0% (1996-2000)

TABLE 3-2

FAIRBANKS - TANANA VALLEY AREA
UTILITY FORECASTS AND EXTRAPOLATED PROJECTIONS

Year	Fairbanks Municipal Utilities System			Alaska 6 - Golden Valley Electric Association, Inc.		
	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)
1979	144.3	50.0	32.9	450.0	46.3	111.0
1980	153.0	50.0	34.9	501.8	46.6	122.9
1981	162.2	50.0	37.0	559.5	46.9	136.2
1982	171.9	50.0	39.2	624.6	47.2	150.9
1983	182.2	50.0	41.6	692.6	47.3	167.1
1984	193.2	50.0	44.1	768.8	47.3	185.5
1985	204.7	50.0	46.7	853.4	47.4	205.5
1986	217.0	50.0	49.5	947.3	47.4	228.1
1987	230.0	50.0	52.5	1,050.0	47.5	252.3
1988	243.9	50.0	55.7	1,155.0	47.5	277.6
1989	258.5	50.0	59.0	1,270.5	47.6	304.7
1990	274.0	50.0	62.6	1,397.6	47.6	335.2
1991	287.7	50.0	65.7	1,537.3	47.7	367.9
1992	302.1	50.0	69.0	1,691.0	47.7	404.7
1993	317.2	50.0	72.4	1,843.2	47.8	440.2
1994	333.0	50.0	76.0	2,009.1	47.8	479.8
1995	349.7	50.0	79.8	2,189.9	47.9	521.0
1996	367.2	50.0	83.8	2,387.0	47.9	568.9
1997	385.5	50.0	88.0	2,601.8	48.0	618.8
1998	404.8	50.0	92.4	2,809.9	48.0	668.3
1999	425.1	50.0	97.1	3,034.7	48.0	721.7
2000	446.3	50.0	101.9	3,277.5	48.0	779.5

Growth Rates:

	Fairbanks Municipal Utilities System	Alaska 6 - Golden Valley Electric Association, Inc.
Reported	6.0% (1978-1990)	11.5% (1977-1982) 11.0% (1983-1987)
Projected	5.0% (1991-2000)	10.0% (1988-1992) 9.0% (1993-1997) 8.0% (1998-2000)

TABLE 3-3

COMBINED UTILITY FORECASTS FOR RAILBELT AREA

	Anchorage Cook - Inlet			Fairbanks - Tanana Valley			Combined Load Areas		
Year	Net Energy (GWh)	Load Factor (%)	Peak Demand 1/ (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand 2/ (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand 3/ (MW)
1979	2,332.5	56.1	475	594.3	47.6	142	2,926.8	55.3	605
1980	2,689.3	56.4	544	654.8	47.9	156	3,344.1	55.6	686
1981	3,085.9	56.2	627	721.7	48.0	171	3,807.6	55.6	782
1982	3,540.8	56.0	722	795.9	48.3	188	4,336.7	55.5	892
1983	4,030.2	55.7	826	874.8	48.3	207	4,905.0	55.3	1,012
1984	4,587.8	55.5	944	962.0	48.3	227	5,549.8	55.2	1,148
1985	5,218.5	55.2	1,079	1,058.1	48.4	250	6,276.6	55.0	1,302
1986	5,883.0	54.9	1,223	1,164.3	48.4	275	7,047.3	54.8	1,468
1987	6,633.8	54.6	1,387	1,280.0	48.4	302	7,913.8	54.6	1,655
1988	7,423.5	54.7	1,548	1,398.9	48.4	330	8,822.4	54.7	1,840
1989	8,306.2	54.9	1,728	1,529.0	48.5	360	9,835.2	54.9	2,046
1990	9,293.3	55.0	1,928	1,671.6	48.5	394	10,964.9	55.0	2,276
1991	10,308.9	55.2	2,133	1,825.0	48.5	429	12,133.9	55.2	2,511
1992	11,436.7	55.3	2,360	1,993.1	48.5	469	13,429.8	55.3	2,772
1993	12,583.5	55.5	2,587	2,160.4	48.6	507	14,743.9	55.5	3,032
1994	13,842.5	55.7	2,836	2,342.1	48.6	550	16,184.6	55.7	3,318
1995	15,208.5	55.9	3,105	2,539.6	48.6	596	17,748.1	55.9	3,627
1996	16,575.0	56.1	3,372	2,754.2	48.7	646	19,329.2	56.0	3,938
1997	18,074.6	56.3	3,663	2,987.3	48.7	700	21,061.9	56.2	4,276
1998	19,533.3	56.5	3,947	3,214.7	48.7	753	22,748.0	56.4	4,606
1999	21,113.4	56.8	4,244	3,459.8	48.7	811	24,573.2	56.6	4,954
2000	22,825.7	57.0	4,569	3,723.8	48.7	873	265,49.5	56.8	5,333

Diversified Demand
for Coincidence Factor: 1/ 0.96 2/ 0.99 3/ 0.98

TABLE 3-4
Sheet 1 of 2

LOAD FORECAST FOR UPPER SUSITNA PROJECT BY ALASKA POWER ADMINISTRATION

1. ANCHORAGE-COOK INLET AREA POWER DEMAND AND ENERGY REQUIREMENTS

(Excluding National Defense)

	1977	1980	1985	1990	1995	2000
Peak Demand (MW)						
Utility Loads						
High		620	1,000	2,150	3,180	7,240
Median	424	570	810	1,500	2,045	3,370
Low		525	650	1,040	1,320	1,520
Industrial Loads						
Extra high		32	344	399	541	683
High		32	64	119	261	403
Median	25	32	64	119	199	278
Low		27	59	70	87	104
Total						
Extra high		652	1,344	1,914	2,691	3,863
High		652	1,064	1,634	2,411	3,583
Median	449	602	874	1,234	1,699	2,323
Low		552	709	890	1,127	1,424
Annual Energy (GWh)						
Utility Loads						
High		2,720	4,390	6,630	9,430	13,920
Median	1,790	2,500	3,530	4,880	6,570	8,960
Low		2,300	2,840	3,590	4,560	5,770
Industrial Loads						
Extra high		170	1,810	2,100	2,840	3,590
High		170	340	625	1,370	2,120
Median	70	170	340	630	1,050	1,460
Low		141	312	370	460	550
Total						
Extra high		2,890	6,200	8,730	12,270	17,510
High		2,890	4,730	7,255	10,800	16,040
Median	1,860	2,670	3,870	5,510	7,620	10,420
Low		2,441	3,152	3,960	5,020	6,320

TABLE 3-4
Sheet 2 of 2

LOAD FORECAST FOR UPPER SUSITNA PROJECT
BY
ALASKA POWER ADMINISTRATION

	1977	1980	1985	1990	1995	2000
2. FAIRBANKS-TANANA VALLEY AREA POWER DEMAND AND ENERGY REQUIREMENTS (Excluding National Defense)						
Peak Demand (MW)						
Utility Loads						
High		158	244	358	495	685
Median	119	150	211	281	358	452
Low		142	180	219	258	297
Annual Energy (GWh)						
Utility Loads						
High		690	1,070	1,570	2,170	3,000
Median	483	655	925	1,230	1,570	1,980
Low		620	790	960	1,130	1,300
3. COMBINED ANCHORAGE-COOK INLET AND FAIRBANKS-TANANA VALLEY AREAS						
Peak Demand (MW)						
Extra high		810	1,588	2,272	3,186	4,548
High		810	1,308	1,992	2,906	4,268
Median	568	752	1,085	1,515	2,057	2,775
Low		694	889	1,109	1,385	1,721
Annual Energy (GWh)						
Extra high		3,580	7,270	10,300	14,440	20,510
High		3,580	5,800	8,825	12,970	19,040
Median	2,343	3,325	4,795	6,740	9,190	12,400
Low		3,061	3,942	4,920	6,150	7,620

TABLE 3 - 5

LOAD DEMAND FORECASTS FOR RAILBELT AREA
TO
DETERMINE STATISTICAL AVERAGE FORECAST

	Anchorage - Cook Inlet			Fairbanks - Tanana Valley			Combined Load Areas		
Year	Combined Utilities Forecast (MW)	Alaska Power Administration Median Forecast (MW)	Statistical Average Forecast (MW)	Combined Utilities Forecast (MW)	Alaska Power Administration Median Forecast (MW)	Statistical Average Forecast (MW)	Combined Utilities Forecast (MW)	Alaska Power Administration Median Forecast (MW)	Statistical Average Forecast (MW)
1979	475	546	511	142	139	141	605	685	645
1980	544	602	573	156	150	153	686	752	719
1981	627	648	638	171	161	166	782	809	796
1982	722	698	710	188	172	180	892	870	881
1983	826	752	789	207	184	196	1012	936	974
1984	944	810	877	227	197	212	1148	1007	1078
1985	1079	874	977	250	211	231	1302	1085	1194
1986	1223	937	1080	275	223	249	1468	1160	1314
1987	1387	1004	1196	302	237	270	1655	1241	1448
1988	1548	1077	1313	330	251	291	1840	1328	1584
1989	1728	1154	1441	360	265	313	2046	1419	1733
1990	1928	1234	1581	394	281	338	2276	1515	1896
1991	2133	1315	1724	429	295	362	2511	1610	2061
1992	2360	1402	1881	469	310	390	2772	1712	2242
1993	2587	1495	2041	507	325	416	3032	1820	2426
1994	2834	1593	2215	550	342	446	3318	1935	2627
1995	3105	1699	2402	596	358	477	3627	2057	2842
1996	3372	1809	2591	646	375	511	3938	2184	3061
1997	3663	1925	2794	700	393	547	4276	2318	3297
1998	3947	2049	2998	753	412	583	4606	2461	3534
1999	4244	2182	3213	811	432	622	4954	2614	3784
2000	4569	2323	3446	873	452	663	5333	2755	4054

TABLE 3-6

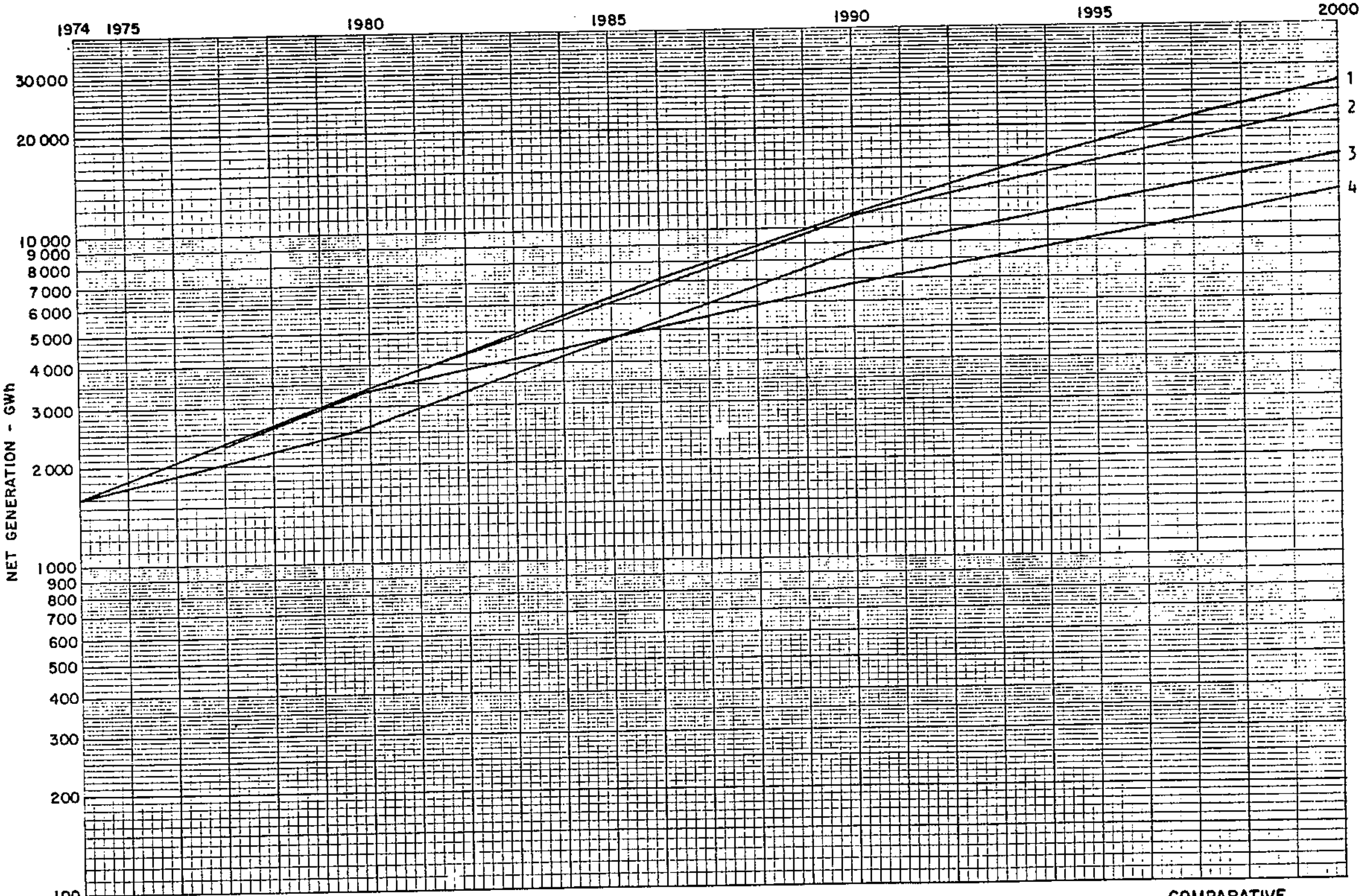
PEAK LOAD DEMAND FORECASTS FOR RAILBELT AREA

WITH

RANGE LIMITS FOR SENSITIVITY ANALYSIS

	Anchorage - Cook Inlet			Fairbanks - Tanana Valley			Combined Load Areas		
Year	Lower Range Limit* (MW)	Peak Load Demand Forecast** (MW)	Upper Range Limit (MW)	Lower Range Limit* (MW)	Peak Load Demand Forecast** (MW)	Upper Range Limit (MW)	Lower Range Limit* (MW)	Peak Load Demand Forecast** (MW)	Upper Range Limit (MW)
1979	508	511	514	140	141	142	641	645	649
1980	570	573	576	151	153	155	744	749	754
1981	635	638	641	163	166	169	790	795	802
1982	702	710	718	175	180	185	874	831	888
1983	765	789	813	188	196	204	949	974	999
1984	832	877	922	202	212	222	1031	1078	1125
1985	908	977	1046	218	231	244	1121	1194	1267
1986	985	1080	1175	232	249	266	1212	1314	1416
1987	1068	1196	1324	248	270	292	1310	1448	1586
1988	1156	1313	1470	264	291	318	1413	1584	1755
1989	1250	1441	1632	281	313	345	1523	1733	1943
1990	1350	1581	1812	300	338	376	1642	1895	2150
1991	1451	1724	1997	317	362	407	1760	2061	2362
1992	1562	1881	2200	337	390	443	1888	2242	2596
1993	1677	2041	2405	355	416	477	2021	2426	2831
1994	1800	2215	2630	377	446	515	2167	2627	3087
1995	1933	2402	2871	398	477	556	2319	2842	3365
1996	2070	2591	3112	420	511	602	2476	3061	3646
1997	2215	2794	3373	444	547	650	2644	3297	3950
1998	2365	2998	3631	469	583	697	2820	3534	4248
1999	2526	3213	3900	495	622	749	3004	3784	4564
2000	2697	3446	4195	522	663	804	3203	4054	4905

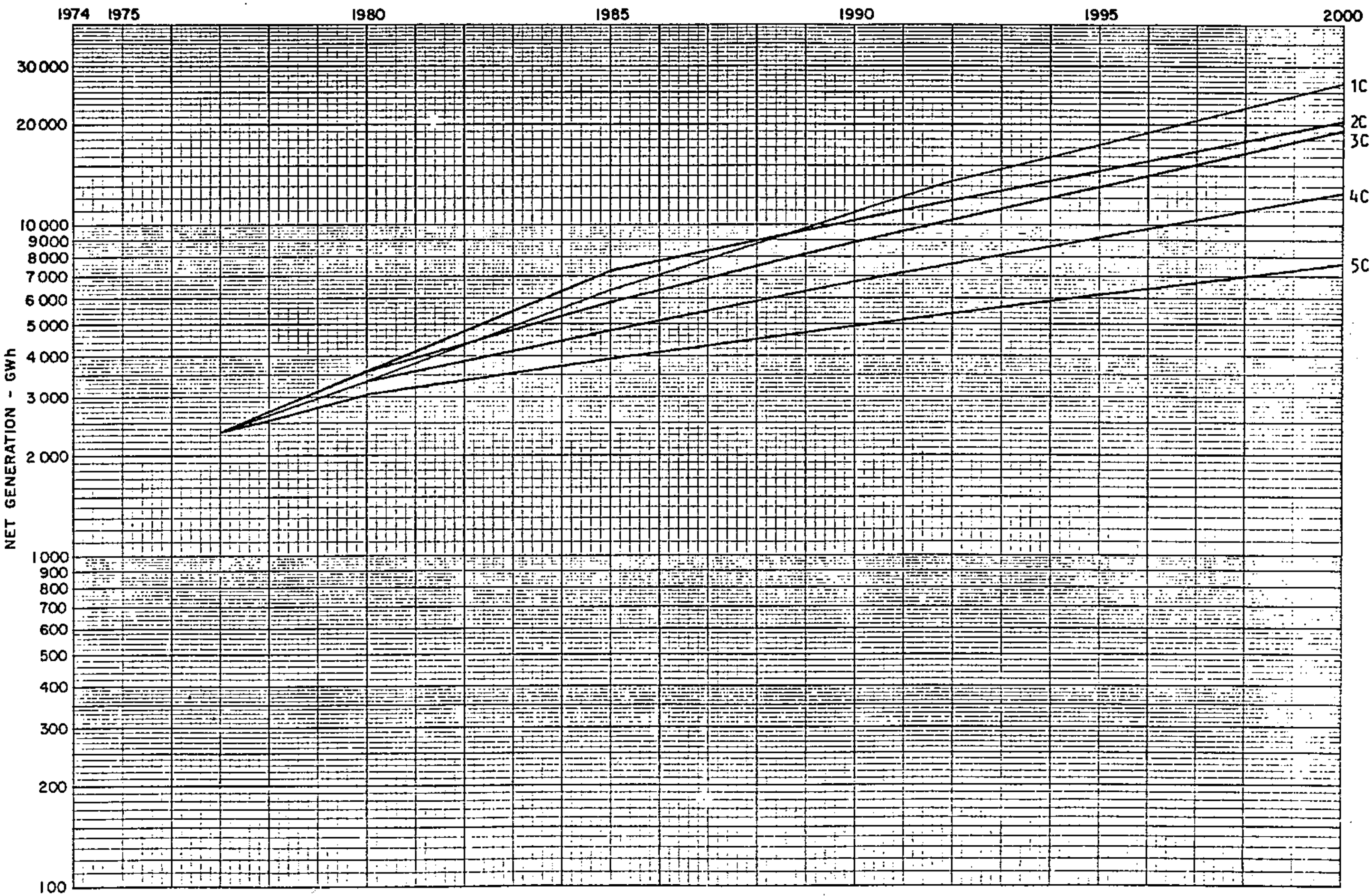
* Low load forecast case in this study.
** Probable load forecast case in this study.



1 COMBINED UTILITIES FORECAST
2 UPPER BOUND - BATTELLE STUDY FORECAST, MARCH 1978
3 LOWER BOUND - BATTELLE STUDY FORECAST, MARCH 1978
4 MEDIAN FORECAST - ALASKA POWER ADMINISTRATION, SUSITNA PROJECT MARKET STUDY, REVISIONS OF AUGUST 1978

COMPARATIVE
NET ENERGY GENERATION
FORECASTS FOR COMBINED
UTILITIES AND INDUSTRIAL LOAD
RAILBELT AREA

FIGURE 3-1

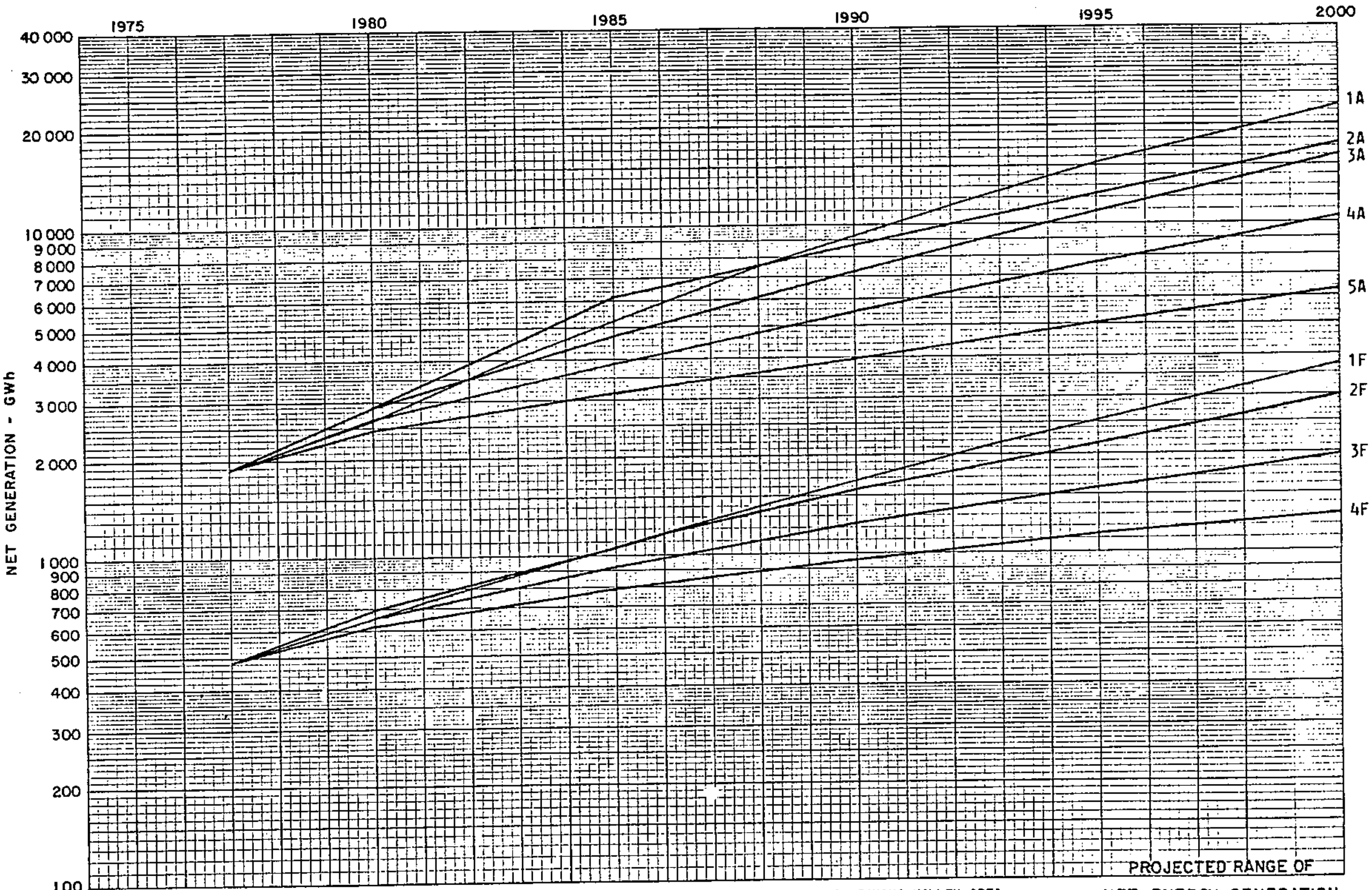


1C COMBINED UTILITIES FORECAST
2C EXTRA HIGH FORECAST
3C HIGH FORECAST
4C MEDIAN FORECAST
5C LOW FORECAST

} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

PROJECTED RANGE OF NET ENERGY GENERATION FORECASTS FOR COMBINED UTILITIES AND INDUSTRIAL LOAD RAILBELT AREA

FIGURE 3-2

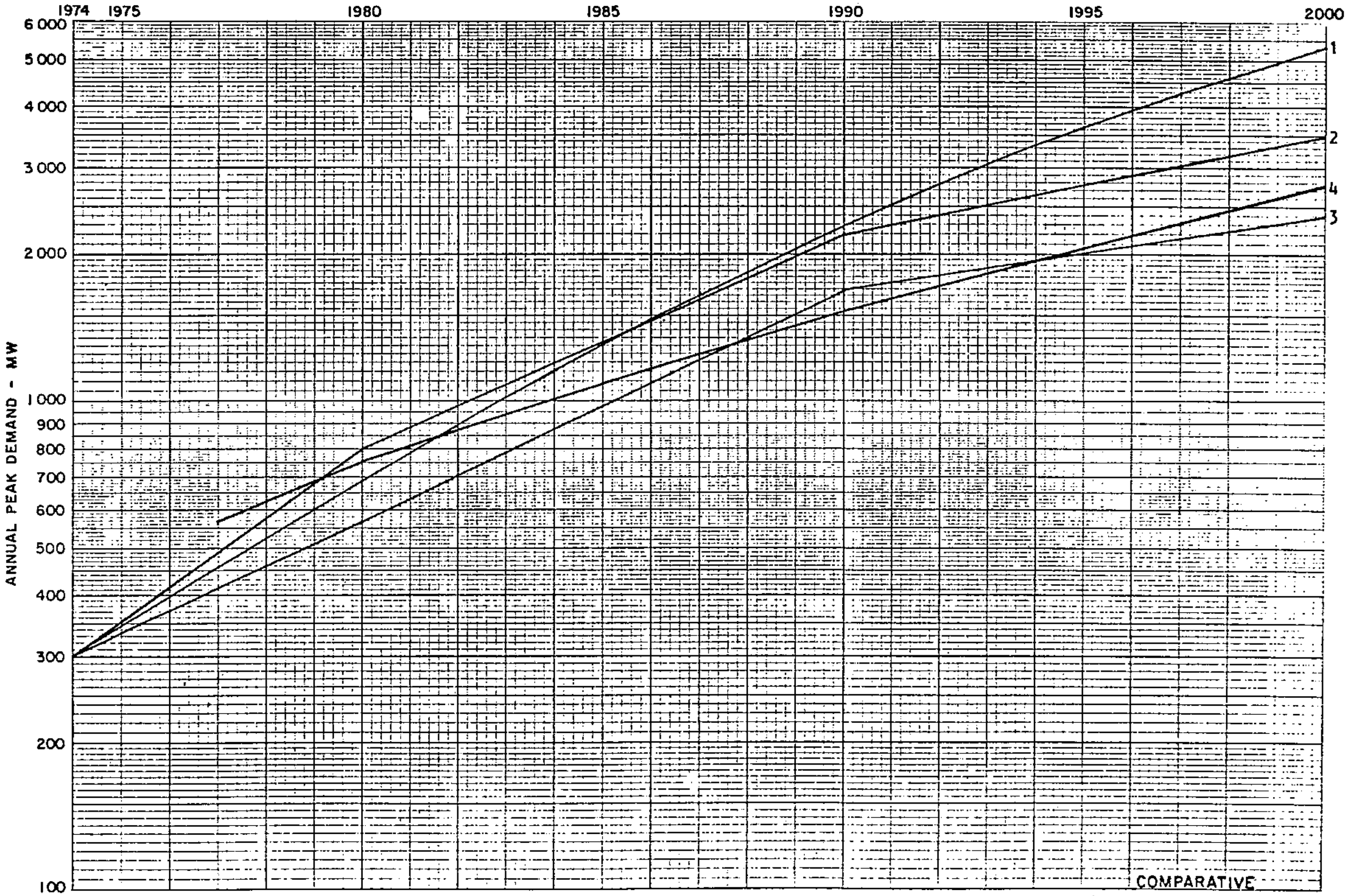


1A UTILITIES FORECAST FOR ANCHORAGE - COOK INLET AREA
2A EXTRA HIGH FORECAST
3A HIGH FORECAST
4A MEDIAN FORECAST
5A LOW FORECAST
} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

1F UTILITIES FORECAST FOR FAIRBANKS - TANANA VALLEY AREA
2F HIGH FORECAST
3F MEDIAN FORECAST
4F LOW FORECAST
} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

PROJECTED RANGE OF
NET ENERGY GENERATION
FORECASTS FOR COMBINED
UTILITIES AND INDUSTRIAL LOAD
ANCHORAGE - COOK INLET AREA AND
FAIRBANKS - TANANA VALLEY AREA

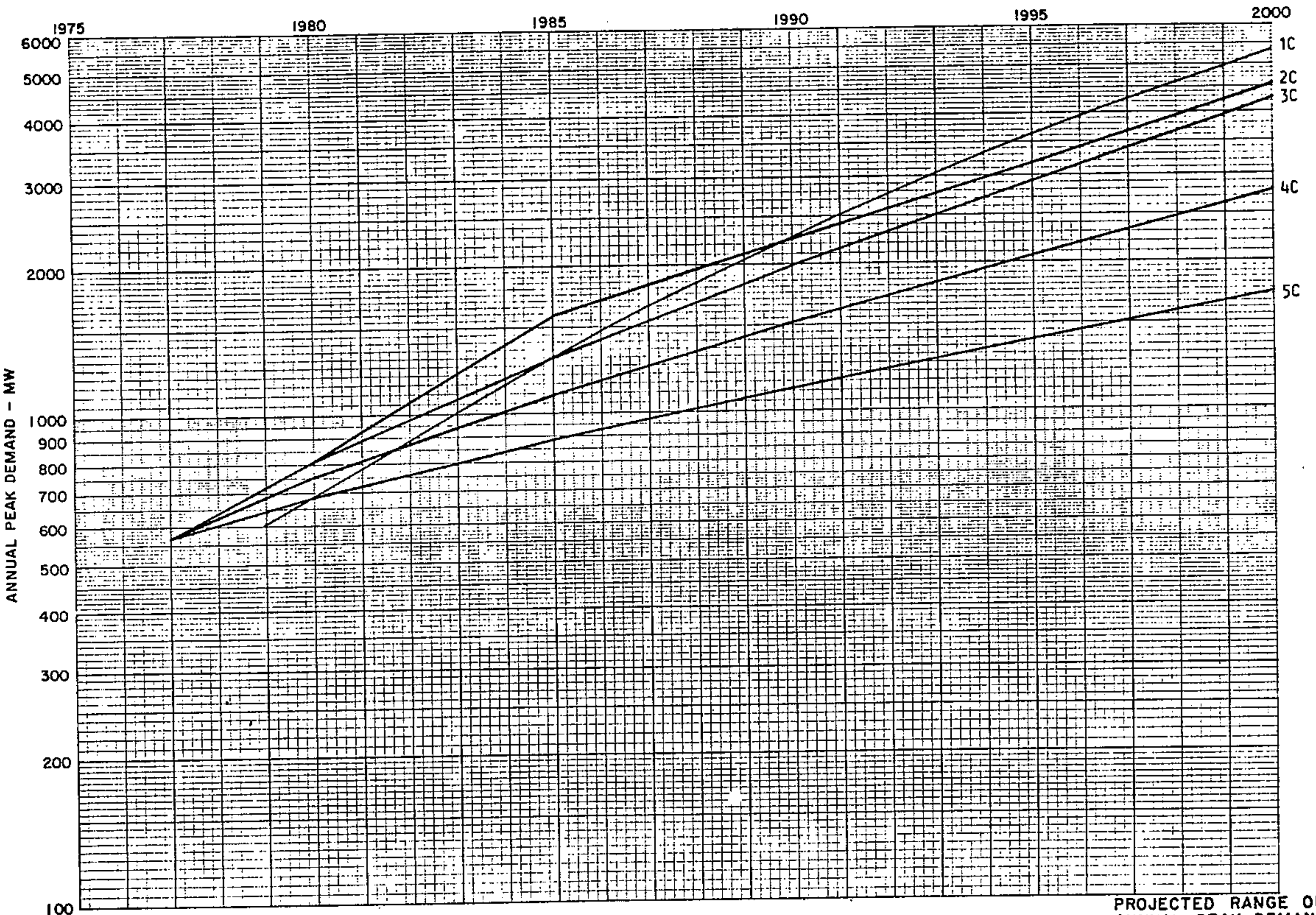
FIGURE 3-3



1 COMBINED UTILITIES FORECAST
2 UPPER BOUND - BATTELLE STUDY FORECAST, MARCH 1978
3 LOWER BOUND - BATTELLE STUDY FORECAST, MARCH 1978
4 MEDIAN FORECAST - ALASKA POWER ADMINISTRATION, SUSITNA PROJECT MARKET STUDY, REVISIONS OF AUGUST 1978

COMPARATIVE
ANNUAL PEAK DEMAND
FORECASTS FOR COMBINED
UTILITIES AND INDUSTRIAL LOAD
RAILBELT AREA

FIGURE 3-4

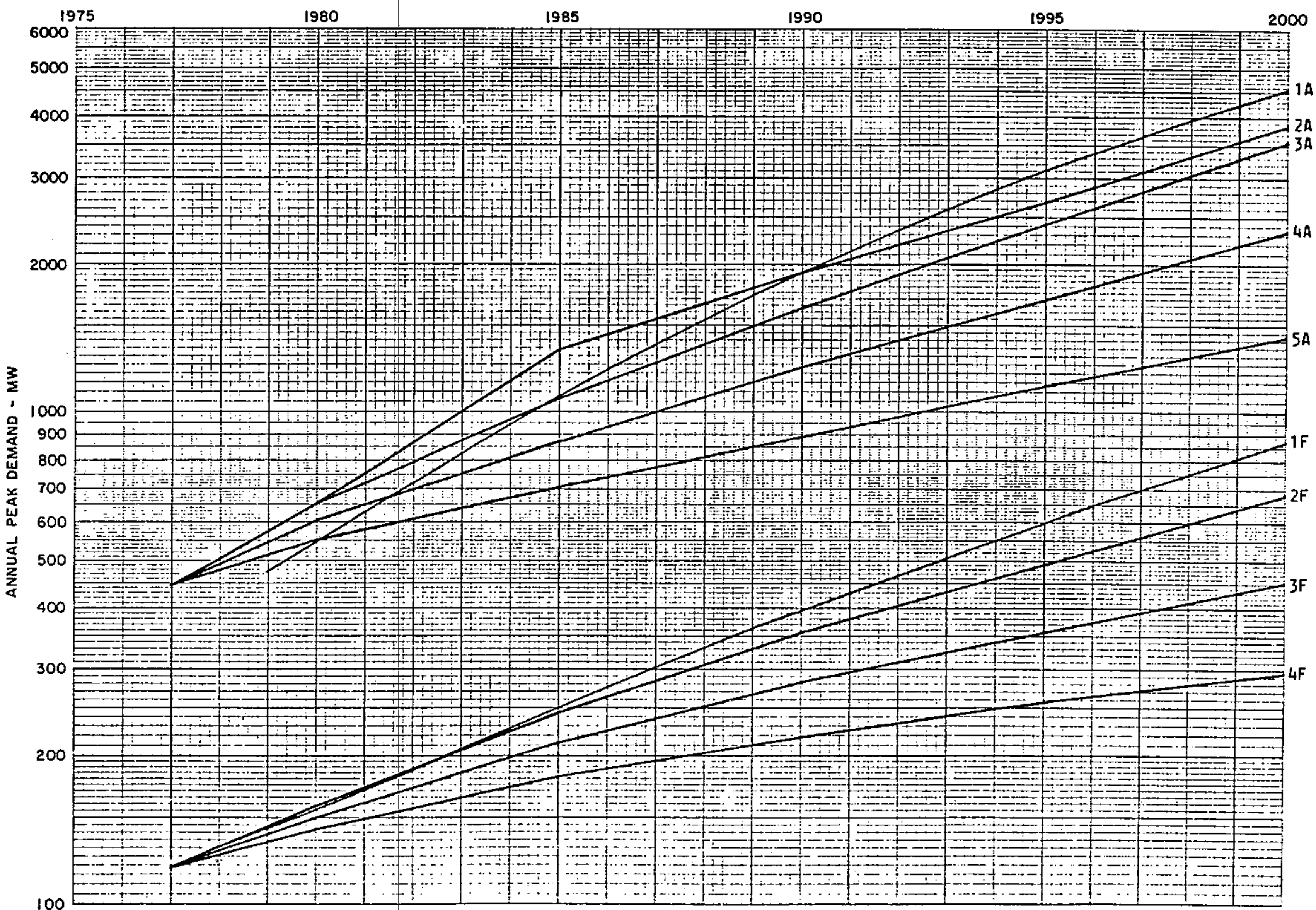


1C COMBINED UTILITIES FORECAST
2C EXTRA HIGH FORECAST
3C HIGH FORECAST
4C MEDIAN FORECAST
5C LOW FORECAST

} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

PROJECTED RANGE OF ANNUAL PEAK DEMAND FORECASTS FOR COMBINED UTILITIES AND INDUSTRIAL LOAD RAILBELT AREA

FIGURE 3-5

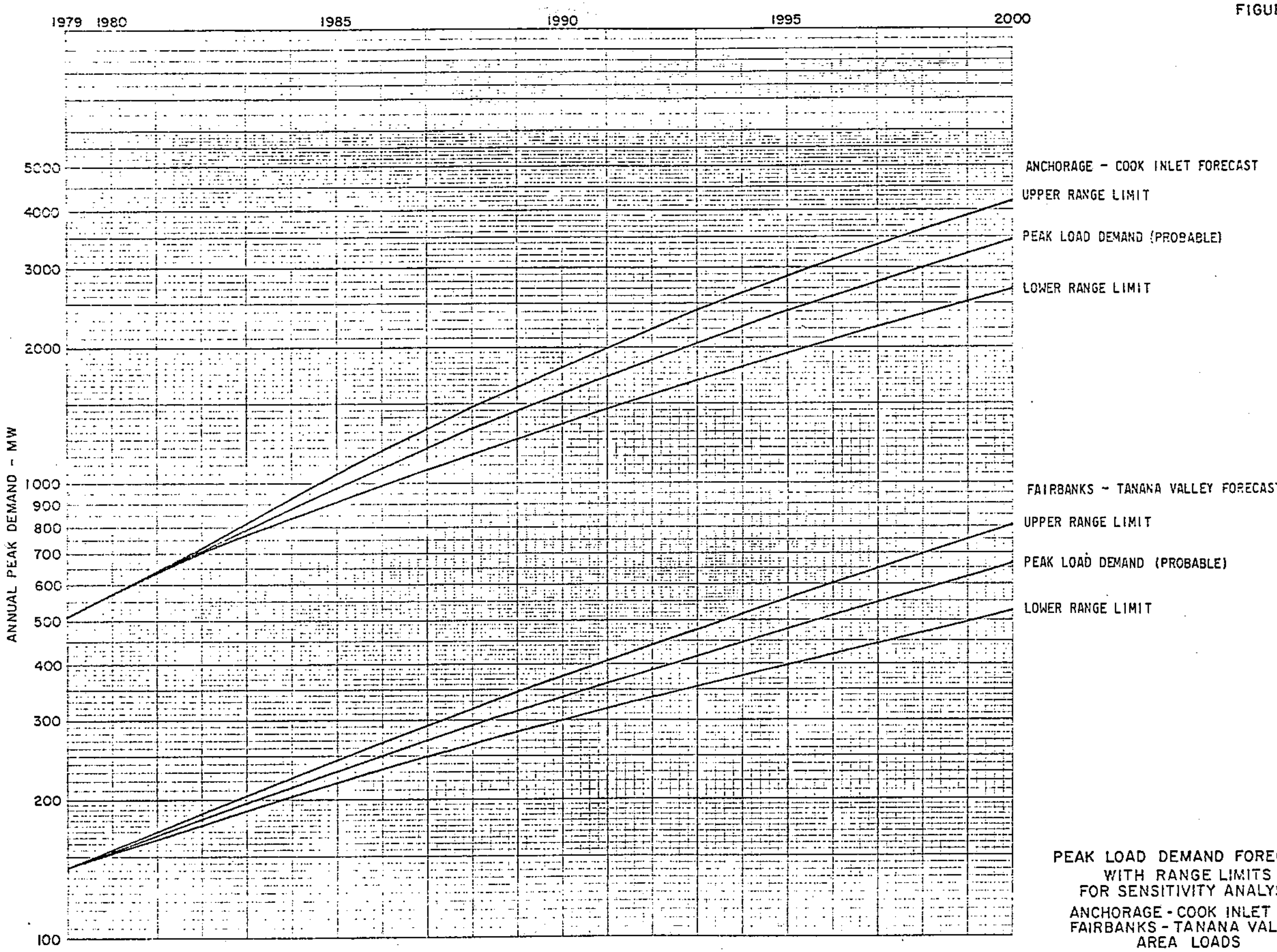


1A UTILITIES FORECAST FOR ANCHORAGE - COOK INLET AREA
2A EXTRA HIGH FORECAST
3A HIGH FORECAST
4A MEDIAN FORECAST
} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

1F UTILITIES FORECAST FOR FAIRBANKS - TANANA VALLEY AREA
2A HIGH FORECAST
3F MEDIAN FORECAST
4F LOW FORECAST
} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

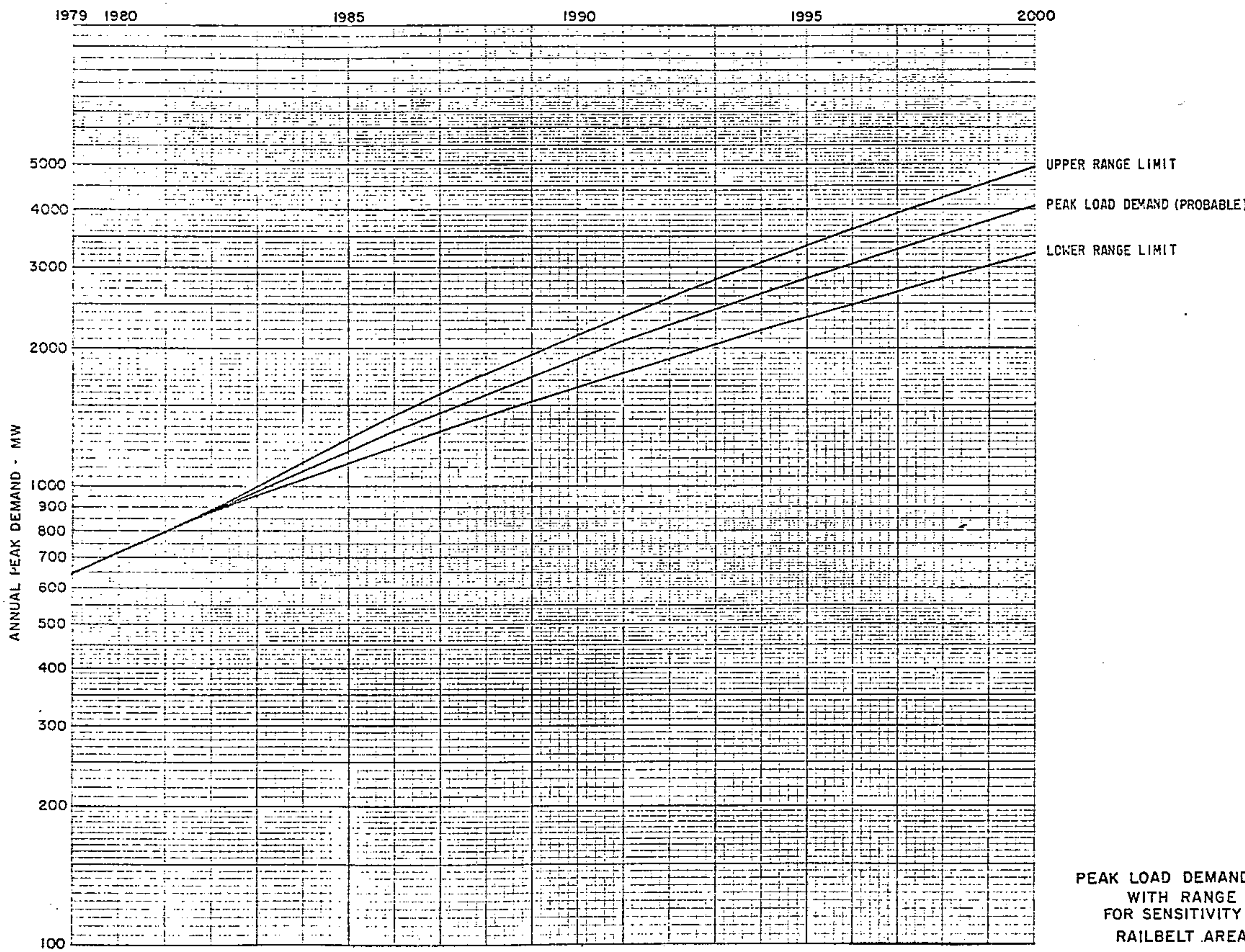
ANNUAL PEAK DEMAND
FORECASTS FOR COMBINED
UTILITIES AND INDUSTRIAL LOAD
ANCHORAGE - COOK INLET AREA AND

FIGURE 3-6



PEAK LOAD DEMAND FORECASTS
WITH RANGE LIMITS
FOR SENSITIVITY ANALYSIS
ANCHORAGE - COOK INLET AND
FAIRBANKS - TANANA VALLEY
AREA LOADS

FIGURE 3-8



PEAK LOAD DEMAND FORECAST
WITH RANGE LIMITS
FOR SENSITIVITY ANALYSIS
RAILBELT AREA LOADS

FIGURE 3-8

CHAPTER 4

SELECTION OF INTERTIE ROUTE

CHAPTER 4

SELECTION OF INTERTIE ROUTE

4.1 REVIEW OF EARLIER STUDIES

A number of studies have considered the electrical interconnection of the Fairbanks, South Central, and Anchorage areas (Refs. 1-8). The Susitna Hydroelectric Project Interim Feasibility Report (Ref. 2), hereafter called Susitna Report, reviewed a number of alternative transmission corridors in considerable depth. None of the studies included a specific route for a transmission line. The Susitna Report provides an excellent inventory of topography, geology, soils, vegetation, wildlife, climate, existing development, land ownership status, existing rights-of-way, and scenic quality and recreation values by corridor segments of about 5-mile widths.

4.2 SURVEY OF ALTERNATIVE CORRIDORS

Alternative corridors reviewed for this report were those along or near the Railbelt region between the Anchorage and Fairbanks areas. A reconnaissance (by USGS Quad's and local knowledge) of routes connecting the Railbelt area to Glennallen was also made to provide a basis for estimating the cost of such a connection at a later date.

4.3 PREFERRED ROUTE FOR TRANSMISSION INTERTIE

The preferred corridor described in the Susitna Report was further defined by making an actual preliminary layout of a definitive route (with some alternatives) using engineering techniques. This preliminary routing provides a basis for refining cost estimates, displaying a definitive location for use in studying potential environmental impacts, and providing a specific engineering recommendation for use in right-of-way negotiations.

The preliminary line routing is shown on the accompanying maps, Figures 4-1, 4-2, and 4-3, these being spatially related to the key map on the inside of the front cover of this report. These routes come from a working strip map of 1" = 1 mile (USGS Quad's.) on which these preliminary routes are drawn. The route was plotted by an engineer with nearly 30 years of experience with Alaskan transmission systems. It was also visually inspected throughout much of its length over the Parks Highway from Anchorage to Fairbanks.

The definitive line route was established within the preferred corridor, with due regard to the following restraints, insofar as they could be identified in this preliminary review:

- Avoidance of highway rights-of-way, which are better locations for distribution lines that will be required to serve homes and enterprises served by the highway.

- Avoidance of telephone lines, because of electrical interference problems. (An open-wire telephone circuit exists on the entire length of the Alaska Railroad right-of-way.)

- Avoidance of aircraft landing and takeoff corridors, including all lakes of sufficient size to accommodate small floatplanes. Where lines may cross landing patterns, at least 1/2 mile is allowed from the end of runways or lakes, so that special designs are not required.

- Avoidance of highly subdivided land areas and dwellings.

- Avoidance of crossings over developed agricultural lands.

- Selection of routings that provide for minimum visibility from highways and homes.

- Avoidance of heavily timbered lands.

- Selection of routes that provide for minimum changes in grade as the terrain will allow.

- Parallel alignments with property lines are favored, if not precluded by other considerations.

- Avoidance of sensitive wildlife areas, if practicable, and cooperation in regard to construction and operating restraints where lines pass through such areas.

- Alignments located in reasonable proximity to transportation corridors (roads, railroads, navigable waterways) so that construction, operation, and maintenance routines are not inordinately difficult.

4.4 FIELD INVESTIGATIONS

Principal engineers of the IECO-RWRA team made field trips by helicopter and surface transportation to important sites and typical structures of existing transmission lines in both the Anchorage and Fairbanks areas. Particular attention was given to lines using designs developed especially for Alaskan conditions of muskeg swamp, permafrost, and flood plain. These designs have had more than ten years of successful service, and are the basis for more recent tubular steel structure designs now being installed on Alaska projects.

Actual field records of Resident Engineers and Inspectors on Alaska transmission line construction projects were analyzed along with contractor bids for these projects to provide authoritative basic data on the actual man-hours, materials use, and dollar costs of completed transmission lines.

4.5 PRELIMINARY ENVIRONMENTAL ASSESSMENT

A. Description of the Environment

1. Point MacKenzie to Talkeetna - The corridor travels north along the east flank of the Susitna River Valley, an extremely wide and poorly drained plain. Heavy forests of bottomland spruce and poplar, interspersed with muskeg and black spruce, are typical. The soils vary from deep, very poorly drained peat to well-drained gravels and loams, with the well-drained soils being more abundant. Although permafrost is almost absent in this lower part of the Susitna Valley, the poorly drained areas are subject to freezing and heaving in the winter.

A sizeable concentration of moose inhabits the lower Susitna River Valley. This valley also supports black and brown bear and a moderate density of water fowl.

The proposed transmission line route generally follows a "tractor trail" (USGS designation) to three miles northeast of Middle Lake. Here, at the approach to the Nancy Lake area, an alternate route (A) may be used to avoid this area. The proposed route (B) is located in marshes and wetlands, between Papoose Twins and Finger Lakes, across the Little Susitna River. The corridor then travels northward along the east side of Lynx Lake, Rainbow Lake, and Long Lake where it crosses the Willow River. Here alternate routes (A) and (B) rejoin and intersect an existing 115-kV MEA transmission corridor at the Little Willow Junction and a proposed corridor to Anchorage on the east side of Knik Arm. Travelling north, the corridor crosses several major tributaries of the Susitna River including Sheep Creek and the Kashwitna River. In this area the terrain becomes more rolling, and the relative proportion of well-drained soils supporting thick poplar-spruce forests is considerably greater than to the south. The corridor then travels some five miles east of Talkeetna to the Bartlett Hills P.I. (point of intersection).

2. Talkeetna to Gold Creek - From Bartlett Hills P.I. the corridor crosses the Talkeetna River near the confluence of the Talkeetna and Chulitna Rivers, where it follows the west bank of the Chulitna River at a mean elevation of 600 feet. Where the Chulitna River curves eastward, the corridor travels northward, along the Susitna River Valley, through forested uplands, gradually rising to an elevation of 1000 feet. The uplands above the valley support sparser forests, and increasing amounts of permafrost soils are encountered. At the 1000-foot elevation, one to three miles east of the Susitna River, the corridor crosses Lane Creek, MacKenzie Creek, Portage Creek, Deadhorse Creek, and numerous other small tributaries of the Susitna River. It then crosses Gold Creek and the Susitna River, 1-1/2 miles east of A.R.R. Mile 265, to the Susitna Junction, one mile east of A.R.R. Mile 266. At the Susitna Junction, the proposed Devil Canyon-Watana-Glennallen line meets the corridor.

3. Gold Creek to Glennallen - The corridor parallels the Susitna River to the proposed Devil Canyon damsite and then travels east to the proposed Watana damsite. The vegetation in the canyons varies from upland spruce-hardwood to alpine tundra. Soils vary from poorly drained river bottoms to unstable talus. Permafrost occurs in this portion of the corridor. Some localized moose populations are crossed. The corridor passes through low lake areas west of Lake Louise until it intersects the Richardson Highway at Tazlina. From Tazlina the route follows the Richardson Highway into Glennallen.

4. Gold Creek to Cantwell - The transmission corridor travels north some 1 to 3 miles east of the Alaska Railroad between elevation 1500 and 2000 feet. The timber density becomes successively less in this area. This portion of the corridor is a good bear and moose habitat. Shallow permafrost occurs in this portion. The corridor crosses several major and minor tributaries to the Chulitna River including Honolulu Creek, Antimony Creek, Hardage Creek, the East Fork of the Chulitna River, and the Middle Fork of the Chulitna River. The corridor area is of medium scenic quality and is not readily accessible, except at the Denali Highway Crossing.

5. <u>Cantwell to Healy</u> - The corridor rises to the 3200 foot level along the west side of Reindeer Hills and then descends into the Nenana River Valley. It follows the east flank of the Nenana River northward at the 2200 foot level, through sparsely timbered country. This is an area of high scenic quality especially in the canyons. The terrain varies from rolling hills and valleys to high passes and sharp ridges. Habitats of moose, bear, and Dall sheep are traversed. Bedrock is exposed in the canyons. The corridor crosses several tributaries to the Nenana River including Slime Creek, Carlo Creek, Yanert Fork, and Montana Creek, and the Nenana River itself. It also crosses the Alaska Railroad at the Moody Tunnel, near A.R.R. Mile 354 and the Healy River. The boundary of Mt. McKinley National Park is on the west flank of the Nenana River.

6. <u>Healy to Ester</u> - The corridor leaves Healy and crosses the Parks Highway near Dry Creek. It then roughly parallels the west side of the highway at elevation 1500 feet, crossing several tributaries to the Nenana River. It crosses the GVEA line 1-1/2 miles north of Bear Creek, the Alaska Railroad and the Nenana River at A.R.R. Mile 383, and the Parks Highway. The route then parallels the GVEA line. The corridor crosses the Tanana River at the Tanana P.I. and follows the Tanana River flood plain for several miles until the route again crosses the highway where it travels on the west side of the Bonanza Creek Experimental Forest. The route parallels the GVEA right-of-way the rest of the way to Ester. The Healy to Ester portion of the route passes through some private lands (mining claims, homesteads, etc.), as well as near the towns of Healy, Lignite, and Nenana. An archeological site exists near Dry Creek. Portions of the corridor are heavily forested and provide habitat for moose, caribou, and bear. Poorly drained areas in this corridor are subject to potential permafrost degradation and frost heaving.

B. Environmental Impacts

Construction and maintenance of other Alaskan transmission systems has shown that most negative environmental impacts caused by a transmission system can be minimized. Golden Valley Electric Association, Matanuska Electric Association, and Chugach Electric Association have constructed and are operating several lines on poor soils and under harsh climatic conditions. Except for anticipated slight visual impacts, most environmental impacts caused by a transmission system would be far less than those of many transportation and communication systems. Specific areas to be impacted are discussed below.

1. Ecosystems - The major positive impact will be on human environment, while adverse effects to the other ecosystems will be minimal. The route has been selected to avoid adverse impacts on these ecosystems wherever possible. The human environment will be benefited by the provision of energy, vital to the growing state of Alaska. The development of many potential renewable energy resources will be made feasible by the Anchorage-Fairbanks intertie. The project will contribute to the reduction in costs of electrical energy, improvement in reliability of electrical service, and enhancement of opportunities for renewable energy resources (such as hydro and wind) to displace non-renewable energy resources (such as gas and oil) for the generation of electricity.

Alteration of vegetation patterns will affect wildlife. This corridor traverses many areas of moose concentrations, and moose should benefit from the introduction of brush resulting from regrowth on the clearing. Since the clearing must be maintained, this brush area will last for the lifetime of the project. Animals such as squirrels will suffer loss and displacement. However, their faster reproductive rates will allow their populations to adjust rapidly.

Construction itself will affect wildlife. Larger mammals may temporarily leave the area to return after the construction activity. Smaller animals will suffer individual losses, but should recuperate rapidly once construction is completed. The density of forest in portions of the corridor will allow animals to move only a short distance to avoid contact with construction activities.

Vegetation suppression, by whatever method, will periodically remove cover from along the right-of-way. However, due to the surrounding cover of the uncleared forests, this impact will be insignificant.

2. Recreation - The corridor will approach several recreational and wayside areas in the lower Susitna Valley. The largest of these is the Nancy Lake Recreational Area. The corridor will also approach the Denali State Park, but will be separated from the Park by the Susitna River.

This corridor will provide access to areas previously difficult to reach. The largest such area is that south of Nancy Lake to Point MacKenzie. Dense forest and muskeg limit travel.

Further north the corridor parallels the east border of Mt. McKinley National Park, being separated by the Parks Highway, the Nenana River, and the Alaska Railroad.

3. Cultural Resources - The National Register of Historical and Archaeological Sites lists the following sites which will be approached by the transmission corridor: Knik Village, Dry Creek, and the Tangle Lake Archaeological District. The line will be routed to bypass these areas.

During construction and preconstruction surveys, other archaeological sites may be discovered which may be eligible for nomination to the National Register. This is a positive benefit of the corridor, as archaeological and other cultural resources are often difficult to find in the great Alaska wilderness.

4. <u>Scenic Resources</u> - The southern portion of the corridor does not traverse any areas of good or high quality scenic values. The northern portion is, however, more scenic than the southern portion. In the northern portion the fairly continuous, moderately dense forest will provide ample screening from transportation routes. Further south, the forests are more intermingled with open muskeg. Glimpses of the transmission line will be seen from the highway or railroad through these muskeg areas. South of Nancy Lake the transmission corridor and the transportation corridors diverge, and although cover becomes more sporadic, the line will no longer be visible from the transportation routes. The transmission line will not be visible from most of the Nancy Lake Recreation Area.

As the Alaska Railroad and the transmission corridor approach Gold Creek, the valley becomes more confined, and screening becomes more difficult. However, it appears that the line can be concealed through most of this portion.

The corridor passes through an area recognized as being of good to high scenic quality from Devil Canyon to Healy. The possibility of screening throughout this area varies from moderate in the southern portion around Chulitna, to minimal in the Broad Pass and the upper and lower canyons of the Nenana River. Scenic quality will be impacted, the impact being a function of existing scenic quality and the opportunity for screening. The proposed line design will incorporate weathering tubular steel towers which blend well into the environment. Non-specular conductors might be used where light reflection from the line would cause unacceptable adverse visual impact. Impact in the Nenana Canyon will be high; impact on Broad Pass will be moderate to high; impact elsewhere will be moderate. Two favorable factors mitigate the impact somewhat: 1) the corridor is not visually intact as the Alaska Railroad and the Anchorage-Fairbanks Highway have already reduced scenic quality somewhat; and 2) the major views south of the canyons are to the west, toward the Mt. McKinley massif, whereas the transmission line corridor lies to the east of the transportation routes.

5. Social - Some economic impact can be expected, as flying services, motels, restaurants, and entertainment facilities receive business, not only from the transmission line workers, but from related personnel. Due to the high cost of a low-load tap on a high voltage line, the likelihood of use of the energy by small communities along the corridor is remote. However, in places where the demand could justify such a tap, it would provide a reliable source of electrical energy for growing communities.

C. Special Impact Mitigation Efforts During Construction

Right-of-way clearing will be accomplished by approved methods such as the hydro axe, and chips will be spread along the right-of-way. The line will be screened wherever possible. The towers will be designed to blend into the environment, thereby reducing visual impact.

Movement of men and equipment during construction will be scheduled to avoid excessive damage to the ground cover. This is generally accomplished by winter construction. The tower design will allow movement of men and equipment along the right-of-way centerline, thereby eliminating the need for an access road in addition to the transmission line clearing.

Major river crossings will be required over the Talkeetna River, Tanana River, Healy Creek, and the Susitna River. Minor stream crossings may be made either by fording or ice crossings. Special efforts will be made to avoid siltation of fish streams. Oil will be carefully handled to avoid spillage. Where larger quantities of oil are to be stockpiled, dikes will be constructed to protect against spills.

Since most of the construction will occur far from communities, noise is not anticipated to be a problem. Suitable muffling devices will be used to protect men and wildlife from excessive noise.

Prior to and during construction, special efforts will be made to consult with State historical and archaeological authorities, the Soil Conservation Service, the Bureau of Land Management, the Alaska Department of Fish and Game, and the U.S. Forest and Wildlife Service, and any other agencies having jurisdiction over the construction area, in an effort to ensure sound environmental practices.

4.6 REFERENCES

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2. U.S. Army Corps of Engineers, Southcentral Railbelt Area, Alaska, Upper Susitna River Basin Interim Feasibility Report, (Appendix I, Part II (G) Marketability Analysis, (H) Transmission System, (I) Environmental Assessment for Transmission Systems, December 1975.

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

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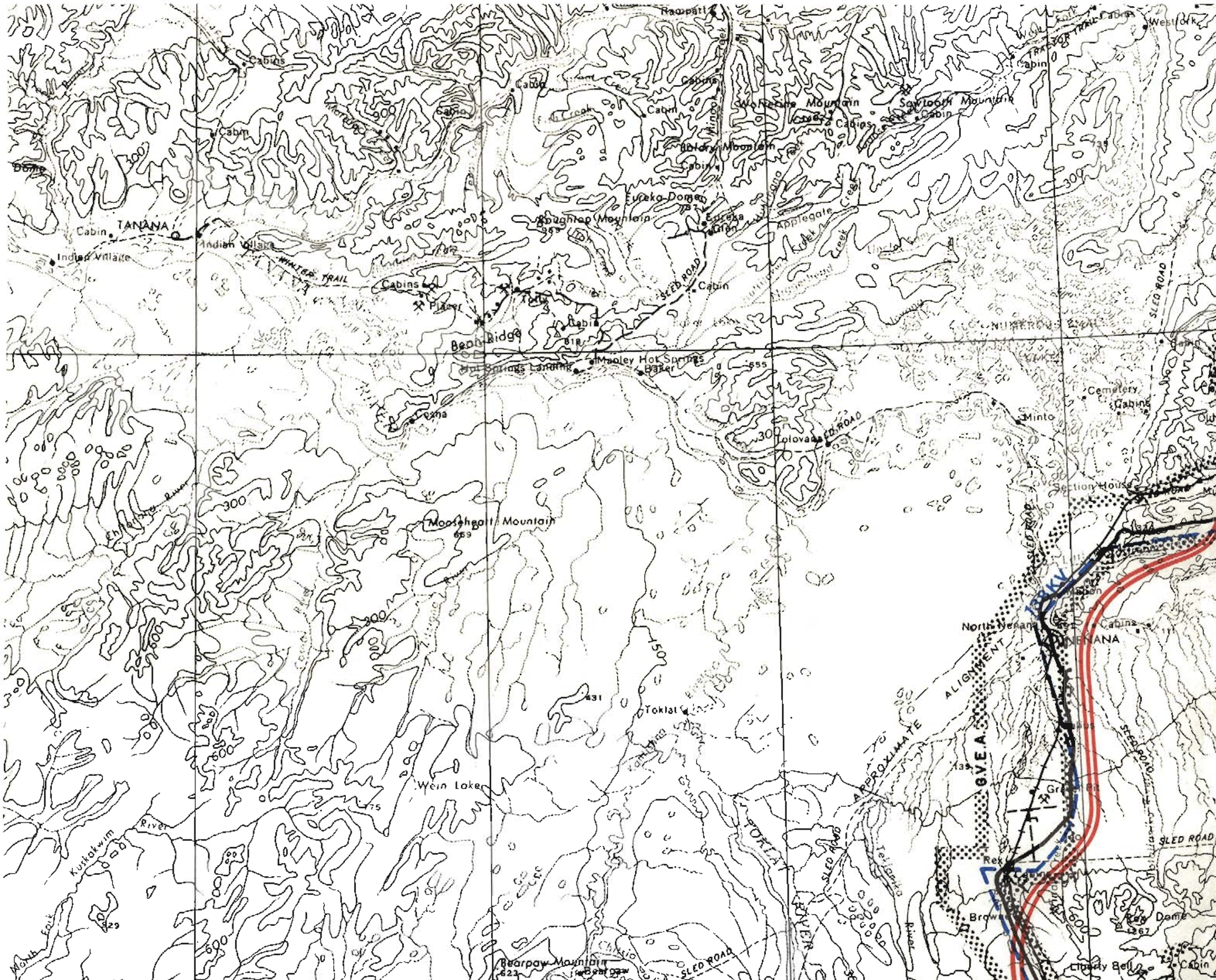
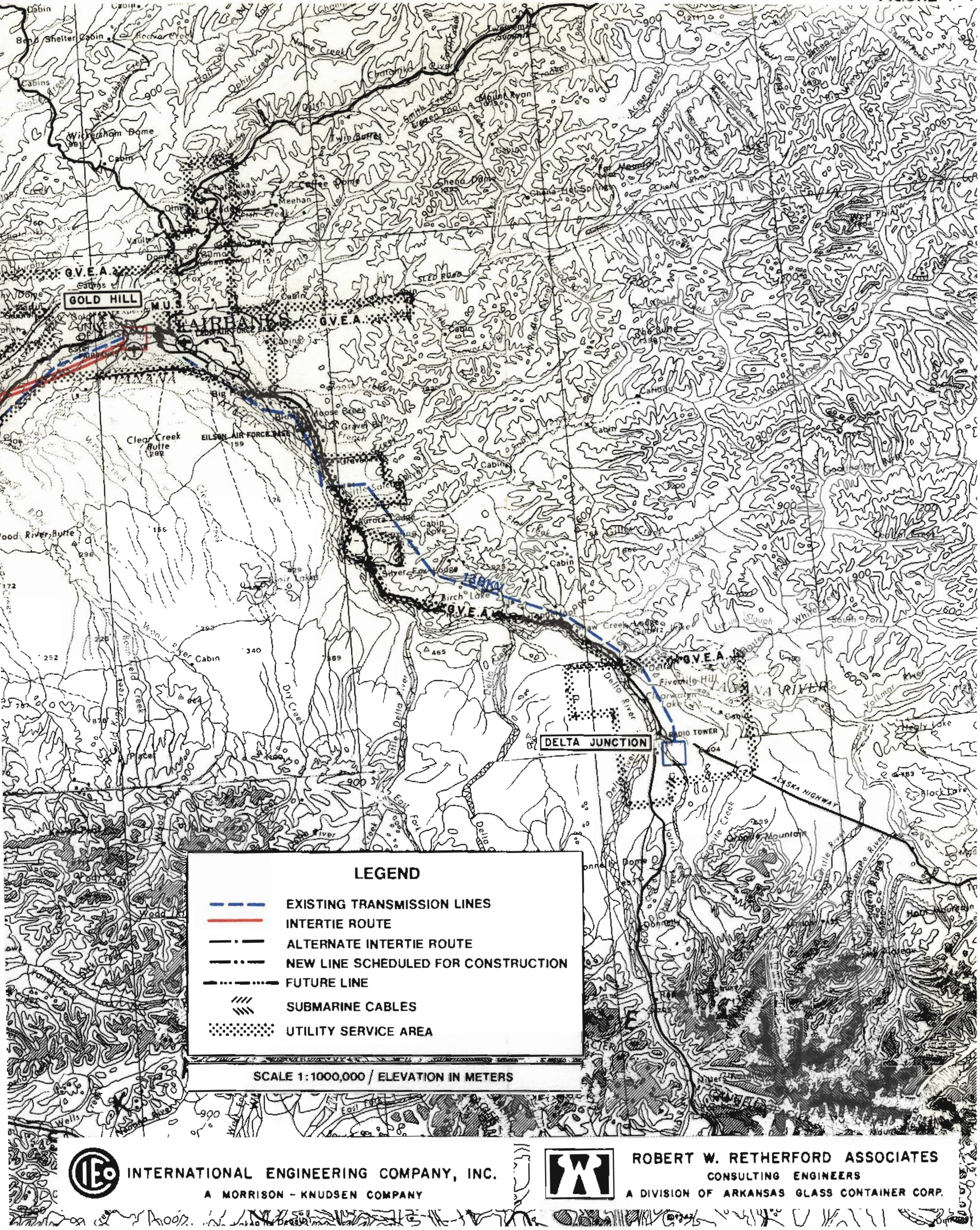


Rampart
Wolverine Mountain
Sawtooth Mountain
Boldry Mountain
Eureka Dome
Roughtop Mountain
Eureka
TANANA
Indian Village
WINTER TRAIL
SLED ROAD
Applegate Creek
Cabins
Placer
Manley Hot Springs
Hot Springs Landing
Baker
Tolovana
Minto
Cemetery
Section House
Moosehead Mountain
North Nenana
NENANA
APPROXIMATE ALIGNMENT
G.V.E.A.
Toklat
Wein Lake
Kuskokwim River
TOKLAT RIVER
Teklanika River
Red Dome
Liberty Bell
Bearpaw Mountain
Roosevelt
Nineteenmile
Caribou Mountain
Jumbo Dome
Lignite Creek
UNSURVEYED
Minchumina
Lake Minchumina
Cabin
Diamond
Lake Tukomina
HEALY
Glacier
ANTIMONY
Kantishna
Camp
Wonder Lake
McKinley River
Slippery Creek
Birch Creek
Herron River
Clearwater Creek
MT. McKINLEY NATIONAL PARK
POLYCHROME PASS
GLACIER

FIGURE 4–1



NENANA–FAIRBANKS–TANANA TRANSMISSION SYSTEM

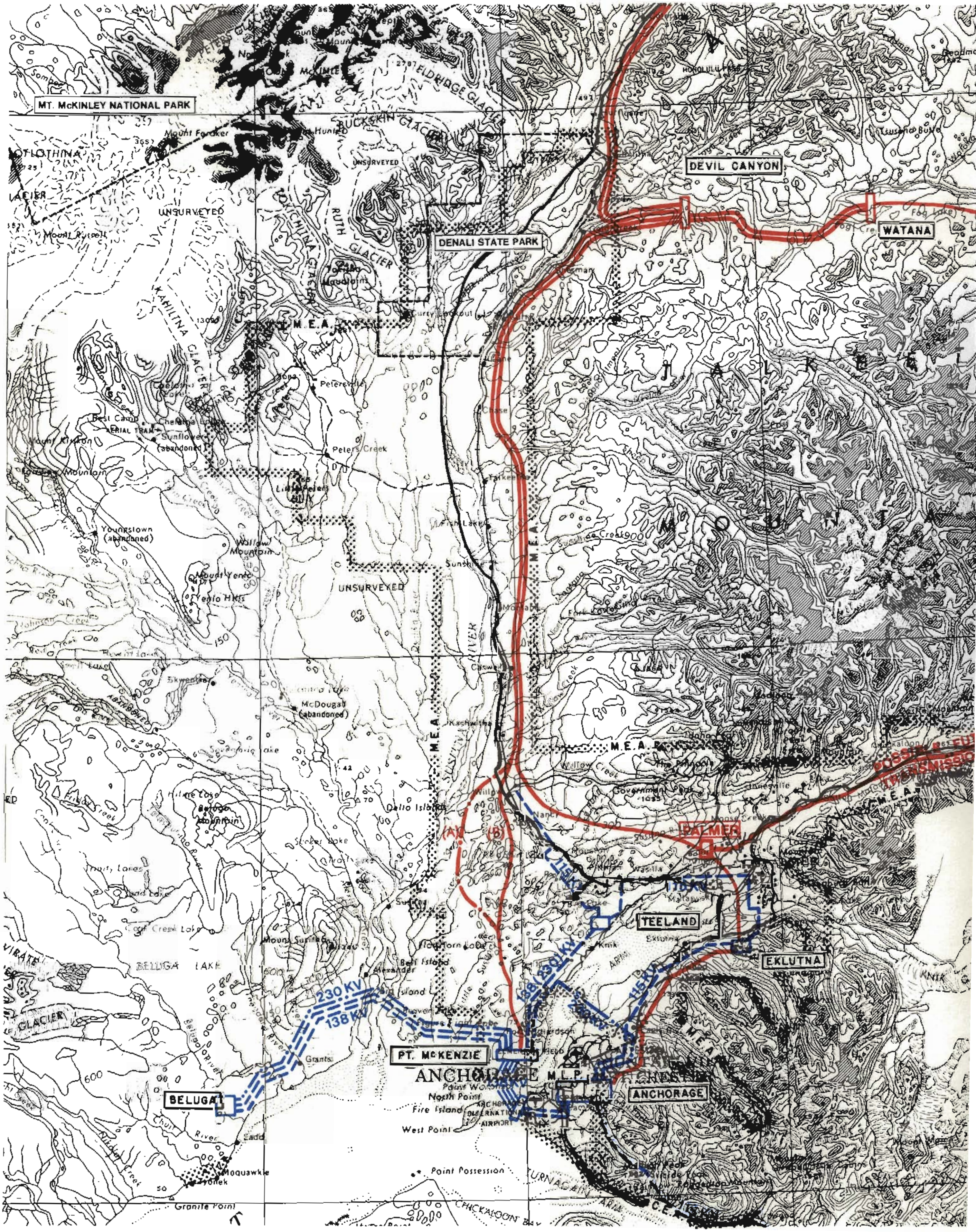
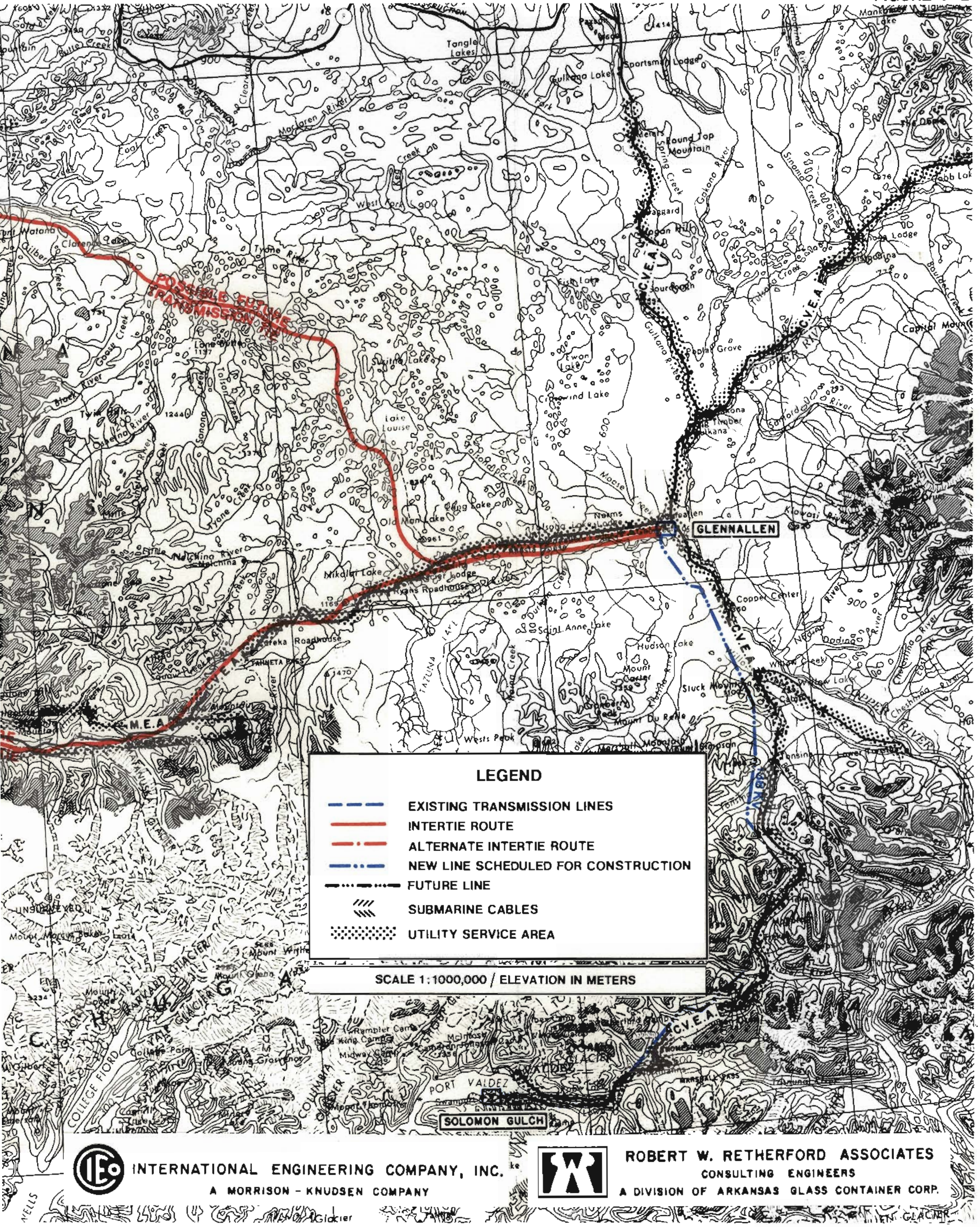
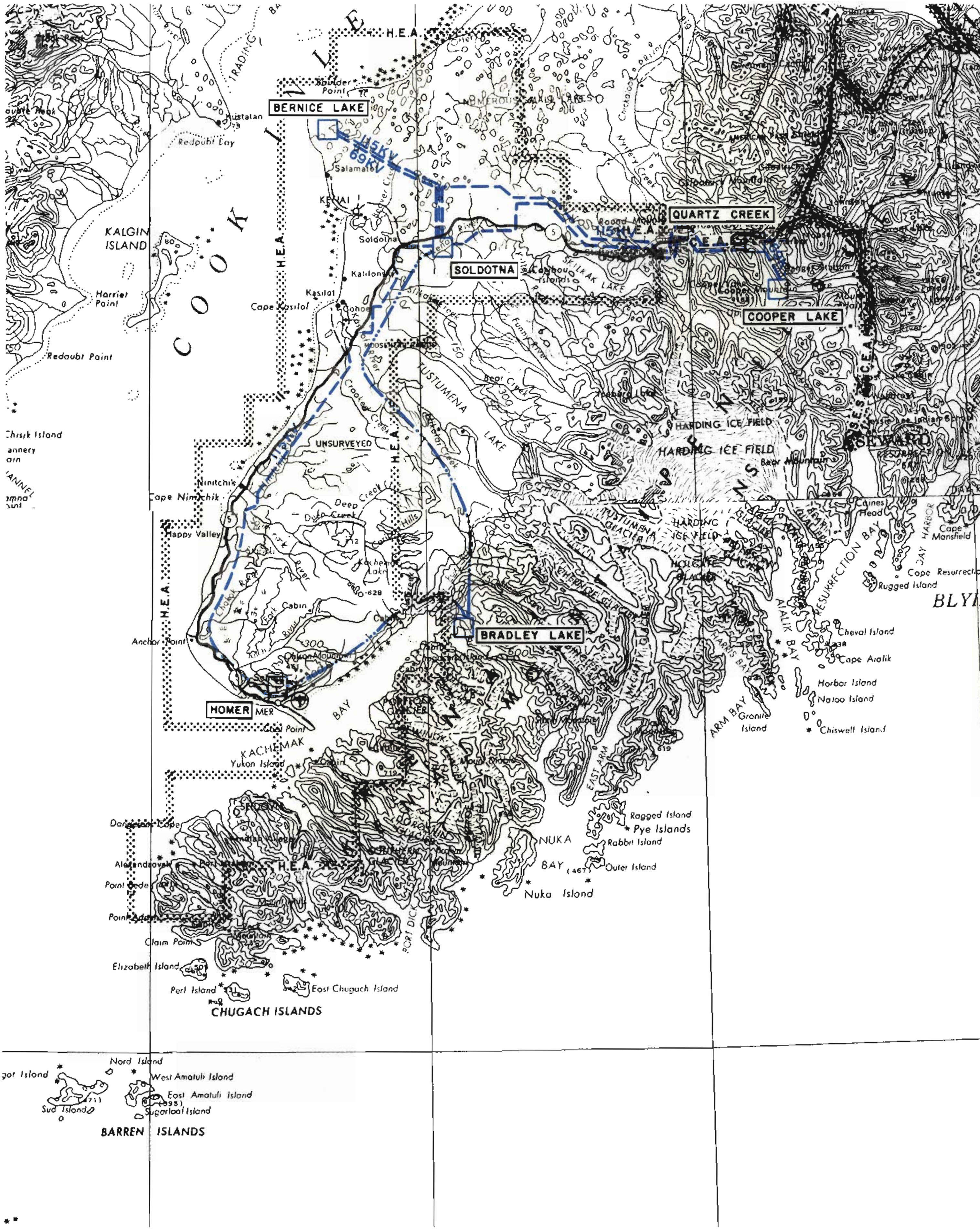

MT. McKINLEY NATIONAL PARK
DEVIL CANYON
WATANA
DENALI STATE PARK
M.E.A.
UNSURVEYED
PALMER
TEELAND
EKLUTNA
ANCHORAGE
PT. McKENZIE
BELUGA
230 KV
138 KV
115 KV
M.L.P.
C.E.
ANCHORAGE
TALKEETNA MOUNTAINS
BELUGA LAKE
Point Possession
West Point
North Point
Fire Island
Granite Point
Moquawkie
Tyonek
Grants
(A)
(B)

FIGURE 4–2

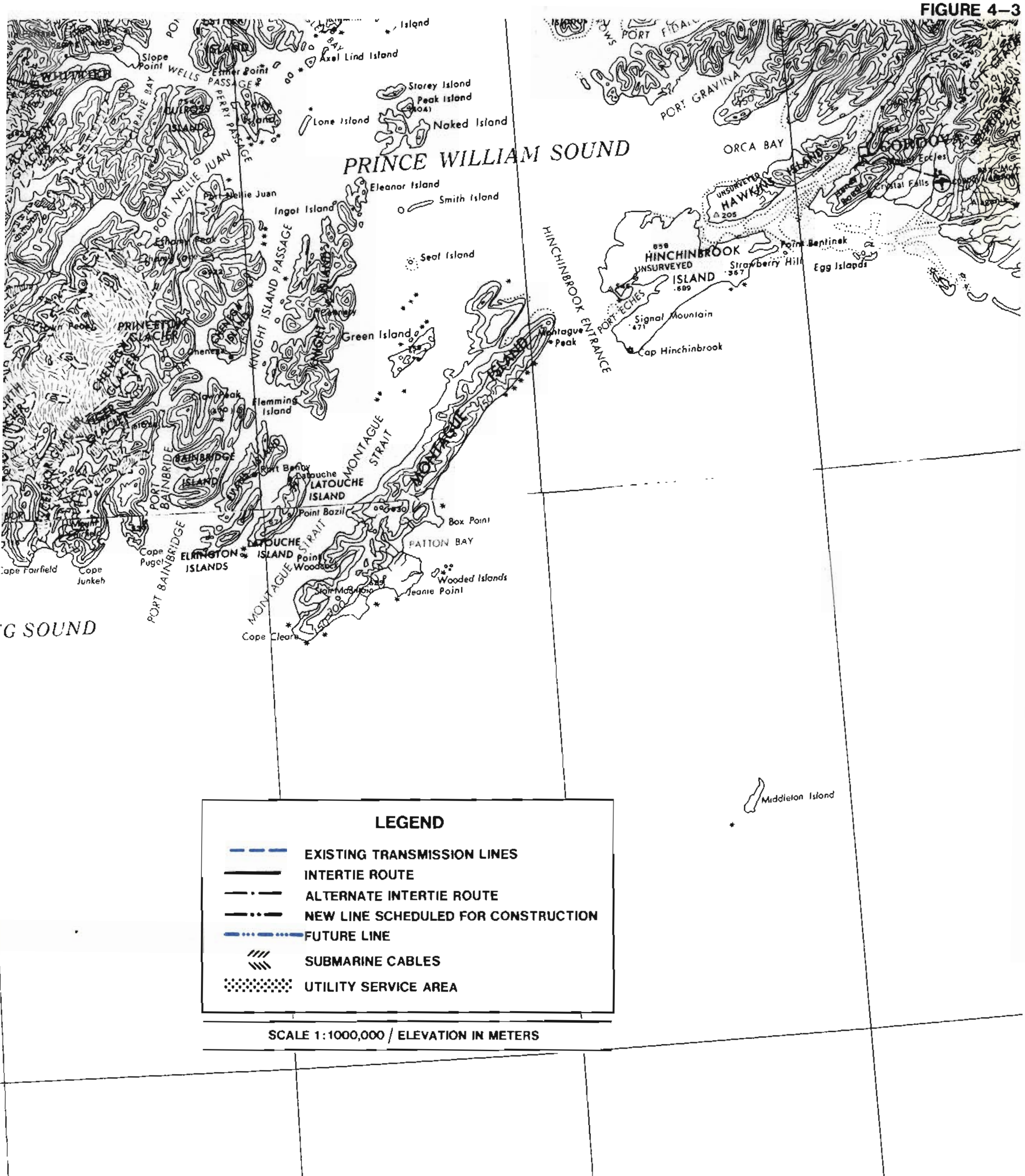


ANCHORAGE–MATANUSKA–SUSITNA–GLENNALLEN–VALDEZ TRANSMISSION SYSTEM



BERNICE LAKE
SOLDOTNA
QUARTZ CREEK
COOPER LAKE
BRADLEY LAKE
HOMER
115KV
69KV
H.E.A.
COOK INLET
KALGIN ISLAND
Harriet Point
Redoubt Point
Redoubt Bay
Tustatan
Salamatof
KENAI
Soldotna
Kalifonsky
Kasilof
Cape Kasilof
Cohoe
Ninilchik
Cape Ninilchik
Happy Valley
Anchor Point
UNSURVEYED
Deep Creek
Crooked Creek
TUSTUMENA LAKE
Bear Creek
Funny River
SKILAK LAKE
HARDING ICE FIELD
Bear Mountain
SEWARD
Caines Head
Cape Mansfield
Cape Resurrection
Rugged Island
RESURRECTION BAY
BLYIN
Cheval Island
Cape Aialik
AIALIK BAY
Harbor Island
Natoa Island
Chiswell Island
Granite Island
ARM BAY
HARRIS BAY
EAST ARM
Ragged Island
Pye Islands
Rabbit Island
Outer Island
NUKA BAY
Nuka Island
KACHEMAK BAY
Yukon Island
Dangerous Cape
Alexandrovsk
Point Gede
Point Adam
Claim Point
Elizabeth Island
Perl Island
East Chugach Island
CHUGACH ISLANDS
Nord Island
West Amatuli Island
East Amatuli Island
Sugarloaf Island
Sud Island
BARREN ISLANDS
Chisik Island

FIGURE 4–3



INTERNATIONAL ENGINEERING COMPANY, INC.
A MORRISON - KNUDSEN COMPANY

ROBERT W. RETHERFORD ASSOCIATES
CONSULTING ENGINEERS
A DIVISION OF ARKANSAS GLASS CONTAINER CORP.

COOK INLET – KENAI PENINSULA TRANSMISSION SYSTEM

CHAPTER 5

TRANSMISSION LINE DESIGN

CHAPTER 5
TRANSMISSION LINE DESIGN

5.1 BASIC DESIGN REQUIREMENTS

Experience in Alaska with both wood-pole H-frame, aluminum lattice guyed-X towers, and tubular steel guyed-X towers with high-strength conductors (such as Drake 795 kcmil ACSR) has demonstrated the excellent performance of lines designed with relatively long spans and flexible structures. This general philosophy has been followed in establishing the input parameters for the Transmission Line Cost Analysis Program (TLCAP) used to optimize line designs for the Anchorage-Fairbanks Intertie study. Sample outputs of TLCAP and descriptions of the program methodology are found in Appendix B.

The results of this computer analysis for 230-kV lines favor relatively long spans (1300 ft) and high-strength conductors (such as Cardinal 954 kcmil ACSR). This confirms the previous Alaskan experience and contributes substantially to a more economical design, as Chapter 7 will illustrate.

5.2 SELECTION OF TOWER TYPE USED IN THE STUDY

Due to rather unique soil conditions in Alaska, with extensive regions of muskeg and permafrost, conventional self-supporting or rigid towers will not provide a satisfactory performance or solution for the proposed intertie. Permafrost and seasonal changes in the soil are known to cause large earth movements at some locations, requiring towers with a high degree of flexibility and capability for handling relatively large foundation movements without appreciable loss of structural integrity.

The guyed tower is exceptionally well suited for these type of conditions. Therefore, the final choice of tower for this study was the hinged-guyed X-type design, which has been considered for both the 230-kV and 345-kV alternatives. These towers are essentially identical in design to towers presently used on some lines in Alaska, which have proven themselves during more than ten years of service. The design features include hinged connections between the leg members and the foundations which, together with the longitudinal guy system, provides for large flexibility combined with excellent stability in the direction of the line. Transverse stability is provided by the wide leg base which also accounts for relatively small and manageable footing reactions.

The foundations are pile-type, consisting of heavy H-pile beams driven to an expected depth of 20 to 30 feet depending upon the soil conditions.

Tower outlines with general dimensions for the two voltage levels are shown on Figures 5-1 and 5-2.

5.3 DESIGN LOADING ASSUMPTIONS

According to available information and experience on existing lines, heavy icing is not a serious problem in most parts of Alaska. NESC Heavy Loading is presently used for all line designs throughout the Railbelt region. However, there are locations where Light Loading probably could be used. Some line failures have occurred due to exceptionally heavy wind combined with very little or no ice. Such locations should be identified and carefully investigated prior to the final line design.

In this study, NESC Heavy Loading or heavy wind on bare conductor (corresponding to NESC Light Loading) was used, whichever is more severe.

5.4 TOWER WEIGHT ESTIMATION

In order to arrive at realistic tower weights and material costs for the study, actual tower designs for both the 230-kV and the 345-kV alternatives were obtained from Meyer Industries of Red Wing, Minnesota (Ref. 1). This company has designed similar towers for other lines in Alaska.

Based on these reference designs and additional manual calculations, tower weight formulas were developed to account for variations in tower weight due to changes in tower height and load as a function of the type of conductor used.

5.5 CONDUCTOR SELECTION

Conductor size (see Table 5-1) was selected by the use of the Transmission Line Cost Analysis Program (TLCAP) which was specially developed by IECO for this type of study. Given an appropriate range of conductor types and sizes, span lengths, and other pertinent data, TLCAP determines the most economical conductor-span combination.

The program includes a sag-tension routine which calculates the conductor sag and tension for a given set of criteria. Using this information, the tower height and loads are then determined for each discrete span length. These values are then applied to the tower weight formula with the pertinent overload factors included.

In the process of this analysis, the program also evaluated the effect of the cost of the power losses over a specified number of years. The power losses were minimized by varying the sending and receiving end voltages by ± 10% and by providing required shunt compensation at both line terminals. Applicable material and labor costs, together with projected escalation rates, were included to enable the program to calculate the total installed cost of the line. A discount rate of 7% per annum was used for the determination of the present worth of transmission line losses.

For this particular study, material and labor costs were obtained from "as built" cost information realized on recently completed (138-kV and 230-kV) lines in Alaska.

5.6 POWER TRANSFER CAPABILITIES

Preliminary transmission line capabilities, based on surge impedance loading (SIL) criteria, were obtained from the National Power Survey Report (Ref. 2). Additional investigations indicate that for the 230-kV alternatives (Cases IA, IB, and ID), the calculated intertie power angle is near 30 degrees. To improve the 230-kV intertie's steady state and transient transmission capability, series capacitors will be necessary. Interconnected power system studies should be performed to determine the final series and shunt compensation requirements. Such studies are outside the scope of this work.

5.7 HVDC TRANSMISSION SYSTEM

Because of its asynchronous nature, the interconnection of two isolated alternating current (ac) systems by a point-to-point HVDC transmission link provides the desired power exchange without being prone to inherent stability problems. Furthermore, HVDC transmission can provide stabilizing power, and be very effective in damping system oscillations. While the state-of-the-art in HVDC technology is advancing, the resulting developments are keeping pace with inflation.

Preliminary investigations have shown that HVDC transmission, using 180-kV mono-polar transmission and ground return, is competitive with single-circuit 230-kV ac transmission in the transfer 130 MW of power over 323 miles. However, if the point-to-point transmission link is required to supply intermediate locations with power (either initially or in the future) then it is unlikely that dc transmission can be competitive with an ac alternative.

5.8 REFERENCES

1. Letter from ITT Meyer Industries to Robert W. Retherford Associates, Anchorage, Alaska, January 15, 1979.

2. FPC Advisory Committee Report No. 6, National Power Survey, Vol. II, p. IV2-12, 1964.

TABLE 5-1

CONDUCTOR SIZE SELECTION CRITERIA

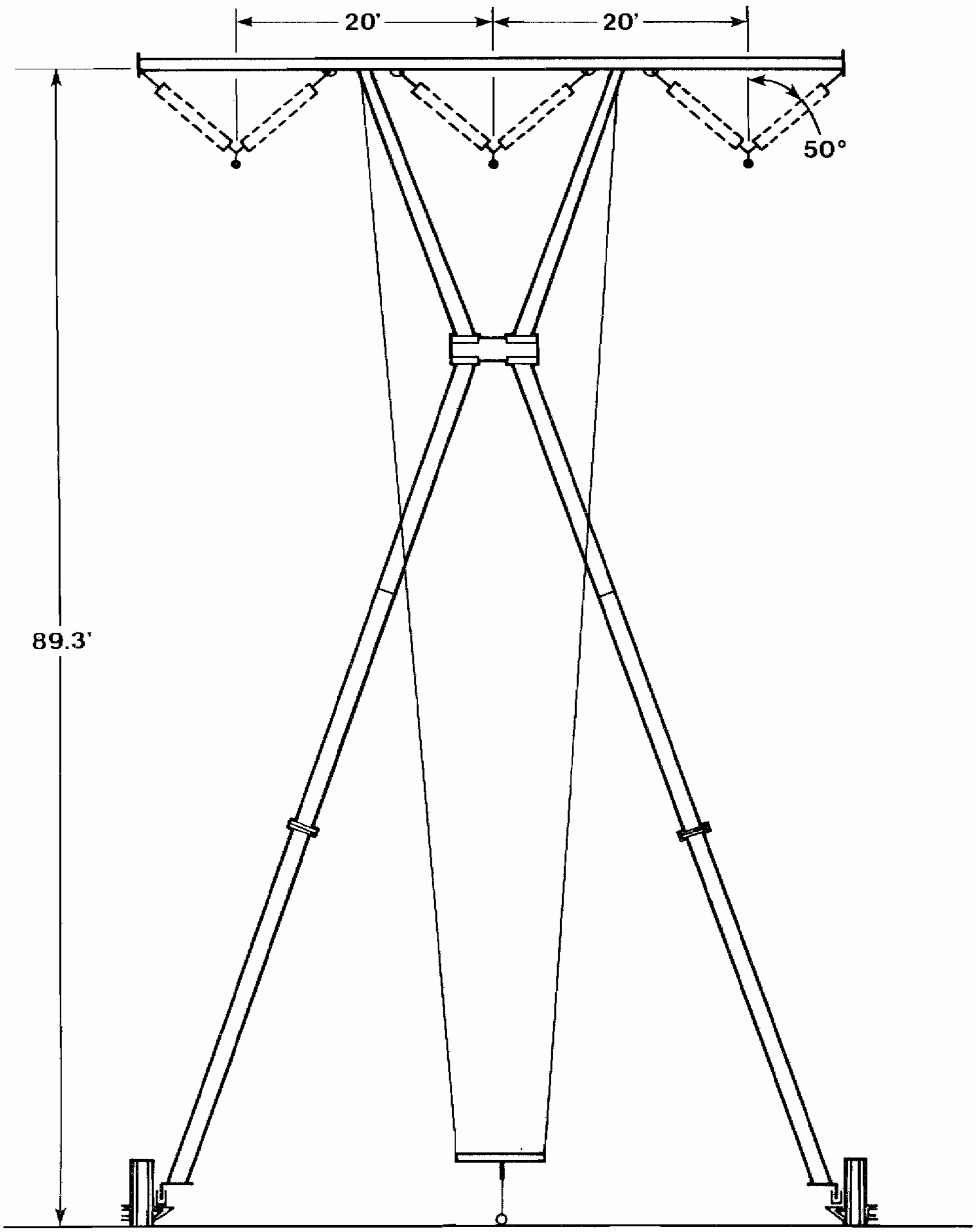
Case and Alternative[1/]	Interconnection	Voltage (kV + 10%)	Line Length (miles)	Optimum ACSR Conductor (kcmil)	Load[2/] Per Circuit (MW)
I A & B	Anchorage-Ester	230 s/c	323	1/c - 954	130
I C	Anchorage-Ester	345 s/c	323	2/c - 795	380
I D	Anchorage-Palmer Healy-Ester	230 s/c	323	2/c - 954	130
II A	Anchorage-Devil Canyon	345 s/c[3/]	155	2/c - 954	600
	Devil Canyon-Ester	230 s/c[3/]	189	1/c - 1510	185
	Watana-Devil Canyon	230 s/c[3/]	27	1/c - 2156	488

1/ Case I Alternatives exclude the proposed Susitna Project; Case II Alternative A includes the Susitna Project.

2/ 100% voltage support at both ends.

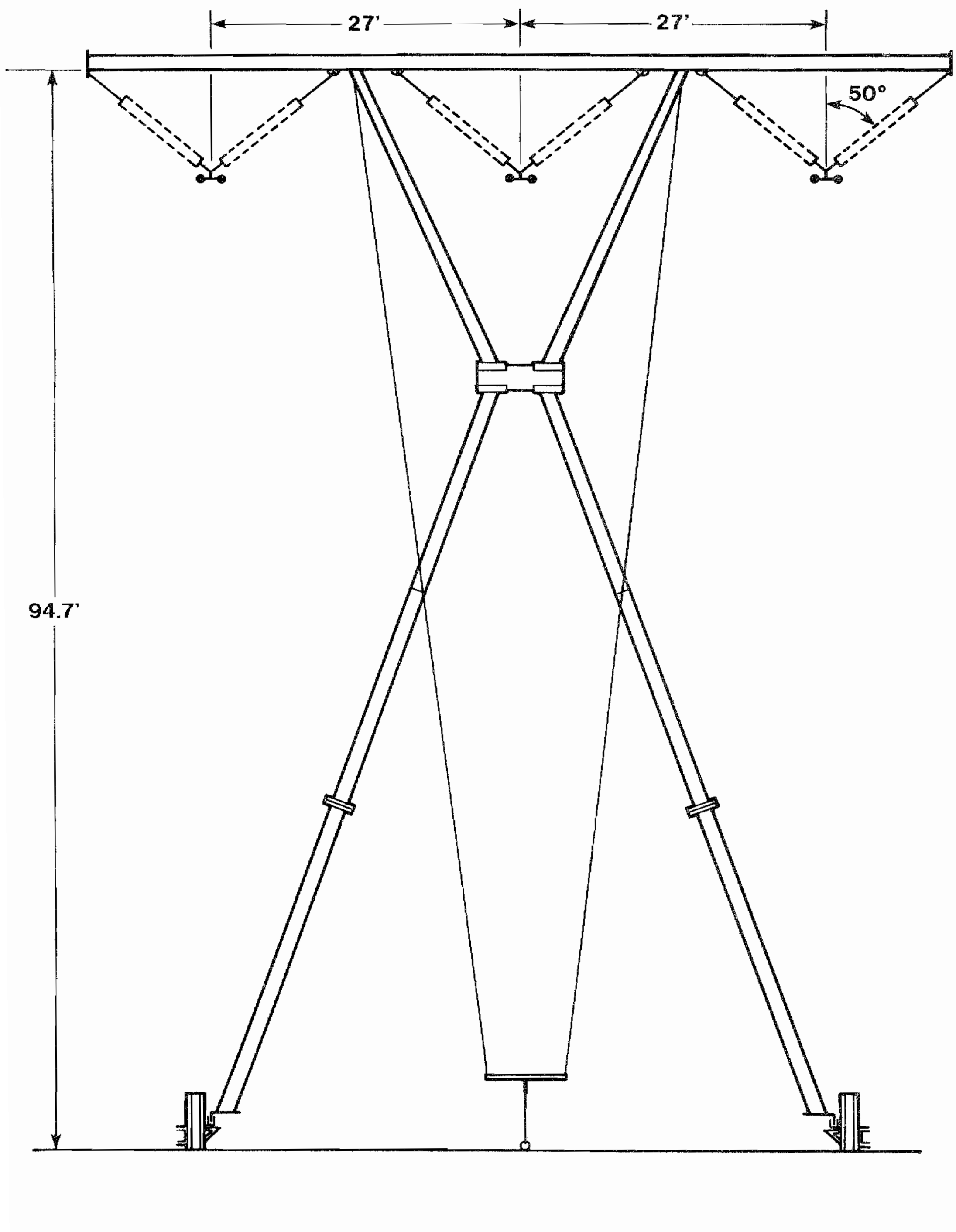
3/ Two single-circuit lines on the same right-of-way.

Note: s/c = single circuit; 1/c = single conductor; 2/c = two conductor bundle.



230KV TANGENT TOWER

FIGURE 5–2



345KV TANGENT TOWER

CHAPTER 6

SYSTEM EXPANSION PLANS

CHAPTER 6

SYSTEM EXPANSION PLANS

One benefit of transmission interconnection between two independent power systems is the reduction in the installed generating capacity that is possible, while maintaining the same electric power supply (generation) reliability level for both the independent and interconnected power systems. To calculate this reduction in installed generating plant capacity (megawatts), generation expansion plans had to be developed for both the independent and the interconnected power systems.

This chapter describes the actual process used in the generation expansion planning for the independent power systems of the Anchorage and Fairbanks areas, and for an interconnected Anchorage - Fairbanks power system. Generation expansion planning is a rather complex process. A brief description of the somewhat simplified method used in this Economic Feasibility Study is described below.

6.1 GENERATION PLANNING CRITERIA

A. Generating Unit Data

Existing generating unit data were obtained from the Battelle (Ref. 1) and University of Alaska, August 1976 (Ref. 2) reports. These available data were reviewed and updated using new information obtained by IECO-RWRA engineers during interviews with the managers of the Railbelt utilities. The updated existing generation unit data is presented in Tables 6-1 and 6-2.

Preliminary information on near future (1979-1986) generation expansion planning, including probable generation capacity requirements, for the AML&P and CEA systems was obtained directly from the two utilities. More detailed information on GVEA generation expansion plans was available in the review copy of the report Power Supply Study - 1978 (Ref. 3) and the Report on FMUS/GVEA Net Study (Ref. 4).

B. Installed Reserve Capacity

At the present time, there is apparently no uniform policy as to the required installed generation reserve margins for Alaskan electric power utilities. By definition, the installed generation reserve capacity includes spinning reserve, "hot" and "cold" standby reserves, and generating units on maintenance and overhaul work. No effort is made in this study to separate the installed reserve capacity into spinning and other types of reserves. Utilities in Alaska currently keep spinning reserves to the very minimum, mainly because of the no-load fuel cost incurred by the spinning reserves, and because most generating units in Alaska's Railbelt area are quick starting, combustion turbine-type units. This situation may change in the future when new larger, slow starting, thermal power plants are constructed, exceptions being hydro plant units which can be started rather rapidly.

To develop alternative generation expansion plans for this study, guidelines for installed reserve generation capacity had to be established. A minimum of 20% reserve margin or the largest single unit at the time of peak system load was decided on as the installed generation reserve guideline. In general, the 20% value is close to the actual installed reserve margin of most U.S.A. utilities. Recently, the Department of Energy's Economic Regulatory Administration reported the following for the 1978 winter peak load of the lower 48 states:

> "According to the forecast, total available power resources for the lower 48 states will total nearly 500,000 MW. Peak demand is anticipated at 380,000 MW, for a reserve of nearly 120,000 MW or 31.5 percent. The lowest reserve - the 21.1 percent - will occur for the southeastern Electric Reliability Council, the DOE said, with the Mid-Atlantic Council experiencing the highest reserve margin at 45.1 percent" (Ref. 5).

C. Unit Retirement

Except for the Knik Arm Power Plant (CEA), no other generating units were reported for retirement by the Railbelt utilities during the 1980-1992 period. Later, to include the effect of the proposed Susitna Hydroelectric Project and to obtain a better economic analysis, this study period was extended through 1997. An assumption was made that the generating units available from 1980-1992 will also be available from 1993 through 1997. Many of them, however, will serve as system standby reserve units.

D. Generation Expansion Planning

To program the economic feasibility study and to establish transmission line interconnection benefits, generation expansion plans for the 1980-1997 period were developed for:

- Independent Anchorage area system.
- Independent Fairbanks area system.
- Interconnected Anchorage-Fairbanks system (intertie for reserve sharing only).
- Interconnected Anchorage-Fairbanks system (intertie for reserve sharing and power transfer).
- Interconnected Anchorage-Fairbanks system (with Susitna Hydroelectric Project).

Basically, generation planning includes three aspects: forecasting future loads (previously described in Chapter 3); developing generation reserve and reliability criteria (discussed later in this chapter); and determining when, how much, and what type of generation capacity is needed (which is discussed below).

Generation timing and capacity were determined by the most probable load forecasts for the Anchorage, Fairbanks, and combined Anchorage-Fairbanks areas, as described in Chapter 3.

Unit sizes for the alternative system expansion plans were determined by the ability of the power system to withstand the loss of a generating unit (or units) and still maintain reasonable system generation reliability. In determining unit sizes, due consideration was given to the valuable generation expansion planning data for the 1979-1986 period which was obtained by IECO-RWRA engineers from the Railbelt area utilities, and as the power system grows the economy of larger unit sizes.

IECO-RWRA engineers determined the type of generation mix for the expansion plans based on:

- Preliminary planning information obtained through interviews with Railbelt utilities.
- Information available in the Battelle Report and Alaska Power Administration's January 1979 report draft (Ref. 6).
- The judgment of IECO-RWRA power system planners.

Most of the planned generation additions are baseload-type thermal steam power plants burning coal, gas, or oil as fuel. They are mixed with a few additional peaking-type combustion turbine generating units using natural gas or oil as fuel. It is assumed that in the later years of this study many existing combustion turbine generating units, presently used as baseload or intermediate units, will become peaking or standby units.

6.2 MULTI-AREA RELIABILITY STUDY

A. Purpose

The PTI Multi-Area Reliability (MAREL) Computer Program is used for alternative generation expansion planning, mainly for its ability to maintain a nearly constant level of generation supply reliability in all cases. This approach provides a nearly equal reliability level as far as generation ability to meet the load is concerned. The MAREL program gives reliability equivalence to both individual area and interconnected system generation planning alternatives. The MAREL program manual (Ref. 7) introduces this program with the following:

> "The PTI Multi-Area Reliability Program MAREL determines the reliability of multi-area power systems. It has been written in FORTRAN IV for use on a PRIME 400 time-sharing computer. Reliability indices computed by the program include system loss of load probability (LOLP), LOLP values for the individual areas, probability of various failure conditions and probability that each transmission (intertie) link is limiting in the transfer of generation reserves from one area to another."

MAREL program results helped determine the effectiveness of a transmission line intertie between the Anchorage and Fairbanks areas, and established the amount of generating capacity needed to give the individual areas approximately the same LOLP as for the interconnected system. MAREL study results are also applicable to the alternative which includes the Upper Susitna Project. In this instance the study became a three area reliability study with the Susitna area having only net generation and no load.

B. Reliability Index

To perform individual and interconnected system reliability studies (MAREL), it was necessary to select a reference system generation reliability index. As described above, the MAREL program uses LOLP calculation techniques for each study case. For each load condition the program user adjusts input data, specifically generator unit sizes, generator types, location of generating plants, and intertie capacities, to obtain generation expansion plans of near equal reliability for various alternatives. The LOLP method is very much the adapted method used by U.S.A. utilities during the last 30 years. According to the IEEE/PES Working Group on

Performance Records for Optimizing System Design, Power System Engineering Committee (Ref. 8):

> "This (LOLP reliability) index is defined as the long run average number of days in a period of time that load exceeds the available installed capacity. The index may be expressed in any time units for the period under consideration and, in general, can be considered as the expected number of days that the system experiences a generating capacity deficiency in the period. This index is commonly, but mistakenly, termed the "loss of load probability, (LOLP)". A year is generally used as the period of consideration. In this case, the LOLP index is the long-run number of days/year that the hourly integrated daily peak load exceeds the available installed capacity."

There is no standard value of LOLP which is used throughout the electric power industry. However, one day in ten years is a very much accepted value by the lower 48 utilities. Since to the authors' knowledge, LOLP index has not previously been used in Alaska, it was decided to use one day in ten years as reference LOLP index in this study. The use of this LOLP index may imply larger generation reserve margins than are presently used in Alaska, but an equal or even lower LOLP index is justifiable for Alaska for at least the following reasons:

- In very cold climatic zones the loss of electric power may be more critical than in more temperate climates.

- There is very little information on existing generation and transmission outage rates in Alaska. Therefore, there is more uncertainty about the study input data.

- At present, most of the power systems in Alaska are independently operated. In case of emergency, utilities cannot rely on help from neighboring utilities or power pools as can most of utilities in the lower 48. Therefore, a lower LOLP reliability index is justifiable.

- Higher planned generation reserves may be needed to provide protection against possible unplanned delays in construction of new larger thermal units.

C. Program Methodology

A general description of the MAREL computer program methodology is contained in Appendix C. The particular program application to this study is "Planning of interconnections to achieve regional integration and more widespread sharing of generation reserves" (Ref. 7). Briefly, the program models each area as a one-bus system to which all generators and loads are connected. Transmission interties between areas are modeled as having limited power transfer capabilities and specified line outage rates. The method assumes that each area takes care of its own internal transmission needs.

D. Load Model

Annual load models were developed for the Anchorage and Fairbanks areas. Daily peak load data for 1975 were obtained from AML&P, CEA, FMUS, and GVEA. The Railbelt utility representatives agreed that 1975 was a typical year with normal weather conditions. The 1975 load models were converted into per unit system for the MAREL program. The computer program multiplied this 1975 load model (input) by the respective study year peak loads to obtain annual load models for each year of the study. Forecasted annual peak loads and the per unit annual load models for the Anchorage and Fairbanks areas are shown in Tables 6-3 through 6-6. Annual demand curves indicating biweekly non-coincident peaks are shown on Figure 6-1. Figure 6-1 also indicates that there is very little diversity between the loads of the Anchorage and Fairbanks areas.

E. Generating Unit Data

Information on existing generating unit data, as indicated in Tables 6-1 and 6-2, was used in the study. Unit base ratings were rounded off to the nearest megawatt in the study. Sizes for new generating units used in the expansion plans are indicated on Figures 6-2 through 6-8.

Generating unit outage rates, which are required for calculating LOLP indexes, were obtained from the most recent Edison Electric Institute (EEI) report on equipment availability (Ref. 9). The rates for combustion turbines were obtained from the actual operating experience of CEA and GVEA at the Beluga and Zehnder Power Plants. The EEI publication defines the forced outage rate as:

$$\text{Forced Outage Rate} = FOH/(SH + FOH) \times 100$$

Where FOH represents forced outage hours and SH represents service hours. Generating unit outage rates used in the MAREL study are indicated below:

Unit Designation	Forced Outage Rate (%)
Combustion Turbine*	5.5
Hydroelectric Plant	1.6
Thermal Steam Plant (small units)	5.9
Thermal Steam Plant (100-200 MW)	5.7
Thermal Steam Plant (300 MW)	7.9

* The Forced Outage Rate for combustion turbines was based on the following information:

- CEA experience at Beluga during 1977-1978 period, six units base loaded.

Unit availability	87% of the time
Scheduled maintenance	8% of the time
Forced outage	5% of the time

Therefore, the calculated Forced Outage Rate equals 5.4%.

- In 1975 GVEA experience at Zehnder Station, Units No. 1 and 2 provides calculated Forced Outage Rates of 4.2% and 4%, respectively; however, these units were basically standby units.

F. Generating Unit Maintenance

The MAREL program automatically schedules generating unit maintenance within the specified restrictions. For the purpose of this study, it was assumed that no unit maintenance will be scheduled during the November-March winter season.

G. Intertie Data

The MAREL program models the transmission intertie by limiting intertie transfer capabilities and considering intertie outage rates. No load loss sharing method was used. This means that one area will share its generating reserves only up to the limit of intertie transfer capability or available reserves in the other area, whichever is limiting. The forced outage rates (on a per year basis) used in the study for transmission and line terminal equipment are indicated below:

Line Voltage (kV)	Forced Outage Rate (per unit/100 miles)
230	0.00113
345	0.00225

Note: The following outage rate was used for both 230-kV and 345-kV line terminals: 36 hours/10 years.

6.3 SYSTEM EXPANSION PLANS

A. Planning Study Period

Based on generation planning criteria and the results of the MAREL reliability study (previously described in this chapter), alternative generation expansion plans were developed. The 1984-1997 period was selected for the alternative expansion plans for the following reasons:

- 1984 is the earliest year when the interconnected system can be operational.
- The 1992-1997 period includes the Upper Susitna Hydroelectric Project, based on the optimistic assumption that Watana Unit No. 1 will be on-line in January 1992.
- The study period is long enough for the present worth economic analysis method, and includes most of the costs and benefits obtainable by the introduction of an intertie in 1984.

To close the gap between the existing generation systems and the first study year (1984) of the intertie economic feasibility study, generation expansion plans for the independent Anchorage and Fairbanks areas for 1980 through 1983 were developed. Information on planned generation additions supplied by the generating utilities in the Railbelt area was used for this purpose.

B. Independent System Expansion Plans

Generation expansion plans for the independent Anchorage and Fairbanks systems were also needed to calculate economic benefits of the interconnection. The planned generation additions consist of thermal base load and peaking units. They do not include the Upper Susitna Project (Watana and Devil Canyon Hydro Plants), which are only included in the interconnected system expansion plans. The independent Anchorage and Fairbanks generation expansion plans are indicated on Figure 6-2 for the probable load forecast case and Figure 6-6 for the low load forecast case.

C. Interconnected System Expansion Plans

Two cases of system interconnection were studied - Case I, direct interconnection between Anchorage and Fairbanks (Ester), and Case II, interconnection between Watana-Devil Canyon with Anchorage and Fairbanks systems. Under Case I the alternatives were developed as follows:

- Case IA includes a single-circuit 230-kV transmission line having 130-MW power transfer capability allocated for reserve sharing only. This plan is shown on Figures 6-3 and 6-9 for the probable load forecast case and on Figures 6-7 and 6-9 for the low load forecast case.

- Case IB includes one single-circuit 230-kV transmission line (1984-1991) and two single-circuit 230-kV transmission lines (1992-1997) having the following generation reserve sharing capabilities: 100 MW (1984-1987), 130 MW (1989-1991) and 190 MW (1992-1997). In addition, this alternative has a firm power transfer capability of 30 MW (1984-1987), supplying 14% of peak load in Fairbanks area in 1984, and 70 MW (1992-1997) supplying 18% of peak load in Fairbanks area in 1992. This plan is shown on Figures 6-4 and 6-9 for the probable load forecast case and on Figures 6-8 and 6-9 for the low load forecast case.

- Case IC includes one single-circuit 345-kV transmission line having a total of 380 MW power transfer capability allocated for generation reserve sharing and for firm power transfer. The case is similar to Case IB (230 kV) except that only one 345 kV line is required during the 1992-1997 period. This plan is shown on Figures 6-4 (similar) and 6-10.

- Case ID is the same as Case IA, except with intermediate switching stations at Palmer and Healy. This plan is shown on Figures 6-3 and 6-11 for the probable load forecast case and on Figures 6-7 and 6-11 for the low load forecast case.

Under Case II, only one solution was studied: two single-circuit 230-kV transmission lines from Watana to Devil Canyon; two single-circuit 230-kV lines from Devil Canyon to Ester (Fairbanks); and two single-circuit 345-kV lines from Devil Canyon to Anchorage.

D. Reliability Indexes

The results of the MAREL study show loss of load probability (LOLP) indexes for independent system expansion plans and plans for an interconnected system (with and without the Upper Susitna Project), and are indicated in Tables 6-7 through 6-12. As previously discussed in Subsection 6.2B, the LOLP index of one day in ten years (0.1 day/year) was used as a reference standard throughout the study for comparing different alternatives. During the performance of the MAREL study the LOLP index was kept as close to the standard as reasonably possible.

6.4 REFERENCES

1. Battelle Pacific Northwest Laboratories, Alaskan Electric Power, An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region, Vol. I, March 1978.

2. University of Alaska, Institute for Social and Economic Research, Electric Power in Alaska, 1976 - 1995, August 1976.

3. Stanley Consultants, Power Supply Study - 1978 for Golden Valley Electric Association, Inc.

4. Alaska Resource Sciences Corporation, Report FMUS/GVEA Net Study, Vol. 1, May 1978.

5. Electric Light and Power, Capacity Can Meet Winter Peaks - DOE, November 1978.

6. Alaska Power Administration, Upper Susitna River Project, POWER MARKET ANALYSES, Draft, January 1979.

7. Power Technologies, Inc. PTI Multi-Area Reliability Program (MAREL), Computer Program Manual, September 1978.

8. "Reliability Indices for Use in Bulk Power Supply Adequacy Evaluation", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-97, No. 4, July/August 1978.

9. Edison Electric Institute, Report on Equipment Availability for the Ten-Year Period 1967-1976, December 1977.

TABLE 6-1

EXISTING GENERATION SOURCES

ANCHORAGE - COOK INLET AREA

Name/Location	Unit Reference	Year of Installation	Type	Unit Rating Base (kW)	Unit Rating Peak (kW)	Dependable Capacity (kW)	Remarks
ANCHORAGE MUNICIPAL LIGHT AND POWER (AML&P)							
Anchorage			Diesel	2,200			Black start unit
Anchorage	Unit 1		SCGT	15,130	18,000		
Anchorage	Unit 2		SCGT	15,130	18,000		
Anchorage	Unit 3	1968	SCGT	18,650	21,000		
Anchorage	Unit 4	1972	SCGT	31,700	35,000		
Anchorage	Unit 5	1975	SCGT	36,800	40,000		Combined cycle installation
Anchorage	Unit 6	1979	HRST	12,000			
CHUGACH ELECTRIC ASSOCIATION (CEA)							
Beluga	Unit 1		SCGT	15,150	18,700		
Beluga	Unit 2		SCGT	15,150	18,700		
Beluga	Unit 3		RCGT	53,500	67,000		
Beluga	Unit 4		SCGT	9,300	10,000		
Beluga	Unit 5		RCGT	53,500	67,000		
Beluga	Unit 6		SCGT	67,810	72,900		
Beluga	Unit 7	1978	SCGT	67,810	72,900		
Bernice Lake	Unit 1		SCGT	8,200	16,500		
Bernice Lake	Unit 2		SCGT	19,600	20,500		
Bernice Lake	Unit 3	1978	SCGT	24,000			
International	Unit 1		SCGT	14,530	16,500		
International	Unit 2		SCGT	14,530	16,500		
International	Unit 3		SCGT	18,600	21,500		
Cooper Lake	Unit 1		Hydro	7,500	9,600		
Cooper Lake	Unit 2		Hydro	7,500	9,600	16,500	
Knik Arm	Several (1,2,3,4 & 5)		ST	14,500	17,700		To be retired in 1985
MATANUSKA ELECTRIC ASSOCIATION (MEA)							
Talkeetna			Diesel	600			Standby
HOMER ELECTRIC ASSOCIATION (HEA)							
English Bay			Diesel	100			
Homer-Kenai			Diesel	300			Leased to CEA
Homer (2 x 3500)			SCGT	7,000			Leased from GVEA (1977-1979)
Port Graham			Diesel	200			
Seldovia			Diesel	1,648		1,500	
SEWARD ELECTRIC SYSTEM (SES)							
Seward	Unit 1		Diesel	1,500		5,500	Standby
	Unit 2		Diesel	1,500	1,500		
	Unit 3		Diesel	2,500	3,000		
ALASKA POWER ADMINISTRATION (APA)							
Eklutna	Unit 1 & 2		Hydro	30,000	35,000	30,000	Two 15,000 kW units

TABLE 6-2

EXISTING GENERATION SOURCES
FAIRBANKS - TANANA VALLEY AREA

Name/Location	Unit Reference	Year of Installation	Type	Unit Rating Base (kW)	Unit Rating Peak (kW)	Dependable Capacity (kW)	Remarks
FAIRBANKS MUNICIPAL UTILITIES SYSTEM (FMUS)							
Fairbanks	Chena 1	1954	ST	5,000			
Fairbanks	Chena 2	1952	ST	2,000			
Fairbanks	Chena 3	1952	ST	1,500			
Fairbanks	Chena 4	1963	ST	20,000			
Fairbanks	Chena 5	1970	SCGT	5,350	7,000		
Fairbanks	Chena 6	1976	SCGT	23,500			
Fairbanks	Diesel 1	1967	Diesel	2,665			
Fairbanks	Diesel 2	1968	Diesel	2,665			
Fairbanks	Diesel 3	1968	Diesel	2,665			
GOLDEN VALLEY ELECTRIC ASSOCIATION (GVEA)							
Zehnder Sub.	Unit 1	1971	SCGT	17,553	20,000	17,400	Peaking Service
Zehnder Sub.	Unit 2	1972	SCGT	17,553	20,000	17,400	
Zehnder Sub.	Unit 3	1975	SCGT			3,500	Leased to HEA
Zehnder Sub.	Unit 4	1975	SCGT			3,500	(1977-1979)
Zehnder Sub.	Units 1-7	1970	Diesel			12,900	
Healy	Unit-1	1967	ST			26,200	
Healy			Diesel	2,500			
Northpole	Unit 1	1976	SCGT	64,800	70,000		
Northpole	Unit 2	1977	SCGT	64,800	70,000		
U. of Alaska	Units 7&8		Diesel			5,100	
Delta			Diesel			500	Mobile Unit

TABLE 6-3

LOAD MODEL DATA
ANCHORAGE AREA
PROBABLE LOAD FORECAST CASE

ANNUAL PEAK LOAD IN MW
(1983 - 1997)

789. 877. 977. 1080. 1196. 1313. 1441. 1581. 1724. 1881.
2041. 2215. 2402. 2591. 2794.

INTERVAL PEAK LOADS IN P.U. OF ANNUAL PEAK LOAD
(26 INTERVALS / YEAR)

.8333 .6667 .7404 .7500 .6571 .6346 .6122 .5865 .5481 .5353 .5224 .5160 .5064
.4904 .5032 .4968 .5160 .5737 .5769 .6154 .6827 .8429 .8526 .91351.0000 .8301

DAILY PEAK LOADS IN P.U. OF INTERVAL PEAK LOAD
(260 WEEK DAYS / YEAR)

1.0000	.9769	.9731	.9538	.9500	.9462	.8962	.8731	.8577	.8423
1.0000	.9808	.9663	.9663	.9615	.9615	.9519	.9519	.9423	.9375
1.0000	.9913	.9784	.9827	.9697	.9654	.9437	.9307	.9221	.8918
1.0000	.9829	.9487	.9359	.9017	.8889	.8889	.8846	.8333	.8034
1.0000	.9512	.9317	.9171	.9171	.9073	.9073	.9024	.9024	.8976
1.0000	.9848	.9798	.9747	.9646	.9495	.9444	.9343	.9293	.9141
1.0000	.9686	.9634	.9529	.9529	.9476	.9424	.9372	.9058	.9058
1.0000	.9781	.9727	.9617	.9563	.9563	.9344	.9344	.9071	.9071
1.0000	.9883	.9883	.9825	.9825	.9708	.9708	.9649	.9591	.9415
1.0000	.9940	.9820	.9701	.9581	.9461	.9401	.9341	.9281	.9162
1.0000	.9939	.9877	.9571	.9571	.9509	.9509	.9448	.9202	.8589
1.0000	.9938	.9814	.9689	.9565	.9379	.9379	.9379	.9255	.9255
1.0000	.9810	.9684	.9620	.9494	.9494	.9430	.9367	.9304	.9177
1.0000	.9804	.9739	.9739	.9673	.9608	.9542	.9542	.9477	.8824
1.0000	.9873	.9745	.9554	.9490	.9490	.9427	.9427	.9299	.9299
1.0000	1.0000	.9935	.9871	.9806	.9742	.9677	.9613	.9548	.9484
1.0000	.9938	.9814	.9689	.9627	.9565	.9565	.9441	.9441	.9379
1.0000	.9777	.9609	.9441	.9274	.9106	.8883	.8715	.8715	.8045
1.0000	.9944	.9944	.9722	.9722	.9722	.9611	.9278	.9222	.9222
1.0000	.9948	.9896	.9896	.9687	.9583	.9531	.9375	.9323	.8802
1.0000	.9859	.9484	.9437	.9390	.9296	.9249	.9202	.9155	.9014
1.0000	.9962	.9658	.9468	.9468	.9087	.7985	.7757	.7719	.8555
1.0000	1.0000	.9887	.9662	.9549	.9511	.9474	.9398	.9361	.9323
1.0000	.9754	.8632	.8596	.8421	.8386	.8386	.8386	.8386	.8175
1.0000	.9840	.9679	.9519	.9359	.9327	.9327	.9135	.8654	.8045
1.0000	.9730	.9730	.9614	.9614	.9575	.9575	.9537	.9421	.8340

TABLE 6-4

LOAD MODEL DATA

FAIRBANKS AREA

PROBABLE LOAD FORECAST CASE

ANNUAL PEAK LOAD IN MW
(1983 - 1997)

```
196.  212.  231.  249.  270.  291.  313.  338.  362.  390.
416.  446.  477.  511.  547.
```

INTERVAL PEAK LOADS IN P.U. OF ANNUAL PEAK LOAD
(26 INTERVALS / YEAR)

```
0.87590.69900.73710.76040.57490.59710.56630.51110.43240.41150.38330.37470.3587
0.35380.38080.41770.42010.43730.46190.53190.57490.89190.93370.93491.00000.7690
```

DAILY PEAK LOADS IN P.U. OF INTERVAL PEAK LOAD
(260 WEEK DAYS / YEAR)

```
1.00000.97480.94670.94670.94530.93130.89480.86540.84290.8177
1.00000.93670.92790.92790.90510.89980.88050.85940.82790.7891
1.00000.99330.96670.94830.94000.92330.90330.88000.86670.8267
1.00000.97580.96120.94510.86910.83200.82390.81100.79000.6769
1.00000.98500.98290.95940.95300.94660.91880.90810.90170.8825
1.00000.99790.99590.98770.97940.95880.93620.90530.89300.8827
1.00000.98480.95010.93710.91970.89370.88070.87200.86120.8091
1.00000.96870.96150.95190.93510.91590.88700.88220.87980.8558
1.00000.99150.99150.99150.97160.96870.93180.89200.88920.8693
1.00001.00000.96120.93130.92840.92840.92240.90750.90450.8955
1.00000.99040.99040.94550.92310.91990.91670.91350.87820.8558
1.00000.96720.95410.92790.92460.90490.89840.89510.87870.8721
1.00000.96920.96920.95890.95890.94520.94520.93150.92120.9041
1.00000.98960.97220.96870.95830.94790.93400.92360.92010.8507
1.00000.96770.93870.93230.91290.90320.90320.90320.87100.8677
1.00000.87350.87060.86760.86460.85880.84710.84410.83820.8059
1.00000.94440.90640.90640.89470.82750.82750.82460.81870.8012
1.00000.99720.97750.96350.96350.94940.93820.93820.91010.8904
1.00000.99470.96810.93090.92820.90960.90690.90160.88830.8856
1.00000.98850.93300.91450.90990.89610.88910.88450.86370.8568
1.00000.99150.98080.97650.94020.92950.92740.91880.91450.9017
1.00000.96690.91180.89260.88840.79890.73970.64460.61020.6088
1.00000.97710.91050.90790.90790.89340.88950.88550.86320.8434
1.00000.97110.86330.83050.81870.79630.79240.74510.73320.7201
1.00000.99510.98160.97300.97170.95580.91650.88450.82430.6818
1.00000.99840.93930.92010.89940.88980.88500.84820.81310.7971
```

TABLE 6-5

LOAD MODEL DATA

ANCHORAGE AREA

LOW LOAD FORECAST CASE

ANNUAL PEAK LOAD IN MW
(1983 - 1997)

765. 832. 908. 985. 1068. 1156. 1250. 1350. 1451. 1562.
1677. 1800. 1933. 2070. 2215.

INTERVAL PEAK LOADS IN P.U. OF ANNUAL PEAK LOAD
(26 INTERVALS / YEAR)

.8333	.6667	.7404	.7500	.6571	.6346	.6122	.5865	.5481	.5353	.5224	.5160	.5064
.4904	.5032	.4968	.5160	.5737	.5769	.6154	.6827	.8429	.8526	.9135	1.0000	.8301

DAILY PEAK LOADS IN P.U. OF INTERVAL PEAK LOAD
(260 WEEK DAYS / YEAR)

1.0000	.9769	.9731	.9538	.9500	.9462	.8962	.8731	.8577	.8423
1.0000	.9808	.9663	.9663	.9615	.9615	.9519	.9519	.9423	.9375
1.0000	.9913	.9784	.9827	.9697	.9654	.9437	.9307	.9221	.8918
1.0000	.9829	.9487	.9359	.9017	.8889	.8889	.8846	.8333	.8034
1.0000	.9512	.9317	.9171	.9171	.9073	.9073	.9024	.9024	.8976
1.0000	.9848	.9798	.9747	.9646	.9495	.9444	.9343	.9293	.9141
1.0000	.9686	.9634	.9529	.9529	.9476	.9424	.9372	.9058	.9058
1.0000	.9781	.9727	.9617	.9563	.9563	.9344	.9344	.9071	.9071
1.0000	.9883	.9883	.9825	.9825	.9708	.9708	.9649	.9591	.9415
1.0000	.9940	.9820	.9701	.9581	.9461	.9401	.9341	.9281	.9162
1.0000	.9939	.9877	.9571	.9571	.9509	.9509	.9448	.9202	.8589
1.0000	.9938	.9814	.9689	.9565	.9379	.9379	.9379	.9255	.9255
1.0000	.9810	.9684	.9620	.9494	.9494	.9430	.9367	.9304	.9177
1.0000	.9804	.9739	.9739	.9673	.9608	.9542	.9542	.9477	.8824
1.0000	.9873	.9745	.9554	.9490	.9490	.9427	.9427	.9299	.9299
1.0000	1.0000	.9935	.9871	.9806	.9742	.9677	.9613	.9548	.9484
1.0000	.9938	.9814	.9689	.9627	.9565	.9565	.9441	.9441	.9379
1.0000	.9777	.9609	.9441	.9274	.9106	.8883	.8715	.8715	.8045
1.0000	.9944	.9944	.9722	.9722	.9722	.9611	.9278	.9222	.9222
1.0000	.9948	.9896	.9896	.9687	.9583	.9531	.9375	.9323	.8802
1.0000	.9859	.9484	.9437	.9390	.9296	.9249	.9202	.9155	.9014
1.0000	.9962	.9658	.9468	.9468	.9087	.7985	.7757	.7719	.8555
1.0000	1.0000	.9887	.9662	.9549	.9511	.9474	.9398	.9361	.9323
1.0000	.9754	.8632	.8596	.8421	.8386	.8386	.8386	.8386	.8175
1.0000	.9840	.9679	.9519	.9359	.9327	.9327	.9135	.8654	.8045
1.0000	.9730	.9730	.9614	.9614	.9575	.9575	.9537	.9421	.8340

TABLE 6-6

LOAD MODEL DATA

FAIRBANKS AREA

LOW LOAD FORECAST CASE

ANNUAL PEAK LOAD IN MW
(1983 - 1997)

188. 2Ø2. 218. 232. 248. 264. 281. 3ØØ. 317. 337.
355. 377. 398. 42Ø. 444.

INTERVAL PEAK LOADS IN P.U. OF ANNUAL PEAK LOAD
(26 INTERVALS / YEAR)

0.87590.69900.73710.76040.57490.59710.56630.51110.43240.41150.38330.37470.3587
0.35380.38080.41770.42010.43730.46190.53190.57490.89190.93370.93491.00000.7690

DAILY PEAK LOADS IN P.U. OF INTERVAL PEAK LOAD
(260 WEEK DAYS / YEAR)

1.00000.97480.94670.94670.94530.93130.89480.86540.84290.8177
1.00000.93670.92790.92790.90510.89980.88050.85940.82790.7891
1.00000.99330.96670.94830.94000.92330.90330.88000.86670.8267
1.00000.97580.96120.94510.86910.83200.82390.81100.79000.6769
1.00000.98500.98290.95940.95300.94660.91880.90810.90170.8825
1.00000.99790.99590.98770.97940.95880.93620.90530.89300.8827
1.00000.98480.95010.93710.91970.89370.88070.87200.86120.8091
1.00000.96870.96150.95190.93510.91590.88700.88220.87980.8558
1.00000.99150.99150.99150.97160.96870.93180.89200.88920.8693
1.00001.00000.96120.93130.92840.92840.92240.90750.90450.8955
1.00000.99040.99040.94550.92310.91990.91670.91350.87820.8558
1.00000.96720.95410.92790.92460.90490.89840.89510.87870.8721
1.00000.96920.96920.95890.95890.94520.94520.93150.92120.9041
1.00000.98960.97220.96870.95830.94790.93400.92360.92010.8507
1.00000.96770.93870.93230.91290.90320.90320.90320.87100.8677
1.00000.87350.87060.86760.86460.85880.84710.84410.83820.8059
1.00000.94440.90640.90640.89470.82750.82750.82460.81870.8012
1.00000.99720.97750.96350.96350.94940.93820.93820.91010.8904
1.00000.99470.96810.93090.92820.90960.90690.90160.88830.8856
1.00000.98850.93300.91450.90990.89610.88910.88450.86370.8568
1.00000.99150.98080.97650.94020.92950.92740.91880.91450.9017
1.00000.96690.91180.89260.88840.79890.73970.64460.61020.6088
1.00000.97710.91050.90790.90790.89340.88950.88550.86320.8434
1.00000.97110.86330.83050.81870.79630.79240.74510.73320.7201
1.00000.99510.98160.97300.97170.95580.91650.88450.82430.6818
1.00000.99840.93930.92010.89940.88980.88500.84820.81310.7971

TABLE 6-7

LOSS OF LOAD PROBABILITY INDEX (LOLP)1/

FOR

STUDY CASES IA & ID2/

PROBABLE LOAD FORECAST CASE

	Anchorage		Fairbanks	
Study Year	Independent Expansion3/	Interconnected Expansion4/	Independent Expansion3/	Interconnected Expansion4/
1984	0.0262	0.0063	0.8193	0.0066
1985	0.0123	0.0275	0.1446	0.0242
19865/	0.0199	0.0113	0.2868	0.0236
1987	0.0247	0.0208	0.6795	0.0546
1988	0.0408	0.0698	0.1140	0.0278
1989	0.0290	0.0613	0.2318	0.0376
1990	0.0242	0.0625	0.0593	0.0652
1991	0.0184	0.0595	0.1550	0.1276
1992	0.0168	0.0259	0.0276	0.0269
1993	0.0539	0.0297	0.0586	0.0598
1994	0.0393	0.0296	0.1583	0.1358
1995	0.0307	0.0622	0.0373	0.0426
1996	0.0901	0.0568	0.0899	0.1014
1997	0.0676	0.0367	0.0441	0.0419

1/ LOLP in days per year.

2/ 230 kV s/c, 130 MW reserve sharing only.

3/ See Figure 6-2.

4/ See Figure 6-3.

5/ Starting in 1986 includes Bradley Lake Hydro Project.

TABLE 6-8

LOSS OF LOAD PROBABILITY INDEX (LOLP)[1/]

FOR

CASE IB[2/]

PROBABLE LOAD FORECAST CASE

	Anchorage		Fairbanks	
Study Year	Independent Expansion[3/]	Interconnected Expansion[4/]	Independent Expansion[3/]	Interconnected Expansion[4/]
1984	0.0262	0.0077	0.8193	0.0018
1985	0.0123	0.0329	0.1446	0.0096
1986	0.0293	0.0220	0.2868	0.0152
1987	0.0288	0.0306	0.6766	0.0299
1988	0.0482	0.0799	0.1140	0.0300
1989	0.0330	0.0677	0.2318	0.0394
1990	0.0265	0.0680	0.0593	0.0670
1991	0.0193	0.0633	0.1550	0.0130
1992	0.0189	0.0644	0.0276	0.0227
1993	0.0546	0.0703	0.0586	0.0354
1994	0.0427	0.0550	0.1583	0.0654
1995	0.0326	0.0991	0.0373	0.0369
1996	0.0931	0.0838	0.0899	0.0506
1997	0.0676	0.0520	0.0441	0.0244

1/ LOLP in days per year.

2/ 230-kV transmission system with reserve sharing and firm power transfer capability.

3/ See Figure 6-2.

4/ See Figure 6-4.

TABLE 6-9

LOSS OF LOAD PROBABILITY INDEX (LOLP)[1/]

FOR

CASE IIA[2/]

PROBABLE LOAD FORECAST CASE

	Anchorage		Fairbanks	
Study Year	Independent Expansion[4/]	Interconnected Expansion[3/]	Independent Expansion[4/]	Interconnected Expansion[3/]
1992	0.0189	0.0476	0.0276	0.0972
1993	0.0546	0.0418	0.0586	0.0299
1994	0.0427	0.0235	0.1583	0.0244
1995	0.0326	0.0070	0.0373	0.0089
1996	0.0931	0.0226	0.0899	0.0207
1997	0.0676	0.1240	0.0441	0.0461

1/ LOLP in days per year.

2/ Includes interconnections between Devil Canyon-Anchorage (345 kV), Devil Canyon-Watana (230 kV), and Devil Canyon-Ester (230 kV).

3/ Interconnected expansion for three area system: Anchorage, Fairbanks, and Upper Susitna (generation only). See also Figure 6-5.

4/ See Figure 6-2.

TABLE 6-10

LOSS OF LOAD PROBABILITY INDEX (LOLP)1/

FOR

STUDY CASES IA & ID2/

LOW LOAD FORECAST CASE

Study Year	Anchorage: Independent Expansion3/	Anchorage: Interconnected Expansion4/	Fairbanks: Independent Expansion3/	Fairbanks: Interconnected Expansion4/
1984	0.0262	0.0063	0.8193	0.0066
1985	0.0123	0.0275	0.1446	0.0242
1986	0.0199	0.0113	0.2868	0.0236
1987 5/	0.0134	0.0527	0.2697	0.0501
1988	0.0095	0.0068	0.0329	0.0035
1989	0.0724	0.0701	0.0741	0.0222
1990	0.0309	0.0376	0.1511	0.0207
1991	0.0350	0.0533	0.0061	0.0387
1992	0.0182	0.0334	0.0591	0.0502
1993	0.0359	0.0351	0.1207	0.0173
1994	0.0190	0.0264	0.2499	0.0264
1995	0.0129	0.0211	0.0340	0.0463
1996	0.0075	0.0601	0.0711	0.0152
1997	0.0393	0.0393	0.0207	0.0225

1/ LOLP in days per year.

2/ 230 kV s/c, 130 MW reserve sharing only.

3/ See Figure 6-6.

4/ See Figure 6-7.

5/ From 1987, figures include Bradley Lake Hydro Project.

TABLE 6-11

LOSS OF LOAD PROBABILITY INDEX (LOLP)[1/]
FOR
CASE IB[2/]
LOW LOAD FORECAST CASE

Study Year	Anchorage Independent Expansion[3/]	Anchorage Interconnected Expansion[4/]	Fairbanks Independent Expansion[3/]	Fairbanks Interconnected Expansion[4/]
1984	0.0064	0.0012	0.4650	0.0006
1985	0.0105	0.0225	0.0807	0.0044
1986	0.0232	0.0745	0.1515	0.0176
1987	0.0217	0.0918	0.2697	0.0393
1988	0.0121	0.0090	0.0329	0.0037
1989	0.0869	0.0822	0.0740	0.0238
1990	0.0344	0.0428	0.1511	0.0219
1991	0.0393	0.0602	0.2557	0.0413
1992	0.0189	0.0366	0.0591	0.0515
1993	0.0366	0.0393	0.1207	0.0180
1994	0.0209	0.0288	0.2499	0.0271
1995	0.0133	0.0207	0.0340	0.0024
1996	0.0078	0.0126	0.0711	0.0195
1997	0.0427	0.0692	0.0207	0.0029

1/ LOLP in days per year.

2/ 230-kV transmission system with reserve sharing and firm power transfer capability.

3/ See Figure 6-6.

4/ See Figure 6-8.

TABLE 6-12

LOSS OF LOAD PROBABILITY INDEX (LOLP)[1/]

FOR

CASE IC[2/]

PROBABLE LOAD FORECAST CASE

Study Year	Anchorage		Fairbanks	
	Independent Expansion[3/]	Interconnected Expansion[4/]	Independent Expansion[3/]	Interconnected Expansion[4/]
1984	0.0262	0.0063	0.8193	0.0066
1985	0.0123	0.0275	0.1446	0.0242
1986[5/]	0.0199	0.0113	0.2868	0.0236
1987	0.0247	0.0208	0.6795	0.0546
1988	0.0408	0.0698	0.1140	0.0278
1989	0.0290	0.0613	0.2318	0.0376
1990	0.0242	0.0625	0.0593	0.0652
1991	0.0184	0.0595	0.1550	0.1276
1992	0.0168	0.0616	0.0276	0.0388
1993	0.0539	0.0666	0.0586	0.0620
1994	0.0393	0.0511	0.1583	0.1198
1995	0.0307	0.0971	0.0373	0.0486
1996	0.0901	0.0830	0.0899	0.0699
1997	0.0676	0.0516	0.0441	0.0354

1/ LOLP in days per year.

2/ 345-kV transmission system with reserve sharing and firm power transfer capability.

3/ See Figure 6-2.

4/ See Figure 6-4. The 345 kV (Case IC) is similar to 230 kV (Case IB) except that only one 345-kV line is required during the 1992-1997 period, instead of two 230-kV lines.

5/ Starting in 1986 includes Bradley Lake Hydro Project.

NON-COINCIDENT 1975 PEAK DEMANDS
ANCHORAGE AND FAIRBANKS AREAS

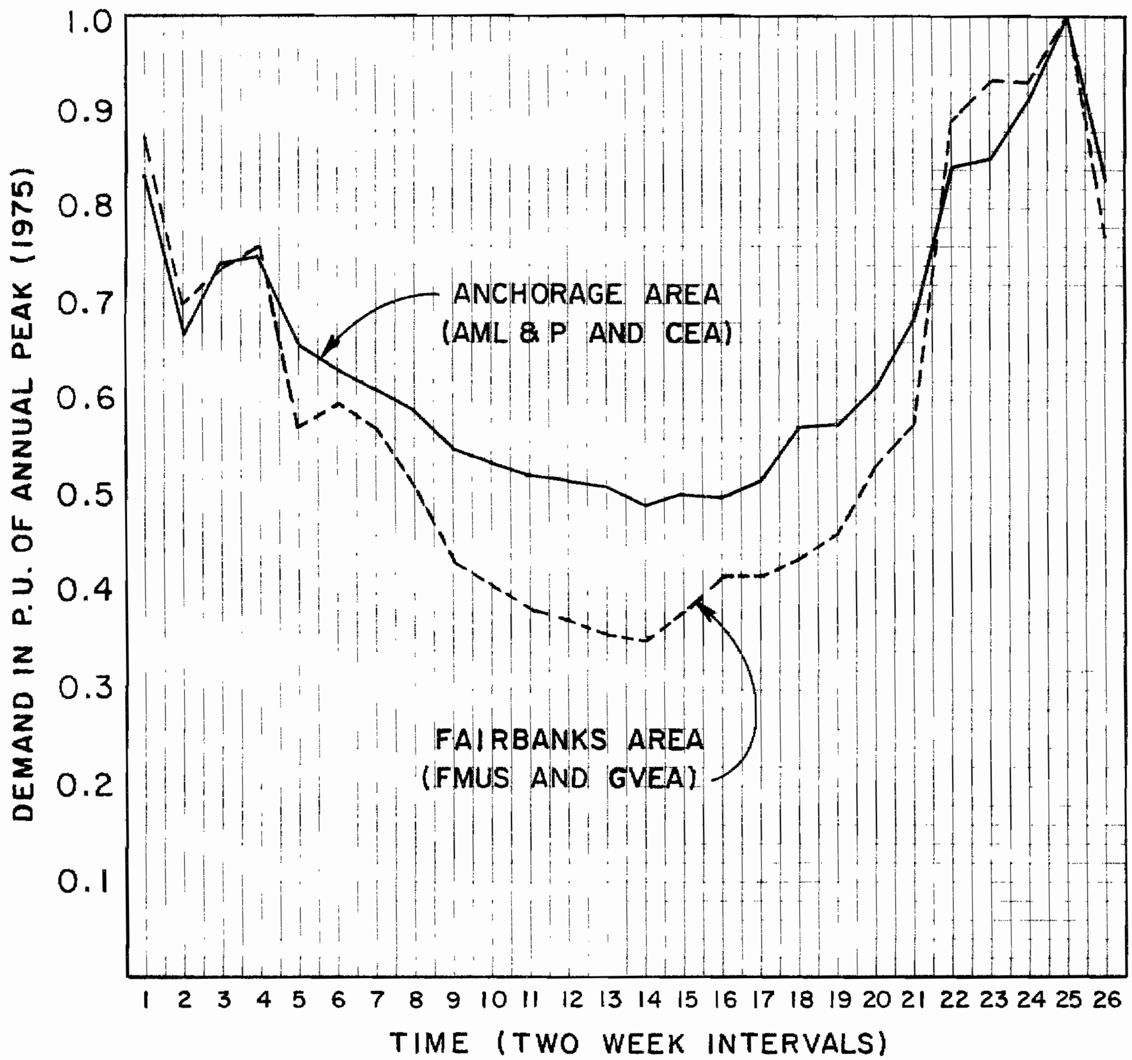
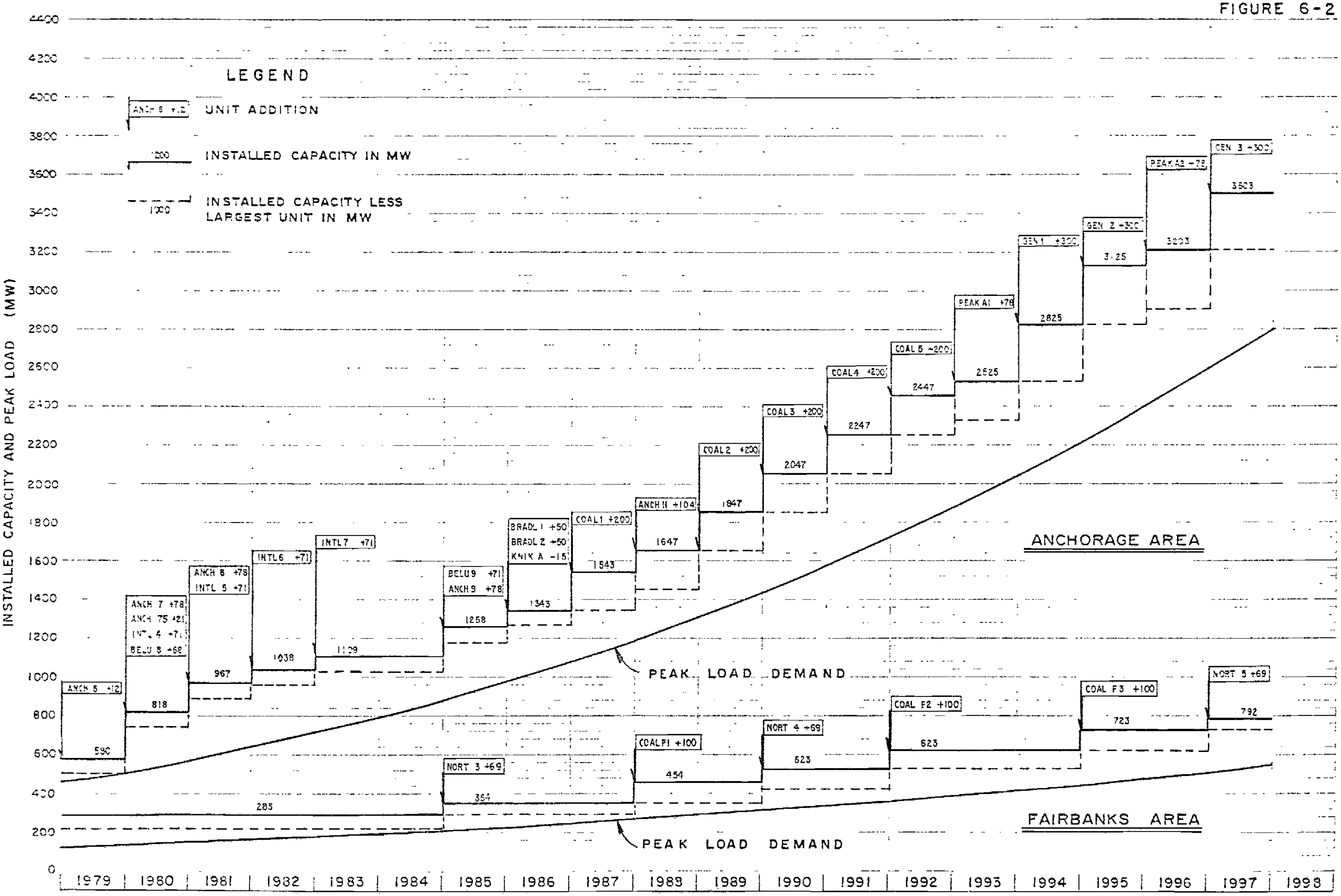


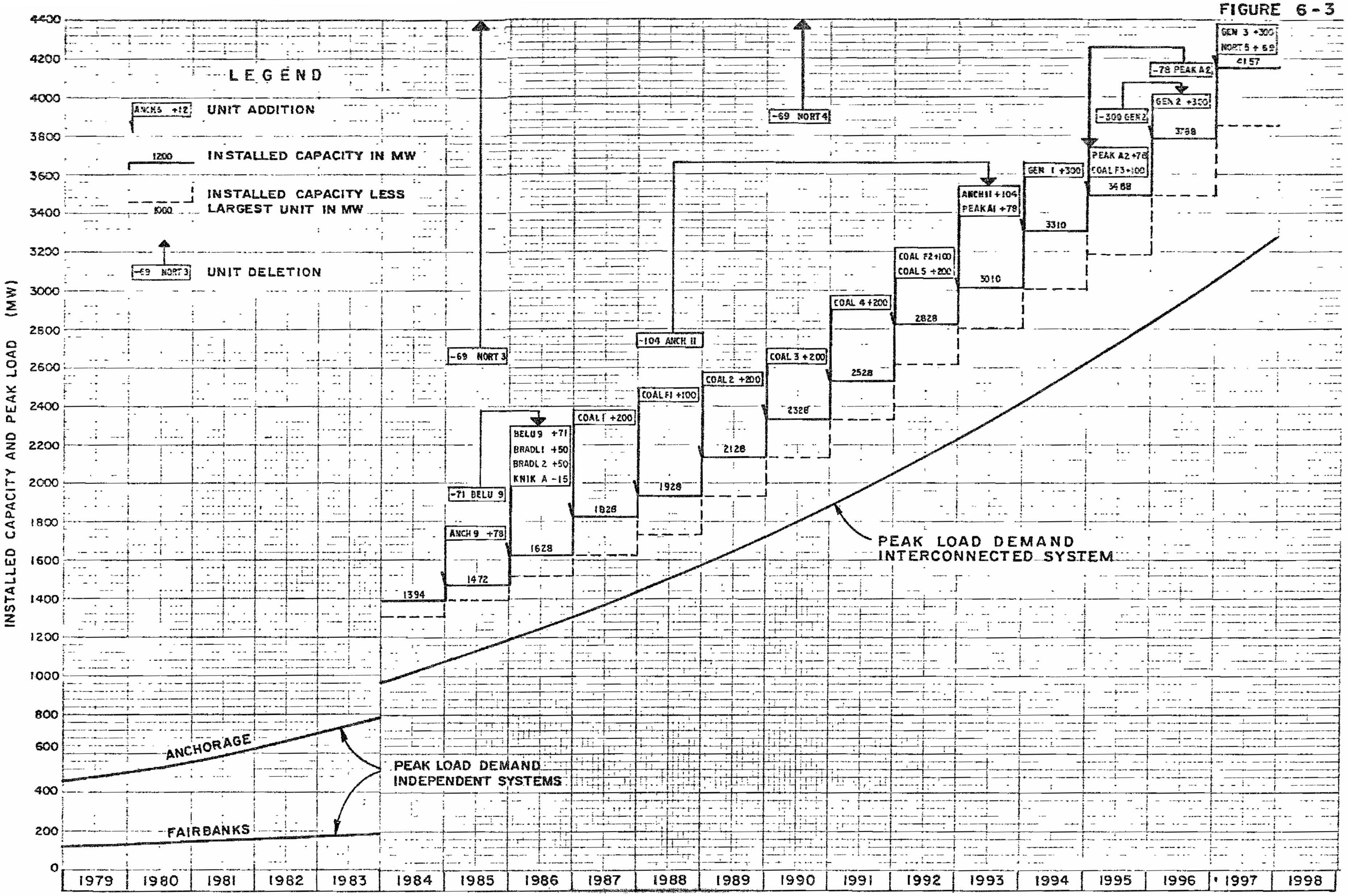
FIGURE 6-2



INDEPENDENT SYSTEM EXPANSION PLANS
ANCHORAGE AND FAIRBANKS AREAS
PROBABLE LOAD FORECAST CASE

FIGURE 6-2

FIGURE 6-3

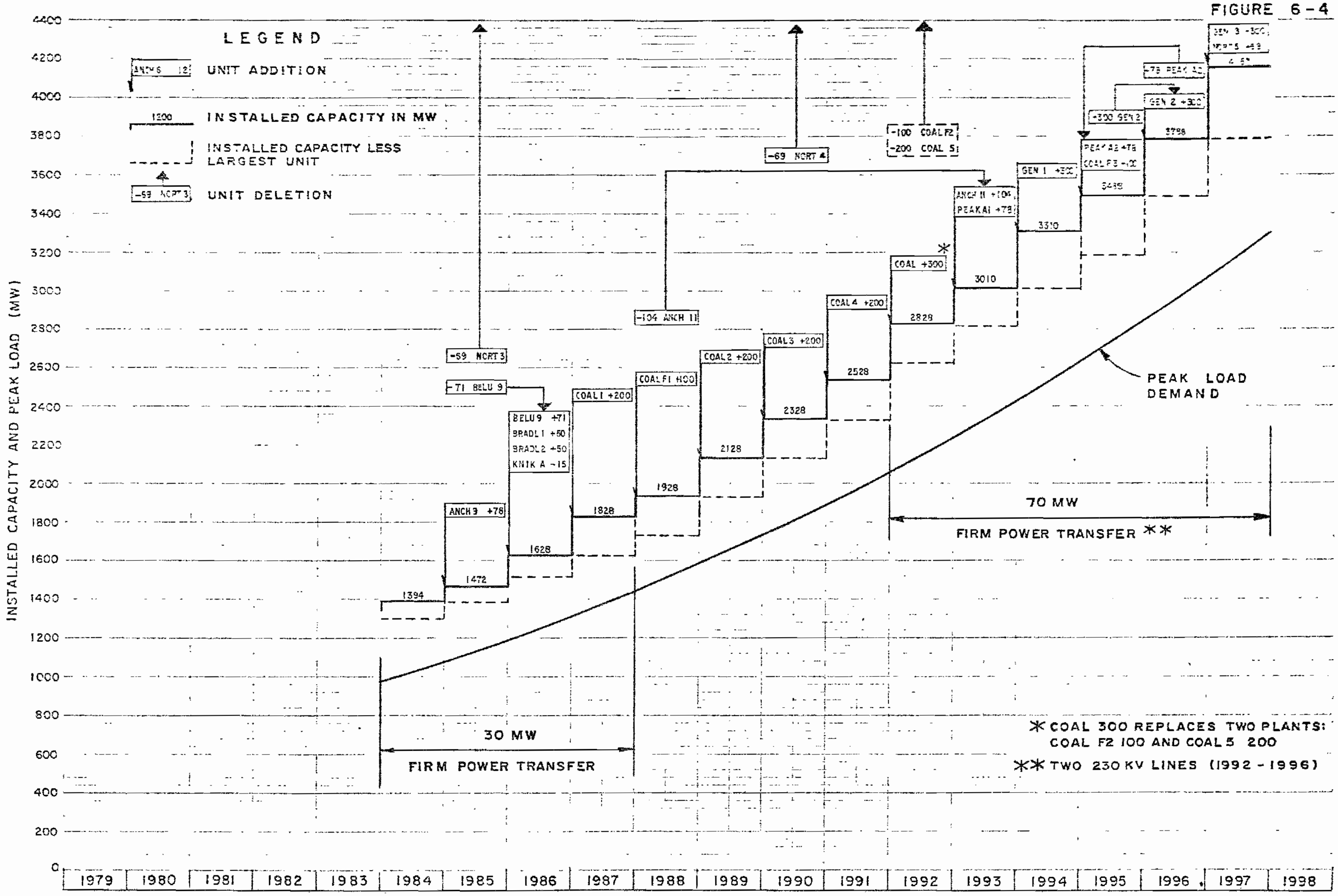


INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
WITHOUT SUSITNA PROJECT
PROBABLE LOAD FORECAST CASE

8/79

FIGURE 6-3
CASE IA & ID

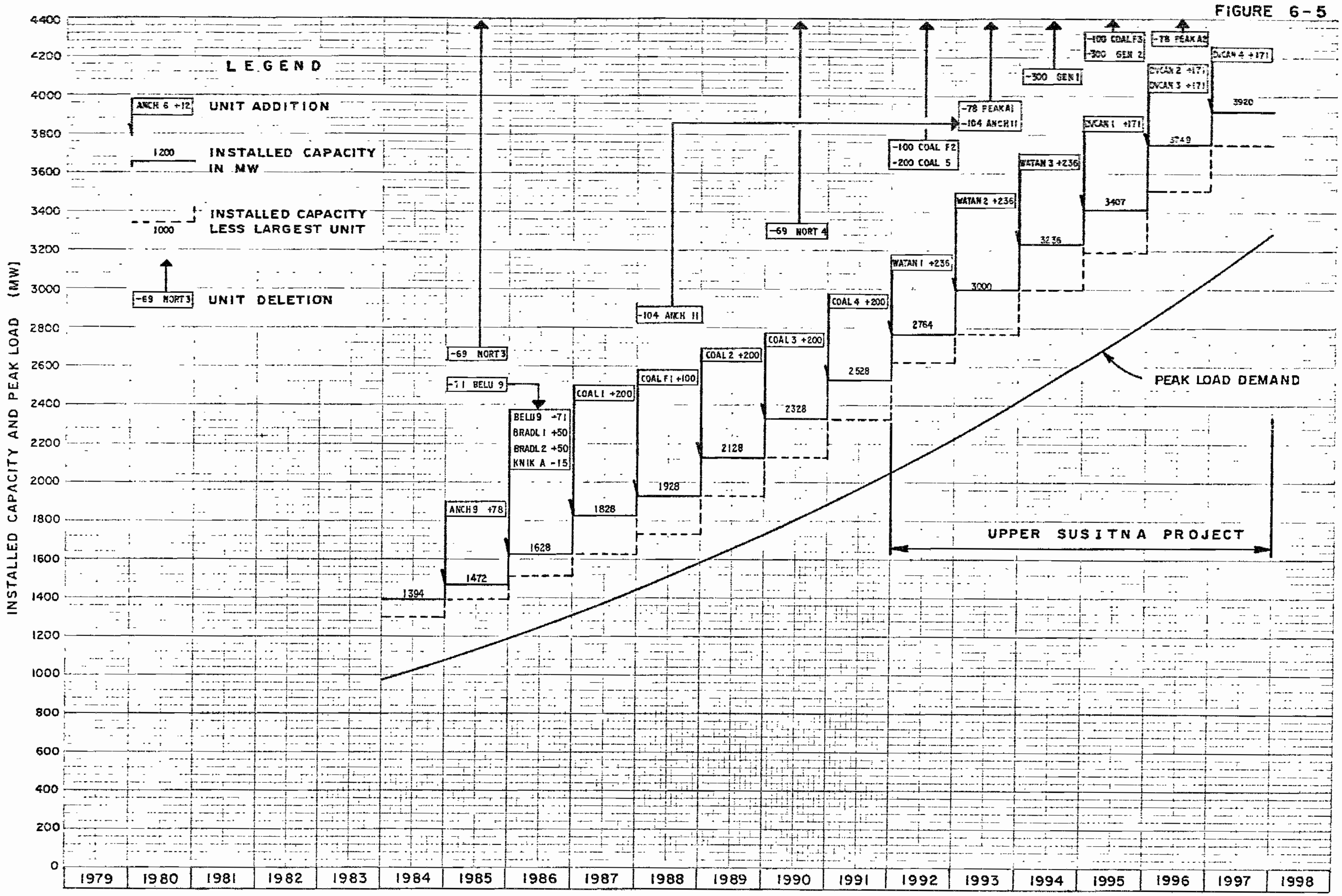
FIGURE 6-4



INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
WITH FIRM POWER TRANSFER
PROBABLE LOAD FORECAST CASE

8/79

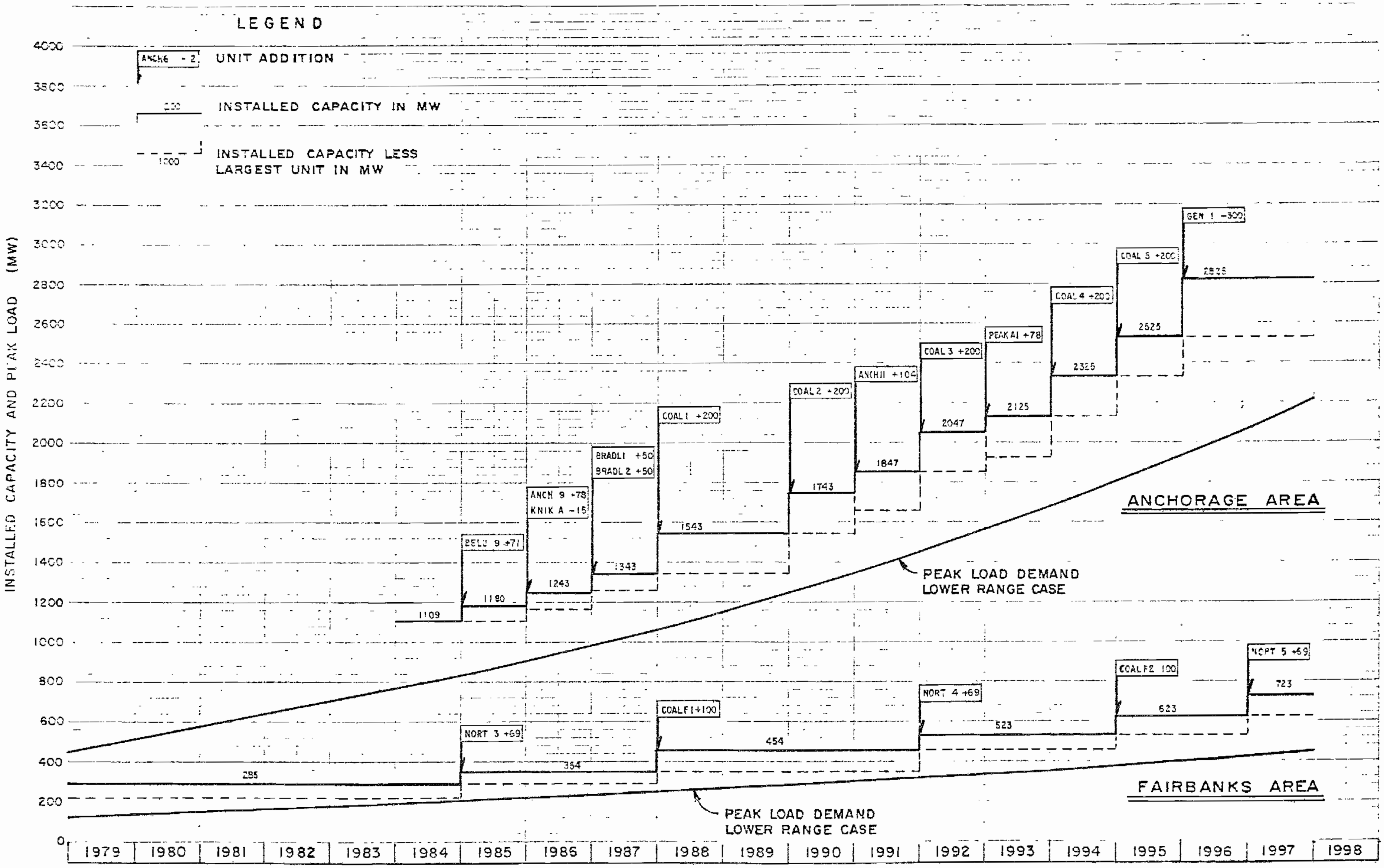
FIGURE 6-4
CASE IB



INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE-FAIRBANKS AREA
WITH UPPER SUSITNA PROJECT
PROBABLE LOAD FORECAST CASE 8/79

FIGURE 6-5
CASE II

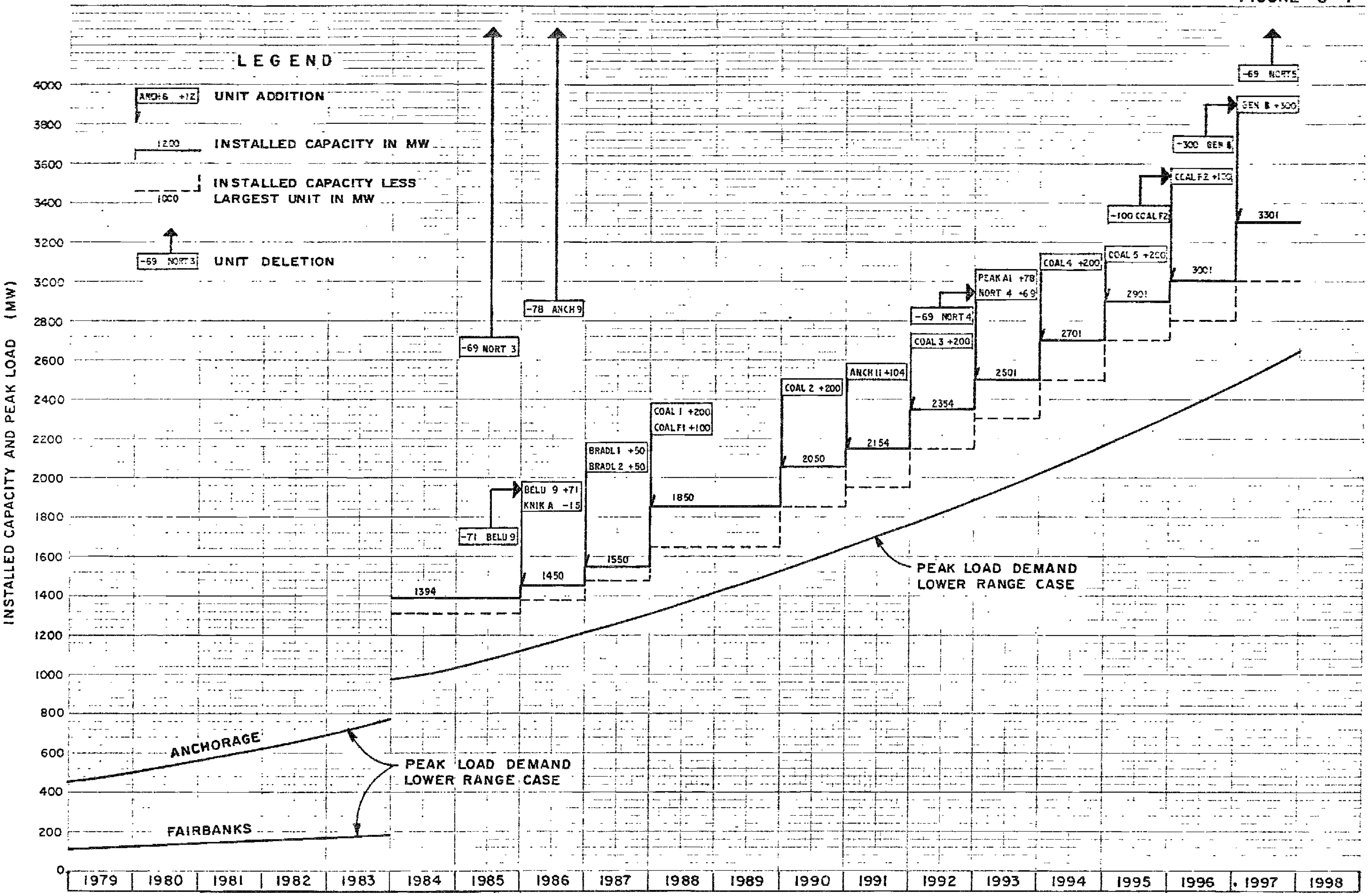
FIGURE 6-6



INDEPENDENT SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
LOW LOAD FORECAST CASE

FIGURE 6-6

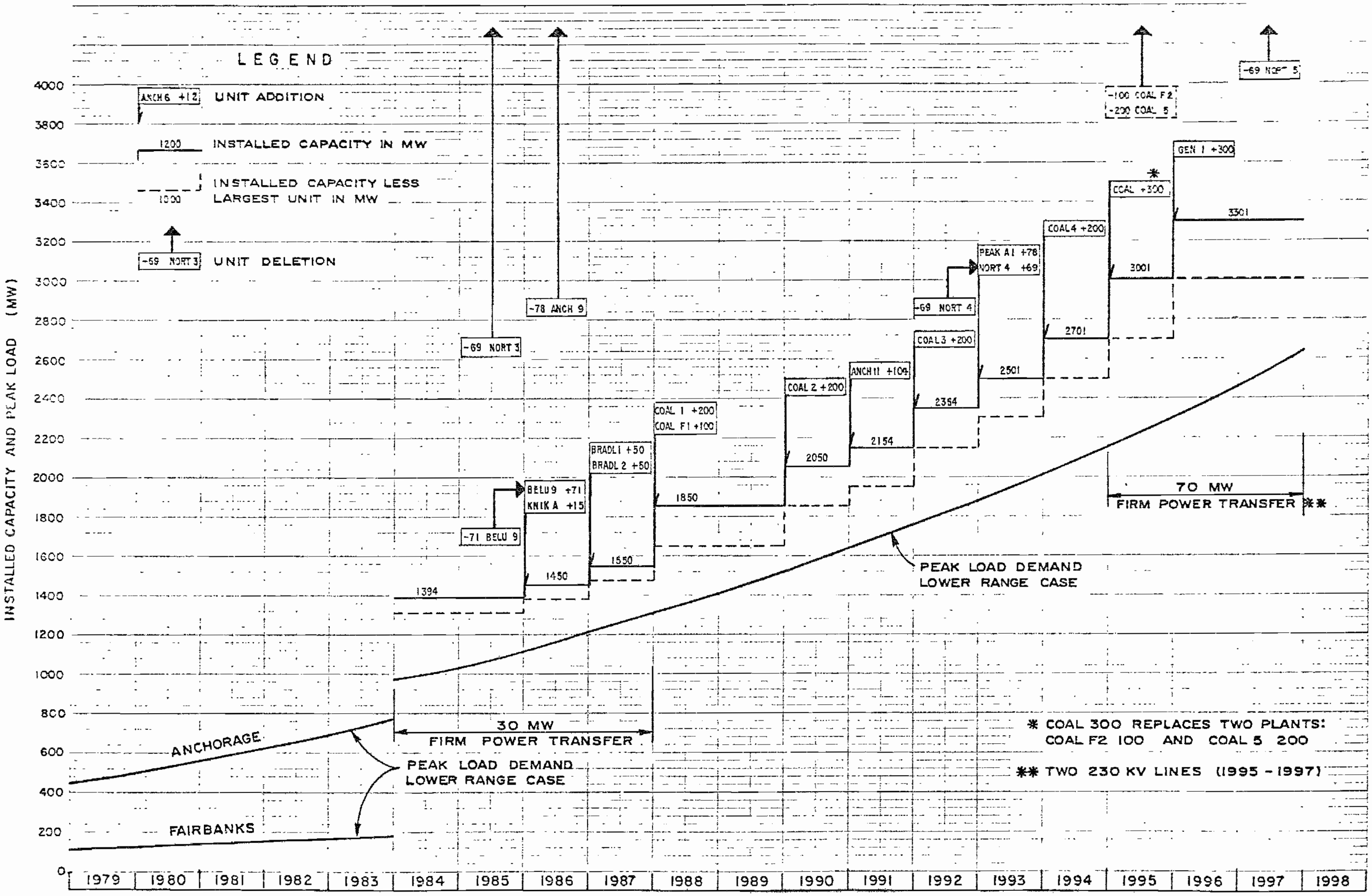
FIGURE 6-7



INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE-FAIRBANKS AREA
LOW LOAD FORECAST CASE

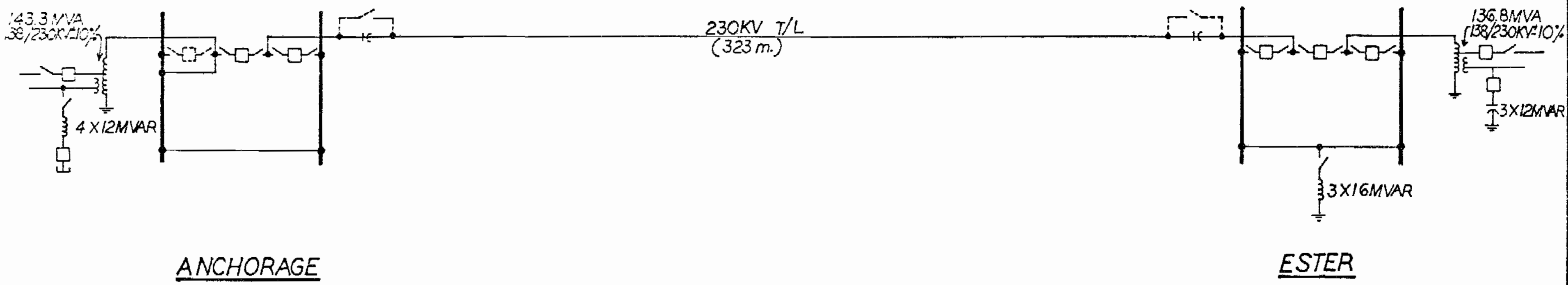
FIGURE 6-7
CASE IA & ID

FIGURE 6-8



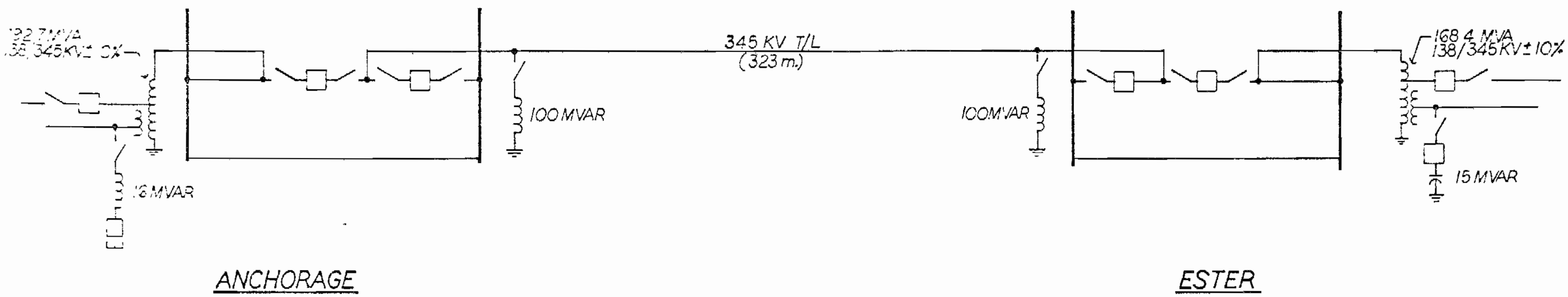
INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
LOW LOAD FORECAST CASE
WITH FIRM POWER TRANSFER

FIGURE 6-8
CASE IB



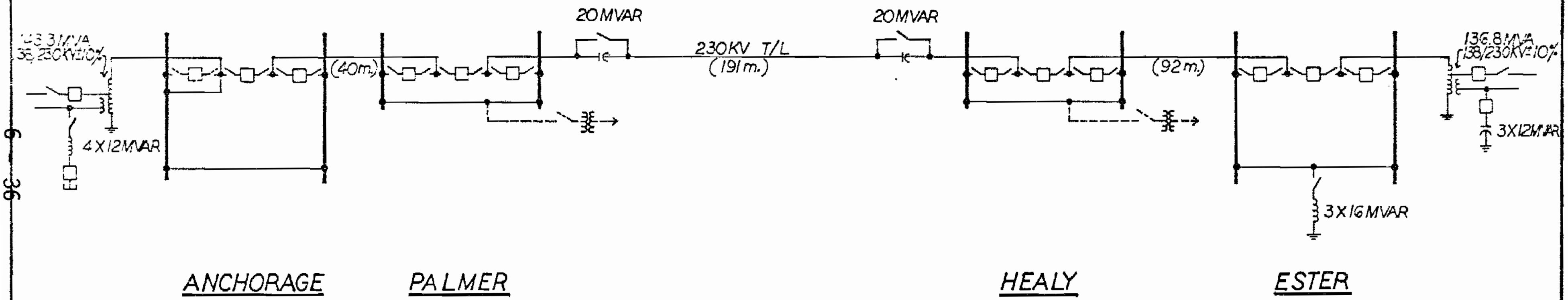
CASE I
Alternatives A & B

FIGURE 6-9



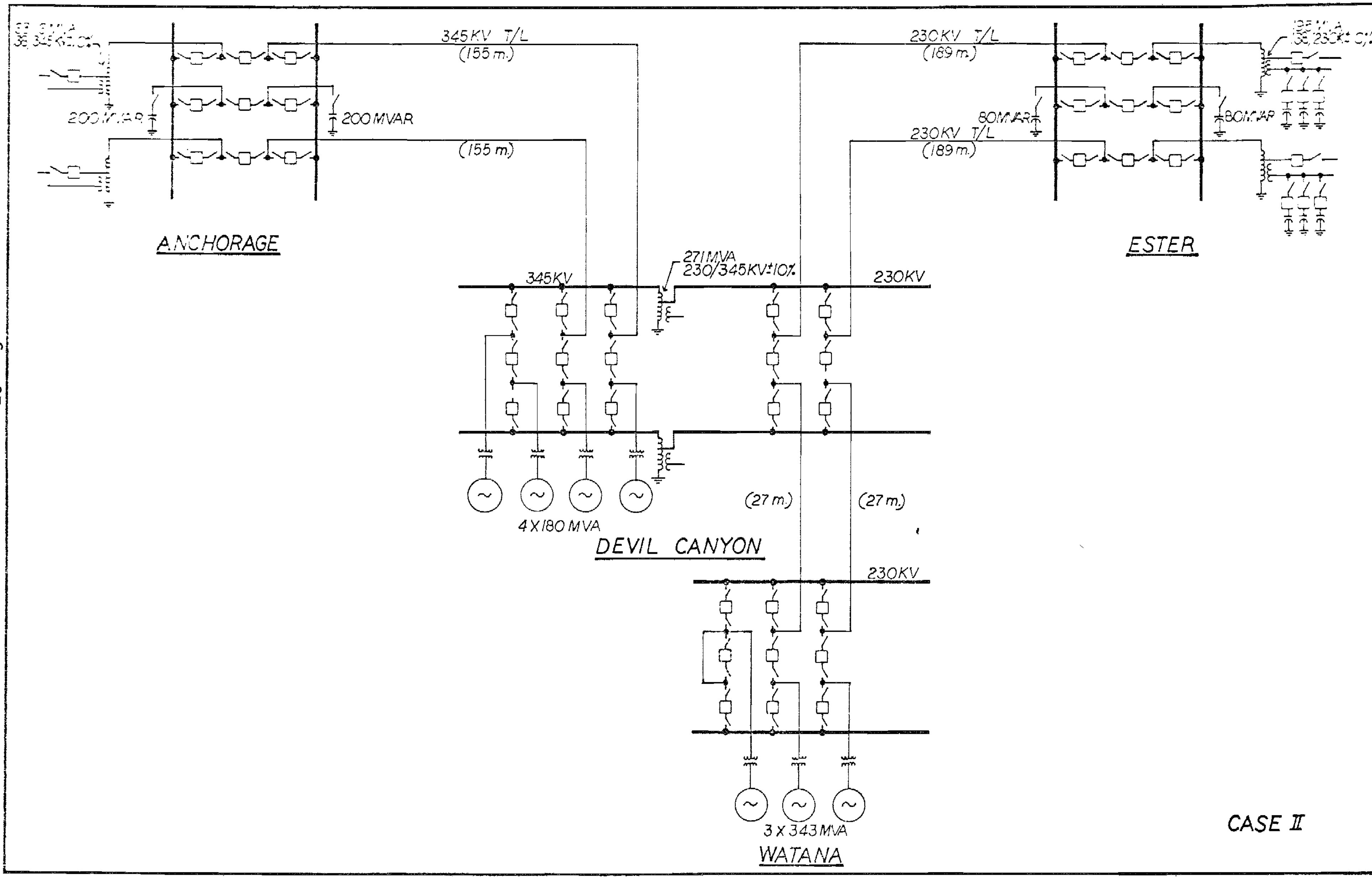
CASE I
Alternative C

FIGURE 6-10



CASE I
Alternative D

FIGURE 6-11



345KV T/L
(155 m.)
200 MVAR
(155 m.)
ANCHORAGE
230KV T/L
(189 m.)
80MVAR
230KV T/L
(189 m.)
ESTER
271 MVA
230/345KV±10%
345KV
230KV
(27 m.)
(27 m.)
4 X 180 MVA
DEVIL CANYON
230KV
3 X 343 MVA
WATANA
CASE II

FIGURE 6-12

CHAPTER 7
FACILITY COST ESTIMATES

CHAPTER 7

FACILITY COST ESTIMATES

7.1 TRANSMISSION LINE COSTS

The transmission line costs were obtained from past and current experience of the Consultants with the design and construction of transmission lines in Alaska. Cost data was escalated to 1979 levels and a factor of 1.46 (AVF = Average Value Factor) was applied to total costs to give an average value for construction in the area. The AVF includes a 10% addition for anticipated difficulty with the constraints associated with the selected line route.

A. Alaskan Experience

Facility cost estimates for alternative transmission intertie designs are based on an in-depth analysis of pertinent Alaskan transmission lines that have been built and are now in successful operation. Analyses were made based on actual experience to develop material and man-hour costs, together with specific installation requirements for structures, conductors, and footing assemblies. In addition, typical right-of-way clearing costs and other costs associated with the solicitation and obtainment of right-of-way easements, permits, and environmental reviews were gathered to provide representative costs for estimating component items for the Anchorage-Fairbanks Intertie.

The first Alaskan transmission line capable of operating at voltages as high as 230 kV was the Beluga Line. It was constructed for Chugach Electric Association (CEA) in 1967 by City Electric, Inc. of Anchorage. This line traverses about 42.5 miles of undeveloped land, of which about 65% was muskeg swamp. No roads existed to connect the line right-of-way to any highway or railroad, requiring that access be by water (Cook Inlet - Susitna River), by air (helicopter), or by ORV (off-road vehicle). One major river crossing was required along the transmission line route.

The Beluga Line was constructed of aluminum lattice, X-shape, hinged-guyed towers and Drake (795 kcmil ACSR) conductor by the Contractor. Using one tower assembly yard at Anchorage, the Contractor made extensive use of helicopter delivery of men and materials with ORV equipment during winter weather to construct the line. This project was completed at a cost of about $50,000 per mile, including right-of-way clearing.

The hinged-guyed, X-shaped tower proved successful and has since been used for the following lines described below.

1. Knik Arm Transmission Line - 230 kV (Aluminum Lattice Towers, 795 kcmil Drake ACSR Conductor), 1975. This line was built using Owner-furnished material by force account and contract methods. The Owner (CEA) installed the piling and anchors, and contracted for the right-of-way clearing, tower erection, and wire stringing. Piling and anchors were installed using ORV equipment to carry the power tool for installing anchors and the Del Mag-5 diesel hammer and welding equipment for the piling work. City Electric, Inc. accomplished the tower erection and wire stringing using helicopter and ORV equipment.

Summary of Actual Costs:	$/Mile
Construction Cost	87,294
Right-of-way Clearing Cost	19,049
Right-of-way Solicitation Cost	7,706
TOTAL (w/o Engineering)	114,049

2. Willow Transmission Line - 115 kV (Tubular Steel Towers, 556.5 kcmil Dove ACSR Conductor), 1978. This line was built by contract using Owner-furnished material. Right-of-way clearing was accomplished by one contractor and line construction by another (Rogers Electric - an experienced Alaska contractor). This line contractor used a vibratory driver to install the 8" H-pile with great success. (This driver has since been used to drive 10" H-pile for another line. In one case, the tool drove a 14" H-pile for a sign support. The contractors are preparing

to drive more 14" piles for a new CEA line.) The introduction of the vibratory pole-driving technique, together with the application of the tubular steel, hinged-guyed, X-tower is expected to realize substantial cost savings on future transmission line projects.

Summary of Actual Costs:	$/Mile
Construction Cost	73,863
Right-of-way Clearing Cost	10,312
Right-of-way Solicitation Cost	4,909
TOTAL (w/o Engineering)	89,084

B. Material Costs

The estimated cost for the tower steel, as well as the physical characteristics were obtained from ITT Meyer Industries (Ref. 1). The cost of steel, therefore, has 1979 as the reference year.

The cost of foundation steel was taken to be $0.31 per lb for WG Beam. This value is somewhat conservative, as the current market price is $0.22 per lb.

Prices for insulators and conductors have a reference year of 1977; thereafter, the price was escalated at 7 percent per year through 1979. The cost of right-of-way was based on actual average values paid by utilities in the same area as the proposed lines. Other factors used, that provide good indication of projected costs for the transmission line are:

- Terrain Factor - This factor is used to correct the number of calculated towers per mile to actual towers per mile.

- Line Angle Factor - This factor is used to increase the effective transversal load on the tower, and accounts for the 3^{o} design-angle for the towers.

- Tower Weight Factor - This factor is used to increase the total estimated tower weight, to account for heavy angle and dead-end towers.

C. Labor Costs

Labor costs were obtained from actual construction experience, obtained by the Consultants' construction records for transmission lines built in Alaska. This information included the cost of labor and a detailed breakdown of the man-hours required for every specific task included in the construction program. A multiplier of 1.33 was applied to the estimated cost of labor for this period, which then was multiplied by 1.1 as explained in 7.1 above to obtain the 1.46 AVF indicated above.

D. Transportation Costs

An estimated unit cost of $100 per ton was taken to represent the transportation and shipping costs from the Pacific Northwest to the line route staging depot, including loading and unloading (Ref. 2).

7.2 SUBSTATIONS COSTS

For this report, the facility costs for substations were obtained from the U.S. Department of Energy 1978 version of the previous FPC publication "Hydroelectric Power Evaluation" (Ref. 3). As the values included in the publication are list prices, with 1977 as reference year, they were adjusted to 1979 values by using the U.S. Bureau of Reclamation Index (Ref. 4). The cost of the substations includes the shunt compensation, required at both ends, for operation from no-load to full-load. No reactive power (VAR) compensation support from the source generators was considered in this study.

7.3 CONTROL AND COMMUNICATIONS SYSTEM COSTS

Control and communications sytems costs are included in the intertie cost estimates. The system is necessary to provide effective control of power system operations, and economic energy dispatch throughout the interconnected Anchorage-Fairbanks area. The cost estimates include a power line carrier type communications system, a digital supervisory control and data acquisition (SCADA) system, and automatic generation control equipment.

7.4 TRANSMISSION INTERTIE FACILITY COSTS

As previously discussed in Chapter 5, transmission line costs were calculated using TLCAP. Computer printout sheets indicating input data and the calculated results for all five intertie alternatives are shown in Appendix B. Costs for substation facilities and the control and communications system were added to the transmission line costs, thus obtaining the investment cost for the total intertie facilities. A cost summary for each of the five alternatives studied is presented in Table 7-1. Detailed cost estimates and supporting data are included in Appendix D.

7.5 COST OF TRANSMISSION LOSSES

The Transmission Line Optimization Program (TLCAP) for the selection of the optimum span-conductor combination, includes the cost of demand and energy losses for long transmission lines. The loss components are optimized by varying the voltages at the receiving and sending ends. The program assumes 100 percent volt support at both ends. Table 7-2 presents the present worth (1979) costs of calculated transmission line energy and demand losses.

7.6 BASIS FOR GENERATING PLANT FACILITY COSTS

Cost estimates were prepared for all new generating plants (five gas-turbine units and five coal-fired steam plants), and associated substation and transmission facilities which will be affected by the transmission interconnection. The costs for the facilities are summarized in Table 7-3.

The most recent cost data and estimates available for both gas-turbine and coal-fired steam plants planned for the Railbelt area was used as a basis for the generating plant estimates. The three principal sources of cost data and information are included in the references at the end of this chapter. The Battelle study report (Ref. 2) provided background information and specific factors to determine applicable Alaskan construction cost location adjustment factors. The Stanley Consultants report to GVEA (Ref. 5) provided detailed cost estimates for both the 104-MW coal-fired plant at Healy and combustion turbines at the Northpole substation in Fairbanks. These estimates were then used to derive reference costs for other gas-turbine and coal-fired units of different capacity at other Railbelt sites. The nomogram developed by Arkansas Power & Light Company (Ref. 6) was used to determine the 100-MW reference cost estimate from reported costs relevant to the 104-MW coal-fired plant at Healy. The same nomogram was then used to determine plant costs for unit ratings of 200 and 300 MW, taking into consideration economies of scale. Subsequently, the Alaskan construction cost location adjustment factors were applied to derive site specific cost estimates.

Cost estimates for the associated transmission facilities were obtained from cost data developed during this study for the transmission intertie, the Stanley Consultants report (Ref. 5), and typical costs experienced in recent Alaskan transmission projects.

The cost estimates and supporting data are contained in Appendix D.

7.7 GENERATING PLANT FUEL COSTS

Benefits in addition to those resulting from generation reserve capacity sharing will result from the supply of firm power over the intertie. An analysis was made of the relative generation costs for both independent and interconnected system expansions to determine the comparative economic advantage of firm power interchange. The fuel cost component of operating expenses is the salient factor which affects the economic comparison of alternative system expansions. Therefore, a year-by-year analysis of alternative modes of generation was completed for each period during which firm power transfer over the intertie is possible, as follows:

			Transmission Intertie Firm Power Transfer			
From	To	Duration	Capacity	% Power Loss 1/	Energy 2/	% Energy Loss 1/
1984	1987	4 yrs.	30 MW	6.9	145 GWh	1.05
1992	1996	5 yrs.	70 MW	6.9	337 GWh	1.05

1/ Case IB.

2/ Annual Transmission Capacity Factor of 0.55 assumed for analysis.

Fuel costs were estimated utilizing the trend curves from the Battelle report for future natural gas and coal prices in the Railbelt area. The energy loss component of firm power transfer over the intertie was considered, in estimating the total cost of fuel required to generate sufficient energy in one area to displace a block of energy otherwise generated by a local plant in an independently supplied area.

A year-by-year analysis of the comparative cost of generation is given in Appendix D. Table 7-4 summarizes these costs. Although this analysis is germane to the confirmation of salient considerations regarding the economic feasibility of the intertie, this level of study of fuel costs is in no way a definitive substitution for a detailed year-by-year analysis of production costing for the multi-area interconnection.

7.8 MEA UNDERLYING SYSTEM COSTS

The construction of transmission intertie with the intermediate substation at Palmer (Case ID) provides an opportunity for Matanuska Electric Association (MEA) to purchase power at the intermediate substation at Palmer. Information in the System Planning Report (Ref. 8) indicates the following MEA system expansion investment cost for transmission lines and substation facilities with and without the intertie:

Interconnected System	\$1,356,000 (1987)
Independent System	\$6,646,000 (1987)
Independent System	\$2,004,000 (1992)

The above costs are in 1979 dollars, values were escalated by 10% from 1978 to 1979 level. These values were used in an economic analysis to obtain additional benefits for Case ID.

7.9 CONSTRUCTION POWER COSTS FOR THE UPPER SUSITNA PROJECT

Completion of the transmission interconnection, prior to the development of the Watana and Devil Canyon sites of the Upper Susitna Project will enable the supply of electrical energy for construction power. A temporary wood-pole line to the sites will be supplied from a transmission tap along the intertie route, near the junction of the site access road with the main highway between Anchorage and Fairbanks. Generally, isolated diesel generation is used at such remote hydropower plant sites.

A comparison was made of the relative costs of isolated diesel generation and energy supply to the sites via the tap-line. Table 7-5 shows alternative cost streams through the construction period corresponding to the introduction of the Watana and Devil Canyon units to the interconnected Railbelt generation expansion, shown on Figure 6-5. The construction schedule, as outlined on page 94 of the Interim Feasibility Report (Ref. 7), was followed to establish the time frame for economic comparison of alternative modes of construction power supply. Results of the economic comparison indicate a clear advantage for utilizing the intertie as a source of construction power.

7.10 REFERENCES

1. Letter from ITT Meyer Industries to R. W. Retherford Associates, Anchorage, Alaska, January 15, 1979.

2. Battelle Pacific Northwest Laboratories, Alaska Electric Power: An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region, March 1978.

3. DOE, Federal Energy Regulatory Commission, Hydroelectric Power Evaluation (Final Draft), August 1978.

4. U.S. Bureau of Reclamation, "BuRec Construction Costs", Engineering News Record, 22 March 1979.

5. Stanley Consultants, Power Supply Study - 1978, Review Copy of Report to Golden Valley Electric Association, Inc.

6. Power Engineering, "Nomogram calculates economy of scale in power plants", Volume 83, February 1979.

7. U.S. Army Corps of Engineers, South-Central Railbelt Area, Alaska, Upper Susitna River Basin Interim Feasibility Report, December 1975.

8. Robert W. Retherford Associates, System Planning Report, Matanuska Electric Association, Inc., January 1979.

TABLE 7-1

COST SUMMARY FOR INTERTIE FACILITIES[1/]

	Total Cost at 1979 Levels ($1000)				
	Case IA	Case IB	Case IC	Case ID	Case II
1. Transmission Line:					
Eng'g. & Constr. Supv.	3,012	3,012	7,988	3,012	15,442
Right-of-Way	8,837	8,837	7,573	8,837	12,994
Foundations	8,445	8,445	12,160	8,445	22,966
Towers	21,615	21,615	33,990	21,615	64,974
Hardware	477	477	477	477	1,096
Insulators	503	503	755	503	1,396
Conductor	10,761	10,761	17,663	10,761	36,946
Subtotal	53,650	53,650	80,606	53,650	155,814
2. Substations:					
Eng'g. & Constr. Supv.	1,352	1,352	1,855	2,816	6,902
Land	57	57	46	81	185
Transformers	1,703	1,703	3,291	1,703	11,917
Circuit Breakers	1,093	1,093	1,323	1,953	6,410
Station Equipment	1,223	1,223	1,933	1,345	4,375
Structures & Accessories	3,628	3,628	3,978	4,026	16,411
Subtotal	9,056	9,056	12,426	11,924	46,200
3. Control and Communications:					
Eng'g. & Constr. Supv.	125	125	125	165	200
Equipment	2,375	2,375	2,375	3,135	3,600
Subtotal	2,500	2,500	2,500	3,300	3,800
Total Baseline 1979 Costs	65,206	65,206	95,532	68,874	205,814

1/ The interest and escalation during the construction and other financial charges are excluded from the costs in this summary. These costs are not relevant for the economic analysis and they appear only in the financial analysis (See Chapter 9 for Case ID).

TABLE 7-2

PRESENT WORTH OF INTERTIE LINE LOSSES
1984-1997 STUDY PERIOD[1/]

Case	$ x 1000 (1979)
IA & ID (230 kV)	5,410
IB (230 kV)	7,071
IC (345 kV)	6,429
II A (230 & 345 kV)	
Anchorage - Devil Canyon	11,476
Devil Canyon - Ester	7,076
Watana - Devil Canyon	2,708

[1/] Cost of losses, energy, and demand, escalated at 3% per year.

TABLE 7-3

COST SUMMARY FOR GENERATING FACILITIES[5/]
(Costs at 1979 Levels[1/])

Unit Name	Code [2/]	Type[3/]	MW	Installed Cost Thousand $	Installed Cost $/kW	Total Cost[4/] Thousand $	Total Cost[4/] $/kW
Northpole #3	NORT 3	SCGT	69	24,385	353	27,934	405
Beluga #9	BELU 9	SCGT	71	33,548	473	42,498	598
Northpole #4	NORT 4	SCGT	69	24,385	353	25,185	365
Anchorage	PEAK A2	SCGT	78	22,620	290	23,400	300
Northpole #5	NORT 5	SCGT	69	24,385	353	25,185	365
Anchorage #11	ANCH 11	Coal	104	99,084	953	105,636	1016
Unit F2	COAL F2	Coal	100	130,000	1300	151,980	1520
Unit No. 5	COAL 5	Coal	200	200,000	1000	212,245	1061
Unit No. 6	COAL 6	Coal	300	274,000	913	292,250	974
Unit No. 1	GEN 1	Coal	300	274,000	913	292,250	974
Unit No. 2	GEN 2	Coal	300	274,000	913	292,250	974

1/ Investment costs adjusted to January 1979 levels, excluding IDC.

2/ Code name used in MAREL study.

3/ SCGT - Simple cycle combustion turbine, includes NO_x removal equipment.
COAL - Steam turbine, coal-fired with FGD equipment.

4/ Total cost includes substation and transmission costs.

5/ The interest and escalation during the construction and other financial charges are excluded from the costs in this summary. These costs are not relevant for the economic analysis and they appear only in the financial analysis.

TABLE 7-4

SUMMARY

OF

ALTERNATIVE GENERATING PLANT FUEL COSTS

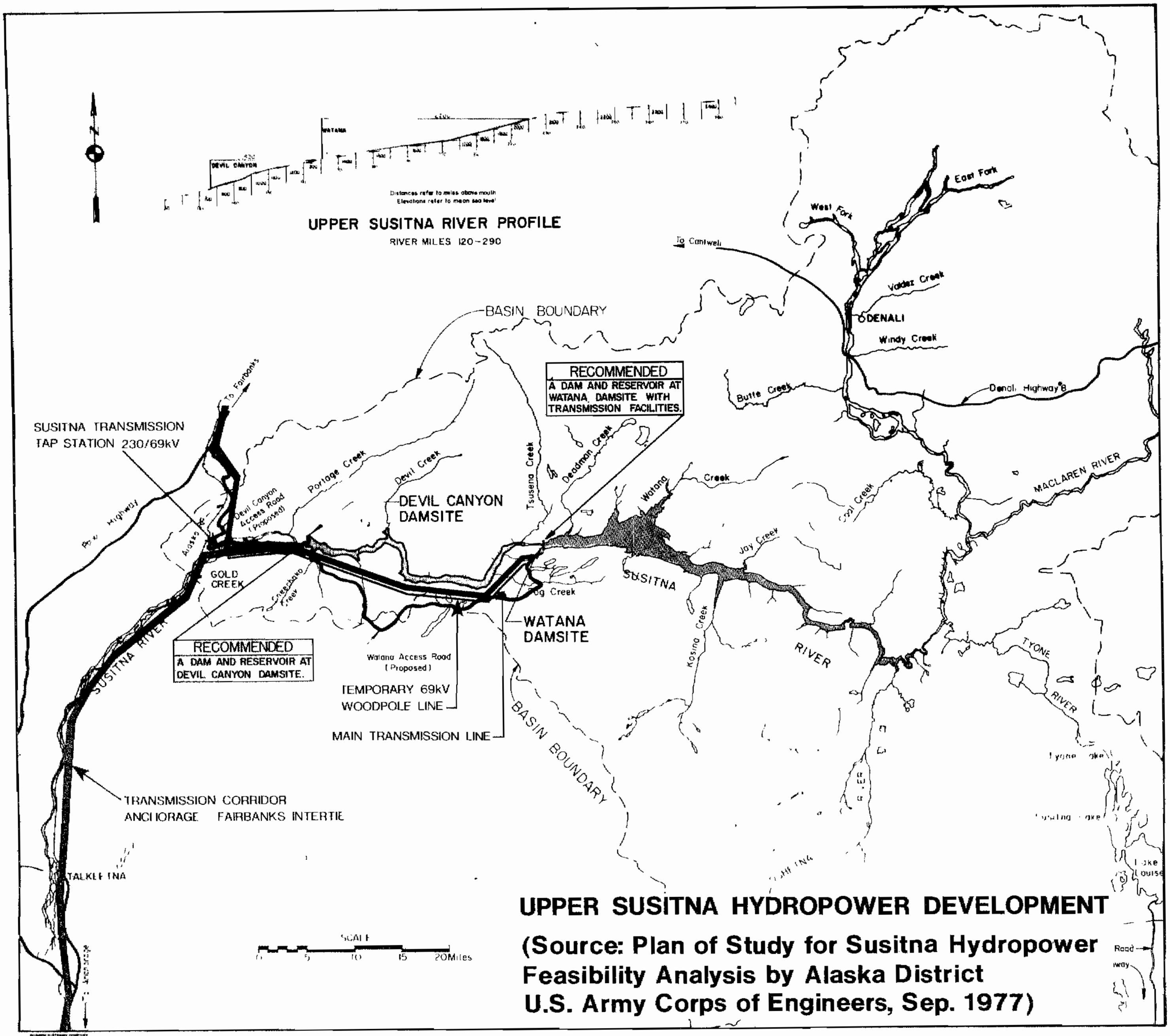
Year	\$ 1000 (Escalated) Independent System Operation	Interconnected System Operation
1984	-	-
1985	8,468	7,648
1986	9,324	8,498
1987	10,267	9,029
1992	6,851	8,324
1993	7,212	8,654
1994	7,933	8,016
1995	8,654	8,745
1996	9,015	9,109

TABLE 7-5

ALTERNATIVE COSTS FOR CONSTRUCTION POWER SUPPLY
TO
WATANA AND DEVIL CANYON HYDROPOWER SITES
DURING
CONSTRUCTION OF UPPER SUSITNA PROJECT

	1979 Baseline Costs - $1000	
Year	Isolated Diesel Generation at Site	Tapline Supply From Intertie
1985	2,835	267
1986	695	483
1987	697	481
1988	696	478
1989	3,055	752
1990	1,324	902
1991	187	734
1992	623	430
1993	623	419
1994	-500 1/	304

1/ Negative sign indicates that resale value of generating plant exceeds cost of generation in final year.



CONSTRUCTION PLAN FOR UPPER SUSITNA PROJECT:

Ref. Interim Feasibility Report - P.94, US Army Corps of Engineers, 12 Dec. 1975

Construction Period for Selected Projects:

Watana Dam - 6 Years
Devil Canyon Dam - 5 Years
Total Period - 10 Years (1 Year Overlap)

SUGGESTED REVISED SCHEDULE:

Ref. Chapter 6, Figure 6-5

First Unit On-Line at Watana - Beginning Year 1992
Last Unit On-Line at Devil Canyon - End of Year 1996
Period of Overlap in Construction - 2 Years
Due to Introduction of First Unit at Devil Canyon in 1994

CHAPTER 8

ECONOMIC FEASIBILITY ANALYSIS

CHAPTER 8

ECONOMIC FEASIBILITY ANALYSIS

An economic feasibility analysis was performed to determine which system expansion plan provides the best use of available resources for supplying electrical power to the Railbelt area. Alternative system expansion plans and facility cost estimates were developed in Chapters 6 and 7. In this chapter, the results of the economic feasibility analysis are presented.

8.1 METHODOLOGY

This economic analysis uses the conventional present-worth model. Annual capital disbursement tables, on a year-by-year basis, were prepared for independent and interconnected system expansion plans. To evaluate these plans on an equal basis all capital disbursements were discounted to the 1979 base year and then totalized for each plan to obtain a single 1979 present-worth value for each plan. The difference between the two present worth values is the net present worth or project benefits. This approach does not include additional capital disbursements after 1997. Such disbursements will be required later to replace retired facilities. However, the extension of the present-worth model over the whole life of the proposed intertie will not significantly affect the results of this feasibility study. The year 1997 was chosen as the final year of the study period to include the last unit of Upper Susitna Hydropower Project (Devil Canyon Unit No. 4).

Figures 6-2 thru 6-8 in Chapter 6 show that many plant additions for both independent and interconnected system expansion plans do not vary. Therefore, in this economic analysis, facility costs for the new generating plants not affected by the introduction of the intertie are not considered. Also excluded from the analysis are plant fixed operation and maintenance costs. The exclusion of these O&M costs will somewhat favor the independent system expansion alternatives.

Only capital costs are used to evaluate generation reserve capacity sharing benefits. This simplification is based on the assumption that an average operating cost of generation for reserve sharing is approximately the same in the Anchorage and Fairbanks areas. To account for generating plant operating costs with reasonable accuracy, a multi-area production cost study would be needed. The multi-area production cost model simulates an economic dispatching of generating units in the system and computes expected fuel and variable O&M costs based on the energy (MWh) output for each unit, taking into consideration intertie transfer limits. Since such a study is outside the scope of the present work, a somewhat simplified method was used in this feasibility study. It is definitely recommended that a multi-area production cost study be performed as the next step to finalize this Intertie Economic Feasibility Study.

8.2 SENSITIVITY ANALYSIS

A computer program was developed by IECO to analyze the sensitivity of different escalation and discount rates on the capital costs of various alternatives. This program, the Transmission Line Economic Analysis Program (TLEAP), provides the following outputs:

- Tables indicating independent minus interconnected system costs, discounted to the base year 1979.
- Separate tables indicating the discounted value of base year (1979) costs for the independent and interconnected systems.
- Cost disbursement tables for alternative system expansion plans. These tables also include intertie line losses.

Computer printout sheets indicating input data and calculated results for all alternatives included in this economic feasibility analysis are found in Appendix E.

8.3 ECONOMIC ANALYSIS

Tables included in this chapter and in Appendix E indicate economic analyses for a range of annual escalation rates of 0% to 12%, and a range of discount rates from 8% to 12%. For principal investigations below, a 10% discount rate is used and cash flow for facilities under consideration is expressed in constant 1979 dollars, only the fuel related energy costs are escalated. The 10% is regarded as the appropriate discount value for Opportunity Cost of Capital and is now required by the Office of Management and Budget (Ref. 1) for economic analyses to determine benefits for all federal projects.

For the purposes of the economic analysis, it is the discount rate corresponding to the opportunity cost of capital which is used to calculate all present values of costs and benefits; the particular cost of interest actually paid on bonds or other obligations is irrelevant since it bears no relationship whatsoever to the project's internal rate of return. It is only a financial (or budgeting) parameter. Therefore, the interest during construction and other financial changes are excluded from the economic analysis. These charges appear only in the financial analysis.

A. Benefits Due to Generation Reserve Capacity Sharing (Case IA)

Three cases were investigated to determine intertie benefits due to generation reserve capacity sharing alone; the 230-kV single circuit intertie between Anchorage and Fairbanks. In all cases 130 MW of power transfer capacity was allocated for generation reserve capacity sharing purposes. The economic analysis results indicate the following benefits due to intertie (differential of present worth):

Load Forecast	Intertie Cost (Percent)	Reference Table	Benefits ($ x 1000) (PW 1979)
Probable	100	8-1	12,475
Probable	125	8-1x	945
Low	100	8-1-LL	2,704

The above results indicate that the 230-kV intertie is economically feasible based on generation reserve capacity sharing alone.

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-1, 8-1x and 8-1-LL. Computer printouts indicating details are included in Appendix E.

B. Benefits Due to Generation Reserve Capacity Sharing and Firm Power Transfer (Case 1B)

Six cases were investigated to determine combined 230-kV intertie benefits due to both firm power transfer and generation reserve capacity sharing. These study cases have one 230-kV single circuit line during the 1984-1991 period and two single circuit 230-kV lines during the 1992-1997 period except for low load forecast case (Table 8-3LL) when the second 230-kV circuit is added in 1995. The economic analysis results indicate the following intertie benefits (differential of present worth):

Load Forecast	Intertie Cost (Percent)	Reference Table	Benefits ($ x 1000) (PW 1979)
Probable	100	8-3	24,054
Probable	125	8-3x	12,533
Low	100	8-3-LL	-2,626

If the above intertie benefits are combined with the additional benefits due to supply of construction power to the Upper Susitna Hydropower Project site (see Section 7.9), the economic analysis results indicate the following benefits (differential of present worth):

Load Forecast	Intertie Cost (Percent)	Reference Table	Benefits ($ x 1000) (PW 1979)
Probable	100	8-4	29,633
Probable	125	8-4x	18,112

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-3, 8-3x, 8-3-LL, 8-4 and 8-4x. Computer printouts indicating details are included in Appendix E.

C. <u>Benefits Due to Generation Reserve Sharing and Firm Power Transfer (Case IC)</u>

Two cases were investigated to determine 345 kV intertie benefits due to both: generation reserve sharing only (first line) and generation reserve sharing combined with firm power transfer (second line). These study cases consider one 345 kV single circuit line between Anchorage and Fairbanks. The economic study results indicate the following intertie benefits (differential of present worth):

Load Forecast	Intertie Cost (Percent)	Reference Table	Benefits ($ x 1000) (PW 1979)
Probable	100	8-2	-3,556
Probable	100	8-7	- 426

The above results indicate that the 345 kV intertie is not economically feasible based on the conditions specified in this study. Additional studies, including interconnected system production costing, may prove the 345 kV intertie feasible.

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-2 and 8-7. Computer printouts indicating details are included in Appendix E.

D. 230-kV Intertie with Intermediate Substations (Case ID)

Four cases were investigated to determine additional benefits due to supply of power to the MEA System at Palmer substation, and construction power to the Upper Susitna Hydropower Project. These cases include a 230-kV single circuit line between Anchorage and Fairbanks (Ester), with intermediate substations at Palmer and Healy. The economic analysis results indicate the following intertie benefits:

Load Forecast	Intertie Cost (Percent)	Reference Table	Benefits ($ x 1000) (PW 1979)
Probable	100	8-5	17,814
Probable	125	8-5x	9,125

If the above intertie benefits are combined with the additional benefits due to supply of construction power to the Upper Susitna Hydropower Project sites (see Section 7.9), the economic analysis results indicated the following benefits (differential of present worth):

Load Forecast	Intertie Cost (Percent)	Reference Table	Benefits ($ x 1000) (PW 1979)
Probable	100	8-6	20,344
Probable	125	8-6x	11,656

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-5, 8-5x, 8-6 and 8-6x. Computer printouts indicating details are included in Appendix E.

E. Intertie with Upper Susitna Hydropower Project

Only system reliability (MAREL) analyses and facility cost estimates were developed for this alternative system expansion plan (Case II, Chapter 6). The economic feasibility analysis was not performed for this alternative because:

- The methodology of this economic analysis is more appropriate for thermal generation systems. It is not applicable to a large mixed hydro/thermal generation systems. A multi-area production cost study, involving extensive analyses of optimum hydro operations in conjunction with thermal plants, would be required to obtain accurate results.

- A draft copy of the Upper Susitna project report prepared by the Alaska Power Administration (Ref. 2) was received by the Consultants in the course of this study. It includes revisions to unit ratings for the Upper Susitna Project used in the MAREL analyses (as described in Chapter 6). The new total installed capacity is 1573 MW, versus the 1392 MW installed capacity used in development of the expansion plans analyzed in this report.

A study should be performed to accommodate the above revisions to the Susitna power ratings and change to the production economics due to major hydro substitution for thermal energy. The study should examine in detail the economic feasibility of Susitna hydropower, due to the displacement of large increments of thermal power.

For reference, Figure 6-5 in Chapter 6 indicates the initial expansion plan developed for this study. This figure also indicates the thermal generating unit displacement by Upper Susitna Hydropower units.

MAREL study results indicate the following intertie requirements for maintaining the study criteria of equal reliability system expansion with introduction of Upper Susitna power:

Period	Requirement
1992	One 345-kV S/C line to Anchorage One 230-kV S/C line to Fairbanks
1993	One 345-kV S/C line to Anchorage Two 230-kV S/C lines to Fairbanks
1994-1997	Two 345-kV S/C lines to Anchorage Two 230-kV S/C lines to Fairbanks

8.4 REFERENCES

1. Business Week, Economics, Pages 96-97, February 19, 1979.

2. Alaska Power Administration, Upper Susitna River Project Market Analyses Report, March 1979.

CASE IA, 230 kV GENERATION RESERVE SHARING ONLY

PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	10,913	2,434	-1,210	-5,662	-11,042	-17,486	-25,147	-34,196	-41,825	-57,252
8.25	11,173	3,202	-257	-4,491	-9,619	-15,771	-23,095	-31,756	-41,939	-53,853
8.50	11,414	3,927	647	-3,379	-8,265	-14,137	-21,136	-29,424	-39,179	-50,600
8.75	11,634	4,612	1,503	-2,324	-6,977	-12,579	-19,268	-27,197	-36,540	-47,488
9.00	11,836	5,258	2,314	-1,321	-5,752	-11,096	-17,486	-25,071	-34,017	-44,511
9.25	12,020	5,868	3,081	-371	-4,588	-9,683	-15,786	-23,040	-31,605	-41,663
9.50	12,188	6,442	3,606	531	-3,481	-8,339	-14,166	-21,102	-29,301	-38,938
9.75	12,339	6,983	4,491	1,385	-2,430	-7,059	-12,621	-19,252	-27,099	-36,533
10.00	12,475	7,491	5,138	2,194	-1,431	-5,841	-11,149	-17,486	-24,996	-33,841
10.25	12,596	7,969	5,749	2,960	-484	-4,682	-9,747	-15,802	-22,987	-31,458
10.50	12,703	8,417	6,324	3,685	415	-3,581	-8,411	-14,195	-21,068	-29,181
10.75	12,797	8,838	6,867	4,371	1,268	-2,534	-7,139	-12,662	-19,235	-27,003
11.00	12,879	9,231	7,378	5,019	2,076	-1,540	-5,928	-11,202	-17,486	-24,922
11.25	12,949	9,599	7,858	5,630	2,841	-595	-4,776	-9,809	-15,816	-22,934
11.50	13,007	9,943	8,309	6,208	3,566	301	-3,680	-8,482	-14,223	-21,034
11.75	13,055	10,264	8,732	6,752	4,252	1,152	-2,637	-7,218	-12,703	-19,219
12.00	13,093	10,562	9,129	7,265	4,900	1,959	-1,647	-6,014	-11,253	-17,486

Note:

In early years of the expansion plan capital requirements are higher for the independent system plan, but in the later years capital requirements are higher for the interconnected system plan. As the discount rate increases, the sum of present worth decreases more for the interconnected system plan than for the independent system plan, therefore, the differential of the sums of the discounted values increases with the increase in the discount rate.

Due to larger capital requirements in the later years of the expansion plan, the increase in the escalation rate causes a greater increase in capital costs for the interconnected system. As a consequence, the differential of the discounted values (benefits) decrease.

Refer to APPENDIX E for capital disbursement tables and tables of discounted values.

CASE IA, GENERATION RESERVE SHARING ONLY
TRANSMISSION LINE COSTS INCREASED BY 25%
PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	-1,410	-11,778	-15,927	-20,897	-26,809	-33,798	-42,019	-51,642	-62,860	-75,889
8.25	-1,046	-10,891	-14,850	-19,598	-25,253	-31,946	-39,824	-49,054	-59,821	-72,333
8.50	-704	-10,048	-13,824	-18,360	-23,768	-30,175	-37,725	-46,577	-56,910	-68,924
8.75	-383	-9,247	-12,847	-17,178	-22,350	-28,484	-35,718	-44,206	-54,122	-65,658
9.00	-81	-8,485	-11,917	-16,052	-20,997	-26,868	-33,798	-41,937	-51,451	-62,528
9.25	201	-7,761	-11,032	-14,979	-19,705	-25,323	-31,962	-39,766	-48,894	-59,529
9.50	466	-7,074	-10,190	-13,957	-18,473	-23,848	-30,207	-37,688	-46,446	-56,656
9.75	714	-6,422	-9,389	-12,982	-17,297	-22,440	-28,529	-35,700	-44,102	-53,903
10.00	945	-5,803	-8,627	-12,054	-16,176	-21,095	-26,926	-33,798	-41,857	-51,265
10.25	1,161	-5,216	-7,903	-11,171	-15,107	-19,810	-25,393	-31,979	-39,708	-48,738
10.50	1,361	-4,659	-7,215	-10,330	-14,088	-18,585	-23,928	-30,238	-37,651	-46,318
10.75	1,548	-4,132	-6,562	-9,529	-13,116	-17,415	-22,528	-28,574	-35,682	-43,999
11.00	1,721	-3,632	-5,941	-8,768	-12,190	-16,298	-21,191	-26,983	-33,798	-41,779
11.25	1,881	-3,159	-5,353	-8,044	-11,308	-15,233	-19,914	-25,461	-31,995	-39,652
11.50	2,030	-2,712	-4,794	-7,355	-10,468	-14,217	-18,695	-24,006	-30,269	-37,615
11.75	2,166	-2,289	-4,265	-6,701	-9,668	-13,248	-17,530	-22,616	-28,618	-35,665
12.00	2,291	-1,889	-3,763	-6,079	-8,907	-12,325	-16,418	-21,287	-27,039	-33,798

Note:

This case is similar to the case presented in Table 8-I, except for the increase in intertie costs by 25 percent which caused an increase in capital requirements for the interconnected system expansion plan. For case analysis refer to note in Table 8-I.

CASE IA, 230 kV, GENERATION RESERVE SHARING ONLY

LOW LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	4,292	6,955	7,203	7,166	6,765	5,904	4,475	2,351	-619	-4,605
8.25	4,095	6,860	7,167	7,206	6,903	6,167	4,895	2,964	232	-3,466
8.50	3,897	6,754	7,114	7,225	7,014	6,396	5,272	3,523	1,016	-2,409
8.75	3,698	6,638	7,048	7,225	7,100	6,593	5,607	4,031	1,736	-1,430
9.00	3,499	6,513	6,968	7,207	7,163	6,759	5,904	4,491	2,397	-524
9.25	3,300	6,379	6,876	7,172	7,203	6,897	6,165	4,906	3,001	312
9.50	3,101	6,237	6,773	7,122	7,224	7,008	6,392	5,278	3,552	1,083
9.75	2,902	6,088	6,660	7,058	7,225	7,095	6,588	5,610	4,053	1,791
10.00	2,704	5,933	6,537	6,981	7,209	7,159	6,753	5,904	4,507	2,442
10.25	2,507	5,772	6,406	6,892	7,177	7,201	6,891	6,163	4,917	3,037
10.50	2,311	5,606	6,267	6,791	7,129	7,223	7,003	6,388	5,284	3,580
10.75	2,116	5,435	6,121	6,681	7,068	7,226	7,090	6,583	5,613	4,074
11.00	1,923	5,261	5,969	6,561	6,993	7,212	7,155	6,748	5,904	4,522
11.25	1,731	5,083	5,811	6,433	6,907	7,182	7,198	6,885	6,161	4,927
11.50	1,541	4,902	5,647	6,296	6,809	7,136	7,222	6,997	6,385	5,290
11.75	1,353	4,718	5,479	6,153	6,701	7,077	7,227	7,085	6,578	5,615
12.00	1,166	4,532	5,308	6,004	6,584	7,005	7,214	7,151	6,742	5,904

Note:

In the early years of the expansion plan capital requirements are somewhat lower for the independent system expansion plan (less new generating capacity is required). In the later years capital requirements are lower for the interconnected system plan. As the discount rate increases, the sum of the present worth decreases more for the independent system plan, therefore, the differential of the sums of the discounted values decrease with the increase in the discount rate.

The above analysis is applicable at the lower escalation rates. Due to marginal differences between capital requirements for both independent and interconnected expansion plans, at higher escalation rates the situation reverses, the differential discounted values (benefits) increase with the increase in the discount rate and decrease with the increase in the escalation rate.

Refer to APPENDIX E for capital disbursement tables and tables of discounted values.

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE IC, 345 kV GENERATION RESERVE SHARING ONLY
PROBABLE LOAD FORECAST

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	-4,886	-10,869	-13,279	-16,167	-19,601	-23,658	-28,421	-33,984	-40,450	-47,934
8.25	-4,679	-10,354	-12,653	-15,412	-18,698	-22,583	-27,150	-32,489	-38,700	-45,893
8.50	-4,484	-9,865	-12,057	-14,692	-17,835	-21,556	-25,935	-31,058	-37,023	-43,936
8.75	-4,302	-9,401	-11,489	-14,006	-17,011	-20,574	-24,771	-29,687	-35,415	-42,059
9.00	-4,132	-8,959	-10,950	-13,351	-16,225	-19,636	-23,658	-28,374	-33,874	-40,259
9.25	-3,973	-8,540	-10,436	-12,728	-15,474	-18,739	-22,593	-27,117	-32,397	-38,532
9.50	-3,824	-8,143	-9,947	-12,134	-14,756	-17,882	-21,575	-25,913	-30,982	-36,876
9.75	-3,685	-7,766	-9,483	-11,568	-14,075	-17,063	-20,601	-24,761	-29,626	-35,289
10.00	-3,556	-7,408	-9,042	-11,029	-13,423	-16,282	-19,669	-23,658	-28,328	-33,766
10.25	-3,436	-7,070	-8,622	-10,517	-12,802	-15,535	-18,779	-22,603	-27,083	-32,307
10.50	-3,325	-6,749	-8,224	-10,029	-12,210	-14,823	-17,928	-21,593	-25,892	-30,908
10.75	-3,222	-6,445	-7,847	-9,565	-11,646	-14,143	-17,115	-20,627	-24,751	-29,567
11.00	-3,127	-6,158	-7,488	-9,123	-11,108	-13,494	-16,338	-19,702	-23,658	-28,282
11.25	-3,040	-5,885	-7,149	-8,704	-10,596	-12,875	-15,596	-18,819	-22,612	-27,051
11.50	-2,959	-5,630	-6,827	-8,305	-10,109	-12,285	-14,887	-17,973	-21,611	-25,871
11.75	-2,886	-5,388	-6,522	-7,927	-9,645	-11,722	-14,210	-17,165	-20,652	-24,741
12.00	-2,819	-5,159	-6,233	-7,568	-9,204	-11,186	-13,564	-16,393	-19,735	-23,658

CASE IB, 230 kV, GENERATION RESERVE SHARING PLUS FIRM POWER TRANSFER PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	24,726	23,316	22,034	20,252	17,393	14,872	11,092	6,448	821	-5,918
8.25	24,678	23,565	22,395	20,745	18,541	15,700	12,128	7,723	2,372	-4,055
8.50	24,619	23,788	22,725	21,203	19,147	16,478	13,106	8,932	3,844	-2,278
8.75	24,549	23,987	23,028	21,627	19,713	17,209	14,028	10,075	5,242	-589
9.00	24,468	24,163	23,303	22,017	20,240	17,894	14,898	11,157	6,568	1,016
9.25	24,378	24,317	23,551	22,377	20,729	18,536	15,716	12,179	7,825	2,543
9.50	24,279	24,450	23,774	22,706	21,184	19,136	16,486	13,144	9,016	3,993
9.75	24,171	24,563	23,973	23,007	21,604	19,697	17,209	14,056	10,144	5,369
10.00	24,054	24,658	24,149	23,281	21,995	20,219	17,887	14,915	11,211	6,676
10.25	23,931	24,734	24,304	23,529	22,350	20,705	18,523	15,724	12,220	7,916
10.50	23,800	24,793	24,438	23,752	22,678	21,157	19,118	16,485	13,174	9,091
10.75	23,662	24,835	24,552	23,951	22,978	21,575	19,674	17,201	14,075	10,204
11.00	23,518	24,865	24,648	24,128	23,252	21,961	20,192	17,873	14,924	11,258
11.25	23,369	24,876	24,726	24,284	23,499	22,317	20,675	18,503	15,725	12,255
11.50	23,214	24,874	24,787	24,419	23,723	22,644	21,123	19,093	16,478	13,197
11.75	23,053	24,860	24,831	24,535	23,923	22,944	21,539	19,644	17,187	14,087
12.00	22,888	24,833	24,861	24,632	24,100	23,217	21,924	20,159	17,853	14,928

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE IB, 230 kV, GENERATION RESERVE SHARING PLUS FIRM POWER TRANSFER TRANSMISSION LINE COSTS INCREASED BY 25% PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	12,411	9,113	7,326	5,026	2,136	-1,430	-5,769	-10,987	-17,202	-24,544
8.25	12,467	9,481	7,811	5,648	2,917	-465	-4,591	-9,564	-15,499	-22,522
8.50	12,509	9,822	8,264	6,233	3,654	449	-3,473	-8,211	-13,876	-20,591
8.75	12,540	10,138	8,687	6,781	4,350	1,315	-2,411	-6,924	-12,330	-18,748
9.00	12,559	10,429	9,081	7,296	5,005	2,133	-1,404	-5,700	-10,857	-16,990
9.25	12,567	10,697	9,448	7,778	5,621	2,906	-450	-4,537	-9,454	-15,314
9.50	12,565	10,943	9,788	8,228	6,201	3,636	454	-3,432	-8,119	-13,715
9.75	12,550	11,168	10,103	8,649	6,740	4,325	1,310	-2,383	-6,848	-12,190
10.00	12,533	11,373	10,394	9,042	7,257	4,975	2,121	-1,387	-5,640	-10,738
10.25	12,504	11,558	10,661	9,407	7,736	5,587	2,887	-443	-4,491	-9,354
10.50	12,466	11,725	10,907	9,746	8,185	6,163	3,610	451	-3,399	-8,036
10.75	12,421	11,875	11,133	10,060	8,604	6,704	4,294	1,299	-2,362	-6,782
11.00	12,369	12,008	11,338	10,351	8,995	7,212	4,938	2,102	-1,378	-5,588
11.25	12,309	12,125	11,524	10,619	9,359	7,689	5,546	2,861	-444	-4,453
11.50	12,244	12,228	11,692	10,865	9,697	8,135	6,118	3,578	442	-3,374
11.75	12,172	12,316	11,844	11,091	10,011	8,552	6,656	4,256	1,282	-2,348
12.00	12,095	12,391	11,978	11,297	10,302	8,942	7,161	4,896	2,077	-1,374

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE IB, 230 kV, GENERATION RESERVE SHARING PLUS FIRM POWER TRANSFER LOW LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	-729	4,879	6,790	8,952	11,395	14,152	17,258	20,755	24,689	29,111
8.25	-996	4,430	6,279	8,373	10,739	13,408	16,416	19,802	23,611	27,892
8.50	-1,254	3,995	5,786	7,813	10,104	12,688	15,601	18,881	22,569	26,714
8.75	-1,503	3,575	5,309	7,271	9,490	11,993	14,814	17,990	21,562	25,576
9.00	-1,743	3,169	4,847	6,748	8,896	11,321	14,053	17,129	20,589	24,476
9.25	-1,976	2,776	4,401	6,242	8,322	10,671	13,318	16,297	19,648	23,413
9.50	-2,200	2,396	3,969	5,752	7,767	10,042	12,606	15,493	18,738	22,385
9.75	-2,417	2,029	3,552	5,279	7,231	9,434	11,918	14,714	17,859	21,391
10.00	-2,626	1,674	3,149	4,821	6,711	8,846	11,253	13,962	17,008	20,431
10.25	-2,828	1,331	2,759	4,378	6,209	8,278	10,609	13,234	16,186	19,502
10.50	-3,023	999	2,381	3,949	5,724	7,727	9,987	12,530	15,390	18,603
10.75	-3,212	678	2,016	3,535	5,254	7,195	9,384	11,849	14,621	17,734
11.00	-3,394	368	1,664	3,134	4,799	6,680	8,802	11,190	13,876	16,894
11.25	-3,569	67	1,322	2,747	4,360	6,182	8,238	10,553	13,156	16,081
11.50	-3,739	-223	992	2,372	3,934	5,700	7,693	9,936	12,460	15,294
11.75	-3,902	-503	673	2,009	3,523	5,234	7,165	9,339	11,785	14,533
12.00	-4,060	-775	364	1,658	3,124	4,783	6,654	8,762	11,133	13,797

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE IB , 230 kV, GENERATION RESERVE SHARING PLUS FIRM POWER TRANSFER & SUSITNA PROJECT CONSTRUCTION POWER PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	31,206	32,272	31,731	30,748	29,249	27,151	24,364	20,785	16,303	10,791
8.25	31,037	32,350	31,908	31,041	29,679	27,742	25,143	21,783	17,552	12,330
8.50	30,859	32,407	32,058	31,302	30,072	28,289	25,870	22,719	18,730	13,787
8.75	30,672	32,443	32,183	31,534	30,429	28,794	26,547	23,597	19,840	15,164
9.00	30,478	32,460	32,285	31,736	30,751	29,258	27,177	24,418	20,884	16,465
9.25	30,276	32,458	32,363	31,912	31,042	29,684	27,761	25,187	21,866	17,694
9.50	30,068	32,438	32,421	32,062	31,301	30,072	28,301	25,904	22,789	18,852
9.75	29,853	32,402	32,458	32,187	31,531	30,426	28,800	26,572	23,653	19,945
10.00	29,633	32,351	32,476	32,288	31,733	30,746	29,259	27,194	24,464	20,973
10.25	29,407	32,284	32,476	32,368	31,908	31,034	29,680	27,770	25,222	21,940
10.50	29,176	32,204	32,458	32,426	32,057	31,292	30,065	28,305	25,929	22,849
10.75	28,941	32,110	32,424	32,465	32,182	31,520	30,416	28,798	26,589	23,702
11.00	28,702	32,003	32,374	32,484	32,285	31,721	30,733	29,253	27,203	24,501
11.25	28,458	31,885	32,310	32,486	32,365	31,896	31,020	29,670	27,773	25,249
11.50	28,211	31,756	32,232	32,470	32,425	32,046	31,276	30,052	28,302	25,948
11.75	27,961	31,616	32,140	32,438	32,465	32,172	31,504	30,399	28,790	26,600
12.00	27,709	31,466	32,037	32,391	32,486	32,275	31,704	30,715	29,240	27,207

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE IB, 230 kV, GENERATION RESERVE SHARING PLUS FIRM POWER TRANSFER & SUSITNA CONSTRUCTION POWER TRANSMISSION LINE COSTS INCREASED BY 25% PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	18,891	18,069	17,024	15,523	13,492	10,849	7,502	3,350	-1,721	-7,835
8.25	18,825	18,266	17,324	15,944	14,055	11,578	8,424	4,495	-319	-6,139
8.50	18,749	18,441	17,596	16,332	14,579	12,260	9,291	5,576	1,009	-4,527
8.75	18,663	18,594	17,842	16,688	15,065	12,899	10,108	6,598	2,268	-2,995
9.00	18,569	18,726	18,063	17,015	15,516	13,496	10,875	7,562	3,460	-1,542
9.25	18,466	18,838	18,260	17,313	15,934	14,053	11,595	8,471	4,588	-163
9.50	18,355	18,931	18,435	17,584	16,319	14,572	12,270	9,328	5,654	1,145
9.75	18,237	19,007	18,588	17,629	16,673	15,054	12,902	10,134	6,661	2,385
10.00	18,112	19,066	18,720	18,049	16,997	15,502	13,492	10,892	7,613	3,559
10.25	17,980	19,109	18,833	18,246	17,294	15,916	14,044	11,603	8,510	4,671
10.50	17,843	19,136	18,927	18,421	17,564	16,298	14,558	12,271	9,356	5,722
10.75	17,700	19,149	19,004	18,574	17,808	16,650	15,036	12,896	10,152	6,716
11.00	17,552	19,149	19,064	18,707	18,028	16,972	15,480	13,481	10,901	7,655
11.25	17,399	19,135	19,108	18,821	18,225	17,268	15,691	14,028	11,605	8,541
11.50	17,242	19,109	19,138	18,916	18,400	17,537	16,271	14,537	12,266	9,377
11.75	17,080	19,072	19,153	18,994	18,553	17,781	16,621	15,012	12,885	10,164
12.00	16,915	19,024	19,154	19,056	18,687	18,001	16,942	15,452	13,464	10,905

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE ID, 230 kV, GENERATION RESERVE SHARING WITH INTERMEDIATE SUBSTATIONS PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	18,460	17,550	16,592	15,239	13,431	11,100	8,168	4,552	157	-5,122
8.25	18,406	17,728	16,858	15,610	13,924	11,735	8,967	5,541	1,363	-3,665
8.50	18,343	17,886	17,101	15,953	14,384	12,330	9,721	6,476	2,508	-2,280
8.75	18,272	18,026	17,322	16,269	14,812	12,889	10,431	7,362	3,595	-963
9.00	18,194	18,148	17,521	16,560	15,210	13,413	11,100	8,198	4,625	289
9.25	18,108	18,253	17,700	16,827	15,580	13,902	11,729	8,989	5,601	1,478
9.50	18,016	18,343	17,860	17,070	15,922	14,359	12,320	9,734	6,525	2,608
9.75	17,918	18,417	18,002	17,292	16,238	14,785	12,874	10,438	7,400	3,680
10.00	17,814	18,476	18,126	17,492	16,528	15,182	13,394	11,100	8,228	4,696
10.25	17,704	18,522	18,234	17,673	16,795	15,550	13,880	11,723	9,009	5,660
10.50	17,589	18,555	18,325	17,835	17,040	15,891	14,335	12,309	9,747	6,574
10.75	17,470	18,576	18,402	17,978	17,262	16,207	14,759	12,860	10,444	7,438
11.00	17,346	18,585	18,464	18,104	17,464	16,497	15,154	13,376	11,100	8,256
11.25	17,217	18,582	18,513	18,214	17,646	16,765	15,521	13,859	11,718	9,030
11.50	17,085	18,569	18,548	18,307	17,809	17,009	15,861	14,311	12,299	9,760
11.75	16,949	18,547	18,572	18,386	17,954	17,232	16,176	14,733	12,845	10,450
12.00	16,810	18,514	18,583	18,451	18,082	17,435	16,467	15,126	13,358	11,100

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE ID, GENERATION RESERVE SHARING PLUS INTERMEDIATE SUBSTATIONS
TRANSMISSION LINE COSTS INCREASED BY 25%
PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	9,155	6,772	5,420	3,663	1,439	-1,319	-4,689	-8,755	-13,611	-19,363
8.25	9,181	7,043	5,783	4,133	2,036	-577	-3,778	-7,651	-12,285	-17,783
8.50	9,197	7,294	6,121	4,575	2,598	125	-2,915	-6,601	-11,022	-16,276
8.75	9,205	7,524	6,436	4,989	3,128	789	-2,095	-5,603	-9,819	-14,838
9.00	9,204	7,736	6,729	5,377	3,626	1,417	-1,319	-4,655	-8,673	-13,466
9.25	9,195	7,931	7,001	5,740	4,095	2,009	-584	-3,754	-7,583	-12,159
9.50	9,179	8,108	7,252	6,078	4,535	2,568	113	-2,899	-6,546	-10,912
9.75	9,155	8,269	7,484	6,393	4,948	3,094	771	-2,088	-5,559	-9,725
10.00	9,125	8,415	7,697	6,686	5,335	3,590	1,394	-1,319	-4,621	-8,594
10.25	9,089	8,546	7,893	6,959	5,697	4,057	1,982	-590	-3,730	-7,517
10.50	9,047	8,663	8,072	7,211	6,035	4,495	2,538	100	-2,884	-6,492
10.75	8,999	8,767	8,235	7,444	6,350	4,907	3,061	754	-2,081	-5,516
11.00	8,946	8,858	8,383	7,658	6,644	5,293	3,555	1,372	-1,319	-4,589
11.25	8,888	8,938	8,516	7,856	6,917	5,654	4,020	1,956	-596	-3,707
11.50	8,825	9,006	8,636	8,036	7,170	5,992	4,456	2,508	88	-2,870
11.75	8,758	9,063	8,742	8,201	7,404	6,308	4,867	3,029	737	-2,074
12.00	8,687	9,109	8,835	8,351	7,620	6,602	5,252	3,520	1,350	-1,319

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE ID, 230 kV, GENERATION RESERVE SHARING WITH INTERMEDIATE SUBSTATIONS & SUSITNA CONSTRUCTION POWER PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	21,345	21,367	20,677	19,609	18,101	16,085	13,486	10,219	6,190	1,296
8.25	21,244	21,483	20,877	19,909	18,518	16,639	14,200	11,117	7,301	2,651
8.50	21,134	21,580	21,055	20,182	18,903	17,156	14,869	11,964	8,352	3,937
8.75	21,018	21,660	21,212	20,430	19,259	17,637	15,497	12,762	9,346	5,156
9.00	20,895	21,723	21,348	20,653	19,585	18,085	16,085	13,513	10,285	6,312
9.25	20,766	21,770	21,465	20,854	19,884	18,499	16,634	14,218	11,172	7,407
9.50	20,630	21,803	21,565	21,033	20,157	18,883	17,147	14,881	12,008	8,443
9.75	20,490	21,821	21,647	21,191	20,405	19,237	17,625	15,503	12,797	9,423
10.00	20,344	21,826	21,712	21,329	20,629	19,562	18,069	16,085	13,539	10,350
10.25	20,194	21,818	21,762	21,448	20,831	19,660	18,481	16,630	14,237	11,226
10.50	20,039	21,798	21,797	21,549	21,011	20,133	18,862	17,138	14,893	12,052
10.75	19,880	21,766	21,818	21,633	21,170	20,381	19,215	17,612	15,508	12,831
11.00	19,717	21,724	21,826	21,701	21,309	20,606	19,539	18,053	16,085	13,564
11.25	19,551	21,672	21,821	21,753	21,430	20,808	19,837	18,463	16,625	14,255
11.50	19,382	21,610	21,804	21,791	21,533	20,988	20,109	18,842	17,129	14,904
11.75	19,209	21,539	21,776	21,815	21,619	21,149	20,357	19,193	17,600	15,514
12.00	19,034	21,459	21,737	21,825	21,689	21,290	20,582	19,516	18,038	16,085

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE ID, 230 kV, GENERATION RESERVE SHARING WITH INTERMECIATE SUBSTATIONS & SUSITNA CONSTRUCTION POWER TRANSMISSION LINE COST INCREASED BY 25% PROBABLE LOAD FORECAST CASE

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	12,040	10,589	9,506	8,032	6,108	3,666	629	-3,088	-7,578	-12,946
8.25	12,018	10,798	9,802	8,432	6,629	4,328	1,454	-2,074	-6,348	-11,467
8.50	11,968	10,967	10,075	8,804	7,117	4,951	2,234	-1,113	-5,179	-10,059
8.75	11,951	11,158	10,326	9,150	7,574	5,537	2,971	-203	-4,068	-8,719
9.00	11,905	11,311	10,556	9,470	8,001	6,089	3,666	660	-3,013	-7,443
9.25	11,852	11,447	10,766	9,767	8,400	6,606	4,322	1,476	-2,012	-6,230
9.50	11,793	11,568	10,956	10,040	8,771	7,091	4,940	2,248	-1,063	-5,077
9.75	11,727	11,673	11,128	10,292	9,116	7,546	5,522	2,977	-163	-3,981
10.00	11,656	11,764	11,283	10,523	9,436	7,971	6,069	3,666	690	-2,940
10.25	11,579	11,842	11,421	10,733	9,732	8,367	6,583	4,316	1,497	-1,952
10.50	11,496	11,906	11,544	10,925	10,006	8,737	7,065	4,929	2,261	-1,014
10.75	11,409	11,958	11,651	11,099	10,258	9,082	7,517	5,506	2,983	-124
11.00	11,318	11,998	11,745	11,255	10,489	9,401	7,940	6,050	3,666	719
11.25	11,222	12,027	11,824	11,395	10,701	9,698	8,336	6,560	4,310	1,518
11.50	11,122	12,040	11,891	11,520	10,894	9,972	8,704	7,040	4,918	2,274
11.75	11,018	12,055	11,946	11,629	11,069	10,224	9,048	7,489	5,491	2,990
12.00	10,911	12,054	11,989	11,725	11,227	10,456	9,367	7,911	6,031	3,666

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

CASE IC , 345 kV, GENERATION RESERVE SHARING PLUS FIRM POWER TRANSFER & SUSITNA PROJECT CONSTRUCTION POWER PROBABLE LOAD FORECAST

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	-1,444	-6,495	-8,636	-11,240	-14,375	-18,116	-22,547	-27,760	-33,860	-40,959
8.25	-1,277	-6,035	-8,069	-10,549	-13,540	-17,115	-21,354	-26,349	-32,198	-39,013
8.50	-1,122	-5,601	-7,532	-9,892	-12,745	-16,159	-20,215	-24,999	-30,608	-37,148
8.75	-979	-5,190	-7,023	-9,268	-11,987	-15,249	-19,128	-23,709	-29,087	-35,363
9.00	-848	-4,802	-6,540	-8,675	-11,267	-14,381	-18,090	-22,477	-27,631	-33,653
9.25	-728	-4,436	-6,083	-8,113	-10,582	-13,554	-17,100	-21,299	-26,239	-32,016
9.50	-618	-4,091	-5,651	-7,579	-9,950	-12,766	-16,155	-20,174	-24,907	-30,449
9.75	-517	-3,766	-5,242	-7,073	-9,311	-12,016	-15,254	-19,099	-23,634	-28,949
10.00	-426	-3,459	-4,856	-6,594	-8,723	-11,302	-14,395	-18,073	-22,417	-27,513
10.25	-344	-3,171	-4,492	-6,139	-8,164	-10,622	-13,576	-17,094	-21,253	-26,139
10.50	-270	-2,901	-4,147	-5,709	-7,634	-9,976	-12,795	-16,159	-20,141	-24,825
10.75	-205	-2,647	-3,823	-5,302	-7,131	-9,361	-12,052	-15,267	-19,079	-23,567
11.00	-146	-2,409	-3,517	-4,917	-6,654	-8,777	-11,343	-14,416	-18,064	-22,365
11.25	-95	-2,186	-3,230	-4,554	-6,201	-8,222	-10,669	-13,604	-17,094	-21,215
11.50	-51	-1,978	-2,959	-4,210	-5,773	-7,694	-10,027	-12,830	-16,169	-20,115
11.75	-13	-1,783	-2,705	-3,886	-5,367	-7,194	-9,417	-12,093	-15,285	-19,065
12.00	18	-1,602	-2,467	-3,581	-4,984	-6,719	-8,836	-11,390	-14,442	-18,060

TABLE 8-7

CHAPTER 9

FINANCIAL PLANNING CONCEPTS

FINANCIAL PLANNING CONCEPTS

The approach taken towards the financial planning for the intertie facilities represents an initial effort to structure the financial package required to implement the Railbelt interconnection. The concepts included in this chapter are intended to be representative of the conditions under which funding would proceed but are in no way definitive recommendations. Rather, they are anticipated to stimulate discussion amongst the participants and increase the understanding of projected financial obligations.

The proportionate allocation of total project costs between participants has been determined in relation to the tangible cost savings derived from the interconnection and represent an equitable division of the total financial burden. The acceptance of these allocations by participants to an Alaska Intertie Agreement (AIA) will require individual utility financial positions to be evaluated. Provision has been made for projected debt service to be analyzed for each participant, to facilitate the evaluation of financial impact on individual utility operations. What follows is an initial exploration of possible financial arrangements, which will serve as a starting point for successive evaluations by each potential participant as more definitive financial plans are evolved.

9.1 SOURCES OF FUNDS

An initial appraisal of possible sources of funds has been made, to determine a combination which will be both financially advantageous and appropriate to the principal division of cost savings between REA and municipal utilities.

The following sources were examined:

- State of Alaska revenue bonds floated by APA
- REA loans negotiated by APA and participants
- FFB loans negotiated as part of REA loan package
- CFC loans negotiated in conjunction with REA loans
- Municipal bond issues by Anchorage and Fairbanks

A. State of Alaska Revenue Bonds

As State of Alaska revenue bonds would be legally secured by project revenues, a complex formula for revenue generation would be required to arrive at an acceptable level of cash flow to repay the bonds. The formulation could be based on wheeling charges for power flow over the intertie but the number of participants and the differences between their operational requirements could prove an insupperable obstacle to the realization of a final agreement. It is thought that the issue of State bonds should be deferred from present consideration, until such time as a combined generation and transmission project is ready for funding. Within the confines of the Railbelt development, this would be appropriate when consideration is given to the financing of the first hydropower development of the Upper Susitna Project, together with its associated transmission facilities.

Although APA bonds have been retained in the Transmission Line Financial Analysis Program (TLFAP), for analytical purposes, consideration has been given only to the remaining sources in these initial financial plans for implementation of the intertie. The transmission intertie facilities represent what may be regarded as the first stage development of the ultimate transmission system that will be required for the Watana and Devil Canyon hydropower plants of the Upper Susitna Project.

The financial sources discussed in the following sections were considered for composite funding of the Anchorage-Fairbanks Interconnection.

B. Rural Electrification Administration (REA)

The prospective participants, with the exception of the Anchorage and Fairbanks municipal systems, are all REA utilities of the Alaska District. Therefore, a combination of REA insured and guaranteed loans is assumed for the maximum amount of total project financial requirements allowed by federal regulations. REA loans are normally limited to 70 percent of total project costs; however, as OMB restrictions are expected to affect future REA commitments for project funding, this 70 percent limitation was taken to be the magnitude of a loan package comprising both REA and FFB loans. The percentage division between the two sources varies, recent past experience and future projections indicating a range of possibilities, with the FFB portion considerably larger than that of REA.

In the present study, a range of between 20/80 and 40/60 for the combination of REA/FFB loan funds has been assumed for analytical purposes, these percentages being applied to the 70 percent limit for the total loan package, as a proportion of total project costs.

REA loans carry a 5 percent interest rate and have a repayment period of 35 years, the first three years of which require interest only.

C. Federal Financing Bank (FFB)

REA makes guaranteed loans through FFB as a source of supplementary funding for REA utilities. Interest rates for FFB vary but are generally within the range of 9 to 9-1/2 percent. An average of 9-1/4 percent has been used in the financial analysis for this study. A similar 35 year repayment period to that for REA insured loans is normal, with the first three years of interest only also applicable.

The combination REA/FFB loan package offers a means of financing 70 percent of project costs with a minimum of negotiation, as precedents have been set for this type of financial arrangement. The goal of negotiation would be to maximize the REA loan portion and secure the best interest rate applicable to the FFB loan.

D. National Rural Utilities Cooperative Finance Corporation (CFC)

CFC makes loans to REA utilities to supplement REA funds, although these loans are generally used for distribution type facilities. It is possible that a CFC loan could be obtained for a transmission project such as the Intertie but for purposes of this analysis it has been assumed that CFC funding will not be required. If at the time of negotiation there is a definite advantage to be gained by inclusion of a CFC loan portion with sufficiently attractive terms, the resultant impact on the financial plan can be determined.

E. Municipal Bonds

Anchorage and Fairbanks municipalities both have the authority to arrange financing for a portion of the project by the issuance of tax-exempt, general obligation bonds. As separate bond issues would possibly be made, the bonding rate pertaining to Anchorage could differ from that of Fairbanks. A recent bond issue by the Anchorage Municipal Bond Bank to cover G & T expansion on the AML & P system realized a bond rate of 6.48 percent, with 20 year maturity bonds. A rate of 6.5 percent has been used in this study for the projected Anchorage bonds, with a somewhat more conservative level of 7 percent assumed for the Fairbanks bonding. Both sets of bonds were assumed to be of 20 year maturity.

9.2 PROPORTIONAL ALLOCATIONS BETWEEN SOURCES

In the ultimate financial package for the Transmission Intertie, the final negotiated amounts for debt financing and bonding will be agreed to by APA and AIA participants. To arrive at the final allocation of total project costs between possible sources will require a concerted effort on the part of APA and AIA participants, in the successive negotiations with REA and other federal funding agencies such as FFB, together with the officials responsible for decisions relating to issuance of municipal bonds.

To assist with an evaluation of financial positions in relation to possible agreement on questions pertaining to proportional allocations between sources, the Consultants offer the following approach for further consideration.

- A combination of REA and FFB funds would be used to finance a total of 70 percent of project costs. In order to examine the relative improvement of composite financial terms by changes to the percentage allocation between the two sources over a range of combinations, the following allocations were evaluated:

	Combination REA/FFB - %	
Allocation within loan package	20/80	40/60
Allocation of total project costs	14/56	28/42

- The balance of funding, 30 percent of project costs, would be obtained from the following bond issues:

	General Obligation Bonds	
	Anchorage	Fairbanks
Percentage allocation by municipality	18	12

In preparing a financial plan to follow this approach the following analysis was completed using computer programs TLFAP and COMPARE. The results of this analysis are contained in Appendix F, Sheets F-1 thru F-29.

1. An initial run of TLFAP was made with the following allocations and assumptions for funding terms and conditions:

Project Funding	Source	Interest Rate
14%	REA	5%
56%	FFB	9.25%

Above loans have 35 year repayment period with interest only for first three years, during construction period.

18%	AMU	6.5%
12%	FMU	7.0%

Above bond issues have 20 year maturity.

2. On the assumption that the overall financial terms can be improved by changing the proportions of the combination REA/FFB loan package, a second run of TLFAP was made with the following adjustments:

Project Funding	Source	Interest Rate
28%	REA	5%
42%	FFB	9.25%

All other components of project funding remained the same.

It is of interest to compare the composite interest rate for project funding to determine the overall improvement in financial terms. The net effect was a decrease from 8.9 to 8.3 percent for the entire project funding, including all financial sources.

3. To translate this improvement into a present value for purposes of comparison of the respective loan packages, two runs were made using program COMPARE to determine the differential present value of future debt service associated with the two REA/FFB combinations. A net reduction of $1,472,000 in total financial costs was realized. These computations are shown on Sheets F-27 thru F-29.

9.3 ALLOCATED FINANCIAL RESPONSIBILITY FOR PARTICIPANTS

A. Basis for Assumption of Financial Obligation

The approach followed to determine the allocated responsibility for financial participation and debt service matched the proportions of total project costs to allocated cost savings derived from interconnection. The cost savings to be realized from implementation of the transmission intertie are several, these being derived from:

1. Reserve capacity sharing, resulting in cancellation or postponement of in-service dates for certain generating units that would be required with independent system expansion. This in turn results in a reduction of total capital investment.

2. Improvement in overall economics of system operation, within the limits of potential power transfers over the intertie.

3. Reduction in capital expenditures for transmission expansion that would be required if the intertie were not built. A definite saving of this type would be realized by Matanuska Electric Association (MEA) if their system could be supplied from the Palmer bus.

4. Reduction in the cost of construction power for the Susitna Project, by use of a transmission tap-line.

Of the above cost savings, the first and third have been fully quantified in this study, the second would require a detailed computer analysis of the operational costs using a multi-area production costing program. In estimating the cost advantages of power transfer, a simplified analysis was made of the potential economies to be obtained from substitution of selected generation blocks on the basis of fuel cost only. This demonstrates adequately the potential for cost saving but is no substitute for a comprehensive analysis of system operation. This would provide a breakdown by year of the production cost for each unit on the system, whether independent or interconnected, and would include both fuel and O & M components. The simulation of economic dispatch for units on alternative systems is essential for a definitive apportionment of the operational savings between utility participants.

Accordingly, the allocation of cost savings has been determined on the basis of reduction in capital investment by reserve sharing and the elimination of certain expenditures by MEA for transmission expansion. The cost savings to the Susitna Project is not germane to the financial allocations between utilities and has been excluded from analysis.

The cost savings from reserve sharing have been determined by segregating capital disbursements for generating units affected by interconnection between the respective utilities owning and operating the particular units. Table 9-1 indicates the annual capital disbursements by generating utility for independent and interconnected system expansion, together with the cumulative present worth for each of the investment streams.

Cost savings for each participating utility are given by the differential present worth between independent and interconnected investment streams. To these are added the cost savings to MEA for elimination of alternative transmission supply facilities by establishment of the Palmer bus. The cost savings are derived as follows:

Participating Utility	Present Worth of Future Investment - $1000		
	Independent	Interconnected	Cost Savings
AML&P	103,647	91,869	11,778
CEA	236,840	229,941	6,899
MEA			2,097*
GVEA	43,203	-	43,203
		TOTAL	63,977

* MEA Cost savings obtained from Section 8.3C on P.8-6.

The large magnitude of savings accruing to GVEA (68% of total) should be subdivided between GVEA and FMUS, as the municipal system will also benefit directly by association with GVEA and the continued purchase of power generated by GVEA will ultimately be reflected in the customer rates of the FMUS service area. To approximate the division of savings, a long-term average ratio between load forecasts for the two systems in the Fairbanks area was taken to be representative of relative magnitudes and resulted in the following apportionment:

	GVEA	FMUS
Percentage Allocation of Cost Savings	56	12

No further breakdown of allocated benefits was deemed appropriate at this stage; however, it may well be that other utilities such as Homer Electric Association (HEA) may decide to assume a minor share of the responsibility for debt service of the total investment in support of the project. In which case non-generating utilities can participate on an elective basis and future analysis can take into consideration minimum funding participation as a percentage of the total. The only utility which is not an immediate direct beneficiary of the intertie is CVEA. Although TLFAP contains a provision for later participation by this utility, it is not anticipated that CVEA will exercise this option prior to the connection of the Glennallen-Valdez system to the Railbelt system, following completion of the first stage development of the Upper Susitna Project.

The assumption of financial obligation was taken to be directly related to the proportionate division of allocated cost savings. The basis for financial apportionment of total project costs is as follows:

Participating Utility	Cost Savings $ 1000	Percentage Participation
AML&P	11,778	18
CEA	6,899	11
MEA	2,097	3
GVEA	35,827	56
FMUS	7,677	12
TOTAL	63,977	100

These values of percentage participation were used for financial analysis.

B. Allocation of Total Project Costs

An attempt was made to relate the allocation of project costs between participants to physical facilities in sections of the intertie. Table 9-2 contains a division of total project costs on a percentage basis and a breakdown of percentage allocations between participants, to relate their percentage allocation of total project costs with projected potential ownership of physical facilities within their own service area.

The allocation of costs was aided by considering the logical division of the total facility into three sections:

Section	From	To	Distance (Miles)	% Total
I	Anchorage	Palmer	40	12
II	Palmer	Healy	191	59
III	Healy	Ester	92	29

The costs included in Table 9-2 pertain to Case ID transmission facilities for the probable load forecast expansion, consisting of a single-circuit 230 kV transmission line with intermediate switching at Palmer and Healy. This also allows the realization of investment participation by MEA in the AIA to the extent indicated in Table 9-2, which corresponds to the allocated percentage for MEA. These costs are assumed to be largely associated with the Palmer substation. Similarly, the costs allocated to FMUS are assumed to be related to the Healy-Ester line section, on a joint basis with GVEA.

C. Allocation of Debt Repayment and Sinking Fund Payments

The responsibility for loan servicing and payment of sinking fund installments is shared by utility participants, in direct proportion to the cost savings derived from the interconnection. A tabulation of the annual payments by each participating utility is given in Appendix F, Sheets F-13 through F-18. It should be noted that the annual payments do include the pro-rata share of payments to the municipal bond sinking funds tabulated on Sheets F-19 and F-20. The totals are given on Sheets F-21 through F-26.

9.4 COSTS FOR RESERVE SHARING AND FIRM POWER TRANSFER

An analysis was made of the relative costs of reserve capacity and firm power transfer for the two alternative financial plans. Tables 9-3A and B provide annual costs for reserve capacity and firm power transfer based upon the total debt service per year required for the two alternative financial plans, including REA/FFB loan packages in two proportionate combinations.

The division of costs between reserve capacity sharing and firm power transfer was made on the basis of the line capacity which was allocated to each specifc purpose. The total transfer capacity of the 230 kV single-circuit line is 130 MW, this being divided into 100 MW for reserve capacity and 30 MW for firm power transfer. The annual costs for firm power transfer were converted into energy costs equivalent to wheeling charges for load factors of 40, 55 and 70 percent and energy transfer of 105, 145 and 184 GWh, respectively.

The cost streams progressively diminish according to the magnitude of total debt service for the transmission interconnection facilities. The following summary tabulation provides an indication of the average values over the 32 year loan repayment period, following the interest only three year construction period.

AVERAGE VALUES FOR RESERVE CAPACITY AND ENERGY TRANSFER

Combination REA/FFB Loan Package	Reserve Capacity Cost ($/kW/Yr)	Energy Transfer Cost Equivalent to Wheeling Charge Energy Cost - Mills/kWh (40% LF)	(55% LF)	(70% LF)
20/80	43	12	9	7
40/60	41	12	8	7

It may be observed that the average values correspond approximately to the actual values at the year 2003.

9.5 FINANCIAL PLANS FOR FUTURE STAGED DEVELOPMENT

The following is one possible way to plan for funding successive expansions and extensions of the projected interconnection of Railbelt utilities.

A. Interconnection Extension Between Systems

The implementation of the Anchorage-Fairbanks Transmission Intertie will cause Railbelt utilities to examine their system expansions in relation to those of other utilities, to determine mutual benefits of additional transmission facilities to firm ties between adjacent systems. The cost of associated facilities could be financed on a comprehensive basis, possibly on more advantageous terms than if attempted by individual utilities or municipalities. The cost of such additions to utility systems could be met from a revolving fund administered by APA, on behalf of the participants.

One possibility for application of major funds for system extension would be the interconnection of the CVEA system to the Anchorage end of the intertie. The participation of CVEA in the AIA would then be desirable, with possibly a small allocation for initial intertie facilities, prior to the determination of the timing and cost of the facilities to link the initial interconnection with the CVEA system at Glennallen. This could be implemented on a separate basis, or as part of an integrated plan for transmission of hydropower from the Susitna Project.

B. Expansion of a Susitna Transmission System

The implementation of the Susitna Hydropower Project would require that a comprehensive financial plan be followed for funding the generation project and associated transmission facilities. The large increments of power possible from the Susitna development would require the expansion of the initial intertie, to receive energy for transmission to Anchorage and Fairbanks.

As part of the comprehensive financial plan, the funding of transmission line and substation facility expansion through time could be arranged on the basis of total incremental funding, with partition of costs and financial obligations between APA and utility participants, on a similar basis to that used for this initial approach to first stage financing of the transmission system interconnection in the Railbelt.

9.6 REFERENCES

1. International Engineering Company, Inc.
   Financial Planning Model

2. Moody's Bond Record
   'Tax Exempt Bond Fields by Ratings'
   'Tax Exempts Vs. Governments and Corporates'
   January 1979

TABLE 9-1

ALTERNATIVE DISBURSEMENTS OF CAPITAL INVESTMENT FOR GENERATION EXPANSION

$1000
(1979)

Year	pw'	Anchorage Municipal Light & Power System Expansion		Chugach Electric Association System Expansion		Golden Valley Electric Association System Expansion	
		Independent	Interconnected	Independent	Interconnected	Independent	Interconnected
1979	1.0000						
1982	0.9151	2,009					
1983	0.8885	8,037		10,959		7,670	-
1984	0.8626	30,139		31,539	10,959	20,264	-
1985	0.8375	37,172			31,539		
1986	0.8131	21,127					
1987	0.7894	7,152	2,009				
1988	0.7664		8,037			7,555	-
1989	0.7441		30,139	5,480		17,630	-
1990	0.7224		37,172	21,920	5,480		
1991	0.7014		21,127	82,200	21,920		
1992	0.6810		7,152	101,380	82,200		
1993	0.6611		7,020	58,450	101,380		
1994	0.6419	7,020	16,380	22,820	58,450		
1995	0.6232	16,380			22,820		
	TOTAL pw	103,647	91,869	236,840	229,941	43,203	-

NOTE: Present worth obtained using 3% discount rate, equivalent to 7% cost escalation and 10% discount rate.

TABLE 9-2

ALLOCATION OF TOTAL PROJECT COSTS BETWEEN PARTICIPANTS

TO

ALASKAN INTERTIE AGREEMENT

A I A

SECTIONAL INTERCONNECTION DIVISIONS

	Anchorage – Palmer	Palmer – Healy	Healy – Ester	
	Section I	Section II	Section III	
	40 M	191 M	92 M	
INTERTIE COMPONENTS	**PROJECT COSTS - 1979 $1000 (%)**			**TOTAL FACILITY**
Transmission Line	6644 (10)	31,726 (46)	15,282 (22)	53,652 (78)
Substations:				
Anchorage	3976 (6)			3,976 (6)
Palmer	717 (1)	717 (1)		1,434 (2)
Healy		717 (1)	717 (1)	1,434 (2)
Ester			5,080 (7%)	5,080 (7)
Control & Communications	1,450 (2)	400 (1)	1,450 (2)	3,300 (5)
TOTAL	12,787 (19)	33,560 (49)	22,529 (32)	68,876 (100)
AIA PARTICIPANTS	**ALLOCATIONS OF TOTAL PROJECT COSTS (%)**			
AM&LP	(8)	(10)		(18)
CEA	(8)	(3)		(11)
MEA	(3)			(3)
GVEA		(36)	(20)	(56)
FMUS			(12)	(12)

TABLE 9.3A

ALLOCATED COSTS FOR RESERVE CAPACITY SHARING AND FIRM POWER TRANSFER

WITH

FINANCIAL PLAN ALT. 1 - 20/80% COMBINATION REA/FFB LOAN PACKAGE

AND

MUNICIPAL BONDS

		Cost of Reserve Capacity Sharing and Firm Power Transfer Based on Capacity Allocation					
		100 MW Reserve (Annual Cost of Reserve Capacity)		30 MW Firm Power Transfer			
				Annual Cost	(Energy Charge - Mills/kWh)		
Year	Total Debt Service (1979/$1000)	($1000)	($/kW/Yr.)	($1000)	(40% LF)	(55% LF)	(70% LF)
1984	8,670	6,669	67	2,001	19	14	11
1985	8,523	6,556	66	1,967	19	14	11
1986	8,376	6,443	64	1,933	19	13	10
1987	8,229	6,330	63	1,899	18	13	10
1988	8,082	6,217	62	1,865	18	13	10
1989	7,934	6,103	61	1,831	18	13	10
1990	7,787	5,990	60	1,797	17	12	10
1991	7,640	5,877	59	1,763	17	12	10
1992	7,493	5,764	58	1,729	17	12	9
1993	7,346	5,651	57	1,695	16	12	9
1994	7,199	5,538	55	1,661	16	11	9
1995	7,052	5,425	54	1,627	16	11	9
1996	6,905	5,312	53	1,593	15	11	9
1997	6,758	5,198	52	1,560	15	11	8
1998	6,611	5,085	51	1,526	15	11	8
1999	6,464	4,972	50	1,492	14	10	8
2000	6,317	4,859	49	1,458	14	10	8
2001	6,170	4,746	47	1,424	14	10	8
2002	6,023	4,633	46	1,390	13	10	8
2003	5,876	4,520	45	1,356	13	9	7
2004	3,515	2,704	27	811	8	6	4
2005	3,368	2,591	26	777	7	5	4
2006	3,221	2,478	25	743	7	5	4
2007	3,074	2,365	24	709	7	5	4
2008	2,927	2,252	23	675	6	5	4
2009	2,780	2,138	21	642	6	4	3
2010	2,633	2,025	20	608	6	4	3
2011	2,486	1,912	19	574	6	4	3
2012	2,339	1,799	18	540	5	4	3
2013	2,192	1,686	17	506	5	3	3
2014	2,045	1,573	16	472	5	3	3
2015	1,898	1,460	15	438	4	3	2

TABLE 9.3B

ALLOCATED COSTS FOR RESERVE CAPACITY SHARING AND FIRM POWER TRANSFER

WITH

FINANCIAL PLAN ALT. 2 - 40/60% COMBINATION REA/FFB LOAN PACKAGE

AND

MUNICIPAL BONDS

		Cost of Reserve Capacity Sharing and Firm Power Transfer Based on Capacity Allocation					
		100 MW Reserve (Annual Cost of Reserve Capacity)		30 MW Firm Power Transfer			
				Annual Cost	(Energy Charge - Mills/kWh)		
Year	Total Debt Service (1979/$1000)	($1000)	($/kW/Yr.)	($1000)	(40% LF)	(55% LF)	(70% LF)
1984	8,194	6,303	63	1,891	18	13	10
1985	8,061	6,201	62	1,860	18	13	10
1986	7,929	6,099	61	1,830	18	13	10
1987	7,797	3,998	60	1,799	17	12	10
1988	7,665	5,896	59	1,769	17	12	10
1989	7,533	5,795	58	1,738	17	12	9
1990	7,401	5,693	57	1,708	16	12	9
1991	7,268	5,591	56	1,677	16	12	9
1992	7,136	5,489	55	1,647	16	11	9
1993	7,004	5,388	54	1,616	16	11	9
1994	6,872	5,286	53	1,586	15	11	9
1995	6,740	5,185	52	1,555	15	11	8
1996	6,608	5,083	51	1,525	15	11	8
1997	6,475	4,981	50	1,494	14	10	8
1998	6,343	4,879	49	1,464	14	10	8
1999	6,211	4,778	48	1,433	14	10	8
2000	6,079	4,676	47	1,403	13	10	8
2001	5,947	4,575	46	1,372	13	9	7
2002	5,815	4,473	45	1,342	13	9	7
2003	5,682	4,371	44	1,311	13	9	7
2004	3,337	2,567	26	770	7	5	4
2005	3,204	2,465	25	739	7	5	4
2006	3,072	2,363	24	709	7	5	4
2007	2,940	2,262	23	678	7	5	4
2008	2,808	2,160	22	648	6	4	4
2009	2,676	2,058	21	618	6	4	3
2010	2,544	1,957	20	587	6	4	3
2011	2,411	1,855	19	556	5	4	3
2012	2,279	1,753	18	526	5	4	3
2013	2,147	1,652	17	495	5	3	3
2014	2,015	1,550	16	465	4	3	3
2015	1,883	1,448	14	435	4	3	2

CHAPTER 10

INSTITUTIONAL CONSIDERATIONS

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INSTITUTIONAL CONSIDERATIONS

The Intertie Advisory Committee has proven itself most useful during this study. It has enabled initial discussions to be held between potential participants in the projected interconnection of Railbelt utilities via the Anchorage-Fairbanks Transmission Intertie. This committee represents a sure, first step towards the formation of a continuing, viable, cohesive entity, through which the intertie can be built and the resulting benefits realized by the continued expansion and operation of the interconnected utility systems in the Railbelt.

10.1 PRESENT INSTITUTIONS AND RAILBELT UTILITIES

The predominant pattern of ownership management and operating responsibility by public power organizations in Alaska is exemplified by the prospective participants to an Alaskan Intertie Agreement (AIA). In addition to REA and municipal utilities in the Railbelt, it is anticipated that both the Alaska Power Administration and the Alaska Power Authority would be parties to the AIA. The probable composition of institutions and participating utilities is anticipated to be:

- Alaska Power Authority
- Anchorage Municipal Light and Power
- Chugach Electric Association, Inc.
- Homer Electric Association, Inc.
- Matanuska Electric Association, Inc.
- Golden Valley Electric Association, Inc.
- Fairbanks Municipal Utility System
- Alaska Power Administration

The above group of utilities may be joined by Copper Valley Electric Association, Inc. at a later date, to extend the interconnected facilities to the Glennallen-Valdez system.

A. Statutes and Limitations

The enabling legislation for the Alaska Power Authority (APA) is contained in HB 442 for the Legislature of the State of Alaska. It provides for the establishment of power projects and the authorization to proceed with developments that will serve "to supply power at the lowest reasonable cost to the state's municipal electric, rural electric, cooperative electric, and private electric utilities, and regional electric authorities, and thereby to the consumers of the state, as well as to supply existing or future industrial needs".

APA would mainly act on behalf of the municipal and rural electric utilities as a party to the AIA. Therefore, it is not presently anticipated that the authorized "powers to construct, acquire, finance, and incure debt" would be required for the Intertie Project. Rather APA could integrate and coordinate the efforts of the other participants to the AIA, to ensure that an expeditious approach is maintained during the course of the project.

APA is in an excellent position to coordinate regional programs with its state-wide involvement. For example, such coordination may assist in the process of securing an abridgement of the two county rule for the transmission intertie. Left unresolved, such existing statutes may otherwise constitute a roadblock to the realization of the benefits to be achieved by interconnection of systems of participating utilities over the large geographical area encompassed.

B. Jurisdiction and Service Territories

The Alaska Power Authority exercises jurisdiction over power projects in Alaska as a State entity. It parallels the Alaska Power Administration, which has federal jurisdiction in Alaska for the United States Department of Energy in Washington, D.C.

Both State and Federal entities have statewide responsibility in Alaska.

The service territories of the municipal and rural electric utilities are shown on the maps of Figures 4-1, 4-2, and 4-3 in Chapter 4. The confines of the Railbelt result in elongated geographical service areas. Such areas are particularly appropriate in relation to the transmission corridor for the intertie and enable the delineation of easements along the route to be made relative to existing transmission and distribution facilities in the area.

10.2 ALASKAN INTERCONNECTED UTILITIES

To provide an identity for the utility participants to the AIA, it is suggested that the name Alaskan Interconnected Utilities (AIU) be adopted by the existing Railbelt utilities to be included in the institutional and management plan for the implementation and operation of the intertie.

A. Present Arrangements and Future Requirements

To a certain extent, the operating utilities in the Anchorage and Fairbanks areas have already evolved mutual interests. These interests now need to be augmented, to satisfy future operating requirements.

Prior to interconnection, there would be a need to coordinate revised planning for system expansion, the scheduled construction of facilities, and the separate building programs of each utility. A Planning Subcommittee of the Intertie Advisory Committee, composed of technical staff from AIU, would be desirable in the near future if this program is implemented. This planning subcommittee could be empowered to resolve joint planning problems affecting participating members.

Later on, an Operating Subcommittee would be required to determine operating procedures and coordinate system planning policy, working towards centralized economic dispatch for the interconnected system. The need for communications facilities will also need to be addressed, together with the mode of overall system control and data acquisition for interconnected facilities.

B. Evolution of Institutional Framework

In any approach toward projecting institutional requirements for the establishment of the necessary framework to support the Anchorage-Fairbanks Transmission Intertie, it is essential to preserve a sense of perspective towards the future and allow for the possibility of integrating the presently conceived plans and concepts within a larger and more comprehensive institutional structure. This is particularly appropriate to the task of system interconnection, when successive expansions are necessary to accommodate the incremental additions associated with major generating plants.

In the case of the Railbelt, the possible implementation of the major hydropower developments of the Upper Susitna Project, would require that the institutional structure required for the transmission intertie be compatible with future institutional needs of the Susitna developments. Thus, whatever institutional changes would be brought about by a program of hydropower development of the Susitna should represent only a transition between organizational requirements keyed to transmission system expansion without the facilities of the Susitna developments and with the addition of major hydropower sources, such as Watana and Devil Canyon.

The evolutionary approach to effecting this transition is preferable over an abrupt change of institutional structures and it is thought that, with the acceptance of a pattern of multiple participation in the planning, financing, implementation, and operation of the Intertie, a suitable mode of proportionate involvement can also be considered for applicability to other transmission facilities required for the Susitna Project. This division of fiscal and managerial responsibility can also be extended into the operation of the system.

In this way a maximum of local utility participation can be achieved, with a financially beneficial allocation of total project costs between funding sources to arrive at a least financial cost package to multiple borrowers having pre-arranged sharing of debt-service obligations.

10.3 REFERENCES

1. Battelle Pacific Northwest Laboratories, Alaska Electric Power: An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region, March 1978.

2. University of Alaska, Institute for Social and Economic Research, Electric Power in Alaska 1976-1995, August 1976.

3. House Bill 442 in the Legislature of the State of Alaska, Finance Committee, Tenth Legislature - Second Session.

APPENDIX A

NOTES ON FUTURE USE OF ENERGY IN ALASKA

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NOTES ON FUTURE USE OF ENERGY IN ALASKA

Power requirements studies analyzing historical data and forecasting future trends have been regularly accomplished for the REA-financed electric utilities in Alaska since they began operation. These studies and their forecasts over the years provide an interesting perspective as to the changes in use of electricity and the change in numbers of users, but do not fully account for the forces that produce these changes.

It is observed that electrical uses increase as the dreary, manual routines of everyday life are displaced by the equivalent electrically-powered devices. This allows the human effort to be directed elsewhere or eliminated. Electric lighting, water pumping (many Alaska homes have their own water systems) and heating, clothes washing, refrigerator, freezer, vacuum cleaner, dishwasher, cooking aids, radio and TV (education and recreation), lawn mower, chain saw, etc., all direct electrical energy toward improving the quality of life and making human effort more productive.

The typical Alaskan family is becoming more productive as a unit through an increasing percentage of the family partners entering the community group of wage earners. Increasing income allows the family to seek out new means of improving the quality of living.

There are on the horizon a number of technological triumphs that will undoubtedly find uses in those communities where the families can assign some of their resources to enhancing their lives. The home computer with its implications of many more "robots" to come and the electric car are just two of such items nearing the scene.

These considerations certainly support the trends of electrical energy use that are being forecast and could well result in the forecasts being exceeded, if the rising standards of Alaskan life are maintained into the future.

The following paragraphs are a direct excerpt from a system planning report (see Ref. 7 in Section 3) completed in early 1979 for the Matanuska Electric Association, Inc. of Palmer, Alaska. This electric system is the oldest REA-financed system in Alaska and the statistics cited which relate the use of electrical energy to the average family earnings over a period of 35 years of actual history and a forecast of 15 to 25 years are interesting indeed.

*INTRODUCTION

The accomplishment of long-range planning requires that data be estimated for future conditions and that technical answers for those conditions be evaluated in a prudent manner. Technical answers to a defined set of conditions can be readily developed using state-of-the-art methods. An occasional set of conditions prompts innovation when conventional methods appear limited; but, it is demonstrably clear that the <u>estimate of future conditions</u> is the single most significant factor affecting the ultimate value of a long-range plan.

It will be noted in the following System Planning Report a great effort was made to provide <u>accurate and detailed historical data</u>. A better understanding of the nature of electrical consumers and their actual performance amidst the set of observed environmental restraints (political and natural) is bound to be enhanced by such data. It is believed that forecasts of future conditions will also benefit in sufficient measure to make the effort a bargain.

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* Excerpted from MEA System Planning Report, January 1979 - see Chapter 3, Ref. 7.

The understanding of a long-range plan in the context of the whole growth of a community or region and in terms more useful to the consumer of electricity and his representatives is believed extra difficult today because of environmental concerns, high inflation and other cost aberrations.

To provide some perspective that is intended to illuminate the broad impact and position of the MEA electric supply system on its service area a tabular listing of significant MEA statistics is included herewith on the following page, Table A-1.

This table contains the 35-year history of MEA and a 20-year forecast based on the data in the Long-Range Plan. The numbers listed may surprise the reader at first inspection but this simple listing of historic factual data and related future estimates serves to demonstrate the powerful influence of electricity on the quality of life and the productivity of the MEA service area.

TABLE A-1

MEA STATISTICAL SUMMARY - PAST, PRESENT AND FORECAST

Year	Ave. No. Served / Average kWh/Mo.	Ave. No. (w/o LP) / Average kWh/Mo.	Miles of Line Dist. / Trans.	Const. Per Mile Dist.	Ave. Cost Purch. Power $/kWh	Average Revenue Total Sales $/kWh	Average Revenue (w/o LP) $/kWh	Average Bill/Const. (w/o LP) $/Mo.	Average Family Income $/Mo.	Portion of Income Percent
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1942	210/142	188/47	90/0	2.3	0.020	0.0628	0.1074	5.07	175	2.9
1954	1401/533	1393/335	313/0	4.5	0.0196	0.0450	0.0531	17.82	590	3.02
1966	3134/951	3113/694	708/63	4.4	0.0114	0.0348	0.0366	25.40	885	3.9
1977	9434/1578	9352/1318	1430/97	6.6	0.0128	0.0359	0.0368	48.50	2248	2.4
					See Footnotes					
Level I ('82-85')	16693/2100	16510/1785	2212/241	7.5	0.0187	0.0546	0.0559	99.78	3303	3.02
Level II ('87-'92)	30510/2799	30060/2488	2705/269	11.3	0.0348	0.0692	0.0705	175.30	4853	3.60
Level III ('92-'99)	55744/3714	54956/3494	3041/293	18.3	0.0488	0.0829	0.0837	292.45	7131	4.10

The basic historical data was taken from the REA From 7. Each column is explained as follows:

(1) The year of operation - MEA first energized its system on January 19, 1942. Level I, II, and III refer to the Load Levels of the December 1978 Long Range Plan. The years in parenthesis are estimated dates when these levels might be reached.

(2) The total average number of consumers with LPs and their average monthly energy (kWh) use.

(3) The average number of consumers (w/o LPs) and their average monthly energy (kWh) use.

(4) Miles of line at year end.

(5) Average number of consumers served per mile of distribution line - Columns (2) divided by Column (4).

(6) Cost of purchased power - at Levels I, II and III these are estimates developed by RWR from miscellaneous sources. These forecast are believed to be consistent with other elements of the forecast.

(7), (8), and (9) For levels I, II and III the figures resulted from a generalized forecast of costs using the investments indicated by the Long Range Plan escalated at 7% per year, the operating costs per consumer escalated @ 7% per year and the purchased power costs of Column (6). It was also assumed that there would be 10% losses of energy and that MEA margins would be 10% of Gross Revenue.

(10) The estimated average family income is developed from old payroll records, the "Statistical Abstract of the U.S." (Public by Bureau of the Census) 1977, and "The Alaska Economy, Year-End Performance Report 1977" (Published by Alaska Department of Commerce and Economic Development). Future income estimates made by escalating 1977 numbers at 1.08 per year which is the approximate average growth rate of income for the last 35 years.

(11) Column (9) divided by Column (10) multiplied by 100.

APPENDIX B
TRANSMISSION LINE COST ANALYSIS PROGRAM (TLCAP)

APPENDIX B
TRANSMISSION LINE COST ANALYSIS PROGRAM (TLCAP)

B.1 GENERAL DESCRIPTION

The Transmission Line Cost Analysis Program (TLCAP) calculates the installation, operation, and maintenance costs of a transmission line using a detailed unit cost model. It also automatically determines the "optimum" span and conductor size combination. Applications include the following:

- Voltage Selection - TLCAP examines the relative economics of various voltage levels.

- Span and Conductor Optimization - Span and conductor are optimized simultaneously to provide a matrix of present worth costs. Sensitivity of present worth costs to assumed discount rate is also automatically included.

- Tower Type Selection - TLCAP compares the cost impact of alternate tower types.

B.2 COMPUTER PROGRAM APPLICATIONS FOR OPTIMUM TRANSMISSION LINE COSTS

Choosing the most economical voltage level and other line parameters for any projected transmission line is a complex problem. It requires the simultaneous consideration of a multitude of interrelated factors, each of which will have a decided influence on line performance and the installed and operational costs of both the line and the overall system. The installed cost of a line increases rapidly with the voltage used. For typical single-circuit ac lines, the cost increase is approximately in direct proportion to the increase in voltage. On the other hand, the load carrying capacity of a line increases with the square of the voltage, but this is partially offset by the increase in phase spacing and the resultant increase of line impedance.

Another factor affecting the load carrying capacity and line cost is the size of the conductor and the number of conductors per phase. Since the installed cost of the conductors may constitute as much as 28% of the total line cost, the selection of the conductor is an important decision in any line design.

For EHV lines, conductor size selection is first governed by two basic electrical requirements - the current carrying capacity and the corona performance in terms of corona loss radio interference (R.I.) and television interference (T.V.I.). As the line voltage increases, the corona performance becomes more and more the governing factor in selecting conductor size and bundle configuration.

If consideration is given to the electrical aspects alone, there is an optimum solution as to the size and number of conductors for each voltage level and load carrying requirement. However, the size of the conductor affects the loads on the structures supporting it, as well as the sag, tension, span length, and tower height and weight. All such factors influence the total cost and economics of the line. Hence, both the electrical and mechanical aspects must be considered together in order to arrive at a truly optimized overall line cost. Often a solution which is entirely satisfactory from the electrical viewpoint alone will be in conflict with the mechanical requirements. This is particularly true at locations where heavy ice loading is encountered. For example, a small conductor in a bundle of three may meet all the electrical requirements but may be entirely unsatisfactory mechanically due to excessive sag and overstress. This results in higher towers or shorter spans with more towers per unit length of line than would a larger conductor in a bundle of two. A large number of conductor and phase configurations must usually be tried before an optimum solution is found for a specific voltage level.

The voltage level for any given line should be chosen on the basis of its effect on the system to which it will be connected. This may require medium- or long-range estimation of load flow. For example, it may be more advantageous to build a single 750-kV line instead of two 400-kV lines. Each solution has its own impact on the system with respect to reliability, stability, switching over-voltages, transfer of power, and possibly the cost of future expansion. In other words, the line should be custom designed to meet present and future needs of the system within which it is to operate. It should also provide for the lowest overall cost in terms of investment and operation. Without proper attention to future needs, the "lowest initial cost solution" for a line between two given points may not necessarily be the most desirable or satisfactory one.

In addition to the variables mentioned above, there are numerous other line parameters that must be considered to properly evaluate and compare the various solutions. A few of the more important ones are:

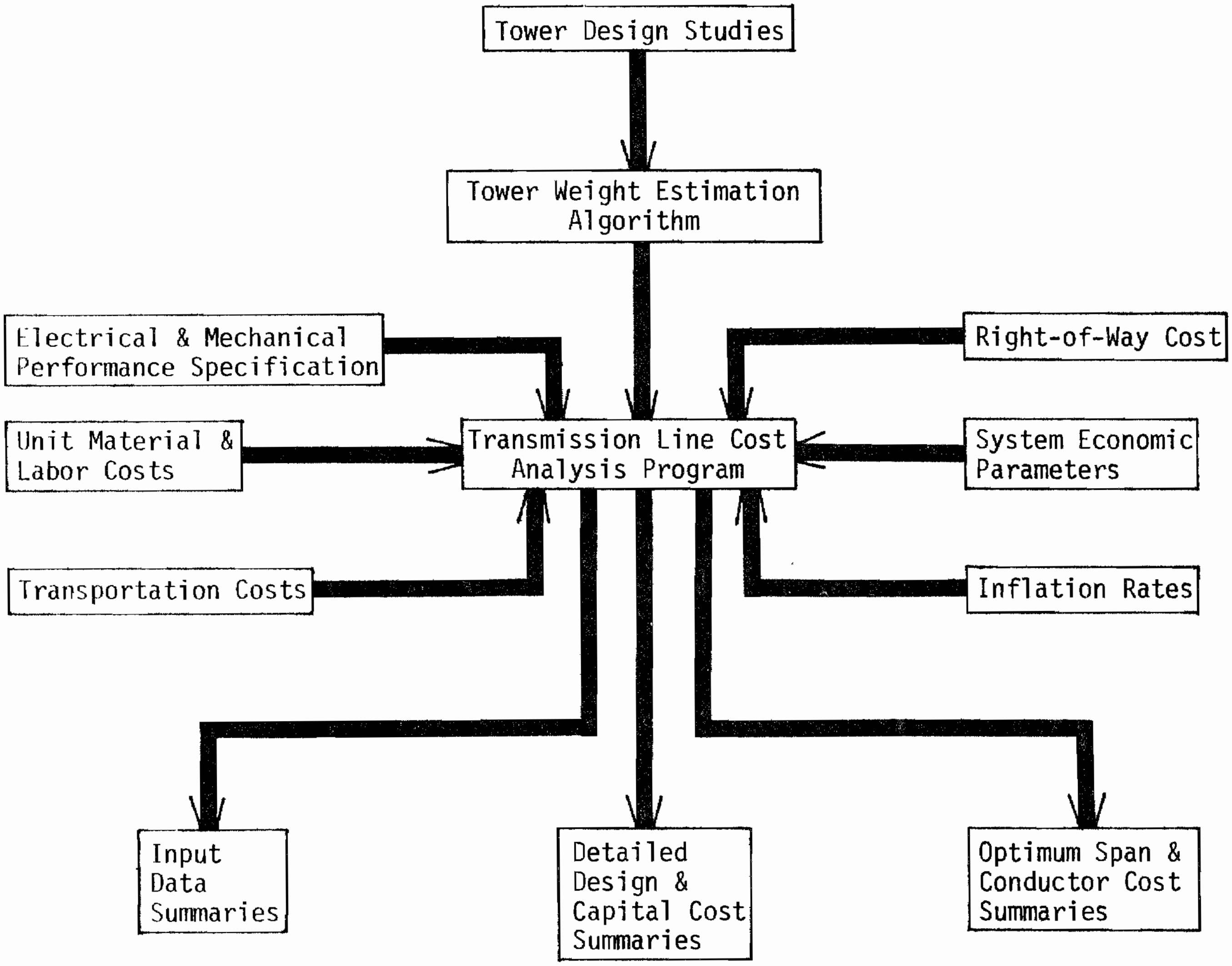
- Conductor material, size, and stranding.
- Tower types, such as rigid or guyed, single or double-circuit, ac or dc, metal or wood.
- Foundation costs.
- Wind and ice load criteria, and their effect on tower cost through transverse, vertical, broken-wire, and/or construction loads.
- Number and strength of insulators.
- Insulator swing and air gap.
- Applicable material and labor costs.
- Investment charges, demand, and annual energy loss charges.

To accurately assess all the complexities and interrelationships, and to integrate them into a totally coordinated design that will produce a line of required performance at minimum cost, a carefully engineered computer program was developed by IECO. Program methodology of TLCAP is shown on Figure C-1. Briefly, program elements include:

FIGURE B-1

TRANSMISSION LINE COST ANALYSIS PROGRAM (TLCAP)

METHODOLOGY



- Conductor Selection - A large variety of conductor sizes and strandings are on file for automatic use by the program. Depending upon line voltage and load, the program determines the minimum power and energy losses for each conductor studied.

- Insulation Selection - The program calculates the incremental cost differences caused by changes in the insulator length, which together with other studies of system performance indicates the best insulation for each voltage level. To ensure maximum transmission capacity, the minimum possible phase spacing is used with each type of tower, considering clearance to tower steel and insulator swing.

- Tower Selection and Span Optimization - The installed cost of towers represents a large portion of the total line cost. Therefore, this item is given special and careful consideration in the calculations. The installed cost of a tower is usually a function of the weight of the steel used. A considerable difference in weight between different tower configurations can be experienced, even in cases where the loads are identical. If to this variable, the variations in loads due to conductor size, bundling, and climatic criteria are added, it becomes evident that correct tower weights can only be determined by an actual tower design in which all the variables are properly considered. Therefore, the optimization program is complemented with a tower design program. Appropriate foundation and insulation costs are added to each tower solution to obtain the total installed cost per tower location. This information is then used by the optimization program to determine the optimum span length (the span that results in the lowest tower cost per unit length of line) for each conductor configuration being considered.

In processing these criteria, including a present worth evaluation of annual energy loss and other time-related charges, the optimization program arrives at a long-range minimum cost solution for each voltage level investigated. However, as previously mentioned, the final evaluation of the adequacy of a line should be based upon its present and future effect on the system as a whole. Therefore, the lowest cost solution for a select number of conductor configurations, with their specific electrical characteristics, should be tried in a few additional system study runs to obtain a proper basis for a final decision.

B.3 TLCAP SAMPLE OUTPUTS

Sample outputs of the TLCAP computer program are shown on the following pages. The output cases are listed below:

- Anchorage - Fairbanks, 230 kV (Case IA).
- Anchorage - Fairbanks, 230 kV (Case IB).
- Anchorage - Fairbanks, 345 kV (Case IC).
- Anchorage - Devil Canyon, 345 kV (Case II-1).
- Devil Canyon - Ester, 230 kV (Case II-2A).
- Watana - Devil Canyon, 230 kV (Case II-3A).

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 1: 23 FEB 1979,

ANCHORAGE-FAIRBANKS INTERTIE   CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

****
*   *
*   INPUT DATA   *
*   *
****

SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
STARTING YEAR OF STUDY	1979	
ENDING YEAR OF STUDY	1996	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	136.8 MVA	1992
AVERAGE CIRCUIT LOADING	41.0 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATE:		
MINIMUM	7.0 PERCENT	1984
MAXIMUM	10.0 PERCENT	1984
NUMBER OF INTERVALS	1	
O&M COST FACTOR	1.5 % CAP.COST	1979
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

****
* INPUT DATA *
****

CONDUCTOR DATA

NUMBER PER PHASE	1	
CONDUCTOR SPACING	0.0	IN
VOLTAGE	230	KV
VOLTAGE VARIATION	10.00	PCT
LINE FREQUENCY	60	CPS
FAIRWEATHER LOSSES	0.00	KW/MI
LINE LENGTH	323.00	MILES
POWER FACTOR	0.95	

GROUNDWIRE DATA

NUMBER PER TOWER	0	
DIAMETER	0.00	IN
WEIGHT	0.0000	LBS/FT

SPAN DATA

MINIMUM	1200.	FT
MAXIMUM	1600.	FT
INTERVAL	100.0	FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18	IN/HR
MAXIMUM RAINFALL DURATION	1	HRS/YR
AVERAGE RAINFALL RATE	0.03	IN/HR
AVERAGE RAINFALL DURATION	636	HRS/YR
MAXIMUM SNOWFALL RATE	1.87	IN/HR
MAXIMUM SNOWFALL DURATION	1	HRS/YR
AVERAGE SNOWFALL RATE	0.13	IN/HR
AVERAGE SNOWFALL DURATION	264	HRS/YR
RELATIVE AIR DENSITY	1.000	

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

INPUT DATA

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	20.0 FEET	D1	20.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	20.00 FT
GROUND CLEARANCE	28.0 FEET	D3	40.00 FT
NO. OF INSULATORS PER TOWER	48	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	6.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 9: 230KV TOWER

TW = 0.00016*TH**2 - 3.09797*TH**0.3333 - 0.08943*EFFVDL -
0.27367*EFFTDL + 0.00510*TH*EFFTDL + 0.00160*TH*EFFVDL +
18.37912 KIPS

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

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* INPUT DATA *
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CONDUCTOR SUMMARY
****

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
24	GROSBEAK	636.0	26/ 7	0.8750	0.9900	0.5809	11.00	10.3
25	EGRET	636.0	30/19	0.9880	1.0190	0.6134	11.30	9.7
26	FLAMINGO	666.0	24/ 7	0.8590	1.0000	0.5914	10.55	10.7
27	GANNET	666.0	26/ 7	0.9180	1.0140	0.6087	11.00	10.3
28	STILT	715.0	24/ 7	0.9210	1.0360	0.6348	10.55	10.7
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9

ANCHORAGE-FAIRBANKS INTERTIE   CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
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CONDUCTOR SUMMARY

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
24	GROSBEAK	25000.0	0.0335	0.628/1977	790.	0.1452	0.4118	2.6347
25	EGRET	31500.0	0.0351	0.609/1977	870.	0.1447	0.4060	2.6136
26	FLAMINGO	23700.0	0.0335	0.640/1977	810.	0.1399	0.4118	2.6294
27	GANNET	26200.0	0.0343	0.609/1977	820.	0.1373	0.4092	2.6347
28	STILT	25500.0	0.0347	0.627/1977	840.	0.1320	0.4066	2.6400
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816

ANCHORAGE-FAIRBANKS INTERTIE   CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79   TIME: 9:29:47

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*   INPUT DATA  *
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UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	100.0 $/TON
FOUNDATION CONCRETE	100.0 $/YD
FOUNDATION STEEL	100.0 $/TON
CONDUCTOR	100.0 $/TON
GROUND WIRE	100.0 $/TON
INSULATOR	100.0 $/TON OR $/M**3
HARDWARE	100.0 $/TON

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
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AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

CONDUCTOR			INSTALLED COST					PRESENT WORTH		
								LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSPORTATION	INSTALLATION	ENG/IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
39	954.	1300.	68147.	3834.	84796.	9328.	166104.	32600.	3284.	201988.
35	795.	1300.	64664.	3721.	82616.	9088.	160089.	39120.	3151.	202359.
35	795.	1400.	65375.	3684.	82031.	9023.	160113.	39120.	3161.	202394.
37	900.	1300.	67299.	3772.	84608.	9307.	164986.	34543.	3257.	202784.
39	954.	1400.	69552.	3828.	84673.	9314.	167367.	32600.	3322.	203288.
37	900.	1400.	68697.	3766.	84494.	9294.	166251.	34543.	3294.	204088.
35	795.	1500.	66879.	3689.	82176.	9039.	161784.	39120.	3206.	204109.
32	795.	1300.	65558.	3685.	83893.	9228.	162364.	39523.	3195.	205082.
30	715.	1300.	63510.	3615.	82301.	9053.	158478.	44166.	3112.	205756.
30	715.	1400.	64204.	3576.	81729.	8990.	158498.	44166.	3122.	205787.
34	795.	1300.	65807.	3659.	84359.	9279.	163104.	39599.	3209.	205913.
32	795.	1400.	66784.	3669.	83683.	9205.	163342.	39523.	3226.	206091.
39	954.	1500.	71843.	3870.	85337.	9387.	170437.	32600.	3397.	206433.
38	954.	1300.	70136.	3831.	86787.	9547.	170300.	32997.	3371.	206667.
39	954.	1200.	70386.	4033.	87082.	9579.	171080.	32600.	3385.	207065.
37	900.	1500.	70983.	3807.	85172.	9369.	169331.	34543.	3369.	207242.
34	795.	1400.	67235.	3653.	84298.	9273.	164459.	39599.	3248.	207306.
35	795.	1600.	69124.	3735.	82979.	9128.	164966.	39120.	3282.	207367.
30	715.	1500.	65702.	3580.	81896.	9009.	160187.	44166.	3167.	207520.
35	795.	1200.	66889.	3916.	85020.	9352.	165176.	39120.	3254.	207549.
37	900.	1200.	69631.	3977.	86926.	9562.	170096.	34543.	3361.	207999.
29	715.	1300.	64091.	3593.	83683.	9205.	160573.	44804.	3150.	208527.
24	636.	1200.	58648.	3345.	82481.	9073.	153548.	52193.	2975.	208715.
32	795.	1500.	68883.	3701.	84257.	9268.	166109.	39523.	3295.	208926.
36	900.	1300.	69499.	3780.	86682.	9535.	169496.	36096.	3351.	208942.

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 39
954. KCMIL 1300. FT SPAN 87.7 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY	MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840. FT	14086.	9.73	973.	18257.	33316.
GROUNDWIRE	0. FT	0.	0.00	0.	0.	0.
INSULATORS	207. UNITS	1313.	1.14	244.		1557.
HARDWARE		1429.	0.47	47.		1477.
TOWERS	4.3 UNITS	38870.	20.31	2031.	26019.	66921.
FOUNDATIONS	4.3 UNITS	3327.		538.	22280.	26145.
RIGHT OF WAY	13. ACRES	9120.			18241.	27361.
IDC/ENGINEERING		9328.				9328.
TOTALS		68147.	31.65	3834.	84796.	166104.

	PRESENT VALUE ($)		
LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	24588.	7992.	32580.
CORONA LOSSES	0.	19.	19.
TOTALS	24588.	8011.	32600.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
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ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

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*   INPUT DATA   *
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SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
STARTING YEAR OF STUDY	1979	
ENDING YEAR OF STUDY	1996	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	136.8 MVA	1992
AVERAGE CIRCUIT LOADING	49.2 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATE:		
MINIMUM	7.0 PERCENT	1984
MAXIMUM	10.0 PERCENT	1984
NUMBER OF INTERVALS	1	
O&M COST FACTOR	1.5 % CAP.COST	1979
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

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*   INPUT DATA   *
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CONDUCTOR DATA

NUMBER PER PHASE	1
CONDUCTOR SPACING	0.0 IN
VOLTAGE	230 KV
VOLTAGE VARIATION	10.00 PCT
LINE FREQUENCY	60 CPS
FAIRWEATHER LOSSES	0.00 KW/MI
LINE LENGTH	323.00 MILES
POWER FACTOR	0.95

GROUNDWIRE DATA

NUMBER PER TOWER	0
DIAMETER	0.00 IN
WEIGHT	0.0000 LBS/FT

SPAN DATA

MINIMUM	1200. FT
MAXIMUM	1600. FT
INTERVAL	100.0 FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18 IN/HR
MAXIMUM RAINFALL DURATION	1 HRS/YR
AVERAGE RAINFALL RATE	0.03 IN/HR
AVERAGE RAINFALL DURATION	636 HRS/YR
MAXIMUM SNOWFALL RATE	1.87 IN/HR
MAXIMUM SNOWFALL DURATION	1 HRS/YR
AVERAGE SNOWFALL RATE	0.13 IN/HR
AVERAGE SNOWFALL DURATION	264 HRS/YR
RELATIVE AIR DENSITY	1.000

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

INPUT DATA

SAG/TENSION DESIGN FACTORS

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ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

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TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	20.0 FEET	D1	20.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	20.00 FT
GROUND CLEARANCE	28.0 FEET	D3	40.00 FT
NO. OF INSULATORS PER TOWER	48	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	6.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 9: 230KV TOWER

TW = 0.00016*TH**2 - 3.09797*TH**0.3333 - 0.08943*EFFVDL -
0.27367*EFFTDL + 0.00510*TH*EFFTDL + 0.00160*TH*EFFVDL +
18.37912 KIPS

ANCHORAGE-FAIRBANKS INTERTIE   CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

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CONDUCTOR SUMMARY
****

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEFF. ALPHA*E-6 PER DEG F
24	GROSBEAK	636.0	26/ 7	0.8750	0.9900	0.5809	11.00	10.3
25	EGRET	636.0	30/19	0.9880	1.0190	0.6134	11.30	9.7
26	FLAMINGO	666.0	24/ 7	0.8590	1.0000	0.5914	10.55	10.7
27	GANNET	666.0	26/ 7	0.9180	1.0140	0.6087	11.00	10.3
28	STILT	715.0	24/ 7	0.9210	1.0360	0.6348	10.55	10.7
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

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* INPUT DATA *
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CONDUCTOR SUMMARY
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ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
24	GROSBEAK	25000.0	0.0335	0.628/1977	790.	0.1452	0.4118	2.6347
25	EGRET	31500.0	0.0351	0.609/1977	870.	0.1447	0.4060	2.6136
26	FLAMINGO	23700.0	0.0335	0.640/1977	810.	0.1399	0.4118	2.6294
27	GANNET	26200.0	0.0343	0.609/1977	820.	0.1373	0.4092	2.6347
28	STILT	25500.0	0.0347	0.627/1977	840.	0.1320	0.4066	2.6400
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816

ANCHORAGE-FAIRBANKS INTERTIE   CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79   TIME: 9:37:07

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* INPUT DATA   *
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UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	100.0 $/TON
FOUNDATION CONCRETE	100.0 $/YD
FOUNDATION STEEL	100.0 $/TON
CONDUCTOR	100.0 $/TON
GROUND WIRE	100.0 $/TON
INSULATOR	100.0 $/TON OR $/M**3
HARDWARE	100.0 $/TON

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

CONDUCTOR			INSTALLED COST					PRESENT WORTH		
								LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSPORTATION	INSTALLATION	ENG/IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
39	954.	1300.	68147.	3834.	84796.	9328.	166104.	35856.	3284.	205244.
37	900.	1300.	67299.	3772.	84608.	9307.	164986.	37993.	3257.	206235.
35	795.	1300.	64664.	3721.	82616.	9088.	160089.	43028.	3151.	206267.
35	795.	1400.	65375.	3684.	82031.	9023.	160113.	43028.	3161.	206302.
39	954.	1400.	69552.	3828.	84673.	9314.	167367.	35856.	3322.	206545.
37	900.	1400.	68697.	3766.	84494.	9294.	166251.	37993.	3294.	207538.
35	795.	1500.	66879.	3689.	82176.	9039.	161784.	43028.	3206.	208017.
32	795.	1300.	65558.	3685.	83893.	9228.	162364.	43468.	3195.	209027.
39	954.	1500.	71843.	3870.	85337.	9387.	170437.	35856.	3397.	209689.
34	795.	1300.	65807.	3659.	84359.	9279.	163104.	43545.	3209.	209858.
38	954.	1300.	70136.	3831.	86787.	9547.	170300.	36293.	3371.	209963.
32	795.	1400.	66784.	3669.	83683.	9205.	163342.	43468.	3226.	210036.
30	715.	1300.	63510.	3615.	82301.	9053.	158478.	48561.	3112.	210151.
30	715.	1400.	64204.	3576.	81729.	8990.	158498.	48561.	3122.	210182.
39	954.	1200.	70386.	4033.	87082.	9579.	171080.	35856.	3385.	210321.
37	900.	1500.	70983.	3807.	85172.	9369.	169331.	37993.	3369.	210693.
34	795.	1400.	67235.	3653.	84298.	9273.	164459.	43545.	3248.	211251.
35	795.	1600.	69124.	3735.	82979.	9128.	164966.	43028.	3282.	211275.
37	900.	1200.	69631.	3977.	86926.	9562.	170096.	37993.	3361.	211450.
35	795.	1200.	66889.	3916.	85020.	9352.	165176.	43028.	3254.	211457.
30	715.	1500.	65702.	3580.	81896.	9009.	160187.	48561.	3167.	211915.
36	900.	1300.	69499.	3780.	86682.	9535.	169496.	39701.	3351.	212547.
38	954.	1400.	72348.	3861.	87234.	9596.	173039.	36293.	3440.	212771.
32	795.	1500.	68883.	3701.	84257.	9268.	166109.	43468.	3295.	212871.
29	715.	1300.	64091.	3593.	83683.	9205.	160573.	49222.	3150.	212944.

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 39
954. KCMIL 1300. FT SPAN 87.7 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY		MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840.	FT	14086.	9.73	973.	18257.	33316.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	207.	UNITS	1313.	1.14	244.		1557.
HARDWARE			1429.	0.47	47.		1477.
TOWERS	4.3	UNITS	38870.	20.31	2031.	26019.	66921.
FOUNDATIONS	4.3	UNITS	3327.		538.	22280.	26145.
RIGHT OF WAY	13.	ACRES	9120.			18241.	27361.
IDC/ENGINEERING			9328.				9328.
TOTALS			68147.	31.65	3834.	84796.	166104.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	24588.	11249.	35837.
CORONA LOSSES	0.	19.	19.
TOTALS	24588.	11268.	35856.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 2: 02 AUG 1979.

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 14:06:42

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*   INPUT DATA  *
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SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
BASE YEAR FOR PW ANALYSIS	1979	
ENDING YEAR OF STUDY	1997	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	168.4 MVA	1984
AVERAGE CIRCUIT LOADING	58.9 MVA	1984
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATES:		
	7.0 PERCENT	1984
	10.0 PERCENT	1984
O&M COST FACTOR	1.5 % CAP.COST	1984
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 14:06:42

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INPUT DATA
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CONDUCTOR DATA			GROUNDWIRE DATA			SPAN DATA		
NUMBER PER PHASE	2		NUMBER PER TOWER	0		MINIMUM	1000.	FT
CONDUCTOR SPACING	18.0	IN	DIAMETER	0.00	IN	MAXIMUM	1600.	FT
VOLTAGE	345	KV	WEIGHT	0.0000	LBS/FT	INTERVAL	100.0	FT
VOLTAGE VARIATION	10.00	PCT						
LINE FREQUENCY	60	CPS						
FAIRWEATHER LOSSES	1.70	KW/MI						
LINE LENGTH	323.00	MILES						
POWER FACTOR	0.95							

WEATHER DATA		
MAXIMUM RAINFALL RATE	1.18	IN/HR
MAXIMUM RAINFALL DURATION	1	HRS/YR
AVERAGE RAINFALL RATE	0.03	IN/HR
AVERAGE RAINFALL DURATION	636	HRS/YR
MAXIMUM SNOWFALL RATE	1.87	IN/HR
MAXIMUM SNOWFALL DURATION	1	HRS/YR
AVERAGE SNOWFALL RATE	0.13	IN/HR
AVERAGE SNOWFALL DURATION	264	HRS/YR
RELATIVE AIR DENSITY	1.000	

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 14:06:42

INPUT DATA

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	27.0 FEET	D1	27.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.00	D2	27.00 FT
GROUND CLEARANCE	32.0 FEET	D3	54.00 FT
NO. OF INSULATORS PER TOWER	72	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	9.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 10: 345KV TOWER

TW = 0.00043*TH**2 - 0.992111*TH**0.6000 - 0.10371*EFFVDL -
0.27365*EFFTDL + 0.00503*TH*EFFTDL + 0.00181*TH*EFFVDL +
20.77701 KIPS

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 14:06:42

INPUT DATA

CONDUCTOR SUMMARY

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9
40	ORTOLAN	1033.0	45/ 7	1.1650	1.2130	0.8678	9.40	11.5

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 14:06:42

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INPUT DATA
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CONDUCTOR SUMMARY
****

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816
40	ORTOLAN	28900.0	0.0401	0.670/1977	1020.	0.0924	0.3902	2.4658

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 14:06:42

INPUT DATA

UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS

REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS

TOWER	131.0 $/TON
FOUNDATION CONCRETE	131.0 $/YD
FOUNDATION STEEL	131.0 $/TON
CONDUCTOR	131.0 $/TON
GROUND WIRE	131.0 $/TON
INSULATOR	131.0 $/TON OR $/M**3
HARDWARE	131.0 $/TON

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 14:06:42

AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

PRESENT WORTH ($)

CONDUCTOR			INSTALLED COST						LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSP.	INSTALL.	ENGINEER.	IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
35	795.	1300.	108253.	6482.	110086.	24730.	0.	249551.	46122.	3372.	299046.
35	795.	1400.	110039.	6483.	108849.	24791.	0.	250162.	46122.	3381.	299665.
30	715.	1300.	105622.	6257.	109368.	24337.	0.	245584.	52150.	3319.	301053.
35	795.	1200.	107799.	6557.	112490.	24953.	0.	251799.	46122.	3403.	301324.
30	715.	1400.	107324.	6253.	108105.	24385.	0.	246066.	52150.	3325.	301541.
37	900.	1300.	112812.	6579.	112648.	25524.	0.	257563.	41403.	3481.	302447.
32	795.	1300.	109255.	6395.	111472.	24983.	0.	252106.	47191.	3407.	302703.
35	795.	1500.	113021.	6550.	108617.	25101.	0.	253289.	46122.	3423.	302834.
39	954.	1300.	114706.	6710.	113084.	25795.	0.	260295.	39129.	3517.	302941.
37	900.	1200.	111385.	6608.	114494.	25574.	0.	258061.	41403.	3487.	302951.
39	954.	1200.	113228.	6736.	114915.	25837.	0.	260716.	39129.	3523.	303367.
30	715.	1200.	105232.	6336.	111787.	24569.	0.	247924.	52150.	3350.	303424.
34	795.	1300.	109378.	6337.	111931.	25041.	0.	252687.	47590.	3415.	303691.
32	795.	1200.	108121.	6439.	113468.	25083.	0.	253111.	47191.	3420.	303722.
29	715.	1300.	105955.	6199.	110878.	24534.	0.	247565.	53308.	3345.	304219.
34	795.	1200.	107991.	6369.	113774.	25095.	0.	253229.	47590.	3422.	304242.
30	715.	1500.	110237.	6316.	107857.	24685.	0.	249095.	52150.	3366.	304611.
32	795.	1400.	111805.	6432.	110688.	25182.	0.	254106.	47191.	3434.	304731.
37	900.	1400.	115679.	6631.	112024.	25777.	0.	260112.	41403.	3515.	305029.
29	715.	1200.	104868.	6246.	112878.	24639.	0.	248632.	53308.	3360.	305300.
39	954.	1400.	117620.	6765.	112473.	26054.	0.	262913.	39129.	3553.	305594.
29	715.	1400.	108480.	6233.	110103.	24730.	0.	249545.	53308.	3372.	306225.
34	795.	1400.	112220.	6386.	111322.	25292.	0.	255220.	47590.	3449.	306259.
35	795.	1100.	108831.	6718.	116263.	25499.	0.	257312.	46122.	3477.	306911.
37	900.	1100.	111580.	6730.	117785.	25970.	0.	262065.	41403.	3541.	307009.

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 14:06:42

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 35
795. KCMIL 1300. FT SPAN 89.3 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY		MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	31680.	FT	35171.	19.56	2563.	33947.	71681.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	310.	UNITS	2582.	1.70	480.		3062.
HARDWARE			1874.	0.47	62.		1936.
TOWERS	4.3	UNITS	83824. - ?	33.41 -	4377. -	49735.	137936.
FOUNDATIONS	4.3	UNITS	6280.		1015.	42054.	49349.
RIGHT OF WAY (107FT)	13.	ACRES	12167.			18565.	30732.
SUB-TOTALS			141897.	55.15	8497.	144301.	294695.
IDC							0.
ENGINEERING							32416.
						TOTAL	327111.
PRESENT WORTH			108253.		6482.	110086.	224821.
IDC							0.
ENGINEERING							24730.
						TOTAL	249551.

PRESENT WORTH ($)

LOSS ANALYSIS		DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES		25483.	14441.	39924.
CORONA LOSSES:	INSULATORS	1624.	3145.	4768.
	CONDUCTOR	-	1430.	1430.
TOTALS		27107.	19015.	46122.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 2: 02 AUG 1979,

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 15:56:14

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*   INPUT DATA   *
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SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
BASE YEAR FOR PW ANALYSIS	1979	
ENDING YEAR OF STUDY	1997	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	631.6 MVA	1992
AVERAGE CIRCUIT LOADING	347.4 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATES:		
	7.0 PERCENT	1984
	10.0 PERCENT	1984
O&M COST FACTOR	1.5 % CAP.COST	1984
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 15:56:14

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CONDUCTOR DATA

NUMBER PER PHASE	2
CONDUCTOR SPACING	18.0 IN
VOLTAGE	345 KV
VOLTAGE VARIATION	10.00 PCT
LINE FREQUENCY	60 CPS
FAIRWEATHER LOSSES	1.70 KW/MI
LINE LENGTH	155.00 MILES
POWER FACTOR	0.95

GROUNDWIRE DATA

NUMBER PER TOWER	0
DIAMETER	0.00 IN
WEIGHT	0.0000 LBS/FT

SPAN DATA

MINIMUM	1000. FT
MAXIMUM	1600. FT
INTERVAL	100.0 FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18 IN/HR
MAXIMUM RAINFALL DURATION	1 HRS/YR
AVERAGE RAINFALL RATE	0.03 IN/HR
AVERAGE RAINFALL DURATION	636 HRS/YR
MAXIMUM SNOWFALL RATE	1.87 IN/HR
MAXIMUM SNOWFALL DURATION	1 HRS/YR
AVERAGE SNOWFALL RATE	0.13 IN/HR
AVERAGE SNOWFALL DURATION	264 HRS/YR
RELATIVE AIR DENSITY	1.000

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 15:56:14

INPUT DATA

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	27.0 FEET	D1	27.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	27.00 FT
GROUND CLEARANCE	32.0 FEET	D3	54.00 FT
NO. OF INSULATORS PER TOWER	72	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	9.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 10: 345KV TOWER

TW = 0.00043*TH**2 - 0.992111*TH**0.6000 - 0.10371*EFFVDL -
0.27365*EFFTDL + 0.00503*TH*EFFTDL + 0.00181*TH*EFFVDL +
20.77701 KIPS

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 15:56:14

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CONDUCTOR SUMMARY
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ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9
40	ORTOLAN	1033.0	45/ 7	1.1650	1.2130	0.8678	9.40	11.5

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 15:56:14

INPUT DATA

CONDUCTOR SUMMARY

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816
40	ORTOLAN	28900.0	0.0401	0.670/1977	1020.	0.0924	0.3902	2.4658

ANCHORAGE-DEVIL CANYON CASE II-1

345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION

DATE: 15 AUG 79 TIME: 15:56:14

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UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	225.0 $/TON
FOUNDATION CONCRETE	225.0 $/YD
FOUNDATION STEEL	225.0 $/TON
CONDUCTOR	225.0 $/TON
GROUND WIRE	225.0 $/TON
INSULATOR	225.0 $/TON OR $/M**3
HARDWARE	225.0 $/TON

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 15:56:14

AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

PRESENT WORTH ($)

CONDUCTOR			INSTALLED COST						LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSP.	INSTALL.	ENGINEER.	IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
39	954.	1300.	114706.	6707.	106803.	25104.	0.	253320.	103751.	3423.	360494.
39	954.	1200.	113228.	6733.	109119.	25199.	0.	254279.	103751.	3436.	361466.
40	1033.	1200.	117782.	6833.	111149.	25934.	0.	261697.	96912.	3536.	362145.
39	954.	1400.	117620.	6763.	105670.	25306.	0.	255358.	103751.	3451.	362560.
40	1033.	1300.	120420.	6862.	109426.	26038.	0.	262747.	96912.	3551.	363209.
37	900.	1300.	112812.	6577.	106335.	24830.	0.	250553.	109695.	3386.	363634.
37	900.	1200.	111385.	6606.	108671.	24933.	0.	251594.	109695.	3400.	364689.
40	1033.	1100.	116899.	6903.	114340.	26196.	0.	264337.	96912.	3572.	364821.
37	900.	1400.	115679.	6629.	105183.	25024.	0.	252516.	109695.	3412.	365623.
39	954.	1100.	113373.	6852.	112838.	25637.	0.	258700.	103751.	3496.	365947.
38	954.	1200.	114994.	6655.	110421.	25528.	0.	257598.	105138.	3481.	366218.
38	954.	1300.	117510.	6678.	108644.	25611.	0.	258442.	105138.	3492.	367073.
39	954.	1500.	121880.	6892.	105583.	25779.	0.	260134.	103751.	3515.	367400.
40	1033.	1400.	124683.	6982.	108982.	26471.	0.	267117.	96912.	3610.	367639.
38	954.	1100.	114231.	6732.	113666.	25809.	0.	260438.	105138.	3519.	369096.
37	900.	1100.	111580.	6728.	112411.	25379.	0.	256098.	109695.	3461.	369253.
35	795.	1300.	108253.	6480.	104166.	24079.	0.	242978.	123194.	3283.	369455.
35	795.	1400.	110039.	6480.	102462.	24088.	0.	243069.	123194.	3285.	369548.
37	900.	1500.	119895.	6755.	105080.	25490.	0.	257220.	109695.	3476.	370391.
38	954.	1400.	121645.	6790.	108142.	26023.	0.	262601.	105138.	3549.	371288.
35	795.	1500.	113021.	6548.	101728.	24343.	0.	245640.	123194.	3319.	372154.
35	795.	1200.	107799.	6555.	107003.	24349.	0.	245705.	123194.	3320.	372220.
32	795.	1300.	109255.	6393.	105210.	24294.	0.	245153.	124675.	3313.	373141.
36	900.	1200.	113498.	6546.	110037.	25309.	0.	255389.	114545.	3451.	373385.
34	795.	1300.	109378.	6334.	105529.	24337.	0.	245578.	124885.	3319.	373781.

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 15:56:14

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 39
954. KCMIL 1300. FT SPAN 94.7 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY	MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	31680. FT	63449.	19.47	4380.	58264.	126094.
GROUNDWIRE	0. FT	0.	0.00	0.	0.	0.
INSULATORS	310. UNITS	4436.	1.70	824.		5260.
HARDWARE		3219.	0.47	107.		3326.
TOWERS	4.3 UNITS	154265.	35.79	8052.	90323.	252640.
FOUNDATIONS	4.3 UNITS	10790.		1744.	72256.	84790.
RIGHT OF WAY (113FT)	14. ACRES	22181.			19697.	41877.
SUB-TOTALS		258340.	57.43	15107.	240540.	513987.
IDC						0.
ENGINEERING						56539.
					TOTAL	570526.
PRESENT WORTH		114706.		6707.	106803.	228216.
IDC						0.
ENGINEERING						25104.
					TOTAL	253320.

PRESENT WORTH ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	53177.	48068.	101245.
CORONA LOSSES: INSULATORS	696.	1498.	2194.
CONDUCTOR	-	313.	313.
TOTALS	53872.	49879.	103751.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 2: 02 AUG 1979,

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 16 AUG 79 TIME: 13:14:31

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*  INPUT DATA   *
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SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
BASE YEAR FOR PW ANALYSIS	1979	
ENDING YEAR OF STUDY	1997	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	194.7 MVA	1992
AVERAGE CIRCUIT LOADING	107.1 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATES:		
	7.0 PERCENT	1984
	10.0 PERCENT	1984
O&M COST FACTOR	1.5 % CAP.COST	1984
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 16 AUG 79 TIME: 13:14:31

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* INPUT DATA *
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CONDUCTOR DATA

NUMBER PER PHASE	1
CONDUCTOR SPACING	0.0 IN
VOLTAGE	230 KV
VOLTAGE VARIATION	10.00 PCT
LINE FREQUENCY	60 CPS
FAIRWEATHER LOSSES	0.00 KW/MI
LINE LENGTH	189.00 MILES
POWER FACTOR	0.95

GROUNDWIRE DATA

NUMBER PER TOWER	0
DIAMETER	0.00 IN
WEIGHT	0.0000 LBS/FT

SPAN DATA

MINIMUM	1000. FT
MAXIMUM	1400. FT
INTERVAL	100.0 FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18 IN/HR
MAXIMUM RAINFALL DURATION	1 HRS/YR
AVERAGE RAINFALL RATE	0.03 IN/HR
AVERAGE RAINFALL DURATION	636 HRS/YR
MAXIMUM SNOWFALL RATE	1.87 IN/HR
MAXIMUM SNOWFALL DURATION	1 HRS/YR
AVERAGE SNOWFALL RATE	0.13 IN/HR
AVERAGE SNOWFALL DURATION	264 HRS/YR
RELATIVE AIR DENSITY	1.000

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 16 AUG 79 TIME: 13:14:31

INPUT DATA

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

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TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	20.0 FEET	D1	20.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	20.00 FT
GROUND CLEARANCE	28.0 FEET	D3	40.00 FT
NO. OF INSULATORS PER TOWER	48	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	6.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 9: 230KV TOWER

TW = 0.00016*TH**2 - 3.09797*TH**0.3333 - 0.08943*EFFVDL -
0.27367*EFFTDL + 0.00510*TH*EFFTDL + 0.00160*TH*EFFVDL +
18.37912 KIPS

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 16 AUG 79 TIME: 13:14:31

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* INPUT DATA *
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CONDUCTOR SUMMARY
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ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9
40	ORTOLAN	1033.0	45/ 7	1.1650	1.2130	0.8678	9.40	11.5
41	CURLEW	1033.0	54/ 7	1.3310	1.2460	0.9169	10.85	10.9
42	BLUEJAY	1113.0	45/ 7	1.2550	1.2590	0.9346	9.40	11.5
43	FINCH	1113.0	54/19	1.4310	1.2930	0.9849	10.30	10.8
44	BUNTING	1192.0	45/ 7	1.3440	1.3020	1.0010	9.40	11.5
45	GRACKLE	1192.0	54/19	1.5330	1.3330	1.0552	10.30	10.8
46	BITTERN	1272.0	45/ 7	1.4340	1.3450	1.0680	9.40	11.5
47	PHEASANT	1272.0	54/19	1.6350	1.3820	1.1256	10.30	10.8
48	DIPPER	1351.0	45/ 7	1.5220	1.3850	1.1350	9.40	11.5
49	MARTIN	1351.0	54/19	1.7370	1.4240	1.1959	10.30	10.8
50	BOBOLINK	1431.0	45/ 7	1.6130	1.4270	1.2020	9.40	11.5
51	PLOVER	1431.0	54/19	1.8400	1.4650	1.2663	10.30	10.8
52	NUTHATCH	1510.0	45/ 7	1.7020	1.4660	1.2680	9.40	11.5
53	PARROT	1510.0	54/19	1.9420	1.5060	1.3366	10.30	10.8
54	LAPWING	1590.0	45/ 7	1.7920	1.5020	1.3350	9.40	11.5
55	FALCON	1590.0	54/19	2.0440	1.5450	1.4076	10.30	10.8

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 16 AUG 79 TIME: 13:14:31

INPUT DATA

CONDUCTOR SUMMARY

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816
40	ORTOLAN	28900.0	0.0401	0.670/1977	1020.	0.0924	0.3902	2.4658
41	CURLEW	37100.0	0.0420	0.628/1977	1040.	0.0913	0.3849	2.4446
42	BLUEJAY	30900.0	0.0416	0.669/1977	1070.	0.0861	0.3860	2.4341
43	FINCH	40200.0	0.0436	0.639/1977	1090.	0.0855	0.3802	2.4130
44	BUNTING	33200.0	0.0431	0.665/1977	1120.	0.0808	0.3817	2.4077
45	GRACKLE	43100.0	0.0451	0.642/1977	1130.	0.0797	0.3759	2.3866
46	BITTERN	35400.0	0.0445	0.665/1977	1160.	0.0760	0.3780	2.3813
47	PHEASANT	44800.0	0.0466	0.638/1977	1180.	0.0750	0.3722	2.3602
48	DIPPER	37600.0	0.0459	0.663/1977	1210.	0.0723	0.3738	2.3602
49	MARTIN	47600.0	0.0480	0.638/1977	1230.	0.0708	0.3680	2.3338
50	BOBOLINK	39800.0	0.0472	0.662/1977	1250.	0.0686	0.3712	2.3338
51	PLOVER	50400.0	0.0494	0.637/1977	1270.	0.0671	0.3648	2.3074
52	NUTHATCH	41600.0	0.0485	0.664/1977	1300.	0.0649	0.3670	2.3126
53	PARROT	53200.0	0.0508	0.630/1977	1320.	0.0602	0.3622	2.2862
54	LAPWING	43800.0	0.0497	0.660/1977	1340.	0.0623	0.3638	2.2915
55	FALCON	56000.0	0.0521	0.636/1977	1360.	0.0612	0.3580	2.2704

DEVIL CANYON-ESTER CASE II-2A

230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION

DATE: 16 AUG 79 TIME: 13:14:31

INPUT DATA

UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	225.0 $/TON
FOUNDATION CONCRETE	225.0 $/YD
FOUNDATION STEEL	225.0 $/TON
CONDUCTOR	225.0 $/TON
GROUND WIRE	225.0 $/TON
INSULATOR	225.0 $/TON OR $/M**3
HARDWARE	225.0 $/TON

DEVIL CANYON-ESTER CASE II-2A

230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION

DATE: 16 AUG 79 TIME: 13:14:31

AUTOMATIC CONDUCTOR SELECTION

ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

PRESENT WORTH ($)

CONDUCTOR NO.	KCM	SPAN(FT)	INSTALLED COST MATERIALS	TRANSP.	INSTALL.	ENGINEER.	IDC	SUBTOTAL	LINE LOSSES SUBTOTAL	O&M COST SUBTOTAL	LINE COST TOTAL
53	1510.	1300.	77500.	4475.	77209.	17510.	0.	176693.	26241.	2388.	205322.
45	1192.	1300.	71932.	4085.	75510.	16668.	0.	168194.	35382.	2273.	205849.
53	1510.	1400.	79192.	4486.	76292.	17597.	0.	177568.	26241.	2400.	206209.
45	1192.	1400.	73329.	4080.	74456.	16705.	0.	168571.	35382.	2278.	206231.
53	1510.	1200.	76778.	4517.	78952.	17627.	0.	177874.	26241.	2404.	206519.
49	1351.	1300.	75070.	4291.	76525.	17148.	0.	173034.	31161.	2338.	206533.
47	1272.	1300.	73744.	4201.	76187.	16954.	0.	171086.	33142.	2312.	206540.
43	1113.	1300.	70592.	3997.	75192.	16476.	0.	166257.	38174.	2247.	206678.
51	1431.	1300.	76397.	4383.	76872.	17342.	0.	174994.	29429.	2365.	206787.
43	1113.	1400.	71977.	3992.	74137.	16512.	0.	166617.	38174.	2252.	207043.
47	1272.	1400.	75327.	4205.	75226.	17023.	0.	171782.	33142.	2321.	207245.
49	1351.	1400.	76685.	4298.	75577.	17222.	0.	173781.	31161.	2348.	207290.
45	1192.	1200.	71486.	4142.	77380.	16831.	0.	169839.	35382.	2295.	207516.
51	1431.	1400.	78051.	4392.	75939.	17422.	0.	175804.	29429.	2376.	207608.
41	1033.	1300.	69272.	3918.	74975.	16298.	0.	164464.	41005.	2222.	207692.
49*	1351.	1200.	74425.	4338.	78300.	17277.	0.	174340.	31161.	2356.	207857.
47	1272.	1200.	73131.	4249.	77974.	17089.	0.	172443.	33142.	2330.	207916.
55	1590.	1300.	79058.	4566.	77541.	17728.	0.	178894.	26692.	2417.	208003.
51	1431.	1200.	75715.	4428.	78630.	17465.	0.	176238.	29429.	2382.	208048.
41	1033.	1400.	70679.	3913.	73936.	16338.	0.	164865.	41005.	2228.	208098.
43	1113.	1200.	70161.	4055.	77066.	16641.	0.	167924.	38174.	2269.	208368.
55	1590.	1400.	80792.	4580.	76642.	17821.	0.	179835.	26692.	2430.	208957.
55	1590.	1200.	78298.	4606.	79267.	17839.	0.	180010.	26692.	2433.	209134.
41	1033.	1200.	68813.	3976.	76829.	16458.	0.	166075.	41005.	2244.	209324.
48	1351.	1300.	76070.	4234.	77504.	17359.	0.	175166.	31875.	2367.	209408.

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 16 AUG 79 TIME: 13:14:31

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 53
1510. KCMIL 1300. FT SPAN 84.9 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY		MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840.	FT	49971.	15.38	3461.	45797.	99229.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	207.	UNITS	2957.	1.14	549.		3507.
HARDWARE			3219.	0.47	107.		3326.
TOWERS	4.3	UNITS	91008.	21.11	4750.	60247.	156006.
FOUNDATIONS	4.3	UNITS	7493.		1211.	50178.	58882.
RIGHT OF WAY (101FT)	12.	ACRES	19895.			17667.	37562.
SUB-TOTALS			174544.	38.10	10078.	173889.	358511.
IDC							0.
ENGINEERING							39436.
						TOTAL	397947.
PRESENT WORTH			77500.		4475.	77209.	159183.
IDC							0.
ENGINEERING							17510.
						TOTAL	176693.

PRESENT WORTH ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	13781.	12459.	26240.
CORONA LOSSES: INSULATORS	0.	0.	0.
CONDUCTOR	-	1.	1.
TOTALS	13781.	12460.	26241.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 2: 02 AUG 1979,

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 16:29:16

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*   INPUT DATA *
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SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
BASE YEAR FOR PW ANALYSIS	1979	
ENDING YEAR OF STUDY	1997	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	514.0 MVA	1992
AVERAGE CIRCUIT LOADING	282.7 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATES:		
	7.0 PERCENT	1984
	10.0 PERCENT	1984
O&M COST FACTOR	1.5 % CAP.COST	1984
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 16:29:16

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CONDUCTOR DATA

NUMBER PER PHASE	1
CONDUCTOR SPACING	0.0 IN
VOLTAGE	230 KV
VOLTAGE VARIATION	10.00 PCT
LINE FREQUENCY	60 CPS
FAIRWEATHER LOSSES	0.00 KW/MI
LINE LENGTH	27.00 MILES
POWER FACTOR	0.95

GROUNDWIRE DATA

NUMBER PER TOWER	0
DIAMETER	0.00 IN
WEIGHT	0.0000 LBS/FT

SPAN DATA

MINIMUM	1200. FT
MAXIMUM	1600. FT
INTERVAL	100.0 FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18 IN/HR
MAXIMUM RAINFALL DURATION	1 HRS/YR
AVERAGE RAINFALL RATE	0.03 IN/HR
AVERAGE RAINFALL DURATION	636 HRS/YR
MAXIMUM SNOWFALL RATE	1.87 IN/HR
MAXIMUM SNOWFALL DURATION	1 HRS/YR
AVERAGE SNOWFALL RATE	0.13 IN/HR
AVERAGE SNOWFALL DURATION	264 HRS/YR
RELATIVE AIR DENSITY	1.000

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 16:29:16

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SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	20.0 FEET	D1	20.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	20.00 FT
GROUND CLEARANCE	28.0 FEET	D3	40.00 FT
NO. OF INSULATORS PER TOWER	48	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	6.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 9: 230KV TOWER

TW = 0.00016*TH**2 - 3.09797*TH**0.3333 - 0.08943*EFFVDL -
0.27367*EFFTDL + 0.00510*TH*EFFTDL + 0.00160*TH*EFFVDL +
18.37912 KIPS

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 16:29:16

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* INPUT DATA *
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CONDUCTOR SUMMARY

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
52	NUTHATCH	41600.0	0.0485	0.664/1977	1300.	0.0649	0.3670	2.3126
53	PARROT	53200.0	0.0508	0.630/1977	1320.	0.0602	0.3622	2.2862
54	LAPWING	43800.0	0.0497	0.660/1977	1340.	0.0623	0.3638	2.2915
55	FALCON	56000.0	0.0521	0.636/1977	1360.	0.0612	0.3580	2.2704
56	CHUKAR	53600.0	0.0534	0.675/1977	1440.	0.0560	0.3548	2.2387
57	BLUEBIRD	63400.0	0.0588	0.673/1977	1610.	0.0475	0.3443	2.1648
58	KIWI	50900.0	0.0570	0.699/1977	1600.	0.0480	0.3480	2.1806

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 16:29:16

INPUT DATA

CONDUCTOR SUMMARY

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
52	NUTHATCH	1510.0	45/ 7	1.7020	1.4660	1.2680	9.40	11.5
53	PARROT	1510.0	54/19	1.9420	1.5060	1.3366	10.30	10.8
54	LAPWING	1590.0	45/ 7	1.7920	1.5020	1.3350	9.40	11.5
55	FALCON	1590.0	54/19	2.0440	1.5450	1.4076	10.30	10.8
56	CHUKAR	1780.0	84/19	2.0740	1.6020	1.5120	9.05	11.3
57	BLUEBIRD	2156.0	84/19	2.5120	1.7620	1.8280	9.05	11.3
58	KIWI	2167.0	72/ 7	2.3040	1.7370	1.7760	9.25	12.0

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 16:29:16

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*   INPUT DATA  *
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UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	225.0 $/TON
FOUNDATION CONCRETE	225.0 $/YD
FOUNDATION STEEL	225.0 $/TON
CONDUCTOR	225.0 $/TON
GROUND WIRE	225.0 $/TON
INSULATOR	225.0 $/TON OR $/M**3
HARDWARE	225.0 $/TON

WATANA-DEVIL CANYON CASE II-3A

230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION

DATE: 15 AUG 79 TIME: 16:29:16

AUTOMATIC CONDUCTOR SELECTION

ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

PRESENT WORTH ($)

CONDUCTOR			INSTALLED COST						LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSP.	INSTALL.	ENGINEER.	IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
57	2156.	1300.	89569.	5100.	80419.	19260.	0.	194349.	140540.	2626.	337515.
57	2156.	1400.	92123.	5155.	79928.	19493.	0.	196698.	140540.	2658.	339896.
57	2156.	1200.	90137.	5212.	82759.	19592.	0.	197700.	140540.	2672.	340911.
58	2167.	1300.	92415.	5120.	82288.	19780.	0.	199603.	142049.	2697.	344350.
57	2156.	1500.	95769.	5263.	80188.	19934.	0.	201155.	140540.	2718.	344413.
58	2167.	1200.	92234.	5199.	84224.	19982.	0.	201640.	142049.	2725.	346414.
58	2167.	1400.	95989.	5221.	82335.	20190.	0.	203734.	142049.	2753.	348537.
57	2156.	1600.	100185.	5417.	81131.	20541.	0.	207274.	140540.	2801.	350615.
56	1780.	1300.	82764.	4674.	78631.	18268.	0.	184336.	166266.	2491.	353093.
56	1780.	1400.	84951.	4709.	77966.	18439.	0.	186066.	166266.	2514.	354846.
58	2167.	1500.	100672.	5381.	83211.	20819.	0.	210083.	142049.	2839.	354971.
56	1780.	1200.	83451.	4792.	81029.	18620.	0.	187890.	166266.	2539.	356695.
53	1510.	1300.	77500.	4475.	77209.	17510.	0.	176693.	179055.	2388.	358137.
56	1780.	1500.	88068.	4795.	78040.	18799.	0.	189701.	166266.	2564.	358530.
53	1510.	1400.	79192.	4486.	76292.	17597.	0.	177568.	179055.	2400.	359023.
53	1510.	1500.	81760.	4545.	76087.	17863.	0.	180255.	179055.	2436.	361746.
53	1510.	1200.	79083.	4637.	80048.	18014.	0.	181782.	179055.	2457.	363294.
55	1590.	1300.	79058.	4566.	77541.	17728.	0.	178894.	182109.	2417.	363420.
58	2167.	1600.	106552.	5599.	84847.	21670.	0.	218667.	142049.	2955.	363671.
56	1780.	1600.	92071.	4927.	78781.	19336.	0.	195115.	166266.	2637.	364017.
55	1590.	1400.	80792.	4580.	76642.	17821.	0.	179835.	182109.	2430.	364373.
53	1510.	1600.	85158.	4649.	76521.	18296.	0.	184623.	179055.	2495.	366174.
55	1590.	1500.	83400.	4641.	76453.	18094.	0.	182588.	182109.	2467.	367164.
52	1510.	1200.	72903.	4183.	77499.	17004.	0.	171590.	193430.	2319.	367338.
55	1590.	1200.	80560.	4724.	80343.	18219.	0.	183846.	182109.	2484.	368439.

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 15 AUG 79 TIME: 16:29:16

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 57
2156. KCMTL 1300. FT SPAN 87.4 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY	MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840. FT	69050.	19.90	4476.	48940.	122466.
GROUNDWIRE	0. FT	0.	0.00	0.	0.	0.
INSULATORS	207. UNITS	2957.	1.14	549.		3507.
HARDWARE		3219.	0.47	107.		3326.
TOWERS	4.3 UNITS	98547.	22.86	5144.	63832.	167522.
FOUNDATIONS	4.3 UNITS	7493.		1211.	50178.	58882.
RIGHT OF WAY (104FT)	13. ACRES	20461.			18170.	38630.
SUB-TOTALS		201727.	44.37	11487.	181119.	394333.
IDC						0.
ENGINEERING						43377.
					TOTAL	437710.
PRESENT WORTH		89569.		5100.	80419.	175089.
IDC						0.
ENGINEERING						19260.
					TOTAL	194349.

PRESENT WORTH ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	73819.	66721.	140540.
CORONA LOSSES: INSULATORS	0.	0.	0.
CONDUCTOR	-	0.	0.
TOTALS	73819.	66721.	140540.

APPENDIX C

MULTI-AREA RELIABILITY PROGRAM (MAREL)

POWER TECHNOLOGIES INC	MULTI AREA RELIABILITY PROGRAM (MAREL)	BULLETIN PTI/103 Page 1 of 3
P.O. BOX 1058	SCHENECTADY, NEW YORK 12301	518 374-1220

SUMMARY

The Multi-Area Reliability Program (MAREL) computes the Loss of Load Probability (LOLP) reliability index for electric generating systems of several areas interconnected by a transmission network without any restrictions on the network topology. The program permits the study of large power pools and reliability councils as well as individual utilities imbedded in an extensive interconnection. The program is intended to be used in the design and analysis of generation systems and the interconnection capability requirements needed to share reserves among the interconnected areas. The program may be used for as many as six or seven interconnected areas modeled directly. A greater number may be accommodated by developing equivalent systems. The output includes area and total system LOLP indices as well as data or the probable causes of failures and their locations in the network. The program structure is flexible so that load and capacity models may be as detailed as required and at the same time, the complex evaluation of the individual area reliability levels may be performed with efficiency.

PROGRAM ELEMENTS AND MODELS

The structure of MAREL is shown in block form on Figure 1. Input data may be provided for each case or partially supplied by saved case files. The program structure is set up to analyze one year at a time under the control of the user. This facilitates the development of system expansions interactively or with a series of runs on a batch basis without the risk of the possibility of using excessive computer time.

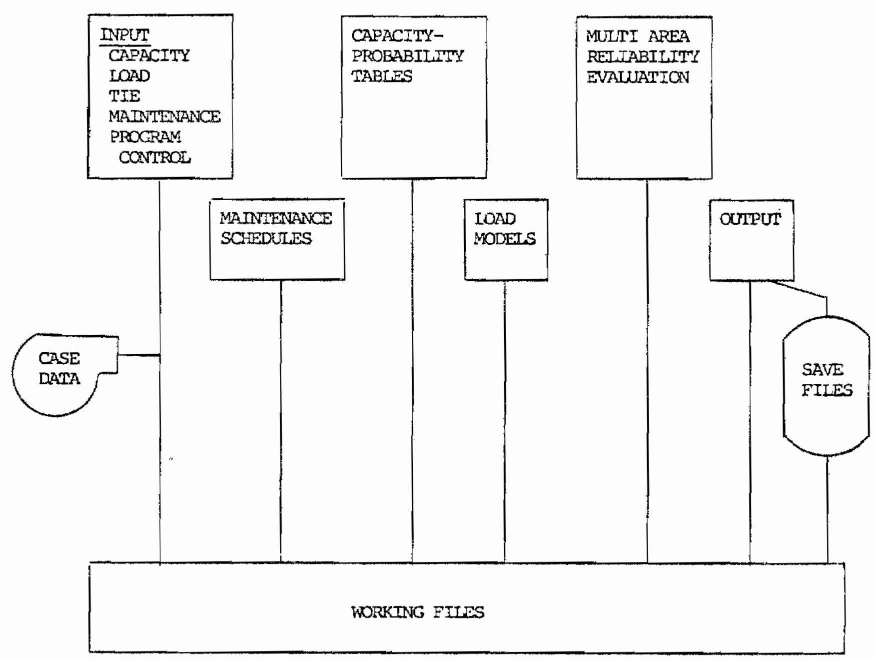

FIGURE 1

STRUCTURE OF MULTI AREA RELIABILITY PROGRAM

- Loads are modeled by area with distributions of peak loads for each 'season' of the year. A season may be of whatever length is appropriate for the study, weeks, months, or longer intervals.

- Capacity Models are developed for each area for each season of the year and are available capacity-probability density tables.

- Maintenance Outages are simulated either by adding the capacity on outage to the appropriate area and season load model or by modification of the proper capa-city-probability table. Maintenance may be prescheduled and input or done automatically within MAREL by an algorithm designed to level available area generation reserves over the year.

- Transmission Interconnections are modeled by the use of a linear flow network which models the limitations on individual tie line transfer capabilities considering their forced outage rates (if desired) without restrictions on the network configuration or topology.

- Program Controls are set by the user to establish the fineness with which the loads and capcities are represented and to set tolerance levels on the LOLP computations to save unnecessary computer effort and cost.

- Program Output may include area load and capacity models as well as maintenance schedules, three sets of both seasonal and annual area and system LOLP indices, the probabilities of various failure modes. That is, the program automatically calculates area LOLP values as though the area were isolated and then two separate LOLP values with the actual interconnection. These two LOLP indices represent the extremes of possible operating policies concerning the sharing of generation reserves, (1) sharing only available reserves, and (2) sharing load losses up to the transfer limitations imposed by the network. Failure mode probabilities show the probabilities and locations of failures caused by generation shortages or transmission limitations as well as combinations and indicate the probabilities that each individual tie may be limiting. These data are useful in developing reliable system designs.

- System Size is not restricted except by limits on acceptable computational effort and cost. Past PTI system studies have included two interconnected reliability councils represented by nine or ten areas and incorporating approximately 500 units for a total of 100,000 mw of generation.

PROGRAM APPLICATIONS

- Generation reliability level analysis which includes the effects of the interconnected system for the expansion planning of individual utilities and power pools.

- Planning of interconnections to achieve regional integration and more widespread sharing of generation reserves.

- Evaluation of the reliability benefits of strengthening ties vis-a-vis additions to generation reserves.

- Assistance in locating weak portions of a system in order to locate new bulk power facilities for maximum reliability improvement.
- Analysis of the reliability benefits of new jointly-owned plants located remotely or within one system's territory.
- Evaluation of the ability of individual utilities to reliably survive the postponement of new plant additions in their own and interconnected systems.

AVAILABILITY AND SUPPORT

MAREL is available for use at PTI for studies by individual utilities or groups of systems. It may also be leased for installation on a client's computer. The lease entitles the user to:

- Complete set of source code for all modules including all MAREL activities and subroutines.
- Engineering and program reference manuals.
- Installation on a suitable PRIME 400 computer at the client's site and a training seminar.

Installation on other computers is feasible but will only be done on the basis of charging for the time and expense required.

Since PTI is a consulting engineering organization and uses MAREL in studies for clients, the program is continually being enhanced and updated.

While updates are not included in the MAREL lease price, PTI will offer all significant MAREL improvements to lessees at add-on prices.

PTI can assist MAREL users in the development of system equivalents where their use is attractive to the user.

FOR FURTHER INFORMATION

Contact: C.K. Pang, Senior Engineer
or
A.J. Wood, Principal Engineer
Power Technologies, Inc.
P.O. Box 1058
Schenectady, N.Y. 12301

Tel. (518) 374-1220
Telex 145498 POWER TECH SCH

1/78

MULTI-AREA RELIABILITY PROGRAM (MAREL)

SAMPLE OUTPUT SHEETS

FOR

TWO-AREA RELIABILITY STUDY - YEAR 1989

Note: The following other output sheets (35 cases) are on file with Alaska Power Authority under a separate cover:

- Independent System Expansion Plans (years 1984 through 1996)
- Interconnected System Expansion Plans (years 1984 through 1996)
- Interconnected System Expansion, Three-Area Realiability Study with Susitna (years 1992 through 1996)
- Interconnected System Expansion Plans, with Firm Power Transfer (years 1984 through 1987 and 1992 through 1996)

IECREL *TIE89   01/18/79 11:01   PRT018

```
  WWW   WWWWW   WWW   WWWW   WWWWW  W
   W    W      W   W  W   W  W      W
   W    W      W      W   W  W      W
   W    WWWW   W      WWWW   WWWW   W
   W    W      W      W W    W      W
   W    W      W   W  W  W   W      W   W
  WWW   WWWWW   WWW   W   W  WWWWW  WWWWW


         WWWWW   WWW   WWWWW   WWW    WWW
 W W W     W      W    W      W   W  W   W
  WWW      W      W    W      W   W  W   W
 WW WW     W      W    WWWW    WWW    WWWW
  WWW      W      W    W      W   W      W
 W W W     W      W    W      W   W     W
           W     WWW   WWWWW   WWW   WWW
```

```
POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM:


---- MULTI-AREA RELIABILITY PROGRAM - MAREL ----

      ---- VERSION : NOVEMBER 15, 1978 ----

       ---- POWER  TECHNOLOGIES, INC. ----


             *********************
             **                 **
             **  01 - 18 - 1979 **
             **                 **
             *********************


    S T U D Y   C A S E:


****************************************************************************
**                                                                        **
**     ANCHORAGE - FAIRBANKS  TRANSMISSION INTERTIE ECONOMIC FEASIBILITY  **
**                                                                        **
**     2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979  **
**                                                                        **
****************************************************************************
```

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

```
*****************************************************************************
**                                                                         **
**    ANCHORAGE - FAIRBANKS  TRANSMISSION INTERTIE ECONOMIC FEASIBILITY    **
**                                                                         **
**    2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979    **
**                                                                         **
*****************************************************************************
```

YEAR OF STUDY = 1989

PROBABILITY THRESHOLD = 0.10E-07

FAILURE PROB. THRESHOLD = 0.20E-08

PROB. RATIO FOR LOAD LEV. = 0.0100

ROUNDING MW STEP SIZE = 1

MAX. NO. OF AREAS WITH NEGATIVE
MARGIN TO BE EXAMINED = 2

MAX. OF CAPACITY STEPS = 50

----- SYSTEM DATA -----

NO. OF AREAS OR BUSES = 2

NO. OF AREAS WITH GENERATION = 2

NO. OF AREAS WITH LOADS = 2

NO. OF LINES WITH OUTAGES = 1

NO. OF FIRM LINES = 0

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

----- DATA FOR LINES WITH OUTAGES -----
--- AVAILABLE CAPACITY PROBABILITY ---

LINE NO. 1, LINK NO. 3
TIE FROM AREA 1 ANCHOR -TO- AREA 2 FAIRBA

LEVEL	CAP(FOR)	CAP(REV)	PROBABILITY
1	0	0	0.004000
2	130	130	0.996000

------ TIME USED IN CPUS : INCREMENT = 2, ELAPSED = 2

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

SUMMARY ON CAPACITY, PEAK LOAD AND MAINTENANCE : AREA ANCHOR

SEASON	1	2	3	4	5	6	7	8	9
INSTALLED CAPACITY (MW)	1747	1747	1747	1747	1747	1747	1747	1747	1747
PEAK LOAD (MW)	1200	882	789	752	729	725	826	886	1441
INSTALLED RESERVES :									
MW	547	865	958	995	1018	1022	921	861	306
PERCENT	45.58	98.07	121.42	132.31	139.64	140.97	111.50	97.18	21.24
CAPACITY ON MAINTENANCE (MW)	0	135	227	256	286	287	188	122	0
RESERVES AFTER MAINTENANCE :									
MW	547	730	731	739	732	735	733	739	306
PERCENT	45.58	82.77	92.65	98.27	100.41	101.38	88.74	83.41	21.24

UNIT RETIREMENTS AND INSTALLATIONS :

NO.	UNIT	CAP(MW)	F.O.R.	RET/INST	SEASON	DATE
1	COAL 2	200	0.057	INST	1	1/1989

C-9

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

SUMMARY ON CAPACITY, PEAK LOAD AND MAINTENANCE : AREA FAIRBA

SEASON	1	2	3	4	5	6	7	8	9
INSTALLED CAPACITY (MW)	385	385	385	385	385	385	385	385	385
PEAK LOAD (MW)	274	177	135	119	112	130	136	166	313
INSTALLED RESERVES :									
MW	111	208	250	266	273	255	249	219	72
PERCENT	40.51	117.51	185.19	223.53	243.75	196.15	183.09	131.93	23.00
CAPACITY ON MAINTENANCE (MW)	0	14	55	72	100	65	54	25	0
RESERVES AFTER MAINTENANCE :									
MW	111	194	195	194	173	190	195	194	72
PERCENT	40.51	109.60	144.44	163.03	154.46	146.15	143.38	116.87	23.00

UNIT RETIREMENTS AND INSTALLATIONS :

NO.	UNIT	CAP(MW)	F.O.R.	RET/INST	SEASON	DATE

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

SUMMARY ON CAPACITY AND PEAK LOAD BY AREA

AREA	ANCHOR	FAIRBA
PEAK LOAD SEASON	9	9
INSTALLED CAPACITY (MW) AT ANNUAL PEAK	1747	385
ANNUAL PEAK LOAD (MW)	1441	313
INSTALLED RESERVES (MW)	306	72
RESERVES IN PERCENT OF ANNUAL PEAK LOAD	21.24	23.00
AREA WEIGHTED AVERAGE UNIT FOR (PERCENT)	5.46	7.42
AREA ANNUAL AVERAGE MAINTENANCE(PERCENT)	9.55	11.11

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

-----SUMMARY BY AREAS-----

	AREA	NO.OF UNITS	CAP.(MW)
1	ANCHOR	36	1747
2	FAIRBA	24	385

SEASONAL RESERVES IN PERCENT OF PEAK LOADS
AFTER MAINTENANCE OF UNITS FOR THE TOTAL SYSTEM

SEASON	RESERVES
1	44.6404
2	87.2521
3	100.2164
4	107.1182
5	107.6100
6	108.1871
7	96.4657
8	88.6882
9	21.5507

ORDER	SEASON	RESERVES
1	9	21.5507
2	1	44.6404
3	2	87.2521
4	8	88.6882
5	7	96.4657
6	3	100.2164
7	4	107.1182
8	5	107.6100
9	6	108.1871

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

MAINTENANCE SUMMARY BY MW AND PERCENT OF TOTAL AREA CAPACITY :

SEASON	AREA ANCHOR		AREA FAIRBA	
1	0	0.00	0	0.00
2	135	7.73	14	3.64
3	227	12.99	55	14.29
4	256	14.65	72	18.70
5	286	16.37	100	25.97
6	287	16.43	65	16.88
7	188	10.76	54	14.03
8	122	6.98	25	6.49
9	0	0.00	0	0.00

AREA EFOR 5.4550 7.4169

SYSTEM EFOR = 5.8093

EFOR : WEIGHTED EFFECTIVE FORCED OUTAGE RATE IN PERCENT.

*** END OF PROGRAM MNTCE ***

----- TIME USED IN CPUS : INCREMENT = 2, ELAPSED = 4

----- TIME USED IN CPUS : INCREMENT = 0, ELAPSED = 4

*** AREA 1 ANCHOR HAS NO UNITS ON ***
*** MAINTENANCE FOR SEASONS : 1 9 ***

*** AREA 2 FAIRBA HAS NO UNITS ON ***

*** MAINTENANCE FOR SEASONS : 1 9 ***

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- LOSS OF LOAD PROBABILITY AT VARIOUS AREAS ---

AT	AREA	PROBABILITY ISOLATED	PROBABILITY WITH LLS	PROBABILITY WITHOUT LLS
1	ANCHOR	0.149268E+00	0.798471E-01	0.676829E-01
2	FAIRBA	0.190494E+01	0.909675E-01	0.394379E-01
	SYSTEM		0.915377E-01	0.915377E-01

NOTE : LLS = LOAD LOSS SHARING

***** ALL PROBABILITIES ARE IN DAYS/PERIOD *****

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- PROBABILITY OF MINIMAL CUTS ---

CUT	PROBABILITY	CUT MEMBERS(LINKS)
1	0.792771E-01	1 2
2	0.570032E-03	1 3
3	0.116904E-01	2 3

***** ALL PROBABILITIES ARE IN DAYS/PERIOD *****

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- MINIMAL CUTS AND DEFICIENT NODES(AREAS) ---

CUT	PROBABILITY	NODES(AREAS) IN DEFICIENT REGION
1	0.792771E-01	1 ANCHOR 2 FAIRBA
2	0.570032E-03	1 ANCHOR
3	0.116904E-01	2 FAIRBA

***** ALL PROBABILITIES ARE IN DAYS/PERIOD *****

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- PROBABILITY THAT EACH LINE IS LIMITING ---

LINE	LINK	DESCRIPTION AREA	TO	AREA	TOTAL PROBABILITY	FORWARD DIRECTION	REVERSE DIRECTION
1	3	1 ANCHOR	TO	2 FAIRBA	0.122604E-01	0.116904E-01	0.570032E-03

***** ALL PROBABILITIES ARE IN DAYS/PERIOD *****

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

ISOLATED SITUATION - SUMMARY :

AREA LOLP IN DAYS/PERIOD BY SEASONS:

SEASON	AREA ANCHOR	AREA FAIRBA
1	0.0021	0.3096
2	0.0000	0.0071
3	0.0000	0.0000
4	0.0000	0.0000
5	0.0000	0.0000
6	0.0000	0.0000
7	0.0000	0.0000
8	0.0000	0.0000
9	0.1472	1.5882
YEAR	0.1493	1.9049

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

ISOLATED SITUATION - SUMMARY :

EXPECTED MW-DAYS LOSS BY SEASONS.

SEASON	AREA ANCHOR	AREA FAIRBA
1	0.09	7.45
2	0.00	0.14
3	0.00	0.00
4	0.00	0.00
5	0.00	0.00
6	0.00	0.00
7	0.00	0.00
8	0.00	0.00
9	8.87	44.23
YEAR	8.9548	51.8097

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

ISOLATED SITUATION - SUMMARY :

EXPECTED MW DEFICIENCY BY SEASON.

SEASON	AREA ANCHOR	AREA FAIRBA
1	42.38	24.04
2	13.57	19.22
3	0.00	0.00
4	0.00	0.00
5	0.00	0.00
6	0.00	0.00
7	0.00	0.00
8	0.00	0.00
9	60.24	27.85

INDICES FOR THE YEAR :

MW-DAYS	8.95	51.81
LOLP-DAYS	0.15	1.90
E(MW)	59.99	27.20

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

INTERCONNECTED WITH LOAD LOSS SHARING :

AREA LOLP IN DAYS/PERIOD BY SEASONS.

SEASON	AREA ANCHOR	AREA FAIRBA
1	0.0004	0.0020
2	0.0000	0.0000
3	0.0000	0.0000
4	0.0000	0.0000
5	0.0000	0.0000
6	0.0000	0.0000
7	0.0000	0.0000
8	0.0000	0.0000
9	0.0794	0.0890
YEAR	0.0798	0.0910

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

INTERCONNECTED WITH NO LOAD LOSS SHARING :

AREA LOLP IN DAYS/PERIOD BY SEASONS.

SEASON	AREA ANCHOR	AREA FAIRBA
1	0.0003	0.0017
2	0.0000	0.0000
3	0.0000	0.0000
4	0.0000	0.0000
5	0.0000	0.0000
6	0.0000	0.0000
7	0.0000	0.0000
8	0.0000	0.0000
9	0.0673	0.0378
YEAR	0.0677	0.0394

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- SYSTEM RESULT SUMMARY IN PER UNIT ---

PROBABILITY OF SUCCESS EVENTS	=	0.999648E+00
PROBABILITY OF FAILURE EVENTS	=	0.352068E-03
PROBABILITY OF NEGLECTED UNSPECIFIED EVENTS	=	0.270125E-08
SUM OF THE ABOVE 3 PROBABILITIES	=	0.100000E+01
PROBABILITY OF UNCLASSIFIED FAILURE EVENTS	=	0.620649E-09

```
****************************************************
*** NOTE: THE SUM OF THE FIRST 3 MUST BE 1.0000 ***
***       WITHIN REASONABLE TOLERANCE.          ***
****************************************************
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DEFINITION OF EVENTS :

SUCCESS : ALL LOADS SATISFIED.

FAILURE : ONE OR MORE AREA LOADS NOT SATISFIED.

UNSPECIFIED : NOT IDENTIFIED AS EITHER SUCCESS OR FAILURE.

UNCLASSED FAILURE : CAUSE OF FAILURE NOT ESTABLISHED.
CAUSE OF FAILURE IS INDICATED BY MINIMAL CUTS.

TOTAL ELAPSED TIME IN CPUS = 20

***** END OF PROGRAM MAREL *****

```
ANCHORAGE - FAIRBANKS  TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1996 : INTERCONNECTED - 1/15/1979
  2    1    0    0    0    0    0    0    0    0
  0    0    0    0    1    0    0    0    0    0
  0    0    0    0    0    0
  1    1    1    4
1996
 0.1E-07   0.2E-07   0.5E-05
0.01 0.10
  2    1   50
  2    1    0    2    2
ANCHORFAIRBA
       1    2    2
  1    0    0  0.004000
  2  130  130  0.996000
LOAD DATA IN PER UNIT INTERVAL DURATION CURVE
TWO AREA SYSTEM          JANUARY 15 1979
  1    1    1
  2   10   26    9   14 1983
  1 0.01 1.00    0
1 1 1 1 1 1 2 2 3 3 4 4 5 5 6 6 7 7 8 8 9 9 9 9 9 9
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
 1  ANCHOR  20         0.0
 789.  877.  977. 1080. 1196. 1313. 1441. 1581. 1724. 1881.
2041. 2215. 2402. 2591.
 .8333 .6667 .7404 .7500 .6571 .6346 .6122 .5865 .5481 .5353 .5224 .5160 .5064
 .4904 .5032 .4968 .5160 .5737 .5769 .6154 .6827 .8429 .8526 .91351.0000 .8301
1.0000 .9769 .9731 .9538 .9500 .9462 .8962 .8731 .8577 .8423
1.0000 .9898 .9663 .9663 .9615 .9615 .9519 .9519 .9423 .9375
1.0000 .9913 .9784 .9827 .9697 .9654 .9437 .9307 .9221 .8918
1.0000 .9829 .9487 .9359 .9017 .8889 .8889 .8846 .8333 .8934
1.0000 .9512 .9317 .9171 .9171 .9073 .9073 .9024 .9024 .8976
1.0000 .9848 .9798 .9747 .9646 .9495 .9444 .9343 .9293 .9141
1.0000 .9686 .9634 .9529 .9529 .9476 .9424 .9372 .9058 .9058
1.0000 .9781 .9727 .9617 .9563 .9563 .9344 .9344 .9071 .9071
1.0000 .9883 .9883 .9825 .9825 .9708 .9708 .9649 .9591 .9415
1.0000 .9940 .9820 .9701 .9581 .9461 .9401 .9341 .9281 .9162
1.0000 .9939 .9877 .9571 .9571 .9509 .9509 .9448 .9202 .8589
1.0000 .9938 .9814 .9689 .9565 .9379 .9379 .9379 .9255 .9255
1.0000 .9810 .9684 .9620 .9494 .9494 .9430 .9367 .9304 .9177
1.0000 .9804 .9739 .9739 .9673 .9608 .9542 .9542 .9477 .8824
1.0000 .9873 .9745 .9554 .9490 .9490 .9427 .9427 .9299 .9299
1.00001.0000 .9935 .9871 .9806 .9742 .9677 .9613 .9548 .9484
1.0000 .9938 .9814 .9689 .9627 .9565 .9565 .9441 .9441 .9379
1.0000 .9777 .9609 .9441 .9274 .9106 .8883 .8715 .8715 .8045
1.0000 .9944 .9944 .9722 .9722 .9722 .9611 .9278 .9222 .9222
1.0000 .9948 .9896 .9896 .9687 .9583 .9531 .9375 .9323 .8802
1.0000 .9859 .9484 .9437 .9390 .9296 .9249 .9202 .9155 .9014
1.0000 .9962 .9658 .9468 .9468 .9087 .7985 .7757 .7719 .8555
1.00001.0000 .9887 .9662 .9549 .9511 .9474 .9398 .9361 .9323
1.0000 .9754 .8632 .8596 .8421 .8386 .8336 .8336 .8326 .8175
1.0000 .9840 .9679 .9519 .9359 .9327 .9327 .9135 .8654 .8045
1.0000 .9730 .9730 .9614 .9614 .9575 .9575 .9537 .9421 .8340
 2  FAIRBA  20         0.0
 196.  212.  231.  249.  270.  291.  313.  338.  362.  390.
```

```
  416.  446.  477.  511.
0.67390.69900.73710.76040.57490.59710.56630.51110.43240.41150.38330.37470.3587
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 40 COAL 4   200 0.057 N   1/1991
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 44 GEN  2   300 0.079 N   1/1996
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-99
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    COOP 2
    EKLUTN
-99
  1
  9
-99
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 14 ZEHND1     3 0.295
 15 ZEHND2     3 0.295
 16 ZEHND3     3 0.295
 17 ZEHND4     2 0.295
 18 ZEHND5     2 0.295
 19 HEAL 1    26 0.059
 20 HEAL D     3 0.295
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 27 COALF2   100 0.057 N  1/1992
 28 COALF3   100 0.057 N  1/1995
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APPENDIX D

DATA AND COST ESTIMATES FOR TRANSMISSION INTERTIE AND GENERATING PLANTS

APPENDIX D

DATA AND COST ESTIMATES FOR

TRANSMISSION INTERTIE AND GENERATING PLANTS

D.1 DATA AND COST ESTIMATES FOR TRANSMISSION INTERTIE

A. Cost Summary and Disbursements for Intertie Facilities

	Total Cost at 1979 Levels - $1000				
	Case IA	Case IB	Case IC	Case ID	Case II
1. Transmission Line:					
Eng'g. & Constr. Supv.	3,012	3,012	7,988	3,012	15,442
Right-of-Way	8,837	8,837	7,573	8,837	12,994
Foundations	8,445	8,445	12,160	8,445	22,966
Towers	21,615	21,615	33,990	21,615	64,974
Hardware	477	477	477	477	1,096
Insulators	503	503	755	503	1,396
Conductor	10,761	10,761	17,663	10,761	36,946
Subtotal	53,650	53,650	80,606	53,650	155,814
2. Substations:					
Eng'g. & Constr. Supv.	1,352	1,352	1,855	2,816	6,902
Land	57	57	46	81	185
Transformers	1,703	1,703	3,291	1,703	11,917
Circuit Breakers	1,093	1,093	1,323	1,953	6,410
Station Equipment	1,223	1,223	1,933	1,345	4,375
Structures & Accessories	3,628	3,628	3,978	4,026	16,411
Subtotal	9,056	9,056	12,426	11,924	46,200
3. Control and Communications:					
Eng'g. & Constr. Supv.	125	125	125	165	200
Equipment	2,375	2,375	2,375	3,135	3,600
Subtotal	2,500	2,500	2,500	3,300	3,800
Total Baseline 1979 Costs	65,206	65,206	95,532	68,874	205,814

Capital disbursements for each of the above cases are given on following computation sheets, these being identical to those later used for financial planning purposes with selected alternative.

CAPITAL INVESTMENT DISBURSEMENTS FOR TRANSMISSION INTERTIE
CASES IA & IB

	1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
1. TRANSMISSION LINE							
ENGINEERING AND CONSTRUCTION							
SUPERVISION	452	753	0	392	693	723	3012
RIGHT OF WAY	0	2209	6628	0	0	0	8837
FOUNDATIONS	0	0	0	2280	6165	0	8445
TOWERS	0	0	0	0	9727	11888	21615
HARDWARE	0	0	0	0	72	405	477
INSULATORS	0	0	0	0	75	428	503
CONDUCTOR	0	0	0	0	1614	9147	10761
SUB-TOTAL	452	2962	6628	2672	18346	22591	53650
2. SUBSTATIONS							
ENGINEERING & CONSTRUCTION							
SUPERVISION	270	270	270	270	135	135	1352
LAND	57	0	0	0	0	0	57
TRANSFORMERS	0	0	341	596	596	170	1703
CIRCUIT BREAKERS	0	0	219	383	383	109	1093
STATION EQUIPMENT	0	0	245	428	428	122	1223
STRUCTURES & ACCESSORIES	0	0	726	1451	1451	0	3628
SUB-TOTAL	327	270	1800	3128	2993	537	9056
3. CONTROL AND COMMUNICATIONS							
ENGINEERING AND INSTALLATION							
SUPERVISION	0	0	0	0	54	71	125
EQUIPMENT	0	0	0	0	950	1425	2375
SUB-TOTAL	0	0	0	0	1004	1496	2500
TOTAL	779	3233	8428	5800	22342	24624	65206
TOTAL FOR YEAR	0	4012	0	14228	0	46967	65206

CAPITAL INVESTMENT DISBURSEMENTS FOR TRANSMISSION INTERTIE
CASE IC

	1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
1. TRANSMISSION LINE							
ENGINEERING AND CONSTRUCTION							
SUPERVISION	1198	1997	0	1038	1837	1917	7988
RIGHT OF WAY	0	1893	5680	0	0	0	7573
FOUNDATIONS	0	0	0	3283	8877	0	12160
TOWERS	0	0	0	0	15296	18695	33990
HARDWARE	0	0	0	0	72	405	477
INSULATORS	0	0	0	0	113	642	755
CONDUCTOR	0	0	0	0	2649	15014	17663
SUB-TOTAL	1198	3890	5680	4322	28844	36672	80606
2. SUBSTATIONS							
ENGINEERING & CONSTRUCTION							
SUPERVISION	371	371	371	371	186	186	1855
LAND	46	0	0	0	0	0	46
TRANSFORMERS	0	0	658	1152	1152	329	3291
CIRCUIT BREAKERS	0	0	265	463	463	132	1323
STATION EQUIPMENT	0	0	387	677	677	193	1933
STRUCTURES & ACCESSORIES	0	0	796	1591	1591	0	3978
SUB-TOTAL	417	371	2476	4254	4068	840	12426
3. CONTROL AND COMMUNICATIONS							
ENGINEERING AND INSTALLATION							
SUPERVISION	0	0	0	0	54	71	125
EQUIPMENT	0	0	0	0	950	1425	2375
SUB-TOTAL	0	0	0	0	1004	1496	2500
TOTAL	1615	4261	8156	8575	33916	39009	95532
TOTAL FOR YEAR	0	5876	0	16731	0	72925	95532

CAPITAL INVESTMENT DISBURSEMENTS FOR TRANSMISSION INTERTIE
CASE ID

		1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
1. TRANSMISSION LINE							
ENGINEERING AND CONSTRUCTION							
SUPERVISION	452	753	0	392	693	723	3012
RIGHT OF WAY	0	2209	6628	0	0	0	8837
FOUNDATIONS	0	0	0	2280	6165	0	8445
TOWERS	0	0	0	0	9727	11888	21615
HARDWARE	0	0	0	0	72	405	477
INSULATORS	0	0	0	0	75	428	503
CONDUCTOR	0	0	0	0	1614	9147	10761
SUB-TOTAL	452	2962	6628	2672	18346	22591	53650
2. SUBSTATIONS							
ENGINEERING & CONSTRUCTION							
SUPERVISION	563	563	563	563	282	282	2816
LAND	81	0	0	0	0	0	81
TRANSFORMERS	0	0	341	596	596	170	1703
CIRCUIT BREAKERS	0	0	391	684	684	195	1953
STATION EQUIPMENT	0	0	269	471	471	135	1345
STRUCTURES & ACCESSORIES	0	0	805	1610	1610	0	4026
SUB-TOTAL	644	563	2369	3924	3642	782	11924
3. CONTROL AND COMMUNICATIONS							
ENGINEERING AND INSTALLATION							
SUPERVISION	0	0	0	0	71	94	165
EQUIPMENT	0	0	0	0	1254	1881	3135
SUB-TOTAL	0	0	0	0	1325	1975	3300
TOTAL	1096	3525	8996	6596	23313	25348	68874
TOTAL FOR YEAR	0	4621	0	15592	0	48661	68874

CAPITAL INVESTMENT DISBURSEMENTS FOR TRANSMISSION INTERTIE
CASE II

	1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
1. TRANSMISSION LINE							
ENGINEERING AND CONSTRUCTION							
SUPERVISION	2316	3861	0	2007	3552	3706	15442
RIGHT OF WAY	0	3249	9746	0	0	0	12994
FOUNDATIONS	0	0	0	6201	16765	0	22966
TOWERS	0	0	0	0	29238	35736	64974
HARDWARE	0	0	0	0	164	932	1096
INSULATORS	0	0	0	0	209	1187	1396
CONDUCTOR	0	0	0	0	5542	31404	36946
SUB-TOTAL	2316	7109	9746	8208	55471	72964	155814
2. SUBSTATIONS							
ENGINEERING & CONSTRUCTION							
SUPERVISION	1380	1380	1380	1380	690	690	6902
LAND	185	0	0	0	0	0	185
TRANSFORMERS	0	0	2383	4171	4171	1192	11917
CIRCUIT BREAKERS	0	0	1282	2244	2244	641	6410
STATION EQUIPMENT	0	0	875	1531	1531	438	4375
STRUCTURES & ACCESSORIES	0	0	3282	6564	6564	0	16411
SUB-TOTAL	1565	1380	9203	15890	15200	2960	46200
3. CONTROL AND COMMUNICATIONS							
ENGINEERING AND INSTALLATION							
SUPERVISION	0	0	0	0	86	114	200
EQUIPMENT	0	0	0	0	1440	2160	3600
SUB-TOTAL	0	0	0	0	1526	2274	3800
TOTAL	3882	8489	18948	24099	72197	78198	205814
TOTAL FOR YEAR	0	12371	0	43047	0	150396	205814

B. Case IA & IB, Anchorage-Fairbanks Intertie, 230 kV s/c Transmission System, 323 Miles

1. Cost Summary

T/L Cost @ $166,104 per mile	$53,652,000
Anchorage Substation	3,974,000
Ester Substation	5,080,000
Control and Communications System	2,500,000
TOTAL	$65,206,000

2. Anchorage Substation Costs

1	138-kV Circuit Breaker	$ 86,000
	Structures and Accessories	108,000
1	138-kV Air Disconnect Switch	11,000
	Structures and Accessories	38,000
4	13.8-kV, 12-MVAR Shunt Reactor Bank	420,000
	Structures and Accessories	315,000
4	13.8-kV Circuit Breaker	154,000
	Structures and Accessories	119,000
4	13.8-kV Air Disconnect Switch	31,000
	Structures and Accessories	64,000
4	1Ø - 48 MVA, 138/230-kV Autotransformer	1,020,000
	Structures and Accessories	538,000
2	230-kV Circuit Breakers	338,000
	Structures and Accessories	407,000
4	230-kV Air Disconnect Switch	70,000
	Structures and Accessories	232,000
	Land 2 acres	23,000
	TOTAL	$3,974,000

3. Ester Substation Costs

1	138-kV Circuit Breaker Structures and Accessories	$ 86,000 108,000
1	138-kV Air Disconnect Switch Structures and Accessories	11,000 38,000
3	13.8-kV, 12-MVAR Shunt Capacitor Bank Structures and Accessories	265,000 198,000
3	13.8-kV Circuit Breaker Structures and Accessories	116,000 89,000
4	1Ø, 46 MVA, 138/230-kV Autotransformer Structures and Accessories	984,000 516,000
3	230-kV Circuit Breaker Structures and Accessories	507,000 613,000
9	230-kV Air Disconnect Switch Structures and Accessories	157,000 528,000
3	230-kV, 16-MVAR Reactor Structures and Accessories	474,000 356,000
	Land 3 acres	34,000
	TOTAL	$5,080,000

C. Case IC, Anchorage-Fairbanks Intertie, 345 kV s/c Transmission System, 323 miles

1. Cost Summary

T/L Cost @ $249,551 per mile	$80,606,000
Anchorage Substation	6,195,000
Ester Substation	6,231,000
Control and Communications System	2,500,000
TOTAL	$95,532,000

2. Anchorage Substation Costs

1	138-kV Circuit Breaker Structures and Accessories	$ 86,000 108,000
1	138-kV Air Disconnect Switch Structures and Accessories	11,000 38,000
1	13.8-kV 16-MVAR Shunt Reactor Bank Structures and Accessories	112,000 84,000
1	13.8-kV Circuit Breaker Structures and Accessories	39,000 30,000
1	13.8-kV Air Disconnect Switch Structures and Accessories	8,000 16,000
4	1Ø - 48-MVA, 138/345-kV Autotransformer Structures and Accessories	1,936,000 725,000
2	345-kV Circuit Breaker Structures and Accessories	653,000 340,000
5	345-kV Air Disconnect Switch Structures and Accessories	114,000 330,000
4	1Ø - 33-1/3-MVAR, 345-kV Shunt Reactor Structures and Accessories	882,000 660,000
	Land 2 acres	23,000
	TOTAL	$6,195,000

3. Ester Substation Cost

1	138-kV Circuit Breaker Structures and Accessories	$ 86,000 108,000
1	138-kV Air Disconnect Switch Structures and Accessories	11,000 38,000
1	13.8-kV, 15-MVAR Shunt Capacitor Structures and Accessories	132,000 100,000
1	13.8-kV Circuit Breaker Structures and Accessories	39,000 30,000
1	13.8-kV Air Disconnect Switch Structures and Accessories	8,000 16,000

3. Ester Substation Cost (Continued)

4	1Ø - 48 MVA, 138/345-kV Autotransformer Structures and Accessories	$1,936,000 725,000
2	345-kV Circuit Breaker Structures and Accessories	653,000 340,000
5	345-kV Air Disconnect Switch Structures and Accessories	114,000 330,000
4	1Ø - 33-1/3-MVAR, 345-kV Shunt Reactor Structures and Accessories	882,000 660,000
	Land 2 acres	23,000
	TOTAL	$6,231,000

D. Case ID, Anchorage-Fairbanks Intertie, 230 kV s/c Transmission System, 323 miles

1. Cost Summary

T/L Cost @ $166,104 per mile	$53,652,000
Anchorage Substation	3,976,000
Palmer Substation	1,434,000
Healy Substation	1,434,000
Ester Substation	5,080,000
Control and Communications System	3,300,000
TOTAL	$68,876,000

2. Anchorage-Palmer, 230 kV s/c Transmission System, 40 miles

T/L Cost @ $166,104 per mile	$ 6,644,000
Anchorage Substation	3,976,000
Palmer Substation	717,000
Control and Communications System	1,450,000
TOTAL	$12,787,000

3. Palmer-Healy, 230 kV s/c Transmission System, 190.5 miles

T/L Cost @ $166,104 per mile	$31,726,000
Palmer Substation	717,000
Healy Substation	717,000
Control and Communications System	400,000
TOTAL	$33,560,000

4. Healy-Ester, 230 kV s/c Transmission System, 92 miles

T/L Cost @ $166,104 per mile	$15,282,000
Healy Substation	717,000
Ester Substation	5,080,000
Control and Communications System	1,450,000
TOTAL	$22,529,000

5. Anchorage Substation Costs

1	138-kV Circuit Breaker	$ 86,000
	Structures and Accessories	108,000
1	138-kV Air Disconnect Switch	11,000
	Structures and Accessories	38,000
4	13.8-kV, 12-MVAR Shunt Reactor Bank	420,000
	Structures and Accessories	315,000
4	13.8-kV Circuit Breaker	154,000
	Structures and Accessories	119,000
4	13.8-kV Air Disconnect Switch	31,000
	Structures and Accessories	64,000
4	1Ø - 48-MVA, 138/230-kV Autotransformer	1,020,000
	Structures and Accessories	538,000
2	230-kV Circuit Breakers	338,000
	Structures and Accessories	407,000
4	230-kV Air Disconnect Switch	70,000
	Structures and Accessories	234,000
	Land 2 acres	23,000
	TOTAL	$ 3,976,000

6. Palmer Substation - (One Line Bay)

1.5	230-kV Circuit Breaker	$ 253,000
	Structures and Accessories	305,000
2	230-kv Air Disconnect Switch	36,000
	Structures and Accessories	117,000
	Land	6,000
	TOTAL	$ 717,000

7. Healy Substation - (One Line Bay)

1.5	230-kV Circuit Breaker	253,000
	Structures and Accessories	305,000
2	230-kV Air Disconnect Switch	36,000
	Structures and Accessories	117,000
	Land	6,000
	TOTAL	$ 717,000

8. Ester Substation Costs

1	138-kV Circuit Breaker	$ 86,000
	Sturctures and Accessories	108,000
1	138-kV Air Disconnect Switch	11,000
	Structures and Accessories	38,000
3	13.8-kV, 12-MVAR Shunt Capacitor Bank	265,000
	Structures and Accessories	198,000
3	13.8-kV Circuit Breaker	116,000
	Structures and Accessories	89,000
4	1Ø - 46-MVA, 138/230-kV Autotransformer	984,000
	Structures and Accessories	516,000
3	230-kV Circuit Breaker	507,000
	Structures and Accessories	613,000

8. Ester Substation Costs (Continued)

9	230-kV Air Disconnect Switch	$ 157,000
	Structures and Accessories	528,000
3	230-kV, 16-MVAR Reactor	474,000
	Structures and Accessories	356,000
	Land 3 acres	34,000
	TOTAL	$5,080,000

E. Case II, Anchorage - Upper Susitna - Fairbanks Intertie

345 kV 2-s/c Anchorage-Devil Canyon 155 miles

230 kV 2-s/c Devil Canyon-Ester 189 miles

230 kV 2-s/c Watana-Devil Canyon 27 miles

1. Cost Summary

Anchorage - Devil Canyon T/L @ $506,640 per mile*	$ 78,529,000
Devil Canyon - Ester T/L @ $353,386 per mile*	66,790,000
Watana - Devil Canyon T/L @ $388,698 per mile*	10,495,000
Anchorage Substation	23,160,000
Devil Canyon Substation	10,109,000
Ester Substation	11,339,000
Watana Substation	1,592,000
Control and Communications System	3,800,000
TOTAL	$205,814,000

* Includes two single-circuit lines.

2. Anchorage Substation Cost

2	138-kV Circuit Breaker	$ 172,000
	Structures and Accessories	216,000
2	138-kV Air Disconnect Switch	23,000
	Structures and Accessories	76,000
7	1Ø - 210.5-MVA, 138/345-kV Autotransformer	8,516,000
	Structures and Accessories	3,404,000
9	345-kV Circuit Breaker	2,938,000
	Structures and Accessories	1,528,000
18	345-kV Air Disconnect Switch	408,000
	Structures and Accessories	1,191,000
2	345-kV, 200-MVAR Shunt Capacitor	2,647,000
	Structures and Accessories	1,984,000
	Land 5 acres	57,000
	TOTAL	$23,160,000

3. Devil Canyon Substation Cost

3	345-kV Circuit Breaker	$ 981,000
	Structures and Accessories	509,000
6	345-kV Air Disconnect Switch	138,000
	Structures and Accessories	399,000
7	1Ø - 90.3-MVA, 230/345-kV Autotransformer	3,418,000
	Structures and Accessories	1,466,000
6	230-kV Circuit Breaker	1,015,000
	Structures and Accessories	1,224,000
12	230-kV Air Disconnect Switch	210,000
	Structures and Accessories	703,000
	Land 4 acres	46,000
	TOTAL	$10,109,000

4. Ester Substation Cost

2	138-kV Circuit Breaker	$ 172,000
	Structures and Accessories	216,000
2	138-kV Air Disconnect Switch	23,000
	Structures and Accessories	76,000
7	1Ø - 65-MVA, 138/345-kV Autotransformer	2,086,000
	Structures and Accessories	1,253,000
6	13.8-kV Air Disconnects	46,000
	Structures and Accessories	96,000
6	13.8-kV Circuit Breaker	232,000
	Structures and Accessories	181,000
6	13.8-kV, 6-MVAR Capacitor	264,000
	Structures and Accessories	200,000
9	230-kV Circuit Breaker	1,523,000
	Structures and Accessories	1,838,000
18	230-kV Air Disconnect Switch	314,000
	Structures and Accessories	1,055,000
2	230-kV, 80-MVAR Capacitor	968,000
	Structures and Accessories	727,000
	Land 6 acres	69,000
	TOTAL	$11,339,000

5. Watana Substation Cost

3	230-kV Circuit Breakers	$ 508,000
	Structures and Accessories	613,000
6	230-kV Disconnect Switch	106,000
	Structures and Accessories	348,000
	Land	17,000
	TOTAL	$ 1,592,000

D.2 DATA AND COST ESTIMATES FOR GENERATING PLANTS

B. Cost Estimates and Disbursements for Generating Plants

Note: Only specific units affected by interconnection of Anchorage and Fairbanks systems are considered:

1. Northpole #3 (NORT 3) 69 MW SCGT in Fairbanks Area.

This unit is necessary for independent system expansion. Will not be required if interconnection assured.

Rating - 68.6 MW (net) Combustion Turbine
Fuel - Distillate from North Pole Refinery

Ref. Table B-1, Appendix B of Stanley Consultants Review Report

For 1983 Installation:

Unit Cost =	$31,482,000		
NO_x Cost	1,387,000		
Subtotal	$32,869,000	or	$476/kW
Assoc. Transm. 1/	4,783,000		
TOTAL	$37,652,000	or	$546/kW

See Also: P. 45 of GVEA Power Supply Study - 1978 by Stanley Consultants & P. 28 - Table 10 Escalation Rates.

	GNP Deflators		
Period	Labor (% 20%)	Material (% 80%)	Composite
1983-1980	1.085	1.07	1.075
1980-1979	1.095	1.08	1.085

Summary of Costs:

Facility	1979 Baseline Costs		
Gas-Turbine Unit	$24,385,000	or	$353/kW
Assoc. Transm.	3,549,000		
Total Capital Investment	$27,934,000	or	$405/kW

Disbursements - $1000 Pre-Operational Period	1st Year (1983)		2nd Year (1984)	
Gas-Turbine Unit	7,315	(30%)	17,070	(70%)
Assoc. Transm.	355	(10%)	3,194	(90%)
Total Facilities	$7,670		$20,264	

1/ Relocation of facilities and expansion of existing Northpole substation.

2. Beluga #9 (BELU 9) 71 MW RCGT in Anchorage Area.

This unit will be postponed for one year by interconnection, from beginning year 1985 to 1986.

This unit will draw on Beluga gas reserves for fuel supply. Design of unit is assumed to be simple-cycle, similar to existing units on Chugach System - Ref. Beluga Units 1, 2, 4, 6, & 7.

Estimated Cost of Unit:

From Reference Cost Estimate for NORT 3 at Fairbanks

Cost at Bus-bar of 69 MW unit = \$353/kW

By comparison for 71 MW unit = \$350/kW

Now applying Alaskan construction cost location factors from Battelle Report, Table 6.3, P. 6.12

Applicable factor from Fairbanks to Beluga = $\frac{1.62}{1.2}$ = 1.35

Estimated Cost = \$473/kW or \$33,548,000

Disbursements:

Pre-Operational Period	1st Year	2nd Year
Independent Expansion	1983	1984
Interconnected Expansion	1984	1985
Proportion of Total	30%	70%
Investment - \$1000	10,064	23,484

Associated Transmission Facilities:

Transmission Line (allow 50 miles) @ \$126,000/mile

Total Cost of Line Facilities = \$6,300,000

Substation Additions at Beluga and Knik Arm = \$2,650,000

Total Transmission Line and Substation Facilities = \$8,950,000

Disbursements:

	1979 Baseline Costs		
Pre-Operational Period	1st Year	2nd Year	
Independent Expansion	1983	1984	
Interconnected Expansion	1984	1985	
Proportion of Total	10%	90%	
Investment - \$1000 Transm. & Substations	895	8,055	
Total Facilities			\$42,490,000

3. Northpole #4 (NORT 4) 69 MW SCGT in Fairbanks Area.

This unit is necessary for independent system expansion. Will not be required with an interconnected system.

Scheduled In-Service Beginning Year 1990

Unlike NORT 3, no transmission additions will be required, with completion of relocation and expansion of the substation.

Considering only cost of unit with assoc. transf. and swgr.

For 1979 Baseline Cost Levels:

Total Capital Investment = $25,185,000 or $365/kW

Disbursements:

Pre-Operational Period	1st Year (1988)	2nd Year (1989)
GT unit, transf. & swgr.	7,555 (30%)	17,630 (70%)

4. Anchorage Peaking Unit #2 (PEAK A2) 78 MW SCGT

This unit is required for both independent and interconnected systems but in-service date is advanced one year with intertie.

Basing cost of addition on Northpole Unit 4 installation - i.e. SCGT unit with associated transformer and switching. Estimated cost based on rating, with allowance for scale.

For 1979 Baseline Cost Levels:

69 MW GT Unit Total Cost = $25,185,000 or $365/kW

78 MW GT Unit Total Cost = $28,080,000 or $360/kW

Now applying Alaskan construction cost location adjustment factor from Battelle Report Table 6.3 P. 6.12

Applicable factor from Fairbanks to Anchorage = 1/1.2 = 0.83

Total Capital Investment = $23,400,000 or $300/kW

Disbursements:

Year	Independent	Interconnected	% Total	Cost - $1000
1	1994	1993	30	7,020
2	1995	1994	70	16,380

5. Northpole #5 (NORT 5) 69 SCGT in Fairbanks Area.

This unit is necessary for independent system expansion. Will not be required with an interconnected system.

Scheduled In-Service Beginning Year 1997

The addition of this unit completes the expansion for the independent systems of the Railbelt Area, the time frame is such that for interconnected expansion, with the staged increments of hydro capacity from the Susitna development, the last unit at Devil Canyon would be on-line beginning year 1997.

Similar to NORT 4, no transmission additions are assumed to be required, such that power would be delivered from the expanded Northpole Substation to the existing system.

Considering only cost of unit, with associated transf. and swgr.

For 1979 Baseline Cost Levels:

Total Capital Investment = $25,185,000 or $365/kW

Disbursements:

	($1000)	
Pre-Operational Period:	1st Year (1995)	2nd Year (1996)
GT unit, transf. & swgr.	7,555 (30%)	17,630 (70%)

6. Anchorage #11 (ANCH 11) 104 MW Coal-Fired Steam-Electric Plant.

This unit will be required for independent system expansion but will be postponed, with interconnection, from in-service 1988 to 1993.

Cost estimate for this plant is based on Healy Unit 2 estimate prepared by Stanley Consultants, with applicable Alaskan construction cost location adjustment factor.

From Stanley Consultants Report to GVEA, Appendix A, P. A-1.

For 1984 Installation Date (1978 Cost Levels):

Healy Unit 2 Plant (Without FGD):

Plant and Equipment	$102,924,000	or	$ 990/kW
Contingency	3,088,000		
Total Construction Cost	$107,012,000	or	$1029/kW
Eng'g., Legal & Overhead	14,982,000		
TOTAL	$121,994,000	or	$1173/kW
Escalating @ 10% to 1979 Cost Level	. . . .		$1290/kW
Total Baseline 1979 Cost without FGD =	$134,160,000		

Now Including Cost of Desulphurization:

Plant and Equipment	$111,174,000	or	$1069/kW
Contingency	3,335,000		
Total Construction Cost	$114,509,000	or	$1101/kW
Eng'g., Legal & Overhead	16,031,000		
TOTAL	$130,540,000	or	$1255/kW
Escalating @ 10% to 1979 Cost Level	. . . .		$1380/kW
Total Baseline 1979 Cost with FGD =	$143,520,000		

Associated Transmission Facilities:

Assuming relatively short transmission line with substation facilities required, for connection to existing AML&P transmission system in Anchorage area.

Cost Estimate for Transmission Line:

Transmission Line (allow 30 miles) @ $126,000/mile

Total Cost of Line Facilities = $3,780,000

Cost Estimate for Substation Facilities:

Equipment	$2,700,000
Contingency	203,000
Total Construction Cost	$2,903,000
Eng'g., Legal & Overhead	377,000
TOTAL	$3,280,000
Escalating @ 10% to 1979 Cost Level	
Total 1979 Baseline Cost	$3,608,000

Summary of Costs:

	WO/FGD	W/FGD
Coal-Fired Plant (104 MW)	$134,160,000	$143,520,000
Transmission Line	3,780,000	3,780,000
Substation Facilities	3,608,000	3,608,000
TOTAL	$141,548,000	$150,908,000

Now applying Alaskan construction cost location adjustment factor from Table 6.3 P. 6.12 of Battelle Study Report:

From Healy to Anchorage - Location Factor = 1.7/2.42 = 0.70

Applying this factor, Total Costs = $99,084,000 $105,636,000

or = $953/kW $1016/kW

Disbursements - $1000

Coal-Fired Plant (ANCH 11)

Pre-Operational Year:	Independent	Interconnected	1979 Baseline Costs % Total	WO/FGD	W/FGD
1.	1982	1987	2	1,878	2,009
2.	1983	1988	8	7,513	8,037
3.	1984	1989	30	28,174	30,139
4.	1985	1990	37	34,747	37,172
5.	1986	1991	20	18,783	20,093
6.	1987	1992	3	2,817	3,014

Associated Transmission Facilities

5.	1986	1991	20	1,034	1,034
6.	1987	1992	80	4,138	4,138

7. Coal-Fired Unit F2 (COAL F2) 100 MW in Fairbanks Area.

This unit will be required for both the independent and interconnected system expansions, with generation reserve sharing only. However, with both reserve sharing and firm power transfer, it is replaced, together with COAL 5, by a 300 MW unit (COAL 6).

This unit will be very similar to ANCH 11, which in turn was based on the Healy Unit 2 Plant, as reported by Stanley Consultants. The unit costs will be increased proportionately, to allow for the change of unit size from 104 MW to 100 MW. This has been economically scaled using the nomograph (Figures D-1 and D-2) in this appendix.

For Generating Plant COAL F2:

Plant Cost Estimates:	1979 Baseline Cost Levels		
Without FGD	$120,000,000	or	$1200/kW
With FGD	$130,000,000	or	$1300/kW

Associated Transmission Facilities:

Assuming a plant site location at or near Healy, the transmission line and substation requirements are similar to those required for Healy Unit 2. Reference Stanley Consultants Review Report to GVEA, Appendix A, P. A-1:

Transmission Facility Costs:

	1979 Cost Levels (1.1 x 1978 Costs)	
	Transmission Line	Substation Facilities
Equipment and Material	$15,510,000	$3,348,000
Contingency	465,000	100,000
Construction Cost	$15,975,000	$3,448,000
Eng'g., Legal & Overhead	2,455,000	102,000
TOTAL	$18,430,000	$3,550,000

Disbursements - $1000

Coal-Fired Unit (COAL F2):

Pre-Operational Year:		% Total	1979 Baseline Costs WO/FGD	W/FGD
1.	1986	2	2,400	2,600
2.	1987	8	9,600	10,400
3.	1988	30	36,000	39,000
4.	1989	37	44,400	48,100
5.	1990	20	24,000	26,000
6.	1991	3	3,600	3,900
Associated Transmission Facilities:				
5.	1990	20	4,400	4,400
6.	1991	80	17,580	17,580

8. Coal-Fired Unit 5 (COAL 5) 200 MW in Anchorage Area.

This unit will be required for both the independent and interconnected system expansions, with generation reserve sharing only. However, with both reserve sharing and firm power transfer, it is replaced, together with COAL F2, by a 300-MW unit (COAL 6).

The cost estimate for this generating plant was obtained by scaling costs from a base reference of 100 MW to 200 MW, using the nomograph (Figures D-1 and D-2) contained in this Appendix. Then Alaskan construction cost location adjustment factors were used to determine the cost relevant to the Beluga site in the Anchorage Area.

From Healy to Beluga - Location Factor = 2.75/2.42 = 1.14

For Generating Plant COAL 5

Plant Cost Estimates:

	1979 Baseline Cost Levels ($1000) Healy Site	Beluga Site
Without FGD	$165,000 or $825/kW	$188,000 or $ 940/kW
With FGD	$175,000 or $875/kW	$200,000 or $1000/kW

Associated Transmission Facilities:

Assuming a section of transmission line and substation facilities, for connection to existing transmission system in Anchorage area.

Transmission Line (allow 50 miles) @	$174,000/mile
Total Cost of Line Facilities =	$ 8,700,000
Substation Terminal at Knik Arm =	3,545,000
Total Transmission Facilities	$12,245,000

Disbursements - $1000

Coal-Fired Unit (COAL 5)

Pre-Operational Year:		1979 Baseline Costs		
		% Total	WO/FGD	W/FGD
1.	1986	2	3,760	4,000
2.	1987	8	15,040	16,000
3.	1988	30	56,400	60,000
4.	1989	37	69,560	74,000
5.	1990	20	37,600	40,000
6.	1991	3	5,640	6,000
Associated Transmission Facilities:				
5.	1990	20	2,450	2,450
6.	1991	80	9,795	9,795

9. Coal-Fired Unit 6 (COAL 6) 300 MW in Anchorage Area.

This unit will not be required either for independent or interconnected system expansion for generation reserve sharing only. However, with reserve capacity sharing and firm power transfer, it will replace both COAL F2 and COAL 5.

The cost estimate for this plant has been derived from the cost for the reference 100 MW plant, using the nomograph (Figures D-1 and D-2) contained in this Appendix. This enabled consideration of economies of scale obtained when the unit capacity is changed from 100 to 300 MW and the differential costs associated with the two sites, according to the Alaskan construction cost location adjustment factor, similar to that developed for COAL 5.

Plant Cost Estimates:

	1979 Baseline Cost Levels ($1000)	
	Healy Site	Beluga Site
Without FGD	$200,000 or $667/kW	$228,000 or $760/kW
With FGD	$240,000 or $800/kW	$274,000 or $913/kW

Associated Transmission Facilities:

Assuming a section of transmission line and substation facilities, for connection to existing transmission system in Anchorage area.

Transmission Line (allow 50 miles) @	$240,000/mile
Total Cost of Line Facilities =	$12,000,000
Substation Terminal at Knik Arm =	6,250,000
Total Transmission Facilities	$18,250,000

Disbursements - $1000

Coal-Fired Unit (COAL 6)

Pre-Operational Year:	1979 Baseline Costs % Total	WO/FGD	W/FGD
1. 1986	2	4,560	5,480
2. 1987	8	18,240	21,920
3. 1988	30	68,400	82,200
4. 1989	37	84,360	101,380
5. 1990	20	45,600	54,800
6. 1991	3	6,840	8,220
Associated Transmission Facilities:			
5. 1990	20	3,650	3,650
6. 1991	80	14,600	14,600

10. Coal-Fired Unit 2 (GEN 2) 300 MW at New Site in Anchorage Area. This unit is required for both independent and interconnected systems but in-service date postponed one year with intertie.

For Generating Plant COAL 6:
It is assumed that site will be near to previous plant location at Beluga, in sufficient proximity to assume cost basis to be identical, with difference only in the time frame for construction.

Cost estimate for plant and associated transmission facilities are then identical to that for COAL 6.

Disbursements - $1000

Coal-Fired Unit (GEN 2)

Pre-Operational Year:	Independent	Interconnected	1979 Baseline Costs % Total	WO/FGD	W/FGD
1.	1989	1990	2	4,560	5,480
2.	1990	1991	8	18,240	21,920
3.	1991	1992	30	68,400	82,200
4.	1992	1993	37	84,360	101,380
5.	1993	1994	20	45,600	54,800
6.	1994	1995	3	6,840	8,220
Associated Transmission Facilities:					
5.	1993	1994	20	3,650	3,650
6.	1994	1995	80	14,600	14,600

D.3 DATA AND COST ESTIMATES FOR SUPPLY OF CONSTRUCTION POWER TO UPPER SUSITNA PROJECT SITES

The requirements of the combined Railbelt area generation expansion, with inclusion of both Watana and Devil Canyon power from the Susitna development, schedules Unit 1 from Devil Canyon in January 1995, only 3 years after the first unit goes on line at Watana Damsite. Assuming as a first construction schedule that of the U.S. Army Corps of Engineers, the construction periods are 6 and 5 years, respectively, for Watana earthfill dam and the concrete arch dam at Devil Canyon. Thus, with the generation staging of the plan for interconnection, the total construction period would be 11 years, with pre-operational construction periods of 6 years for Watana and 5 years for Devil Canyon. There would be concurrent construction during 2 years.

Prior to the first unit on-line at Watana, construction power would be required for 6 years at Watana and 2 years at Devil Canyon. It is assumed, for purposes of analysis, that separate provision would need to be made for the full construction power needs at both sites. From estimates by the Consultants:

Connected Load

Watana	4000 kW (estimated at 3750 kW)
Devil Canyon	3400 kW (estimated at 3350 kW)

Operational Assumptions for Both Sites:

6 months/yr intensive operation	@ 0.65 LF
6 months/yr light loading	@ 0.30 LF

Corresponding to construction planning assumptions of U.S. Corps of Engineers.

Figure 7-1 of Chapter 7 shows the recommended sites at Watana and Devil Canyon for the Susitna development and the routing of the tap line to the sites from the transmission tap station, located on the main transmission corridor for the Anchorage-Fairbanks Intertie. The tap line can later be used also for a subtransmission circuit for distribution in the area, following the completion of the construction program.

A. Alternative 1 - Cost of Construction Power by Diesel Generation
(This will constitute benefits for B/C analysis)

Basic Assumptions:

1. Diesel units purchased for Watana will be used for a period of 6 years and then sold at depreciated value.

2. Diesel units purchased for Devil Canyon will be used for a period of 5 years and then sold at depreciated value.

3. No provision will be made at Devil Canyon for tapping 230-kV line from Watana once energized, due to prior purchase of diesel units for construction power.

4. Diesel units will be installed in multiples of 675 kW net/unit.
   - 6 units at Watana — 4050 kW net capacity
   - 5 units at Devil Canyon — 3375 kW net capacity

From previous construction power estimates for diesel unit installations:

1979 Cost = $700/kW

Installation for Watana construction power units would be made in 1985, ready for service in January 1986.

Escalating @ 7% through 1985 - Cost Level = $1050/kW.

Installation for Devil Canyon construction power units would be made in 1989, ready for service in January 1990.

Escalating @ 7% through 1989 - Cost Level = $1377/kW.

Cost of Diesel Installations:

Watana	=	$1050 x 4050	=	$4,252,500
Devil Canyon	=	$1377 x 3355	=	$4,647,375

This capital investment would be disbursed in 1985 and 1989, respectively, for Watana and Devil Canyon.

Cost of Diesel Operation During Construction

Basic Assumption: Maximum Coincident Demand = Connected Load

This, incidentally, introduces a measure of maximum loading which tends to compensate for an initial lower estimate of construction power requirements by a factor equivalent to projected diversity.

Average Energy Usage Per Year:

Watana $3750\ (0.65 + 0.30)\ \frac{8760}{2}$ kWh = 15,603,750 kWh

Say 15.60 GWh/yr for 6 yrs.

Devil Canyon $3350\ (0.65 + 0.30)\ \frac{8760}{2}$ kWh = 13,939,350 kWh

Say 13.94 GWh/yr for 5 yrs.

Operating Characteristics of Diesel Units:

Fuel Rate Assumed	- 13 kWh/gal (diesel fuel)
Base Price for Diesel Fuel	- 41.2 ¢/gal (1977 actual)
Plus 5% Allowance for Lube Oil	- 43.3 ¢/gal

To be escalated @ 11% to 1980 and 7% thereafter.

O&M for diesel units estimated at 5% of total cost of incremental generation.

Year	Watana Dam	Year	Devil Canyon
1986	$1,118,500		
1987	1,198,100		
1988	1,280,800		
1989	1,371,200		
1990	1,468,000	1990	$1,311,800
1991	1,569,400	1991	1,402,400
		1992	1,501,300
		1993	1,607,300
		1994	1,708,800

DIESEL GENERATION OPERATING COSTS

Year	Diesel Fuel Including Lube Oil ¢/gal	Diesel Fuel Including Lube Oil mills/kWh	O&M (mills/kWh)	Total Operating Cost (mills/kWh)
1977	43.3	33.3	1.7	35.0
1978	48.1	37.0	1.9	38.9
1979	53.3	41.0	2.1	43.1
1980	59.2	45.5	2.3	47.8
1981	63.3	48.7	2.4	51.1
1982	67.8	52.2	2.6	54.8
1983	72.5	55.8	2.8	58.6
1984	77.6	59.7	3.0	62.7
1985	83.0	63.8	3.2	67.0
1986	88.8	68.3	3.4	71.7
1987	95.1	73.2	3.6	76.8
1988	101.7	78.2	3.9	82.1
1989	108.8	83.7	4.2	87.9
1990	116.5	89.6	4.5	94.1
1991	124.6	95.8	4.8	100.6
1992	133.3	102.5	5.2	107.7
1993	142.7	109.8	5.5	115.3
1994	152.6	117.4	5.9	123.3

Depreciated Value of Diesel Units:

Basic Assumption of 15-Year Service Life.

Assume Straight-Line Depreciation

1. Watana Installation

   Installed Cost (new) = $4,252,500 (1985)

   Depreciation/Year = 283,500

   Depreciated Value (1991) 6-Year Period = $2,551,500

2. Devil Canyon Installation

   Installed Cost (new) = $4,647,375 (1989)

   Depreciation/Year = 309,825

   Depreciated Value (1994) 5-Year Period = $3,098,250

Discounted Value of Benefits (Diesel Generation Alternative)

Base Year 1979 (Discounted @ 7%)

Year	PWF'	Construction Cost ($)	Operating Cost ($)	Total Cost ($)	Present Value ($)
1979	1.00000				
1985	0.66634	4,252,500		4,252,500	2,833,611
1986	0.62274		1,118,500	1,118,500	696,535
1987	0.58200		1,198,100	1,198,100	697,294
1988	0.54393		1,280,800	1,280,800	696,666
1989	0.50834	4,647,375	1,371,200	6,018,575	3,059,482
1990	0.47509		2,779,800	2,779,800	1,320,655
1991	0.44401	-2,551,500	2,971,800	420,300	186,617
1992	0.41496		1,501,300	1,501,300	622,979
1993	0.38781		1,607,300	1,607,300	623,327
1994	0.36244	-3,098,250	1,718,800	-1,379,450	-499,968
				TOTAL PW'	10,237,198

(- sign denotes assumed resale value)

B. Alternative 2 - Cost of Construction Power by Temporary Tapline
(This will represent costs for B/C analysis)

Basic Assumptions:

1. Same loading conditions and time frame as per Alternative 1.

2. Sequence of temporary construction as per previous assumptions.

3. Reuse of substation equipment possible after construction program completed but no salvage value on line material. (Note: Possible reuse as distribution line to recreational areas.) Assume resale value of substation equipment to be depreciated value based on 25-year life of facilities.

4. Cost of power based on wholesale rates in Railbelt area.
From previous estimates for line and substation facilities:

Construction Costs:

69-kV subtransmission line - \$3,200,000 (1985 level)
Susitna tap station + Watana substation facilities
Baseline cost level = \$26.50/kVA (1979)
Escalating @ 7% to 1985 (6 yrs)
Construction Cost = \$40/kVA (1985)
Total Construction Cost = \$400,000

69/4.16 kW, 5 MVA, Substation at Devil Canyon (1979 levels)
Transformer - \$45,000 fob factory (Virginia)
Allowing 5% for shipping and handling, etc.

At jobsite cost	=	\$47,250
Fused Disc. Sw.	=	2,750
Structure, Conc, pad, etc.	=	5,000
TOTAL		\$55,000

Construction Costs:

Equipment	60%	$55,000
Labor	30%	28,000
Design	10%	9,000
TOTAL		$92,000 or $18.4/kVA (1979)

Substation would be installed in 1989.

Escalated at 7% from 1979 levels.

1989 Construction Cost = $36.2/kVA

Total Construction Cost = $181,000

O&M For Temporary Construction Power Line Maintenance

69 kV Wood Pole line - Approximately 40 miles long (11 + 29 M)

	Year	$/M	Total O&M Costs ($)
40 M Total	1986	330	13,200
	1987	345	13,800
	1988	360	14,400
	1989	380	15,200
	1990	400	16,000
	1991	420	16,800
29 M Total	1992	440	12,800
	1993	460	13,300
	1994	485	14,000

Note: That due to overlap in construction schedules for Watana and Devil Canyon the capacity of the Susitna tap station will need to be doubled by addition of second 5 MVA transfer. This will be moved to spares inventory after 2 years.

Cost of Construction Power Supplied over Temporary Line Facility

Based on information from RWRA 2/1/79

Wholesale rates for Railbelt area, with combination of Susitna Hydropower and large coal-fired plant feeding interconnection.

Year	Rate of Change	Wholesale Rate (mills/kWh)	Cost of Energy (mills/kWh) Bus-Bar	Cost of Energy (mills/kWh) Substation
			Note:	1977 Cost Levels
1979	10%	17		
1980		18		
1981		20		
1982		22		
1983	8%	24		
1984		26		
1985		28		
1986		30	27.3	30.2
1987		32		
1988	7%	34		
1989		37		
1990		39	31.0	33.5
1991		42		
1992		45		
1993	5%	47		
1994		50		
1995			33.2	36.6
2000			36.2	39.1

Conversion of Total Energy Rate to 2-Part Tariff

Assumption: 100 MW Power Transfer at 0.6 LF is 525.6 GWh/yr.

Year	Bulk Rate (mills/kWh)	Total Revenue for Bulk Rate ($1000)	50/50 Revenue From: Demand ($1000)	Energy ($1000)	Equivalent Tariff: Demand Rate ($/kWh)	Energy Rate (mills/kWh)
1979	17	8,935.2	4,467.6		74.5	8.5
1980	18	9,460.8	4,730.4		78.8	9.0
1981	20	10,512.0	5,256.0		87.6	10.0
1982	22	11,563.2	5,781.6		96.4	11.0
1983	24	12,614.4	6,307.2		105.1	12.0
1984	26	13,665.6	6,832.8		113.9	13.0
1985	28	14,716.8	7,358.4		122.6	14.0
1986	30	15,768.0	7,884.0		131.4	15.0
1987	32	16,819.2	8,409.6		140.2	16.0
1988	34	17,870.4	8,935.2		148.9	17.0
1989	37	19,447.2	9,723.6		162.1	18.5
1990	39	20,498.4	10,249.2		170.8	19.5
1991	42	22,075.2	11,037.6		184.0	21.0
1992	45	23,652.0	11,826.0		197.1	22.5
1993	47	24,703.2	12,351.6		205.9	23.5
1994	50	26,280.0	13,140.0		219.0	25.0

Allow 5% adder for line and substation losses - assume the resulting rates are applicable to price construction power.

Cost Estimate for Construction Power

Assuming same loading as for diesel generation alternative.

1. Watana Damsite (3750 kW, 15.6 GWh/yr)

Year	Demand Rate ($/kW)	Energy Rate (mills/kWh)	Construction Power Costs Demand ($)	Energy ($)	Total ($)
1986	138.0	15.8	517,500	246,480	763,980
1987	147.2	16.8	552,000	262,080	814,080
1988	156.3	17.9	586,125	279,240	865,365
1989	170.2	19.4	638,250	302,640	940,890
1990	179.3	20.5	672,375	319,800	992,175
1991	193.2	22.1	724,500	344,760	1,069,260

2. Devil Canyon Damsite (3350 kW, 13.94 GWh/yr)

Year	Demand Rate ($/kW)	Energy Rate (mills/kWh)	Construction Power Costs Demand ($)	Energy ($)	Total ($)
1990	179.3	20.5	600,655	285,770	886,425
1991	193.2	22.1	647,220	308,074	955,294
1992	207.0	23.6	693,450	328,984	1,022,434
1993	216.2	24.7	724,270	344,318	1,068,588
1994	230.0	26.3	770,500	366,622	1,137,122

Depreciated Value of Substation Facilities

Basic Assumption of 25-Year Service Life

Assume Straight Line Depreciation

1. Watana Substation

Installed Cost (new)	=	$ 27.6/kVA (1985)
	=	$138,000
Depreciation/Year	=	$ 5,520
Depreciated Value	=	$104,880 (1991) (6-year period)

2. Devil Canyon Substation

Installed Cost (new)	=	$ 36.2/kVA (1989)
	=	$ 181,000
Depreciation/Year	=	$ 7,240
Depreciated Value	=	$ 144,800 (1994) (5-year period)

3. Susitna Tap Station/Watana Bus Tap

Installed Cost (new)	=	$ 262,000 (1985)
Depreciation/Year	=	$ 10,480
Depreciated Value	=	$ 167,680 (1994) (7-year period)

To transfer 5 MVA facility from Susitna Tap to Watana.

Cost of removal and transfer = $30,000 (1991)

Cost of second 5 MVA step-down facility at Susitna tap.

In 1989 for Supplementary power to Devil Canyon = $343,400

Depreciated value after 2 years = $315,900

Discounted Value of Costs (Sub-Transmission Tapline Alternative)

Base Year 1979 (Discounted @ 7%)

Year	PWF'	Construction Cost ($)	O&M ($)	Cost of Power ($)	Total Cost ($)	Present Value ($)
1979	1.00000					
1985	0.66634	400,000			400,000	266,536
1986	0.62274		13,200	763,980	777,180	483,981
1987	0.58200		13,800	814,080	827,880	481,826
1988	0.54393		14,400	865,365	879,765	478,531
1989	0.50834	524,400	15,200	940,890	1,480,490	752,592
1990	0.47509		16,000	1,878,600	1,894,600	900,106
1991	0.44401	-390,780*	16,800	2,024,554	1,650,574	732,871
1992	0.41496		12,800	1,022,434	1,035,234	429,581
1993	0.38781		13,300	1,068,588	1,081,888	419,567
1994	0.36244	-312,480	14,000	1,137,122	838,642	303,957
					TOTAL PW'	5,249,548

* Including one-time cost of transfer of tap facilities and resale value of 5-MVA substation.

B/C Ratio for Construction Power Supply by Tapline.

$$\text{B/C Ratio} = \frac{\text{Discounted Cost of Diesel Generation Alternative}}{\text{Discounted Cost of Tapline Alternative}}$$

$$= \frac{10,237,198}{5,249,548}$$

$$= \underline{1.95}$$

DERIVATION

OF

INPUT COST DATA FOR ECONOMIC ANALYSIS

TO OBTAIN

BASELINE COSTS ASSOCIATED WITH THE TWO CONSTRUCTION POWER ALTERNATIVES

		Alternative I Diesel Generation		Alternative II Tapline Supply	
Year	7% Deflator	Escalated	Deflated	Escalated	Deflated
1979	1.00				
1980	1.07				
1981	1.14				
1982	1.23				
1983	1.31				
1984	1.40				
1985	1.50	4,252,500	2,835,000	400,000	266,670
1986	1.61	1,118,500	694,720	777,180	482,720
1987	1.72	1,198,100	696,570	827,880	481,330
1988	1.84	1,280,800	696,090	879,765	478,130
1989	1.97	6,018,575	3,055,110	1,480,490	751,520
1990	2.10	2,779,800	1,323,710	1,894,600	902,190
1991	2.25	420,300	186,800	1,650,574	733,590
1992	2.41	1,501,300	622,950	1,035,234	429,560
1993	2.58	1,607,300	622,980	1,081,888	419,340
1994	2.76	-1,379,450	-499,800	838,642	303,860

SUMMARY

BASELINE COSTS (1979)

ASSOCIATED WITH TWO CONSTRUCTION POWER ALTERNATIVES

	$1000 (1979)	
Year	(Independent) Diesel Generation	(Interconnected) Tapline Supply
1985	2,835	267
1986	695	483
1987	697	481
1988	696	478
1989	3,055	752
1990	1,324	902
1991	187	734
1992	623	430
1993	623	419
1994	-500[1/]	304

1/ Negative sign indicates net resale value predominates over costs.

D.4 ALTERNATIVE GENERATING PLANT FUEL COSTS

The year-by-year analysis of comparative fuel costs follows:

A. First Period (1984-87) - Firm Power Transfer of 30 MW, 145 GWh

Year	Interconnected System Expansion	Independent System Expansion
1984	The number and type of generating plants is identical to that for each system operating independently.	Each independent system would be supplied by operational units on basis of economic dispatch to meet individual area needs.

The determination of relative economic advantage to either system, of a firm power transfer, would require a detailed analysis, necessitating production costing of economically dispatched units for the Anchorage and Fairbanks systems. It is a reasonable measure to delete the comparison of marginal advantages accruing for this year of operation.

Year	Interconnected System Expansion	Independent System Expansion
1985	ANCH 9 - 78 MW SCGT is added to AML&P system, obviating the need for both NORT 3 and BELU 9.	Two units are required in Anchorage area, ANCH 9 - 78 MW SCGT and BELU 9 - 71 MW RCGT, together with NORT 3 - 69 MW SCGT unit at the Northpole Station in Fairbanks.

As a first approximation, the relative generation cost advantage may be determined by estimating the respective fuel costs associated with the generation of 145 GWh of energy by either ANCH 9 or NORT 3, taking into consideration different primary fuel costs and thermal efficiencies. The unit ratings are sufficiently close to justify this analytical approach, on the basic assumption that equivalent energy would be generated during the year by the two units. An adjustment would then be made to allow for the differential cost of supplying line losses in the transmission intertie, which would amount to 1.5 GWh/yr.

Comparative Fuel Costs:

ANCH 9 - 78 MW SCGT

From Battelle Report (see Figure D-3)
See Figure D-1
Trend Curve for HR8444 New Gas
with 8% inflation and escalation
1985 Fuel Cost = \$3.60/MBTU
Net Heat Rate = 14,500 BTU/kWh
Annual Cost of Fuel (ACF)
to generate 145 GWh:
ACF @ 0.21 PCF[2] = \$3.60 x 145 x 14,500
= \$7,569,000

NORT 3 - 69 MW SCGT

From Stanley Consultants Report P. 21
1978 Fuel Cost = \$1.98/MBTU
Escalating @ 10% per year[1]:
1985 Fuel Cost = \$3.86/MBTU
For distillate from North Pole refinery
From Table 6, P. 22:
Net Heat Rate = 15,130 BTU/kWh
Annual Cost of Fuel (ACF)
to generate 145 GWh:
ACF @ 0.24 PCF[2] = \$3.86 x 145 x 15,130
= \$8,468,000

The total cost comparison is in favor of ANCH 9 generation to supply Fairbanks. Total cost of generation, including loss component = \$7,648,000.

1986 BELU 9 - 71 MW SCGT is added to CEA system, the interconnection having served to delay the in-service of the combustion turbine by one year. It is assumed that this unit will be operated for supply to CEA system only during first year of operation.

ANCH 10 - 104 MW coal-fired plant is added to AML&P system for both independent and interconnected system expansions. KNIK A - 15 MW thermal power plant (CEA) is also retired from both expansions.

The relative economic advantage is attributable to the fuel cost differential between distillate for NORT 3 generation and Beluga gas for generation by either ANCH 9 or BELU 9. Selecting ANCH 9 as in the previous analysis for 1985:

1/ 7% inflation + 3% escalation.
2/ PCF = Plant Capacity Factor.

Comparative Fuel Costs:

ANCH 9 - 79 MW SCGT	NORT 3 - 69 MW SCGT
1986 Fuel Cost = $4.00/MBTU	1986 Fuel Cost = $4.25/MBTU
Net Heat Rate = 14,500 BTU/kWh	Net Heat Rate = 15,130 BTU/kWh
Annual Cost of Fuel (ACF) to generate 145 GWh:	Annual Cost of Fuel (ACF) to generate 145 GWh:
ACF @ 0.21 PCF = $8,410,000	ACF @ 0.24 PCF = $9,324,000

The cost comparison is once again in favor of ANCH 9 generation to supply the equivalent amount of energy over intertie, as would otherwise be generated locally in Fairbanks.

Total cost of ANCH 9 generation, including transmission loss = $8,498,000.

1987 This is the first year of operation of COAL 1 - 200 MW coal-fired plant on the Anchorage system. As this would be the first year of operation for the first major coal-fired plant in the Railbelt, for either independent or interconnected expansions, it would be thus common to the two alternatives. The relative cost advantages would then again be determined by consideration of the relative generation cost for ANCH 9 and NORT 3.

Comparative Fuel Costs:

ANCH 9 - 79 MW SCGT	NORT 3 - 69 MW SCGT
1987 Fuel Cost = $4.25/MBTU	1987 Fuel Cost = $4.68/MBTU
Net Heat Rate = 14,500 BTU/kWh	Net Heat Rate = 15,130 BTU/kWh
Annual Cost of Fuel (ACF) to generate 145 GWh:	Annual Cost of Fuel (ACF) to generate 145 GWh:
ACF @ 0.21 PCF = $8,936,000	ACF @ 0.21 PCF = $10,267,000

Total cost of ANCH 9 generation, including transmission loss = $9,029,000.

B. Second Period (1992-96) - Firm Power Transfer of 70 MW, 337 GWh

Year	Interconnected System Expansion	Independent System Expansion
1992	Interconnected operation obviates the need for COAL 5 - 200 MW unit in Anchorage area and COAL F2 - 100 MW unit in Fairbanks area. Comparable generation is maintained by COAL 6 - 300 MW unit in Anchorage area.	COAL 5 would have to be added to Anchorage system and COAL F2 to Fairbanks.

Comparative economic advantage is determined by relative magnitude of fuel costs, for either COAL 6 or COAL F2, to generate same energy.

Comparative Fuel Costs:

	• COAL 6 - 300 MW	• COAL F2 - 100 MW
From Battelle Report (see Figure D-4)		
Fuel Cost in 1992	\$2.60/MBTU	\$1.90/MBTU
Net Heat Rate	9,500 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	\$8,324,000	\$6,851,000

The comparative advantage in this case moves to the use of Healy coal. However, as with interconnection, the unit COAL F2 will be eliminated in favor of the economies of scale associated with the COAL 6 unit. Without production costing, it is not possible to determine the overall economic advantage of introducing COAL 6, so for present analysis it is assumed that no economic energy transfer is possible. However, as a first approximation, the fuel costs for this year will be entered into economic analysis to consider the effect of the differential.

1993	ANCH 11 - 104 MW coal-fired unit added to AML&P system in this year for interconnected expansion, after an interval of five years following the in-service date for same unit with independent expansion. PEAK A1 - 78 MW combustion turbine also in-service from beginning of year.	PEAK A1 - 78 MW combustion turbine in-service from beginning of year, for independent expansion of Anchorage system.

Of interest in this year is a comparison between the cost of energy generation for ANCH 11 and COAL F2 using the same source of fuel, Healy coal. Thus, the relative advantage of either generating at the existing plant site at Healy or in the vicinity of Anchorage may be examined for similar capacity units having the same thermal efficiency, to determine the economies of energy transfer by intertie.

Comparative Fuel Costs:

	• ANCH 11	• COAL F2
Cost of Healy coal in 1993	\$2.4/MBTU[1/]	\$2.00/MBTU[2/]
Net Heat Rate	10,700 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	\$8,654,000	\$7,212,000

Once again the comparative advantage lies with the generation of energy at the Healy site. However, with interconnection the need for COAL F2 disappears in favor of the economies of scale attendant on COAL 6. It may be noted that the cost differential in favor of Healy disappears if the COAL F2 site would be moved away from Healy for environmental reasons to say Nenana. In this case, the cost of generation would be approximately the same whether coal were transported either to Anchorage or Nenana, as the transmission loss, associated with ANCH 11 (104 MW) generation and transfer over the intertie, would be compensated for by the slightly higher heat rate to be expected with the 100 MW unit of COAL F2.

1/ Delivered to Anchorage plant site.

2/ Delivered to Healy plant site.

1994 As GEN 1 - 300 MW coal-fired generating plant added for both independent and interconnected system expansions, the previous combination of ANCH 11 and COAL F2 can again be examined to determine the differential cost of fuel.

Comparative Fuel Costs:

	• ANCH 11	• COAL F2
Cost of Healy coal in 1994 (Minemouth Generation, FOB Tipple)	$2.5/MBTU	$2.2/MBTU
Net Heat Rate	10,700 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	$9,015,000	$7,933,000

It may be noted that due to divergence of fuel cost trends after 1993, for coal delivered to either Anchorage or Nenana, rather than minemouth, the economic advantage moves progressively towards generation at an Anchorage location, with transfer of the equivalent energy over the intertie. However, in 1994, it is possible to transmit energy generated economically at Healy to Anchorage over the intertie.

Total cost of COAL F2 generation, including transmission loss = $8,016,000.

1995 COAL F3 - 100 MW coal-fired plant is introduced to the Fairbanks area and PEAK A2 - 78 MW combustion turbine is added to the AML&P system. Interconnection results in the postponement by one year of the 300 MW GEN 2 in the Anchorage area.

GEN 2 - 300 MW coal-fired plant is introduced to the Anchorage area with independent system expansion but the 78 MW combustion turbine PEAK A2 is not required in addition to the large coal-fired plant. COAL F3 is added to the system in the Fairbanks area.

As COAL F3 is common to both the independent and interconnected system expansions, it is of interest whether the gas-fired PEAK A2 in Anchorage could economically displace the equivalent energy generated by the coal-fired unit COAL F3 in the Fairbanks area.

Comparative Fuel Costs:

	• PEAK A2	• COAL F3
Cost of New Gas in 1995 (HR 8444 - 8% infl. + esc.)	$7.70/MBTU	
Cost of Healy Coal in 1995 (Minemouth Plant, FOB Tipple)		$2.40/MBTU
Net Heat Rate	14,500 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	$37,626,000	$8,654,000

There is a definite economic advantage to coal generation at Healy and energy transfer over the intertie to displace gas-fired generation in Anchorage.

Total cost of COAL F3 generation, including transmission loss = $8,745,000.

1996 GEN 2 - 300 MW coal-fired plant is introduced to the Anchorage area, the interconnection serving to postpone its in-service date by one year.

PEAK A2 - 78 MW combustion turbine is introduced to the AML&P system in Anchorage.

In this final year of analysis, it is of interest to compare the relative economic advantages of coal-fired generation at either the Fairbanks (Healy) or Anchorage (Beluga) sites.

Comparative Fuel Costs:

	• GEN 2	• COAL F3
Cost of Beluga Coal in 1996	$3.3/MBTU	
Cost of Healy Coal in 1996		2.5/MBTU
Net Heat Rate	9,500 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	$10,565,000	$9,015,000

Once again it is more economical to generate in the Fairbanks area and transfer energy south over the intertie to Anchorage.

Total cost of COAL F3 generation, including transmission loss = $9,109,000.

Nomogram calculates economy of scale in power plants

By JAMES McALISTER, Arkansas Power & Light Co.

Historically, the per unit cost of larger power plants has been less than that of smaller plants. The proportionality was examined in some detail in the article "Economy of Scale in Power Plants" in the August 1977 issue of POWER ENGINEERING Magazine, p. 51

The basic equation is:

$$(C_1/C_2) = (MW_1/MW_2)^P$$

Where:

C_1 cost of plant 1
C_2 cost of plant 2
MW_1 capability of plant 1
MW_2 capability of plant 2
P proportionality factor

For many years, this proportionality factor averaged about 0.6, which led to the so-called "Six-tenths Power Law." However, as explained in the article referred to above, extended project schedules and inflation cause the factor to increase

This nomogram solves the equation and permits a cost comparison of plants of different sizes. It assumes, of course, that they are essentially identical in construction technique, design and time frame, and that the only significant difference is in size.

Example: A 200-MW plant can be built for $200 million. Find the cost of a similar 1000-MW plant.

Solution: (1) Connect unit ratings of 200 MW and 1000 MW on the MW_1 and MW_2 scales, and mark intersection with Reference Line X. (2) Align this point with assumed scaling factor P = 0.6 and extend to cut Reference Line Y. (3) Connect this point with 0.2 on C_1 scale and extend to C_2 scale. Read answer as $0.53 billion. **END**

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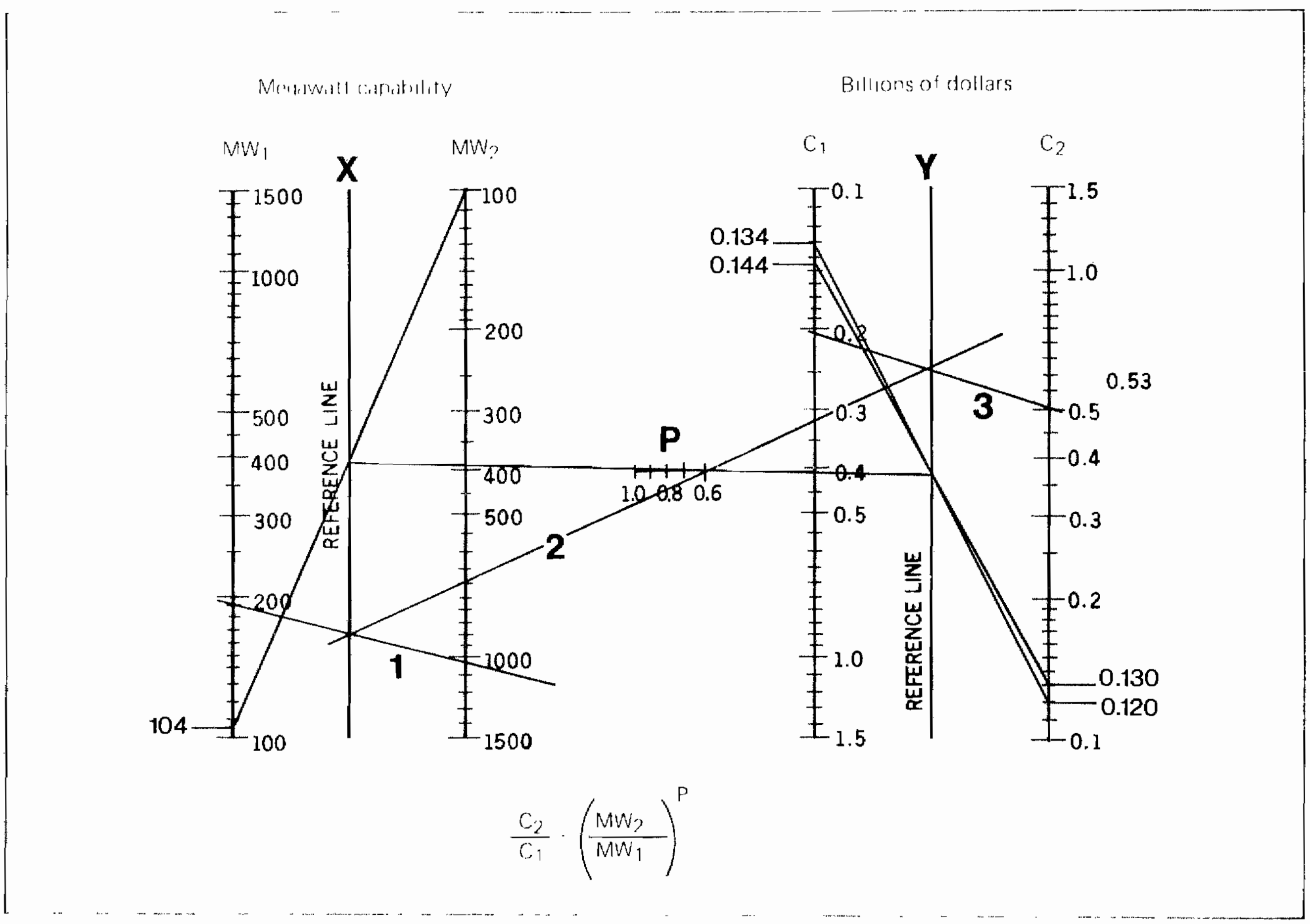

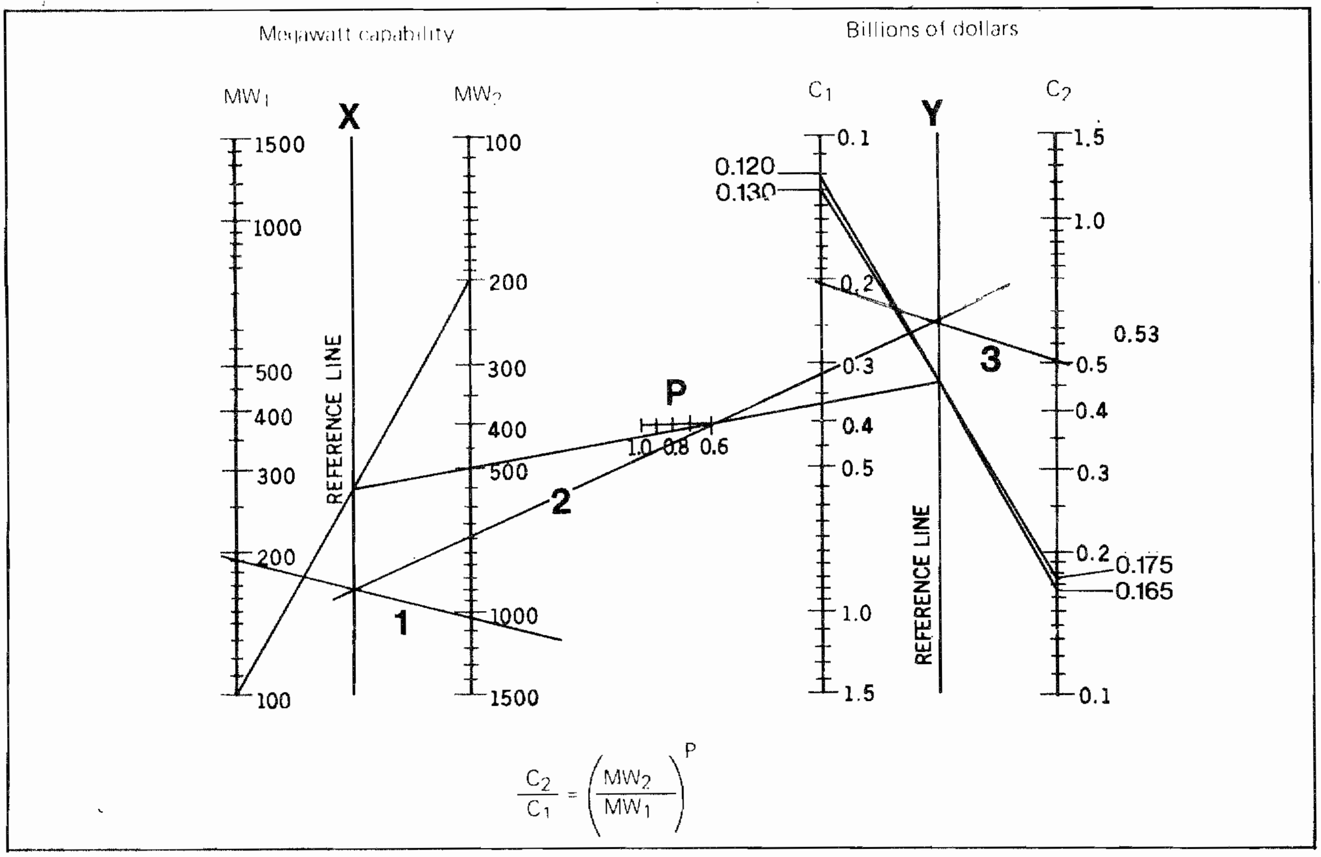
Megawatt capability
Billions of dollars
MW1
MW2
C1
C2
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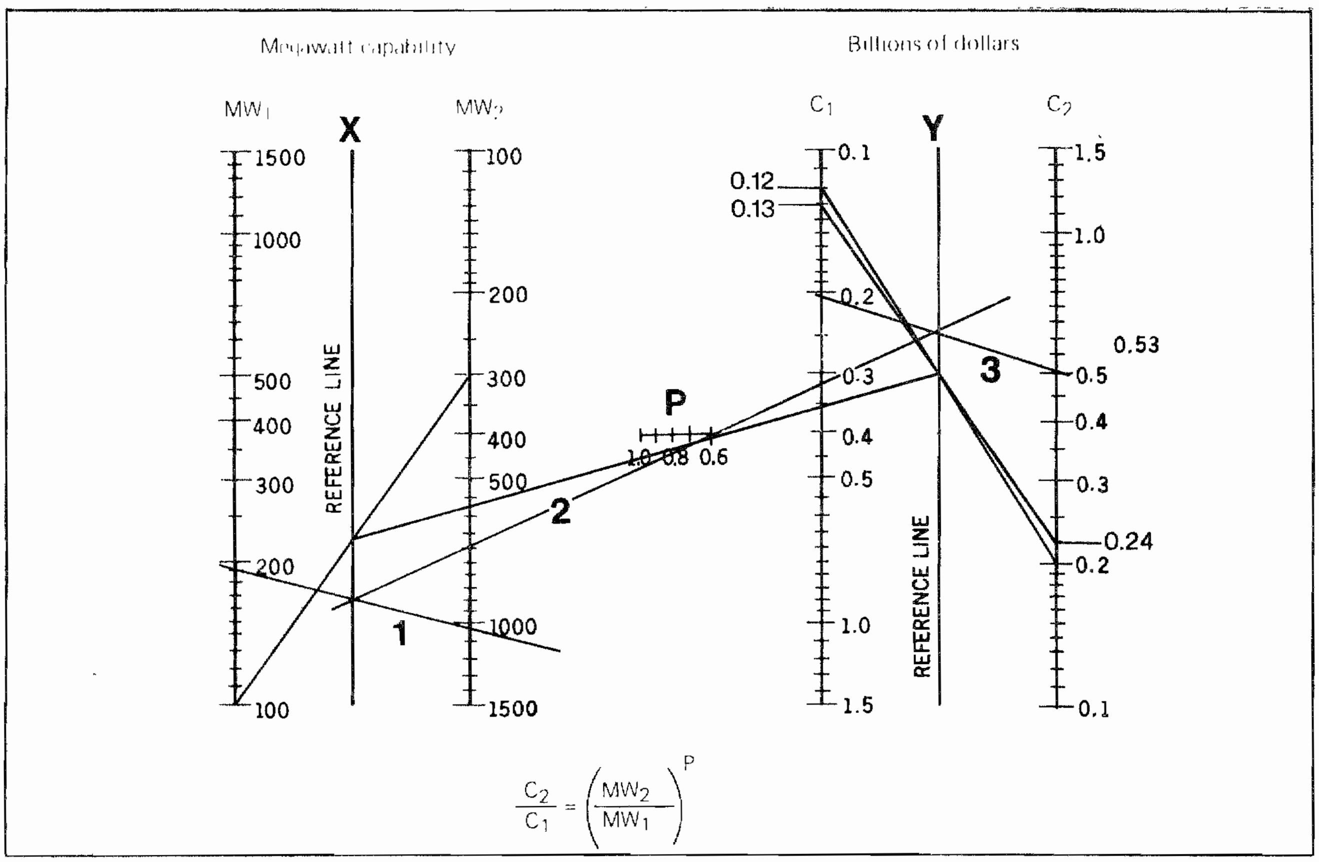
Megawatt capability
Billions of dollars
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MW2
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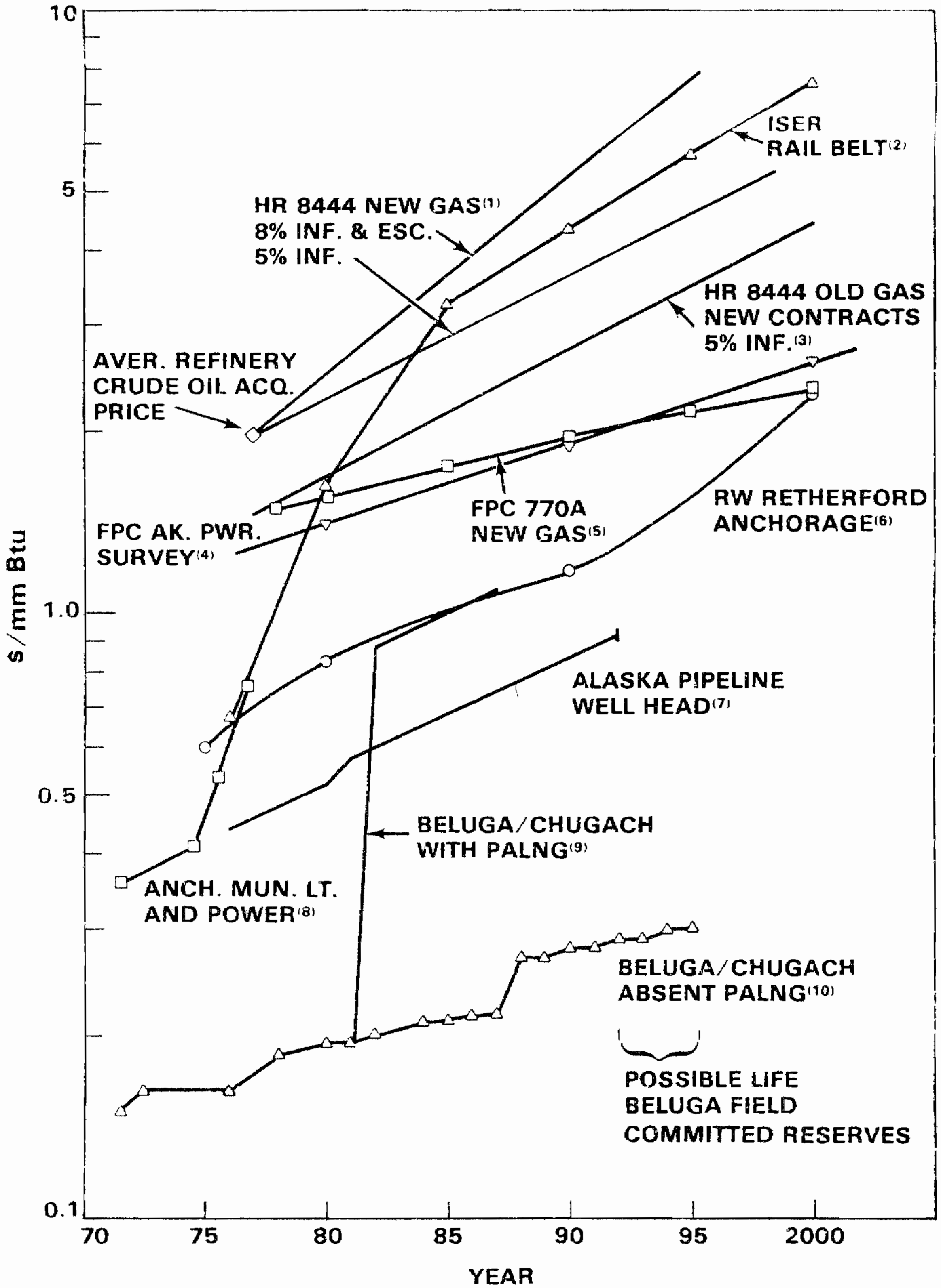
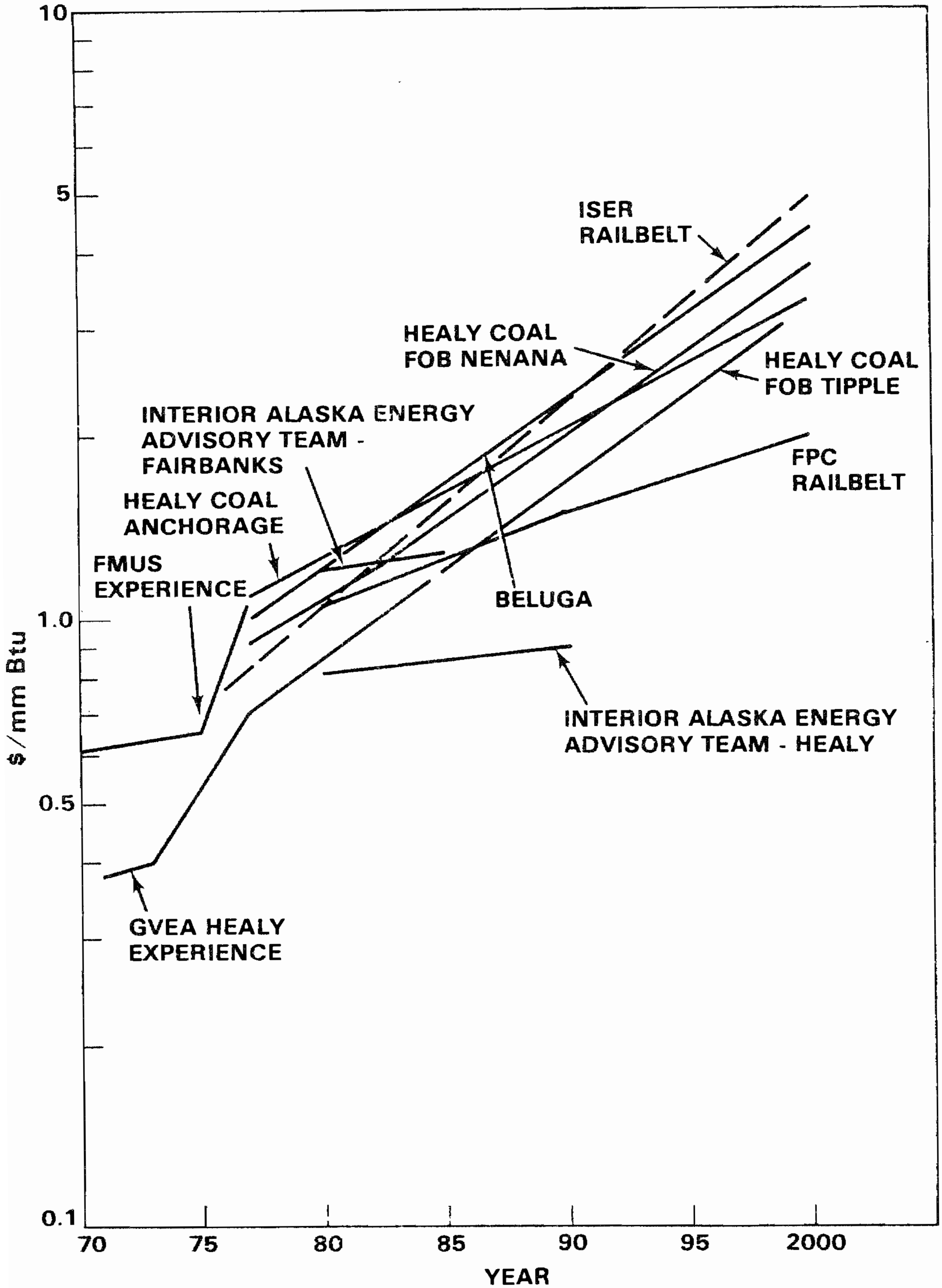


ESTIMATES OF FUTURE NATURAL GAS PRICES
(Source: Battelle Final Report 'Alaskan Electric Power', March 1978/Figure 6-6)



ESTIMATES OF FUTURE COAL PRICES
(Source: Battelle Final Report 'Alaskan Electric Power', March 1978/Figure 6-7)

APPENDIX E

TRANSMISSION LINE ECONOMIC ANALYSIS PROGRAM (TLEAP)

APPENDIX E
TRANSMISSION LINE ECONOMIC
ANALYSIS PROGRAM (TLEAP)

TABLE 8-1	CASE IA
TABLE 8-1x	CASE IA
TABLE 8-1-LL	CASE IA
TABLE 8-2	CASE IC
TABLE 8-3	CASE IB
TABLE 8-3x	CASE IB
TABLE 8-3-LL	CASE IB
TABLE 8-4	CASE IB
TABLE 8-4x	CASE IB
TABLE 8-5	CASE ID
TABLE 8-5x	CASE ID
TABLE 8-6	CASE ID
TABLE 8-6x	CASE ID
TABLE 8-7	CASE IC

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	244,472	354,109	388,978	427,474	469,977	516,903	568,712	625,909	689,048	758,736
8.25	239,365	346,235	380,203	417,695	459,079	504,760	555,184	610,839	672,263	740,046
8.50	234,394	338,581	371,675	408,193	448,493	492,967	542,048	596,209	655,972	721,910
8.75	229,556	331,140	363,386	398,960	438,209	481,513	529,292	582,005	640,159	704,309
9.00	224,847	323,904	355,328	389,987	428,217	470,386	516,903	568,213	624,808	687,225
9.25	220,262	316,868	347,495	381,266	418,507	459,576	504,870	554,820	609,903	670,641
9.50	215,798	310,024	339,878	372,787	409,070	449,073	493,181	541,812	595,430	654,541
9.75	211,451	303,368	332,471	364,545	399,897	438,867	481,824	529,177	581,375	638,909
10.00	207,217	296,892	325,267	356,530	390,981	428,947	470,789	516,903	567,724	623,729
10.25	203,093	290,591	318,259	348,736	382,312	419,305	460,066	504,978	554,464	608,986
10.50	199,076	284,461	311,443	341,156	373,883	409,932	449,644	493,390	541,581	594,667
10.75	195,162	278,494	304,810	333,783	365,686	400,820	439,513	482,129	529,065	580,757
11.00	191,348	272,687	298,357	326,611	357,714	391,959	429,665	471,185	516,903	567,244
11.25	187,631	267,034	292,076	319,632	349,960	383,343	420,091	460,546	505,084	554,114
11.50	184,008	261,530	285,963	312,842	342,417	374,963	410,781	450,204	493,596	541,355
11.75	180,476	256,172	280,013	306,234	335,078	366,811	401,728	440,149	482,429	528,955
12.00	177,033	250,953	274,220	299,802	327,936	358,882	392,923	430,372	471,574	516,903

DISCOUNTED VALUE OF BASE YEAR (1979) INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	233,560	351,674	390,188	433,136	481,019	534,389	593,859	660,105	733,874	815,988
8.25	228,191	343,033	380,460	422,186	468,698	520,531	578,278	642,594	714,202	793,899
8.50	222,980	334,654	371,028	411,573	456,758	507,104	563,184	625,633	695,151	772,510
8.75	217,922	326,528	361,883	401,284	445,186	494,092	548,560	609,202	676,699	751,797
9.00	213,011	318,646	353,015	391,309	433,969	481,482	534,389	593,284	658,825	731,736
9.25	208,242	311,000	344,414	381,636	423,094	469,260	520,656	577,860	641,509	712,304
9.50	203,610	303,582	336,072	372,257	412,551	457,412	507,346	562,914	624,731	693,479
9.75	199,112	296,385	327,980	363,160	402,327	445,925	494,445	548,429	608,474	675,241
10.00	194,743	289,401	320,129	354,336	392,412	434,788	481,938	534,389	592,720	657,569
10.25	190,497	282,623	312,511	345,776	382,796	423,988	469,812	520,779	577,450	640,444
10.50	186,373	276,043	305,118	337,471	373,468	413,513	458,054	507,585	562,649	623,847
10.75	182,364	269,656	297,943	329,412	364,418	403,354	446,652	494,792	548,300	607,760
11.00	178,469	263,455	290,979	321,592	355,638	393,499	435,593	482,386	534,389	592,166
11.25	174,682	257,434	284,218	314,002	347,119	383,938	424,867	470,355	520,900	577,048
11.50	171,000	251,587	277,654	306,634	338,851	374,661	414,461	458,686	507,819	562,389
11.75	167,421	245,908	271,281	299,482	330,826	365,659	404,365	447,367	495,132	548,174
12.00	163,941	240,392	265,091	292,538	323,036	356,923	394,569	436,386	482,827	534,389

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	244,472	354,109	388,978	427,474	469,977	516,903	568,712	625,909	689,048	758,736
8.25	239,365	346,235	380,203	417,695	459,079	504,760	555,184	610,839	672,263	740,046
8.50	234,394	338,581	371,675	408,193	448,493	492,967	542,048	596,209	655,972	721,910
8.75	229,556	331,140	363,386	398,960	438,209	481,513	529,292	582,005	640,159	704,309
9.00	224,847	323,904	355,328	389,987	428,217	470,386	516,903	568,213	624,808	687,225
9.25	220,262	316,668	347,495	381,266	418,507	459,576	504,870	554,820	609,903	670,641
9.50	215,798	310,024	339,878	372,787	409,070	449,073	493,181	541,812	595,430	654,541
9.75	211,451	303,368	332,471	364,545	399,897	438,867	481,824	529,177	581,375	638,909
10.00	207,217	296,892	325,267	356,530	390,981	428,947	470,789	516,903	567,724	623,729
10.25	203,093	290,591	318,259	348,736	382,312	419,305	460,066	504,978	554,464	608,986
10.50	199,076	284,461	311,443	341,156	373,883	409;932	449,644	493,390	541,581	594,667
10.75	195,162	278,494	304,810	333,783	365,686	400,820	439,513	482,129	529,065	580,757
11.00	191,348	272,687	298,357	326,611	357,714	391,959	429,665	471,185	516,903	567,244
11.25	187,631	267,034	292,076	319,632	349,960	383,343	420,091	460,546	505,084	554,114
11.50	184,008	261,530	285,963	312,842	342,417	374,963	410,781	450,204	493,596	541,355
11.75	180,476	256,172	280,013	306,234	335,078	366,811	401,728	440,149	482,429	528,955
12.00	177,033	250,953	274,220	299,802	327,936	358,882	392,923	430,372	471,574	516,903

DISCOUNTED VALUE OF BASE YEAR (1979) INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	245,883	365,887	404,905	448,371	496,785	550,701	610,731	677,551	751,908	834,625
8.25	240,411	357,126	395,053	437,293	484,332	536,706	595,008	659,893	732,084	812,379
8.50	235,098	348,629	385,499	426,553	472,261	523,143	579,773	642,786	712,882	790,834
8.75	229,939	340,386	376,233	416,139	460,559	509,997	565,009	626,211	694,281	769,967
9.00	224,928	332,389	367,245	406,040	449,213	497,254	550,701	610,150	676,259	749,753
9.25	220,061	324,629	358,527	396,245	438,212	484,900	536,832	594,586	658,798	730,171
9.50	215,332	317,098	350,067	386,744	427,543	472,922	523,388	579,500	641,876	711,197
9.75	210,737	309,789	341,859	377,527	417,195	461,306	510,353	564,877	625,477	692,811
10.00	206,272	302,695	333,894	368,585	407,157	450,042	497,715	550,701	609,581	674,994
10.25	201,933	295,807	326,162	359,907	397,419	439,116	485,458	536,956	594,172	657,724
10.50	197,714	289,120	318,658	351,486	387,971	428,517	473,572	523,628	579,233	640,985
10.75	193,614	282,626	311,372	343,312	378,802	418,234	462,042	510,703	564,748	624,756
11.00	189,626	276,319	304,298	335,378	369,905	408,257	450,857	498,167	550,701	609,022
11.25	185,749	270,193	297,429	327,676	361,268	398,576	440,005	486,007	537,078	593,766
11.50	181,978	264,242	290,757	320,197	352,885	389,180	429,476	474,211	523,865	578,970
11.75	178,310	258,461	284,277	312,935	344,746	380,059	419,258	462,765	511,048	564,620
12.00	174,742	252,843	277,983	305,881	336,844	371,206	409,341	451,659	498,612	550,701

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,011		
1982		14,228		
1983	18,629	46,967		
1984	58,823	11,515		
1985	16,380	32,062		
1986		492		
1987		463		
1988		436		
1989	2,600	410		
1990	23,435	2,986		
1991	78,550	23,799		
1992	130,300	78,892		
1993	131,780	130,623		
1994	79,930	132,084		
1995	30,375	80,216		
1996	17,630	23,090		
1997		254		

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985				
1986				
1987				
1988				
1989				
1990				
1991				
1992				
1993				
1994				
1995				
1996				
1997				

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,872		
1982	2,009	18,056		
1983	26,666	72,604		
1984	81,942	11,326		
1985	37,172	31,886		
1986	21,127	328		
1987	7,152	2,319		
1988	7,555	8,529		
1989	23,110	30,604		
1990	21,920	43,092		
1991	82,200	43,463		
1992	101,380	89,973		
1993	58,450	108,988		
1994	29,840	75,387		
1995	23,935	23,347		
1996	17,630	499		
1997		473		

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985				
1986				
1987				
1988				
1989				
1990				
1991				
1992				
1993				
1994				
1995				
1996				
1997				

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	450,441	646,867	708,932	777,234	852,386	935,064	1,026,007	1,126,021	1,235,993	1,356,889
8.25	440,558	632,139	692,045	759,218	832,456	913,013	1,001,606	1,099,020	1,206,114	1,323,827
8.50	430,938	617,813	676,806	741,701	813,080	891,578	977,892	1,072,784	1,177,086	1,291,712
8.75	421,574	603,877	661,401	724,667	794,242	870,742	954,844	1,047,287	1,148,882	1,260,512
9.00	412,458	590,320	646,415	708,101	775,923	850,484	932,439	1,022,507	1,121,474	1,230,199
9.25	403,582	577,128	631,838	691,987	758,109	830,787	910,658	998,420	1,094,838	1,200,744
9.50	394,939	564,292	617,654	676,312	740,783	811,632	889,481	975,006	1,068,948	1,172,120
9.75	386,522	551,799	603,854	661,063	723,929	793,004	868,888	952,241	1,043,783	1,144,300
10.00	378,323	539,640	590,424	646,225	707,534	774,885	848,863	930,107	1,019,317	1,117,258
10.25	370,337	527,804	577,353	631,787	691,583	757,260	829,386	908,583	995,530	1,090,971
10.50	362,558	516,282	564,630	617,737	676,063	740,113	810,441	887,650	972,400	1,065,414
10.75	354,978	505,063	552,246	604,061	660,959	723,430	792,011	867,290	949,907	1,040,564
11.00	347,592	494,139	540,188	590,749	646,260	707,196	774,081	847,485	928,031	1,016,399
11.25	340,394	483,501	528,448	577,791	631,952	691,398	756,635	828,218	906,752	992,899
11.50	333,379	473,141	517,016	565,174	618,025	676,022	739,658	809,472	886,052	970,041
11.75	326,542	463,049	505,883	552,889	604,467	661,056	723,136	791,231	865,915	947,807
12.00	319,876	453,218	495,040	540,925	591,265	646,486	707,055	773,480	846,318	926,177

DISCOUNTED VALUE OF BASE YEAR (1979) INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	425,715	623,551	686,899	756,982	834,493	920,193	1,014,914	1,119,573	1,235,172	1,362,807
8.25	415,880	608,574	670,250	738,473	813,914	897,313	989,478	1,091,297	1,203,742	1,327,880
8.50	406,320	594,025	654,080	720,498	793,933	875,100	964,786	1,063,852	1,173,242	1,293,990
8.75	397,026	579,890	638,372	703,040	774,529	853,533	940,815	1,037,212	1,143,640	1,261,101
9.00	387,990	566,157	623,113	686,083	755,684	832,590	917,541	1,011,350	1,114,906	1,229,183
9.25	379,204	552,811	608,287	669,610	737,380	812,251	894,942	986,242	1,087,013	1,198,201
9.50	370,660	539,842	593,880	653,606	719,599	792,496	872,995	961,861	1,059,933	1,168,127
9.75	362,351	527,236	579,881	638,056	702,325	773,307	851,680	938,186	1,033,639	1,138,930
10.00	354,269	514,983	566,274	622,945	685,542	754,666	830,976	915,192	1,008,106	1,110,582
10.25	346,407	503,071	553,049	608,259	669,233	736,555	810,863	892,859	983,310	1,083,055
10.50	338,758	491,489	540,192	593,985	653,384	718,957	791,323	871,165	959,226	1,056,323
10.75	331,315	480,228	527,693	580,110	637,981	701,855	772,338	850,089	935,832	1,030,360
11.00	324,073	469,277	515,540	566,621	623,008	685,235	753,889	829,612	913,106	1,005,142
11.25	317,025	458,626	503,723	553,507	608,453	669,081	735,960	809,715	891,027	980,644
11.50	310,166	448,266	492,230	540,755	594,303	653,378	718,535	790,379	869,573	956,844
11.75	303,488	438,189	481,052	528,354	580,544	638,112	701,597	771,586	848,726	933,720
12.00	296,988	428,385	470,179	516,294	567,165	623,270	685,131	753,321	828,465	911,250

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	450,441	646,867	708,932	777,234	852,386	935,064	1,026,007	1,126,021	1,235,993	1,356,889
8.25	440,558	632,139	692,645	759,218	832,456	913,013	1,001,606	1,099,020	1,206,114	1,323,827
8.50	430,938	617,813	676,806	741,701	813,080	891,578	977,892	1,072,784	1,177,086	1,291,712
8.75	421,574	603,877	661,401	724,667	794,242	870,742	954,844	1,047,287	1,148,882	1,260,512
9.00	412,458	590,320	646,415	708,101	775,923	850,484	932,439	1,022,507	1,121,474	1,230,199
9.25	403,582	577,128	631,838	691,987	758,109	830,787	910,658	998,420	1,094,838	1,200,744
9.50	394,939	564,292	617,654	676,312	740,783	811,632	889,481	975,006	1,068,948	1,172,120
9.75	386,522	551,799	603,854	661,063	723,929	793,004	868,888	952,241	1,043,783	1,144,300
10.00	378,323	539,640	590,424	646,225	707,534	774,885	848,863	930,107	1,019,317	1,117,258
10.25	370,337	527,804	577,353	631,787	691,583	757,260	829,386	908,583	995,530	1,090,971
10.50	362,558	516,282	564,630	617,737	676,063	740,113	810,441	887,650	972,400	1,065,414
10.75	354,978	505,063	552,246	604,061	660,959	723,430	792,011	867,290	949,907	1,040,564
11.00	347,592	494,139	540,188	590,749	646,260	707,196	774,081	847,485	928,031	1,016,399
11.25	340,394	483,501	528,448	577,791	631,952	691,398	756,635	828,218	906,752	992,899
11.50	333,379	473,141	517,016	565,174	618,025	676,022	739,658	809,472	886,052	970,041
11.75	326,542	463,049	505,883	552,889	604,467	661,056	723,136	791,231	865,913	947,807
12.00	319,876	453,218	495,040	540,925	591,265	646,486	707,055	773,480	846,318	926,177

DISCOUNTED VALUE OF BASE YEAR (1979) INTERCONNECTED SYSTEM COSTS IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	438,030	637,754	701,606	772,207	850,250	936,495	1,031,776	1,137,008	1,253,195	1,381,433
8.25	428,091	622,658	684,834	753,570	829,539	913,478	1,006,197	1,108,585	1,221,613	1,346,349
8.50	418,429	607,991	668,541	735,469	809,426	891,129	981,365	1,080,995	1,190,963	1,312,303
8.75	409,035	593,739	652,713	717,886	789,892	869,427	957,255	1,054,211	1,161,211	1,279,261
9.00	399,899	579,891	637,334	700,805	770,919	848,351	933,843	1,028,207	1,132,331	1,247,190
9.25	391,015	566,431	622,390	684,209	752,488	827,881	911,108	1,002,957	1,104,292	1,216,058
9.50	382,374	553,349	607,867	668,084	734,582	807,996	889,026	978,437	1,077,067	1,185,834
9.75	373,968	540,631	593,751	652,414	717,183	788,679	867,578	954,624	1,050,631	1,156,490
10.00	365,790	528,268	580,030	637,184	700,277	769,910	846,742	931,494	1,024,957	1,127,996
10.25	357,834	516,246	566,691	622,381	683,847	751,673	826,499	909,026	1,000,021	1,100,325
10.50	350,091	504,557	553,723	607,991	667,878	733,951	806,831	887,199	975,800	1,073,450
10.75	342,557	493,188	541,113	594,001	652,355	716,726	787,718	865,991	952,269	1,047,346
11.00	335,223	482,131	528,850	580,399	637,265	699,984	769,143	845,383	929,408	1,021,988
11.25	328,085	471,376	516,924	567,172	622,594	683,709	751,089	825,357	907,195	997,352
11.50	321,135	460,913	505,324	554,309	608,328	667,887	733,540	805,893	885,609	973,415
11.75	314,370	450,733	494,040	541,798	594,455	652,503	716,480	786,974	864,631	950,156
12.00	307,782	440,828	483,062	529,628	580,963	637,544	699,893	768,583	844,241	927,552

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	237,690	352,449	389,849	431,534	477,981	529,713	587,311	651,414	722,726	802,024
8.25	232,026	343,607	379,955	420,460	465,585	515,836	571,777	634,027	703,268	780,253
8.50	226,529	335,031	370,360	409,724	453,568	502,386	556,724	617,180	684,417	759,164
8.75	221,192	326,713	361,055	399,312	441,917	489,349	542,134	600,855	666,153	738,734
9.00	216,009	318,642	352,029	389,216	430,621	476,710	527,992	585,033	648,454	718,939
9.25	210,977	310,812	343,274	379,423	419,667	464,455	514,283	569,698	631,302	699,759
9.50	206,090	303,214	334,779	369,924	409,043	452,572	500,992	554,833	614,678	681,172
9.75	201,342	295,840	326,537	360,709	398,739	441,049	488,105	540,421	598,564	663,157
10.00	196,730	288,683	318,539	351,769	388,743	429,872	475,608	526,448	582,943	645,696
10.25	192,250	281,735	310,777	343,093	379,045	419,031	463,487	512,899	567,798	628,769
10.50	187,896	274,990	303,242	334,674	369,636	408,514	451,732	499,759	553,112	612,359
10.75	183,665	268,441	295,928	326,503	360,506	398,310	440,328	487,015	538,871	596,447
11.00	179,552	262,082	288,827	318,572	351,645	388,409	429,265	474,653	525,059	581,018
11.25	175,555	255,906	281,932	310,872	343,044	378,801	418,531	462,661	511,663	566,054
11.50	171,669	249,908	275,237	303,396	334,696	369,476	408,115	451,026	498,667	551,541
11.75	167,890	244,081	268,734	296,138	326,591	360,425	398,006	439,736	486,060	537,463
12.00	164,216	238,420	262,419	289,089	318,722	351,639	388,195	428,781	473,827	523,806

DISCOUNTED VALUE OF BASE YEAR (1979) INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	238,419	347,569	383,059	422,582	466,586	515,562	570,053	630,659	698,037	772,913
8.25	233,022	339,177	373,675	412,087	454,846	502,429	555,362	614,225	679,657	752,361
8.50	227,783	331,036	364,574	401,911	443,464	489,698	541,122	598,299	661,848	732,450
8.75	222,695	323,138	355,747	392,041	432,428	477,356	527,320	582,865	644,591	713,158
9.00	217,753	315,474	347,182	382,468	421,725	465,389	513,939	567,904	627,865	694,463
9.25	212,953	308,036	338,873	373,182	411,345	453,784	500,965	553,401	611,654	676,346
9.50	208,290	300,818	330,810	364,172	401,276	442,530	488,386	539,340	595,940	658,787
9.75	203,759	293,811	322,985	355,431	391,508	431,614	476,187	525,707	580,705	641,766
10.00	199,356	287,009	315,390	346,948	382,032	421,026	464,355	512,486	565,935	625,265
10.25	195,078	280,405	308,018	338,716	372,836	410,753	452,878	499,665	551,612	609,268
10.50	190,919	273,992	300,861	330,725	363,913	400,786	441,745	487,229	537,722	593,756
10.75	186,876	267,764	293,912	322,968	355,252	391,115	430,944	475,166	524,250	578,713
11.00	182,946	261,715	287,164	315,437	346,845	381,729	420,463	463,463	511,183	564,124
11.25	179,124	255,839	280,610	308,125	338,685	372,619	410,293	452,108	498,506	549,974
11.50	175,407	250,130	274,245	301,025	330,761	363,776	400,422	441,090	486,208	536,247
11.75	171,792	244,584	268,062	294,129	323,068	355,191	390,841	430,397	474,274	522,930
12.00	168,276	239,194	262,055	287,431	315,597	346,856	381,541	420,019	462,694	510,010

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		5,014		
1982	2,009	17,785		
1983	26,666	58,709		
1984	81,942	11,551		
1985	37,172	32,097	8,468	7,648
1986	27,727	6,006	9,324	8,498
1987	33,552	24,420	10,267	9,029
1988	106,555	90,673		
1989	145,210	135,940		
1990	94,760	115,716		
1991	119,475	113,198		
1992	101,380	89,694	6,851	8,324
1993	58,450	108,723	7,212	8,654
1994	29,840	75,134	7,933	8,016
1995	23,935	23,106	8,654	8,745
1996	17,630	270	9,015	9,109
1997		254		

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985			2,835	267
1986			695	483
1987	6,646	1,356	697	481
1988			696	478
1989			3,055	752
1990			1,324	902
1991			187	734
1992	2,004		623	430
1993			623	419
1994			-500	304
1995				
1996				
1997				

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,621		
1982	2,009	15,594		
1983	26,666	48,874		
1984	81,942	11,515		
1985	37,172	32,062		
1986	21,127	492		
1987	7,152	2,472		
1988	7,555	8,473		
1989	23,110	30,549		
1990	21,920	43,038		
1991	82,200	43,411		
1992	101,380	89,694		
1993	58,450	108,723		
1994	29,840	75,134		
1995	23,935	23,106		
1996	17,630	270		
1997		254		

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985				
1986				
1987	6,646	1,356		
1988				
1989				
1990				
1991				
1992	2,004			
1993				
1994				
1995				
1996				
1997				

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	261,027	381,019	419,402	461,886	508,913	560,973	618,607	682,411	753,044	831,230
8.25	255,466	372,366	409,734	451,083	496,843	547,488	603,542	665,583	734,247	810,239
8.50	250,057	363,958	400,344	440,594	485,127	534,401	588,925	649,258	716,017	789,885
8.75	244,795	355,789	391,222	430,408	473,752	521,698	574,740	633,419	698,335	770,146
9.00	239,676	347,851	382,360	420,515	462,706	509,367	560,973	618,051	681,181	751,002
9.25	234,694	340,136	373,750	410,905	451,980	497,394	547,610	603,137	664,538	732,432
9.50	229,846	332,636	365,382	401,568	441,562	485,769	534,638	588,663	648,389	714,417
9.75	225,127	325,346	357,250	392,497	431,442	474,479	522,043	574,613	632,717	696,937
10.00	220,534	318,257	349,346	383,681	421,610	463,513	509,813	560,973	617,506	679,976
10.25	216,062	311,364	341,661	375,114	412,057	452,862	497,936	547,730	602,741	663,515
10.50	211,707	304,660	334,190	366,786	402,774	442,514	486,400	534,870	588,406	647,538
10.75	207,466	298,140	326,925	358,691	393,753	432,459	475,194	522,381	574,488	632,028
11.00	203,336	291,796	319,860	350,820	384,984	422,688	464,307	510,251	560,973	616,971
11.25	199,312	285,625	312,988	343,167	376,459	413,193	453,730	498,468	547,847	602,351
11.50	195,392	279,620	306,303	335,724	368,171	403,963	443,450	487,020	535,099	588,154
11.75	191,573	273,776	299,799	328,484	360,112	394,990	433,461	475,897	522,714	574,366
12.00	187,851	268,088	293,471	321,442	352,275	386,267	423,750	465,089	510,682	560,973

DISCOUNTED VALUE OF BASE YEAR (1979) INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 0%	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	239,682	359,652	398,725	442,277	490,812	544,888	605,121	672,193	746,854	829,934
8.25	234,223	350,883	388,857	431,175	478,325	530,849	589,342	654,466	726,946	807,588
8.50	228,923	342,378	379,289	420,413	466,223	517,245	574,055	637,294	707,665	785,948
8.75	223,777	334,130	370,010	409,978	454,493	504,061	559,243	620,658	688,989	764,990
9.00	218,781	326,128	361,012	399,861	443,121	491,282	544,888	604,539	670,896	744,690
9.25	213,929	318,366	352,284	390,051	432,095	478,895	530,976	588,919	653,367	725,025
9.50	209,216	310,834	343,818	380,535	421,404	466,886	517,491	573,782	636,381	705,974
9.75	204,637	303,525	335,604	371,306	411,036	455,242	504,418	559,110	619,920	687,514
10.00	200,190	296,431	327,634	362,353	400,981	443,951	491,744	544,888	603,967	669,625
10.25	195,868	289,546	319,900	353,666	391,227	433,001	479,455	531,100	588,504	652,289
10.50	191,668	282,862	312,393	345,237	381,764	422,380	467,537	517,732	573,513	635,486
10.75	187,586	276,373	305,107	337,058	372,583	412,078	455,979	504,769	558,980	619,198
11.00	183,618	270,072	298,034	329,119	363,674	402,083	444,768	492,198	544,888	603,407
11.25	179,761	263,953	291,167	321,413	355,029	392,385	433,893	480,005	531,223	588,096
11.50	176,011	258,010	284,499	313,933	346,638	382,974	423,341	468,178	517,969	573,250
11.75	172,364	252,237	278,023	306,670	338,493	373,842	413,103	456,704	505,114	558,852
12.00	168,817	246,629	271,734	299,617	330,585	364,977	403,168	445,572	492,644	544,888

APPENDIX F

TRANSMISSION LINE FINANCIAL ANALYSIS

APPENDIX F
TRANSMISSION LINE FINANCIAL ANALYSIS

ANCHORAGE-FAIRBANKS INTERCONNECTION

SEMI-ANNUAL DISBURSEMENTS

FOR

TRANSMISSION INTERTIE FACILITIES

(TLFAP)

1979

BASE-LINE

AND

ESCALATED

COSTS

16 AUGUST 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
SEMI-ANNUAL DISBURSEMENTS FOR TRANSMISSION INTERTIE FACILITIES
UNINFLATED 1979 LEVEL COSTS

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
102.0	1. TRANSMISSION LINE							
104.0	ENGINEERING AND CONSTRUCTION							
105.0	SUPERVISION	452	753	0	392	693	723	3012
106.0	RIGHT OF WAY	0	2209	6628	0	0	0	8837
108.0	FOUNDATIONS	0	0	0	2280	6165	0	8445
110.0	TOWERS	0	0	0	0	9727	11888	21615
112.0	HARDWARE	0	0	0	0	72	405	477
114.0	INSULATORS	0	0	0	0	75	428	503
116.0	CONDUCTOR	0	0	0	0	1614	9147	10761
119.0								
120.0	SUB-TOTAL	452	2962	6628	2672	18346	22591	53650
122.0								
130.0	2. SUBSTATIONS							
132.0	ENGINEERING & CONSTRUCTION							
133.0	SUPERVISION	563	563	563	563	282	282	2816
134.0	LAND	81	0	0	0	0	0	81
136.0	TRANSFORMERS	0	0	341	596	596	170	1703
138.0	CIRCUIT BREAKERS	0	0	391	684	684	195	1953
140.0	STATION EQUIPMENT	0	0	269	471	471	135	1345
141.0	STRUCTURES & ACCESSORIES	0	0	805	1610	1610	0	4026
145.0								
146.0	SUB-TOTAL	644	563	2369	3924	3642	782	11924
149.0								
150.0	3. CONTROL AND COMMUNICATIONS							
152.0	ENGINEERING AND INSTALLATION							
153.0	SUPERVISION	0	0	0	0	71	94	165
154.0	EQUIPMENT	0	0	0	0	1254	1881	3135
156.0								
158.0	SUB-TOTAL	0	0	0	0	1325	1975	3300
160.0								
162.0	TOTAL	1096	3525	8996	6596	23313	25348	68874
164.0								
166.0	TOTAL FOR YEAR	0	4621	0	15592	0	48661	68874

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ANCHORAGE - FAIRBANKS INTERCONNECTION
FUNDING SOURCES AND
INTEREST DURING CONSTRUCTION

40-60 REA-FFB

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
400.0	FUNDING SOURCES							
401.0	APA BOND	0	0	0	0	0	0	0
402.0	REA LOAN	307	1027	2725	2077	7636	8635	22407
403.0	CFC LOAN	0	0	0	0	0	0	0
404.0	FFB LOAN	460	1540	4087	3116	11455	12953	33610
405.0	AMU SHORT TERM LOAN	197	660	1751	1335	4909	5551	14404
406.0	FMU SHORT TERM LOAN	132	440	1168	890	3273	3701	9603
408.0								
409.0	TOTAL	1096	3666	9730	7419	27273	30839	80024
410.0								
411.0	INTEREST DURING CONSTRUCTION							
412.0	APA BOND	0	0	0	0	0	0	0
413.0	REA LOAN	4	21	67	127	249	452	920
414.0	CFC LOAN	0	0	0	0	0	0	0
415.0	FFB LOAN	11	57	187	354	691	1255	2554
416.0	AMU SHORT TERM LOAN	10	53	173	328	640	1163	2366
417.0	FMU SHORT TERM LOAN	7	35	116	218	427	775	1578
420.0								
421.0	TOTAL	31	165	543	1027	2006	3645	7418
422.0								

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ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT TABLE AND
COMPOSITE INTEREST RATE

40-60 REA-FFB

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
430.0	% DEBT ASSUMED BY EACH UTILITY							
432.0	AML & P	18	0	0	0	0	0	18
434.0	CEA	11	0	0	0	0	0	11
436.0	MEA	3	0	0	0	0	0	3
438.0	HEA	0	0	0	0	0	0	0
442.0	FMUS	12	0	0	0	0	0	12
444.0	GVEA	56	0	0	0	0	0	56
446.0	CVEA	0	0	0	0	0	0	0
447.0								
448.0								
449.0								
450.0	DEBT ASSUMED BY EACH UTILITY							
452.0	AML & P	197	660	1751	1335	4909	5551	14404
454.0	CEA	121	403	1070	816	3000	3392	8803
456.0	MEA	33	110	292	223	818	925	2401
458.0	HEA	0	0	0	0	0	0	0
462.0	FMUS	132	440	1168	890	3273	3701	9603
464.0	GVEA	614	2053	5449	4155	15273	17270	44814
466.0	CVEA	0	0	0	0	0	0	0
468.0								
470.0	TOTAL DEBT	1096	3666	9730	7419	27273	30839	80024
472.0								
474.0								
476.0								
510.0	COMPOSITE INTEREST RATE	0.083	0.0	0.0	0.0	0.0	0.0	0.083