ALASKA POWER AUTHORITY

Anchorage - Fairbanks Transmission Intertie
Economic Feasibility Study Report

DRAFT

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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, and 14 February 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 "most probable" forecast.

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

	Anchorage	Fairbanks	Combined System
1980	573	153	749
1985	977	231	1194
1990	1581	338	1869
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. All system expansion plans were prepared to meet the "most probable" load demand projections.

To assume a nearly constant level of 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 very 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 the 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 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 using the discounted present-worth method. 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. In this analysis, a 7% long-term average annual escalation rate and a 10% discount rate was used for principal investigations.

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. The present-worth of net benefits is $7,968,000.

- A considerable increase in benefits is obtained if the 230-kV single circuit intertie (double circuit after 1992), in addition to line capacity allocated to reserve sharing, includes firm power transfer capability (Case IB). The increase in present-worth net benefits is from $7,968,000 to $14,589,000, or an increase of 83 percent. Additional benefits due to supply of construction power to the Upper Susitna Project sites is $2,943,000, or an added increase of 18 percent.

- The 345-kV single circuit intertie (Case IC) is not economically feasible in 1984 if based only on the benefits due to reduction of installed generation reserve capacity. Further studies, not made, will probably indicate that a 345-kV intertie would be feasible if firm power transfer benefits are included.

- The 230-kV intertie with intermediate substations at Palmer and Healy (Case ID) has the following net benefits:

Study Case	PW of Net Benefits
IA (Reserve sharing only)	$ 7,968,000
ID (Plus supply to MEA)	$10,065,000
ID (Plus constr. power supply)	$13,113,000

- 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.

- Expansion plans for the interconnected system with the 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.

- Generation and interconnection planning is a complex and continuous process. This Intertie Feasibility Study is only a part of the overall power system expansion plans for the Railbelt area. Further intertie 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.

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 projections is given in Table 3-4. These projections include only utility and industrial load forecasts, 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 load forecasts was based on a ± 20% spread from projected mid-range growth to 1980. The industrial load projected by Battelle was included in the 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 consumption, 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 maximum growth 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 acceptable as a single demand projection, 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

Once the range of load forecasts has been established, it remains to select definitive demand forecasts for generation expansion planning. Between the upper limit of the combined utilities forecast and the lower limit, represented by the median forecast by the Alaska Power Administration, lies a range of possible load growth projections, each having a certain probability of realization through time.

A. Probabilistic Representation of Load Forecast Uncertainty

On the assumption that the load forecast range obeys a normal probability distribution, the uncertainty associated with the forecast can be represented by the normal continuous probability curve of Figure 3-7A. The most probable forecast for this symmetrical representation is then the statistical average between the maximum and minimum limits, these being assumed to occur at the $\pm$ 3 standard deviation extremities of the normal bell curve. The statistical average forecasts for the Railbelt area are given in Table 3-5, these being now designated the most probable forecasts for the selected range. The statistical average or mean value is the same as the most probable value, due to the basic assumption regarding the symmetrical shape of the normal probability distribution curve.

The variability of the forecast is defined in terms of standard deviations from a most probable value, with the bandwidth of the forecast taken to be within $\pm$ 2 standard deviations from the most probable value. The degree of uncertainty associated with the forecast range determines this bandwidth, which may be expressed as a 95% chance that the actual peak demand will lie between the limits of the selected bandwidth.

As the uncertainty associated with a load forecast increases with time, the demand value defined by the bandwidth will increase with time; however, the probability of being within the bandwidth will remain constant. The demand values corresponding to this bandwidth are given in Table 3-6, these being obtained from the range of forecasts, as follows:

The demand forecast limits define the range of possible values, such that the actual future peak demand will have a 99.8% probability of being within the upper and lower forecast limits, these being the $\pm$ 3 standard deviation bounds. This can be represented by the probability plot of Figure 3-8, the implicit assumption being that the forecast limits correspond approximately to the 99.9 percentile on the three standard deviation limit. Connection of the extreme percentile limits enables the determination of the bandwidth between the $\pm$ 2 standard deviations limits, as a 2/3 ratio between the high and most probable forecasts at any point in time. The bandwidth is given in terms of demand values, as tabulated in Table 3-6. The probability multipliers given in this table, for the load levels corresponding to the forecast bandwidth, are obtained from the discrete representation of forecast uncertainty shown on Figure 3-7B, this being the usual representation of forecast uncertainty for generation planning studies.

B. <u>Selection of Demand Forecasts for the Railbelt Area</u>

The most probable load demands and forecast bandwidths for the Anchorage - Cook Inlet, Fairbanks - Tanana Valley and the Railbelt areas are shown on Figures 3-9 and 3-10. As the $\pm$ 2 standard load level limits cross over for the Anchorage - Cook Inlet area, the divergent bandwidth is shown on Figure 3-9 as beginning in 1982. The most probable forecast then appears as a single demand line from 1979 through 1981, which considering the short time projection is quite reasonable. The demand trend is well established for the Anchorage area and can be expected to persist in the immediate short-range time frame.

The long-range load projections are given in Table 3-6, with a total diversified demand for the combined areas of the Railbelt 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

Year	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.		
	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	Matanuska	Homer	Kenai City	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

	Fairbanks Municipal Utilities System			Alaska 6 - Golden Valley Electric Association, Inc.		
Year	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

	1977	1980	1985	1990	1995	2000
1. ANCHORAGE-COOK INLET AREA POWER DEMAND AND ENERGY REQUIREMENTS (Excluding National Defense)						
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

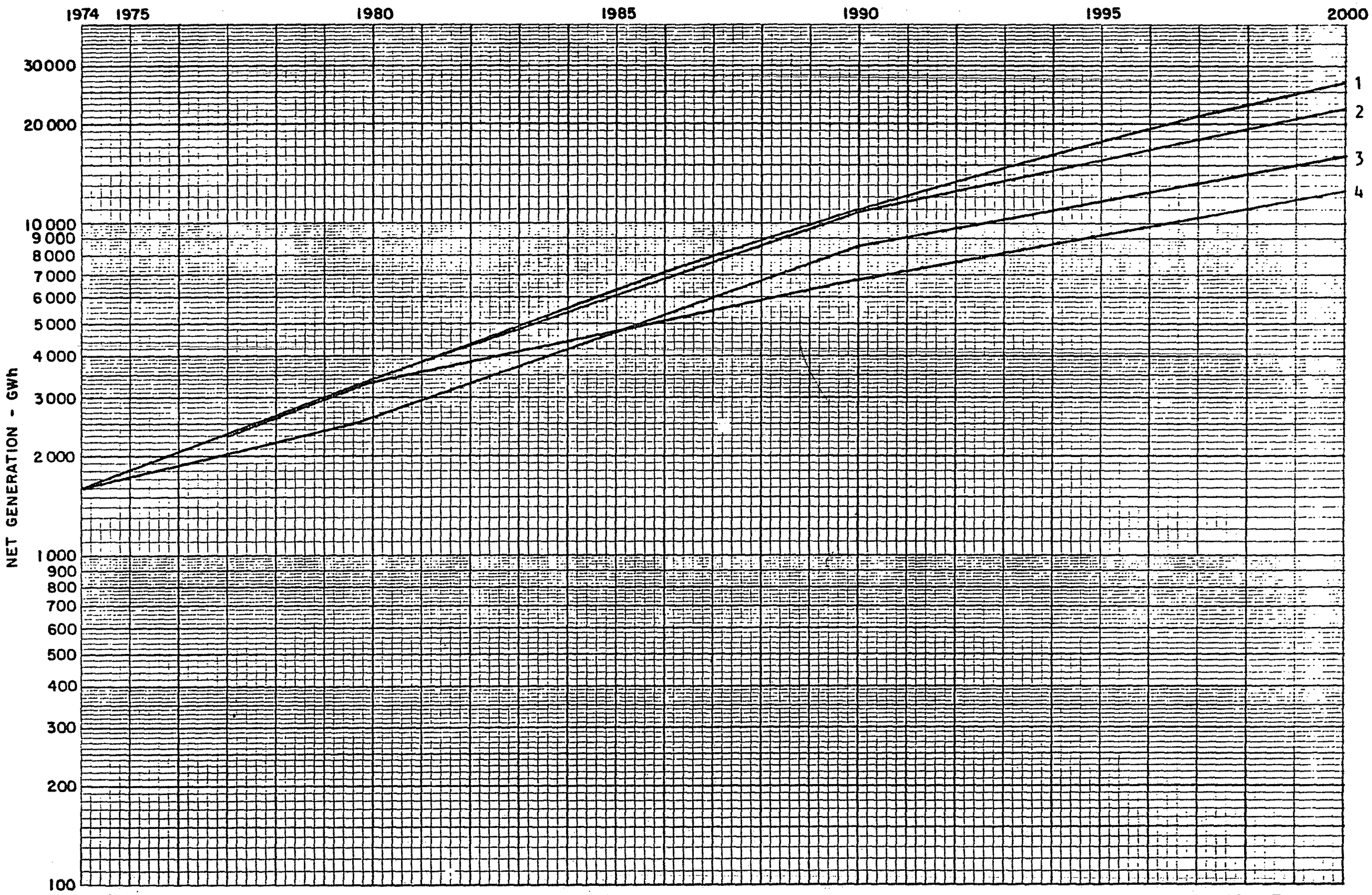
LOAD DEMAND FORECASTS FOR RAILBELT AREA TO DETERMINE STATISTICAL AVERAGE FORECAST

	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

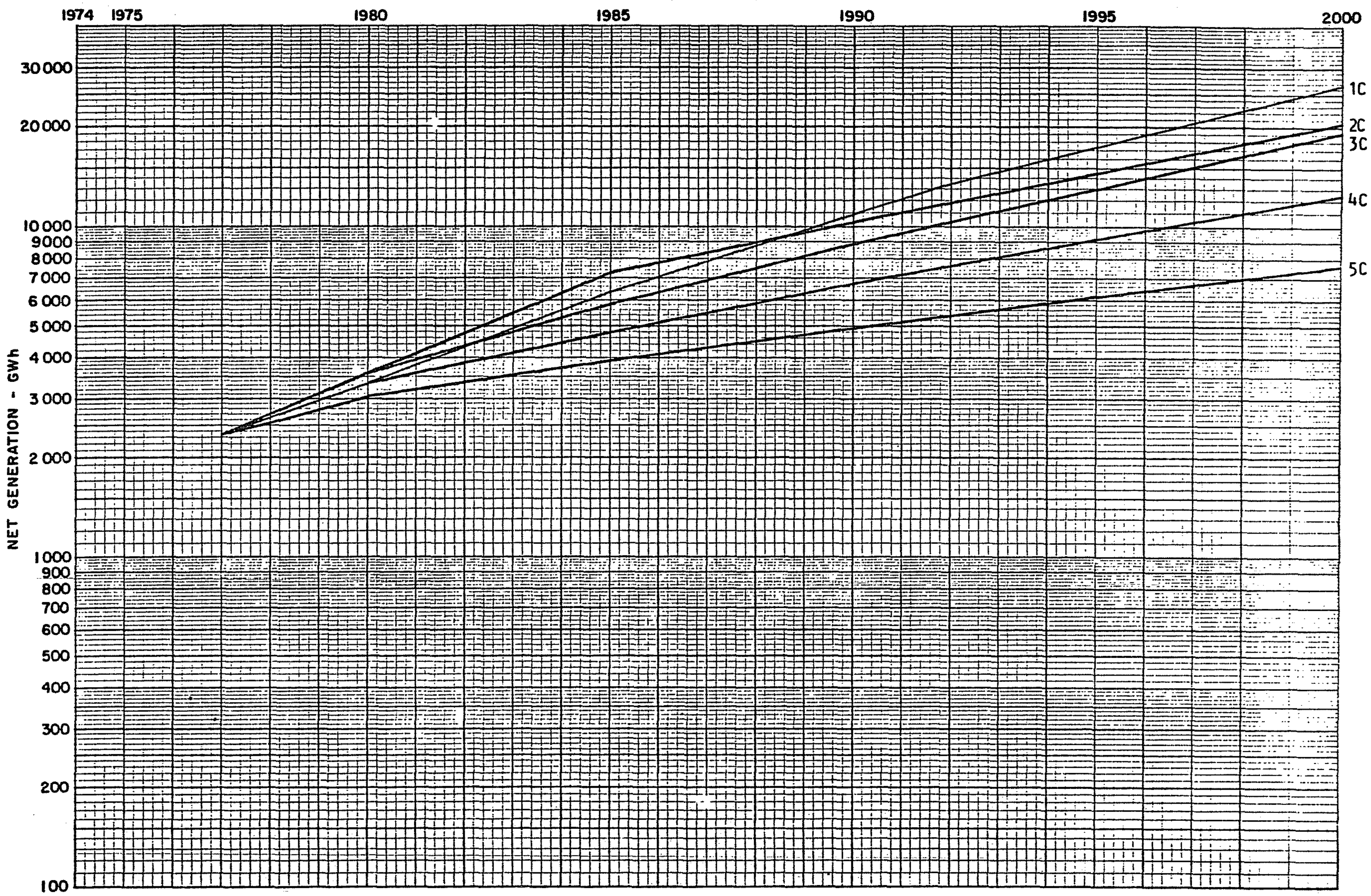
LOAD DEMAND BANDWIDTH FOR RAILBELT AREA FORECASTS
"MOST PROBABLE" FORECAST ± 2 STANDARD DEVIATIONS

Year	Anchorage - Cook Inlet			Fairbanks - Tanana Valley			Combined Load Areas		
	Load Level -2 Standard Deviations (MW)	Most Probable Forecast (MW)	Load Level +2 Standard Deviations (MW)	Load Level -2 Standard Deviations (MW)	Most Probable Forecast (MW)	Load Level +2 Standard Deviations (MW)	Load Level -2 Standard Deviations (MW)	Most Probable Forecast (MW)	Load Level +2 Standard Deviations (MW)
1979	535	511	487	140	141	142	671	645	619
1980	592	573	554	151	153	155	741	749	697
1981	644	638	632	163	166	169	805	796	787
1982	702	710	718	175	180	185	874	881	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	1896	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
Probability Multipliers	0.0665	0.383	0.0665	0.0665	0.383	0.0665	0.0665	0.383	0.0665



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

FIGURE 3-1
COMPARATIVE NET ENERGY GENERATION FORECASTS FOR COMBINED UTILITIES AND INDUSTRIAL LOAD RAILBELT AREA

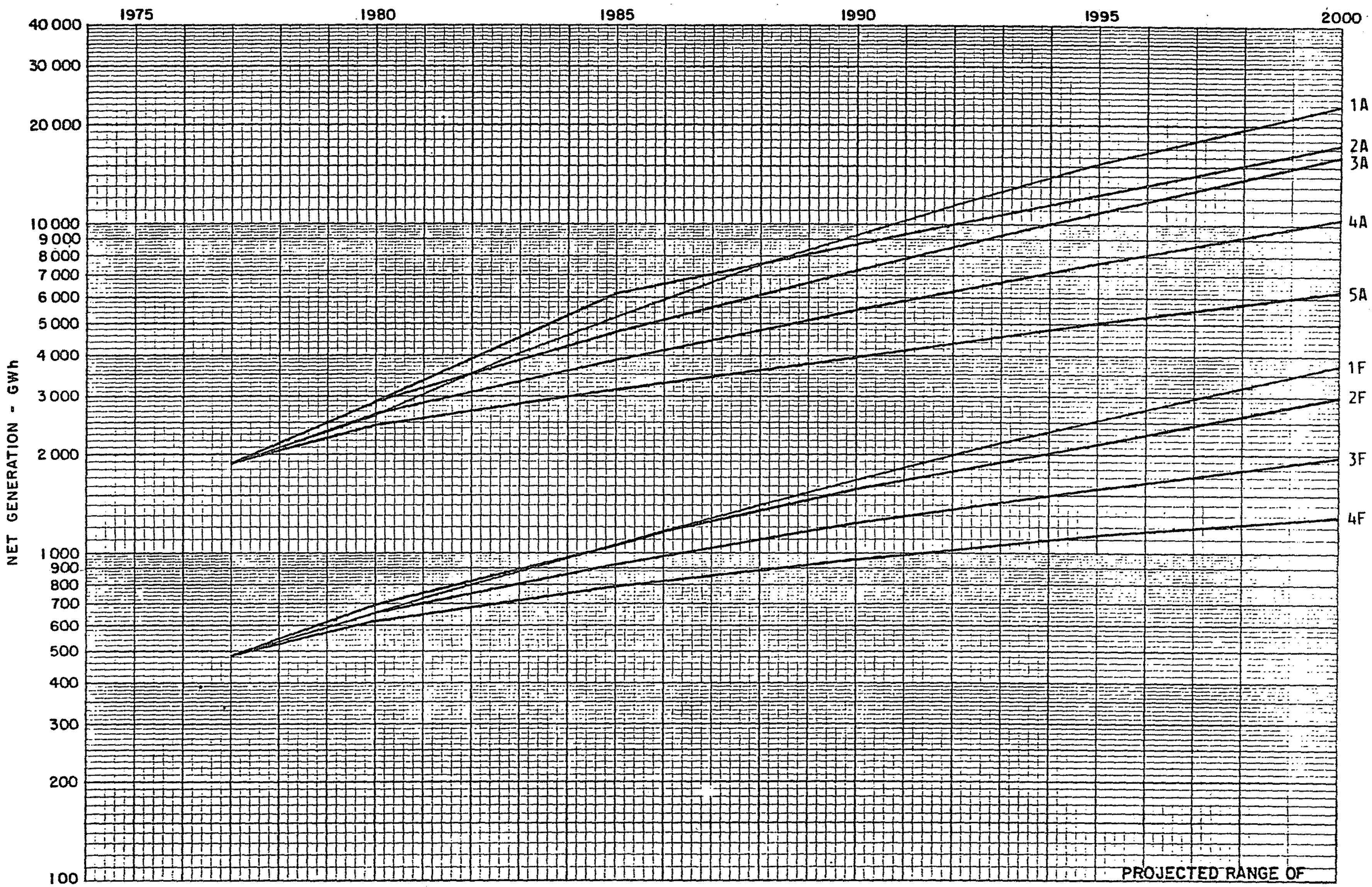


1C COMBINED UTILITIES FORECAST
2C EXTRA HIGH FORECAST
3C HIGH FORECAST
4C MEDIAN FORECAST
5C LOW FORECAST

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

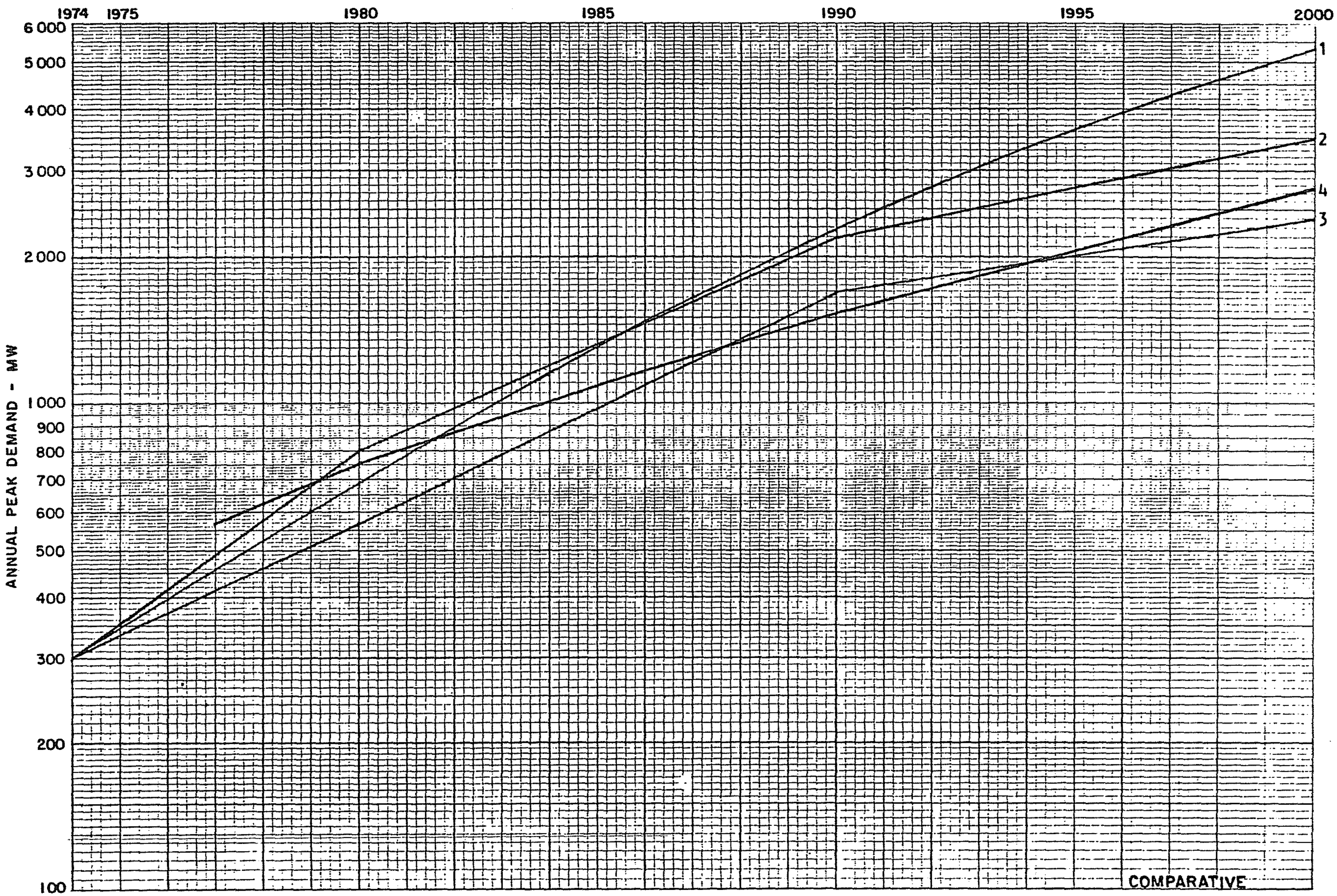


1A UTILITIES FORECAST FOR ANCHORAGE - COOK INLET AREA
2A EXTRA HIGH FORECAST
3A HIGH FORECAST
4A MEDIAN FORECAST
5A LOW FORECAST
(2A–5A: ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978)

1F UTILITIES FORECAST FOR FAIRBANKS - TANANA VALLEY AREA
2F HIGH FORECAST
3F MEDIAN FORECAST
4F LOW FORECAST
(2F–4F: 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

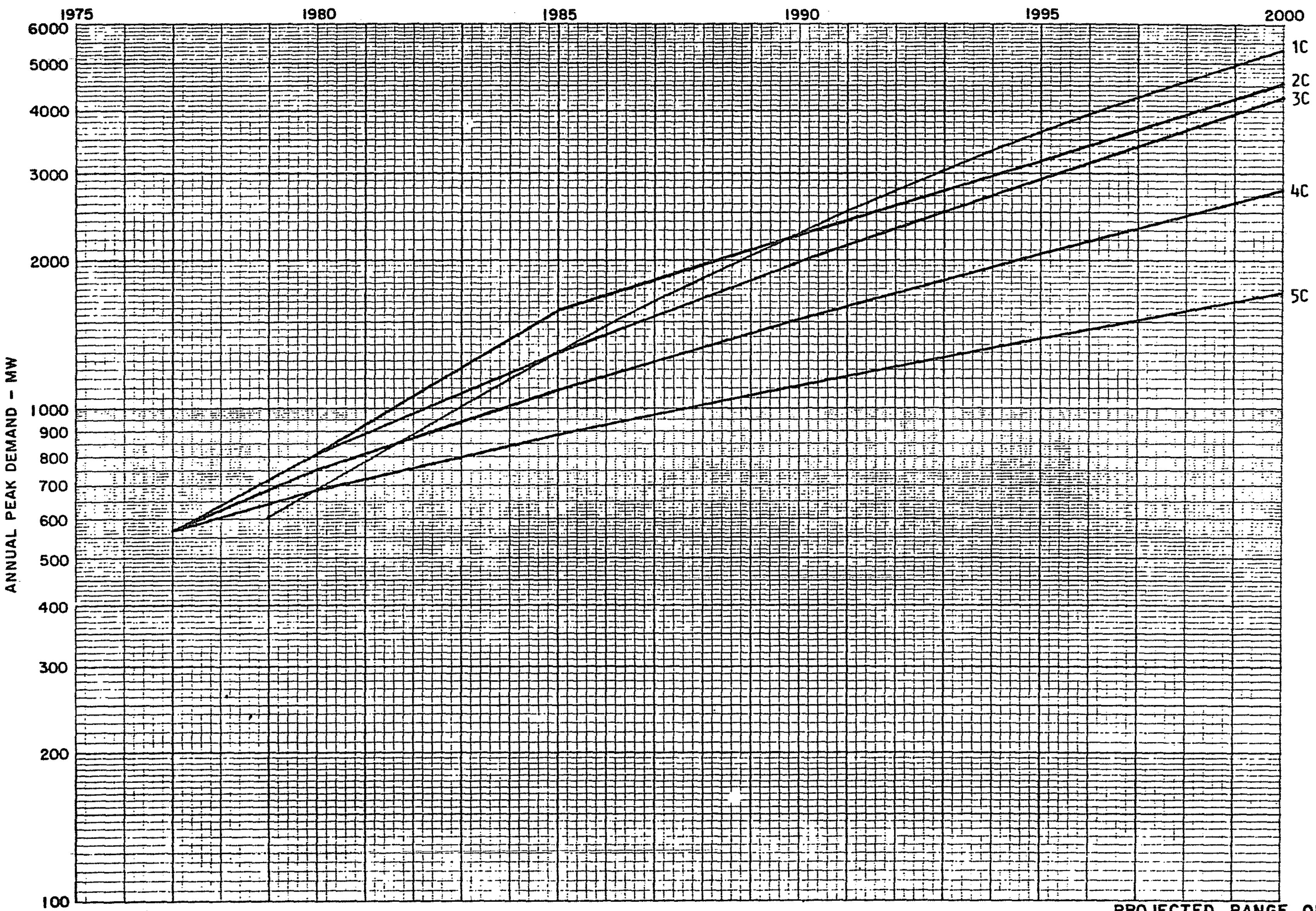
FIGURE 3-3



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

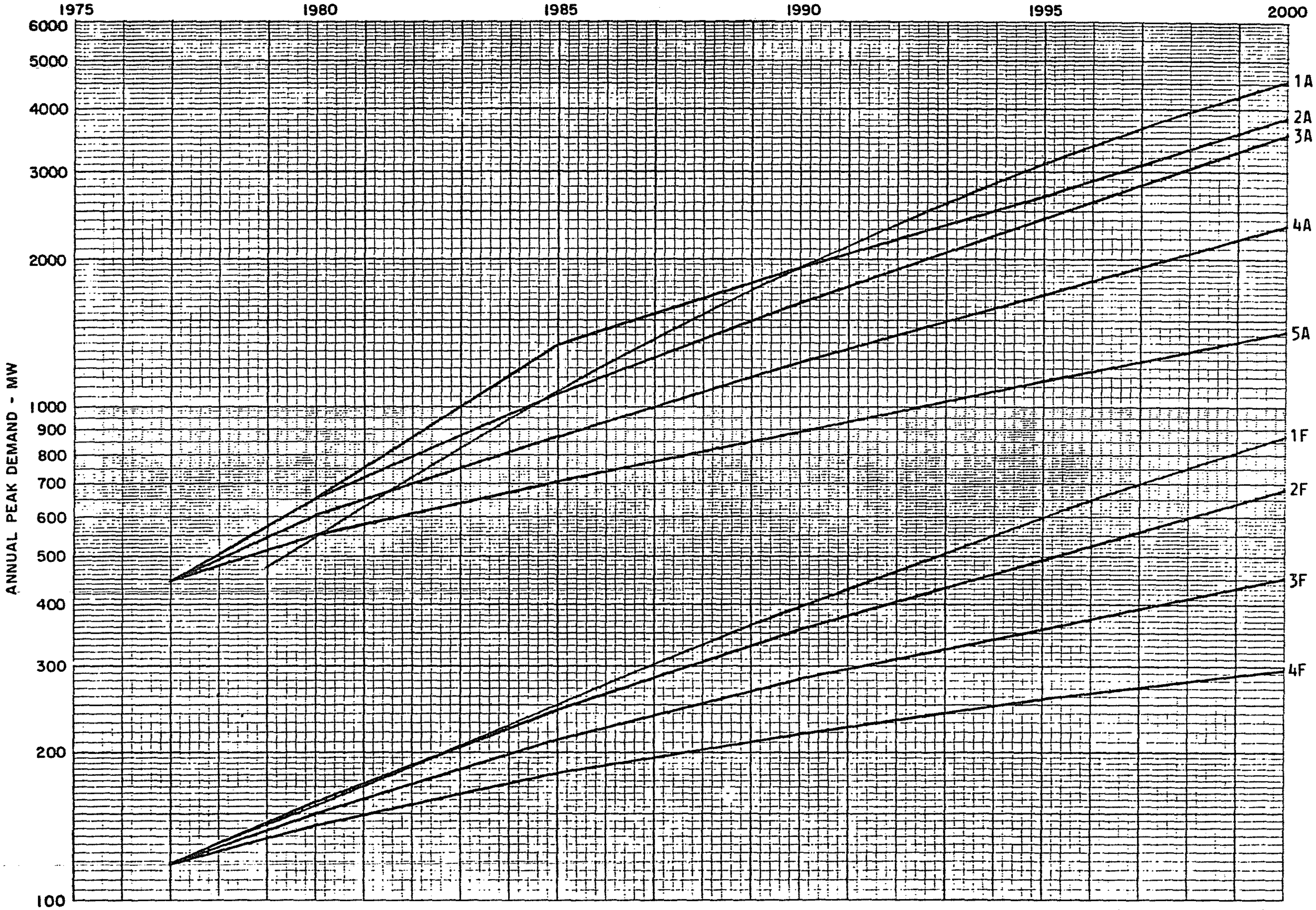


1C COMBINED UTILITIES FORECAST
2C EXTRA HIGH FORECAST
3C HIGH FORECAST
4C MEDIAN FORECAST
5C LOW FORECAST

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
5A LOW 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 FAIRBANKS - TANANA VALLEY AREA

FIGURE 3-6

PROBABILITY MODEL REPRESENTATION OF LOAD FORECAST UNCERTAINTY

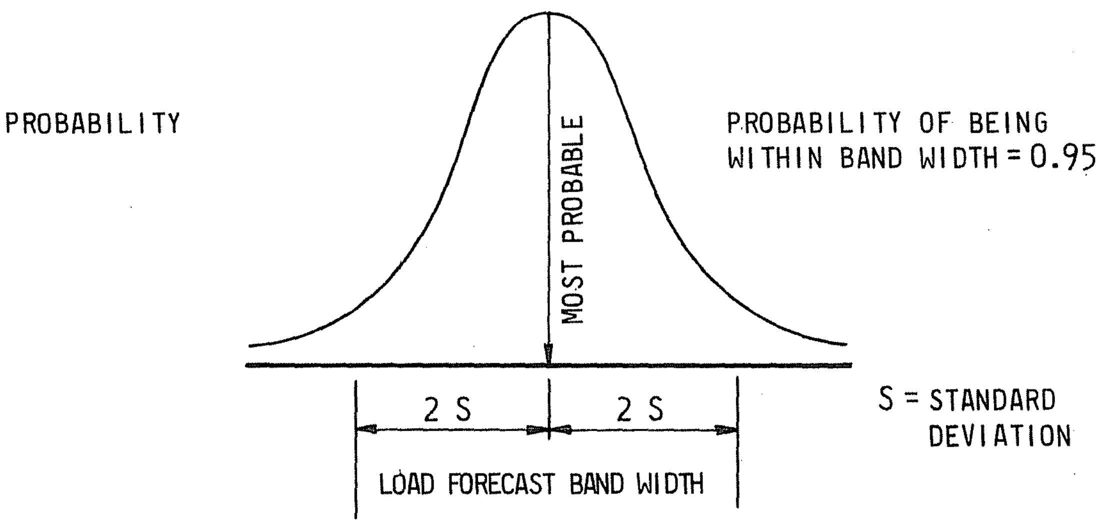


FIGURE 3-7A CONTINUOUS REPRESENTATION

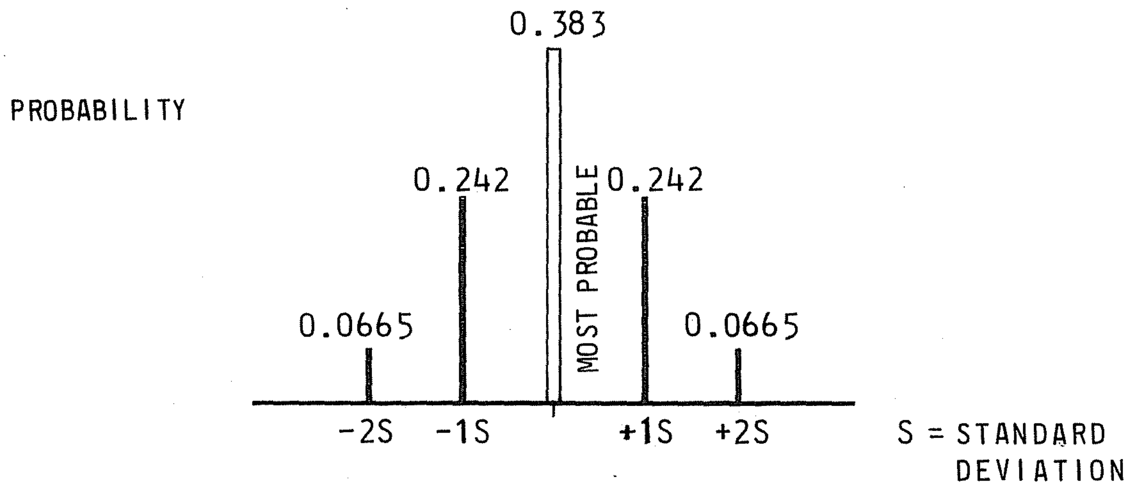
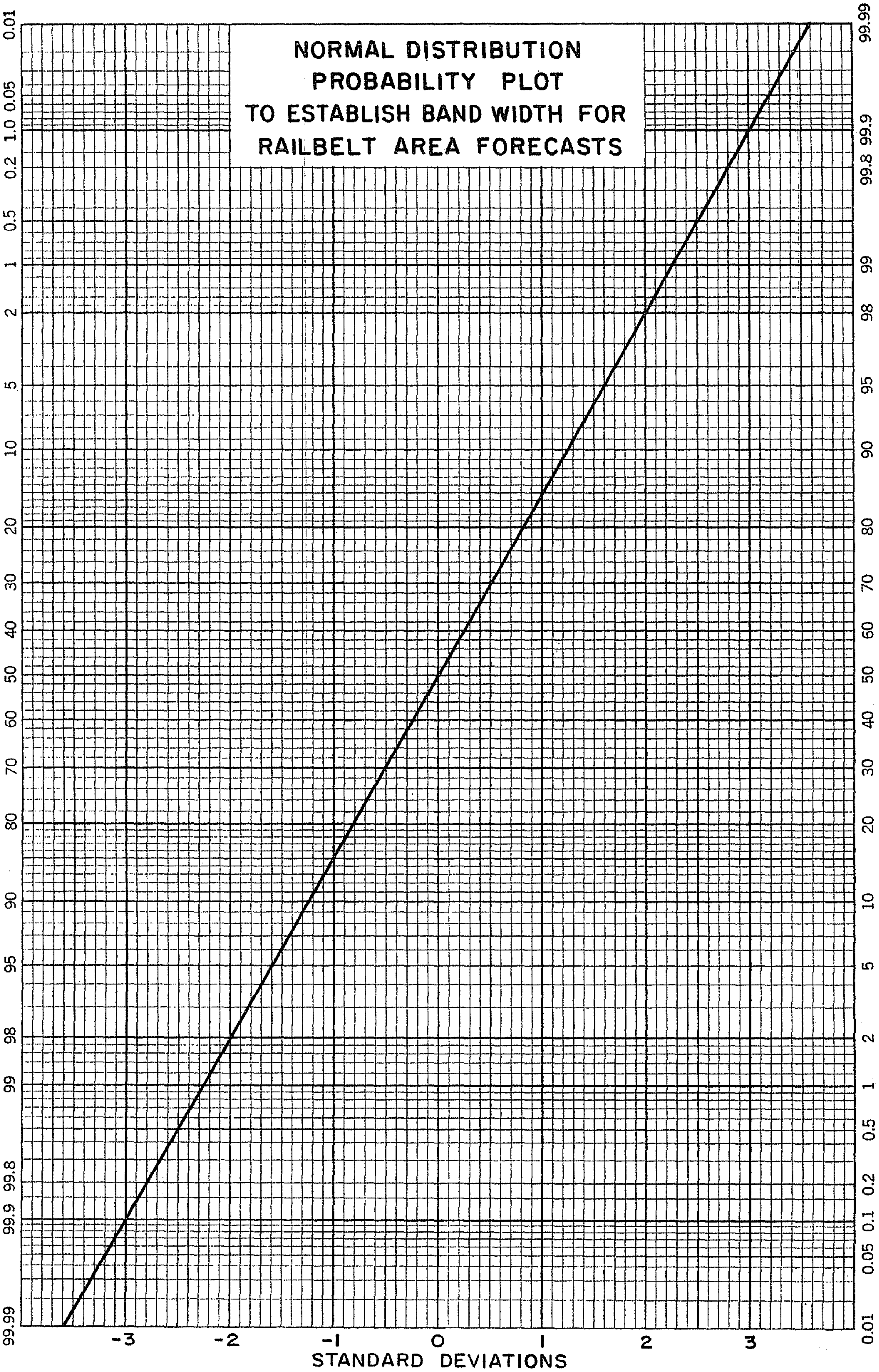
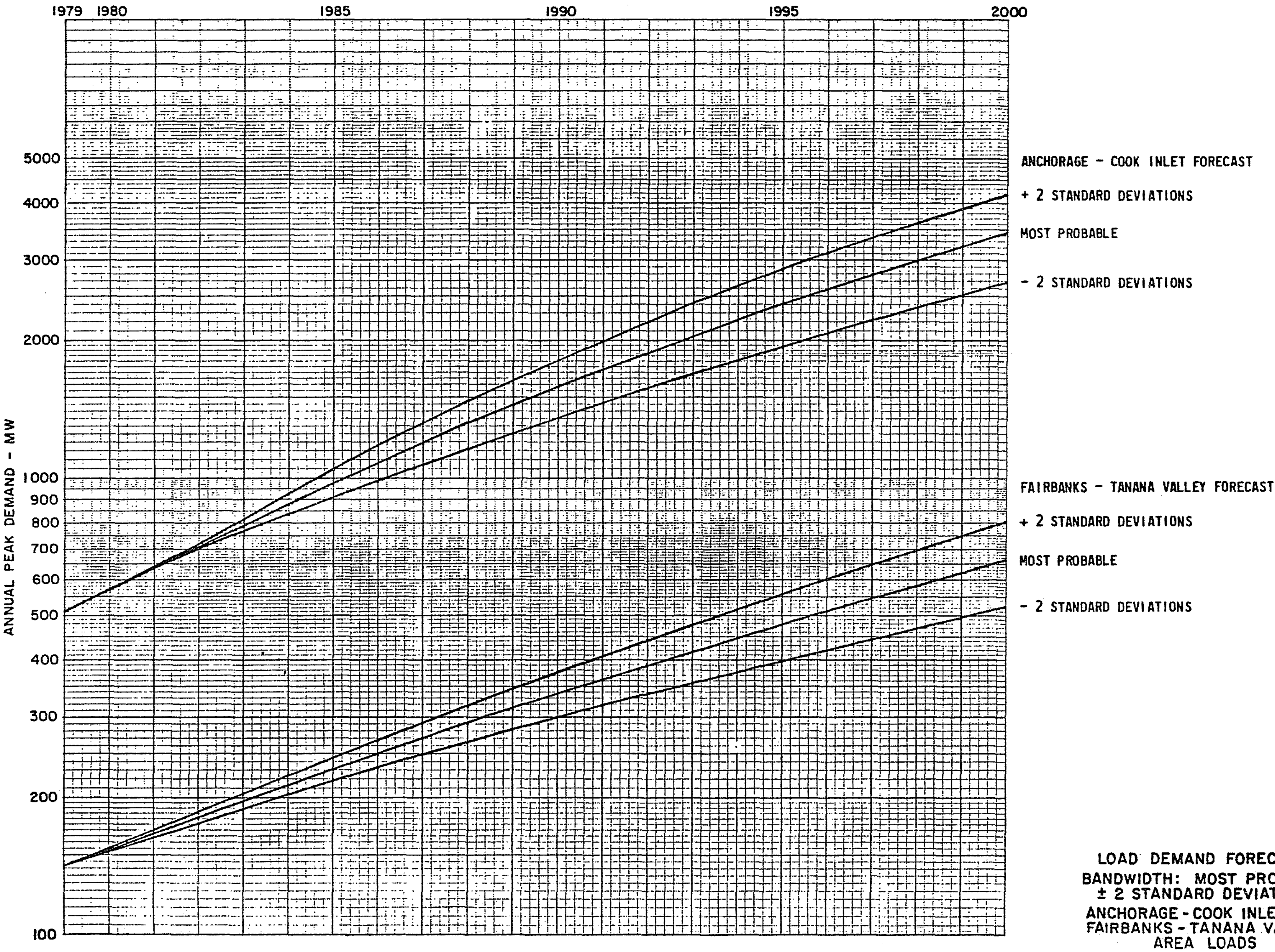


FIGURE 3-7B DISCRETE REPRESENTATION

FIGURE 3-8



NORMAL DISTRIBUTION
PROBABILITY PLOT
TO ESTABLISH BAND WIDTH FOR
RAILBELT AREA FORECASTS
0.01
0.05
1.0
0.2
0.5
1
2
5
10
20
30
40
50
60
70
80
90
95
98
99
99.8
99.9
99.99
-3
-2
-1
0
1
2
3
STANDARD DEVIATIONS

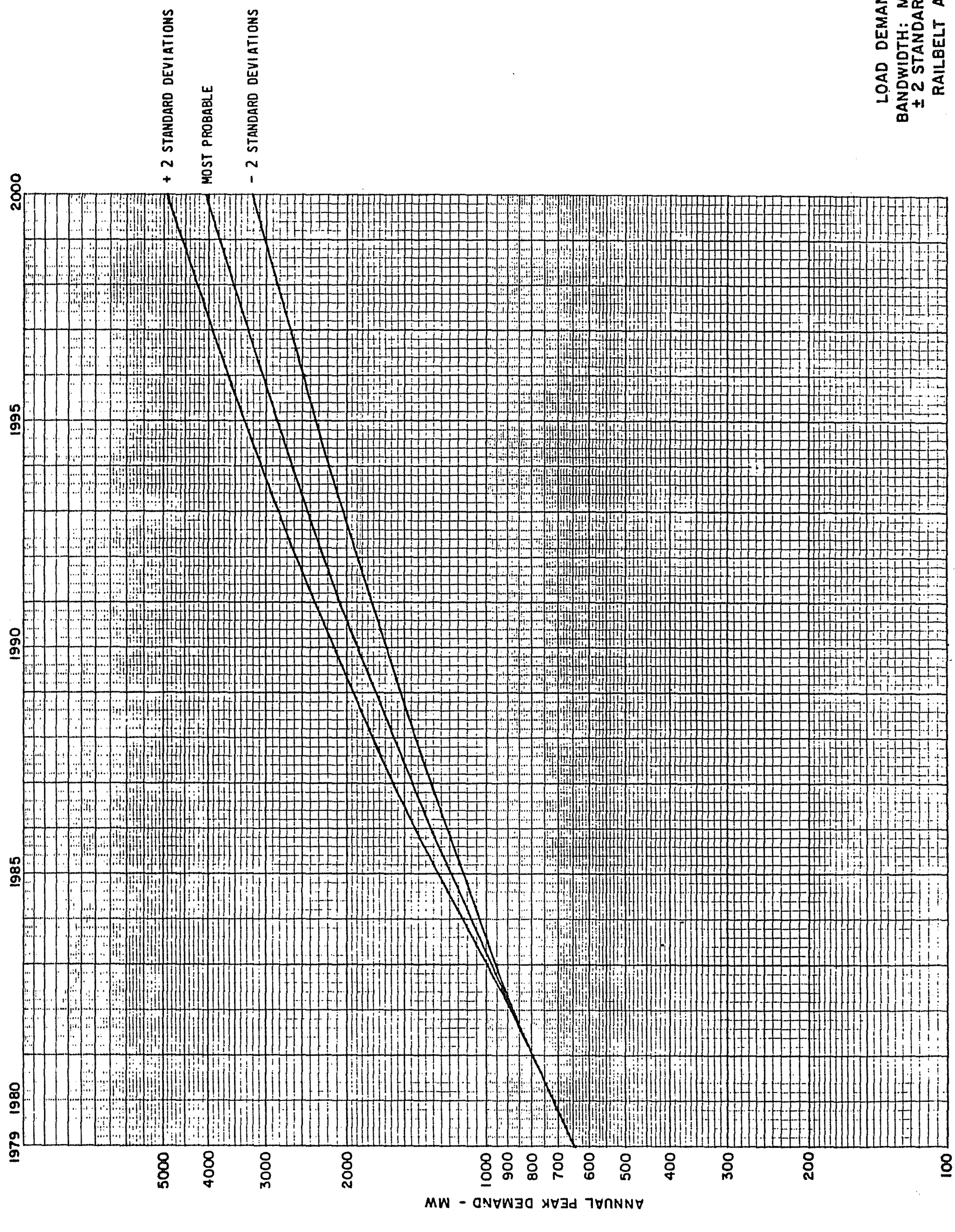


LOAD DEMAND FORECASTS
BANDWIDTH: MOST PROBABLE
± 2 STANDARD DEVIATIONS
ANCHORAGE - COOK INLET AND
FAIRBANKS - TANANA VALLEY
AREA LOADS

FIGURE 3-9

FIGURE 3-10

LOAD DEMAND FORECAST
BANDWIDTH: MOST PROBABLE
± 2 STANDARD DEVIATIONS
RAILBELT AREA LOADS



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. Scenic Resources - 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.

3. Kozak, Edwin, under the direction of J. R. Eaton, Performance Characteristics of a 350-Mile Electric Power Transmission Line (Fairbanks to Anchorage), A project in EE 494, Department of Electrical Engineering, University of Alaska, June 1973.

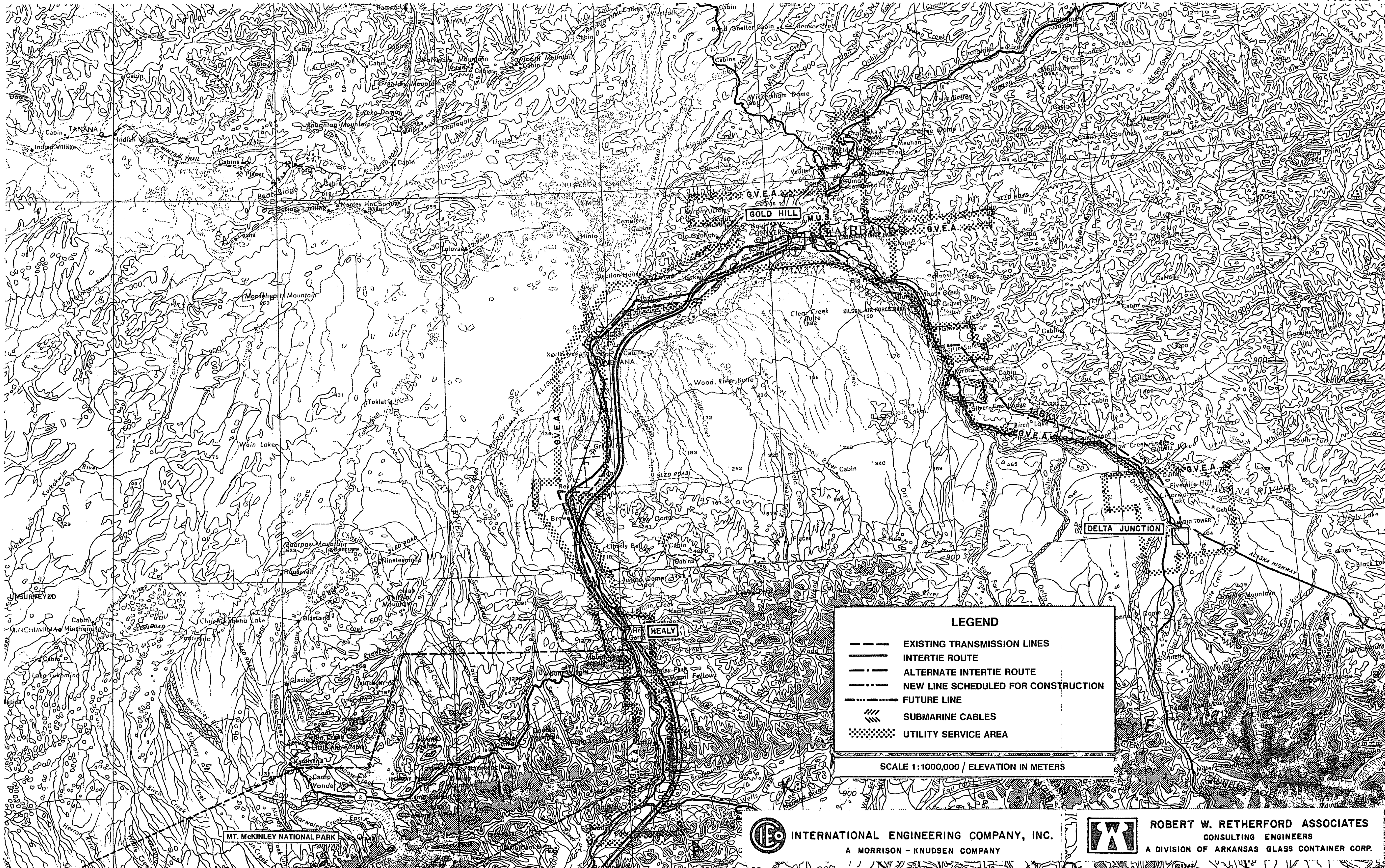
4. Ch2M-Hill, Electric Generation and Transmission Intertie System for Interior and Southcentral Alaska, 1972.

5. Federal Power Commission, Alaska Power Survey, 1969.

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

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

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



NENANA–FAIRBANKS–TANANA TRANSMISSION SYSTEM

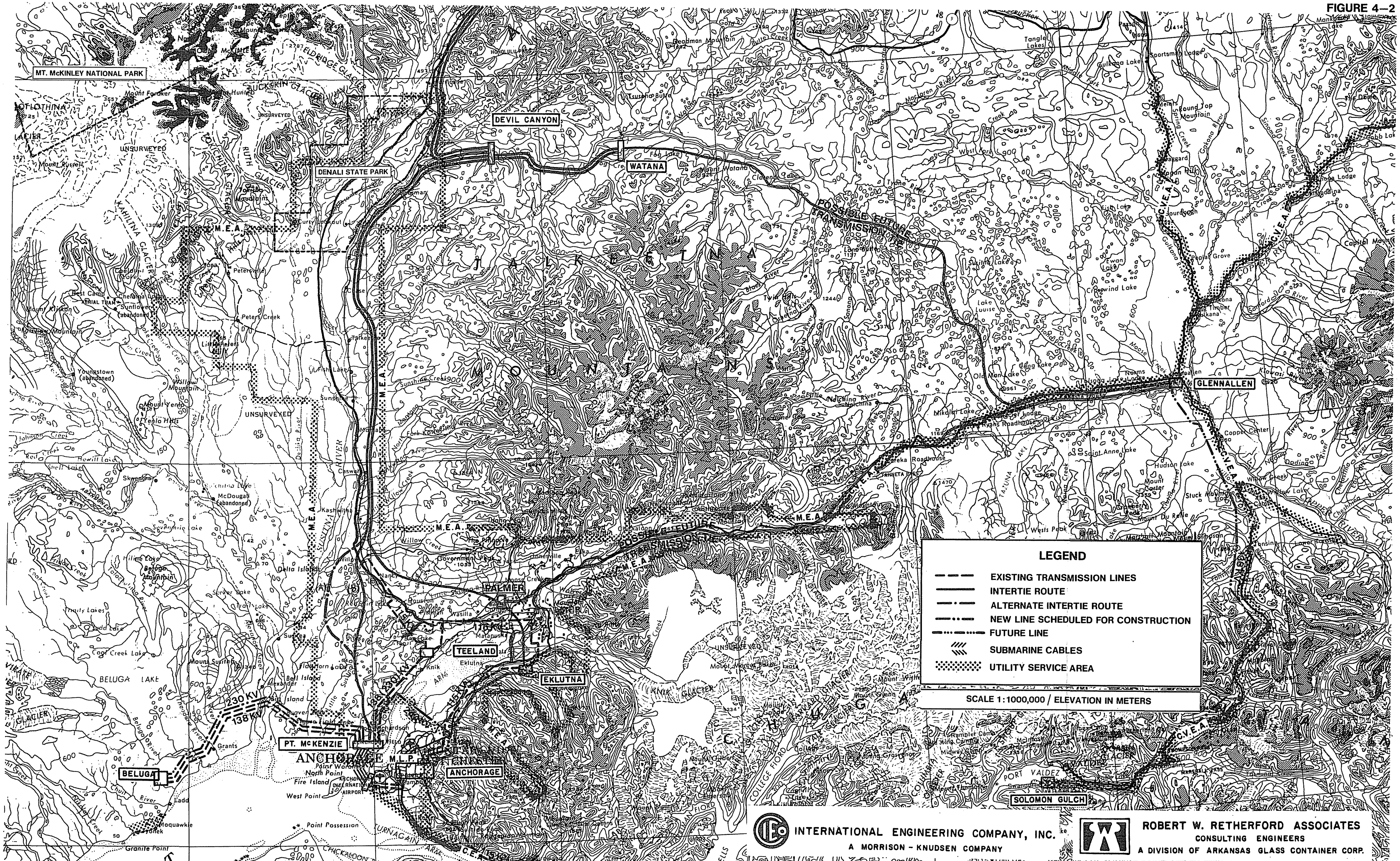
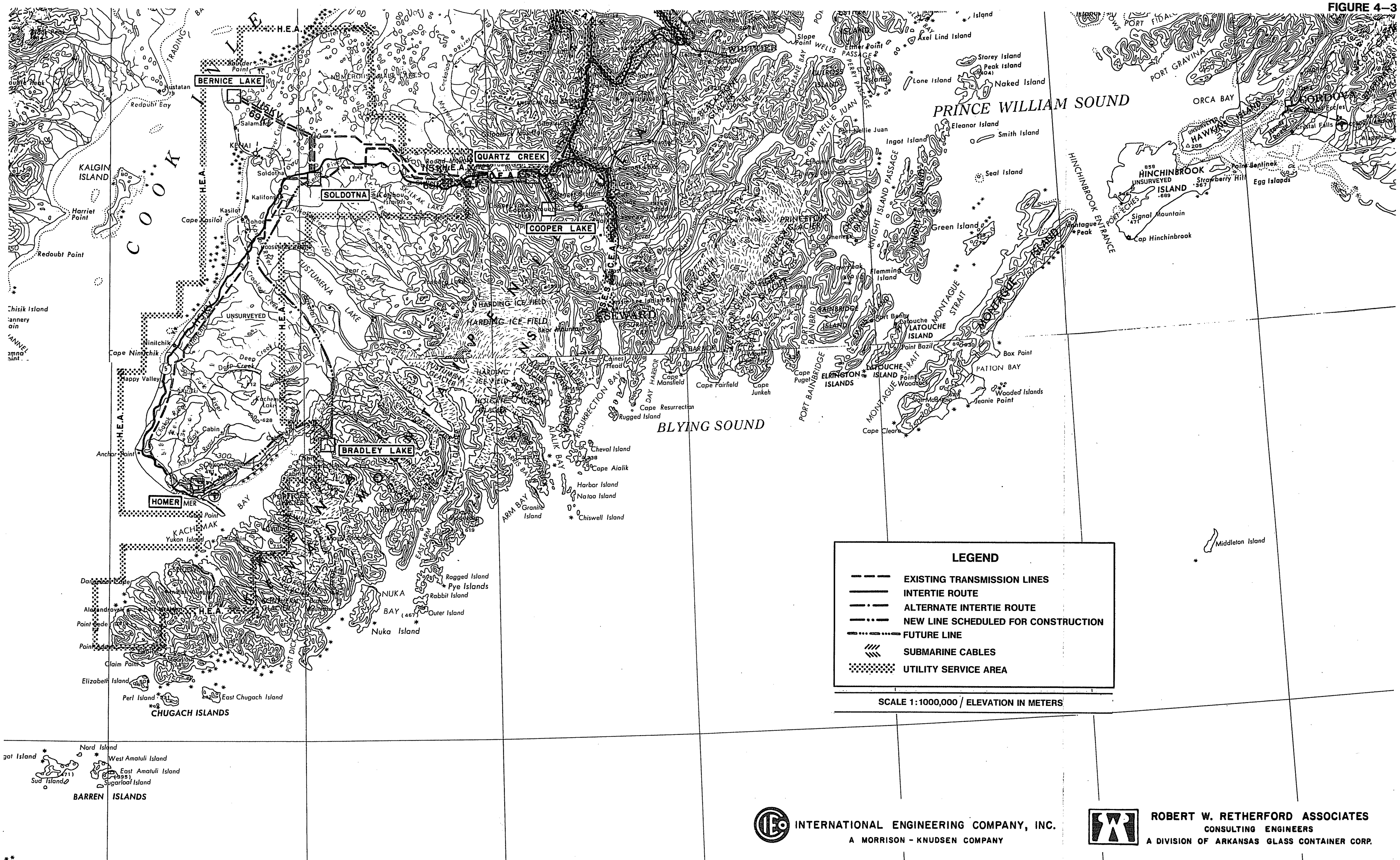


FIGURE 4-2

ANCHORAGE–MATANUSKA–SUSITNA–GLENNALLEN–VALDEZ TRANSMISSION SYSTEM



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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 $\pm$ 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

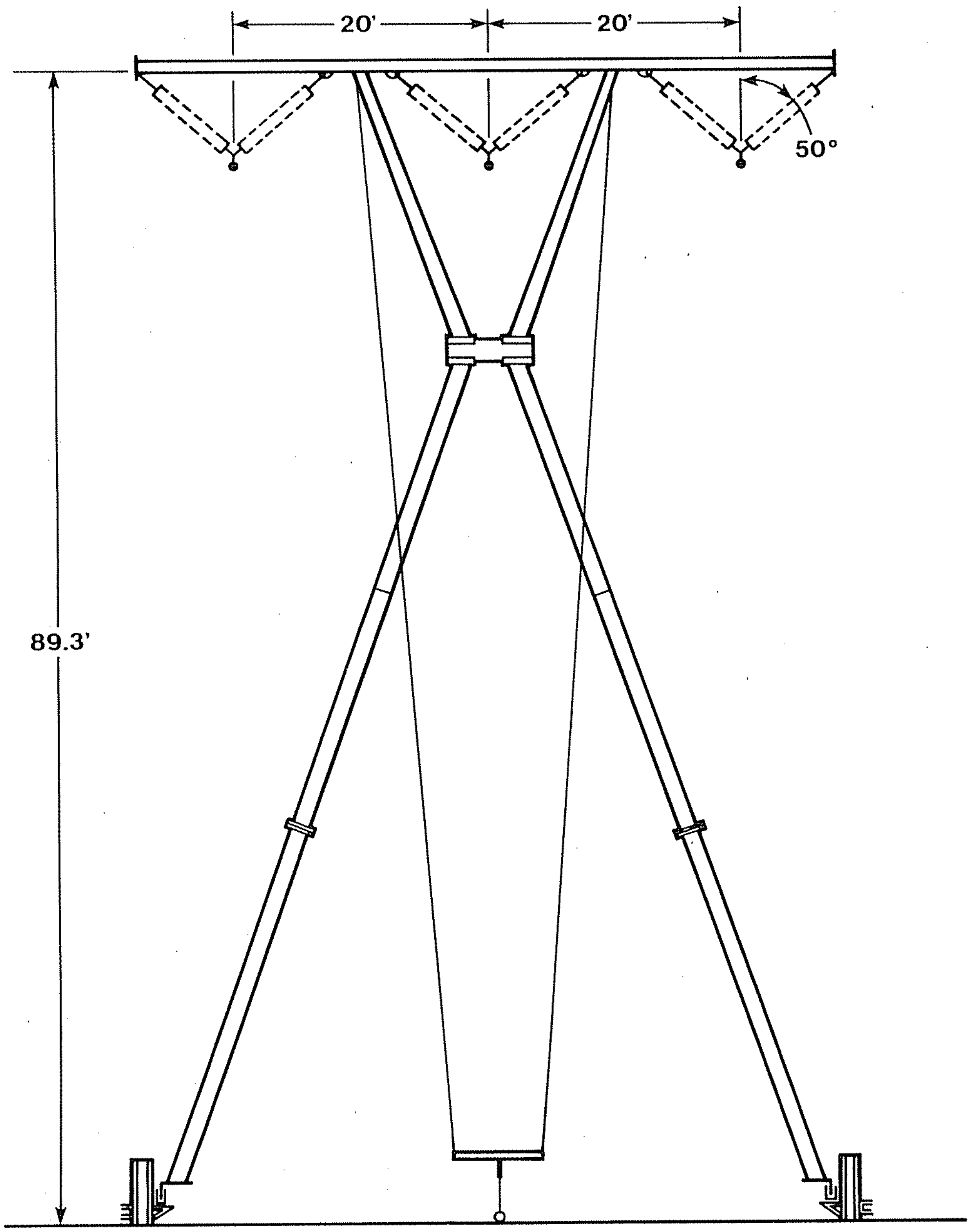
Case and Alternative 1/	Interconnection	Voltage (kV + 10%)	Line Length (miles)	Optimum ACSR Conductor (kcmil)	Load 2/ Per Circuit (MW)
I A & B	Anchorage-Ester	230 s/c	323	1/c - 954	130
I C	Anchorage-Ester	345 s/c	323	2/c - 715	380
I D	Anchorage-Palmer Healy-Ester	230 s/c	323	2/c - 954	130
II A	Anchorage-Devil Canyon	345 s/c 3/	155	2/c - 954	600
	Devil Canyon-Ester	230 s/c 3/	189	1/c - 954	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.

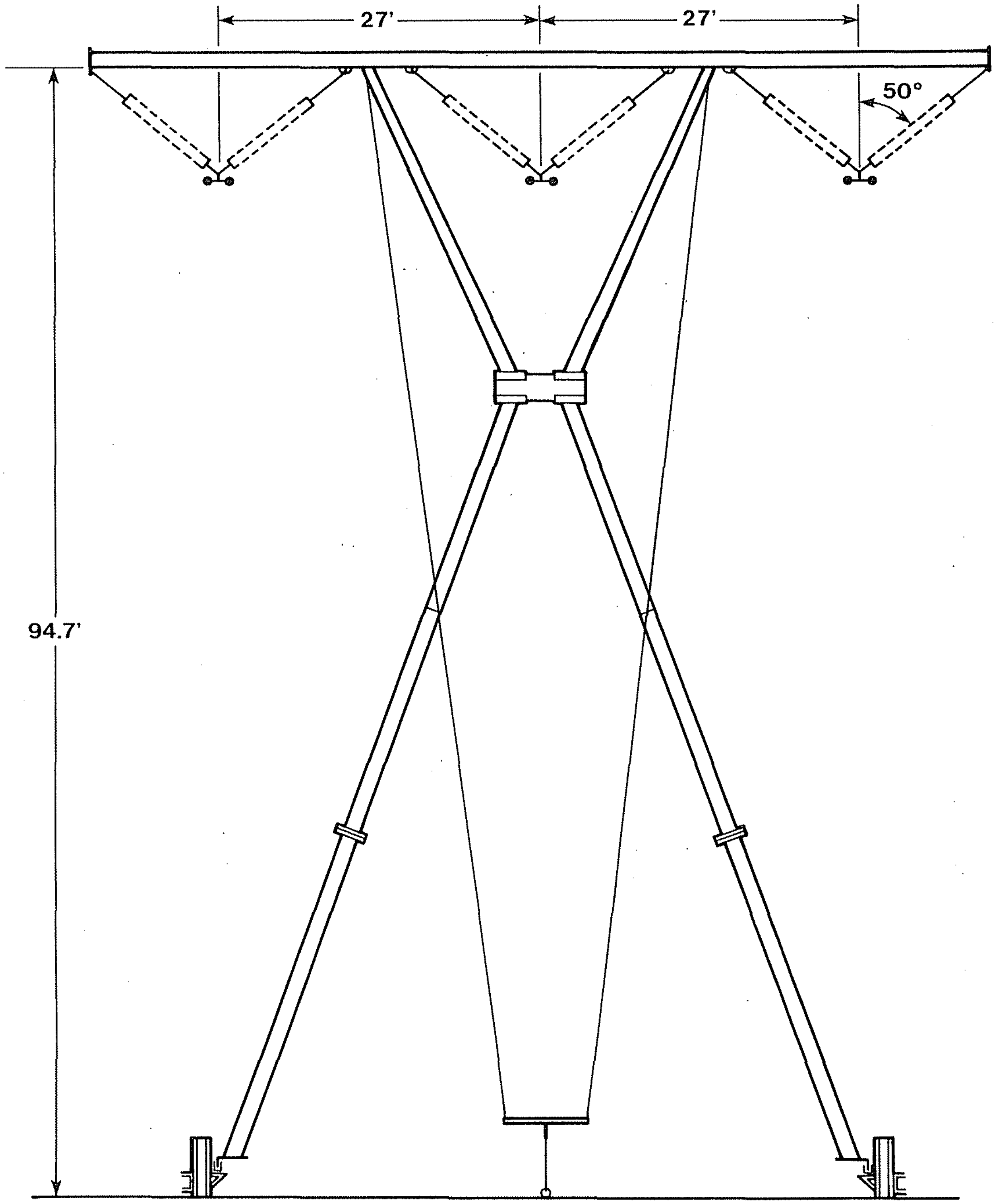
2/ 100% voltage support at both ends.

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



345KV TANGENT TOWER

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 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, a criterion for installed reserve generation capacity had to be established. A 20% reserve margin or the largest single unit at the time of peak system load was decided on as the installed generation reserve criterion. In general, the 20% value is close to the installed reserve goals 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.

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 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 and 6-4. 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, 6-3, 6-4, and 6-5.

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.

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 four 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 6-6.

- 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) and 70 MW (1992-1997). This plan is shown on Figures 6-4 and 6-6.

- Case IC includes one single-circuit 345-kV transmission line having a 130-MW power transfer capability allocated for generation reserve sharing and a 250-MW capacity available for firm power transfer. This case was developed for comparative cost information purposes only without generation expansion plans (MAREL study) and is presented on Figure 6-7.

- 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 6-8.

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, 6-8, and 6-9. As previously discussed in Subsection 6.2B, the LOLP index of one day in ten years (0.1 day/year) or lower was maintained throughout the study.

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
Anchorage	Unit 6	1979	HRST	12,000			installation
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	
Knit Arm	Several		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			SCGT	7,000			Leased from GVEA
Port Graham			Diesel	200			(1977-1979)
Seldovia			Diesel	1,648		1,500	
SEWARD ELECTRIC SYSTEM (SES)							
Seward	Unit 1		Diesel	1,500			
	Unit 2		Diesel	1,500	1,500	5,500	Standby
	Unit 3		Diesel	2,500	3,000		
ALASKA POWER ADMINISTRATION (APA)							
Eklutna	Unit 1		Hydro	30,000	35,000	30,000	

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 (1977-1979)
Zehnder Sub.	Unit 4	1975	SCGT			3,500	
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

ANNUAL PEAK LOAD IN MW
(1983 - 1996)

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

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 6-4

LOAD MODEL DATA

FAIRBANKS AREA

ANNUAL PEAK LOAD IN MW
(1983 - 1996)

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

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

LOSS OF LOAD PROBABILITY INDEX (LOLP)[1/]
FOR
STUDY CASES IA & ID[2/]

Study Year	Anchorage Independent Expansion	Anchorage Interconnected Expansion	Fairbanks Independent Expansion	Fairbanks Interconnected Expansion
1984	0.0262	0.0063	0.8193	0.0066
1985	0.0123	0.0275	0.1446	0.0242
1986	0.0293	0.0178	0.2868	0.0268
1987	0.0288	0.0255	0.6766	0.0575
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	0.0286	0.0276	0.0275
1993	0.0546	0.0316	0.0586	0.0606
1994	0.0427	0.0321	0.1583	0.1365
1995	0.0326	0.0652	0.0373	0.0426
1996	0.0931	0.0586	0.0899	0.1021

1/ LOLP in days per year.

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

TABLE 6-6

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

	Anchorage		Fairbanks	
Study Year	Independent Expansion	Interconnected Expansion	Independent Expansion	Interconnected Expansion
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	0.0359	0.0276	0.0143
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

1/ LOLP in days per year.

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

TABLE 6-7

LOSS OF LOAD PROBABILITY INDEX (LOLP)1/

FOR

CASE IIA2/

Study Year	Anchorage: Independent Expansion	Anchorage: Interconnected Expansion3/	Fairbanks: Independent Expansion	Fairbanks: Interconnected Expansion3/
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

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).

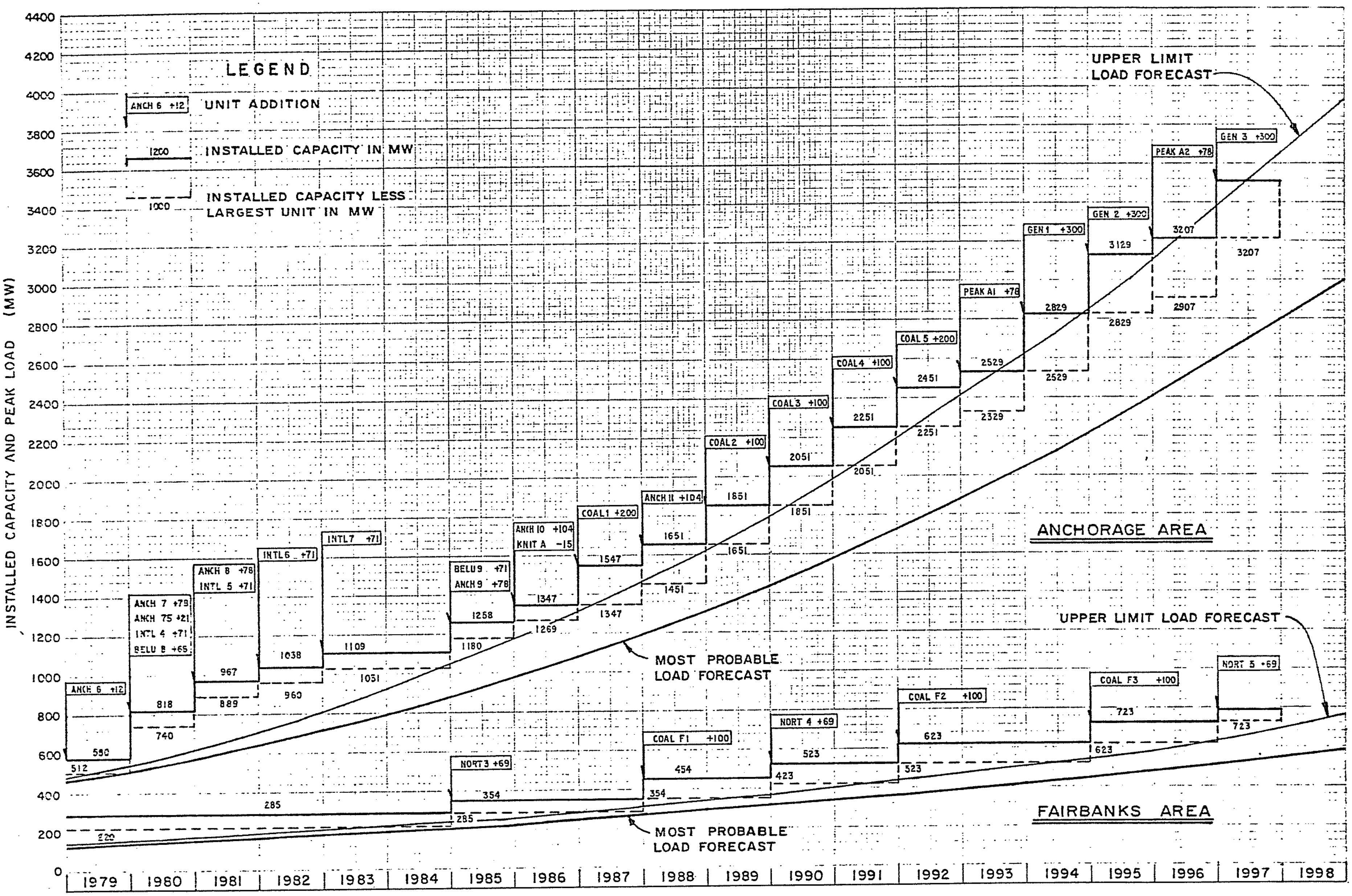
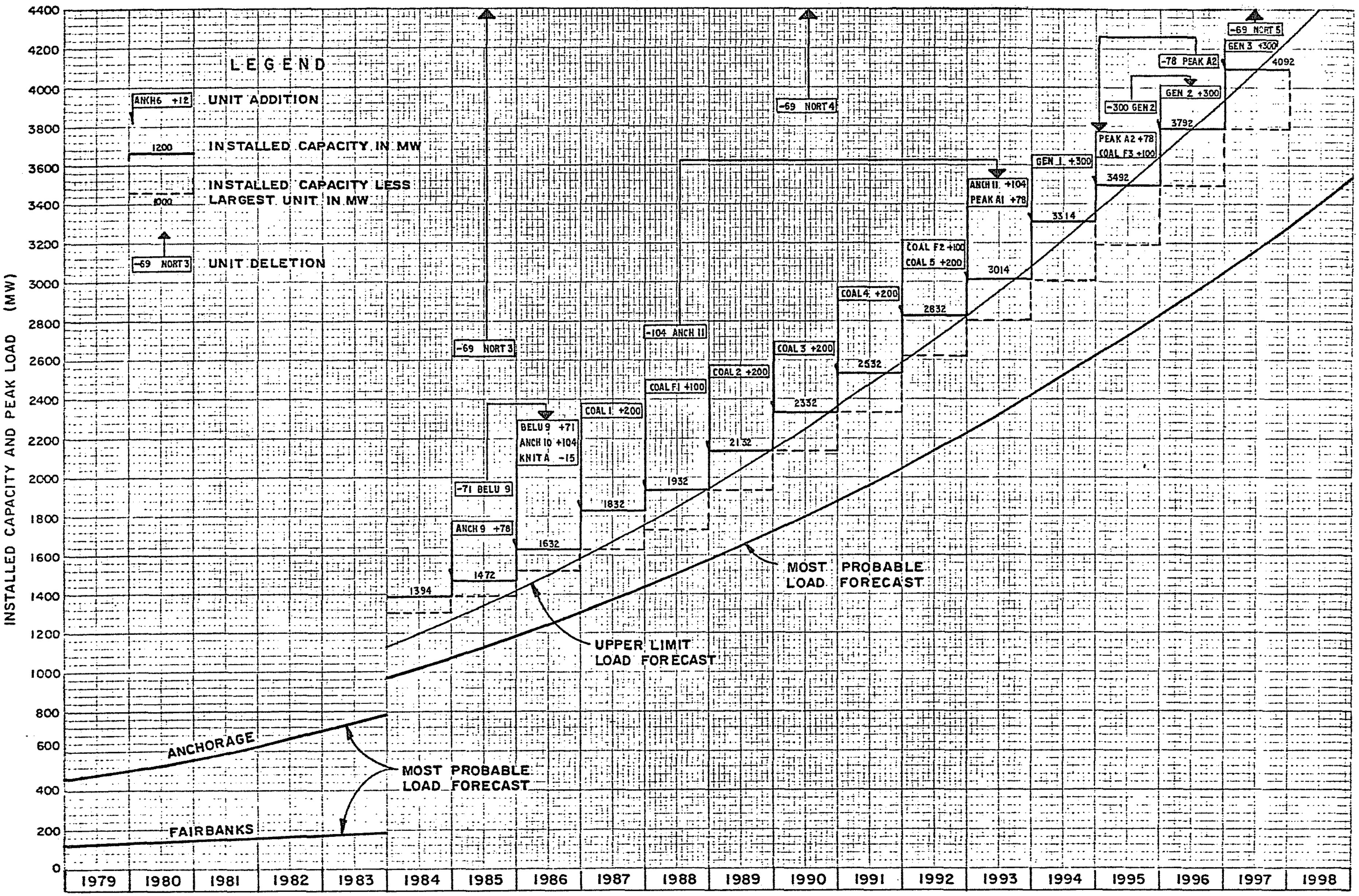


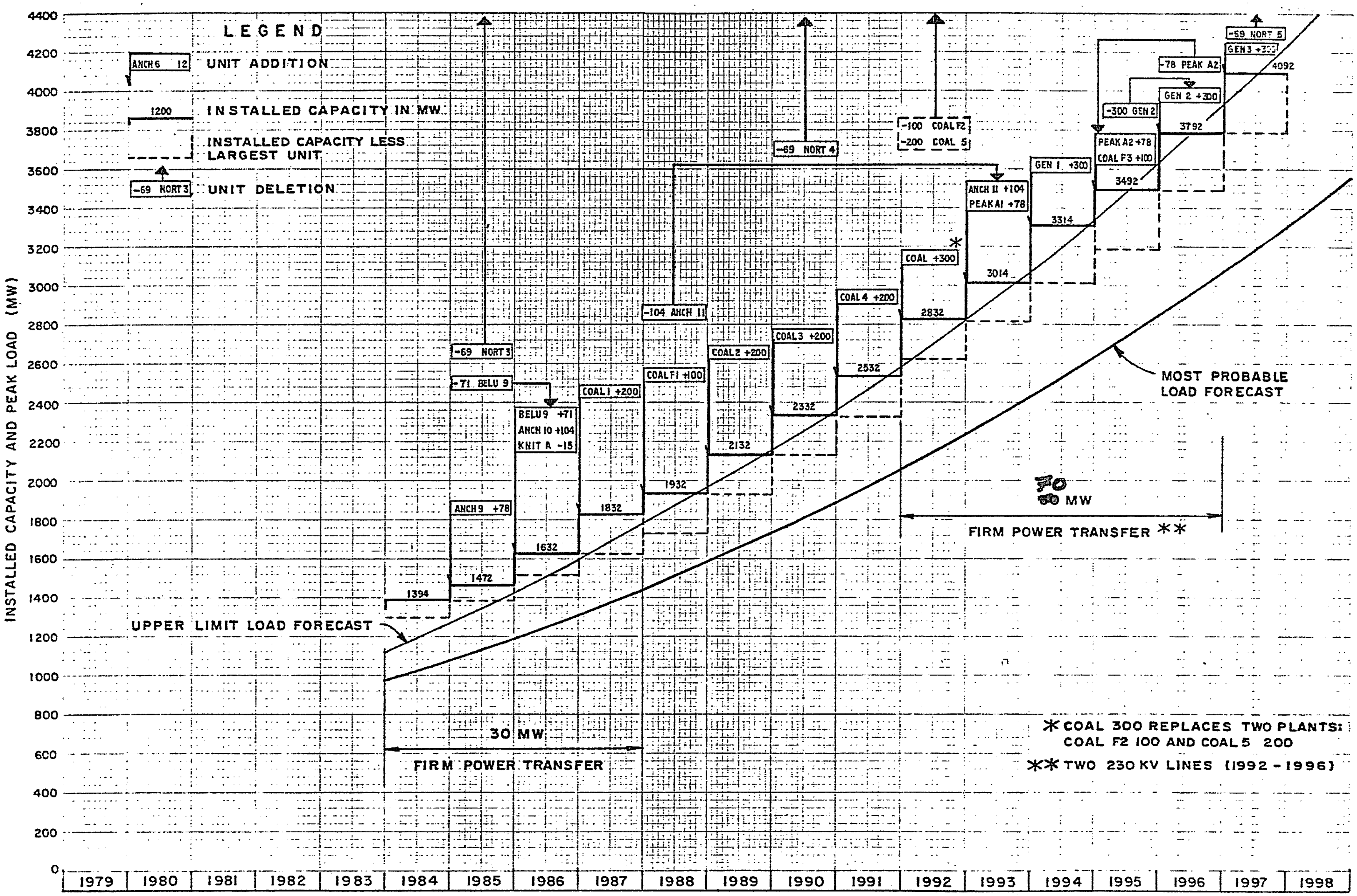
FIGURE 6-2

INDEPENDENT SYSTEM EXPANSION PLANS
ANCHORAGE AND FAIRBANKS AREAS



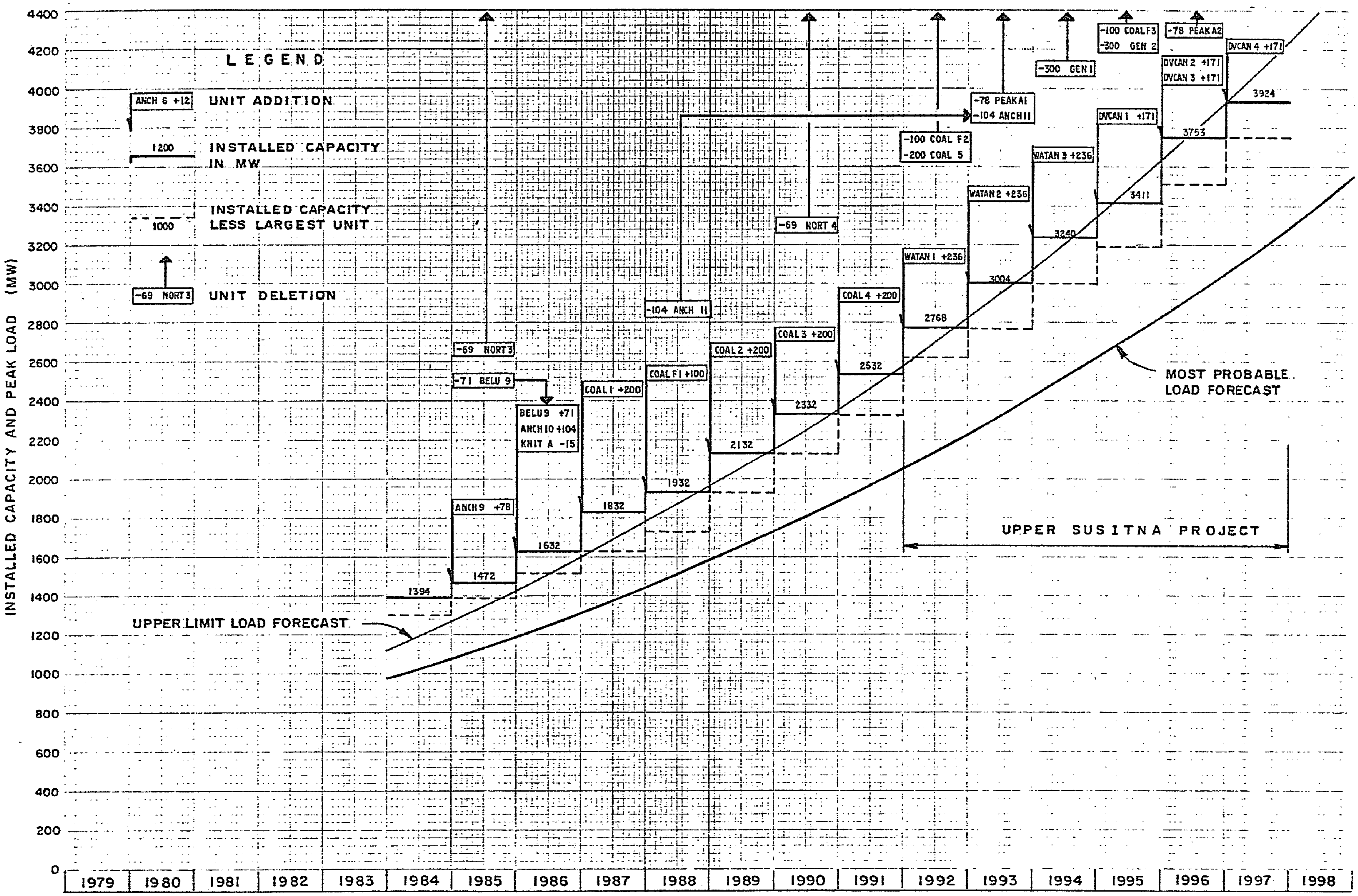
INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
WITHOUT SUSITNA PROJECT

FIGURE 6-3



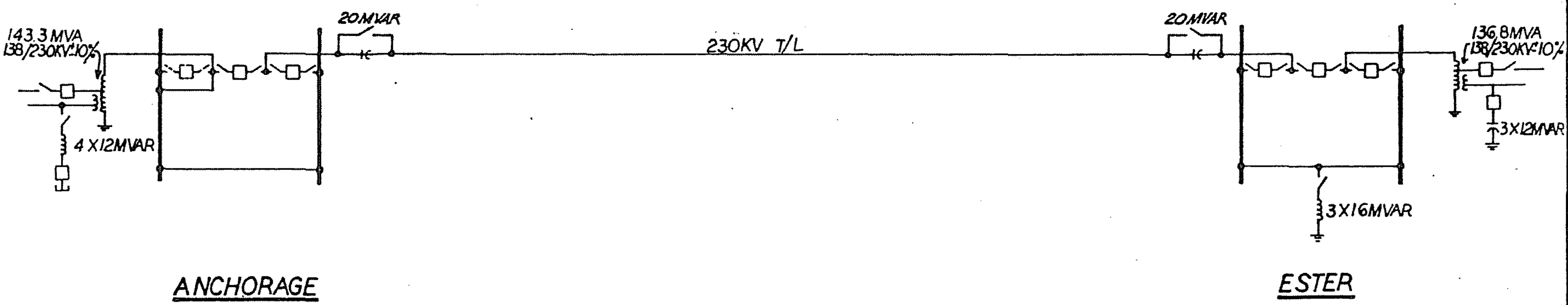
INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
WITH FIRM POWER TRANSFER

FIGURE 6-4



INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
WITH UPPER SUSITNA PROJECT

FIGURE 6-5



CASE I
Alternatives A & B

FIGURE 6-6

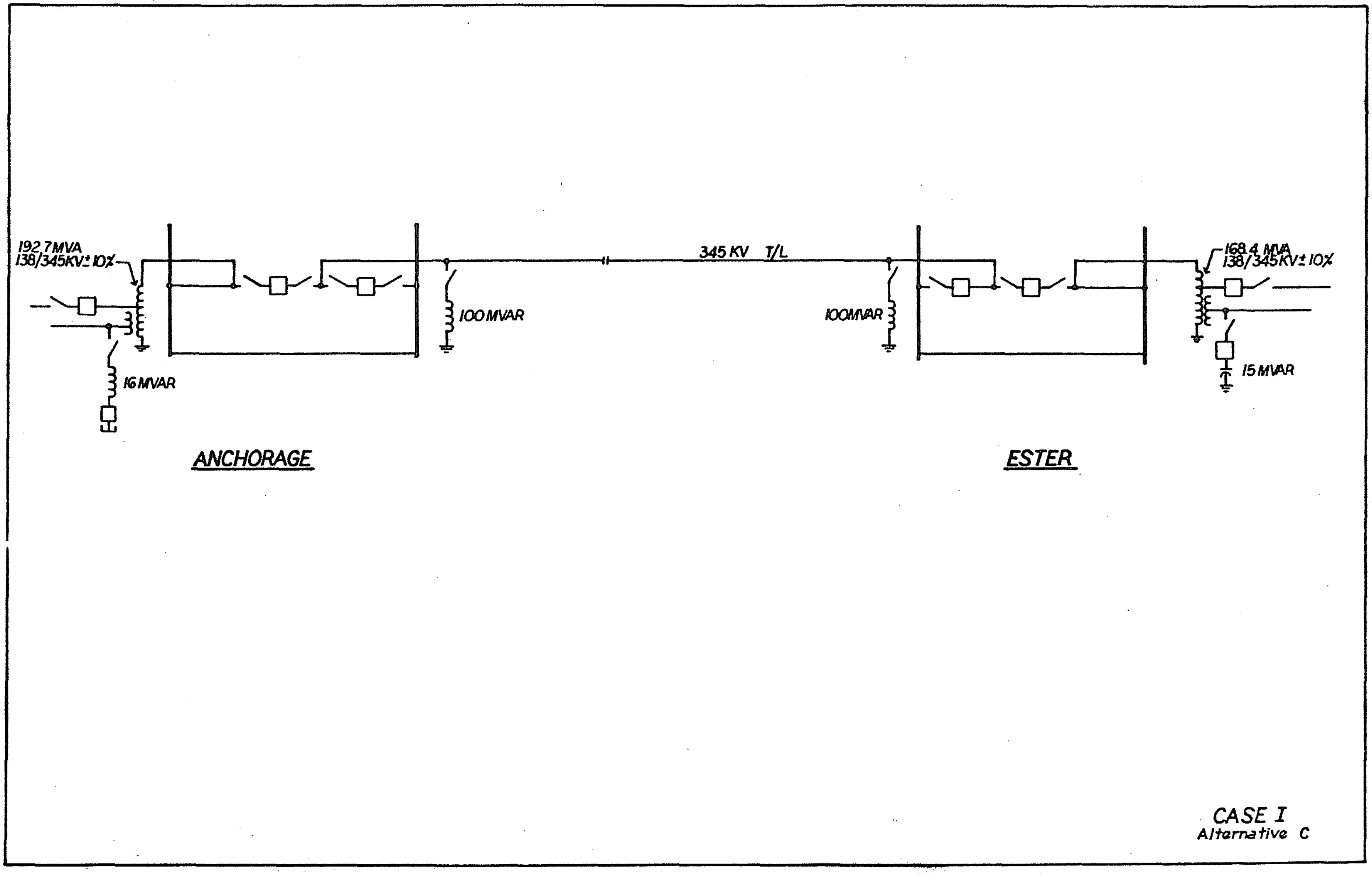
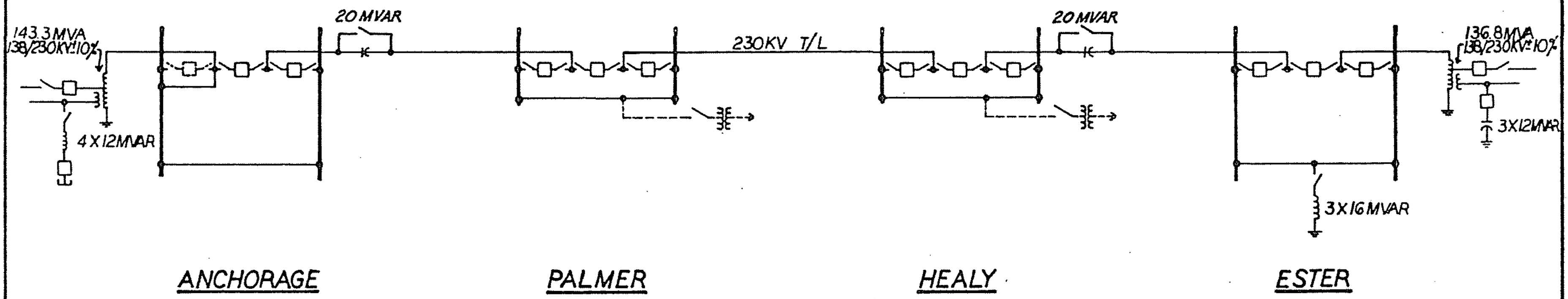

192.7 MVA
138/345KV ± 10%
16 MVAR
100 MVAR
345 KV T/L
100MVAR
168.4 MVA
138/345KV ± 10%
15 MVAR
ANCHORAGE
ESTER
CASE I
Alternative C

FIGURE 6-7



CASE I
Alternative D

FIGURE 6-8

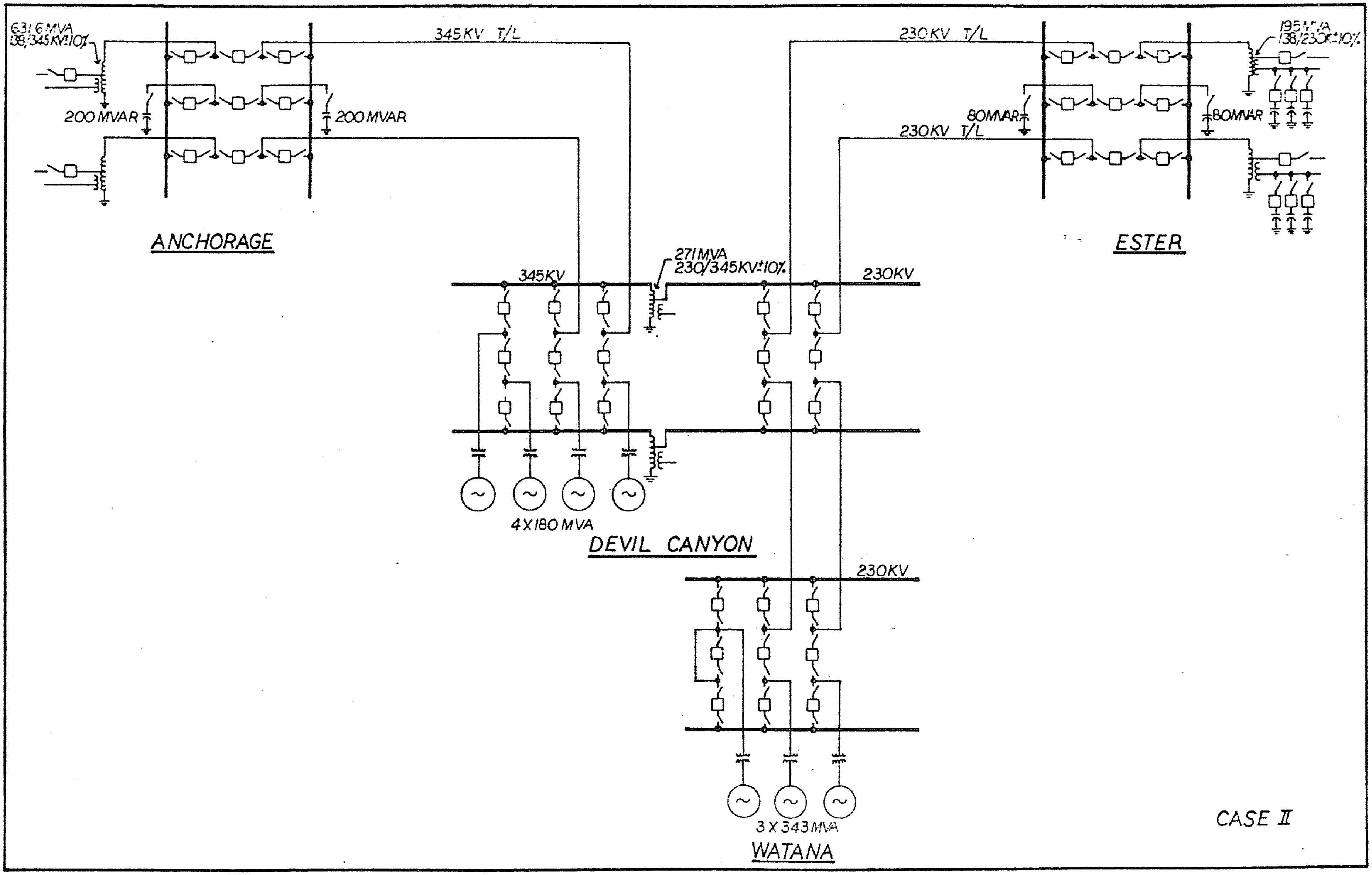

345KV T/L
230KV T/L
200 MVAR
200 MVAR
80MVAR
80MVAR
230KV T/L
ANCHORAGE
ESTER
271MVA
230/345KV±10%
345KV
230KV
4 X 180 MVA
DEVIL CANYON
230KV
3 X 343 MVA
WATANA
CASE II

FIGURE 6-9

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 clearance costs and other costs associated with the solicitation and obtention 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 clearance.

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. A 10 percent addition to the material cost was included to account for the 1.46 AVF explained above.

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 2 was applied to the estimated cost of labor for this period, in order 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 adjustement 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

	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	4,043	3,012	8,079
Right-of-Way	8,837	8,837	9,080	8,837	20,973
Foundations	8,445	8,445	12,160	8,445	22,966
Towers	21,615	21,615	33,719	21,615	64,088
Hardware	477	477	477	477	1,096
Insulators	503	503	755	503	1,396
Conductor	10,761	10,761	16,708	10,761	32,886
Subtotal	53,650	53,650	76,942	53,650	151,484
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	91,868	68,874	201,484

TABLE 7-2

PRESENT WORTH OF INTERTIE LINE LOSSES
1984-1996 STUDY PERIOD[1/]

Case	$ x 1000 (1979)	
IA & ID (230 kV)	10,530	
IB (230 kV)	11,582	
IC (345 kV)	7,341	
II A (230 & 345 kV)		
Anchorage - Devil Canyon	28,027	
Devil Canyon - Ester	14,816	$49,125
Watana - Devil Canyon	6,282	

[1/] Cost of losses, energy, and demand, escalated at 7% per year.

TABLE 7-3

COST SUMMARY FOR GENERATING FACILITIES
(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. 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.

TABLE 7-4

SUMMARY
OF
ALTERNATIVE GENERATING PLANT FUEL COSTS

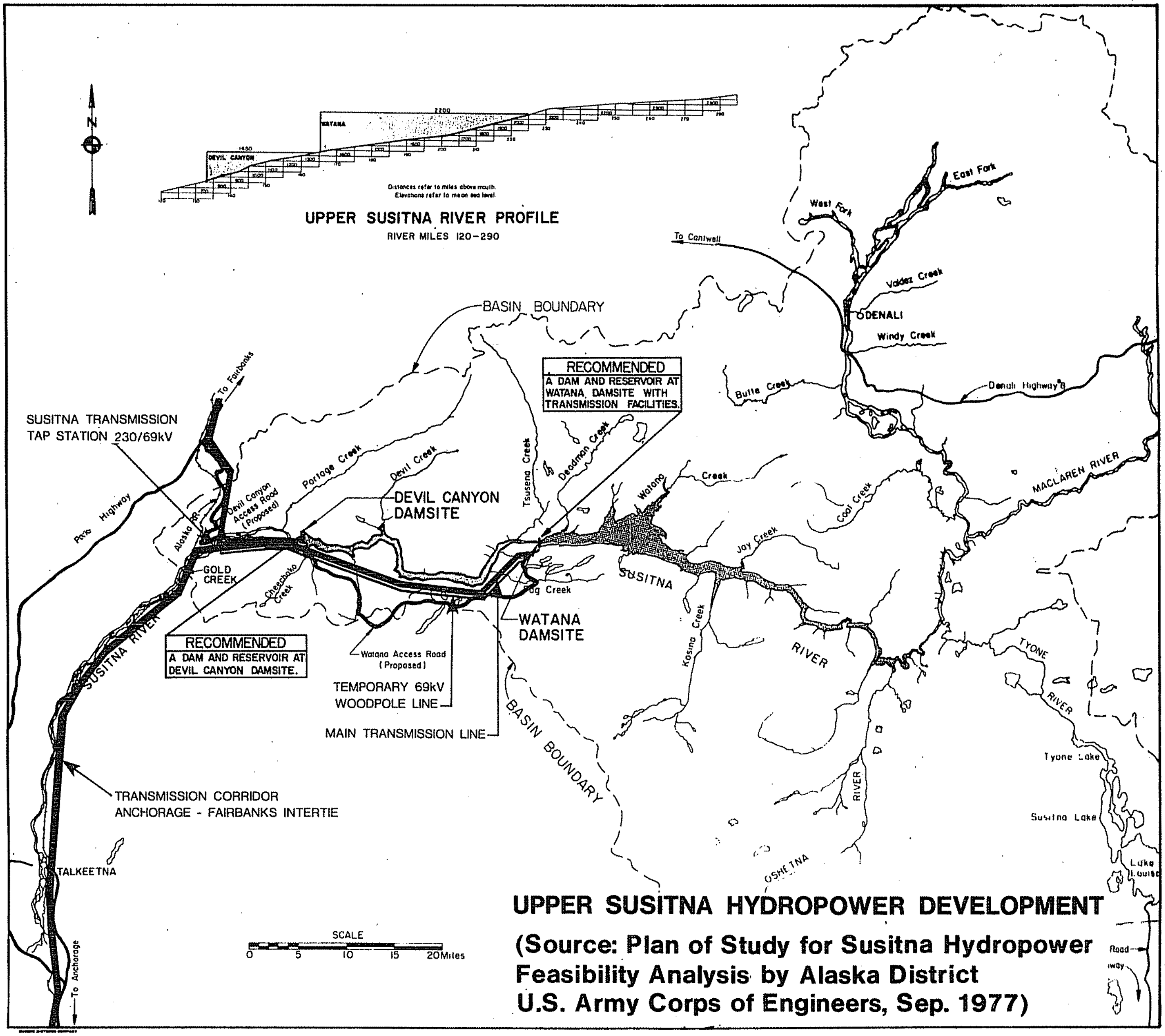
Year	$ 1000 (Escalated) Independent System Operation	Interconnected System Operation	
1984	-	-	
1985	8,468	7,648	30 MW 145 GWh Firm Power Transfer
1986	9,324	8,498	
1987	10,267	9,029	
1992	6,851	8,324	70 MW 337 GWh Firm Power Transfer
1993	7,212	8,654	
1994	7,933	8,016	
1995	8,654	8,745	
1996	9,015	9,109	

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.



UPPER SUSITNA HYDROPOWER DEVELOPMENT
(Source: Plan of Study for Susitna Hydropower Feasibility Analysis by Alaska District U.S. Army Corps of Engineers, Sep. 1977)

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

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. This approach does not include additional capital disbursements after 1996. 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 1996 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 6-5 in Chapter 6 show that many facility costs 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 eliminated. 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 recommended that a multi-area production cost study be performed at a later time.

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 Economics Analysis Program (TLEAP), provides the following outputs:

- Cost disbursement tables for alternative system expansion plans.
- Discounted cost ratio (independent/interconnected) tables for system expansion alternatives.
- Tables indicating independent minus interconnected system costs.
- Separate tables indicating the discounted value of base year (1979) costs for the independent and interconnected systems.

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 4% to 12%, and a range of discount rates from 8% to 12%. In the analysis of the results below, a long-term average annual escalation rate of 7% and a 10% discount rate are used. The 10% discount rate is now required by the Office of Management and Budget for federal projects.

A. Benefits due to Generation Reserve Capacity Sharing

Two cases were investigated to determine intertie benefits due to generation reserve capacity sharing alone: the 230-kV single circuit intertie and 345-kV single circuit intertie between Anchorage and Fairbanks. In both cases 130 MW of power transfer capacity was allocated for generation reserve capacity sharing purposes (Cases IA and IC in Chapter 6). The economic analysis results indicate:

230 kV	PW (1979 Costs x 1000)
Independent Systems	$406,853
Interconnected System	388,355
Benefit	18,498
Less cost of line losses	10,530
Net Benefit	$ 7,968

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

345 kV	PW (1979 Costs x $1000)
Independent Systems	$406,853
Interconnected System	412,338
Benefit	-5,485
Less cost of line losses	-7,341
Net Benefit	$-12,826

The above results indicate that the 345-kV intertie is not economically feasible based on 130 MW power transfer capacity. To analyze the 345-kV intertie with different (higher) power transfer capacities allocated to generation reserve capacity sharing would require development of additional expansion plans and new MAREL studies.

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-1 and 8-2. Computer printouts, indicating cost disbursements, discounted cost ratios, and discounted value tables, are included in Appendix E (Economic Analyses Nos. 1 and 7).

B. Benefits due to Firm Power Transfer and Generation Reserve Capacity Sharing

One case was investigated to determine combined 230-kV intertie benefits due to both firm power transfer and generation reserve capacity sharing (Case IB in Chapter 6). This study case has one 230-kV single circuit line during the 1984-1991 period and two single circuit 230-kV lines during the 1992-1996 period. The economic analysis results indicate:

	PW (1979 Costs x $1000)
Independent Systems	$707,534
Interconnected System	681,364
Benefit	26,171
Less cost of line losses	11,582
Net Benefit	$ 14,589

The above intertie benefits can be combined with additional benefits due to supply of construction power to the Upper Susitna Hydropower Project sites (see Section 7.9).

	PW (1979 Costs x $1000)
Independent Systems	$715,566
Interconnected System	685,295
Benefit	30,271
Less cost of line losses[1/]	12,740
Net Benefit	$ 17,531

The increase in net benefits due to supply of construction power to the Upper Susitna Hydropower Project sites is $2,942,000 or approximately 20 percent.

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-3 and 8-4. Computer printouts, indicating cost disbursements, discounted cost ratios and discounted value tables, are included in Appendix E (Economic Analyses Nos. 2 and 8).

C. 230-kV Intertie with Intermediate Substations

Two 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 (Case ID, Chapter 6). 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:

[1/] Losses were increased by 10% to account for construction power.

D. 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 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. 1) 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 installaed 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 Uppwer 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
1994-1996	Two 345-kV S/C lines to Anchorage Two 230-kV S/C lines to Fairbanks

8.4 REFERENCES

1. Alaska Power Administration, Upper Susitna Project Power Market Report (Draft), February 1979.

5 APRIL 79

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

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

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	19,512	18,560	17,215	15,417	13,098	10,183	6,590	2,226	-3,011
8.25	19,688	18,825	17,584	15,907	13,729	10,977	7,572	3,423	-1,567
8.50	19,845	19,066	17,925	16,365	14,322	11,727	8,502	4,560	-193
8.75	19,983	19,286	18,240	16,791	14,878	12,433	9,381	5,639	1,114
9.00	20,104	19,483	18,529	17,187	15,398	13,098	10,213	6,662	2,357
9.25	20,207	19,661	18,794	17,554	15,885	13,724	10,998	7,632	3,537
9.50	20,295	19,819	19,036	17,894	16,340	14,311	11,740	8,550	4,659
9.75	20,367	19,959	19,256	18,208	16,764	14,863	12,439	9,420	5,723
10.00	20,425	20,082	19,455	18,498	17,158	15,380	13,098	10,242	6,733
10.25	20,469	20,188	19,634	18,763	17,525	15,864	13,718	11,019	7,691
10.50	20,500	20,278	19,794	19,005	17,864	16,316	14,301	11,753	8,598
10.75	20,519	20,352	19,936	19,226	18,178	16,738	14,848	12,445	9,457
11.00	20,525	20,413	20,060	19,426	18,467	17,130	15,362	13,098	10,270
11.25	20,521	20,460	20,168	19,607	18,732	17,495	15,842	13,713	11,039
11.50	20,506	20,494	20,260	19,768	18,975	17,834	16,292	14,291	11,766
11.75	20,481	20,515	20,337	19,912	19,197	18,147	16,712	14,834	12,451
12.00	20,446	20,525	20,400	20,038	19,398	18,436	17,103	15,344	13,098

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

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

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	-3,562	-5,375	-7,604	-10,311	-13,564	-17,438	-22,016	-27,391	-33,665
8.25	-3,183	-4,899	-7,016	-9,594	-12,698	-16,400	-20,781	-25,932	-31,950
8.50	-2,825	-4,449	-6,459	-8,912	-11,872	-15,409	-19,602	-24,536	-30,308
8.75	-2,488	-4,024	-5,931	-8,265	-11,086	-14,465	-18,475	-23,201	-28,736
9.00	-2,171	-3,622	-5,430	-7,649	-10,338	-13,564	-17,399	-21,925	-27,232
9.25	-1,873	-3,243	-4,956	-7,065	-9,627	-12,705	-16,372	-20,705	-25,792
9.50	-1,594	-2,885	-4,507	-6,510	-8,949	-11,887	-15,392	-19,539	-24,414
9.75	-1,331	-2,548	-4,082	-5,984	-8,306	-11,108	-14,456	-18,426	-23,097
10.00	-1,086	-2,230	-3,681	-5,485	-7,694	-10,365	-13,564	-17,361	-21,836
10.25	-856	-1,932	-3,302	-5,012	-7,112	-9,658	-12,713	-16,345	-20,631
10.50	-641	-1,651	-2,944	-4,564	-6,560	-8,986	-11,902	-15,375	-19,479
10.75	-441	-1,387	-2,607	-4,141	-6,036	-8,346	-11,128	-14,448	-18,377
11.00	-254	-1,140	-2,289	-3,740	-5,539	-7,737	-10,392	-13,564	-17,324
11.25	-80	-909	-1,989	-3,361	-5,068	-7,159	-9,690	-12,720	-16,318
11.50	80	-693	-1,708	-3,003	-4,621	-6,610	-9,022	-11,916	-15,358
11.75	229	-491	-1,443	-2,665	-4,198	-6,088	-8,386	-11,149	-14,440
12.00	367	-302	-1,195	-2,347	-3,798	-5,592	-7,781	-10,417	-13,564

TABLE 8-2

5 APRIL 79

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

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

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	27,096	26,190	24,824	22,926	20,414	17,198	13,177	8,242	2,268
8.25	27,259	26,456	25,212	23,456	21,110	18,086	14,288	9,608	3,927
8.50	27,400	26,695	25,567	23,948	21,760	18,921	15,337	10,902	5,503
8.75	27,519	26,908	25,891	24,402	22,367	19,705	16,325	12,127	6,998
9.00	27,617	27,096	26,185	24,820	22,932	20,440	17,257	13,285	8,417
9.25	27,695	27,259	26,450	25,205	23,456	21,127	18,133	14,379	9,761
9.50	27,754	27,400	26,687	25,557	23,943	21,770	18,957	15,412	11,035
9.75	27,795	27,519	26,899	25,879	24,393	22,370	19,731	16,387	12,241
10.00	27,820	27,618	27,086	26,171	24,808	22,929	20,457	17,306	13,382
10.25	27,828	27,697	27,250	26,434	25,189	23,448	21,136	18,171	14,460
10.50	27,821	27,757	27,391	26,671	25,539	23,930	21,772	18,984	15,479
10.75	27,799	27,800	27,511	26,883	25,859	24,376	22,366	19,749	16,440
11.00	27,764	27,826	27,611	27,070	26,149	24,788	22,919	20,466	17,347
11.25	27,715	27,836	27,691	27,234	26,412	25,167	23,434	21,138	18,201
11.50	27,655	27,831	27,753	27,376	26,649	25,515	23,911	21,767	19,005
11.75	27,583	27,811	27,797	27,497	26,860	25,833	24,354	22,355	19,760
12.00	27,499	27,778	27,825	27,598	27,048	26,123	24,763	22,903	20,470

TABLE 8-3

5 APRIL 79

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

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

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	30,913	30,276	29,194	27,595	25,399	22,515	18,844	14,275	8,685
8.25	31,014	30,476	29,511	28,050	26,015	23,319	19,865	15,546	10,243
8.50	31,094	30,649	29,796	28,467	26,586	24,070	20,824	16,746	11,720
8.75	31,153	30,798	30,051	28,848	27,115	24,771	21,725	17,878	13,117
9.00	31,192	30,922	30,278	29,195	27,604	25,425	22,571	18,945	14,440
9.25	31,212	31,024	30,477	29,509	28,053	26,033	23,363	19,950	15,689
9.50	31,214	31,104	30,650	29,793	28,466	26,597	24,104	20,895	16,870
9.75	31,199	31,164	30,798	30,046	28,844	27,120	24,796	21,783	17,985
10.00	31,169	31,204	30,923	30,271	29,188	27,604	25,442	22,617	19,035
10.25	31,123	31,225	31,025	30,470	29,500	28,049	26,042	23,398	20,025
10.50	31,063	31,229	31,106	30,642	29,781	28,458	26,601	24,130	20,957
10.75	30,990	31,216	31,166	30,791	30,033	28,832	27,118	24,813	21,833
11.00	30,903	31,188	31,208	30,916	30,258	29,174	27,596	25,451	22,655
11.25	30,805	31,144	31,231	31,019	30,455	29,483	28,037	26,045	23,427
11.50	30,695	31,086	31,236	31,100	30,628	29,763	28,443	26,597	24,149
11.75	30,575	31,015	31,226	31,162	30,777	30,014	28,814	27,110	24,824
12.00	30,444	30,932	31,199	31,205	30,902	30,238	29,154	27,583	25,455

TABLE 8-4

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

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

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	21,225	20,637	19,694	18,339	16,509	14,133	11,132	7,418	2,896
8.25	21,319	20,810	19,960	18,715	17,014	14,787	11,958	8,443	4,149
8.50	21,397	20,962	20,202	19,062	17,483	15,399	12,736	9,412	5,337
8.75	21,458	21,095	20,420	19,381	17,920	15,973	13,469	10,328	6,464
9.00	21,503	21,209	20,616	19,673	18,324	16,509	14,157	11,193	7,531
9.25	21,534	21,305	20,790	19,939	18,699	17,009	14,804	12,008	8,541
9.50	21,551	21,385	20,943	20,180	19,044	17,475	15,410	12,777	9,496
9.75	21,554	21,448	21,078	20,399	19,361	17,908	15,978	13,501	10,400
10.00	21,545	21,496	21,193	20,595	19,652	18,310	16,509	14,181	11,253
10.25	21,525	21,529	21,291	20,770	19,918	18,682	17,005	14,821	12,058
10.50	21,493	21,548	21,372	20,924	20,159	19,025	17,467	15,421	12,817
10.75	21,450	21,555	21,438	21,060	20,378	19,342	17,897	15,983	13,532
11.00	21,398	21,549	21,488	21,177	20,574	19,632	18,296	16,509	14,205
11.25	21,336	21,531	21,523	21,277	20,750	19,897	18,666	17,001	14,837
11.50	21,265	21,502	21,545	21,360	20,905	20,138	19,007	17,459	15,431
11.75	21,185	21,462	21,554	21,427	21,042	20,357	19,322	17,886	15,988
12.00	21,098	21,413	21,551	21,479	21,161	20,554	19,611	18,282	16,509

TABLE 8-5

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

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

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	25,042	24,722	24,063	23,008	21,494	19,450	16,798	13,451	9,313
8.25	25,074	24,829	24,259	23,309	21,918	20,019	17,534	14,381	10,465
8.50	25,090	24,916	24,431	23,582	22,309	20,548	18,224	15,256	11,554
8.75	25,091	24,985	24,581	23,828	22,668	21,039	18,869	16,079	12,583
9.00	25,078	25,036	24,709	24,048	22,996	21,494	19,472	16,853	13,554
9.25	25,051	25,070	24,817	24,243	23,296	21,915	20,034	17,579	14,469
9.50	25,011	25,089	24,906	24,416	23,567	22,302	20,557	18,260	15,332
9.75	24,958	25,092	24,976	24,566	23,812	22,659	21,043	18,697	16,143
10.00	24,895	25,081	25,029	24,696	24,032	22,985	21,494	19,493	16,906
10.25	24,820	25,057	25,066	24,805	24,228	23,283	21,911	20,048	17,623
10.50	24,735	25,020	25,087	24,895	24,401	23,553	22,296	20,566	18,295
10.75	24,641	24,971	25,093	24,968	24,552	23,797	22,649	21,047	18,924
11.00	24,537	24,910	25,084	25,023	24,682	24,017	22,974	21,494	19,513
11.25	24,425	24,839	25,063	25,061	24,793	24,213	23,270	21,907	20,063
11.50	24,305	24,757	25,029	25,084	24,885	24,386	23,539	22,289	20,575
11.75	24,177	24,666	24,982	25,093	24,959	24,538	23,783	22,640	21,052
12.00	24,042	24,566	24,925	25,087	25,015	24,669	24,002	22,962	21,494

TABLE 8-6

CHAPTER 9

FINANCIAL PLANNING CONCEPTS

The approach taken in this study towards the financial planning for the intertie facilities represents the preliminary conceptual structuring of the ultimate financial package needed to implement the Railbelt transmission system expansion on a progressive basis. This approach seeks to be demonstrative of the methodology employed, rather than an attempt to arrive at specific recommendations. The acceptance of debt allocations by participants to the Alaskan Intertie Agreement (AIA) will require individual financial positions to be evaluated, prior to negotiations on specific portions of the total debt for which a particular participant will ultimately agree to sign. Therefore, what follows is an initial exploration of possible financial arrangements, and will serve as a starting point for successive evaluations by each potential participant to the AIA.

9.1 SOURCES OF FUNDS

An initial appraisal of viable sources of funds has been made to determine the combination which will represent the most financially advantageous terms and also will reflect the projected allocation of financial responsibility that may be acceptable to each of the participants.

The following principal sources were examined:

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

The conditions under which each of the above sources would be negotiable are dependent upon the ability to generate revenue to make repayment.

A. State of Alaska Revenue Bonds

Of these sources, the issue of State of Alaska bonds would require the most complex formula for revenue generation, to arrive at an acceptable agreement to ensure complete payback through time on a steady cash flow basis. 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. Accordingly, although programmatic inclusion of APA bonds is retained in the Transmission Line Financial Analysis Program (TLFAP), for present analytical purposes, consideration has been given only to the remaining sources for analysis of initial financial plans for 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. Only the financial sources discussed in the following sections were then considered for initial funding of the Anchorage-Fairbanks Interconnection.

B. Rural Electrification Administration (REA)

The principal participants, with the exception of the Anchorage and Fairbanks municipal systems, are all REA utilities of the Alaska District. Therefore, REA funding is assumed for the maximum amount of total project financial requirements. In accordance with REA stipulations, the loan ceiling is normally 70 percent of total project costs. Thus, a maximum of the full amount under the 70 percent ceiling was considered for the prime source of funds, at an interest rate of 5 percent over a repayment period of 35 years.

Although not considered at this first level of financial planning, REA also makes guaranteed loans, which normally are made for prevailing interest rates of the order of 8-1/2 percent.

OMB restrictions are expected to reflect through future REA commitments for project funding. Therefore, with the large capital outlay necessary for the intertie, it may be necessary to consider alternative sources of supplementary capital to structure a complementary loan package for the project. The Consultants have accordingly considered the CFC and FFB as part of financial contingency plans.

C. National Rural Utilities Cooperative Finance Corporation (CFC)

The CFC makes loans to REA utilities to supplement REA funds, with loans that are currently carrying an interest rate of 8.75 percent, with a repayment period of 35 years. To structure a loan package for the balance of project costs, CFC funds would be drawn on to the extent justifiable under the primary criteria of providing the most advantageous overall financial terms.

D. Federal Finance Bank (FFB)

The FFB also provides supplementary funding, complementary to CFC as a financial source, with loans that bear interest at a higher rate than that to be obtained from CFC. Currently, the interest rate for FFB loans is 9.375 percent for project funding, with a repayment period of 35 years.

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. For purposes of analysis, the interest rate was assumed to be 7.5 percent under prevailing market conditions, with a maturity period of 35 years. These terms are to be construed as conservative under present market conditions. In practice some measure of improvement can be anticipated depending upon prevailing economic and financial considerations at the time of entry to the bond market. For purposes of illustration, a final interest rate of 7.25 percent was assumed to simulate the progressive improvement of terms anticipated for this project.

Thirty percent of the total project costs are assumed to be funded by municipal bonds, which is deemed reasonably reflective of the participation of the municipal systems in the Alaskan Intertie Agreement. It also is the complementary portion of total project costs that would meet the ceiling of the maximum REA loan available to member utilities.

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 proportional allocation of total project costs between possible sources will require protracted effort on the part of APA and AIA participants, in the successive negotiations with REA and other federal funding agencies, 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 resolution of questions pertaining to proportional allocations between sources, the Consultants offer the following approach for initial consideration:

- REA funds would be used to the limit of the normal 70 percent ceiling, as a proportion of project costs. If due to budgetary restraints REA is not amenable to funding the full proportion, supplementary loans would be sought from a combination of CFC and FFB.

- The balance of funding, 30 percent of projects costs, would be obtained through a joint issue of general obligation bonds, by the municipalities of Anchorage and Fairbanks.

In preparing a financial plan to follow this approach the following analysis was completed using computer programs TLFAP and COMPARE.

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

   - 70% funding by REA loan, at 5% interest rate.
   - 30% funding by general obligation municipal bonds, with equal division of obligation between Anchorage and Fairbanks. A conservative rate of 7.5% was assumed for this issue.
   - 35-year repayment period for both sources.

2. On the assumption that REA funds would have to be supplemented by loans arranged jointly with CFC and FFB, an analysis was made of a 20% portion of the total REA allocation, to illustrate the capability of minimizing total financial obligations through judicious combinations within the package. This was accomplished using program COMPARE, which derives the present value of future payments for up to three loan sources under varying loan terms. To simplify the procedure, a similar repayment period of 35 years was assumed with base case and sensitivity runs, as follows:

   - Equal division 10/10% between CFC and FFB, with interest rates of 8.75% and 9.375%, respectively.
   - Sensitivity runs of ±5% for both CFC and FFB, in converse proportion, at the same interest rates.

3. The best of the three test-cases, selected on the basis of least present value to borrower, was then substituted in TLFAP, with the following modifications to previous input of 1. above.

   - 50% allocation to REA funding @ 5% interest rate.
   - 20% source allocation; divided between CFC and FFB according to the results of the COMPARE analysis:

     - 15% of total by CFC loan at 8.75% interest rate
     - 5% of total by FFB loan at 9.375% interest rate

   This combination results in the lowest present value of the three alternative divisions, presented on Sheets F-7, F-8 and F-9 of Appendix F.

- 30 % source allocation to municipal bonds at an improved interest rate of 7.25%, to indicate possible positive offset to the higher composite rate resulting from the combination of loans from CFC and FFB.

The results of this analysis are contained in Appendix F.

9.3 ALLOCATED FINANCIAL RESPONSIBILITY FOR PARTICIPANTS

A. Basis for Assumption of Financial Obligation

Once the source allocations are determined, the next step involving discussions, evaluations, and negotiations between the participants is the determination of the allocated responsibility for debt assumption and subsequent service over the repayment period. The approach followed was to match percentage of total funds to the AIA participants on the basis of service jurisdictions, potential benefits from facilities, and a certain judgement in relation to the acceptability, or otherwise, of certain allocations to individual participants. A degree of tokenism was also judged to be appropriate at this initial stage, to allow for minimum funding participation by utilities without major generating plants.

This enables all utilities, that are directly affected by the interconnection to take a major or minor share of the responsibility for debt service of the total facility costs in support of the project.

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 intertie, at or before completion of the first stage development of the Upper Susitna Project.

B. Allocation of Total Project Costs

Table 9-1 provides a division of total project costs on a percentage basis and a subsequent allocation between participants. This preliminary set of debt service allocations was used for the financial planning projections contained in Appendix F. These may be used by individual participants as a starting point for their own analysis and evaluation of the impact of their assumed obligation on their own financial operations.

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

Section	From	To	Distance (Miles)
I	Anchorage	Palmer	40
II	Palmer	Healy	191
III	Healy	Ester	92

The costs included in Table 9-1 pertain to Case ID transmission facilities, 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 9-1. Although the benefits of the interconnection are more indirect for HEA, a small percentage participation in the intertie project is included for this utility.

C. Effect of Sinking Fund on Total Revenue Requirements

In evaluating the revenue requirements for each participant to the AIA, the cumulative effect of the municipal bond sinking fund on the allocated debt repayment should be noted. The total revenue required from each participant is indicated on pages F-8, F-9, and F-10 and F-19, F-20, and F-21 of Appendix F, and includes both debt service and sinking fund payments over the 35-year period, to full loan amortization and bond maturity.

9.4 FINANCIAL PLAN FOR STAGED DEVELOPMENT

The following is intended as one possible view of future plans for financing successive expansions and extensions of the initial 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 token allocation, 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 the transmission system associated with the development of Susitna hydropower.

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 firm power possible from the Susitna development would require the expansion of the initial intertie, to receive the energy blocks 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 participants, on a similar basis to that used for this initial approach to first stage financing of the transmission system interconnection via the Railbelt.

9.5 REFERENCES

1. International Engineering Company, Inc.
   Financial Planning Model

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

TABLE 9 - 1

ALLOCATION OF TOTAL PROJECT COSTS BETWEEN PARTICIPANTS
TO
ALASKAN INTERTIE AGREEMENT
A I A

SECTIONAL INTERCONNECTION DIVISIONS

	Anchorage		Palmer		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		(5)		(10)				(15)
CEA		(10)		(20)				(30)
HEA		(1)						(1)
MEA		(3)						(3)
CVEA				(9)		(27)		(36)
FMUS				(10)		(5)		(15)

CHAPTER 10
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 improved 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 impact 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

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.

* 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.

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.

TABLE A-1

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.

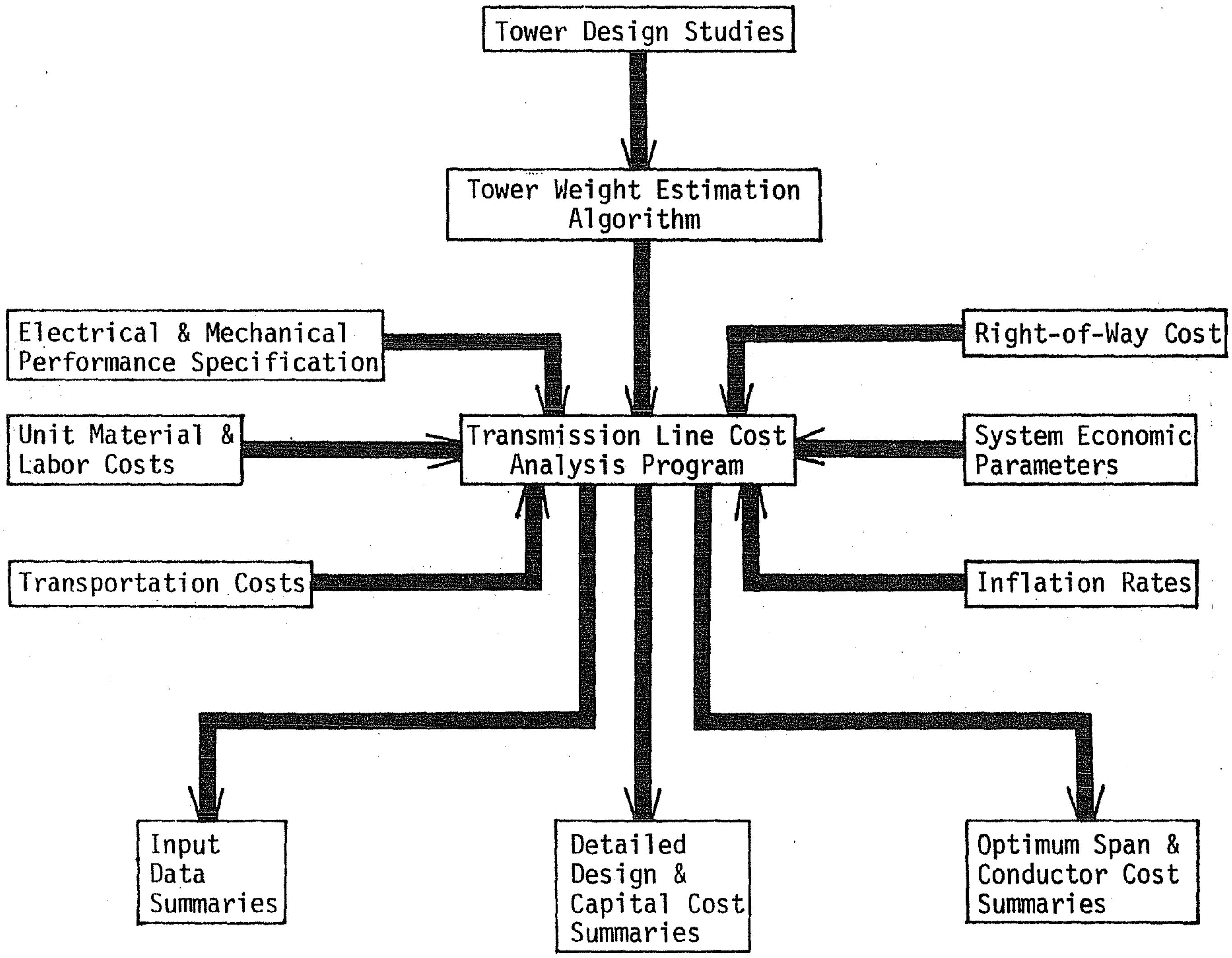
In addition to the variables mentioned above, there are numerous other line parameters that must be considered to properly evaluate and compare the various solutions. A few of the more important ones are:

- 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:

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 TEMPERATURE	0.	DEGREES F
HIGH WIND TEMPERATURE	40.	DEGREES F
EXTREME ICE TEMPERATURE	30.	DEGREES F
MAX DESIGN TEMP FOR GND CLEARANCE	120.	DEGREES F
EDS TENSION (PCT UTS)	20.	PERCENT
NESC CONSTANT	0.31	LBS/FT

ICE AND WIND TENSION (PCT UTS)	50.	PERCENT
HIGH WIND TENSION (PCT UTS)	50.	PERCENT
EXTREME ICE TENSION (PCT UTS)	70.	PERCENT
ICE THICKNESS WITH WIND	0.50	INCHES
WIND PRESSURE WITH ICE	4.00	LBS/SQ.FT.
HIGH WIND	9.0	LBS/SQ.FT.
EXTREME ICE	0.50	INCHES

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	
PHASE SPACING	20.0	FEET
CONDUCTOR CONFIGURATION FACTOR	1.02	
GROUND CLEARANCE	28.0	FEET
NO. OF INSULATORS PER TOWER	48	
INSULATOR SAFETY FACTOR	2.50	
STRING LENGTH	6.5	FEET
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	

DISTANCE BETWEEN PHASES:

D1	20.00 FT
D2	20.00 FT
D3	40.00 FT
D4	0.00 FT
D5	0.00 FT
D6	0.00 FT

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

****
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
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
DATE: 12 APR 79 TIME: 9:29:47

****
*   *
*   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)
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

REFFRENCE 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
DATE: 12 APR 79   TIME: 9:29:47

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 INTERTIF 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
VERSION 1: 23 FEB 1979,

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

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 IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

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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

B-17

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

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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
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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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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
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

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

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*    AUTOMATIC CONDUCTOR SELECTION    *
*       ALL QUANTITIES PER MILE       *
*                                     *
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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 1: 23 FEB 1979,

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

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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	168.4 MVA	1992
AVERAGE CIRCUIT LOADING	58.9 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 I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

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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	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	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-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

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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	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
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ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

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: 12 APR 79 TIME: 10:10:52

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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: 12 APR 79 TIME: 10:10:52

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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 I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

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
30	715.	1300.	105622.	6261.	113812.	12519.	238214.	22728.	4821.	265762.
35	795.	1300.	108253.	6486.	114488.	12594.	241821.	19629.	4908.	266357.
30	715.	1400.	107324.	6256.	112903.	12419.	238902.	22728.	4854.	266483.
35	795.	1400.	110039.	6487.	113599.	12496.	242620.	19629.	4944.	267192.
30	715.	1200.	105232.	6340.	115902.	12749.	240223.	22728.	4843.	267793.
35	795.	1200.	107799.	6561.	116571.	12823.	243753.	19629.	4929.	268310.
29	715.	1300.	105955.	6203.	115588.	12715.	240461.	23923.	4857.	269240.
30	715.	1500.	110237.	6320.	113036.	12434.	242026.	22728.	4939.	269692.
29	715.	1200.	104868.	6250.	117221.	12894.	241233.	23923.	4852.	270008.
32	795.	1300.	109255.	6399.	116128.	12774.	244556.	20589.	4960.	270105.
35	795.	1500.	113021.	6554.	113739.	12511.	245825.	19629.	5031.	270485.
32	795.	1200.	108121.	6443.	117764.	12954.	245282.	20589.	4955.	270825.
34	795.	1300.	109378.	6341.	116691.	12836.	245246.	21069.	4972.	271286.
29	715.	1400.	108480.	6237.	115211.	12673.	242600.	23923.	4922.	271445.
34	795.	1200.	107991.	6373.	118160.	12998.	245522.	21069.	4956.	271546.
32	795.	1400.	111805.	6435.	115732.	12731.	246703.	20589.	5026.	272318.
37	900.	1300.	112812.	6583.	117342.	12908.	249645.	17916.	5082.	272642.
37	900.	1200.	111385.	6612.	118824.	13071.	249892.	17916.	5065.	272872.
30	715.	1100.	106343.	6506.	119395.	13133.	245378.	22728.	4931.	273036.
35	795.	1100.	108831.	6723.	120046.	13205.	248805.	19629.	5014.	273448.
34	795.	1400.	112220.	6390.	116486.	12813.	247910.	21069.	5049.	274027.
29	715.	1100.	105362.	6388.	120302.	13233.	245285.	23923.	4916.	274124.
39	954.	1300.	114706.	6714.	117754.	12953.	252127.	16883.	5143.	274153.
39	954.	1200.	113228.	6740.	119225.	13115.	252308.	16883.	5125.	274315.
31	795.	1200.	109517.	6440.	119187.	13111.	248254.	21550.	5016.	274820.

ANCHORAGE-FAIRBANKS INTERTIE CASF I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 30
715. KCMIL 1300. FT SPAN 90.1 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY	MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	31680. FT	24661.	17.60	1760.	25306.	51727.
GROUNDWIRE	0. FT	0.	0.00	0.	0.	0.
INSULATORS	310. UNITS	1970.	1.70	366.		2336.
HARDWARE		1429.	0.47	47.		1477.
TOWERS	4.3 UNITS	63399.	33.12	3312.	37681.	104393.
FOUNDATIONS	4.3 UNITS	4791.		775.	32083.	37648.
RIGHT OF WAY	13. ACRES	9371.			18742.	28114.
IDC/ENGINEERING		12519.				12519.
TOTALS		105622.	52.90	6261.	113812.	238214.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	9670.	3735.	13405.
CORONA LOSSES	2088.	7235.	9323.
TOTALS	11758.	10970.	22728.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

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

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

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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	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 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-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

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* INPUT DATA *
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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	

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	

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

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

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*   INPUT DATA   *
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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	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: 12 APR 79 TIME: 10:25:33

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-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

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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-DEVIL CANYON CASE II-1

345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION

DATE: 12 APR 79 TIME: 10:25:33

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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

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ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

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.	114706.	6714.	117754.	12953.	252127.	90411.	5143.	347681.
39	954.	1200.	113228.	6740.	119225.	13115.	252308.	90411.	5125.	347843.
40	1033.	1200.	117782.	6840.	121885.	13407.	259913.	84621.	5295.	349829.
37	900.	1300.	112812.	6583.	117342.	12908.	249645.	95660.	5082.	350386.
39	954.	1400.	117620.	6769.	117532.	12928.	254849.	90411.	5222.	350482.
37	900.	1200.	111385.	6612.	118824.	13071.	249892.	95660.	5065.	350616.
39	954.	1100.	113373.	6859.	122168.	13438.	255838.	90411.	5176.	351425.
40	1033.	1100.	116899.	6910.	124193.	13661.	261664.	84621.	5307.	351591.
40	1033.	1300.	120420.	6869.	121120.	13323.	261732.	84621.	5358.	351711.
37	900.	1400.	115679.	6635.	117111.	12882.	252308.	95660.	5159.	353126.
38	954.	1200.	114994.	6662.	121202.	13332.	256189.	91853.	5204.	353246.
35	795.	1300.	108253.	6486.	114488.	12594.	241821.	107119.	4908.	353847.
37	900.	1100.	111580.	6734.	121780.	13396.	253490.	95660.	5118.	354268.
35	795.	1400.	110039.	6487.	113599.	12496.	242620.	107119.	4944.	354683.
38	954.	1300.	117510.	6684.	120390.	13243.	257827.	91853.	5262.	354942.
38	954.	1100.	114231.	6738.	123557.	13591.	258117.	91853.	5220.	355190.
35	795.	1200.	107799.	6561.	116571.	12823.	243753.	107119.	4929.	355800.
39	954.	1500.	121880.	6899.	118425.	13027.	260230.	90411.	5357.	355998.
40	1033.	1400.	124683.	6989.	121712.	13388.	266772.	84621.	5488.	356881.
35	795.	1500.	113021.	6554.	113739.	12511.	245825.	107119.	5031.	357975.
32	795.	1300.	109255.	6399.	116128.	12774.	244556.	108934.	4960.	358450.
37	900.	1500.	119895.	6762.	117998.	12980.	257634.	95660.	5293.	358587.
32	795.	1200.	108121.	6443.	117764.	12954.	245282.	108934.	4955.	359170.
36	900.	1200.	113498.	6552.	120883.	13297.	254229.	100106.	5156.	359491.
34	795.	1300.	109378.	6341.	116691.	12836.	245246.	109437.	4972.	359654.

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

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	28172.	19.47	1947.	25870.	55989.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	310.	UNITS	1970.	1.70	366.		2336.
HARDWARE			1429.	0.47	47.		1477.
TOWERS	4.3	UNITS	68496.	35.79	3579.	40104.	112179.
FOUNDATIONS	4.3	UNITS	4791.		775.	32083.	37648.
RIGHT OF WAY	14.	ACRES	9848.			19697.	29545.
IDC/ENGINEERING			12953.				12953.
TOTALS			114706.	57.43	6714.	117754.	252127.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	44314.	39493.	83807.
CORONA LOSSES	2088.	4517.	6604.
TOTALS	46401.	44010.	90411.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

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

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

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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	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 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	

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

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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	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

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

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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
PHASE SPACING	20.0 FEET
CONDUCTOR CONFIGURATION FACTOR	1.02
GROUND CLEARANCE	28.0 FEET
NO. OF INSULATORS PER TOWER	48
INSULATOR SAFETY FACTOR	2.50
STRING LENGTH	6.5 FEET
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

DISTANCE BETWEEN PHASES:

D1	20.00 FT
D2	20.00 FT
D3	40.00 FT
D4	0.00 FT
D5	0.00 FT
D6	0.00 FT

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: 12 APR 79 TIME: 9:45:19

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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

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

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)
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

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

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	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

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

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*   AUTOMATIC CONDUCTOR SELECTION    *
*      ALL QUANTITIES PER MILE       *
*                                    *
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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.	36988.	3284.	206376.
37	900.	1300.	67299.	3772.	84608.	9307.	164986.	39195.	3257.	207436.
35	795.	1300.	64664.	3721.	82616.	9088.	160089.	44359.	3151.	207598.
35	795.	1400.	65375.	3684.	82031.	9023.	160113.	44359.	3161.	207633.
39	954.	1400.	69552.	3828.	84673.	9314.	167367.	36988.	3322.	207676.
37	900.	1400.	68697.	3766.	84494.	9294.	166251.	39195.	3294.	208739.
35	795.	1500.	66879.	3689.	82176.	9039.	161784.	44359.	3206.	209348.
32	795.	1300.	65558.	3685.	83893.	9228.	162364.	44830.	3195.	210389.
39	954.	1500.	71843.	3870.	85337.	9387.	170437.	36988.	3397.	210821.
38	954.	1300.	70136.	3831.	86787.	9547.	170300.	37456.	3371.	211126.
34	795.	1300.	65807.	3659.	84359.	9279.	163104.	44915.	3209.	211228.
32	795.	1400.	66784.	3669.	83683.	9205.	163342.	44830.	3226.	211398.
39	954.	1200.	70386.	4033.	87082.	9579.	171080.	36988.	3385.	211453.
30	715.	1300.	63510.	3615.	82301.	9053.	158478.	50049.	3112.	211639.
30	715.	1400.	64204.	3576.	81729.	8990.	158498.	50049.	3122.	211669.
37	900.	1500.	70983.	3807.	85172.	9369.	169331.	39195.	3369.	211894.
35	795.	1600.	69124.	3735.	82979.	9128.	164966.	44359.	3282.	212607.
34	795.	1400.	67235.	3653.	84298.	9273.	164459.	44915.	3248.	212621.
37	900.	1200.	69631.	3977.	86926.	9562.	170096.	39195.	3361.	212651.
35	795.	1200.	66889.	3916.	85020.	9352.	165176.	44359.	3254.	212788.
30	715.	1500.	65702.	3580.	81896.	9009.	160187.	50049.	3167.	213402.
36	900.	1300.	69499.	3780.	86682.	9535.	169496.	40968.	3351.	213814.
38	954.	1400.	72348.	3861.	87234.	9596.	173039.	37456.	3440.	213934.
32	795.	1500.	68883.	3701.	84257.	9268.	166109.	44830.	3295.	214233.
38	954.	1200.	71305.	3980.	88398.	9724.	173407.	37456.	3431.	214293.

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

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	19547.	17422.	36969.
CORONA LOSSES	0.	19.	19.
TOTALS	19547.	17441.	36988.

INTERNATIONAL ENGINFERING CO. INC
SAN FRANCISCO CALIFORNIA

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

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

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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	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 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	

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

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	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: 12 APR 79 TIME: 9:02:43

****
*   *
*   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

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

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* 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.COFF. 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: 12 APR 79 TIME: 9:02:43

****
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)
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: 12 APR 79 TIME: 9:02:43

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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

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

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
57	2156.	1300.	89569.	5105.	90521.	9957.	195153.	116334.	3992.	315478.
57	2156.	1200.	90137.	5217.	92027.	10123.	197504.	116334.	4033.	317870.
57	2156.	1400.	92123.	5160.	90934.	10003.	198219.	116334.	4071.	318623.
58	2167.	1300.	92415.	5125.	93237.	10256.	201033.	117583.	4114.	322730.
58	2167.	1200.	92234.	5204.	94210.	10363.	202012.	117583.	4125.	323720.
57	2156.	1500.	95769.	5268.	92163.	10138.	203339.	116334.	4194.	323866.
56	1780.	1300.	82764.	4678.	88729.	9760.	185931.	137630.	3767.	327327.
58	2167.	1400.	95989.	5226.	94328.	10376.	205919.	117583.	4233.	327734.
56	1780.	1400.	84951.	4714.	88966.	9786.	188417.	137630.	3833.	329879.
56	1780.	1200.	83451.	4796.	90292.	9932.	188471.	137630.	3812.	329912.
53	1510.	1300.	77500.	4479.	87032.	9573.	178584.	148218.	3590.	330391.
57	2156.	1600.	100185.	5423.	94144.	10356.	210108.	116334.	4350.	330792.
53	1510.	1400.	79192.	4490.	86974.	9567.	180224.	148218.	3637.	332078.
56	1780.	1500.	88068.	4799.	90008.	9901.	192776.	137630.	3937.	334342.
53	1510.	1200.	79083.	4642.	89077.	9798.	182601.	148218.	3669.	334486.
55	1590.	1300.	79058.	4570.	87330.	9606.	180565.	150744.	3640.	334949.
58	2167.	1500.	100672.	5386.	96330.	10596.	212984.	117583.	4397.	334964.
53	1510.	1500.	81760.	4550.	87688.	9646.	183644.	148218.	3721.	335582.
55	1590.	1400.	80792.	4584.	87283.	9601.	182260.	150744.	3688.	336692.
52	1510.	1200.	72903.	4188.	87159.	9587.	173837.	160117.	3459.	337413.
55	1590.	1200.	80560.	4729.	89344.	9828.	184460.	150744.	3716.	338920.
55	1590.	1500.	83400.	4646.	88008.	9681.	185734.	150744.	3773.	340251.
56	1780.	1600.	92071.	4932.	91788.	10097.	198888.	137630.	4079.	340596.
54	1590.	1300.	79970.	4495.	89119.	9803.	183387.	153527.	3692.	340605.
53	1510.	1600.	85158.	4653.	89108.	9802.	188721.	148218.	3840.	340778.

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

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

INSTALLED COST BREAKDOWN	QUANTITY	MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840. FT	30659.	19.90	1990.	21730.	54378.
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	43756.	22.86	2286.	28342.	74384.
FOUNDATIONS	4.3 UNITS	3327.		538.	22280.	26145.
RIGHT OF WAY	13. ACRES	9085.			18170.	27255.
IDC/ENGINEERING		9957.				9957.
TOTALS		89569.	44.37	5105.	90521.	195153.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	61516.	54818.	116334.
CORONA LOSSES	0.	0.	0.
TOTALS	61516.	54818.	116334.

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.

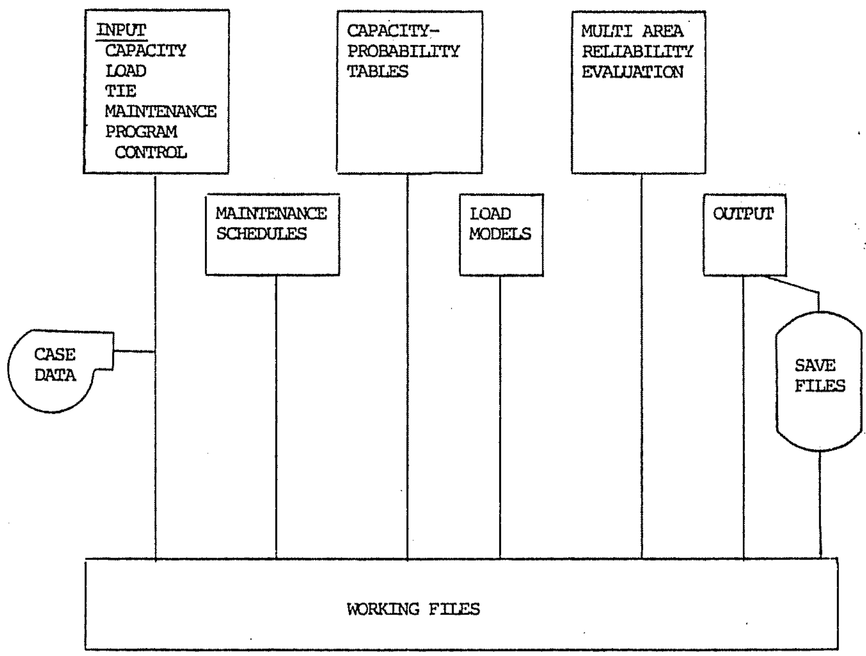

FIGURE 1

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 capacity-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)

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 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
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POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

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

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

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

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**                  **
**  01 - 18 - 1979  **
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S T U D Y   C A S E:

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**                                                                        **
**   ANCHORAGE - FAIRBANKS  TRANSMISSION INTERTIE ECONOMIC FEASIBILITY    **
**                                                                        **
**   2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979    **
**                                                                        **
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POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

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

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
JANUARY 15 1979

TWO AREA SYSTEM

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

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

POWER TECHNOLOGIES, INC.
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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 ***

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.
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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.
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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

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****************************************************
*** 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
1.0030 .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 .9373 .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 .8386 .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.
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  416.  446.  477.  511.
0.87390.69900.73710.76040.57490.59710.56630.51110.43240.41150.38330.37470.3587
0.35380.38080.41770.42010.43730.46190.53190.57490.89190.93370.93491.00000.7690
1.00000.97420.94670.94670.94530.93130.89480.86540.84290.8177
1.00000.93670.92790.92790.90510.89980.88950.85940.82790.7891
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
1.00000.99040.99040.94350.92310.91990.91670.91350.87820.8558
1.00000.96720.95410.92790.92460.90490.89840.89510.87870.8721
1.00000.96920.96920.95890.95890.94520.94520.93150.92120.9041
1.00000.98960.97220.96870.95880.94790.93400.92360.92010.8507
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
1.00000.99720.97750.96350.96350.94940.93820.93320.91010.8904
1.00000.99470.96810.93090.92820.90960.90690.90160.88830.8856
1.00000.93330.93300.91450.90990.89610.88910.88450.86370.8568
1.00000.99150.98980.97650.94920.92950.92740.91880.91450.9017
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
1.00000.99840.93920.92010.89940.88980.88500.84820.81310.7971
   GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
   TWO AREA SYSTEM                        JANUARY 15 1979
    1     1     1
    2     1    1.0E-12
     ANCHOR    44    12
  1.0
   1 ANCH 1    15 0.055
   2 ANCH 2    15 0.055
   3 ANCH 3    19 0.055
   4 ANCH 4    32 0.055
   5 ANCH 5    37 0.055
   6 ANCH 6    12 0.055
   7 ANCH 7    78 0.055
   8 ANCH7S    21 0.055
   9 ANCH 8    78 0.055
  10 BELU 1    15 0.055
  11 BELU 2    15 0.055
  12 BELU 3    54 0.055
  13 BELU 4     9 0.055
  14 BELU 5    54 0.055
  15 BELU 6    68 0.055
  16 BELU 7    68 0.055
  17 BELU 8    68 0.055
  18 BERN 1     8 0.055
  19 BERN 2    20 0.055
  20 BERN 3    24 0.055
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21 INTL 1    14 0.055
22 INTL 2    14 0.055
23 INTL 3    19 0.055
24 COOP 1     8 0.016
25 COOP 2     8 0.016
26 KNIT A    15 0.059 R   1/1986
27 INTL 4    71 0.055
28 INTL 5    71 0.055
29 INTL 6    71 0.055
30 INTL 7    71 0.055
31 HOMER      7 0.055
32 EKLUTN    30 0.016
33 BELU 9    71 0.055 N   1/1986
34 ANCH 9    78 0.055 N   1/1985
35 ANCH10   104 0.057 N   1/1986
36 COAL 1   200 0.057 N   1/1987
37 ANCH11   104 0.057 N   1/1993
38 COAL 2   200 0.057 N   1/1989
39 COAL 3   200 0.057 N   1/1990
40 COAL 4   200 0.057 N   1/1991
41 COAL 5   200 0.057 N   1/1992
42 PEAKA1    78 0.055 N   1/1993
43 GEN  1   300 0.079 N   1/1994
44 GEN  2   300 0.079 N   1/1996
45 PEAKA2    78 0.055 N   1/1995
-99
   COOP 1
   COOP 2
   EKLUTN
-99
  1
  9
-99
   FAIRBA    26    12
 1.0
 1 CHEN 1     5 0.059
 2 CHEN 2     2 0.059
 3 CHEN 3     2 0.059
 4 CHEN 4    20 0.059
 5 CHEN 5     5 0.055
 6 CHEN 6    24 0.055
 7 DIES 1     3 0.295
 8 DIES 2     3 0.295
 9 DIES 3     2 0.295
10 ZEHN 1    17 0.055
11 ZEHN 2    17 0.055
12 ZEHN 3     4 0.055
13 ZEHN 4     4 0.055
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
```

```
 21 NORT 1    65 0.055
 22 NORT 2    65 0.055
 23 UALASK     5 0.295
 25 COALF1   100 0.057 N   1/1988
 27 COALF2   100 0.057 N   1/1992
 28 COALF3   100 0.057 N   1/1995
-99
-99
  1
  9
-99
```