STUDY OF THE FEASIBILITY OF ELECTRICAL INTERCONNECTION BETWEEN ANCHORAGE AND FAIRBANKS

FOR THE

ALASKA POWER AUTHORITY

Engineering Report R-2274
May 1981

Gilbert/Commonwealth
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May 12, 1981

MAY 14

Attached is a copy of the feasibility study for the proposed Anchorage-Fairbanks Intertie Project.

This study concludes that such an electrical transmission intertie is a viable investment across a wide range of possible economic and use scenerios. Accordingly, design has been started for an intertie capable of handling 345 kv, with initial use at 138 kv (this combination is called Plan 1B in the feasibility report). A request for construction funding is presently pending with the State Legislature.

Route selection studies are also in progress, and the planning includes sufficient right-of-way to accommodate future Railbelt transmission needs that would emerge from the Susitna Hydroelectric Project or a large fossil fuel generating plant.

Construction start and line energization is dependent on when authority to proceed is received from the State Legislature and the various federal and state permitting agencies. We are hopeful al' necessary authorizations will be received this year, so construction can start early 1982.

If you have any questions or comments about this project, feel free to contact me at the address above, or call me at (907) 277-7641.

Sincerely,

David D. Wozniak
Project Manager

(1) Attachment:
Feasibility Report

Gilbert/Commonwealth engineers consultants architects
COMMONWEALTH ASSOCIATES INC., 209 E. Washington Avenue, Jackson, MI 49201 Tel. 517 788-3000

May 1, 1981

Mr. Robert A. Mohn
Director of Engineering
Alaska Power Authority
333 West 4th Avenue
Suite 31
Anchorage, AK 99501

Dear Mr. Mohn:

Attached is a report documenting our findings on the feasibility of an electrical interconnection between Anchorage and Fairbanks. The intertie has been found to be feasible and its operation will result in significant economic benefits to both areas. Additional conclusions and recommendations are included in the report.

We will be happy to answer any questions that may arise concerning this matter.

Yours very truly,

[signature] for RDC

R. D. Camburn

DAS/rc

FEASIBILITY STUDY OF ELECRICAL INTERCONNECTION BETWEEN ANCHORAGE AND FAIRBANKS

MAY 1981

ENGINEERING REPORT R-2274

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TABLE OF CONTENTS

	Page
Purpose of Report	1
Situation	1
Scope of Study	6
Basis for Study	8
Formulation of Alternatives	10
Transfer Capacity	13
Capital Cost Estimates	15
Economy Interchange Benefits	17
Reserve Sharing Benefits	18
Cost/Benefit Analysis	21
Sensitivity Analysis	22
Intertie Load Taps	23
Conclusions	25
Recommendation	27

EXHIBITS (See Next Page)

APPENDICES

A. Load Growth

B. Future Power Sources

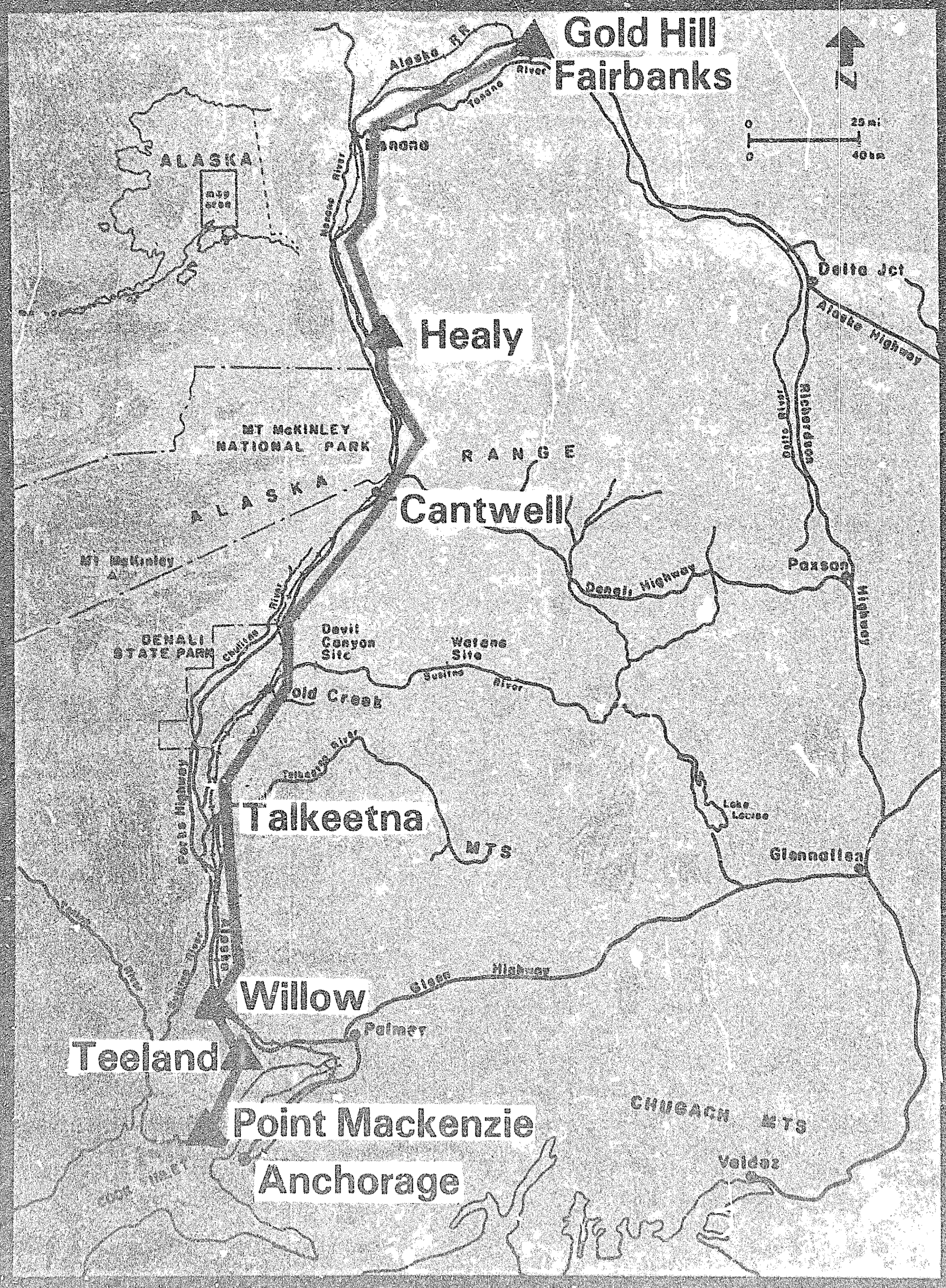
C. New Coal-Fired Power Plants

D. Alternative Fuels in the Fairbanks Area

LIST OF EXHIBITS

Exhibit No.	Description
1	Energy and Demand Forecasts
2	Existing Generating Units
3	Economic Parameters
4	Intertie Alternatives
5	Transfer Capability and System Losses
6	Capital Cost Estimates
7	Economy Interchange Benefits
8	Reserve Sharing Benefits
9	Life-Cycle Costs and Benefits
10	Sensitivity Analysis
11	Cost of Load Taps

ANCHORAGE—FAIRBANKS INTERCONNECTION
ALASKA POWER AUTHORITY



PURPOSE OF REPORT

In July of 1980, the Alaska Power Authority engaged Gilbert/Commonwealth, a firm of consulting engineers, to provide a variety of services pertaining to the study and design of a first interconnection between the electric power systems existing in the Anchorage area and those existing in the Fairbanks area. One of the initial tasks assigned was to make a study of the feasibility of such an interconnection. This report describes the nature and results of that study.

SITUATION

In the Anchorage area, there are five electric utilities that are interconnected, namely Anchorage Municipal Light and Power, Chugach Electric Association, Homer Electric Association, Matanuska Electric Association and Seward Electric System. The amount of generating capacity in the Anchorage area is:

AMLP	225 megawatts
CEA	476
APA	30
Total	731 megawatts

Of this amount, approximately 6 percent is hydro. The rest is fired with natural gas.

There are two interconnected utilities in the Fairbanks area; Fairbanks Municipal Utility System and Golden Valley Electric Association. The amount of generating capacity is:

FMUS	71 megawatts
GVEA	221
Total	292 megawatts

Of this amount, approximately 18 percent is coal-fired and the remainder is oil-fired.

For a number of years, it has been conceived that substantial economies in the production of electricity can be achieved by interconnecting the two systems. In fact, there have been a number of prior studies dealing with this question. It is the intention that this should be the final and most definitive feasibility study yet made, preparatory to the actual undertaking to construct such an interconnection.

There are two potential benefits of interconnection. In technical terms, the first is called "economy interchange" and the second "reserve sharing".

The merit of economy interchange hinges upon the fact that the oil burned in Fairbanks is, and promises to be, substantially more costly than the natural gas burned in Anchorage. Thus, if energy provided by lower cost gas could be transported to Fairbanks to replace energy produced there with oil, there would be a cost reduction overall. The cost of fuel is a substantial component in the cost of producing electrical energy and directly impacts the cost of energy to the consumer.

Economy interchange is made practical by the cyclic nature of the system load. As with all utilities, the Anchorage system must have installed generating capacity to meet the peak demands and provide reserve for the scheduled and unscheduled outages of individual generating units. When the system load is not at its peak, and/or most generating units are capable of operating normally, Anchorage is capable of producing energy above and beyond the immediate need of its consumers. Given an interconnection, that extra energy could be transported to Fairbanks, and Fairbanks generation reduced accordingly, to achieve the benefits of economy interchange. This practice is common among interconnected utilities throughout the United States. In most all cases, the resultant savings are split 50-50 between the sending and receiving utilities.

The second benefit of interconnection, reserve sharing, arises from the fact that the larger the interconnected system, and the greater the diversity of resources thereby encompassed, the more will be its ability to withstand adversities during operation. The potential advantage can be used in either of two ways. It can be used to increase the reliability of the systems joined, or it can be used to reduce the amount of generating capacity required to achieve the same level of service reliability as before interconnection. In the present case, it is assumed that the latter course of action will prevail because it is reported that both the Anchorage and Fairbanks systems have adequate reliability and need no improvement. Thus, the way is open to eventually reduce the total amount of generating capacity required to give the customary degree of service reliability, and correspondingly spend less on additional generating capacity in the future.

One major part of this study was the quantification of the magnitude and economic benefits of these two modes of operation in the presence of an interconnection.

The transmission line distance between Anchorage and Fairbanks is approximately 315 miles following a route within the Railbelt. However, the new facilities needed to make an interconnection need not necessarily be this long. There is an existing 138 kV line extending south from Fairbanks approximately 103 miles. There are existing 138 kV and 115 kV lines extending 52 miles north from Anchorage. If it is possible to utilize these existing lines as a part of the interconnection, the gap to be closed and the length of new line needed to effect interconnection is 160 miles. However, it is not necessarily true that the existing lines can be incorporated into the interconnection under all of the options considered. The possible options and their respective needs for new line construction are defined in the further course of this discussion.

In any case, it is by comparison of the benefits and costs that the feasibility of the interconnection will herein be proven, and the most economic configuration of the interconnection defined.

There is an additional and important factor that is dealt with in this study. That is, the future impact of, and need to coordinate with, the Susitna Hydro Project. The present concept is that there may be installed, beginning in 1994, approximately 1200 megawatts of hydro generation situated roughly midway between Anchorage and Fairbanks. Any transmission lines associated with Susitna will logically overlay or parallel the interconnection which is the subject of this report. That prospect affects the way in which the interconnection is analyzed, and may affect the way in which it is built. This report therefore deals with the merits of interconnection assuming (1) that Susitna will exist within the time frame suggested, or (2) that it may not.

One final consideration, if for some reason the Susitna Project is not built, an alternate source of power for the Railbelt area will need to be sought. The analysis in this report with reference to the Susitna Project would also be applicable to an alternate central station power source located within the Railbelt region.

SCOPE OF STUDY

The fundamental objectives of the feasibility study were thus:

1. To define all of the reasonable alternatives for design and operation of the interconnection.

2. To establish the practicability of each alternative and quantify its ability to transport power in either direction.

3. To estimate the benefits and costs of each alternative.

4. To identify the preferable course of action on the basis of the relative ratios of benefits to costs.

5. To establish economic justification for proceeding to implement the preferred alternative.

Regarding the matter of reasonable alternatives, it has reportedly been determined by Acres American that the preferred voltage for the transmission lines associated with the Susitna Project will be 345 kV. Acres American is the consultant engaged to study that project. Since there must be coordination between plans for the interconnection and plans for the Susitna Project, due to the geography of the situation, it becomes apparent that the alternative voltages for the interconnection must range between the lowest that exists, i.e., 115 kV, and the highest that will be used for Susitna. The standard voltages within this range are 115 kV, 138 kV, 230 kV and 345 kV.

For this analysis of the interconnection, it is therefore reasonable to postulate the following options:

1. Construct the interconnection for 115 kV, 138 kV, 230 kV or 345 kV operation, and so operate it from the beginning.

2. Design the interconnection for future 345 kV operation, but operate it at 115 kV, 138 kV or 230 kV until it may be integrated into the Susitna Project.

This is the range of options dealt with in this study.

With regard to establishing the practicability and capability of each alternative, the evidence that has been developed will be shown later in this report. However, it is to be noted that the analysis along this line has proceeded only far enough to give reasonable assurance that each alternative plan will work satisfactorily within the limits envisioned or intended, and that the capital cost estimate is reasonable and sound. That is the customary limit of investigation in connection with feasibility study.

When it is decided on the basis of these and other findings that the project is to be implemented on the basis of a specific alternative, further technical studies to refine equipment and design details will be required. The basis for this procedure is efficient use of engineering time and minimization of expense.

And finally with regard to costs and benefits, the elements considered in this analysis are:

1. The cost of the interconnection and related system additions and improvements, including capital expenses, fixed charges on investment, operation and maintenance expenses, and capacity and energy charges for I^2R losses.

2. The benefits of economy interchange, including reduction in system fuel expenses and reduction in power plant operation and maintenance expenses.

3. The benefits of reserve sharing, including the reduction in capital expenses for new generating capacity, and related fixed charges on investment.

BASIS FOR STUDY

It will become apparent that most of the basic data used in this study was variously supplied by the utilities involved, Alaska Power Authority and other state agencies, consultants to these agencies, and fuel suppliers. In fact, the development of the data finally used has been the result of considerable interaction with and between these many parties. Thus, there is reason to expect a concensus upon the entering parameters about to be described.

Future electric energy sales within the Railbelt were originally projected by the Institute of Social and Economic Research, and given in a report to the State of Alaska dated May 23, 1980. Acres American subsequently analyzed and expanded the ISER information, projecting the energy unaccounted for and consumed in system losses so as to arrive at a forecast of annual generation for load. Acres American also developed annual system load factors (i.e., ratios of average annual system load to annual peak demand) by which it is possible to make a forecast of future peak demands. Using the information thus provided, and adopting the Acres/ISER "Medium" forecast of the several possibilities that were projected, Gilbert/Commonwealth derived the load data needed for this analysis, i.e., the projected annual energy generation and annual peak demands through year 1995, as shown in Exhibit 1.

Necessary information regarding the existing generating units was furnished by their respective owners as shown in Exhibit 2. Gilbert/Commonwealth estimated the full-load heat rate for each unit as listed in Sheet 3 of Exhibit 2.

Exhibit 3 shows the remaining parameters used in this study, mainly the economic parameters. The fixed charge rate and its components (Item B in Exhibit 3) were provided by Alaska Power Authority. The gas and oil prices used (Item I in Exhibit 3) were agreed upon at a conference on March 18, 1981 involving representatives of Alaska Power Authority, Gilbert/Commonwealth, Chugach Electric Association, Anchorage Municipal Light and Power, Golden Valley Electric Association, Fairbanks Municipal Utility System, Matanuska Electric Association, Homer Electric Association, Alaska Gas and Service Company and Battelle Pacific Northwest Laboratories.

All of the remaining information given in Exhibit 3 was calculated or estimated by Gilbert/Commonwealth.

FORMULATION OF ALTERNATIVES

Upon examination of the existing transmission lines, it was noted that only 26 miles of line in the area of interest are operating at 115 kV. It was further learned that this line can be operated at 138 kV without need for modification. Since the systems to be interconnected operate mainly at 138 kV or above, 115 kV was eliminated as a practical alternative for the interconnection.

In total, five alternatives were developed and evaluated. Diagrams of the five plans are provided in Exhibit 4. The details of the plans are discussed in the following paragraphs.

Plans 1A and 1B

Since the existing lines that may be readily incorporated into the intertie are or can be operated at 138 kV, the first alternative involves utilization of that voltage. The advantage of 138 kV is that the two systems can be connected without need for voltage matching transformers.

The steps required to establish a 138 kV interconnection are listed below, starting from the Anchorage end and proceeding towards Fairbanks.

1. The Anchorage termination of the tie-line is the existing Point MacKenzie substation. The first 26 miles of the tie-line would make use of the existing 138 kV line from Point MacKenzie to Teeland.

2. A 115 kV line 26 miles long exists between Teeland and Willow. This line can be converted to 138 kV operation without modification of the line itself. To operate this line at 138 kV requires making a connection to the existing 138 kV bus at Teeland. The existing distribution substation at Willow would be rebuilt for 138 kV and the 115/24 kV transformer replaced with a 138/24 kV transformer.

3. A new line would be constructed to close the 160 mile gap between Willow and Healy.

4. The existing 103 miles of 138 kV transmission between Healy and Gold Hill would complete the tie-line. Gold Hill substation is the Fairbanks termination of the tie-line.

Two subalternatives were considered. In the first, identified as Plan 1A, the 160 miles of new line would be constructed for a nominal operating voltage of 138 kV. Plan 1B is similar in all respects except the 160 miles of new line would be constructed for a future operating voltage of 345 kV but initially operated at 138 kV. This allows for the possibility of integrating the new line into the future transmission facilities for Susitna or other regional generation source.

Circuit breakers would be installed as shown in Exhibit 4, Sheet 1. This arrangement results in the same level of service reliability as presently provided at the substations along the tie-line.

Plans 2A and 2B

The existing Point MacKenzie to Teeland 138 kV line can be operated at 230 kV if additional insulators are provided. It is understood that Chugach Electric Association plans to convert and build other lines in the vicinity of Point MacKenzie for 230 kV operation. Thus, 230 kV transmission will soon become the major transmission voltage in the Anchorage area. It is therefore a reasonable possibility to extend 230 kV transmission to Fairbanks. The following steps would establish a 230 kV interconnection.

1. The existing 26-mile Point MacKenzie to Teeland 138 kV line would be reinsulated for 230 kV operation and connected to the 230 kV bus at Point MacKenzie.

2. A 230 kV substation would be built at Teeland to supply the existing 115 kV transmission system there.

3. A new 230 kV line 186 miles long would be constructed from Teeland to Healy.

4. A 230/138 kV transformer would be installed at Healy. The existing 103 miles of 138 kV line between Healy and Gold Hill would complete the interconnection.

As in Plan 1, two subalternatives were formulated. In Plan 2A, the 186 miles of new line would be constructed for a nominal operating voltage of 230 kV. Plan 2B is similar to Plan 2A except the line would be designed for future operation at 345 kV. In both plans, the Point MacKenzie to Healy sections would be operated at 230 kV and the Healy-Gold Hill sections at 138 kV. The construction of the new line section for 345 kV rather than 230 kV operation provides for future integration with the Susitna transmission.

Circuit breakers would be provided as shown on Exhibit 4, Sheet 2. This arrangement maintains the same level of service reliability as presently provided at Teeland.

Plan 3

Plan 3 would involve 160 miles of new line constructed for and operated at 345 kV. To accomplish this requires 345/138 kV transformers at both Willow and Healy. The tie-line would be operated at 138 kV from Point MacKenzie to Willow, 345 kV from Willow to Healy, and 138 kV from Healy to Gold Hill. The transformers and circuit breakers would be as shown on Exhibit 4, Sheet 3.

TRANSFER CAPACITY

Load flow modeling was used to analyze all five plans to determine the transfer capability, I^2R losses, and shunt capacitor and reactor requirements for each plan. The results are graphically depicted in Exhibit 5.

There are four factors which may limit the amount of power that can be transferred over the tie-line; thermal rating of the conductors, voltage regulation, steady-state stability, and transient stability. By means of load flow analysis, it is possible to estimate the maximum power transfer of which the tie-line is capable considering all of these factors. Estimates thus arrived at are entirely adequate for purposes of voltage selection and feasibility, although refinement for purposes of equipment application will be required in preparation for actual design of the interconnection.

The studies that were made indicate that the maximum safe transfer over the tie-line from south to north, and from north to south, is approximately 70 megawatts under all plans. Thermal capacity of the existing lines which may form a part of the interconnection is limiting, although voltage regulation and stability will not allow a major increase beyond this figure. The application of reasonable quantities of shunt capacitors to control voltage regulation was assumed in accordance with common engineering practice.

I^2R losses on the tie-line were defined for all five plans. For comparison purposes, the incremental losses between Point MacKenzie and Gold Hill caused by a 60 MW transfer to Fairbanks are estimated as follows:

Plan	Losses on Tie-Line For 60 MW Received at Fairbanks	
	MW	%
1A - 138 kV	12	20
1B - 138/345 kV	10	17
2A - 230 kV	7	11
2B - 230/345 kV	6	10
3 - 345 kV	9	15

As indicated above, shunt capacitors and reactors will be required for voltage regulation. The amount of compensation needed is a function of the tie-line loading as shown on Exhibit 5, Sheet 3. For the purposes of load flow modeling and preparing cost estimates, the preliminary placements of shunt capacitors were 50 MVAR at Teeland and 20 MVAR at Gold Hill. These capacitor banks would be switched in stages as necessary to maintain voltage within prescribed limits. This arrangement of capacitors was used for all five plans.

Shunt reactors were required for Plans 2A, 2B and 3. The placements of shunt reactors were 20 MVAR at Teeland and 40 MVAR at Healy for Plans 2A and 2B. A portion of the reactors at Healy would be switchable, all others are unswitched. In Plan 3, 60 MVAR of unswitched reactor banks are required at both Healy and Willow.

CAPITAL COST ESTIMATES

The capital cost estimates for all five plans are provided on Exhibit 6. These costs include material and labor for transmission lines and substations, right-of-way acquisition, and shunt compensation (capacitors and reactors). Also included in Exhibit 6 is a sketch of the transmission towers which formed a basis for the transmission line costs for the five plans.

Studies to date do not show the need for additions and improvements within the Anchorage or the Fairbanks systems for transmitting the intertie power to the load centers, except in the case of the Gold Hill 138-69 kV autotransformer. The rating of this transformer would need to be approximately doubled, and the cost of same has been included in the estimates.

Also included in the capital cost estimates are the costs associated with engineering, construction management, owner's cost, contingencies, and allowance for funds used during construction.

Capital costs as of January, 1981, were escalated at 12 percent per year to obtain 1984 costs, the expected in-service date of the tie-line.

The capital cost estimates for the five plans are summarized in the following table.

Plan	Installed Costs
1A - 138 kV	$ 56.8 million
1B - 138/345 kV	99.5
2A - 230 kV	77.7
2B - 230/345 kV	120.8
3 - 345 kV	110.3

ECONOMY ENERGY INTERCHANGE BENEFITS

The method used to calculate the economy interchange benefits and the results of that calculation are provided in Exhibit 7.

The amount of economy energy that can be supplied from the Anchorage area to the Fairbanks area is limited by either (1) the needs of Fairbanks, or (2) the availability of generating capacity in Anchorage beyond that required to serve the Anchorage load on an hour-to-hour basis.

It can be seen from Exhibit 7 that the economy energy initially increases until 1992 and then decreases. Initially, the interchange of economy energy is limited by the needs of Fairbanks. In later years it is limited by the available generating capacity in Anchorage. Exhibit 7 indicates that the annual economy energy export from the Anchorage area to the Fairbanks area varies between 200 GWH and 360 GWH in the 1984-93 time period.

Economy energy has been calculated assuming that the installed generating capacity on both the Anchorage and the Fairbanks systems will remain constant over the period between now and 1993. With the tie-line, no additional generating capacity is required in the Fairbanks area before 1993, but the Anchorage area may require approximately 120 MW of additional capacity by 1993. If this additional capacity is constructed, it will increase Anchorage's ability to supply economy energy to Fairbanks. However, this possibility was not included in the calculations of economy energy.

After 1993, the Anchorage and Fairbanks systems will require additional thermal generating capacity, even with the tie-line in service, if it is assumed that Susitna is not built. The bulk of this capacity will be required in the Anchorage area. Presumably, any generation in Anchorage will be fired with coal or natural gas while Fairbanks continues to depend mainly upon the existing oil-fired units. It is therefore assumed that if Susitna is not built the opportunity for economy interchange will extend beyond 1993. It is likely that Fairbanks will eventually install more coal-fired generation, thus reducing the fuel cost differential between the two areas, and diminishing the benefits of economy interchange. Knowing that the economy interchange will not abruptly end in 1993 (even if Susitna is not built) but also realizing potential for diminishing fuel cost differential, it was assumed that the exchange of economy energy would extend 10 years beyond 1993.

RESERVE SHARING BENEFITS

The criteria used to evaluate the generating reserve requirements are given in Exhibit 8. As stated in this Exhibit, the basis of the criteria is to provide installed reserve at least equal to the capacity of the two largest units on the system. The objective is to maintain supply of electric energy to the consumers even in the event of loss of generating capacity. This could occur as a result of outages because of faults or maintenance on the units.

If an isolated system is interconnected to another system, the tie-line becomes a new source of power very much like adding a generator. Thus, the amount of installed reserve generation can be reduced by the amount that can be supplied by the tie-line without reducing the reliability of the energy supply to the consumer.

A difficulty is introduced when substituting a single tie-line for a generating unit. The difficulty is calculating the amount of power that can be supplied by the tie-line. That amount is a function of the size of units on the receiving system, the diversity of load between systems, the installed capacity on the sending system, tie-line capacity, and the tie-line losses. These elements have been considered in the calculations provided in Exhibit 8.

An alternate method of calculating installed reserve requirement is the Loss of Load Probability technique or LOLP for short. In this technique the probability of not being able to supply the consumer (loss of load) is calculated. The desired level of reliability is established by specifying an acceptable loss of load probability index. A commonly accepted standard by lower 48 utility systems is a loss of load probability index of one in ten years.

Either of the criteria mentioned (two largest units or LOLP) could have been used and would have provided comparable results. For purposes of this analysis the "two largest units" criteria was adopted.

As shown on Exhibit 8, both the Anchorage and Fairbanks systems have sufficient installed generating capacity through 1984 but, if not interconnected, both systems will be short of installed capacity by 1985. By interconnecting, the Anchorage system has sufficient capacity through 1988 and the Fairbanks system through 1993.

The reserve benefits of the tie-line are determined on the basis of the incremental generating capacity deferred by the line. For example, in 1984 both Anchorage and Fairbanks have sufficient installed capacity so that the existence of the tie-line does not defer the installation of generating capacity and, therefore, no benefit is assigned in that year. In this situation, the tie-line actually increases the reliability of the interconnected systems, but this has not been quantified or included in the justification of the line since it is an incidental or unintended benefit.

In 1985, without the interconnection, the Anchorage system is short 11 MW and the Fairbanks system is short 7 MW. If the tie-line is not built, each system must make a decision to either reduce service reliability or install a new generating unit. If a new unit is added, the customary and efficient practice is to install a unit that is larger than a single year's incremental shortage. Both the Anchorage and Fairbanks systems are presently installing new units of 60 MW or larger. On the other hand, a utility may elect to accept the risk of having slightly less installed capacity than desired knowing that in the following year or two a new unit will be in service and the installed reserve capacity will be restored to desired levels.

To avoid the problem of ambiguity associated with adding generating capacity this year or next, the reserve benefits of the tie-line are based on the incremental generating capacity needed to maintain service reliability. This approach provides a means for quantifying the reserve benefits provided by the tie-line without overstating the benefits or needing to identify specific locations, sizes, owners, or in-service dates of future units. The cost of the incremental generating capacity is shown in Exhibit 3 and the benefits are calculated in Exhibit 8.

COST/BENEFIT ANALYSIS

The total life-cycle costs were calculated by summing the fixed charges and the operation and maintenance costs expected over the life of the facility. The economic parameters and the capital costs necessary to make these calculations have been previously discussed and are provided on Exhibits 3 and 6. The life-cycle benefits for economy energy and reserve sharing were also previously discussed and are provided on Exhibits 7 and 8. A benefit/cost ratio was calculated for each plan by dividing the life-cycle benefits by the life-cycle costs. The presentation of the life-cycle costs, the summation of the life-cycle benefits, and the calculation of the benefit/cost ratio are provided on Exhibit 9.

The benefit/cost analysis has been made for two scenarios:

1. The Railbelt intertie becomes operational in 1984 and the impact of the Susitna hydroelectric project is not a factor in the economic evaluation of the intertie project.

2. The Railbelt intertie becomes operational in 1984 and its various components are either retired or integrated into the Susitna project transmission system in 1994.

In the first scenario, the tie-line is assumed to be the only interconnecting facility between the Anchorage and Fairbanks areas over its life time of 35 years. However, the economy energy benefits are calculated for only the first twenty years, as previsouly discussed. The reserve sharing benefits, on the other hand, would extend for the 35-year life of the facility.

In the second scenario it is assumed that the Susitna Project and its associated transmission facilities are placed in service in 1994. The Susitna transmission will interconnect the Anchorage and Fairbanks areas and greatly increase the transfer capability between the areas. The initial tie-line will no longer be important as an interconnecting facility since its transfer capacity is limited by the existing line sections that are part of it. If the tie-line is designed for 138 kV or 230 kV it could be dismantled and physically removed to provide room for the Susitna transmission or it could be left in place parallel to the Susitna lines and used to supply local area load requirements. If, on the other hand, the line is built for 345 kV, it would be integrated into the Susitna transmission. For purposes of this analysis the components of the five plans were divided into two catagories, those that could be integrated with Susitna and those that could not. The life-cycle capital costs were then adjusted to properly account for the early retirement or the rededication of these facilities. The economy energy benefits and the reserve sharing benefits were calculated only for the 1984-1993 period in this scenario.

SENSITIVITY ANALYSIS

The economic feasibility of the Anchorage-Fairbanks interconnection is postulated on the basis of the most probable future conditions in the Railbelt region that have been described in the preceeding paragraphs. However, sensitivity analysis was performed for each of the following alternative conditions:

1. Load growth
   a. High load forecast*
   b. Low load forecast*

2. Additional future power sources
   a. Military Generation in the Fairbanks Area
   b. Bradley Lake Hydro Project in the Anchorage Area
   c. Bradley Lake Hydro Project and Military Generation

3. Addition of new power plants using coal

4. Alternative fuels in the Fairbanks Area
   a. North Slope gas via pipeline to Fairbanks
   b. Cook Inlet gas via LNG railcar to Fairbanks

The impact of these possibilities on the viability of the tie-line is summarized in Exhibit 10. Supporting data, observations, and conclusions are presented in Appendices A through D.

INTERTIE LOAD TAPS

In the event a transmission line is built to interconnect the Anchorage and Fairbanks systems, that line will pass through areas of Alaska which have never before had access to a commercial power supply. Residents in the vicinity of the transmission line right-of-way may request that power be made available to them.

*Based on the Acres/ISER high and low forecasts.

This discussion concerns alternative means and approximate costs for supplying such local loads by tapping the tie-line. One possibility involves 2000 kVA, three phase, distribution substations. Another involves 50 and 100 kVA, single-phase, potential transformers. Three possible transmission line voltages must be considered, namely, 138, 230 and 345 kV.

Costs for these alternatives are summarized in Exhibit 11. These costs should be used cautiously. If the tie-line is constructed for future operation at 345 kV, then the load tap must also be designed for future conversion to 345 kV. For the most part, this implies 345 kV construction and costs.

The 2000 kVA substations are considered to be a practical minimum size in the 138 to 345 kV range and would be adequate to serve a relatively large load area. The potential transformers would be adequate to serve only relatively small loads within 500 to 1000 feet of the transmission line right-of-way at 120/240 volts. These are not available at 345 kV.

Each substation or potential transformer connected to the proposed tie-line will increase its exposure to service interruptions.

CONCLUSIONS

Based upon the results of this analysis, Gilbert/Commonwealth concludes as follows:

1. The clear economic choice is between Plan 1A and Plan 1B. Plan 1A involves the construction and operation of the interconnection at 138 kV. Plan 1B is the same as Plan 1A except that the 160 mile section of new transmission line would be constructed for future operation at 345 kV.

2. These two plans are alike in the amount of power they can transfer between Anchorage and Fairbanks - up to approximately 70 MW in either direction.

3. Plan 1A is estimated to cost $56,800,000 while Plan 1B is estimated to cost $99,500,000.

4. Opportunity exists for the interchange of economy energy from the Anchorage area to the Fairbanks area. An average of 260,000 MWH per year from 1984 to 1993 can be exchanged. This would result in avoiding the burning of an estimated 400,000 barrels of oil per year in Fairbanks.

5. Opportunity exists for reserve sharing for both the Anchorage and Fairbanks areas. As early as 1985 the intertie will result in an estimated reserve sharing benefit of 18 MW. The reserve sharing of the intertie builds to a maximum of 135 MW in 1994 (the maximum allowable with a single tie).

6. As to the choice between Plans 1A and 1B, the following observations apply:

   a. If it were certain that the Susitna Project will proceed approximately along the lines now envisioned (its precise timing is not critical) or alternate sources of generation are developed in the Railbelt region, Plan 1B would be the clear choice. As one regards the probability of Susitna, so must one rate the probability that Plan 1B is the correct choice.

   b. If the possibility of Susitna (or alternatives) is ignored, Plan 1A might then be regarded as the better choice. However, this is not a totally sound observation because, as the Anchorage and Fairbanks continue to grow, there will eventually be use or need for greater transfer capability, and the need for a higher interconnection voltage than 138 kV will undoubtedly occur.

   c. There is a counter possibility that a 138 kV interconnection can eventually provide a valuable means of serving the load that may grow up along the line between Anchorage and Fairbanks, allowing higher voltage lines in parallel to assume the function of interconnection.

7. On balance, the odds are in favor of Plan 1B, i.e., construction of the line for future 345 kV operation. Past experience has demonstrated that in transmission planning it is sometimes difficult to justify the

initial change to a higher voltage, but in retrospect the correct decision is the higher voltage as proved by the need to further expand and develop the systems at that voltage.

RECOMMENDATION

Gilbert/Commonwealth recommends proceeding with the construction of an interconnection on the basis of following Plan 1B. This will involve the following steps:

1. Construct approximately 160 miles of new transmission line designed for future operation at 345 kV.

2. Add 138 kV circuit exits at Healy, Willow and Teeland Substations.

3. Add a new 138/24 kV transformer at Willow Substation along with a 138 kV connection.

4. Possibly add a 138/138 kV voltage regulating transformer at Point MacKenzie Substation if studies in preparation for design show a need for it.

5. Install approximately 70 MVAR of switched capacitors to control voltage across the interconnection.

PROJECTED ENERGY GENERATION
(Millions of Kilowatthours)

Year	Anchorage Systems(a)	Fairbanks Systems(a)	Other (b)	Acres/ISER Total(c)
1984	2576	676	1049	4301
85	2705	733	1072	4510
86	2778	748	1079	4605
87	2852	764	1085	4701
88	2928	780	1088	4796
1989	3006	795	1091	4892
90	3086	812	1089	4987
91	3244	853	1112	5209
92	3407	896	1128	543[illegible]
93	3581	942	1130	5653
1994	3763	989	1123	5875
95	3953	1040	1004	6097

(a) Calculated by applying a percentage for "Energy Unaccounted For" to projected energy sales, all taken from the Acres/ISER forecast.

(b) Amount necessary to give the total in the last column. Attributed to isolated and self-supplied loads that are included in the Acres/ISER forecast.

(c) Acres/ISER medium forecast.

PROJECTED ANNUAL PEAK DEMANDS
(Megawatts)

Year	Anchorage Systems(a)	Fairbanks Systems(a)	Total Non-Coincident	Total Coincident (b)
1984	526	156	682	662
85	552	169	721	699
86	567	172	739	717
87	582	176	758	735
88	598	180	778	755
1989	614	183	797	773
90	630	187	817	792
91	662	196	858	832
92	696	206	902	875
93	731	217	948	920
1994	768	228	996	966
95	807	239	1046	1015

(a) Calculated by applying the 10-year historic load factor to the energy projection given on Sheet 1, i.e., Anchorage 55.9 percent
Fairbanks 49.6 percent.

(b) The peak demands of individual systems generally occur at different times. This is referred to as diversity. The non-coincident peak demand of an area is calculated by adding these peak demands of the individual systems. The coincident peak demand is the sum of the demands for the combined systems measured at the same time. Because of the inherent diversity in the individual system demands, the coincident peak demand is always less than the non-coincident peak demand.

The coincident peak demands under this column are calculated by applying a coincidence factor of 97 percent to the non-coincident peak demands in the preceding column as indicated in Acres/IS forecast.

ANCHORAGE GENERATING UNITS

Plant	Unit	Capacity MW(a)	Type	Fuel
Station 1	1	16	CT	Gas
	2	16	CT	Gas
	3	18	CT	Gas
	4	32	CT	Gas
Station 2	5	36	CT(b)	Gas
	6	33	ST(b)	---
	7	74	CT(b)	Gas
AMLP Total		225		
Beluga	1	16	CT	Gas
	2	16	CT	Gas
	3	53	CT	Gas
	5	58	CT	Gas
	6	68	CT(c)	Gas
	7	68	CT(c)	Gas
	8	54	ST(c)	---
Bernice Lake	1	9	CT	Gas
	2	18	CT	Gas
	3	27	CT	Gas
	4	27	CT	Gas
Cooper Lake	1	8	H	---
	2	8	H	---
International	1	14	CT	Gas
	2	14	CT	Gas
	3	18	CT	Gas
CEA Total		476		
Eklutna	1	15	H	---
	2	15	H	---
APA Total		30		
Anchorage Total		731		

(a) Rounded to whole megawatts. Rating of units at 0°F.

(b) Combined cycle unit. Outage of Unit 7 (74 MW) results in 21 MW derate of Unit 6 or a total outage of 95 MW.

(c) Combined cycle unit. Outage of either Unit 6 or 7 (68 MW) results in 27 MW derate of Unit 8 or a total outage of 95 MW.

FAIRBANKS GENERATING UNITS

Plant	Unit	Capacity MW(a)	Type	Fuel
Chena	1	5	ST	Coal
	2	2	ST	Coal
	3	2	ST	Coal
	4	7	CT	Oil
	5	20	ST	Coal
	6	29	CT	Oil
	D1	2	D	Oil
	D2	2	D	Oil
	D3	2	D	Oil
FMUS Total		71		
Healy	S1	25	ST	Coal
	D1	3	D	Oil
North Pole	1	65	CT	Oil
	2	65	CT	Oil
Zehnder	GT1	18	CT	Oil
	GT2	18	CT	Oil
	GT3	3	CT	Oil
	GT4	3	CT	Oil
	D1-7	21	D	Oil
GVEA Total		221		
Fairbanks Total		292		

(a) Rounded to whole megawatts. Rating of units at 0°F.

CATEGORIZATION OF GENERATING UNITS
FOR STUDY PURPOSES

Unit Type	Fuel	Number of Units	Size Each MW	Total MW	Full Load Heat Rate BTU/kWh(a)
Hydro	-	4	8-15	46	-
Combined cycle	Gas A	1	143	143	8550
Combined cycle	Gas C	1	190	190	8430
Combustion turbine	Gas C	1	58	58	10890
Combustion turbine	Gas C	1	53	53	11160
Combustion turbine	Gas A	1	32	32	11720
Combustion turbine	Gas C	2	27	54	11970
Combustion turbine	Gas A	3	16-18	50	12230
Combustion turbine	Gas C	6	14-18	96	12230
Combustion turbine	Gas C	1	9	9	13050
Anchorage Total				731	
Steam turbine	Coal	3	2-5	9	13600
Steam turbine	Coal	1	20	20	13800
Steam turbine	Coal	1	25	25	13200
Combustion turbine	Oil	2	65	130	9200
Combustion turbine	Oil	1	29	29	11720
Combustion turbine	Oil	2	18	36	14400
Combustion turbine	Oil	3	3-7	13	13800
Diesel	Oil	11	2-3	30	11760
Fairbanks Total				292	

(a) Typical

Gas A = AMLP price
Gas C = CEA price

ECONOMIC PARAMETERS

A. Treatment of Inflation

(a) This analysis is based on a constant value of the dollar after January 1, 1984, the assumed in-service date of the tie-line.

(b) Inflationary effects before that date are included.

(c) Real price increases beyond that date are incl led in the case of fuel for power generation.

B. Annual Fixed Charge Rate

Interest on debt(a)	3.00%
Amortization of principal(b)	1.65
Interim replacement expenses	0.15
Insurance costs	0.10
Contribution in lieu of taxes	2.00
Subtotal	6.90%
Funding expense(c)	0.10
Total	7.00%

(a) Historic return to lender over inflation.
(b) Sinking fund amortization over 35-year period.
(c) Based on 1.5 percent discount on bonds to cover expenses and fees of sale.

C. Present Worth Discount Rate

Made equal to the interest rate according to convention.

D. Full Life-Cycle Fixed Charges

The present worth of 7.00 percent per year for 35 years, discounted at the rate of 3.0 percent, equals 150.41 percent.

E. Deduction for Anticipated Early Retirement

Interest on debt	3.00%
Amortization of principal (10 years)	8.72
Interim replacement expenses	0.15
Insurance costs	0.10
Contribution in lieu of taxes	2.00
Subtotal	13.97%
Funding expense	0.21
Total	14.18%
Present worth of 14.18 percent per year for 10 years	120.96%
Full life cycle charges	150.41
Deduction in percent of investment	29.45%

F. Deduction for Future Rededication of Facility

Full life cycle charges	150.41%
Present worth of 7.00 percent per year in years 11 through 45, assuming the option is to install the same facility 10 years hence	111.92
Cost of first use	38.49%
Deduction in percent of investment	111.92%

G. Operation and Maintenance Expenses for Transmission Facilities

	Per Year(a)	Present Worth 10 Years	Present Worth 35 Years
Single circuit, steel tower line			
138 kV, per mile	$ 1200	$ 10236	$ 25785
230 kV, per mile	1700	14501	36528
345 kV, per mile	2400	20473	51569
Circuit exit, each	20000	170600	429700
Transformer, each	40000	341200	859[illegible]00

(a) 1984 dollars.

H. Credit for Reduction in Requirement for Installed Generating Capacity

Capital cost of a 60 MW gas/oil-fired combustion turbine-generator unit for service on January 1, 1984	$278/kW
Credit per kilowatt-year before application of present worth factor (278 x 0.07) =	$ 19.46

I. Predicted Fuel Prices(a)

Year	Dollars Per Million BTU Oil	Gas A(b)	Gas C(c)
1984	8.54	1.91	1.58
85	8.83	1.94	1.58
86	9.10	2.16	1.58
87	9.38	2.41	1.79
88	9.67	2.66	1.88
89	9.97	2.91	2.12
90	10.28	3.16	2.34
91	10.72	3.41	3.38
92	11.18	3.66	3.50
93	11.65	3.91	3.62

(a) Reflecting real price increases only.
(b) Price to AMLP.
(c) Price to CEA.

J. Variable Component of Plant Operation and Maintenance Expenses

Steam units	$2.00 per MWh
Combustion turbines	1.50
Combined cycle units	1.70
Hydro	0.00
Diesel	4.00

COMPARATIVE ENERGY COSTS

Generation Type	MW	Fuel	Heat Rate BTU/kWh	Incremental Energy Costs - Dollars per MWh 1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Hydro	46	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle	190	Gas C	8430	15.02	15.02	15.02	16.79	17.55	19.57	21.43	30.19	31.21	32.22
Combined Cycle	143	Gas A	8550	18.03	18.29	20.17	22.31	24.44	26.58	28.72	30.86	32.99	35.13
Lg. Combustion Turbine(a)	111	Gas C	11020	18.91	18.91	18.91	21.23	22.22	24.86	27.29	38.75	40.07	41.39
(b)	32	Gas A	11720	23.89	24.24	26.82	29.75	32.68	35.61	38.54	41.47	44.40	47.33
Med.Combustion Turbine(c)	150	Gas C	12140	20.68	20.68	20.68	23.23	24.32	27.24	29.91	42.53	43.99	45.45
(d)	50	Gas A	12230	24.86	25.23	27.92	30.97	34.03	37.09	40.15	43.20	46.26	49.32
Sm. Combustion Turbine(b)	9	Gas C	13050	22.12	22.12	22.12	24.86	26.03	29.17	32.04	45.61	47.17	48.74
Anchorage Total	731												
Steam Turbines	54	Coal	13490	-	-	-	-	-	-	-	-	-	-
Lg. Combustion Turbine(e)	130	Oil	9200	80.07	82.74	85.22	87.80	90.46	93.22	96.08	100.12	104.36	108.68
Med.Combustion Turbine(f)	65	Oil	13200	114.23	118.06	121.62	125.32	129.14	133.10	137.20	143.00	149.08	155.28
Sm. Combustion Turbine(g)	13	Oil	13800	119.35	123.35	127.08	130.94	134.95	139.09	143.36	149.44	155.78	162.27
Diesels	30	Oil	11760	104.43	107.84	111.02	114.31	117.72	121.25	124.89	130.07	135.48	141.00
Fairbanks Total	292												

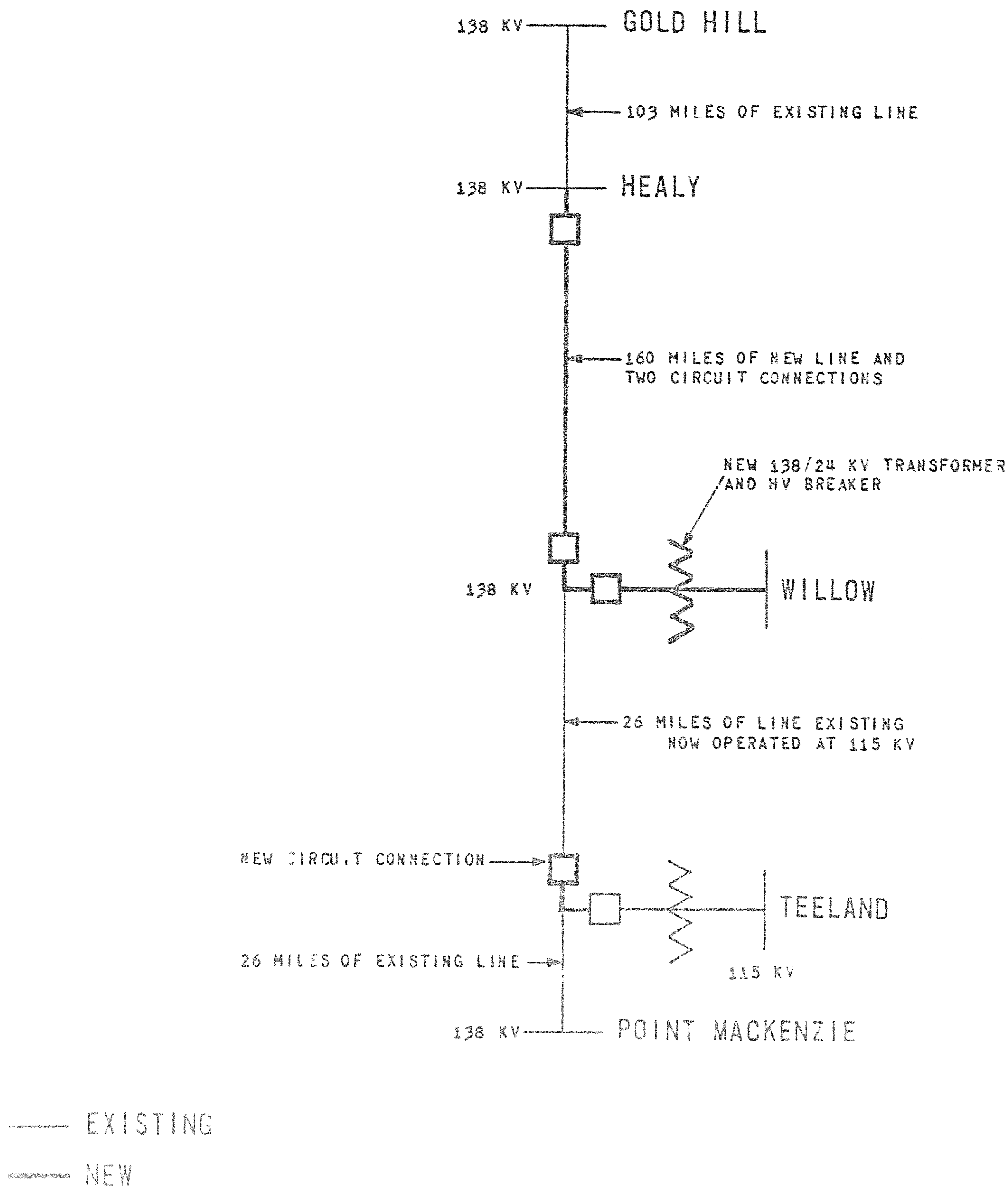
(a) One 53 MW and one 58 MW.
(b) One unit.
(c) Eight units, 14 to 27 MW each.
(d) Three units. 16 to 18 MW each.
(e) Two 65 MW units.
(f) Three units, 18 to 29 MW each.
(g) Three units, 3 to 7 MW each.

EXHIBIT 3
SHEET 4 OF 4

ALTERNATIVE PLAN 1
FOR THE ANCHORAGE-FAIRBANKS TIE-LINE

PLAN 1A: NEW LINE CONSTRUCTED FOR 138 KV OPERATION

PLAN 1B: NEW LINE CONSTRUCTED FOR FUTURE 345 KV OPERATION BUT OPERATED INITIALLY AT 138 KV

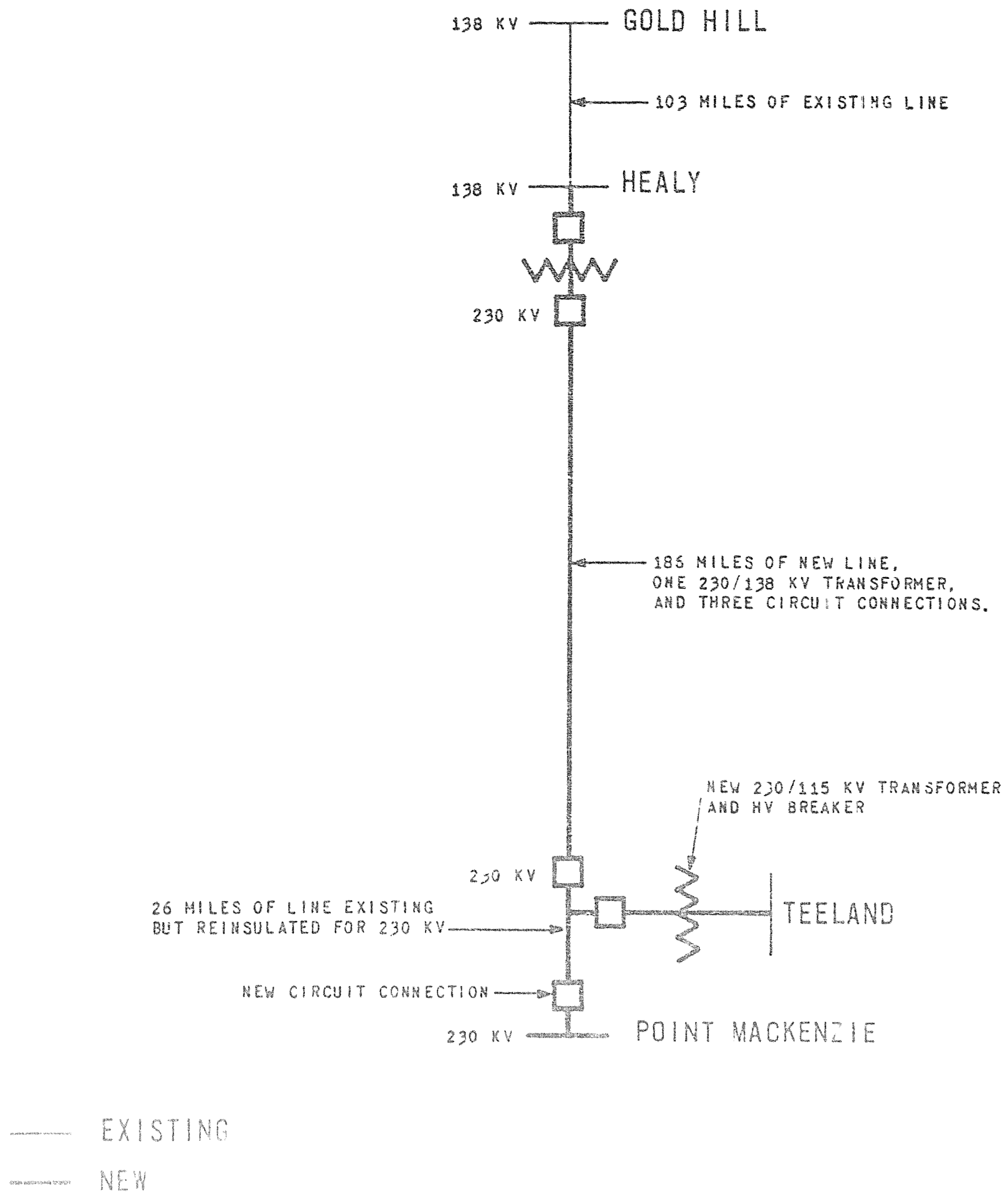


EXISTING SWITCHGEAR NOT SHOWN EXCEPT WHERE NEEDED FOR CLARITY OF CONCEPT.

ALTERNATIVE PLAN 2
FOR THE ANCHORAGE-FAIRBANKS TIE-LINE

PLAN 2A: NEW LINE CONSTRUCTED FOR 230 KV OPERATION

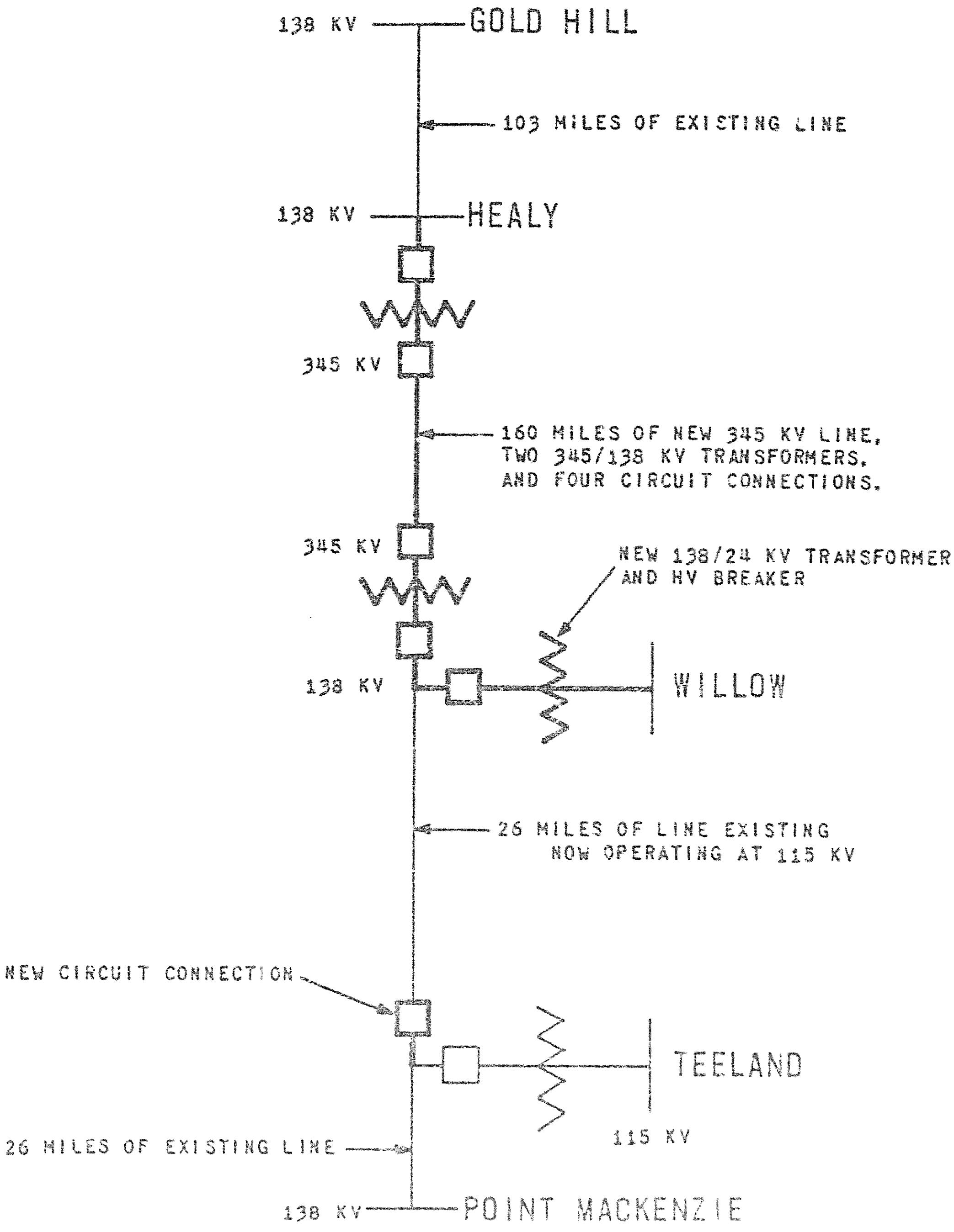
PLAN 2B: NEW LINE CONSTRUCTED FOR FUTURE 345 KV OPERATION BUT OPERATED INITIALLY AT 230 KV



EXISTING SWITCHGEAR NOT SHOWN.

ALTERNATIVE PLAN 3
FOR THE ANCHORAGE-FAIRBANKS TIE-LINE

NEW LINE CONSTRUCTED AND OPERATED AT 345 KV



——— EXISTING

——— NEW

EXISTING SWITCHGEAR NOT SHOWN EXCEPT WHERE NEEDED FOR CLARITY OF CONCEPT.

INTERTIE POWER TRANSFER CAPABILITY

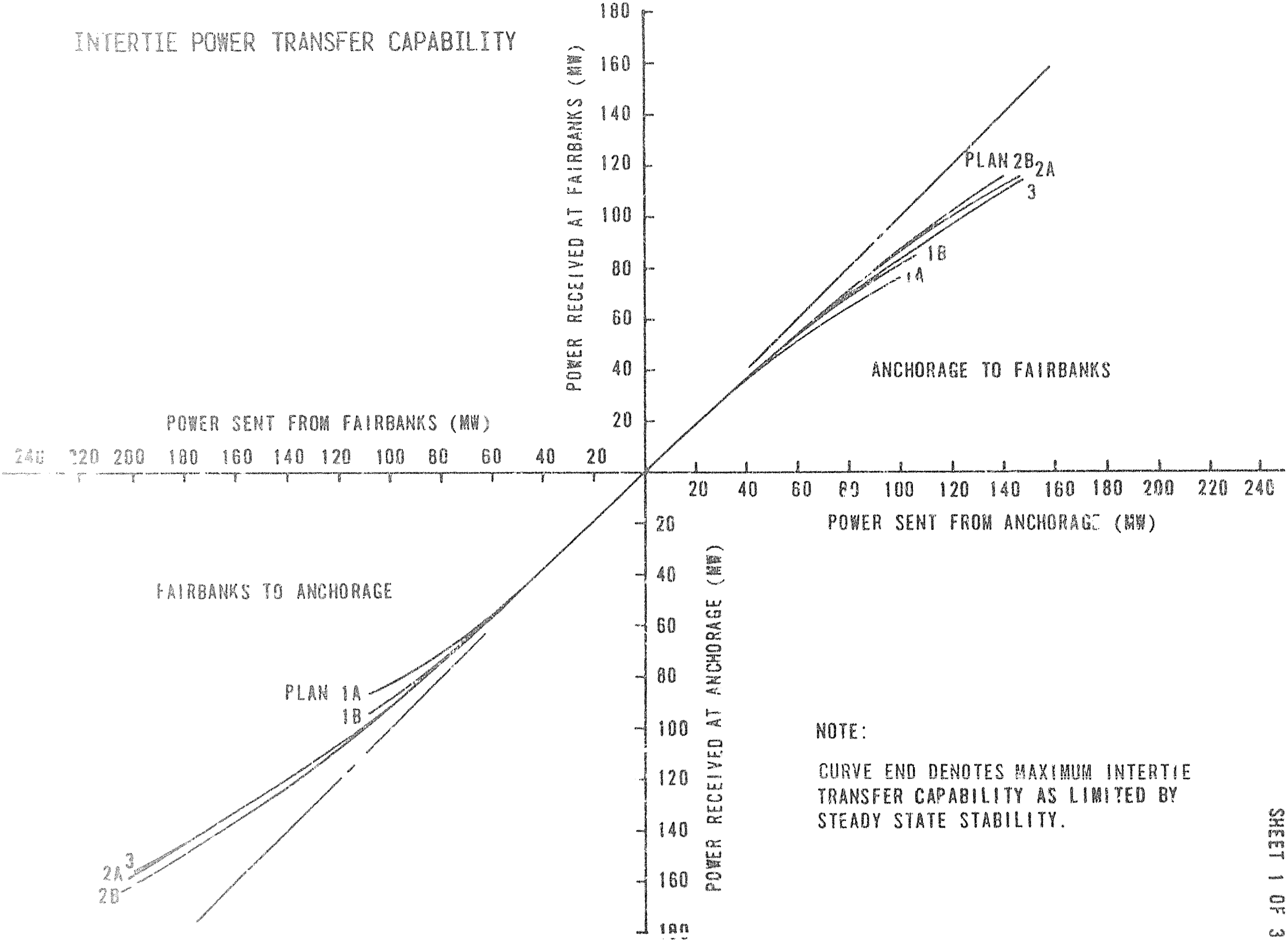
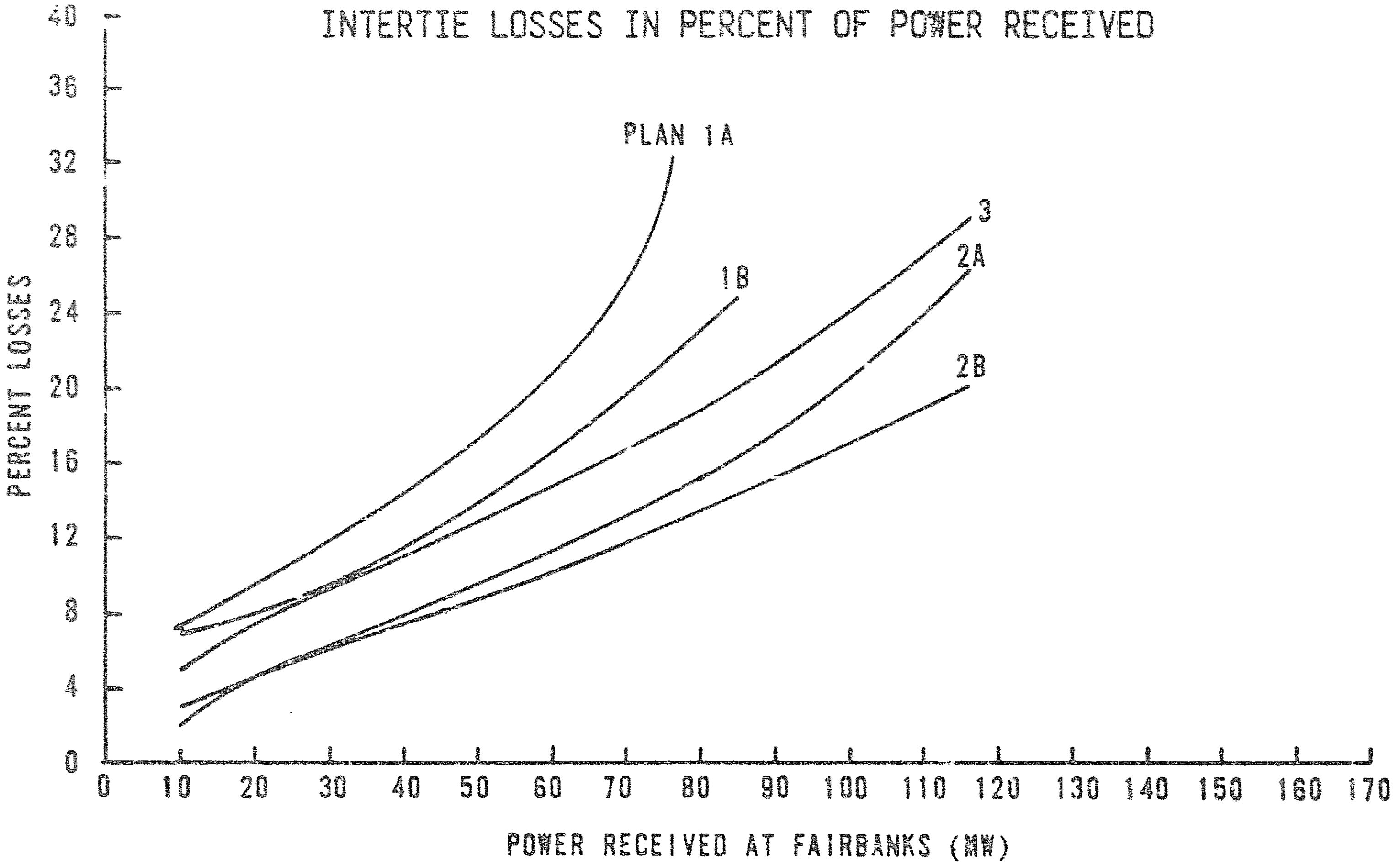
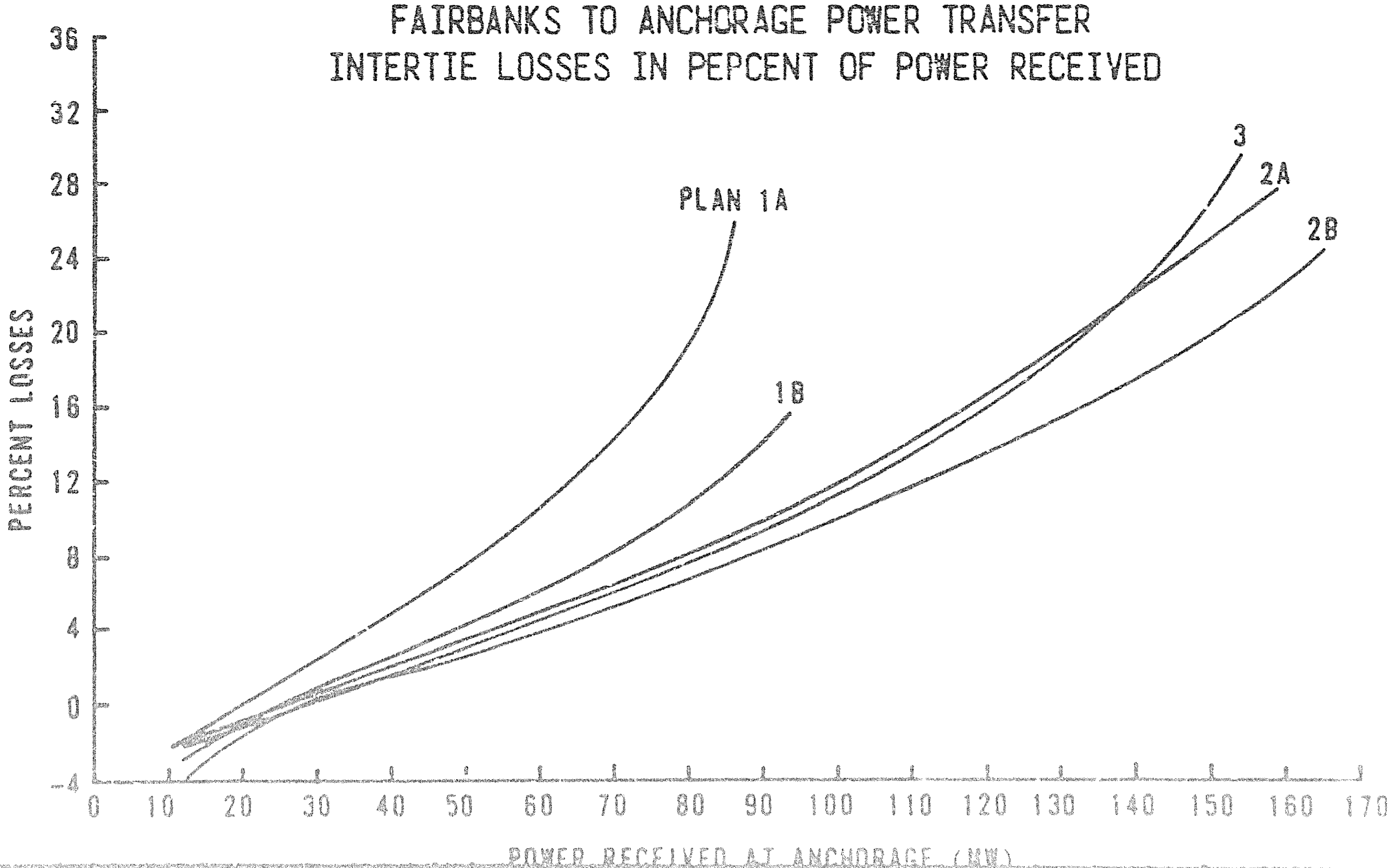


EXHIBIT 5
SHEET 1 OF 3

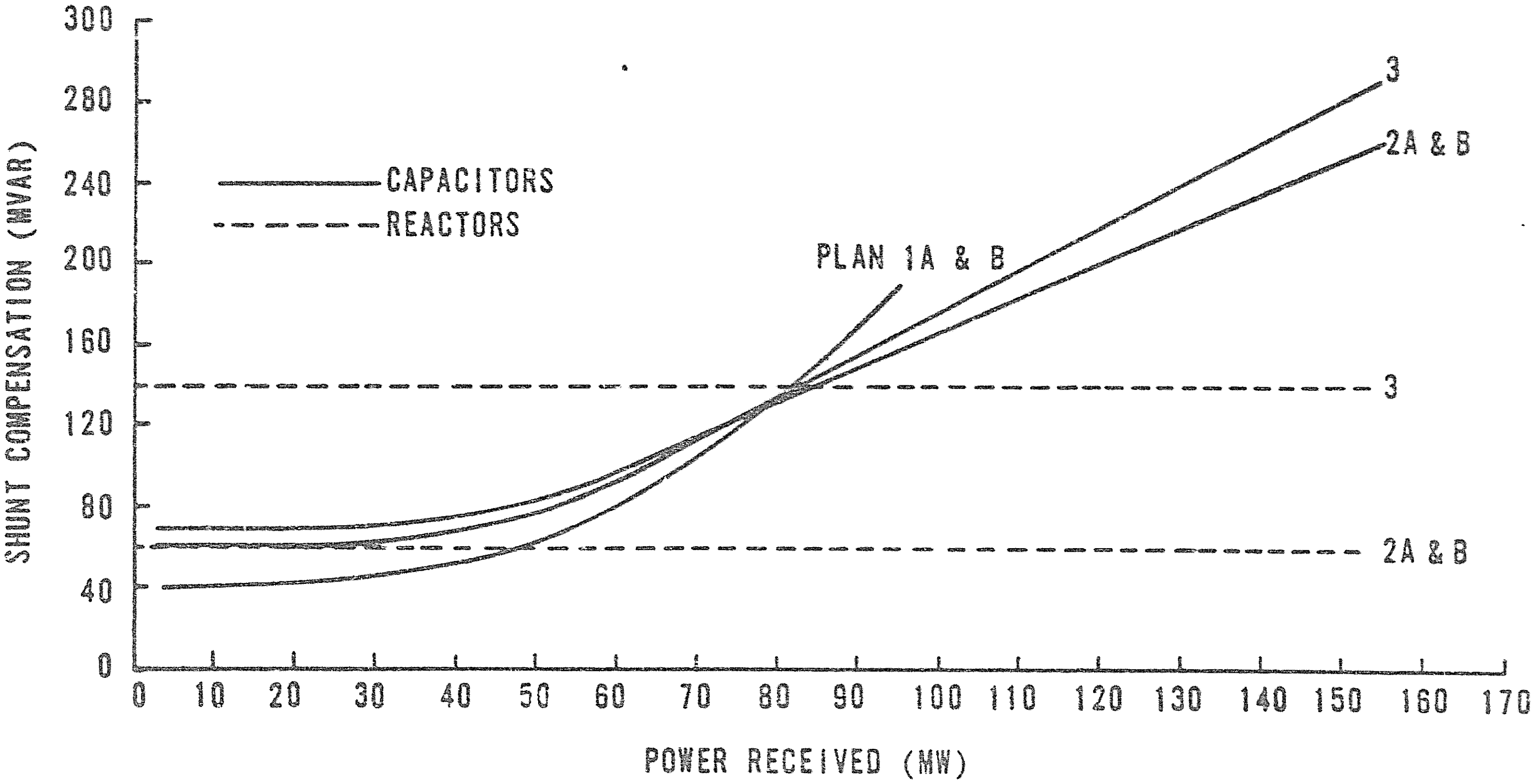
ANCHORAGE TO FAIRBANKS POWER TRANSFER
INTERTIE LOSSES IN PERCENT OF POWER RECEIVED



FAIRBANKS TO ANCHORAGE POWER TRANSFER
INTERTIE LOSSES IN PEPCENT OF POWER RECEIVED



SHUNT CAPACITOR AND REACTOR REQUIREMENTS



CAPITAL COST ESTIMATE
PLANS 1A AND 1B
(Thousands of Dollars)

	Miles	Cost Per Mile	Total 1984 Cost Plan 1A	Total 1984 Cost Plan 1B
Transmission Lines				
Healy-Willow 138 kV	160	323(a)	51,680	-
Healy-Willow 345 kV (Operated 138 kV)	160	590(a)	-	94,400
Willow-Teeland 115 kV (Operated 138 kV)	26	0(b)	0	0
Subtotal			51,680	94,400
Substations(c)				
Teeland			1,394	1,394
Willow			1,720	1,720
Healy			661	661
Gold Hill			1,304	1,304
Subtotal			5,079	5,079
Total Project			56,759	99,479
Recapitulation				
Facilities rededicatable to Susitna Project			0	94,400
Facilities retired by Susitna Project			56,759	5,079
Total			56,759	99,479

(a) See Sheet 4.

(b) The existing Willow-Teeland 115 kV line can be operated at 138 kV without modification.

(c) See Sheet 5.

CAPITAL COST ESTIMATE
PLANS 2A AND 2B
(Thousands of Dollars)

	Miles	Cost Per Mile	Total 1984 Cost Plan 2A	Total 1984 Cost Plan 2B
Transmission Lines				
Healy-Teeland 230 kV	186	358(a)	66,588	-
Healy-Teeland 345 kV (Operated 230 kV)	186	590(a)	-	109,740
Teeland-Pt. MacKenzie 230 kV (Reinsulate existing 138 kV line)	26	6(a)	156	156
Subtotal			66,744	109,896
Substations(b)				
Point MacKenzie			831	831
Teeland			4,361	4,361
Healy			4,415	4,415
Gold Hill			1,304	1,304
Subtotal			10,911	10,911
Total Project			77,655	120,807
Recapitulation				
Facilities rededicatable to Susitna Project			0	109,740
Facilities retired by Susitna Project			77,655	11,067
Total			77,655	120,807

(a) See Sheet 4.

(b) See Sheet 5.

CAPITAL COST ESTIMATE
PLAN 3
(Thousands of Dollars)

	Miles	Cost Per Mile	Total 1984 Cost
Transmission Lines			
Healy-Willow 345 kV	160	590(a)	94,400
Willow-Teeland 115 kV (Operated 138 kV)	26	0(b)	0
Subtotal			94,400
Substations(c)			
Teeland			1,394
Willow			7,574
Healy			5,604
Gold Hill			1,304
Subtotal			15,876
Total Project			110,276
Recapitulation			
Facilities rededicatable to Susitna Project			94,400
Facilities retired by Susitna Project			15,876
Total			110,276

(a) See Sheet 4.

(b) The existing Willow-Teeland 115 kV line can be operated at 138 kV without modification.

(c) See Sheet 5.

TRANSMISSION LINE COSTS PER MILE
(Thousands of Dollars)

	New Construction Single Circuit			Reinsulate(a)
	138 kV	230 kV	345 kV	230 kV
Labor and Material	119.0	133.0	248.0	3.0
Engineering (5%)	6.0	6.7	12.4	.1
Construction Management (5%)	6.0	6.7	12.4	.1
Owner's Costs (2.5%)	2.9	3.2	6.2	.1
Contingencies (20%)	23.8	26.6	49.6	.6
AFUDC (7%)	8.3	9.3	17.4	.2
Subtotal (1981 Dollars)	166.0	185.5	346.0	4.1
Right-of-Way and Clearing	64.0	69.0	74.0	0
Total (1981 Dollars)	230.0	254.5	420.0	4.1
Inflation (12% per year)	93.0	103.5	170.0	1.7
Total (1984 Dollars)	323.0	358.0	590.0	5.8

(a) Estimated cost to reinsulate Pt. MacKenzie-Teeland 138 kV circuit for 230 kV operation.

(b) AFUDC is allowance for funds used during construction.

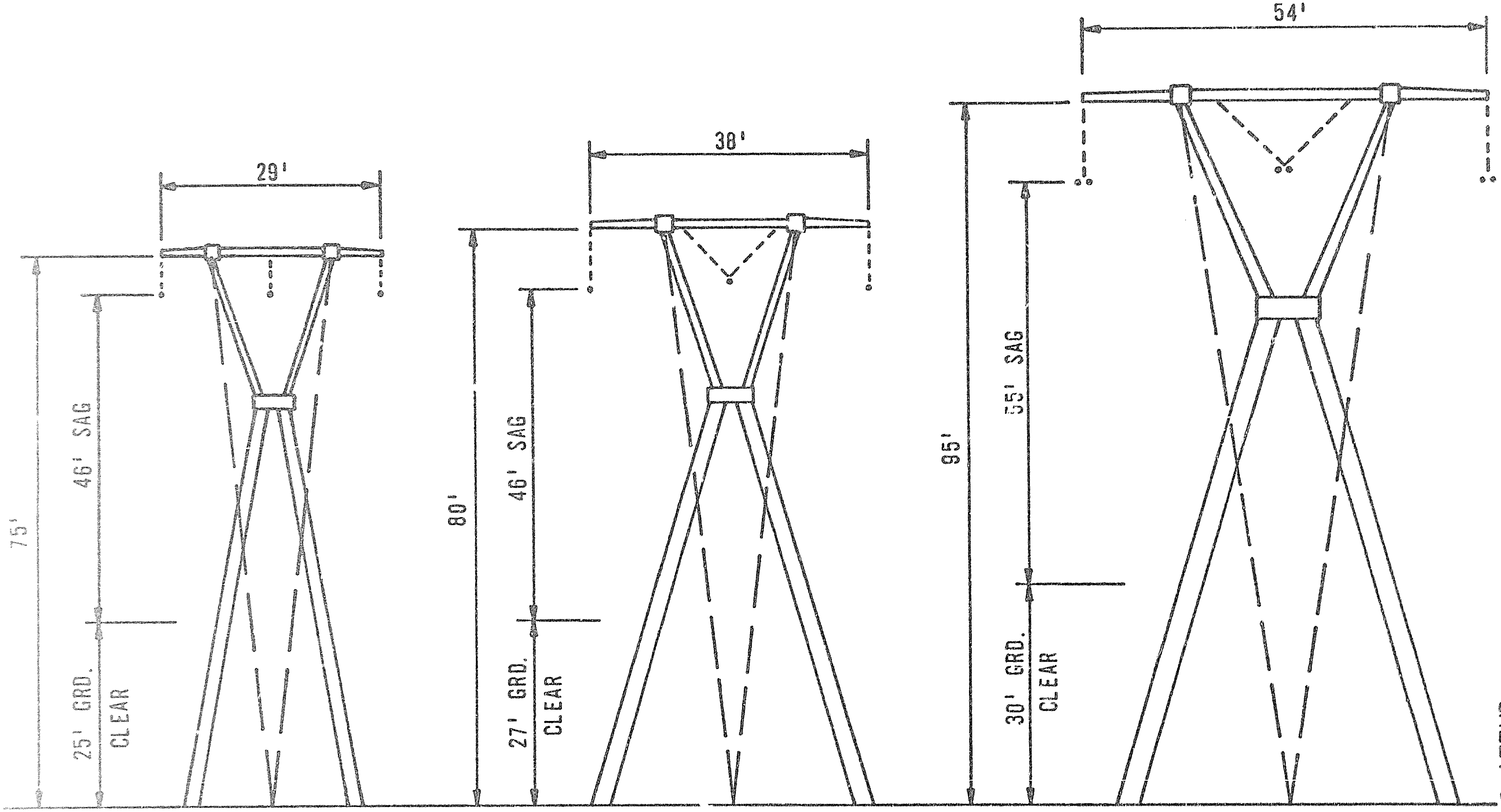
SUBSTATION COSTS
(Thousands of Dollars)

	Plans 1A & 1B				Plans 2A & 2B				Plan 3			
	Teeland	Willow	Healy	Gold Hill	Point MacKenzie	Teeland	Healy	Gold Hill	Teeland	Willow	Healy	Gold Hill
Labor and Material	696.0	859.0	330.0	651.0	415.0	2,178.0	2,205.0	651.0	696.0	3,783.0	2,799.0	651.0
Engineering (10%)	69.6	85.9	33.0	65.1	41.5	217.8	220.5	65.1	69.6	378.3	279.9	65.1
Const. Manag. (5%)	34.8	43.0	16.5	32.6	20.8	108.9	110.3	32.6	34.8	18[illegible].2	140.0	32.6
Owner's Cost (2.5%)	17.4	21.5	8.3	16.3	10.4	54.5	55.1	16.3	17.4	94.6	70.0	16.3
Contingencies (20%)	139.2	171.8	66.0	130.2	83.0	435.6	441.0	130.2	139.2	756.6	559.8	130.2
AFUDC(a)(4.5%)	31.3	38.7	14.9	29.3	18.7	98.0	99.2	29.3	31.3	170.2	126.0	29.3
Total (1981 Dollars)	988.3	1,219.9	468.7	924.5	589.4	3,092.8	3,131.1	924.5	988.3	5,371.9	3,974.7	924.5
Inflation (12% per year)	405.7	500.1	192.3	379.5	241.6	1,268.2	1,283.9	379.5	405.7	2,202.1	1,629.3	379.5
Total (1984 Dollars)	1,394.0	1,720.0	661.0	1,304.0	831.0	4,361.0	4,415.0	1,304.0	1,394.0	7,574.0	5,604.0	1,304.0

(a) AFUDC is allowance for funds used during construction

EXHIBIT 6
SHEET 5 OF 6

TYPICAL TRANSMISSION TOWERS



138 KV	230 KV	345 KV
1200' SPAN	1200' SPAN	1200' SPAN
1-954 KCMIL ACSR	1-954 KCMIL ACSR	2-1272 KCMIL ACSR
CONDUCTOR PER PHASE	CONDUCTOR PER PHASE	CONDUCTORS PER PHASE

ECONOMY INTERCHANGE BENEFITS AFFORDED BY THE ANCHORAGE-FAIRBANKS TIE-LINE

BASIS FOR EVALUATION

A. The economy energy which Anchorage may send to Fairbanks in any given year may be quantified as that which lies above the Anchorage load-duration curve and below a horizontal line representing 602 MW of generating capacity.

B. The 602 MW level is derived thus:

Total Anchorage generation	731 MW
Thermal units less than 10 MW	9
Remainder	722 MW
Average unavailability (Thermal units 15%, hydro 43%)	120
Remainder	602 MW

C. The economy energy which Fairbanks may receive from Anchorage in any given year may be quantified as that which lies below the Fairbanks load-duration curve and above a horizontal line representing 57 to 65 MW of generating capacity, depending upon the year.

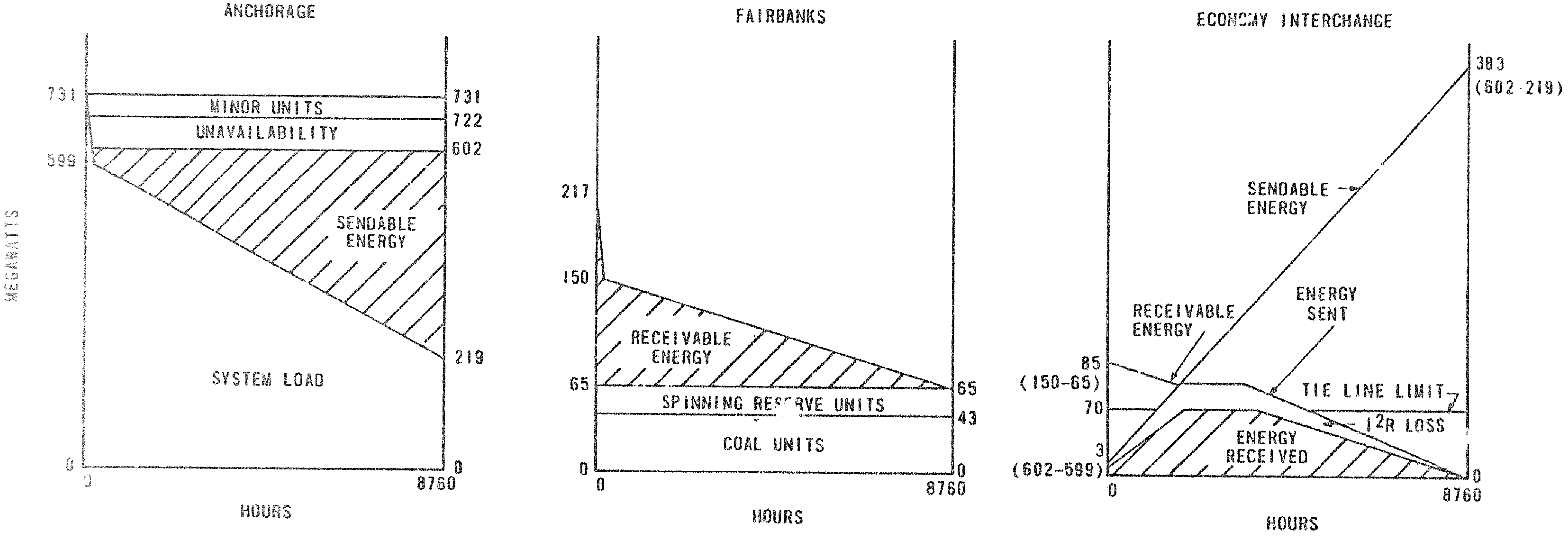
D. The 57 to 65 MW level is derived thus, using 1993 as an example:

Capacity of coal units	54 MW
Average unavailability (15%)	8
Regulating margin (5%)	3
Average output of coal units	43 MW
Average system demand	108 MW
Spinning reserve (Largest coal unit)	25
Average capacity required to spin	133 MW
Average capacity of coal units	46
Remainder	87 MW
Minimum output of remainder (25%)	22
Average output of Fairbanks generation (43 + 22)	65 MW

E. The allowable economy interchange is defined by the extent to which the sendable energy area and the receivable energy area overlap, with adjustment for I^2R losses and tie line limitations. The procedure is illustrated geometrically on Sheet 3. The actual calculations were made by computer.

F. The interchange energy is priced according to the position of the sendable and receivable energy blocks on the load-duration curve using the incremental energy costs shown in Exhibit 3.

ILLUSTRATION OF METHOD USED TO QUANTIFY ECONOMY INTERCHANGE USING 1993 AS AN EXAMPLE



NOTE THE VERTICAL SCALE IS CHANGED AFTER SKETCH I FOR BETTER READABILITY.

EXHIBIT 7
SHEET 3 OF 7

AVERAGE COST OF ANCHORAGE ENERGY FOR ECONOMY INTERCHANGE (c)

Generation type	MW	Fuel	1984 Contr. (%)(b)	1984 Cost ($/MWH)(a)	1985 Contr. (%)(b)	1985 Cost ($/MWH)(a)	1986 Contr. (%)(b)	1986 Cost ($/MWH)(a)	1987 Contr. (%)(b)	1987 Cost ($/MWH)(a)	1988 Contr. (%)(b)	1988 Cost ($/MWH)(a)
Combined Cycle	143	Gas A	18	18.03	15	18.29	40	20.17	36	22.31	55	24.44
Large Combustion Turbines	111	Gas C	45	18.91	37	18.91	7	18.91	6	21.23	6	22.22
Large Combustion Turbines	32	Gas A	-	-	-	-	-	-	1	29.75	3	32.68
Medium Combustion Turbines	150	Gas C	37	20.68	48	20.68	53	20.68	56	23.23	36	24.32
Medium Combustion Turbines	50	Gas A	-	-	-	-	-	-	-	-	-	-
Weighted Average Cost				19.41		19.66		20.34		22.82		24.56

Generation Type	MW	Fuel	1989 Contr. (%)(b)	1989 Cost ($/MWH)(a)	1990 Contr. (%)(b)	1990 Cost ($/MWH)(a)	1991 Contr. (%)(b)	1991 Cost ($/MWH)(a)	1992 Contr. (%)(b)	1992 Cost ($/MWH)(a)	1993 Contr. (%)(b)	1993 Cost ($/MWH)(a)
Combined Cycle	143	Gas A	30	26.58	28	28.72	7	30.86	6	32.99	6	35.13
Large Combustion Turbines	111	Gas C	5	24.86	4	27.29	20	38.75	18	40.07	18	41.39
Large Combustion Turbines	32	Gas A	6	35.61	9	38.54	[illegible]	41.47	12	44.40	12	47.33
Medium Combustion Turbines	150	Gas C	58	27.24	55	29.91	53	42.53	45	43.99	43	45.45
Medium Combustion Turbines	50	Gas A	1	37.09	4	40.15	11	43.20	18	46.26	21	49.32
Weighted Average Cost				27.55		30.60		40.92		43.03		45.21

(a) From Exhibit 3, Sheet 4.

(b) Percent of economy energy supplied by each generation type, assuming the lowest cost units are dispatched first to supply the sending system's own load. The average unit availability assumed is 85 percent.

(c) Based on Plan 1A. Other plans calculated in a similar manner.

ECONOMY INTERCHANGE BENEFITS
PLAN 1A

Year	Anchorage GWH Sent	Anchorage $/MWH(a)	Anchorage Cost ($ Millions)	Fairbanks GWH Received	Fairbanks $/MWH(b)	Fairbanks Cost ($ Millions)	Benefit ($ Millions)	Present Worth(c) ($ Millions)
1984	206	19.41	4.0	186	80.07	14.9	10.9	10.6
85	248	19.66	4.9	222	82.74	18.4	13.5	12.7
86	262	20.34	5.3	234	85.22	19.9	14.6	13.4
87	272	22.82	6.2	242	87.80	21.3	15.1	13.4
88	291	24.56	7.2	259	90.46	23.4	16.2	14.0
1989	297	27.55	8.1	263	93.22	24.5	16.4	13.7
90	316	30.60	9.7	280	96.08	26.9	17.2	14.0
91	346	40.92	14.2	304	100.12	30.5	16.3	12.9
92	359	43.03	15.4	315	104.36	32.8	17.4	13.3
93	345	45.21	15.6	304	108.68	33.0	17.4	13.0
Subtotal							155.0	130.9
1994 to 2018							155.0(d)	98.4
Total							310.0	229.3

(a) See Sheet 4.
(b) Large oil fired combustion turbine cost avoided. See Exhibit 3, Sheet 4.
(c) Discounted at 3 percent per year.
(d) Assuming $15.5 million per year for 10 additional years and $0 per year thereafter.

ECONOMY INTERCHANGE BENEFITS
PLANS 1B and 3

Year	Anchorage GWH Sent	Anchorage $/MWH(a)	Anchorage Cost ($ Millions)	Fairbanks GWH Received	Fairbanks $/MWH(b)	Fairbanks Cost ($ Millions)	Benefit ($ Millions)	Present Worth(c) ($ Millions)
1984	203	19.41	3.9	186	80.07	14.9	11.0	10.6
85	244	19.66	4.8	222	82.74	18.4	13.6	12.8
86	257	20.34	5.2	234	85.22	19.9	14.7	13.5
87	267	22.81	6.1	242	87.80	21.3	15.2	13.5
88	286	24.53	7.0	259	90.46	23.4	16.4	14.1
1989	291	27.53	8.0	263	93.22	24.5	16.5	13.8
90	310	30.57	9.5	280	96.08	26.9	17.4	14.1
91	339	40.92	13.9	305	100.12	30.5	16.6	13.1
92	352	43.03	15.2	316	104.36	33.0	17.8	13.7
93	339	45.20	15.3	305	108.68	33.1	17.8	13.3
Subtotal							157.0	132.5
1994 to 2018							157.0(d)	99.7
Total							314.0	232.2

(a) See Sheet 4.
(b) Large oil fired combustion turbine cost avoided. See Exhibit 3, Sheet 4.
(c) Discounted at 3 percent per year.
(d) Assuming $15.7 million per year for 10 additional years and $0 per year thereafter.

ECONOMY INTERCHANGE BENEFITS
PLANS 2A and 2B

Year	Anchorage GWH Sent	Anchorage $/MWH(a)	Anchorage Cost ($ Millions)	Faribanks GWH Received	Faribanks $/MWH(b)	Faribanks Cost ($ Millions)	Benefit ($ Millions)	Present Worth(c) ($ Millions)
1984	196	19.41	3.8	186	80.07	14.9	11.1	10.8
85	235	19.65	4.6	222	82.74	18.4	13.8	13.0
86	248	20.34	5.0	234	85.22	19.9	14.9	13.6
87	257	22.80	5.9	242	87.80	21.3	15.4	13.7
88	275	24.49	6.7	259	90.46	23.4	16.7	14.4
1989	280	27.47	7.7	263	93.22	24.5	16.8	14.1
90	298	30.50	9.1	280	96.08	26.9	17.8	14.4
91	327	40.92	13.4	306	100.12	30.6	17.2	13.6
92	341	43.03	14.7	318	104.36	33.2	18.5	14.2
93	329	45.20	14.9	307	108.68	33.4	18.5	13.8
Subtotal							160.7	135.6
1994 to 2018							160.7(d)	102.0
Total							321.4	237.6

(a) See Sheet 4.
(b) Large oil fired combustion turbine cost avoided. See Exhibit 3, Sheet 4.
(c) Discounted at 3 percent per year.
(d) Assuming $16.07 million per year for 10 additional years and $0 per year thereafter.

RESERVE SHARING BENEFITS AFFORDED BY THE ANCHORAGE-FAIRBANKS TIE-LINE

BASIS FOR EVALUATION

A. If non-interconnected, Anchorage and Fairbanks must each maintain installed reserve* generation at least equal to the capacity of the two largest units in service on their respective systems.

B. If interconnected, each system may reduce its installed reserve by the net amount of power receivable over the tie-line. Since the tie-line may be out of service, the same as a generating unit, there is a limit to the amount of capacity that can be relied upon by the receiving system. The maximum capacity the tie-line can supply for reserve sharing without decreasing the level of reliability is equal to the size of the second largest unit on the receiving system. The net amount of power receivable is limited by the installed reserve on the opposite system, tie-line capacity, and tie-line losses.

C. Since rules A and B are designed to provide adequate service continuity over an entire yearly load cycle, not just at the time of peak demand, it is proper to include 3 percent load diversity in this analysis.

D. The benefits of reserve sharing are evaluated at the average cost per kilowatt for a gas or oil-fired combustion turbine (assumed 60 MW unit).

*Installed reserve is the excess of the capability of commissioned generating units over the current system peak demand. It is not the same as spinning reserve, although the two are indirectly related. Moreover, reserve sharing does not normally involve the exchange of energy in significant amounts.

REQUIRED ADDITIONAL GENERATING CAPACITY
WITHOUT INTERCONNECTION
(Megawatts)

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Anchorage												
Peak Demand	526	552	567	582	598	614	630	662	696	731	768	807
Largest unit	95	95	95	95	95	95	95	95	95	95	95	95
Second largest unit	95	95	95	95	95	95	95	95	95	95	95	95
Required capacity	716	742	757	772	788	804	820	852	886	921	958	997
Installed	731	731	731	731	731	731	731	731	731	731	731	731
Short	-	11	26	41	57	73	89	121	155	190	227	266
Fairbanks												
Peak demand	156	169	172	176	180	183	187	196	206	217	228	239
Largest unit	65	65	65	65	65	65	65	65	65	65	65	65
Second largest unit	65	65	65	65	65	65	65	65	65	65	65	65
Required capacity	286	299	302	306	310	313	317	326	336	347	358	369
Installed	292	292	292	292	292	292	292	292	292	292	292	292
Short	-	7	10	14	18	21	25	34	44	55	66	77
Total short	-	18	36	55	75	94	114	155	199	245	293	343

EXHIBIT 8
SHEET 2 of 5

REQUIRED ADDITIONAL GENERATING CAPACITY
ANCHORAGE WITH INTERCONNECTION
(Megawatts)

With the Two Largest Units Out of Service at Anchorage	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Anchorage peak demand	526	552	567	582	598	614	630	662	696	731	768	807
Anchorage generation	541	541	541	541	541	541	541	541	541	541	541	541
Short	-	11	26	41	57	73	89	121	155	190	227	266
Tie-line inflow	-	11	26	41	57	70(c)	70(c)	70(c)	70(c)	70(c)	70(c)	70(c)
Short	0	-	-	-	-	3	19	51	85	120	157	196
Fairbanks generation	-	292	292	292	292	292	292	292	292	292	293(d)	304(d)
Fairbanks load(a)	-	147	150	153	157	159	162	170	179	189	198	208
Fairbanks reserve	-	145	142	139	135	133	130	122	113	103	95	96
Tie-line inflow(b)	-	11	26	41	57	70	70	70	70	70	70	70
Tie-line losses	-	1	3	6	11	16	16	16	16	16	16	16
Balance of reserve	-	133	113	92	67	47	44	36	27	17	9	10

(a) Coincident with the Anchorage peak demand.
(b) At Anchorage.
(c) Maximum allowable as limited by tie line.
(d) Assuming Fairbanks adds the generation indicated as a shortage on Sheet 4.

REQUIRED ADDITIONAL GENERATING CAPACITY
FAIRBANKS WITH INTERCONNECTION
(Megawatts)

With the Two Largest Units Out of Service at Fairbanks	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Fairbanks peak demand	156	169	172	176	180	183	187	196	206	217	228	239
Fairbanks generation	162	162	162	162	162	162	162	162	162	162	162	162
Short	-	7	10	14	18	21	25	34	44	55	66	77
Tie-line inflow	-	7	10	14	18	21	25	34	44	55	65(c)	65(c)
Short	-	-	-	-	-	-	-	-	-	-	1	12
Anchorage generation	-	731	731	731	731	734(d)	750(d)	782(d)	816(d)	851(d)	888(d)	927(d)
Anchorage load(a)	-	530	545	559	575	590	605	636	669	703	738	776
Anchorage reserve	-	201	186	172	156	144	145	146	147	148	150	151
Tie-line inflow(b)	-	7	10	14	18	21	25	34	44	55	65	65
Tie-line losses	-	0	1	1	2	2	3	4	7	10	14	14
Balance of reserve	-	194	175	157	136	121	117	108	96	83	71	72
Anchorage short(e)	-	-	-	-	-	3	19	51	85	120	157	196
Fairbanks short	-	-	-	-	-	-	-	-	-	-	1	12
Total short	-	-	-	-	-	3	19	51	85	120	158	208

(a) Coincident with the Fairbanks peak demand.
(b) At Fairbanks
(c) Maximum allowable (size of second largest unit).
(d) Assuming Anchorage adds the generation indicated as shortage on Sheet 3.
(e) From Sheet 3.

ECONOMIC BENEFITS OF RESERVE SHARING

Year	New Capacity Needed(MW) No Tie	With Tie	Difference	Benefit(a) ($Millions)	Present Worth ($Millions)(b)
1984	-	-	-	-	-
85	18	-	18	.35	.33
86	36	-	36	.70	.64
87	55	-	55	1.07	.95
88	75	-	75	1.46	1.26
89	94	3	91	1.77	1.48
90	114	19	95	1.85	1.50
91	155	51	104	2.02	1.60
92	199	85	114	2.22	1.70
93	245	120	125	2.43	1.81
				13.87	11.28
1994 to 2018			135(c)	65.68	34.03
				79.55	45.31

(a) At $19.46 per kW per year (see Exhibit 3).

(b) Discounted at 3 percent per year.

(c) The maximum benefit afforded by a single tie. Limited by the lesser of the tie line limit or the capacity of the second largest unit.

LIFE-CYCLE COSTS AND BENEFITS(a)
OF THE ANCHORAGE-FAIRBANKS TIE-LINE
EXCLUDING SUSITNA IMPACT(b)
(Millions of Dollars)

Alternative Plan	Costs			Benefits			Ratio of Benefits To Costs	Capital Cost
	Fixed Charges	Tie-Line O&M	Total	Economy Interchange	Reserve Sharing(c)	Total		
1A - 138 kV	85.4	6.7	92.1	229.3	45.3	274.6	3.0	56.8
1B - 138/345 kV	149.7	10.8	160.5	232.2	45.3	277.5	1.7	99.5
2A - 230 kV	116.9	10.9	127.8	237.6	45.3	282.9	2.2	77.7
2B - 230/345 kV	181.7	13.7	195.4	237.6	45.3	282.9	1.4	120.8
3 - 345 kV	165.9	13.4	179.3	232.2	45.3	277.5	1.5	110.3

(a) Present worth of additional annual expenses and benefits throughout a 35-year period of debt amortization.

(b) Ignoring any effect that the Susitna Project may have upon the operation and usefulness of the tie-line, or assuming there is no Susitna Project within the period of study.

(c) Including the advantages of load diversity.

LIFE-CYCLE COSTS AND BENEFITS(a)
OF THE ANCHORAGE-FAIRBANKS TIE-LINE
INCLUDING SUSITNA IMPACT(b)
(Millions of Dollars)

	Costs					Benefits			Ratio of	
Alternative Plan	Fixed Charges(c)	Retirement Credit(d)	Rededication Credit(e)	Tie-Line O&M	Total	Economy Interchange	Reserve Sharing(f)	Total	Benefits To Costs	Capital Costs
1A - 138 kV	85.4	(16.7)	-	2.7	71.4	130.9	11.3	142.2	2.0	56.8
1B - 138/345 kV	149.7	(1.5)	(105.7)	4.3	46.8	132.5	11.3	143.8	3.1	99.5
2A - 230 kV	116.9	(22.9)	-	4.3	98.3	135.6	11.3	146.9	1.5	77.7
2B - 230/345 kV	181.7	(3.3)	(122.8)	5.5	61.6	135.6	11.3	146.9	2.4	120.8
3 - 345 kV	165.9	(4.7)	(105.7)	5.3	60.8	132.5	11.3	143.8	2.4	110.3

(a) Present worth of additional annual expenses and benefits during the period 1984 to 1993, inclusive, assuming that in 1994 the tie-line facilities are either retired or rededicated to the Susitna Project, and that costs and benefits after 1993 are therefore irrelevant to this analysis.

(b) Assuming the Susitna Project and associated transmission facilities are placed in service in 1994, and that these facilities serve Anchorage and Fairbanks in parallel.

(c) For 35 years but reduced to the 1984-1993 period by application of the pertinent credits shown in the two columns following.

(d) Deduction from 35-year fixed charges for facilities retired in 1994.

(e) Deduction from 35-year fixed charges for facilities rededicated to the Susitna Project.

(f) Including the advantages of load diversity.

SUMMARY OF SENSITIVITY ANALYSIS
LIFE-CYCLE COSTS AND BENEFITS (a)
EXCLUDING SUSITNA IMPACT (b)

	Capital Costs	Life-Cycle Costs (c)	Life-Cycle Benefits: Economy Interchange	Life-Cycle Benefits: Reserve Sharing (d)	Life-Cycle Benefits: Total	Ratio of Benefits To Costs
Plan 1A - 138 kV						
Base Case	56.8	92.1	229.3	45.3	274.6	3.0
Alternate Cases						
A. Load Growth						
1. High			263.1	52.8	315.9	3.4
2. Low			193.3	37.8	231.1	2.5
B. Future Power Sources						
1. Excess Military Generation			190.2	43.8	234.0	2.5
2. Bradley Lake Hydro			236.6	42.4	279.0	3.0
3. Bradley Lake & Military Generation			196.7	40.9	237.6	2.6
C. Coal Fuel in New Power Plants			229.3	406.3	635.6	6.9
D. Alternate Fuel in the Fairbanks Area						
1. North Slope Gas in Fairbanks			99.8	45.3	145.1	1.6
2. LNG in Fairbanks			176.0	45.3	221.3	2.4
Plan 1B - 138 kV						
Base Case	99.5	160.5	232.2	45.3	277.5	1.7
Alternative Cases						
A. Load Growth						
1. High			267.4	52.8	320.2	2.0
2. Low			195.2	37.8	233.0	1.5
B. Future Power Sources						
1. Excess Military Generation			192.5	43.8	236.3	1.5
2. Bradley Lake Hydro			239.6	42.4	282.0	1.8
3. Bradley Lake & Military Generation			199.0	40.9	239.9	1.5
C. Coal Fuel in New Power Plants			232.2	406.3	638.5	4.0
D. Alternate Fuel in the Fairbanks Area						
1. North Slope Gas in Fairbanks			102.5	45.3	147.8	0.9
2. LNG in Fairbanks			178.8	45.3	224.1	1.4

(a) Present worth of additional annual expenses and benefits throughout a 35 year period of debt amortization.

(b) Ignoring any effect that the Susitna Project may have upon the operation and usefulness of the tie-line, or assuming there is no Susitna Project within the period of study.

(c) Total life-cycle costs from Exhibit 9, Sheet 1.

(d) Including the advantages of load diversity.

SUMMARY OF SENSITIVITY ANALYSIS
LIFE-CYCLE COSTS AND BENEFITS (a)
INCLUDING SUSITNA IMPACT (b)

	Capital Costs	Life-Cycle Costs (c)	Life-Cycle Benefits: Economy Interchange	Life-Cycle Benefits: Reserve Sharing (d)	Life-Cycle Benefits: Total	Ratio of Benefits To Costs
Plan 1A - 138 kV						
Base Case	56.8	71.4	130.9	11.3	142.2	2.0
Alternate Cases						
A. Load Growth						
1. High			151.1	18.8	169.9	2.4
2. Low			110.3	4.6	114.9	1.6
B. Future Power Sources						
1. Excess Military Generation			108.5	9.9	118.4	1.7
2. Bradley Lake Hydro			134.9	8.4	143.3	2.0
3. Bradley Lake & Military Generation			112.0	7.0	119.0	1.7
C. Coal Fuel in New Power Plants			130.9	101.1	232.0	3.3
D. Alternate Fuel in the Fairbanks Area						
1. North Slope Gas in Fairbanks			58.4	11.3	69.7	1.0
2. LNG in Fairbanks			100.6	11.3	111.9	1.6
Plan 1B - 138 kV						
Base Case	99.5	46.8	132.5	11.3	143.8	3.1
Alternative Cases						
A. Load Growth						
1. High			153.5	18.8	172.3	3.7
2. Low			111.3	4.6	115.9	2.5
B. Future Power Sources						
1. Excess Military Generation			109.8	9.9	119.7	2.6
2. Bradley Lake Hydro			136.6	8.4	145.0	3.1
3. Bradley Lake & Military Generation			113.3	7.0	120.3	2.6
C. Coal Fuel in New Power Plants			132.6	101.1	233.7	5.0
D. Alternate Fuel in the Fairbanks Area						
1. North Slope Gas in Fairbanks			60.0	11.3	71.3	1.5
2. LNG in Fairbanks			102.2	11.3	113.5	2.4

(a) Present worth of additional annual expenses and benefits during the period 1984 to 1993, inclusive, assuming that in 1994 the tie-line facilities are either retired or rededicated to the Susitna Project, and that costs and benefits after 1993 are therefore irrelevant to this analysis.

(b) Assuming the Susitna Project and associated transmission facilities are placed in service in 1994, and that these facilities serve Anchorage and Fairbanks in parallel.

(c) Total life-cycle cost from Exhibit 9, Sheet 2.

(d) Including the advantages of load diversity.

CAPITAL COSTS FOR DISTRIBUTION FACILITIES (a)

	2000 kVA Distribution Substation (b) - 3Ø				Potential Transformer Distribution Power Supply (b) - 1Ø			
	With Voltage Reg.		W/O Voltage Reg.		50 kVA		100 kVA	
	$	$/kVA	$	$/kVA	$	$/kVA	$	$/kVA
138 kV	615,000	310	557,000	280	94,000	1,880	100,000	1,000
230 kV	906,000	455	847,000	425	172,000	3,440	180,000	1,800
345 kV	1,235,000	620	1,176,000	590	(c)		(c)	

Distribution System Facilities Required With Substation

7.2/12.47Y kV distribution line from substation, per 1000 ft. $11,000

Distribution System Facilities Required With Potential Transformer

240/120 V distribution circuit from pt, per 1000 ft. $ 5,000

Notes

(a) Including 20 percent contingencies, 10 percent engineering, supervision and overheads, 5 percent construction management, 5 percent AFUDC, and 12 percent per year escalation over a 3-year period from January 1981 to January 1984.
(b) Does not include cost of distribution system beyond substation or potential transformer.
(c) Equipment not available at 345 kV.

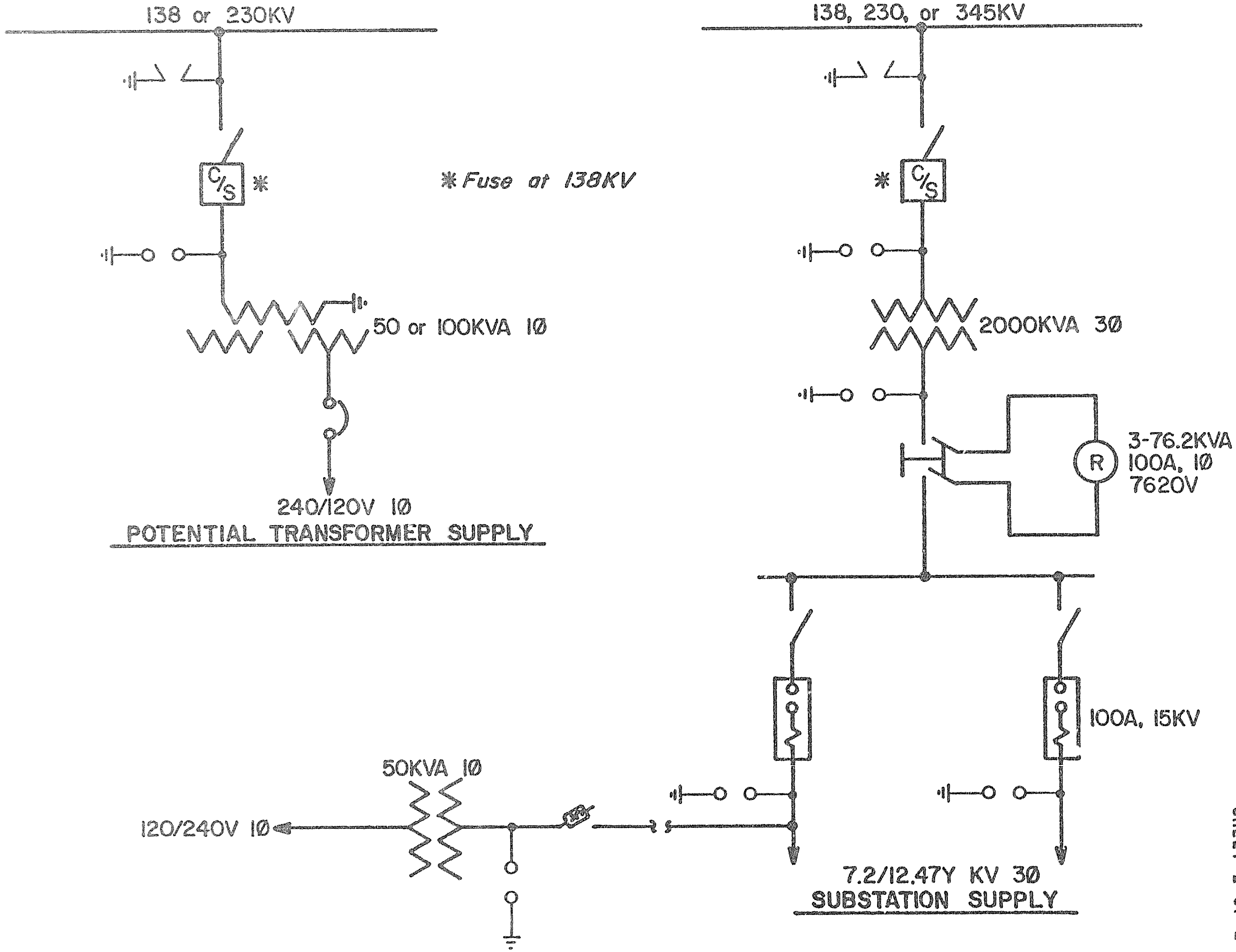


EXHIBIT 11
SHEET 2 OF 2

DISTRIBUTION POWER SUPPLY

APPENDIX A

SENSITIVITY ANALYSIS
OF VARIATIONS IN THE RATE OF LOAD GROWTH

LOAD GROWTH

The base case analysis which is presented in detail on Exhibits 1 through 9 is based on the Acres/ISER medium forecast. Acres/ISER also provided low and high energy forecasts corresponding to minimum and maximum economic growth expectancies for the Railbelt region. Peak demand forecasts for both the low and high forecasts were prepared in the same manner as in the base case of the medium forecast. These are summarized in Exhibit A1 following.

On the basis of these new forecasts, the life-cycle benefits and the benefit/cost ratios for Plans 1A and 1B were calculated in the same manner as in the base case. The results of those calculations are summarized on Exhibit A2. As shown, the higher rate of economic growth results in even greater benefits than calculated for the base case conditions. A low rate of economic growth diminishes the benefits of the tie-line. Within the range of expected economic growth, the life-cycle benefits exceed the costs for all conditions studied.

PROJECTED ANNUAL PEAK DEMANDS (MW)[a]

(LOW AND HIGH LOAD FORECASTS)

	Low Load			High Load		
Year	Anchorage System	Fairbanks System	Total Non-Coinc.	Anchorage System	Fairbanks System	Total Non-Coinc.
1984	493	146	639	566	174	740
1985	510	156	666	606	194	800
1986	521	158	679	630	201	831
1987	532	161	693	655	208	863
1988	544	163	707	681	215	896
1989	556	165	721	708	223	931
1990	569	168	737	736	230	966
1991	593	175	768	783	244	1027
1992	619	182	801	834	259	1093
1993	645	189	834	888	275	1163
1994	673	197	870	944	292	1236
1995	702	205	907	1005	309	1314

(a) Based on the Acres/ISER Low and High Energy Forecasts.

EXHIBIT A1

EXHIBIT A2

LIFE-CYCLE BENEFITS AND BENEFIT/COST RATIOS
LOAD GROWTH SENSITIVITY ANALYSIS

	Life-Cycle Benefits Excluding Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
High load growth	263.1	52.8	315.9
Medium load growth (Base Case)	229.3	45.3	274.6
Low load growth	193.3	37.8	231.1
Plan 1B			
High load growth	267.4	52.8	320.2
Medium load growth (Base Case)	232.2	45.3	277.5
Low load growth	195.2	37.8	233.0

	Life-Cycle Benefits Including Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
High load growth	151.1	18.8	169.9
Medium load growth (Base Case)	130.9	11.3	142.2
Low load growth	110.3	4.6	114.9
Plan 1B			
High load growth	153.5	18.8	172.3
Medium load growth (Base Case)	132.5	11.3	143.8
Low load growth	111.3	4.6	115.9

	Benefit/Cost Ratios	
	Excluding Susitna	Including Susitna
Plan 1A		
High load growth	3.4	2.4
Medium load growth (Base Case)	3.0	2.0
Low load growth	2.5	1.6
Plan 1B		
High load growth	2.0	3.7
Medium load growth (Base Case)	1.7	3.1
Low load growth	1.5	2.5

APPENDIX B

SENSITIVITY ANALYSIS

CONSIDERING ADDITIONAL FUTURE POWER SOURCES

FUTURE POWER SOURCES

This analysis considers possible future power sources in the pre-Susitna period, in addition to the existing facilities included in the base case. These power sources are:

A. Military generation (10 MW) in the Fairbanks area, and

B. Bradley Lake Hydro Project (90 MW) in the Anchorage area.

The impact of including these two possible power sources on the intertie benefits was analyzed individually as well as collectively, as outlined in the following discussion.

Military Generation

Recently passed legislation permits federal military installations to sell excess electrical generating capacity to the local utilities. The excess capacity is estimated at 5 MW at Fort Wainwright and 5 MW at Eielson Air Force Base. Both military bases are connected to the Golden Valley Electric Association transmission system. This generating capacity is coal-fired and affects both the economy energy and the reserve requirements.

The life-cycle benefits and the benefit/cost ratios are summarized on Exhibit B1.

Bradley Lake Hydro Project

The Bradley Lake Hydro Project is located near the northeast end of Kachemak Bay in the Kenai Peninsula. Two units of 45 MW each are planned for installation by mid-1988. The annual plant factor is estimated to be 40 percent.

The amount of generating capability that these units can supply to the Anchorage area will depend upon the future addition of transmission capacity between the Kenai Peninsula and Anchorage. For this analysis, it is assumed that enough transmission capacity is provided to permit all of the Bradley Lake generation in excess of the load in the Kenai Peninsula to be sent to the Anchorage area.

The life-cycle benefits and benefit/cost ratios are summarized on Exhibit B2.

Bradley Lake Hydro Project and Military Generation

This scenario investigates the impact of both the Bradley Lake Hydro Project (90 MW) and the utilization of excess military generation (10 MW) in the Fairbanks area.

The results of the life-cycle cost and benefit analysis are presented on Exhibit B3.

CONCLUSIONS

Review of Exhibits B1 through B3 leads to the following conclusions:

1. The utilization of excess military generation in the Fairbanks area reduces both the economy energy and reserve sharing. This reduces the benefits afforded by the tie-line.

2. The Bradley Lake Hydro Project reduces the reserve requirements of the Anchorage area but increases the ability of the Anchorage area to supply economy energy to Fairbanks. The net result is a slight increase in the benefits provided by the intertie.

3. The analysis with both excess military generation and the Bradley Lake Hydro Project results in a net reduction in benefits of the tie-line.

In all cases, the life-cycle benefits exceed the costs.

LIFE-CYCLE BENEFITS AND BENEFIT/COST RATIOS
MILITARY GENERATION IN FAIRBANKS SENSITIVITY ANALYSIS

	Life-Cycle Benefits Excluding Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
Base case	229.3	45.3	274.5
With military generation	190.2	43.8	234.0
Plan 1B			
Base case	232.2	45.3	277.5
With military generation	192.5	43.8	236.3

	Life-Cycle Benefits Including Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
Base case	130.9	11.3	142.2
With military generation	108.5	9.9	118.4
Plan 1B			
Base case	132.5	11.3	143.8
With military generation	109.8	9.9	119.7

	Benefit/Cost Ratios	
	Excluding Susitna	Including Susinta
Plan 1A		
Base case	3.0	2.0
With military generation	2.5	1.7
Plan 1B		
Base case	1.7	3.1
With military generation	1.5	2.6

LIFE-CYCLE BENEFITS AND BENEFIT/COST RATIOS
BRADLEY LAKE HYDRO SENSITIVITY ANALYSIS

	Life-Cycle Benefits Excluding Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
Base case	229.3	45.3	274.6
Bradley Lake hydro	236.6	42.4	279.0
Plan 1B			
Base case	232.2	45.3	277.5
Bradley Lake hydro	239.6	42.4	282.0

	Life-Cycle Benefits Including Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
Base case	130.9	11.3	142.2
Bradley Lake hydro	134.9	8.4	143.3
Plan 1B			
Base case	132.5	11.3	143.8
Bradley Lake hydro	136.6	8.4	145.0

	Benefit/Cost Ratios	
	Excluding Susitna	Including Susitna
Plan 1A		
Base case	3.0	2.0
Bradley Lake hydro	3.0	2.0
Plan 1B		
Base case	1.7	3.1
Bradley Lake hydro	1.8	3.1

EXHIBIT B3

LIFE-CYCLE BENEFITS AND BENEFIT/COST RATIOS
BRADLEY LAKE HYDRO AND EXCESS
MILITARY GENERATION SENSITIVITY ANALYSIS

	Life-Cycle Benefits Excluding Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
Base case	229.3	45.3	274.6
Bradley Lake hydro and military generation	196.7	40.9	237.6
Plan 1B			
Base case	232.2	45.3	277.5
Bradley Lake hydro and military generation	199.0	40.9	239.9

	Life-Cycle Benefits Including Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
Base case	130.9	11.3	142.2
Bradley Lake hydro and military generation	112.0	7.0	119.0
Plan 1B			
Base case	132.5	11.3	143.8
Bradley Lake hydro and military generation	113.3	7.0	120.3

	Benefit/Cost Ratios	
	Excluding Susitna	Including Susitna
Plan 1A		
Base case	3.0	2.0
Bradley Lake hydro and military generation	2.6	1.7
Plan 1B		
Base case	1.7	3.1
Bradley Lake hydro and military generation	1.5	2.6

APPENDIX C

SENSITIVITY ANALYSIS
OF RESERVE SHARING BENEFITS
ASSUMING ALL FUTURE UNITS ARE
COAL-FIRED STEAM TURBINE-GENERATORS

COAL FUEL IN NEW POWER PLANTS

In the base case it was assumed that future generating capacity would be provided by gas or oil-fired combustion turbines. However, the 1978 Federal Fuel Use Act discourages the future installation of gas or oil-fired units. In view of possible strict implementation of this Act, this scenario considers the impact of more costly generation additions in the Railbelt area, in the form of coal-fired generation.

The following table compares the cost of a 60 MW gas or oil-fired combustion turbine as used in the base case with that of a 90 MW coal-fired steam turbine considered under this scenerio.

	60 MW Gas/Oil Combustion Turbine	90 MW Coal Steam Turbine
Capital cost	$278/KW	$2493/kW
Credit per kW-year	$19.46	$174.51

The life-cycle benefits and the benefit/cost ratios are given on Exhibit C1. It can be seen from these results that because of considerably higher costs of new coal-fired generation, the reserve sharing benefits are almost nine times more than those found in the base case. Benefit/cost ratios are likewise substantially greater than in the base case.

EXHIBIT C1

LIFE-CYCLE BENEFITS AND BENEFIT/COST RATIOS
COAL FUEL IN NEW POWER PLANTS SENSITIVITY ANALYSIS

	Life-Cycle Benefits Excluding Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
Base case (Combustion turbine)	229.3	45.3	274.6
Coal-fired steam turbine	229.3	406.3	635.6
Plan 1B			
Base case (Combustion turbine)	232.2	45.3	277.5
Coal-fired steam turbine	232.2	406.3	638.5

	Life-Cycle Benefits Including Susitna Impact (Millions of Dollars)		
	Economy Interchange	Reserve Sharing	Total
Plan 1A			
Base case (Combustion turbine)	130.9	11.3	142.2
Coal-fired steam turbine	130.9	101.1	232.0
Plan 1B			
Base case (Combustion turbine)	132.5	11.3	143.8
Coal-fired steam turbine	132.5	101.1	233.6

	Benefit/Cost Ratios	
	Excluding Susitna	Including Susitna
Plan 1A		
Base case (Combustion turbine)	3.0	2.0
Coal-fired steam turbine	6.9	3.3
Plan 1B		
Base case (Combustion turbine)	1.7	3.1
Coal-fired steam turbine	4.0	5.0

APPENDIX D

SENSITIVITY ANALYSIS
OF ALTERNATIVE FUELS IN THE FAIRBANKS AREA

ALTERNATIVE FUELS IN THE FAIRBANKS AREA

The opportunity to export economy energy from the Anchorage area to the Fairbanks area exists because of the difference in the cost of natural gas in Anchorage and oil in Fairbanks. If natural gas was made available in Fairbanks, the economy energy benefits would be affected. Two viable methods of supplying natural gas to Fairbanks were suggested. They are:

1. North Slope gas via pipeline to Fairbanks.

2. Cook Inlet gas via LNG railcar to Fairbanks.

This scenario deals with the economic analysis of these two possibilities.

North Slope Gas via Pipeline to Fairbanks

A study to evaluate electric power alternatives in the Railbelt area is presently being performed by Battelle Pacific Northwest Laboratories. Analysis of natural gas supplies in Alaska is a part of this study. A potential supply of natural gas to the Fairbanks area is the delivery of North Slope gas via pipeline. The proposed pipeline could be in service by 1987. The price of the North Slope gas delivered to Fairbanks is estimated to range from $5.15 to $6.84 per million BTU [(1)]. This is a 1986 price and includes escalation.

(1) Provided by Battelle Pacific Northwest Laboratories.

To analyze the impact of natural gas supplies in Fairbanks on the economy energy benefits, it was assumed that (1) North Slope natural gas would be available for electric power generation in Fairbanks at the 1986 price of $5.15 per million BTU, and (2) existing oil-fired generating capacity would be converted to natural gas. Costs to deliver the gas to the power plant and costs to convert existing power plants to burn natural gas were neglected in this analysis.

To be consistent with the technique used in the base case, the $5.15 price of natural gas was adjusted to a 1984 level of $4.29 and then escalated for real price increases to give the values shown in the following table:

	Fairbanks Fuel Price (Dollars Per Million BTU)	
Year	Oil	Gas
1984	7.48	-
1985	7.73	-
1986	7.97	-
1987	-	4.85
1988	-	5.06
1989	-	5.29
1990	-	5.52
1991	-	5.69
1992	-	5.86
1993	-	6.03

The availability of gas in Fairbanks reduces the cost differential for fuel between Anchorage and Fairbanks, but does not eliminate the economy energy benefits. These benefits and the benefit/cost ratios are summarized on Exhibit D1.

Cook Inlet Gas via LNG Railcar to Fairbanks

Under this scenario, it is assumed that Alaska Gas and Service Company supplies LNG to the Fairbanks area via railcars. The price of LNG delivered in Fairbanks was assumed to equal 85 percent of the cost of the distillate fuel now used for power generation. This price structure was provided by the Alaska Gas and Service Company.

The benefits, and benefit-to-cost ratios are presented on Exhibit D2.

CONCLUSIONS

The availability of "low priced" natural gas in Fairbanks as a fuel for power generation substantially reduces the economy energy benefits of the transmission intertie as demonstrated by Exhibits D1 and D2. If natural gas can be supplied to Fairbanks by 1987, the feasibility of the tie-line would be questionable.

LIFE-CYCLE BENEFITS AND BENEFIT/COST RATIOS
NORTH SLOPE GAS IN FAIRBANKS SENSITIVITY ANALYSIS

	Life-Cycle Benefits Excluding Susitna Impact (Millions of Dollars)		
	Economy	Reserve	Total
Plan 1A			
Base Case	229.3	45.3	274.6
North Slope Gas in Fairbanks	99.8	45.3	145.1
Plan 1B			
Base Case	232.2	45.3	277.5
North Slope Gas in Fairbanks	102.5	45.3	147.8

	Life-Cycle Benefits Including Susitna Impact (Millions of Dollars)		
	Economy	Reserve	Total
Plan 1A			
Base Case	130.9	11.3	142.2
North Slope Gas in Fairbanks	58.4	11.3	69.7
Plan 1B			
Base Case	132.5	11.3	143.8
North Slope Gas in Fairbanks	60.0	11.3	71.3

	Benefit/Cost Ratios	
	Excluding Susitna	Including Susitna
Plan 1A		
Base Case	3.0	2.0
North Slope Gas in Fairbanks	1.6	1.0
Plan 1B		
Base Case	1.7	3.1
North Slope Gas in Fairbanks	0.9	1.5

EXHIBIT E2

LIFE-CYCLE BENEFITS AND BENEFIT/COST RATIOS
LNG GAS IN FAIRBANKS SENSITIVITY ANALYSIS

	Life-Cycle Benefits Excluding Susitna Impact (Millions of Dollars)		
	Economy	Reserve	Total
Plan 1A			
Base Case	229.3	45.3	274.6
LNG Gas in Fairbanks	176.0	45.3	221.3
Plan 1B			
Base Case	232.2	45.3	277.5
LNG Gas in Fairbanks	178.8	45.3	224.1

	Life-Cycle Benefits Including Susitna Impact (Millions of Dollars)		
	Economy	Reserve	Total
Plan 1A			
Base Case	130.9	11.3	142.2
LNG Gas in Fairbanks	100.6	11.3	111.9
Plan 1B			
Base Case	132.5	11.3	143.8
LNG Gas in Fairbanks	102.2	11.3	113.5

	Benefit/Cost Ratios	
	Excluding Susitna	Including Susitna
Plan 1A		
Base Case	3.0	2.0
LNG Gas in Fairbanks	2.4	1.6
Plan 1B		
Base Case	1.7	3.1
LNG Gas in Fairbanks	1.4	2.4